Technology Collaboration Programme by iea

IEAGHG

Managing the transition of depleted oil and gas fields to CO2 storage

Technical Report 2024-05
August 2024

IEA Greenhouse Gas R&D Programme

About the IEA Greenhouse Gas R&D Programme

Leading the way to net zero with advanced CCS research. IEAGHG are at the forefront of cutting-edge carbon, capture and storage (CCS) research. We advance technology that reduces carbon emissions and accelerates the deployment of CCS projects by improving processes, reducing costs, and overcoming barriers. Our authoritative research is peer-reviewed and widely used by governments and industry worldwide. As CCS technology specialists, we regularly input to organisations such as the IPCC and UNFCCC, contributing to the global net-zero transition.

About the International Energy Agency

The International Energy Agency (IEA), an autonomous agency, was established in November 1974. Its primary mandate is twofold: to promote energy security amongst its member countries through collective response to physical disruptions in oil supply, and provide authoritative research and analysis on ways to ensure reliable, affordable and clean energy. The IEA created Technology Collaboration Programmes (TCPs) to further facilitate international collaboration on energy related topics.

CONTACT DETAILS

Tel: +44 (0)1242 802911
E-mail: mail@ieaghg.org
Internet: www.ieaghg.org

Address: IEAGHG, Pure Offices,
Cheltenham Office Park, Hatherley Lane,
Cheltenham, GL51 6SH, UK

Citation

The report should be cited in literature as follows: IEAGHG, "Managing the transition of depleted oil and gas fields to CO2 storage", 2024-05, August 2024, doi.org/10.62849/2024-05

Acknowledgements

This report describes work undertaken by TNO on behalf of IEAGHG. The principal researchers were:

- Filip Neele
- Suzanne Hurter
- Ton Wildenborg
- Marianne van Unen

To ensure the quality and technical integrity of the research undertaken by IEAGHG each study is managed by an appointed IEAGHG manager. The report is also reviewed by a panel of independent technical experts before its release.

The IEAGHG manager for this report was: Nicola Clarke

The expert reviewers for this report were:

- Jorg Aarnes, DNV
- Tarald Svanes, Equinor
- Keith Hester, ENI
- George Koperna, ARI
- Sue Hovorka. BEG

MANAGING THE TRANSITION OF DEPLETED OIL AND GAS FIELDS TO CO_2 STORAGE

(IEA/CON/23/295)

Key Messages

- One of the advantages of utilising depleted fields as a CO_2 storage site includes the wealth of data and experience that have been gained in producing the field for hydrocarbons.
- Several current projects where a depleted field is being developed for CO_2 storage have continuity of the hydrocarbon production operator and subsequent storage operator, thereby transferring data and knowledge – however, in the future, this might not be the case and it will be critical to the success of a project how the data is stored and accessed.
- Re-use of infrastructure, although an attractive proposition, is highly site-specific and nuanced, and can be dependent on factors such as remaining life, timing of handover, conditions of well plugging and abandonments.
- A depleted field with low pressure places specific challenges due to the pressure and temperature differential between the incoming CO_2 and reservoir.
- Cost considerations to developing a depleted field into a CO_2 storage site include the value of recoverable hydrocarbons; maintenance of installations prior to CO_2 storage following production, legacy wells workover costs and monitoring; costs to cover lower injection rates at early stages of operation; heating the injection stream and delayed decommissioning costs.
- The transfer of assets between a hydrocarbon production operator and storage operator is poorly resolved in current regulatory frameworks, and its unclear how decommissioning costs and obligations, which are liable to the hydrocarbon asset owners, will be transferred.
- There are remaining challenges in the US in relinquishing mineral rights for CO_2 storage in current CO_2-enhanced oil recovery (CO_2-EOR) projects should oil prices make the site economic in the future.

Background to the Study

Depleted oil and gas (O&G) fields are often perceived to be strong candidates for CO_2 storage sites and key risks have been overcome as demonstrated by numerous enhanced oil recovery (EOR) and pilot sites. The maturity of many sedimentary basins in terms of oil and gas production, coupled with their proximity to large-scale sources of industrial emissions make these regions attractive as they are well characterised, have infrastructure in place and re-use as CO_2 storage sites could delay or defer the need for decommissioning. Storage resources in hydrocarbon fields are estimated at hundreds of gigatons[1].

A smooth transition from hydrocarbon production to CO_2 storage requires alignment on many levels. For example, to reuse a field and its facilities, arrangements for storage should be initiated before regulatory rules require their removal; maintaining (unused) facilities for extended periods of time is often not feasible or permissible. At a technical level, challenges exist around the evaluation of the suitability of a depleted field for CO_2 storage, when a new

[1] CSRC, CO_2 Storage Resources Catalogue (2022), Cycle 3 report, https://www.ogci.com/wp-content/uploads/2023/04/CSRC_Cycle_3_Main_Report_Final.pdf.

operator needs to assemble data and knowledge about the field and, for example, the wells. The availability of such data, especially when a field has been abandoned, is likely to be highly country-dependent.

Scope of Work

This work aims to provide a careful and thorough exploration of the major issues involved in the transfer of use of a field from hydrocarbon extraction to CO_2 storage, to identify both the pros and cons of such a transition. Exploring the technical, economic, regulatory, and commercial factors that need to be navigated. Case studies are included, and recommendations are made on ways to overcome barriers and maximise opportunities.

The following case studies have been included to demonstrate the challenges and opportunities of preparing a depleted hydrocarbon field for CO_2 storage. The Porthos project in the Netherlands gives insight into the technical implementation of injecting CO_2 from a high-pressure transport line into a low-pressure depleted gas field. The Mid-West Clean Energy project in Australia is described where a storage project is planned in a depleted oil field. A description of the regulatory situation regarding the transition from CO_2-EOR to dedicated storage of CO_2 in North Dakota is provided. Lastly the ROAD project, in the Netherlands, is used to demonstrate some of the complexities of commercial considerations. In addition to the case studies and literature reviews, interviews were held with several storage operators (Wintershall DEA CMS, Eni, and Taqa) to strengthen the conclusions of the report.

Findings of the Study

Technical Aspects

Geological storage in depleted oil and gas fields has a TRL of 5-8, with only a limited number of pilot and demonstration projects utilising oil and gas fields for CO_2 storage. Several storage projects are being developed in depleted fields in Europe, mostly in depleted *gas* fields (Table 1). In the USA, CO_2 storage in depleted oil fields is emerging, as is dedicated storage concomitant with oil production.

Advantages of depleted fields that render them attractive as CO_2 storage sites include: a potential wealth of data from exploration and production periods, including experienced personnel; a proven reservoir and prior containment of the hydrocarbon resource; and the potential to reuse wells and other infrastructure. Disadvantages or challenges include: a reservoir at low pressure following hydrocarbon production, the pressure discrepancy between the arrival of CO_2 at the wellhead and the conditions in the reservoir which need to be bridged to avoid unsafe conditions in the storage system; legacy wells, whereby plugged and abandoned wells may have been abandoned under different regulations and their integrity needs to be validated; the re-use of facilities which may add extra cost than new build; and abandonment.

Table 1: Selected CCS projects developing depleted fields for storage. All projects are operated as joint ventures (JV), it is noted only where considered relevant here.

Project	Production operator	Storage operator
Snøhvit – offshore gas field (NO)	Equinor	Equinor
Goldeneye – offshore gas field (UK)	Shell	Shell
ROAD – offshore gas field (NL)[2]	Taqa	ROAD; Taqa involved in storage project development
Porthos – offshore P18 gas fields (NL)	Taqa	Porthos; Taqa involved in storage project development
Offshore K14 gas field (NL)	NAM, in JV, (NAM is partly Shell owned)	Shell, in JV

[2] Note that the ROAD project has been superseded by the Porthos project

Offshore L4 gas field (NL)	TotalEnergies	TotalEnergies
HyNet – offshore gas fields (UK)	Eni	Eni
Ravenna CCS – offshore gas field (IT)	Eni	Eni, in JV with SNAM
Viking – offshore gas fields (UK)	ConocoPhillips, in JV with BP	Harbour Energy, in JV with BP
Greensand – offshore oil fields (DK)	DONG, in JV with Wintershall DEA	INEOS, in JV, with WDEA
Bifrost – offshore gas fields (DK)	TotalEnergies, in JV	Bifrost JV, with TotalEnergies
Prinos – offshore oil field (GR)	Energean	Energean
Donghae – offshore gas field (South Korea)	KNOC	KNOC
Mid-West Clean Energy Project (Cliff head CO_2 Storage project) offshore oil field (AUS)	Triangle Energy (Operations) Pty Ltd – 50% owned by Pilot Energy Limited	Triangle Energy (Operations) Pty Ltd – 100% owned by Pilot Energy Limited

Injection into depleted hydrocarbon fields

One of the major technical considerations of injection into a depleted O&G field is the contrast in temperature and pressure conditions from the transport system (pipeline or ship) to the wellbore and into the reservoir (low pressure and relatively high temperature). This can cause significant Joule-Thomson cooling with potential impacts such as differential shrinkage and thermal fracturing of the well casing, cement, or reservoir rock system, and if water is present, ice, hydrates and salt may form. This study explores the subject of injection into low-pressure reservoirs and hydrate formation and salt precipitation risks and presents these as additional text boxes.

When the reservoir pressure is low, the operation of wells needs to be performed in two-phase flow. In two-phase injection, the pressure and temperature are coupled at the phase boundary between gas and liquid. Low pressure at the wellhead, downstream of the choke leads to very low temperatures. The temperature of CO_2 in the wells and reservoir is more strongly determined by the phase boundary than by Joules-Thompson cooling. The downhole temperature tends to be determined by either the presence of two-phase conditions or the isenthalpic compression from the wellhead to downhole. The temperature limits for the wellhead are related to material specifications, avoiding freezing of annulus fluids and subsurface safety valve (SSSV) operation; limits for the bottom hole are mainly determined by hydrate formation conditions – these limits define a desirable operating envelope. Several options to avoid low wellhead temperature include: heating the fluid before injection (energy requirements are often prohibitive or unavailable); insulating the pipeline; injecting at a constant rate or the addition of downhole chokes.

At low temperatures water and CO_2 can result in hydrate formation, the pressure and temperature at which they form depends on the gas composition. Impurities in the CO_2 stream will typically move the hydrate formation conditions towards higher temperatures, whereas the salinity of the brine shifts the hydrate phase curve towards lower temperatures. An area of uncertainty in low-temperature injection is to what extent pore space is blocked and injectivity affected. Current reservoir simulators have limited capabilities in modelling the risks of near-well processes on storage operations, especially in regard to hydrate formation. The ACT3-RETURN project[3], a European multidisciplinary project, is currently investigating the effects of strong cooling and phase changes of the CO_2 during injection into depleted O&G reservoirs, and how this affects the near-well region and well integrity.

[3] Cerasi P, Huiskes T, de Borst K, Opedal N. Todorovic J, Wollenweber J, Amro M, Bartosek M, 2022. RETURN – re-use of depleted oil and gas fields for CO_2 sequestration, a new ACT project. Proc. 16th Greenhouse Gas Control Tech Conf (GHGT-16), 11pp.

Depleted field development for storage

High-level risks of loss of containment are the same for depleted fields and saline formations although their magnitude may differ: these include leakage along wells and faults, plume migration and loss of integrity of the caprock. As mentioned, the reuse of a depleted field requires a detailed analysis of the conditions of the CO_2 in the transport system, injection wells and reservoir. The operator will need a detailed understanding of the reservoir and seal rock geomechanics and stress regime and the impact of the pressure moving from initial pressure to depleted pressure and then reflated. The injection of CO_2 may have an impact on adjacent producing fields, prospects or storage prospects depending on pressure communication. The injection of CO_2 for permanent storage is fundamentally different from reversing the flow direction of a hydrocarbon operation, therefore care must be undertaken when using the data from production to assess risks and requires a thorough understanding of the processes involved.

Storage capacity in a depleted field has a relatively high level of certainty, with production volume determining capacity in a closed compartment with little to no aquifer support and economic factors may influence capacity in a field with significant aquifer drive.

The caprock that has contained hydrocarbons over millennia needs to be tested as suitable for sealing CO_2, although the presence of a gas cap can provide assurance. Testing needs to account for the intended final pressure of the reservoir whether it is to be brought back to initial pressure, above hydrostatic, and is a key element in the risk of loss of containment. Any assessments need to account for possible leakage of hydrocarbons and brine in addition to CO_2 and the integrity of legacy wells requires detailed attention.

The potential for re-use of facilities, such as platforms and wells, is an attractive feature of depleted fields but also requires site-specific evaluation. Ideally, evaluation would take place early in the planning stage of decommissioning to avoid additional costs and integrity issues, but this is not guaranteed. The highest risks of loss of containment are associated with wells, both legacy and new-build wells, which represent punctures through the caprock. Some fields have wells that have been plugged and abandoned, e.g., early exploration wells. This may have been done in a period with different regulations than the present day for abandoning wells. If such wells are expected to come into contact with CO_2 during or after injection, revisiting these wells may be required. In an onshore environment, re-entering the wells may be possible; and the cost of locating and re-entering abandoned offshore wells may be high.

The REX-CO_2 project[4] concluded that existing wells will likely require workover and recompletion, with replacement of primary barrier elements before they can be qualified for future reuse. Irretrievable secondary barrier elements that cannot be replaced will require verification through logging and/or other integrity testing. The most common issues are related to incompatible completion, unknown corrosion status, unknown structural integrity when subjected to new expected loads, and in some cases unknown or imperfect status of the cement sheath.

The Align CCUS[5] project proposed the following criteria for evaluating the re-use of existing wells: the location of infrastructure relative to sites with sufficient CO_2 storage capacity; timeline of availability for re-use after cessation of production and before decommissioning;

[4] Koning M, Dudu A, Opedal N, Pawar R, Rycroft L, Williams J, Zikovic V, 2022. Final report REX-CO_2 project, Deliverable 1.7, 42p

[5] Gazendam, Joris, Martha Roggenkamp Deliverable (2020). Legal aspects of reuse of offshore hydrocarbon infrastructure for CCS. ALIGN CCUS Deliverable D3.3.4, 60p.

remaining lifespan of infrastructure; transport capacity/weight capacity; compatibility of materials; integrity of wells; and operating pressure.

A mixed method of approaches regarding the reuse of facilities on projects currently in development shows that a variety of options have been taken:

- Re-use of wells (e.g. Porthos, Cliff Head, Prinos, an option at Bifrost, Acorn),
- Side-track existing wells (e.g. Liverpool Bay), or
- Drill new wells (offshore Netherlands, Greensand, Acorn).
- Repurposing pipes-lines (e.g. Acorn, Bifrost, and Cliff Head) and
- Repurposing platforms (e.g. Porthos, Liverpool Bay, Greensand, Bifrost, Ravennna, and Cliff Head).

A risk-based monitoring plan will aim to: prove the safety and integrity of the storage complex; detect deviations from the expected behaviour of the CO_2 in the subsurface; prove the effectiveness of corrective measures; provide information for site closure and inform stakeholders. Monitoring plans as well as being site-specific need to be sufficient, balancing cost with coverage. Key factors in monitoring depleted fields include the challenge of using seismic to monitor the plume and the need to monitor pressure to keep injection within operational safety limits. Seismic might be used as a last resort to verify migration out of the storage complex. Monitoring pressure can be problematic when conditions in the well and reservoir approach the two-phase region. For example, the down-hole pressure gauge may be located at a distance from the perforations whereas the phase transition may be located between the gauge and reservoir and thus readings will be insensitive to the reservoir pressure.

Monitoring of legacy wells, which pose a leakage risk, is complex and challenging – especially depending on the integrity and status of the barriers - and can be further complicated because of the lower density difference and mixing between CO_2 and hydrocarbons (than CO_2 and water). To ensure containment, pressure might be limited to hydrostatic rather than initial pressure. It is expected that monitoring plans will evolve and become more efficient as experience grows and effectiveness is assessed.

Several aspects of pipeline re-use to consider include pipeline operating conditions, pipeline status (active, inactive) and whether re-use is possible or new construction necessary. This might include a lower inlet pressure in a natural gas pipeline resulting in CO_2 being transported in the gas phase. Another consideration is the risk of over-pressure in offshore pipelines due to the higher density of supercritical CO_2 (than natural gas) and the change in elevation from source to sink. Pipeline age and expected lifetimes are specific and need to be factored in with intended use. Shore crossings can be re-used with existing pipelines but new applications made with new pipelines. DNV has published guidelines on the re-use of infrastructure[6].

CO_2 specifications are pertinent to both depleted fields and saline formations and is a key topic that needs to be resolved, with no consensus among CCS projects on the required purity, with early CCS projects setting their own specifications.

CO_2-EOR is well established as a means of maximising oil recovery, particularly in the US where over 143 projects are in operation, but with less than 20% of the CO_2 supplied from industrial sources. The storage of CO_2 is co-incidental, however up to 50Gt could be stored by current CO_2-EOR projects by 2050 and could be eligible for tax credits. Enhanced gas recovery

[6]DNV, Safely re-using infrastructure for CO_2 transport and storage, 2022, https://www.dnv.com/Publications/safely-re-using-infrastructure-for-co2-transport-and-storage-229979.

(EGR) has been the subject of several pilot studies, but no commercial-scale projects have yet been realised. A possible scenario is to start CO_2 injection during late-stage gas production to increase reservoir pressure and produce some of the residual gas with the cash flow supporting the storage operation. This adds complications and risks, such as handling multiple gas streams, the lifetime of combined storage is likely to be short, and storage and hydrocarbon production activities might be located in different legal entities and income streams might not cross over.

Closure, decommissioning and handover of a CO_2 injection site is regulated by law, in most countries. In the EU, the CCS Directive 2009/31/EC prescribes post-closure and post-handover monitoring periods of 20 and 30 years, respectively. These potentially long post-closure periods of continued responsibility for the storage site represent a challenge to storage developers. There is no experience with the required period for a storage site to reach a state at which both operator and regulator agree that handover of responsibility can be done, nor is there evidence yet suggesting that post-closure and/or post-handover periods are different for depleted fields than for saline formations.

Economic considerations

Re-using depleted hydrocarbon reservoirs may result in the following economic considerations:

- the value of recoverable hydrocarbons in the case where storage operations start before the Cessation of Production (CoP), either where production has ceased or in the case of EOR or EGR whereby CO_2 removal of produced hydrocarbons is necessary);
- investments and operational costs to maintain installations where there is a time gap between CoP and storage;
- facilities required to manage variations in CO_2 supply rates;
- the presence of legacy wells and workover costs for requalification;
- costs to cover lower injection rates required at the early stage of operation in pressure-depleted reservoirs;
- changing the operational window of wells and reservoir as the reservoir pressure increases during the lifetime of the storage project;
- capital and operating cost of heating of the injection stream;
- monitoring of legacy wells;
- and extra expenditure related to delayed decommissioning costs.

Re-use of facilities and infrastructure

An IEAGHG study[7] illustrated the attractiveness of using depleted fields for CO_2 storage in terms of estimating the potential cost benefit of re-using fields and facilities. However, re-use brings challenges, with wells, platforms, and pipelines involving costs to remediate and/or modify. Remaining service life is an important factor and requirements for plugging and abandoning wells have become more stringent over time, so the age of legacy wells is also a factor. Re-use of infrastructure needs to be carefully evaluated and is site-specific. Examples are given from Porthos, HyNet, Viking, Hewett and ACORN.

The timing and nature of a transition are influenced by many factors which the include timing of CoP which has economic consequences and may be market-dependent. Mothballing of infrastructure may be necessary if there is a time gap between CoP and CO_2 storage. Production licences may have terms which delay the CoP unless negotiations can be made to inject CO_2 into the water leg during production. Operators are required to decommission facilities and

[7] IEAGHG, 2022. Criteria for Depleted Reservoirs to be Developed for CO_2 Storage, January 2022.

abandon wells directly after CoP which can limit the opportunity to re-use infrastructure unless the transfer of assets is specified between operators.

Field Data

One of the primary advantages a hydrocarbon field has over a saline reservoir is the rich data sets available for appraisal, including seismic surveys, well data, core, and production history, which could shorten development timelines by 2 to 4 years and reduce costs. The transfer of data and licences is common practice between operators, however, there may be reasons for the reluctance to share data if there are concerns over competition for a storage licence, although many current projects are being developed by the same operator. Of greater concern is the potential loss of data and experience for fields that have been abandoned and there is a significant time lag between redevelopment as a CO_2 storage site, whereby operators and experienced personnel move on or cease to exist.

Table 1 shows a selection of currently developing CO_2 projects using depleted fields for storage. In all cases, gas or oil was produced by a joint venture (JV) and at least one of the production JV partners is in the JV for the storage of CO_2. This ensures the flow of data, knowledge and experience from the production phase to the storage project.

Modelling needs to be fit for purpose and reflect the status of the reservoir given that there may be time since production, requiring updating of models. Static models will need to consider the size of the storage complex vs the production model and the relevant overburden requiring re-interpretation of well data and seismic.

Delay of decommissioning, mothballing and hibernation

Mothballing occurs when operation is stopped and includes safeguarding, cleaning, removal of obsolete equipment and conservation. Hibernation follows where operation costs are reduced to a minimum whilst future plans are agreed upon. Capital expenditure (CAPEX) for an offshore platform would be ~10% of the platform abandonment costs, for a typical scenario in the Dutch offshore mothballing and hibernation would be about 3-5% of the total transport and storage system. The maximum duration of hibernation in one study was ~10 years as the costs of requalifying installations may be too high.

Avoiding decommissioning following production may be another driver to re-use depleted fields, certainly from a business case. This was recognised as a benefit in the ROAD project, although difficult to quantify, although some estimates are ~15% of the total CAPEX.

Regulatory Considerations

This section covers permitting CO_2 storage, safeguarding and handover of field data to the storage operator, current regulations regarding enhanced recovery, re-use of production facilities, and the transfer and mothballing of assets and decommissioning. A database of laws and regulations that support a framework for CCUS development is maintained by the IEA[8] covering North America, the EU, the UK, Norway and Australia.

Permitting

Storage permit applications tread a fine balance between the level of detail the competent authorities wish to see and the detail an operator can provide, it is anticipated that clarity will emerge in industry-recommended practice following the first wave of licences which will then support subsequent projects.

[8] https://www.iea.org/data-and-statistics/data-tools/ccus-legal-and-regulatory-database

Examples of evolving storage permit applications are the ROAD and Porthos projects in the Netherlands, the ROAD project was the first application submitted (2011) under the CCS Directive and was awarded in 2013; Porthos took over after ROAD was cancelled in 2017 and due to changing societal views the government required substantially more analysis, especially on the risk of induced seismicity.

Field Data:

Access to valuable field data and experience, should there be a delay in re-using fields, is a concern. A national data repository is one way to mitigate data loss and would for example respond to the requirements outlined in the EU's Net Zero Industry Act (NZIA). A list of data that should be collected as a minimum should be created, and these data stored as part of the decommissioning process.

Enhanced hydrocarbon production and CO_2 storage

Regulations for conventional CO_2-EOR and pure CO_2 storage are reasonably well developed, whereas this is not the case for transitional combined projects – these are still in development. The working group ISO TC 265 is developing a technical report on the transition from EOR to storage to be published shortly, with a focus on potential technical, policy, and regulatory barriers.

In Europe, enhanced recovery is not explicitly addressed by the EU CCS Directive. Combined enhanced recovery of hydrocarbons and CO_2 storage is expected to be addressed in the updated Guidance Documents (due to be published in 2024), these are non-binding clarifications of the Directive. This may take the form of allowing enhanced recovery if CO_2 storage is the primary goal of the combined activity and the CO_2 stored should exceed the life-cycle emissions of the operations, including the combustion of the incremental production. Clarification and transparency of accounting is still needed. Funding requirements for many streams of funding in the EU prohibit enhanced production and may present a barrier to these projects.

In the US, CO_2-EOR has been ongoing for decades e.g. in the Permian Basin. The type of permit[9] required for CO_2-EOR (class II) and CO_2 storage (class VI) differ and transfer from conventional CO_2-EOR to CO_2-EOR with storage is complicated due to different regulation, ownership and operator mindsets. This is further explained in the case study on the transition from CO_2-EOR to dedicated storage in North Dakota.

Well abandonment

Regulations pertaining to the appropriate abandonment of wells prior to and following CO_2 storage are not mature in many countries. Industry best practices for well decommissioning are emerging[10], but not regulated. Where guidance from authorities is lacking, abandonment of legacy wells is up for interpretation. The UK government is working on a CCS abandonment strategy which accepts a limited amount (ALARP) of leakage through the legacy wells, which could be a useful and practical way forward.

Facilities re-use

Guidelines for the assessment of re-use of hydrocarbon production facilities are yet to be developed in most countries, with the experience from the first wave of projects potentially feeding into such guidelines. Current regulations for the hydrocarbon production operator to

[9] https://www.epa.gov/ghgreporting/subpart-rr-geologic-sequestration-carbon-dioxide

[10] OEUK, 2022. OEUK Well Decommissioning for CO_2 Storage Guidelines https://oeuk.org.uk/product/oeuk-well-decommissioning-for-co2-storage-guidelines/.

remove facilities at the end of production may not consider any future use which might significantly alter the procedure employed. Should there be an asset transfer, payments for assets need to be reimbursed and also for future decommissioning costs, with full access to information for the future storage operator to access. JV partners need to be informed and have to agree to return a production licence or continue as partners in the new project, likewise, a transparent process is necessary should a third party wish to take on a CSS licence. One recommendation to prevent a hydrocarbon operator from blocking a licence would be to annually publish their plans for CO_2 storage for every field suitable for CO_2 storage.

The following priorities for a strategy to promote the reuse of infrastructure have been defined: implement an approach to identify existing infrastructure with re-use potential and aligned integrated planning; deal with the potential time gap between the end of production and start of CO_2 injection including the need for maintenance; and to manage decommissioning liabilities. The Bifrost project has demonstrated the potential to gradually convert the Harald platform from production to injection.

Overview of legislation for re-use in selected countries

Not all countries have clear regulations on the re-use of wells or other infrastructure in CO_2 storage operations, the most advanced are the UK, Norway, Australia, and the US. France, the Netherlands, and Romania do not have specific regulations and standards for CO_2 wells or re-use of wells. Decommissioning is a key challenge, especially pertinent is the consideration of reuse and potential postponement of decommissioning as decommissioning of production infrastructure is often a requirement with a certain timeframe after CoP. The following selected countries have been used to give an overview of legislation on the reuse of fields and infrastructure: France; the Netherlands; Norway; Romania; the UK; and the US with a case study on the Q16-Mass field.

Transfer of assets, decommissioning

Whereas transfer of assets between hydrocarbon operators is generally permitted and specific procedures exist, transfer to a storage operator is an issue poorly resolved in current regulatory frameworks. Table 2 shows the regulatory status for a selection of countries. It's unclear how decommissioning costs and obligations, which are liable to the hydrocarbon asset owners, will be transferred if there is re-use.

Table 2 Regulatory and legal aspects for transitioning to CO_2 storage for selected countries[11]

Country	**France**	**Netherlands**	**Norway**	**Romania**	**UK**	**USA**
Permit/procedure to re-use hydrocarbon well for CO_2 storage	None	Existing	None	None	Existing	Existing
Safety standards for CO_2 storage wells	Unknown	Unknown	Existing	Unknown	Existing	Existing
Permit/procedure for the transfer of permits/assets between hydrocarbon licence holders (related to hydrocarbon operations)	Existing	Existing	Existing	Existing	Existing	Existing
Permit/procedure for transfer of assets (wells) from	None	Proposed	None	None	Proposed	Existing

[11] Dudu, A.C., Wildenborg, T., Pagnier, P., Grimstad, A.A., Kvassnes Rajesh Pawar, A.J.S., & Williams, J., (2021) Comparative analysis of regulatory frameworks, REX-CO_2 D6.2

hydrocarbon operation to storage operation						
Procedure for transfer of CO_2 storage assets and fields to the state	Existing	Existing	Existing	Existing	Existing	Known/varies

Three scenarios of transfer of ownership are defined in the Align CCUS project [5]:

- Storage licence awarded during production.
- Licence awarded directly after production ceases
- CO_2 storage starts several years after CoP.

In the first situation, one party could hold both licences, whereas in the second scenario, it is more likely that different parties hold the production and storage licences. In both situations assets and financial reservations for decommissioning need to be transferred. The third scenario is the most challenging with two possible avenues to resolve issues arising. Firstly, the production licence is extended beyond the end of production and before injection, with approval not to decommission infrastructure during this extension period. Alternatively, an interim operator or 'operator of last resort' could be introduced who is responsible for the maintenance of the installation between the end of production and the start of injection. This requires more extensive legislative action.

ZEP (2022) also identifies three cases for transition with recommendations[12]:

- Operator stops production in the licence area – ideally the operator and partners would report on intentions and the competent authority would decide on liabilities of asset and licence holders and a clear pathway to access information.
- Operator continues and intends to store CO_2 in the current licence area, JV partners are invited to join or resign. In case of competition, a transparent licence-granting process would be required.
- The operator blocks a licence because they have no clear priority in the storage application process. A solution would be to request that production licence holders annually report on both their plans for CO_2 storage and CoP dates.

Clarity on the transfer of liabilities with the handover of assets from the production operator to the storage operator would be very helpful for making contractual agreements, though they might be overruled by private law. Change of ownership of existing infrastructure is permitted in Norway, but the original owner will maintain secondary liability for decommissioning of the infrastructure at ownership change. Transferring ownership of plugged but not abandoned wells requires parties to seek a new license and transfer of liabilities[13]. Operators in the Dutch offshore pose that it needs to be ascertained that no liabilities will be left with the producer (last known operator) after the transfer of the assets to the storage operator. The liability of wells put into hibernation is discussed.

The financial responsibility, e.g. in case of bankruptcy, is covered by insurance. In the North Sea, when the current CO_2 storage operator of an infrastructure cannot fulfil the decommissioning obligations, the competent authorities can impose the obligations on previous owners. This could discourage hydrocarbon operators from considering re-use for CO_2 storage projects, as they could be liable when the CO_2 storage operator fails to meet decommission

[12] ZEP, Zero Emissions Platform, (2022) Experience in developing CO_2 storage under the Directive on the geological storage of carbon dioxide.
[13] Dudu AC, Rycroft L, Muriel T, Grimstad A-A, Pawar R, Williams J, 2020. Report on the assessment of policy, legal and environmental framework in participating countries, REX-CO_2 Deliverable D6.1

obligations. In the US, the current owner is always liable and is expected to be aware of the status of the infrastructure. When the operator is bankrupt or in financial difficulty, then the insurance covers these expenses[14].

Commercial Considerations

Concerning the commercial considerations the study has drawn from the ROAD project as an example. Generally, there is a much lower rate of return for a CCS project than hydrocarbon production, and these returns can be capped when linked to a government subsidy scheme – so greater incentives are required to encourage hydrocarbon operators to get involved. Storage capacity can be viewed as a competitive asset and sharing data might be perceived as risking losing knowledge.

Commercial framework proposed in the ROAD CCS project

The ROAD CCS demonstration project, 2010-2017, reached an advanced development stage. Although it did not progress, it resulted in important lessons for future CCS projects and in particular the use of depleted hydrocarbon reservoirs. In this case, the production operator was not interested in developing CO_2 storage and required a commercial incentive to use their facilities and licence area, requiring the storage licence to be transferred to a storage operator as soon as hydrocarbon production ceased.

The two main contractual parties were: the Maasvlakte CCS Project (MCP), the ROAD legal entity; and the Offshore Group, comprising the Platform Group (the platform owners) and the P18-4 Group (production licence owners and the applicant of the CO_2 storage licence). Note the platform was planned to be shared with ongoing hydrocarbon production and CO_2 storage in different reservoirs.

Cost items identified included:

- Direct costs for construction and decommissioning of the platform modification according to normal industry standards, passed on as a direct charge.
- Common facility costs for operating and maintaining the platform according to the value of the fluid handled. Cost sharing was agreed between production and storage dependent on the number of wells used, and updated as changes occur.
- Risk management costs are handled according to standard industry practice for shared facilities.

With rewards for the Offshore Group which also included:

- The benefit of delaying decommissioning.
- The inclusion of a commercial tariff for keeping the facility available.
- Payment per tonne of CO_2 linked to the CO_2 price.

The report also outlines the five main agreements that were established between the parties (and detailed in Wildenborg et al., 2018) that covered construction, operation, and decommissioning[15].

---

[14] Grimstad, A., Pagnier, P., Pawar, R., Rycroft, L., Wildenborg, T., Pearce J., Williams, J., (2021) Recommendations for Improvement of Legal and Environmental Framework, REX-CO_2 D6.3

[15] Wildenborg, T., Logan Brunner, Andy Read, Filip Neele, Marc Kombrink (2018) Close-Out Report on CO_2 Storage (P18-4 and Q16-Maas) – Rotterdam Opslag en Afvang Demonstratieproject, 100p. https://www.globalccsinstitute.com/wp-content/uploads/2019/09/ROAD-Close-Out-Report-on-CO2-Storage-final.pdf

Residual hydrocarbons

Residual hydrocarbon volume in a reservoir represents a potential commercial value that needs to be agreed on between the production operator and storage operator and its market price can be volatile. These negotiations can be lengthy even if these are subsidiaries of the same company. However, operators planning CO_2 storage projects should ideally organise these activities in a separate legal entity. Costs, risks and benefits are then isolated from hydrocarbon production. In an analysis of types of contracts for integrated CO_2-EOR projects[16], it was shown that an indexed price for CO_2 per tonne (in this case as a % of the oil price) was more attractive than a fixed price and the risk of future variations of the oil price is distributed better between the two companies with optimal contingent decision making on changing the capture rate and injection rate.

Case Studies

Porthos, the Netherlands

Porthos is a collaboration of the Dutch state shareholdings Port of Rotterdam, Gasunie and EBN, where CO_2 from industry in the Port of Rotterdam is transported and stored in depleted gas fields (P18-2 and 18-4) 20 km offshore Rotterdam. Up to 10 collection entry ports will allow for up to 10 Mtpa capacity. Current customers Air Liquid, Air Products, Exxon Mobil and Shell will capture ~2.5 Mtpa for 15 years. Final investment decision (FID) was taken in October 2023 and ongoing work is focussed on permit procedures, technical details, contracting contractors and purchasing system components – with operation in view for 2026. The Netherlands is well suited for CCS with a concentration of emitters close to the coast, depleted hydrocarbon fields at the end of their economic life, and potential for re-use of existing infrastructure and transport options (pipelines and shipping corridors).

Mayor learnings from Porthos include:

- The identification of the main risks for system safety and implementation of measures to ensure CO_2 storage safely.
- Obtaining permits for storage in CO_2-depleted gas reservoirs based on solid technical work to substantiate injection and monitoring plans.
- Successfully matched CO_2 emitters and storage providers.

The case study elaborates on the following areas of concern: the composition of the source stream; the geological field selection; well integrity; proper operating conditions; and monitoring. Operating procedures are carefully planned to mitigate operational risks.

The Mid West Clean Energy Project, Australia

The Mid-West Clean Energy Project (MWCEP), Pilot Energy Ltd, aims to develop an integrated CO_2 storage service (at the Cliff Head oil field) and produce clean ammonia leveraging existing oil and gas infrastructure and renewable energy resources. In the pre-FEED/FEED (front-end engineering & design) stage, CO_2 storage is anticipated to commence in 2026 and blue ammonia production from 2028.

The CO_2 storage formation will be in the Cliff Head oil field which started production in 2007 and has 17 years of operational data and existing assets of pipelines and onshore infrastructure. Onshore, supercritical CO_2 will be transported to Cliff Head, an unmanned offshore platform, via conversion of the existing oil production pipeline to a CO_2 pipeline. CO_2 will be aggregated

[16] Agarwal, A., & Parsons, J. (2011) Commercial Structures for Integrated CCS-EOR projects, Energy Procedia, 4, 5786-5793

onshore at the onshore Arrowsmith Stabilisation Plant (ASP) from multiple third-party sources and MWCEP clean hydrogen & ammonia plant.

Installation of offshore mooring infrastructure for direct offshore liquified CO_2 receipt and injection as well as the export of ammonia is being considered for the Project. CO_2 received via the offshore jettyless terminal will be integrated into, and managed by, the same infrastructure that handles CO_2 which the Project receives from onshore sources.

Pilot plans are to re-purpose legacy wells for either injection, pressure management or plume monitoring. As the existing owner of Cliff Head oil-producing assets and the proponent of the CO_2 storage project, data availability has not been an issue for Pilot. Up to ~100 Mt storage capacity has been identified with up to 5 Mtpa CO_2 injection capacity.

A technical advantage of this project is the extended injection and production history of rate and pressure which has been maintained close to the original reservoir pressure during production with re-injection of produced water. This results in limited changes to the subsurface stress regime, reducing risks of fault re-activation during CO_2 injection.

Pilot has undertaken a review of its oil resources to determine to optimal timing for closure and the planned operational commencement for CO_2 storage reflects this timeframe. The report outlines the regulatory process that this project is undertaking as one of the first Australian projects to test the legislation in Australia, and the commercial model. The business model is still in discussion with both domestic and international customers.

Conclusions and Recommendations

The study presents an analysis of the transition of depleted hydrocarbon fields to storage of CO_2, the challenges identified in this report are summarised below in Table 3 and are not insurmountable to reach FID but could be streamlined to make this type of storage more attractive, more efficient, and less costly.

Many of the challenges identified in the table are expected to be resolved by the operators of the first wave of projects that will build a body of experience and operational evidence that will form industry best practices. This includes the injection of CO_2 from high-pressure transport systems into low-pressure reservoirs, the conversion of production wells or other storage for storage and the definition of suitable and sufficient monitoring systems. Knowledge sharing among CO_2 transport and storage projects will be essential for making full use of the experience gained by early projects and speeding up the development of sufficient storage capacity combined with building up the knowledge of competent authorities (see areas in blue on Table 3) who will have to understand the technical issues underlying the best practices to be able to accept them for example for storage licence applications.

Table 3: Summary of challenges identified in the transition from production to storage in depleted hydrocarbon fields. In the column 'Way forward' coloured fonts indicate the stakeholder group who are expected to take the initiative for resolving the issues is expected: industry (black), governments (blue), or the R&D community (green).

Topic	**Challenge, issue**	**Way forward**
Availability of data from production period for permit application	Availability and accessibility of subsurface data after abandonment of field, or after cessation of production	Set up data repository at country level
	Adapting hydrocarbon production workflows to CO_2 injection	Develop industry best practices
Risk assessment for permit application	Find appropriate level of detail in the analysis of risks, e.g. related to existing wells	Develop industry best practices Define metrics in permit application requirements coherent with scientific and engineering knowledge base
Re-use production facilities	Balance risk profile and requalification of production facilities with cost savings	Develop industry best practices
	Regulations and standards for re-use	Develop policy and regulatory basis for the re-use of production assets for storage adjusted to current decommissioning rules
Design injection scenarios	Manage conditions of CO_2 during injection to minimise operational and containment risks	Develop industry best practices
Set up storage license application	Find appropriate level of detail in license application	Develop industry best practices Define metrics in permit application requirements coherent with scientific and engineering knowledge base
Transport	Define CO_2 specifications for entire CCS chain	Continue knowledge development on the impact of impurities on transport risk level; set industry standard
Monitoring	Set up site specific, adequate monitoring system	Develop industry best practices Define metrics in permit application requirements coherent with scientific and engineering knowledge base
Enhanced hydrocarbon recovery as an initial phase of dedicated storage operations	Approve projects transitioning from conventional CO_2-EOR to CO_2-EOR with storage	Develop policy and regulations to enable combined storage and tail-end production, to support the transition from production to dedicated storage
Mothballing (suspending) production facilities	Liability, responsibility during suspension period	Perform study to investigate cost, risk and scale of probable re-use Governments to step in in specific cases of key infrastructure or facilities

Expert Review

Five experts in their field peer-reviewed this work, all their comments have now been addressed and incorporated into the revised report.

One reviewer felt the report addressed the broad scope of the brief and is a useful read, particularly for those unfamiliar with the specific considerations for depleted field storage.

Another reviewer felt it held some useful updates and summaries of recent work, in particular several case studies and the various summaries of new work on flow assurance, hydrates, and management of very low-pressure reservoirs. The comparison of status on various components of the transition of depleted oil and gas field to CO_2 storage in different jurisdictions are also informative, showing the general immaturity of policy and regulations for handing the transition.

Perhaps too heavily weighted towards the benefits and didn't explore the cons, with a strong focus on Europe and particularly the Netherlands and only limited attention given to emerging countries. The authors have added references to projects in Canada, the USA and Australia and downplayed the focus on the Netherlands.

Assumptions are made that depleted fields have demonstrated geological containment because they have held hydrocarbons, whereas this is not a given and containment will still need to be demonstrated. Updates to the text have been made to reflect these comments.

Discussions on post-closure monitoring and liability handover have been adjusted following feedback from one reviewer.

It was recommended that the chapters on the reuse of facilities be further divided into wells, platforms, subsea equipment and pipelines as the issues are significantly different between these. The structure has been improved, and details related to the type of platform (fixed, floating etc) were considered out of scope.

One reviewer offered a suggested process of work that the authorities might undertake on a hydrocarbon field approaching the end of life to ensure a potential transition to a CO_2 storage site, involving external consultants and the production licence partners. This has partly been acknowledged in Section 2, but some of the recommendations may have implications for competition law and were omitted.

One of the main conclusions that one reviewer took from the report is that EOR could be one of the more attractive options in a smooth transition from production to CO_2 storage. Technically, this could be true but politically and societally in many parts of the world, it is viewed in a very unfavourable light and can act to slow progress in CCS acceptance. If we move along this path, we shall demonstrate that this approach facilitates a more rapid implementation of a CCUS project which, as soon as the transition is complete, will be devoted to geological storage only. Every care should be taken to avoid this approach being seen as advocating for EOR as the real purpose beyond CCUS. Text has been added regarding this point.

The authors have restructured the report and rewritten sections, this had led to a clearer structure and less repetition.

TNO innovation for life

Managing the transition of depleted oil and gas fields to CO_2 storage

Energy & Materials Transition
www.tno.nl
+31 88 866 42 56
info@tno.nl

TNO 2024 R10555 – 28 March 2024

Managing the transition of depleted oil and gas fields to CO2 storage

Author(s)	Filip Neele, Suzanne Hurter, Ton Wildenborg, Marianne van Unen
Classification report	TNO Public
Title	Managing the transition of depleted oil and gas fields to CO2 storage
Number of pages	90 (excl. front and back cover)
Number of appendices	2
Sponsor	IEAGHG
Project number	060.56648

Executive summary

Title	Managing the transition of depleted oil and gas fields to CO_2 storage
Authors :	Filip Neele, Suzanne Hurter, Ton Wildenborg, Marianne van Unen
Date :	28 March 2024
Project nr. :	060.56648
Report nr:	TNO 2024 R10555

Background
CO_2 capture and storage is considered to be an indispensable climate abatement technology. Depleted oil and gas fields are attractive targets for geological CO_2 storage next to storage in saline aquifers. The geological structures kept in place hydrocarbons for hundreds of thousands to millions of years, demonstrating containment of hydrocarbons. The exploration and production phases of a field have generated understanding that can shorten the appraisal of the storage site by several years. Some of the hydrocarbon production infrastructure might be re-used for CO_2 storage. In addition, the CO_2 storage scheme may be optimized to enhance hydrocarbon recovery. Some challenges remain in the uses of depleted oil and gas fields as CO_2 stores.

Objectives
The present study investigates the barriers on the route from the production from hydrocarbon fields to their use as CO_2 stores. A smooth transition will help to make efficient use of the storage capacity represented by depleted hydrocarbon fields. This transition has several levels, each with its specific challenges. At some levels, challenges are related to the nascent character of storage in depleted fields and are likely to be resolved by the first wave of projects, which will together develop best practices. At other levels, notably those of a regulatory and legal nature, removing barriers to a smooth transition may require regulations to be adapted. The challenges can be subdivided into four levels: technical, economic, regulatory and commercial. The analysis is based on an extensive literature review complemented with experience from operators of CO_2 storage in depleted fields via interviews and case studies in Europe, the US and Australia.

Results
A significant number of CO_2 storage projects are being developed in depleted fields, in the North Sea and the Mediterranean, as well as in other parts of the world. The majority of these projects plan to become operational before or around 2030 and prove that their developers are confident that the challenges discussed in this report can be met. Operators in the North Sea realm emphasize that current uncertainties in project development have been incorporated into their projects.

Identified challenges are not prohibitive in reaching financial investment decisions (FID) or subsequent development steps; yet, solving these challenges will streamline the various phases of storage in depleted gas and oil fields and make storage more attractive, more efficient and less costly. Depending on the nature of the challenge, the following actors are in the lead: industry in developing best practices, governments to develop enabling policies and regulations, and the R&D community to solve common knowledge gaps.

Experience and operational evidence acquired during the first wave of storage projects in depleted oil and gas fields will be the basis for industry *best practices* and solve the larger part of the identified issues. Examples of these challenges include the injection of CO_2 from high-pressure transport systems into low-pressure reservoirs, the conversion of production wells (or other facilities) for storage, how to deal with legacy wells and the definition of suitable and sufficient monitoring systems.

R&D activities based on the data collected by the first wave of projects in depleted fields will result in understanding the techno-economics of suspension of facilities in the period between the cessation of production (CoP) and the start of construction of storage facilities and of post-closure monitoring and liability.

Knowledge sharing among CO_2 transport and storage projects is much encouraged as this will be essential for making full use of the experience gained by early projects and speeding up the development of sufficient storage capacity. Of equal importance is building up knowledge of competent authorities, who will have to understand the technical issues underlying the best practices to be able to accept them as the basis for, for example, storage license applications.

Competent authorities[1] may take the lead on the following items:

- *Gas and oil field data repository*: Governments should take the lead in setting up repositories for these data, and develop guidance or rules for data to be transferred.

- *Assessment basis for re-use of production facilities*: The evaluation of the feasibility of re-use of assets will provide the basis for an assessment of the cost involved in re-use and redevelopment of production assets. An assessment of the state of facilities and the feasibility of re-use could be part of the decommissioning of production assets and become part of the data transfer as proposed in the previous point.

- *Enabling combined storage and production*: Although currently not widely in operation, concurrent storage and hydrocarbon production could be an attractive option. To provide clarity, governments should develop policies and regulations regarding the combination of storage and enhanced or tail-end production and the transition from conventional enhanced production to dedicated storage.

- *Liability (and ownership) during suspension of production facilities*: Currently developing storage projects present a mixed image with respect to re-use. On a national scale, studies could be performed to investigate the cost, risk and scale of potential re-use. Governments could step in in specific cases of key infrastructure or facilities, to maintain such facilities during the period between CoP and the start of construction of the injection system.

[1] A person or organisation that has the legal authority, capacity, or power to perform a designated function such as enforce and issue regulations as well as having the force of the law.

Contents

1. Introduction

1.1 The need for CCS

Carbon Capture and Storage (CCS) is one of the key technologies necessary to reduce greenhouse gas emissions to limit the rise of global temperature (IEA 2020) and has been proven to be cost-effective and potentially a significant contributor to reducing and removing CO_2 emissions (ZEP 2022a). For this technology to make a meaningful impact on reversing climate change an estimated 510 Gt of CO_2 needs to be stored from bio-based sources alone in the subsurface across the world by 2100 (Luderer et al. 2018). At the moment 300 Mt have been stored worldwide, with an annual storage rate of about 49 Mtpa (GCCSI 2023). Thus, CO_2 storage sites need to be deployed on a vast scale to meet this storage goal (IEA 2020).

There are various geological storage options for CO_2, among which deep saline formations and depleted hydrocarbon fields have the largest capacity. Deep saline aquifers have likely the greatest potential in terms of CO_2 storage capacity, if this potential can be realized (IEAGHG 2009). However, there is limited geological knowledge about deep saline reservoirs due to the lack of exploration in some regions of the world. The estimated global CO_2 storage capacity of deep saline formations is reported to reach up to more than 10,000 Gt, while storage resources in hydrocarbon fields are estimated at hundreds of gigatonnes (IEAGHG 2009; CSRC 2022). This storage potential in hydrocarbon fields is unevenly spread across the globe (IEAGHG 2009); see Figure 1-1. The potential of Enhanced Oil Recovery (EOR) to sequester CO_2 has been estimated to be of the order of 30 Gt (IEA 2022a). Advanced CO_2-EOR methods, designed to co-optimize both oil recovery and CO_2 sequestration, could sequester even more, in the range of 60 to 240 Gt (IEA 2015). CO_2-EOR has been conducted for about 50 years with over 40 operations, mainly in the USA and Canada (Kearns et al. 2021).

Currently, 75% of captured CO_2 that is injected into subsurface formations is used for enhanced oil recovery (CO_2-EOR) and two thirds of operational storage projects are CO_2-EOR operations (GCCSI 2022). Across the world 41 commercial CCS facilities are in operation of which 12 are dedicated CCS projects and 29 are EOR (GCCSI 2023). Figure 1-2 depicts the distribution of CCS facilities in operation or under construction in 2023. Currently, most capture facilities located in the United States (US) deliver CO_2 to enhanced oil recovery operations (GCCSI 2023). With multiple applications for CO_2 storage ('Class VI' wells) waiting for EPA approval, the US balance may soon move from EOR to storage. Projects worldwide in operation are capturing 49 Mtpa. Across the globe, close to 400 CCS facilities are in various stages of development (GCCSI 2023).

In the Net-Zero emissions scenario of the International Energy Agency (IEA), the role of CCS in reducing emissions increases strongly. The current rate of capture, close to 49 Mtpa (GCCSI 2023), should increase to 1.2 Gtpa by 2030 and 6.2 Gtpa in 2050 (IEA 2023). The CO_2 capture and storage capacity of currently developing projects still falls short of the Net-Zero emissions scenario. On the storage side, depleted hydrocarbon fields may support rapid growth of operational storage capacity, due to their potentially shorter development timelines due to data availability and generally smaller extent of geological formations involved, compared to that of saline formations. However the suitability of each hydrocarbon field storage candidate needs to be ascertained.

The EU has defined clear targets for the contribution of CCS to reach climate goals. The Net Zero Industry Act (NZIA) strives to reach net-zero in the EU by 2050 and CCS is a recognized abatement technology in this Act. Implementation of this Act may create business incentives for the oil and gas industry to invest in CO_2 storage capacity in oil and gas fields and stop production; the NZIA advocates the conversion of depleted hydrocarbon fields. Operators active in the period from 2020 to 2023 will be urged to develop a storage capacity volume which is proportional to their share in hydrocarbon production in the EU. The EC sets a target of establishing operational capacity for storage of 50 Mtpa in 2030 in EU Member States.

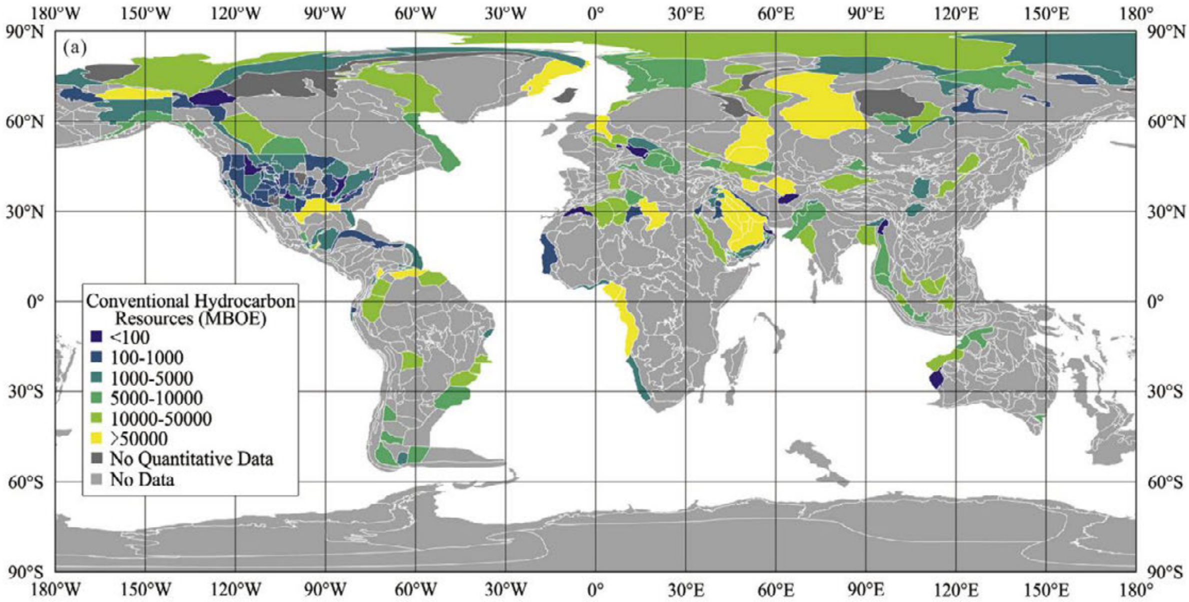

Figure 1-1. Overview of hydrocarbon resources across the world (illustration from Sun et al., 2020).

1.1 Background to this report

The number of CO_2 storage projects has strongly increased in the past few years, and projects developing storage in depleted fields have an increasing share (GCCSI 2023). Especially in NW Europe a large number of depleted oil and gas fields are being redeveloped to become CO_2 stores. This is due to the large number of oil and gas fields that are close to the end of their economic lifetime. The Gulf of Mexico is another example of a region with mature hydrocarbon production where oil and gas fields offer storage capacity in relatively close proximity to large-scale industrial emitters. The production infrastructure offers potential cost savings through re-use; a cost reduction of 20-30% was estimated for storage projects in the UK offshore (OGA 2020).

A smooth transition from production to storage requires alignment on many levels. For example, to enable reuse of a field and facilities, developments for storage should be initiated before regulatory rules require their removal; maintaining (unused) facilities for extended periods of time is often not feasible and may not allowed. At a technical level, challenges exist around the evaluation of suitability of a depleted field for CO_2 storage, when a new operator needs to assemble data and knowledge about the field and, for example, the wells. The availability of such data, especially when a field has been abandoned, is likely to be highly country dependent.

The objective of this study is to investigate the advantages and disadvantages of using oil and gas fields for CO_2 storage and to explore the transition from production to storage. Challenges are explored at various levels, ranging from technical, commercial to regulatory and commercial. Three case studies from currently developing storage projects in depleted (gas) fields from The Netherlands, Australia and USA are included in the report. The study concludes with recommendations for measures to be considered and activities to be undertaken to accelerate and scale up the storage of CO_2 in depleted O&G fields.

1.2 Depleted fields as CO_2 storage reservoirs

In contrast to saline reservoirs, for which often limited data is available, depleted hydrocarbon fields offer extensive reservoir data (reducing geological uncertainty), proven geological containment of hydrocarbons and potentially re-usable infrastructure (IEAGHG 2022). Whether these aspects result in lower cost for storage in depleted fields is highly case dependent (IEAGHG 2022); for each depleted field studies need to be conducted to confirm storage potential and to assess the value of reusing production facilities for storage.

CCS in depleted oil and gas fields may have many advantages, that may lead to an accelerated deployment of CCS projects. Therefore the focus of this study is on CO_2 storage in such fields. Careful screening should be done to determine the suitability of a hydrocarbon field for CO_2 storage. Potential storage sites need to be able to store CO_2 at the desired supply rate for as long as the project requires. Most depleted hydrocarbon fields would tend to have sufficient porosity and permeability for a CO_2 storage project. More importantly, the injection (and final reservoir) pressure needs to be constrained to prevent damage to the caprock and reservoir., The caprock overlying the storage reservoir should be impermeable to CO_2 and prevent it from escaping and moving towards the surface. CO_2 stored as a supercritical or dense fluid phase maximises the amount of stored CO_2 per unit reservoir volume. At the beginning of injection into a depleted hydrocarbon field, pressure will be lower than hydrostatic and injected CO_2 would have low density. In an aquifer, under typical hydrostatic and geothermal conditions, maximum CO_2 density is reached at depths greater than ~800 m. Should a depleted hydrocarbon field be 'filled' with CO_2 up to hydrostatic pressure, then more effective storage would be in fields with top of the reservoir at depths greater than ~800 m. This concept is similar to storage in saline aquifers.

There can be risks associated with the injection and storage of CO_2 in the subsurface. Both saline aquifers and depleted hydrocarbon fields have similar risks but the likelihood and severity for each are markedly different. Technical risks include leakage from wellbores or permeable fractures in the caprock, pressure build-up in the reservoir that could result in caprock fracturing or fault reactivation, and potential contamination of drinking water should the CO_2 or displaced formation water migrate to aquifers suitable or used for this purpose. Storage project design, and monitoring during and after injection aim to minimise these risks. Furthermore, non-technical risks can include that not all potential storage capacity is accessible or commercially viable. This can be due to, for example, factors such as land use constraints and public acceptance. Technical, economic and market analyses are of prime importance.

When considering the risks associated with the storage of CO_2 in the subsurface it is important to also assess the alternative of continuing to release CO_2 into the atmosphere and the need to permanently draw down the current levels of atmospheric CO_2. Hard-to-abate industrial activity will continue to produce greenhouse gas emissions as each industry transitions part or all of existing practices to cleaner alternatives. The risks associated with subsurface storage therefore need to be assessed against the risk of ongoing release of CO_2 into the atmosphere in the absence of CCS.

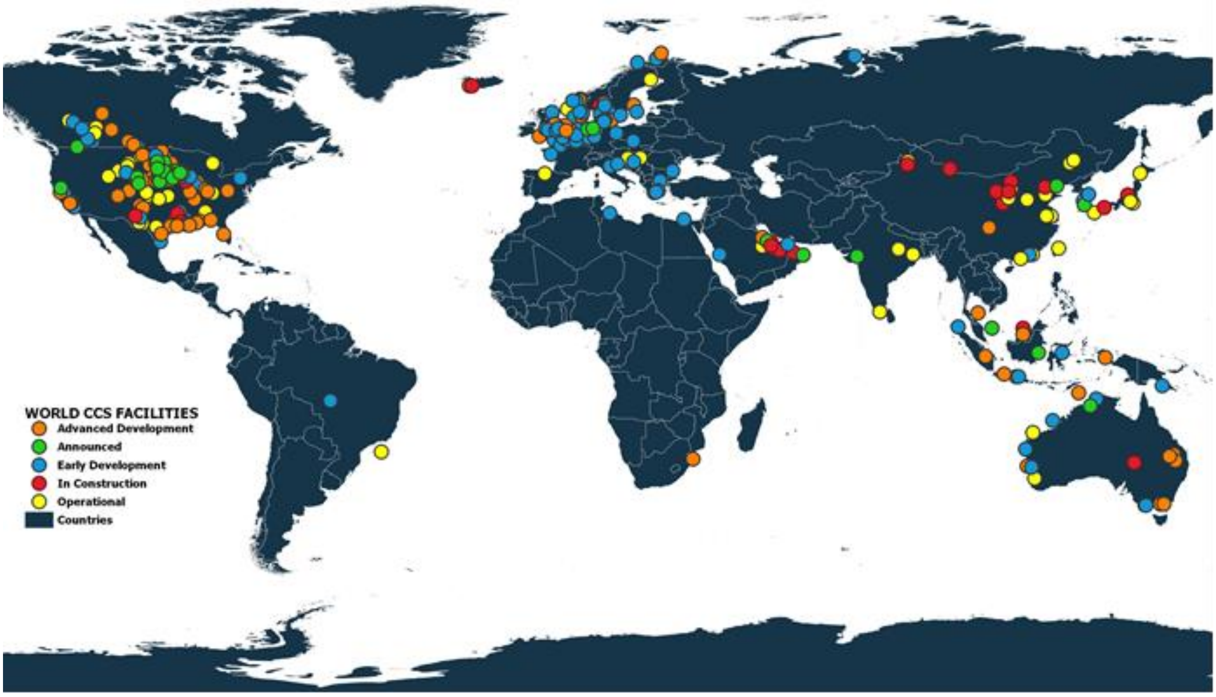

Figure 1-2. World map of CCS facilities in various stages of development (status 2023) (GCCSI, 2023).

1.3 CCS hubs

As in most industries, economies of scale can be obtained by increasing the size of CCS projects (GCCSI 2020; Kearns et al. 2021). This implies that an industrial ecosystem of CCS plants (hubs) associated with multiple customers and suppliers of CCS services can reduce costs and risks, compared to individual plants with a single customer and supplier. CCS hubs aggregate, compress, dehydrate and transport CO_2 from clusters of emitters to storage facilities, enabling better source/sink matching between carbon capture facilities and storage resources, and allow for overall lower cost of compression operations. Additionally, reduced construction times, less time spent in accessing/acquiring land, shorter deployment of facilities, less time spent by staff, and faster operation also bring financial benefits (Kearns et al. 2021). Such hubs can have various economies of scale, mainly influencing the capital costs of compression plants (up to roughly 50MW power) and pipelines (up to roughly 10-15 Mtpa of capacity). It is likely that early transport and storage infrastructure will evolve into systems operating at larger scale, connecting more suppliers to new storage facilities and thus develop into transport and/or storage hubs; not all early transport and/or storage projects may be able to gather the momentum and partners required for a multi-party, large-scale system.

There are oil and gas fields that share facilities and pipelines and may be a different stages of development. As the fields would have different lifetimes, implementing a CO_2 storage project that includes re-use of facilities and pipelines while other fields will longer lifetimes are still requiring them can be an added challenge.

Currently, one of the most advanced hubs in development is the CCS Longship project in the Norwegian North Sea, which includes the Northern Lights Project on transport and storage in saline aquifers (GCCSI, 2020); see also Figure 1-3. Financial support is essential in speeding- and scaling-up CCS incentives (Kearns et al. 2021). Therefore, it is fundamental to have a sufficient value on carbon, because without this there will be no incentive to reduce emissions and to invest in CCS projects (Zapantis et al. 2019).

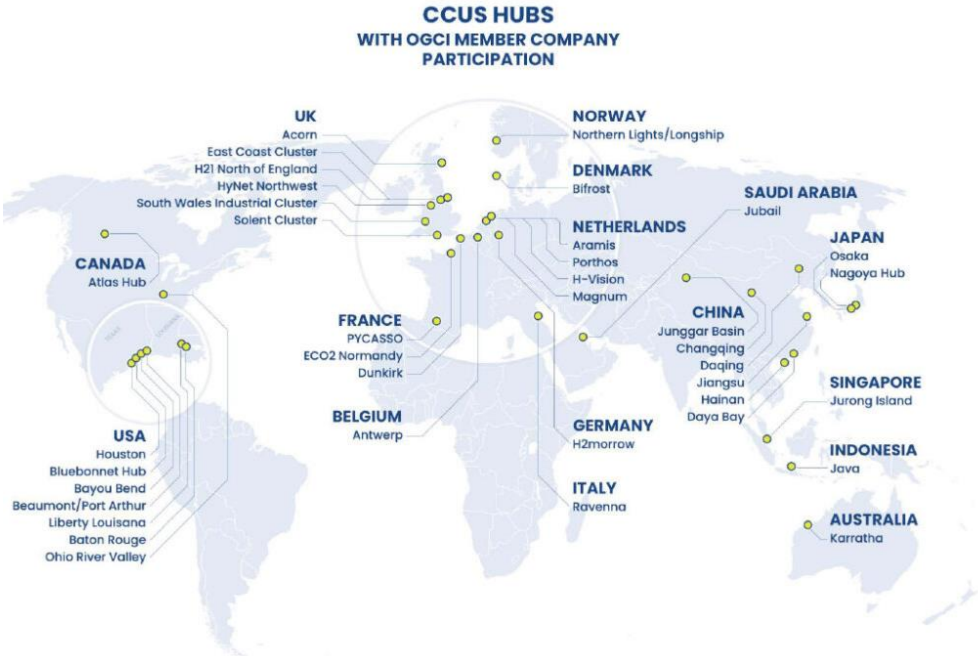

Figure 1-3. CCS hubs and clusters either operating or in development across the world (status 2023) (illustration: CCUS Hub[2]).

1.4 Reading guide

The pros and cons of using oil and gas fields for CO_2 storage, as well as challenges involved, are discussed at various levels. Section 2 addresses technical aspects. These are related to the injection into pressure depleted fields and some numerical examples are included to explain the issue and potential solutions. Reuse of facilities – platforms, well, pipelines – is discussed. Enhanced production of oil and gas is summarised, from a technical point of view. Section 3 discusses economic aspects, notably reuse of facilities and fields. Data availability is a key element in this regard. Regulatory aspects are presented in Section 4, related to reuse, field data availability and permitting. Section 5 uses the case study of the ROAD CCS project (now cancelled) to sketch the complexity of commercial arrangements between production operator and storage operator.

Using the insights gained in Sections 2 through 5, Section 6 summarises conclusions and formulates recommendations for actions to be taken by various stakeholders to support the deployment of oil and gas fields for CO_2 storage.

Appendix 1 presents two case studies: the Porthos CO_2 transport and storage project in The Netherlands, and the Mid-West Clean Energy CCS project in Australia. These case studies were kindly provided by the Porthos and Pilot Energy teams, respectively. Appendix 1 also provides

[2] https://ccushub.ogci.com/ccus-basics/state-of-play/.

a description of the regulatory situation regarding the transition from CO_2-EOR to dedicated storage of CO_2 in North Dakota. This section was provided by EERC. A glossary is included in Appendix 2.

To gather insights from operators developing CO_2 storage projects, and to support some of the conclusions formulated in this report, interviews were held with a number of CO_2 storage developers. We kindly acknowledge Wintershall DEA CMS, Eni and Taqa. Some of their comments have been incorporated into this report, without attribution.

2 Technical Aspects

Geological storage in depleted oil and gas fields has a TRL of 5-8 as actually only a limited number of pilot and demonstration projects have utilized oil and gas fields for CO_2 storage (Kearns et al. 2021). Depleted fields can be attractive storage options, for a number of reasons. Data availability and potential reuse of the production system or parts of it are often mentioned. This section discusses the differences between saline formations and depleted fields and highlights a number of challenges, related to the low or sometimes very low post-production pressure, that project developers may face when redeveloping a hydrocarbon field for storage.

Several storage projects are being developed in depleted fields in Europe, mostly in depleted *gas* fields. In the USA, CO_2 storage in depleted oil fields is emerging, as is dedicated storage concomitant with oil production. This indicates that project developers are confident that they have overcome the challenges; the variety in the solutions in these projects will support other projects aiming to store in depleted fields. On the other hand, the potential of reusing production facilities (wells, pipelines, platforms) may not be as large as expected; also in this respect there is variety among projects in combining reused production facilities with new build elements.

Section 2.1 discusses similarities and differences between saline formations and depleted fields, and their impact on storage project development. Section 2.2 introduces challenges related to injection of CO_2 in pressure-depleted reservoirs. Issues related to project development are the topic of Section 2.3. Although transport of CO_2 is not an issue specific to depleted fields, Section 2.4 offers a brief discussion of pipeline reuse. Enhanced production, of either oil or gas, in combination with CO_2 storage, could be a transition phase between production and dedicated storage (Section 2.5). Finally, section 2.6 discusses decommissioning issues specifically related to depleted fields, which remain to be resolved by the first projects reaching that phase.

2.1 Saline aquifers versus depleted hydrocarbon fields

Current CO_2 storage projects in operation nearly all inject CO_2 into saline formations. The Sleipner project in Norway represents the first large-scale operation, proving the technology and demonstrating that CO_2 can be injected safely and stored securely (e.g. Furre et al. 2017). The Snøhvit project, also in Norway, injects in the water leg of a producing field. In North America, the Quest and Aquistore projects are among the growing number of CO_2 storage projects. Early North American projects combine CO_2 storage with EOR, such as Weyburn (e.g., White 2009), Air Products to Hastings[3] (Saini 2017), Petra Nova to West Ranch (e.g., EPA 2021). Retention of injected CO_2 in EOR fields has been estimated to be as high as 90%, in suitable oil fields with closed-loop recycling systems (Melzer 2012). According to the IEA CCUS projects database, the volumes of CO_2 used in EOR projects worldwide is about 30 Mtpa, which does

[3] https://investors.airproducts.com/node/22341/pdf

not include injection of natural CO_2[4]. Presently this is of the same order as all CO_2 stored globally in saline aquifers (GCCSI 2023). In Western Australia, the Gorgon project is injecting CO_2 since August 2019 (Trupp et al. 2021). Preceding these projects several field pilots were conducted in depleted fields: Lacq/Rousse in France (Thibeau et al. 2013; Total 2015), the Otway project in Australia (Sharma et al. 2011), acid gas injection tests at the Zama oil field in Canada (Smith et al. 2011), and Cranfield (Min et al. 2011) to mention a few.

Saline aquifers in the deep subsurface require extensive data gathering because they are generally unexplored, while depleted hydrocarbon reservoirs offer a storage option, in which storage capacity and injectivity models can make use of the knowledge of the hydrocarbon production history. A depleted field has a proven combination of reservoir formation and seal for hydrocarbons, and the production data provide information about injectivity. Remaining gas may increase storage integrity as the heavier CO_2 tends to stay below the gas cushion (IEAGHG 2022) in the case where no major mixing has occurred or in the very long term as gas migrates upwards relative to injected CO_2. However, also in this case, containment to CO_2 needs to be confirmed in a separate study that addresses caprock integrity, the status of faults and legacy wells.

Another aspect to consider is that hydrocarbon reservoirs may have overlying or underlying saline aquifers or themselves be embedded within aquifers (e.g. fields with strong aquifer drive). These may present opportunities for CO_2 storage with possibly more information gained from the exploration (discovery) and appraisal phase of the hydrocarbon field.

A further advantage of depleted fields is the potential re-use of the production site, wells and pipelines. Depending on the time period between end of production and re-development of a depleted field for CO_2 storage knowledge and experience held by the production staff may be available. It is important to note that potential re-use needs to be carefully examined on a case by case basis. It could happen that extensive (costly) adaptations of the systems may be required such that a new build is more attractive and may further lower risks and offer more flexibility in project design.

Depleted fields have several advantages that render them attractive as potential CO_2 storage sites.

Presence of potentially a wealth of data from exploration and production periods. A depleted field has been produced usually for many years and its behaviour during production gives a good starting point for developing sophisticated subsurface models to assess its response to injection and permanent storage of CO_2. However, using legacy models from the production phase will require careful scrutiny and adaptation to a scenario they were not conceived for. In case the production operator develops and operates the CO_2 storage project, the staff involved in the production period may be available to contribute their experience with the field. However, it is important to keep in mind that some data acquisition may be necessary for confirming or negating the suitability of the field for CCS. See Sections 2.3.1 and 4.1.

Proven reservoir and containment. The total storage volume is generally known with much higher certainty compared to saline aquifer storage sites. The structure (caprock and bounding faults) that has kept hydrocarbons in place is likely to also provide permanent containment for CO_2, although this will need to be confirmed for the specific case of CO_2. See Section 2.3.2.

[4] https://www.iea.org/data-and-statistics/data-product/ccus-projects-database, database updated March 2023.

Re-use of facilities (platforms, pipeline, wells). Should, after careful study (technical and economic), facilities such as platforms, pipelines and wells be found suitable for re-use with minor modifications, significant cost and time reductions for the development of CO_2 storage could be realised compared to new build. In addition, there may be environmental gains as the footprint of the project can be limited. Section 2.3.4 discusses this topic; aspects of cost and regulations can be found in Sections 3 and 4.

Depleted fields also have several disadvantages or challenges to be addressed compared to storing CO_2 in saline aquifers.

Low pressure after production. Some projects have to deal with the low, in some cases very low, reservoir pressure at the start of injection. The ultimate recovery of some of the fields with good reservoir properties may be more than 95%. Without aquifer support, the reservoir pressure at the end of production can be below 10 bar. The pressure gap that exists between conditions at which the CO_2 arrives at the storage site or the wellhead and the conditions in the reservoir must be bridged in a way that avoids unsafe conditions in the storage system. Additionally, each field will have different conditions at the end of production that need to be understood for the design of a storage project. This is discussed further in Section 2.2.

Legacy wells. Wells represent potential pathways for CO_2 to leak from the storage reservoir. P&A'd wells may have been abandoned under different regulations and their integrity in the presence of CO_2 is to be checked and, if necessary, ascertained through a workover keeping in mind that re-entering old wells has also a risk and can be a complex and costly operation The same care is required for the abandonment of production wells that will not or cannot be used in the CO_2 storage project. See Section 2.3.4.

Re-use of facilities (platforms, pipelines, wells). The investigation on the suitability of re-use of facilities is a cost. Some additional modifications of the facilities for CO_2 service may be necessary and could potentially add up to a cost equivalent to new build. New build would allow more flexibility in project design and better performance. Sections 2.3.4, 3 and 4 discuss issues related to re-use.

Abandonment. The removal of production facilities and abandonment of the field falls under the responsibility of the hydrocarbon production operator. Although a transition from production to storage may involve the re-use of some facilities, the field's subsequent use as a CO_2 store may require more extensive or CO_2-specific (potentially more expensive) P&A methods for production wells prior to the start of injection while the removal of platforms will not impact technically the storage project (except for the cost of new platforms) (Section 2.6).

2.2 Injection into depleted hydrocarbon fields

In a pressure depleted reservoir, the CO_2 has to change from the conditions in the surface transport system, which, for pipeline systems, may be transporting CO_2 in dense phase or in gas phase to the low pressure reservoir conditions. The temperature of the CO_2 depends on the ambient conditions; for subsea lines the temperature will be that of the seawater at seafloor, while for an onshore pipeline a wide range is possible depending on seasonal temperature variations. In case the CO_2 is transported by ship, the conditions in the ship will be those of low-pressure (7 bar, -50°C) or of medium-pressure (15 bar, -30°C) (ZEP 2022b) – on-board conditioning using waste heat from the ship engines and further heat exchange with seawater may bring the CO_2 close to ambient conditions prior to arrival at the wellhead.

When CO_2 at high pressure and low temperature flows from a pipeline and well into a low pressure and relatively high temperature reservoir several phenomena may take place. CO_2 expands in the well and near wellbore zone, causing temperatures to decrease significantly due to strong Joule-Thomson cooling. The temperature may reach sub-zero (in °C) downstream of chokes at the wellhead and in the well. Such low temperatures, a risk for the material of the wellhead and well, may lead to freezing of the near well region (with differential shrinkage of the well casing – cement – reservoir rock system) with thermal fracturing and, if water is present, ice and hydrates may form, which may block the well and/or the near-well area in the reservoir. In case of transport by ship, CO_2 will be at a low temperature at the surface, and depending on the conditioning prior to injection, low temperatures may develop in the well during injection. In addition, water in the near wellbore region will be vaporised into the CO_2 injection stream, drying out this region (which would inhibit hydrate formation). As a consequence of the dry-out, salt present in the reservoir brine would precipitate (where salt precipitation is not a risk specific to depleted reservoirs). The consequences of the superposition of these processes is unclear because the kinetics of such processes in porous media are poorly known. The ACT3-RETURN project is conducting research specifically on these processes (Cerasi et al. 2022).

Such risks are both operational (such as hydrate formation causing blockage in the near-well zone) and related to containment (loss of well integrity due to material failure at low, out-of-specifications temperatures, or to thermal fractures in reservoir and caprock). A detailed analysis of the conditions of the CO_2 during injection and the reservoir pressure regime is required to minimise these risks. Text Box 1 explains the conditions of CO_2 during injection into a pressure depleted field and the impact on the operational window of injection wells; Text Box 2 provides some background on hydrate formation and salt precipitation risks.

Text box 1: Injection into low-pressure reservoirs

In aquifers the initial reservoir pressure is roughly equal to the hydrostatic pressure, but in depleted gas fields the pre-injection pressure can be much lower. This can lead to injection from a 100 bar pipeline into a 20 bar (or lower) reservoir. CO_2 is well known for its high Joule-Thomson coefficient. When the pressure is reduced its temperature can decrease by about 1°C per bar. However, a more important reason for cooldown of CO_2 is that operation of wells needs to be performed in two-phase flow when reservoir pressure is low. The presence of gas decreases the hydrostatic pressure gradient and increases the frictional losses during flow down the well. In balance, at low flow rates the wellhead pressure tends to be low and only at high flow rates, it is increased by friction and two-phase conditions can be avoided. In two-phase injection, the pressure and temperature are coupled at the phase boundary between gas and liquid. Low pressure at the wellhead, downstream of the choke, therefore leads to very low temperatures. The temperature of CO_2 in the wells and the reservoir are more strongly determined by the phase boundary than by Joule-Thomson cooling. The downhole temperature tends to be determined by either the presence of two-phase conditions or the isenthalpic compression from wellhead to downhole. At realistic flow rates, the heat exchange with the surroundings tends to be minimal.

Figure 2-1 shows an example of pressure and temperature profiles along a CO_2 injection well, for three reservoirs. Each reservoir is defined by a productivity index (PI), which is related to reservoir permeability and thickness (assuming injection along the entire reservoir thickness). CO_2 conditions at the top of the well (manifold) are 5°C (seawater temperature) and 120 bar (high-pressure pipeline transporting dense-phase CO_2). The lowest PI value, 0.1 (kg/s)/bar, represents reservoirs with low permeability and/or small thickness, leads to high pressure build-up in the well and, consequently, high bottom-hole temperature. In this case, CO_2 in the well is in the liquid phase (third panel in the figure). Much lower bottom-hole pressure is expected for the two other reservoirs of higher PI, 0.5 (kg/s)/bar and 1.0 (kg/s)/bar, respectively. Two-phase conditions exist in the shallower parts of the well (red and blue curves).

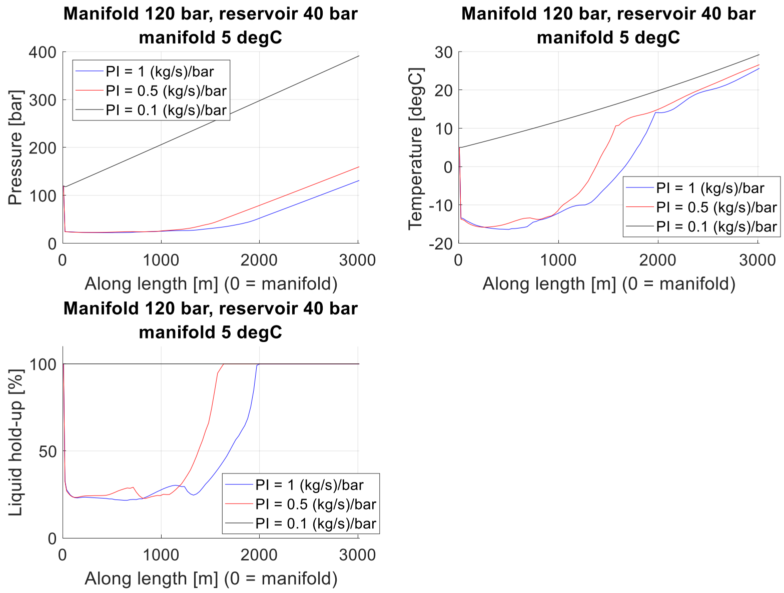

Figure 2-1. Pressure, temperature and liquid-hold-up (liquid fraction) profiles for a CO_2 injection well (3 km deep, pipe ID = 4.8”, manifold pressure 120 bar, reservoir pressure 40 bar, manifold temperature 5°C). The horizontal axis measures depth along the well; the top of the well (manifold) is at zero. Curves are shown for three reservoirs that are defined by their productivity index (PI): low, medium and high injectivity. A PI of 1 (kg/s)/bar corresponds to a good quality (permeability) reservoir.

For the operation, there are limits on flow rate (vibrations, erosion), pressure (pipeline operating pressure, maximum pressure gradient in the near well zone and maximum bottomhole pressure) and temperature, respectively. The temperature limits for the wellhead are related to material specifications, avoiding freezing of annulus fluids and subsurface safety valve (SSSV) operation; limits for the bottomhole are mainly determined by hydrate formation conditions. These limits define a desirable operating envelope, as presented in Figure 2-2. At low manifold temperature, it is hardly possible to choke the flow rate as it will lead to too much cooling downstream of the choke. This narrows the window of injection rates for safe operational conditions. As the injection temperature increases more choking is possible, widening the operational window. The upper limit of the mass flow rate decreases with increasing injection temperature, as the fluid density decreases.

There are several options to avoid low wellhead temperatures.
– Heating up the fluid before injection. This could occur with CO_2 in gas phase, or in liquid phase. The energy consumption of this process is generally prohibitive. In offshore situations, the energy required is usually unavailable. If the distance from the compressor is short, an insulated pipeline may be used to bring warm CO_2 (the heat resulting from compression) to the wellhead – this is the concept deployed by the Porthos project (see Appendix 1).

– Injecting at a constant rate (within a relatively narrow operational window) at which the flow does not need to be choked at the wellhead. This may require buffer storage in order to keep the injection rate within limits. In this case, the injection rate can only be changed meaningfully by changing the number of wells in operation.

– Downhole chokes. In some applications, this could be a viable solution, but it can come at a cost of very low downhole temperatures.

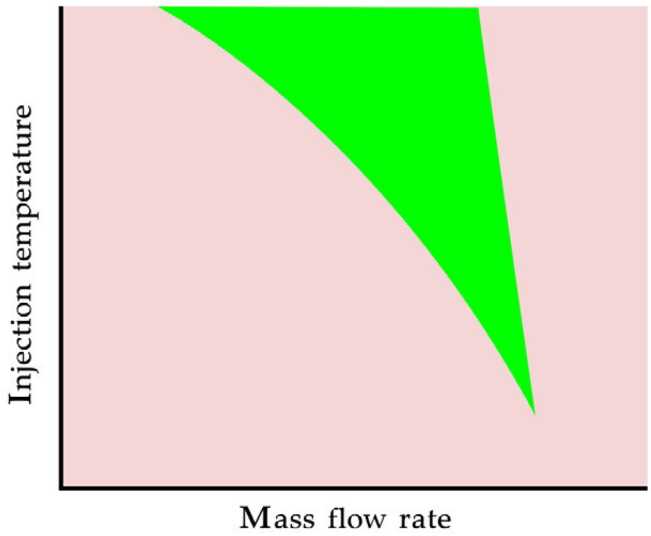

Figure 2-2. Schematic of the operating envelope (green region) of an injection well during injection in the liquid phase. The pink region represents conditions that lead to unsafe conditions in the well. The upper limit of the green region is typically determined by the maximum bottomhole pressure to ensure reservoir integrity and bottomhole temperature above a minimum value, while the lower limit is determined by the wellhead temperature (higher wellhead temperature increases the width of the operational envelope.

The Porthos[5] project is planning to use an approach that first injects warm gas-phase CO_2, using heat from the compression step that is between the onshore collection network and the offshore (insulated) pipeline. When the reservoir pressure has increased sufficiently, to above about 50 bar, the pressure in the pipeline is increased to transport liquid CO_2 and choked before injection. A mixture of gas and dense phase will form in the well and will be injected. Ultimately, for a reservoir pressure above about 70 bar also the injected CO_2 will be in dense phase. The low temperatures that can occur in CO_2 injection wells, such as during brief periods of time during shut-in or start-up of a well, leads to the need for low-temperature equipment. Subsurface safety valves (SSSVs) and elastomer materials that can withstand (short periods of) low or very low temperature are available. Low-temperature SSSVs have been successfully tested for future use in the Porthos project.

Text box 2: hydrate formation
At low temperatures, the presence of both water and CO_2 can lead to the formation of hydrates. Hydrates are a solid structure in which water forms 'cages' that trap gas molecules (Sloan and Koh 2008). The pressure and temperature at which hydrates form depends on the gas composition. Impurities in the CO_2 stream will typically move the hydrate formation conditions towards higher temperatures. Le Goff et al. (2022) provide an overview of experiments to determine the hydrate formation limit (Figure 2-3).

[5] CO2 reduction through storage under the North Sea - Porthos (porthosco2.nl)

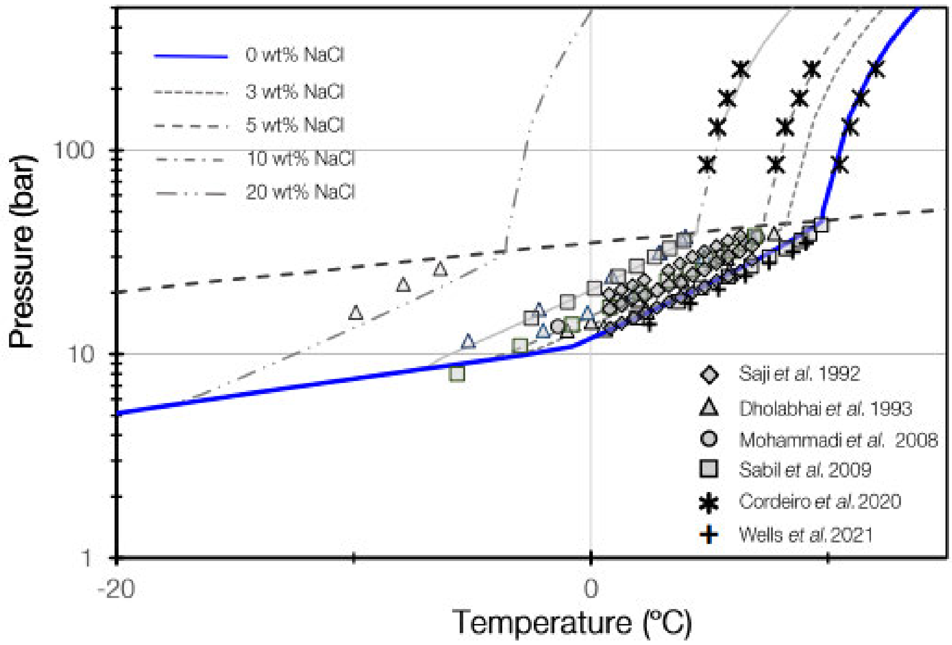

Figure 2-3. Temperature and pressure conditions of hydrate formation. The temperature below which hydrates can form decreases with decreasing pressure and increasing salt concentration of the brine (Le Goff et al. 2022). The area to the left of the blue curve represents the hydrate stability window.

The formation of hydrates in porous media (reservoir rock) is less well understood than that of hydrate formation and dissociation in pipes. Published laboratory and field experiments tend to focus on understanding the formation of gas (methane) hydrates in nature and developing technology to produce them (Rempel and Buffet 1997; Spangenberg et al. 2005; Waite and Spangenberg 2013).

Hydrates can clog a pipeline, a well or the reservoir near the well, depending on where conditions of pressure and temperature for hydrate formation occur. If hydrates were to form, it would occur downstream of the wellhead choke, where in the presence of water both pressure and temperature can become low enough. This is another reason to keep the temperatures at the wellhead sufficiently high.

For hydrate formation in the near-well zone two aspects play a role. If injection takes place in *two-phase conditions*, the injection temperature at the sand face can already be so low that conditions for hydrate formation are reached (i.e., temperatures below about 15°C for pure water). If injection takes place in *single phase conditions*, due to the expansion and Joule-Thomson cooling, the temperature will decrease in the near-well zone. Additionally, several other processes take place at this time. The injected CO_2 vaporises water in the reservoir drying the near-well area. The dry-out will cause some salt precipitation (Miri and Hellevang 2016) but it is expected that for scenarios with only connate water, this will not lead to large blockages. The dry-out may also inhibit hydrate formation by removing water from the system (and, as a result, increasing brine concentration in the remaining water before all water is evaporated). However, the speed of these processes differ such that it is difficult to predict the outcome of the superposition of dry-out, slat precipitation and hydrate formation. In case aquifer ingress is expected during periods when the well is shut in, then sufficient water could be present to form hydrates upon restarting the well.

In porous media, in addition to the gas composition (i.e. impurities in the CO_2 stream), the salinity of the reservoir brine affects hydrate forming conditions by shifting the hydrate phase curve towards lower temperatures (Tamáskovics et al 2023). The porosity (pore size distribution) also influences hydrate formation: small pores inhibit its formation. The combination of reduced pore water activity close to hydrophilic mineral surfaces and the excess internal energy of small crystals confined in pores causes hydrates to form nodules and lenses in shaly rocks and cements in sands (Clennel et al. 1999). If hydrates form, the question remains to what extent pore space is blocked and injectivity could be affected. Microfluidics experiments suggest an incomplete blockage (Le Goff et al. 2022). However, this remains an area of uncertainty for low temperature injection.

In pipelines and wells the combination of free water and CO_2 (including impurities) may not only lead to hydrate formation but also steel corrosion. Therefore, CCS projects require capture facilities to maintain a low water fraction in the CO_2 stream destined for geologic storage.

During the feasibility study for a storage project in a depleted hydrocarbon field, it would be useful to conduct dynamic modelling able to investigate the risks of near well processes on the storage operations especially in the initial stages of injection. Simulations would be useful to show if hydrate forming conditions are attained, if hydrate may cause plugging of the near wellbore, and to test mitigation measures. In addition, the effect of dry-out and salt precipitation should be taken into account. However, current reservoir simulators have limited capabilities for this. Very few are able to simulate temperatures lower than the freezing point of water, and lack the physics around the actual formation and dissipation of hydrates. In the European context, a multidisciplinary project (RETURN[6]) is currently addressing these issues.

The high-capacity Aramis trunkline[7] will be operating at supercritical conditions with a pressure of up to 180 bar. The storage operations will be working with cold (sea temperature) liquid CO_2, resulting in relatively narrow operational windows for the wells (see Text Box 1). As the supply of CO_2 from capture operations may fluctuate (due to maintenance or unexpected down time of the capture facilities), the shipping terminal that is planned close to the Aramis pipeline inlet[8] could be used to stabilise the mass flow rate. Operators in the Dutch offshore indicate that, once the pipeline is operational feeding CO_2 to the first online depleted fields, it will be a challenge to connect new low-pressure fields to the Aramis pipeline when these first fields are already at high pressure. There may be a need for a network manager to organise and safely operate the network and connected wells.

The Goldeneye project proposed using different tapered tubing sizes to meet the challenge of narrow operational windows and to be able to safely inject at different reservoir pressure during the lifetime of the injection period. At the K12-B field, CO_2 could warm up during injection because of the low rates (Hannis et al. 2017; IEAGHG 2017).

Hydrate formation and salt precipitation may clog the near wellbore and are associated with the injection of cold and dry CO_2 into a reservoir in the presence of water which could be at residual water saturation or higher saturation due to the presence of heterogeneity and an active aquifer. More information is provided in Text box 2.

[6] See https://return-act.eu/consortium
[7] https://www.aramis-ccs.com/nl/project
[8] https://co2next.nl/

2.3 Depleted field development for storage

2.3.1 Risk assessment

As with any prospective storage site, the high-level risks of loss of containment are the same for depleted fields and saline formations, namely leakage along wells, leakage along faults, plume migration, loss of integrity of the caprock. Differences between storage in saline formations and depleted fields stem from the relative magnitude of these risks.

Caprock. The impact of pressure variations during production on the caprock integrity should be studied. See Section 2.3.3.

Wells. Depleted fields are likely to have legacy wells, which can be accessible or already P&Ad. Such wells require detailed study, and potentially a workover to render them safe during (and after) CO_2 storage. Wells, and other hydrocarbon production infrastructure may be reused; See Section 2.3.4 for a discussion and an overview of currently developing storage projects in depleted fields.

Faults. Pressure development during the production period is likely to have generated understanding of the nature of faults in the field (if any). A geomechanical analysis is required to study the effect of the pressure change or changes during production on the stability of faults.

Plume migration. The injected CO_2 is to be stored in the hydrocarbon field, preferably within the reservoir volume of the original hydrocarbon accumulation. The CO_2 may preferentially move into certain high-permeability layers and migrate out of the hydrocarbon field. Monitoring is essential to minimise the impact of such an event; see Section 2.3.5.

The text boxes in the previous section illustrate that the reuse of depleted fields for CO_2 storage requires a detailed analysis of the conditions of CO_2 in the transport system, injection wells and reservoir. Further limits arise from geomechanical considerations. The operator will need a detailed understanding of the reservoir and seal rock geomechanics and stress regimes and the impact of the pressure moving from initial pressure to depleted pressure and then re-inflated as a result of injection of CO_2. The temperature and pressure impacts of the injected CO_2 play a key role in this respect. The design of the transport and storage system, and the definition of injection scenarios will be based on the temperature and pressure limits sketched above.

The injection of CO_2 may have an impact on activities, producing fields or prospects in the neighbourhood. The extend of such impact could be derived from pressure data from the production period. Pressure communication with neighbouring storage options is particularly relevant, as it impacts storage capacity.

A challenge in risk assessment of a depleted field for CO_2 storage lies in using the data from the production period for an assessment of risks associated with the injection of CO_2. The challenge exists because the injection of CO_2 for permanent storage is fundamentally different from reversing the flow direction of a hydrocarbon production operation. The re-use of production data, and adapting oil and gas production workflows, data, models and simulators must be done on the basis of a thorough understanding of the processes involved in the response of a subsurface reservoir to the inflow of CO_2. This was also recognised in some of the developing CCS projects (see, e.g., the case study of the Pilot Energy project in Appendix 1).

2.3.2 Capacity and Injectivity

Storage capacity in a depleted field has relatively high level of certainty. A gas reservoir in a closed compartment with little or no aquifer support, the capacity is mostly determined by the produced volume. For a gas field with significant aquifer drive, the capacity will depend on economic considerations (pressure required to push back the brine). IEAGHG (2022) has indicated that residual gas does not necessarily affect storage capacity. Mixing of CO_2 with hydrocarbons may lead to increase in capacity by 3% in oil fields (SACROC) and to a decrease of 6% in a gas field as estimated for the Goldeneye field (IEAGHG 2017; Hannis et al. 2017). Most CO_2 remains in a mobile phase during and after injection. For typical gas reservoirs in the Netherlands (EBN-Gasunie 2017) the pressure at abandonment may go down to 5 to 10 bar, which is less than 5% of the initial pressure, providing significant pressure space for storage. However, other aspects may reduce capacity such as geomechanical constraints and the avoidance of fault reactivation and reduction of injection rates to avoid potential migration out of the structural trap in case flow rates are high enough to push fluids beyond the spill point.

Site characterisation can be seen as developing the scenarios for injection into a storage reservoir that minimise the risk of loss of containment, as well as operational risks, while reaching required injection rates and maximising total injected mass. These scenarios include the design of the injection system: the wells (workover, if any, location, design) and take into account the conditions of the CO_2 as it arrives at the wellhead. The latter implies that the injection process depends on the conditions in the transport pipeline(s); in some cases the transport pipeline system may be designed and operated to satisfy requirements on the conditions of the CO_2 at the wellhead. At the end of production, the pressure in depleted fields is often below or well below initial pressure, and often well below hydrostatic pressure. As the transport of CO_2 is often planned to take place by pipelines that carry CO_2 in liquid phase at a pressure in the range of 80 – 200 bar, the challenge for project developers lies in bridging the pressure gap between pipeline and subsurface reservoir, to avoid too low temperatures in the wells or reservoir.

2.3.3 Geological Containment

The caprock of a depleted field has contained hydrocarbons during geological timescales. Its suitability as sealing layer for CO_2 must be tested, preferably through lab test to measure the capillary entry pressure of CO_2. The presence of a gas cap – even in neighbouring fields under the same geologic unit – could provide assurance of seal quality in the case of oil reservoirs (IEAGHG 2022). Caprock permeability plus the pressure difference between the caprock and the CO_2 at the top of the reservoir determine the transport of CO_2 into the caprock. As long as the pressure in the reservoir is below hydrostatic, there is no pressure drive for the CO_2 to enter the caprock. In case pressure is brought back to initial pressure (i.e., above hydrostatic), modelling is required to estimate rates of transport of CO_2 into the caprock. Here, geochemical reactions should be considered. These could reduce infiltration of the CO_2.

The pressure level In the reservoir is a key element in the management of the risk of loss of containment of the caprock. If reservoir pressure remains below hydrostatic, pressure gradients point into the reservoir. An analysis should be made, as also mentioned in Section 2.2, of the geomechanical impact of the pressure change from initial to depletion pressure after production and back to the final pressure after CO_2 injection. The seal, including the near-well bore, needs to be evaluated for mechanical damage due to compaction during production (IEAGHG 2017, 2022).

The presence of gas chimneys above the reservoir should be considered, as these could be indications of incomplete hydrocarbon containment by the caprock.

An assessment of CO_2 leakage needs to account for possible leakage of hydrocarbons as well (IEAGHG 2017). The integrity of legacy wells and their abandonment status requires particular attention (COSTAIN et al. 2016; IEAGHG 2017, 2022).

2.3.4 Platforms, pipelines and wells

Re-use of facilities (platform, wells, pipelines) is one of the potential advantages of using depleted fields for storage. However, at the end of production, wells are likely to be at the end of their design lifetime, or even beyond, due to prolonged production times. When converted to injection wells, a further 20 or 30 years would be added. An assessment is to be carried out of well integrity, remaining lifetime, opportunities for conversion and risks against potential cost savings.

The highest risks of loss of containment, for storage projects using depleted fields, are associated with wells, both legacy and new-build wells, which represent punctures through the caprock. Some fields have wells that have been plugged and abandoned, e.g., early exploration wells. This may have been done in a period with different regulations than the present day for abandoning wells. If such wells are expected to come into contact with CO_2 during or after injection, revisiting these wells may be required. In on onshore environment, re-entering the wells may be possible; the cost of locating and re-entering abandoned offshore wells may be high.

Existing wells were initially designed for production, not for handling CO_2, and re-use may be limited due to, for example, size or choice of materials. The REX-CO_2 project (Koning et al. 2022) concluded that existing wells will likely require workover and recompletion, with replacement of primary barrier elements before they can be qualified for future reuse. Irretrievable secondary barrier elements that cannot be replaced will require verification through logging and/or other integrity testing. The most common issues are related to incompatible completion, unknown corrosion status, unknown structural integrity when subjected to new expected loads, and in some cases unknown or imperfect status of the cement sheath.

The Align CCUS project proposed several criteria that are relevant when evaluating the re-use of existing wells (Grimstad et al. 2019). Apart from those mentioned above, these included operating pressure, availability (i.e., timing of cessation of production) and location.

A brief overview of a number of recent and developing projects is given below, highlighting choices made regarding reuse.

- The Porthos project in The Netherlands will redevelop the platform and some of the wells. A wells workover plan is in place to create CO_2-proof injection wells (e.g., install new tubing and sensors to monitor CO_2 pressure and temperature). Other legacy wells are P&A'd prior to start of injection (Porthos 2023).

- In their Goldeneye development, Shell planned to re-use existing platform wells. Wells dated from 2003/2004, which at the time of project development gave them an age of about 10 years (Shell 2014).
- Shell and Neptune Energy, in their CO_2 storage plans for offshore Netherlands opted for new wells. Existing wells are old, some of them dating back to the 70s and 80s, and drilling new wells is preferred over extending their lifetime by an additional 20 years or more. This approach is followed by other operators in the Dutch offshore territories.
- For the HyNet project in the Liverpool Bay (UK), Eni proposes to use existing platforms and wells. Side-tracking existing wells was selected as the best option (Becker et al 2021). Technical assessment of the platforms indicates they are fit for reuse; redundant equipment will be removed and new modules will need to be installed (Maslin 2021).
- The ACORN CCS project will re-use the existing 20" Goldeneye pipeline and its connection to one or more wells. They will potentially re-use the Goldeneye 4" chemical injection line to provide methanol to the offshore well(s) and other Peterhead Port infrastructure (where feasible). New infrastructure and wells will be constructed when necessary (ACORN 2021).
- Project Greensand aims to store CO_2 beneath the Danish North Sea in the Nini oil fields. The CO_2 is transported by ship. It is transferred from the ship via a pumping system to the Nini platform, to be pumped into the sandstone reservoirs through new CO_2 injection wells (Greensand, 2023).
- In the Bifrost Project, CO_2 can be transported to the site either via specialised shipping or through the existing pipeline infrastructure and injected into the depleted Harald Field (Bifrost, 2023). The production platform is to be gradually converted to storage, with injected volume increasing while production activities decline. The re-use or conversion of wells is an option. A pipeline will be re-used; the specifications of the CO_2 mixture are defined to minimise risks of pipeline failure (Prevost et al. 2022).
- Eni's major development in the Adriatic Sea, the Ravenna CCS project off Ravenna in Italy, has an industrial set-up including still operating infrastructure. This offers the unique opportunity for CCS, since reusing upstream assets and its proximity to emission plants will result in a short development timeline (Upstream news, 2020). Start-up of the first phase is foreseen for 2024[9].
- Energean plans a CCS project for storage in a depleted oil field in the Prinos area, in the northern part of the Aegean Sea. CO_2 is planned to be permanently stored by use of existing depleted wells (Vujasin 2023).
- Pilot Energy plans to reuse a number of the existing Cliff Head wells, the platform and existing pipelines as part of the Cliff Head CO_2 storage projects pressure management system (Australia). The project plans to convert the existing production pipeline to transport CO_2 aggregated at its onshore Arrowsmith project to the offshore injection wells. See also the Pilot Energy case study, in Appendix 1.

Assessment of the risk of leakage from or failure of repurposed assets will have to be made on a case-by-case basis. The above list of projects gives a mixed image of projects repurposing assets and projects aiming for new facilities. It appears that, apart from the general criteria formulated in, e.g., Grimstad et al (2019), it will mostly depend on the state of individual assets whether re-use is an option. Many options are possible, and each specific

[9] https://www.eni.com/en-IT/media/press-release/2023/11/eni-ravenna-ccs-project.html

case or project is different. At this moment, best practices are emerging, as the first large-scale projects are developing.

2.3.5 Monitoring

Monitoring the storage site is important in order to determine whether the CO_2 is safely (and permanently) stored and to mitigate or prevent risks or any unforeseen behaviour. A risk-based monitoring plan will aim to:

- Prove safety and integrity of the storage complex;
- Detect deviations from expected behaviour of the CO_2 in the subsurface;
- Prove the effectiveness of corrective measures;
- Provide necessary information for site closure and, if relevant, responsibility transfer to the government after injection;
- Provide data to inform stakeholders.

A wide range of monitoring technologies is available for CO_2 storage projects. Similar to the challenges related to risk assessment (Section 2.3.1) and license application (Section 4.1), operators have to define a monitoring system that is, apart from being site specific, sufficient. Regulations request that monitoring be performed before (to collect baseline monitoring data), during and after CO_2 injection[10]. Monitoring plans and systems should take into account the state of the art and consider the value of new monitoring technologies. The choice of technologies, the setting of measurement intervals and other operational monitoring choices is left to the project developer, who once more has to find a balance: between intensity and cost of monitoring, between measuring all possible parameters and performing a fit-for-purpose set of measurements.

The monitoring goals listed above are valid for storage in saline formations, as they are for depleted fields. For saline formations, time-lapse seismic surveys can deliver images of the expanding and potentially migrating CO_2 plume in the subsurface (e.g., Furre et al. 2017). As seismic methods have difficulty in detecting CO_2 inside a former gas accumulation due to the lack of contrast between CO_2 and residual gas (e.g., IEAGHG, 2015, 2022), seismic surveys are likely to be deployed as a contingency monitoring technique in depleted field monitoring systems. The presence of legacy wells, whether plugged and abandoned or converted to injection or monitoring wells, can require significant monitoring linked to containment risk.

The challenge in monitoring storage of CO_2 in depleted fields lies in designing a monitoring system that is sufficient and cost effective, of course similar for saline formations, with the added component of much lower ability of seismic methods to image the behaviour of the CO_2 inside the reservoir. Pressure monitoring is key to keep injection within operational safety limits. Measuring pressure changes above the reservoir could be helpful (IEAGHG 2017, 2022) in identifying CO_2 migrating through the cap rock or along faults, although interpretation of data is difficult. Additional monitoring methods for plume tracking are microseismic and tracer monitoring, respectively, in case production or monitoring wells exist (IEAGHG 2022).

An additional challenge associated with well-based pressure data is monitoring reservoir pressure during the period when the conditions in the well and reservoir are (close to) the two-phase region. A measurement of reservoir pressure requires shutting the well in and waiting for equilibration of pressure in the well and reservoir. In case the down-hole pressure gauge

[10] For Class VI (CO_2 injection) wells, the US EPA requirements can be found here: https://www.epa.gov/uic/class-vi-wells-used-geologic-sequestration-carbon-dioxide

is some distance from the perforations, the phase transition may be located between gauge and reservoir. In that case, pressure readings at gauge level will be insensitive to the pressure in the reservoir (see Figure 2-4). The duration of such insensitivity depends on the size of the reservoir and the injection rate. This will be relevant to wells in which the downhole sensor cannot be placed sufficiently close to the injection point.

Another challenge more relevant for depleted fields than saline formations are legacy wells. Wells penetrate the cap rock, and therefore they are associated with a risk of leakage. Monitoring the integrity of legacy wells deserves particular attention (IEAGHG 2017; Hannis et al. 2017), not only of the wells themselves, but also of the migration from the injectors to these wells. The monitoring of P&A'd wells, some of which may be the initial exploration wells, remains a challenge, especially when there is no access any more. When wells are accessible, cased-hole logging tools may be useful for the monitoring of CO_2 migration (see, e.g., Conner et al. 2020).

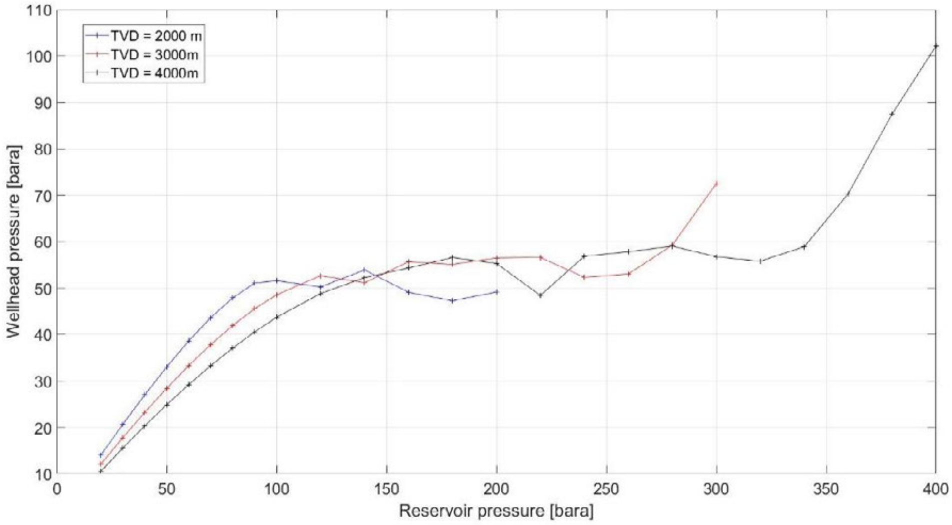

Figure 2-4. Wellhead shut-in pressure versus reservoir pressure in a depleted field, for reservoirs at 2, 3 of 4 km depth. The pressure at the wellhead becomes insensitive to reservoir pressure when the phase transition from gas to liquid occurs between the pressure sensor and the reservoir. The figure shows the extreme case for the pressure sensor at the wellhead, but a similar situation occurs for sensors deep in the well.

To ensure CO_2 containment, early storage projects in depleted fields may limit the final reservoir pressure to hydrostatic, to avoid a pressure gradient that could drive CO_2 out of the reservoir. The risk of post-injection pressure recovery should be assessed, as it would create a pressure gradient and would change the geomechanical state of the storage reservoir. Underpressure in shallower reservoirs, if present, could pose a risk of migration of CO_2 to these zones.

Draft monitoring plans for a storage project in depleted fields without aquifer drive, in a fault-bounded block were proposed recently (Steeghs et al. 2014; Neele et al. 2019). In these plans, day-to-day monitoring was to consist of well-based data (pressure, temperature, flow rate, composition); additional monitoring would be triggered in case of significant deviations from expected behaviour. Seismic methods were only proposed in case there would be reason to believe that CO_2 had migrated out of the storage system. Legacy seismic surveys of sufficient quality were available as a baseline image of the overburden.

During repeated periods of injection of CO_2 in depleted HC fields, e.g., as a result of cyclic injection, pressure cycling could take place, which is currently less well documented. The long-term mechanical response of the caprock, hydraulic interactions and implications on the seal is also less well understood and are highly site-specific (IEAGHG 2017; Hannis et al. 2017).

2.4 Pipeline transport

Several projects described in Section 2.3.4 plan to reuse one or more pipelines. Some aspects of pipeline re-use assessment are described below.

2.4.1.1 Pipeline operating conditions

In general, CO_2 is transported as a liquid. When CO_2 is transported as a gas, the density is much less compared to a supercritical fluid, which reduces the quantity of CO_2 that can be transported for a given pressure difference over a pipeline significantly. Therefore, from an energy point of view it's best to transport CO_2 in supercritical or liquid phase, but project requirements may lead to other choices. Impurities affect the phase behaviour of the CO_2 stream and, consequently, impact the risk of a two-phase fluid regime occurring during transport (Sachde et al. 2022).

When considering re-using offshore pipelines, relevant parameters are the higher density of the CO_2 compared to natural gas and the change in elevation of the pipeline from source to sink. The CO_2 pipeline will generally follow the slope of the seafloor and a CO_2 column (static head) can develop between the CO_2 pipeline inlet (near sea level) and the pipeline on the seafloor at the injection site (Sachde et al. 2022). This CO_2 column increases the static pressure in the pipeline. Thus, while CO_2 is being transported there will be dynamic pressure losses in the pipeline, but the pressure in the pipeline might increase due to the static head. This must be taken into account to avoid over-pressuring the pipeline (Sachde et al. 2022).

2.4.1.2 Pipeline age

Expected pipeline lifetimes range from 60 to 85 years. However, the remaining lifetime depends strongly on specific details of each pipeline such as damage and repairs, state of cathodic protection, corrosion etc (Sachde et al. 2022). A CCS project economic lifetime can be assumed to be several decades of injection for commercial projects (IEAGHG 2009). Thus, when re-using pipelines, a remaining lifetime of maximum 40 years might be favourable, so there can be a minimum of 20 years and maximum of 45 years of useful life for the CCS project (Sachde et al. 2022). CCS projects will decommission fields and wells at the end of the economic lifetime, with a possible exception of monitoring wells that are kept accessible until liability transfer. Additional monitoring and verification of the field are required for 20 years after the end of injection operations. The Competent Authority may then validate the transfer of liabilities that ends the operator's responsibility to monitor the site (IEAGHG 2019).

2.4.1.3 Shore crossings

When re-using pipelines, a new shore crossing is not required to transport CO_2 from an onshore source to offshore storage location. New shore crossings increase costs and regulatory/environmental risk. Existing pipelines may have been installed when different regulatory standards were in place and the same shore crossing location may no longer be possible or practical for an identical new line (Sachde et al. 2022).

2.4.1.4 Inactive versus active pipelines

Inactive pipelines could potentially be re-used in the short-term, and the operator might be willing to rather re-purpose the asset than carrying decommissioning costs or liability. However, the disadvantage of inactive pipelines is that they might have been out of order for a long time associated with outdated data on the pipeline conditions, transferred ownership, or partially decommissioned. These factors make the re-use of inactive pipelines risky or unsuitable. In contrast, active pipelines tend to be newer, have better current records, and might allow for planning to the transition to CO_2 service. However, active pipelines might not be available for short-term usage (Sachde et al. 2022).

2.4.1.5 CO_2 specifications

The topic of CO_2 specifications is relevant to depleted fields, as well as saline formations. However, the topic is currently discussed widely by CCS stakeholders, and some aspects are described below.

First of all, specifications are largely driven by the transport element of a CCS chain. The risk of pipeline corrosion is a strong driver in the definition of (maximum) concentrations for a range of impurities. Generally, requirements arising from transport risk reduction lead to specifications that are suitable for storage (EU, 2023).

The CO_2 from most capture technologies has a purity close to 99%, with CO_2 captured from oxyfuel systems having a markedly higher concentration of impurities. Impurities in the CO_2 stream lead to a cost increase across the CCS chain, due to corrosion, increased compression requirements and displacement of CO_2 in the storage reservoir.

Currently there is no consensus among CCS projects about the required purity of or (maximum) level of specific components in the CO_2. Early CCS projects have developed their own specification, mostly geared towards the quality of the CO_2 that the suppliers can deliver. An example is the composition of the CarbonNet project (CarbonNet 2016).

Recent work shows that purity requirements not only derive from the interaction between the CO_2 and elements of the CCS chain (such as corrosion of pipelines), but also from reactions between components of the captured stream (e.g., Morland et al. 2022). Work has started to explore the possibility of developing an international CO_2 specification (EU 2023), but so far the conclusion is that the set-up of the CO_2 transport and storage system will largely define impurity levels of individual projects. An international CO_2 specification, while extremely helpful in providing clarity to potential CO_2 suppliers, is not in place yet.

While this challenge is not specific to depleted fields, as it also applies to other storage options, it is mentioned here as one of the key topics that need to be resolved in the short term.

2.5 Enhanced hydrocarbon production and CO_2 storage

This section discusses the possibilities of enhanced hydrocarbon production by CO_2 injection or CO_2 flooding and its potential role in CO_2 storage. If CO_2 storage can start before the end of hydrocarbon production, there may be a period of enhanced production. Pressure support from the injected CO_2 could support the tail end of hydrocarbon production, before the injection of CO_2 becomes dedicated storage. Enhanced oil production with CO_2 has been taking place for decades, especially in the USA, but in almost all EOR projects storage of CO_2 is not the goal. Enhanced gas recovery has not been developed to date.

It should be noted here that the purpose of CCS is to reduce the emission of CO_2 to the atmosphere by permanently storing it. If storage is done in subsurface depleted hydrocarbon fields, enhanced recovery can be an option. The enhanced recovery period should be properly monitored to ensure that it does not negate the purpose of storage. In addition the source of CO_2 is important. Extracting naturally occurring CO_2 from a reservoir to subsequently inject it in an EOR project defeats the purpose of emissions reduction. The source of CO_2 should be captured from an industrial process to reduce emissions that would else be vented into the atmosphere.

Section 2.5.1 discusses enhanced oil recovery with injection concomitant with oil production. Some aspects related to the option of enhanced gas recovery with injection concomitant with gas production are discussed in Section 2.5.2.

2.5.1 CO_2 Enhanced Oil Recovery

The main aim of CO_2-EOR is to maximize oil recovery. By doing this the CO_2 will be trapped in the pore space where the oil used to be (Kearns et al. 2021). CO_2-EOR has been in operation for about 50 years and has an TRL of 9. Here, the opportunity to use CO_2-EOR to support emissions reduction is discussed. There have been more than ten thousand articles on CO_2-EOR published since the 1960’s, as a visit to the online library for the petroleum industry OnePetro shows (OnePetro 2024). Currently, there are more than 143 CO_2-EOR projects from 23 operators in the US alone at the end of 2020 (Wallace 2021). In 2018 there were 140 world-wide, mostly in the US, a few in Canada, South America, Middle East (Bui et al. 2018), and China (Hill et al. (2020). In Mexico, CO2-EOR is under consideration (Lacy et al. 2013).These projects are mostly conducted in onshore hydrocarbon fields. A notable exception is the Lula CO_2-EOR project offshore Brazil, in which CO_2 separated from the oil is re-injected in the sub-salt carbonate reservoirs, at a rate of about 2 Mtpa (Negrais Seabra 2020). The Lula project is currently the only offshore CO_2-EOR project.

Above the minimum miscibility pressure (MMP), CO_2 and oil are miscible (mutually soluble), below this pressure CO_2 and oil are immiscible. Low-pressure reservoirs might need re-pressurization by injecting water. As CO_2 dissolves in the oil it reduces the viscosity of the oil improving the displacement process (NETL 2010). To establish if an oil field is suitable for CO_2-EOR, extensive studies are conducted (NETL 2010) that examine: rock and fluid properties (oil gravity and viscosity etc), reservoir pressure and temperature, detailed geologic assessment (structural features affecting sweep efficiency), past production behaviour, whether substantial (economic) residual oil is present (especially after secondary recovery such as water flooding has been conducted), and economic factors including the impact of subsidies or tax rebates (Godec et al. 2011). As an example, a minimum of 1 million barrels (bbl) oil incremental production is suggested as a screening criterium by Núñez et al. (2008). Although most projects have aimed for a miscible EOR process, there are projects in which the displacement is immiscible, e.g. the Bati Raman field in Turkey (Sahin et al. 2008).

In the US production from CO_2-EOR projects (Wallace 2021) was up to 273,000 bbl/day in 2020. Most targeted reservoirs are carbonate formations of the Permian Basin (NETL 2010) which produce 185,000 bbl/day (largest operator Oxy Petroleum). Additionally, the SE Gulf coast produces 39,000 bbl/day (largest operator Denbury, now ExxonMobil), the Mid-Continent 10,000 bbl/day (largest operator Maverick Energy), the Rockies 37,000 bbl/day (largest operator Contango, formerly Fleur De Lis) and Michigan 500 bbl/day (single operator Core Energy).

In CO_2-EOR projects, typically the injected CO_2 is produced together with the oil, separated and then re-injected. Not all injected CO_2 is reproduced and part is retained in the reservoir, a coincidental 'storage' of CO_2. It remains trapped by capillary forces, i.e. becomes immobile within pores (IEA 2015). The Weyburn-Midale project monitoring the CO_2 in the field in the period 2010 – 2012 (Sacuta et al. 2015) conducted research to confirm suitability of the containment complex of this oil field for CO_2 storage. Estimates of the amount of CO_2 that could be stored in depleting oil fields through current CO_2-EOR practices range up to 60 Gt by 2050; if CO_2 storage were to be optimised along with additional oil production, this number could go up to as much as 240 – 360 Gt by 2050 (IEA 2015). Jafari and Faltinson (2013) offer a simulation study that examines a scenario of shifting from conventional primary oil production to water flooding followed by a CO_2-EOR operation using water alternating CO_2 gas (WAG), passing to a long hybrid phase where both EOR and CO_2 storage are conducted simultaneously to a final phase with pure CO_2 injection and storage.

Most current CO_2-EOR projects purchase natural CO_2 that has been extracted from subsurface reservoirs specifically for this purpose. To make a case of using CO_2-EOR for climate mitigation, the source would need to contribute to reducing greenhouse gas emissions such as CO_2 captured from a power plant or industrial processes.

Combined EOR and CO_2 storage is designated CO_2-EOR+ by IEA (2015). While combined storage and enhanced oil production could benefit from both additional oil production and storage fees paid for through emission trading schemes, only very few such projects are in operation today. Gupta et al. (2016) explore the requirements that CO_2-EOR projects need to satisfy in order to be able to obtain storage permits, to qualify as permanent storage operations and to earn carbon storage credits. These requirements include risk assessment, MRV (monitoring, reporting and verification), as well as post-injection monitoring and closure. Additional project elements to meet the regulatory requirements for CO_2 storage projects all can be addressed with existing technology or knowledge and many projects have developed workflows and recommended practices were derived. Therefore, any barriers that keep CO_2-EOR+ projects, from developing must be of policy and/or economic nature (Mourits et al. 2017).

2.5.2 CO_2 Enhanced Gas Recovery

Similar to CO_2-EOR, enhanced recovery could also be developed in depleting gas fields: enhanced gas recovery, or EGR. In principle, the strong contrast in properties of CO_2 and natural gas provides an excellent starting point for EGR, with the much heavier CO_2 migrating below natural gas in a reservoir, which could provide the opportunity for simultaneous injection and production (Liu et al. 2022), perhaps as part of the transitioning from production to storage. That being the case, EGR is more challenging than EOR, and more sensitive to field properties. Economics are more challenging because of the lower unit value of natural gas, compared to oil.

Current understanding is based on experimental and simulation studies (Liu et al. 2022). The pressure difference between injection well and production well or wells, combined with the low CO_2 viscosity will cause it to follow preferential flow paths as well as high-permeability layers. As a result, early CO_2 breakthrough is expected (e.g., Rebscher and Oldenburg 2005; Ennis-King et al. 2011). This leads to early onset of high concentrations in the produced gas, increasing cost as a result of the necessary separation of CO_2 from sales gas (Neele et al. 2018). The start of CO_2 injection is best late in the production of a field, preferably after the end of regular production (Neele et al. 2018; Liu et al. 2022), as breakthrough of CO_2 diminishes the economic lifetime of gas production and ultimate recovery if CO_2 injection is started too soon.

Experience with enhanced gas recovery is very limited. It has been considered for sandstone, shale and coal reservoirs. The pilot-scale project at the offshore K12-B field in The Netherlands showed promising results, and produced valuable insights for larger scale EGR projects. Godec et al. (2014b) studied the scope for enhanced recovery of shale gas, suggesting storage capacities in the gigatonne range, but apart from experimental activities no projects have been developed so far. A similar situation exists for enhanced coalbed methane recovery, which involves injection of CO_2 into coal seams, where it displaces methane adsorbed to coal. The CO_2 adsorbs to the coal and becomes trapped. The most successful trials were conducted in the San Juan Basin in the US. Apart from small-scale trials, no projects have been developed (Godec et al. 2014a). The European RECOPOL field trial in Poland for enhanced coal gas recovery and accompanying laboratory experiments indicated that coal swells in contact with CO_2 diminishing permeability and reducing CO_2 injectivity (Pagnier et al. 2006, Mazumder et al. 2006). This behaviour was also observed in the San Juan Basin (Godec et al. 2014b).

In conventional depleting gas fields, a possible scenario is to start CO_2 injection during late stage gas production to increase reservoir pressure and produce some of the residual gas. The cash flow from the incrementally produced gas could support the storage operations. While perhaps attractive in principle, there are several comments to be made on such a scheme.

- The combination of injection and production complicates operations and adds risk. With CO_2 injected in one part of the field and gas produced from another, the storage project must handle multiple gas streams. Even though the injection and production wells may be located at separate sites, at the start of the storage operations under emission trading scheme rules, the production site will become part of the storage project. A solution could be to not start the storage project until after the end of the enhanced production phase, but that would remove the storage related revenue stream for the duration of enhanced production.
- Simulations suggests that the lifetime of combined storage and production is likely to be short: for gas fields with a size of 5-10 bcm this period is probably measured in months (Neele et al. 2018), due to breakthrough of CO_2 and the cost of reducing CO_2 concentration to sales gas specifications. In fields with poorer reservoir properties (low permeability), the volume of residual gas can be significant, and additional recovery is likely to lie in the range of 5-10%. In fields with good reservoir properties, the ultimate recovery is mostly high, leaving little residual gas and limiting revenues from incremental production.
- It is likely that storage and hydrocarbon production activities will be located in different legal entities – even when they form part of the same larger organisation. In this case, the income from additional production may not benefit the storage project. It could also be that the revenue stream from storing CO_2 may not balance the additional cost of the enhanced production.

To date, no commercial CO_2-EGR projects have emerged. Projects aiming storage in depleted gas fields do not include a first phase of enhanced gas recovery; instead, projects aim to finalise the production phase before starting the storage operations.

2.6 Decommissioning and transfer of liabilities

Closure, decommissioning and handover of a CO_2 injection site is regulated by law, in most countries. In the EU, the CCS Directive 2009/31/EC prescribes post-closure and post-handover monitoring periods of 20 and 30 years, respectively. These potentially long post-closure periods of continued responsibility for the storage site represent a challenge to storage developers. There is no experience with the required period for a storage site to reach a state at which both operator and regulator agree that handover of responsibility can be done, nor is there evidence yet suggesting that post-closure and / or post-handover periods is different for depleted fields than for saline formations.

2.7 Summary

The material presented in the sections above will inform the workflow for the transition of a depleted field from production to storage. Several key steps can be identified that should be taken early in the process, as they can be used to assess the feasibility of redeveloping a field, from both a technical and economic point of view.

- Evaluate the storage capacity, estimate probable injection rates, consider the location and transport options.
- Assess the leakage risk of legacy wells, especially the already P&A'd wells. The cost of well remediation can stop a project, as can the absence of data on wells that were P&A'd long ago.
- For fields at depletion pressure above about 50 bar, the issues described in Text Box 1 (Section 2.2) do not apply. If the depleted pressure is low or very low (lower than 20-30 bar), there may be flow assurance challenges that affect the design and operation of the CO_2 store (i.e., feasible injection rates over its lifetime of the store).

Ideally, such early evaluations are initiated well before the CoP, to be able to benefit from reusing facilities or from the possibility of an early start of injection during the tail-end of production.

The overview of currently developing storage projects in depleted fields shows a variety of project concepts, regarding reuse of production facilities and infrastructure or new build, and also as far as transport to the store is concerned. This suggest confidence of project developers that storage in depleted fields can be done safely and securely. However, operators express a need for guidelines and requirements for reuse. Until governments formulate these, industry is developing experience with reuse and setting up best practices, which can be expected to feed into requirements

Enhanced production may be an option, but should be a temporary activity, during the first phase of injection. Proper monitoring should be done to ensure that the primary purpose of the injection – permanent storage of CO_2 – is not jeopardised .

3 Economic considerations

In re-using depleted hydrocarbon reservoirs the project developer needs to take the following economic aspects into account in developing, operating and dismantling a CO_2 store. In the preparation phase before an investment decision, following aspects can be addressed:

- The valuation of recoverable hydrocarbons when storage operations start before the economic limit of the field is reached, i.e. leaving part of the recoverable hydrocarbons in place. In case CO_2 injection occurs in the water leg or parts of a reservoir where production has ceased, the risk of CO_2 contaminating recoverable hydrocarbons can be low.
- In the case of an enhanced recovery component (or phase) in the storage project: the cost of CO_2 separation facilities.
- The investments and operational costs of maintaining the installations if there is a time gap between the Cessation of Production (CoP) and the start of storage operations. This assumes that the developer has the opportunity to prepare for the storage project before CoP.
- Facilities and system elements required to manage variations in CO_2 supply rates.
- The presence of legacy wells and workover costs for requalification.

In the operational phase:

- The impact of varying injection rates, or intermittent injection on wells and reservoir.
- The changing of the operational window of wells and reservoir as the reservoir pressure increases during the lifetime of the storage project.
- Capital and operational costs of heating the injection stream.
- Monitoring of legacy wells.

In the decommissioning phase:

- Uncertainty in the duration (and cost) of the post-injection period.

These topics are discussed in more detail in the next sections.

3.1 Re-use of facilities

A recent IEAGHG study (IEAGHG 2022) estimated the potential cost benefits of re-using fields and facilities. A reference storage project in a depleted oil and gas field was used, with a storage rate of 1 Mtpa, an injection period of 25 years and post-injection period of 20 years. A 50 km pipeline is part of the project.

The study estimates the CAPEX for a project with new onshore infrastructure at USD 40 million (ranging between USD 28 million and USD 52 million). An onshore project with reuse of infrastructure would have a CAPEX of between USD 9 million and USD 17 million.

The CAPEX of new offshore infrastructure is about an order of magnitude higher than that of onshore projects, with CAPEX ranging from USD 275 million to USD 525 million. Reuse of existing offshore infrastructure could lower the capital costs to between USD 94 million to USD 415 million.

However, the study cautions against the assumption that reuse always, or even often, leads to lower cost. Offshore infrastructure and facilities tend to be tailored to a site which limits their reuse. And a new build may offer economic benefits due to the flexibility of locating infrastructure in an optimised way.

Reuse may involve costs of well remediation and platform or pipeline modifications due to different design specifications, which will offset savings of reuse. IEAGHG (2022) suggests for initial screening that the number of legacy wells preferably is less than 5 but no more than 20, adding the comment that such a number is strongly site dependent. A maximum well age is suggested, in the same study, but again the risk and cost of intervention will be strongly site dependent, also because the location of wells and the expected migration of the CO_2 plume will inform the risk level of a specific well. Older wells may have had less stringent P&A requirements and require additional costs to qualify the integrity for CO_2 storage; in addition, some of the data required for evaluating its integrity may have gone missing. The remaining service life of platforms must be of sufficient length, but the feasibility of re-using will have to be assessed on a case-by-case basis, taking into account the suitability of a specific platform for an additional lifetime as a CO_2 injection platform.

This appears to be in line with current developments of CCS projects in the North Sea. The Porthos project will be re-using wells and platform, all of which are from the period 1990 – 1993. Production from the fields being developed for storage in the K14 and L4 offshore blocks have wells and platforms dating from the 1970s and 1980s and the project developers are going to drill new wells and construct new platforms[11] (see also Section 2.3.4).

For the development of the Viking field and the fields of the HyNet North West project in the UK offshore, a similar picture emerges. No appraisal drilling was planned which would reduce the costs and the time to FID to between 2 and 4 years (Costain et al. 2016). An offshore pipeline will be reused, after inspection campaigns (Becker et al. 2021). Although the Hamilton field started production relatively recently, in the late 1990s, production wells were designed and located for production, and these will be reused, using side tracks to render them fit for purpose and abandoning the production tracks with rock-to-rock cement plugs (Becker et al. 2021). 3D seismic surveys performed in 2022 and redevelopment of four platforms are included in the development plan (Becker et al. 2021).

For the Viking A gas reservoir, which started production in the 1970s, there is uncertainty regarding the status of some of the legacy wells. A new platform is planned for Viking A. No seismic survey is planned because the current operator has access to reprocessed seismic data and also to detailed well by well pressure and production rate records.

In the UK, in earlier CCS competitions, a storage plan was developed for the Goldeneye field. With a production start planned for 2004, re-use of the existing production platform and 5 existing wells was planned.

[11] See the announcement of the Aramis project (a preliminary environmental impact assessment) at https://www.rvo.nl/sites/default/files/2022-06/Concept-NRD-Aramis.pdf

The Bacton Thames Net Zero project in the UK plans to use the Hewett depleted gas field in the Southern North Sea sector of the UK[12]. The current infrastructure is over 40 years old, but reuse is currently under evaluation.

These studies offer an understanding of the risks and opportunities of re-use of facilities but feasibility studies need to be conducted specific to each case and costs compared to those for a new build.

It is a challenge to have a smooth transition from the hydrocarbon production phase to the CO_2 storage phase, with many factors influencing the timing of the transition. The time of cessation of production (CoP) is highly dependent on the fluctuating hydrocarbon market conditions and thus is uncertain. If storage is planned too early this may leave stranded hydrocarbons in the reservoir with a potential economic value, leading to a loss of income for the (production) operator. However the economics of late life hydrocarbon fields compared to those available following conversion to CO_2 operations may justify an early transition away from hydrocarbon production.

If the production phase comes to an end too early, there may be a need for mothballing the existing infrastructure to make it re-usable for future CO_2 storage activities.

The government-approved exploitation plan may include a predefined duration which makes it difficult to stop earlier. The licence holder would need to convince the State to cease production earlier whereas the State has a strategic stake in gas production as well that may be offset by the State's emission reduction obligations. The choice to start earlier with CO_2 storage and to end gas production before the planned CoP needs to be determined, which is of strategic importance. With granting of the storage permit, the authorities need to determine the required period for the transition, weighing the importance of production versus storage.

As soon as the production end date (in the production plan) has been reached the operator is required to decommission the facilities and abandon the wells within a specified period after cease of production. Decommissioning of the hydrocarbon infrastructure may limit the opportunity to re-use infrastructure. For example, under the Dutch Mining Law, an operator may request an extension of the period by which infrastructure is to be removed, if there are plans to redevelop the field for storage. This requires the production operator, or a third party aiming to reuse a depleted field and its assets for storage, to start developing such plans well before the field's economic limit.

Referring to the potential of combining storage with enhanced production during the first phase of storage (see Section 2.5), it should be noted that this approach in the case of a gas field is likely to limit the opportunities of reuse, since the production facilities would be maintained and additional infrastructure would be built to handle the CO_2. In case a field is produced from several locations, a gradual transition to storage may be combined with reuse.

3.2 Field data

An important advantage of using hydrocarbon fields for CO_2 storage purposes is the availability of a wealth of geologic data and information on the static and dynamic properties of the reservoir from the exploration/appraisal and production periods, provided that these have been stored appropriately in databases and core stores. The geological data, static and

[12] https://www.eni.com/static/bactonthamesnetzero/

dynamic models, drill cores or cuttings usually present after a production lifetime offer an excellent starting point for a storage project using a depleted field. Special attention may be required for the seal, as cores may be available for the reservoir formation(s) only. Drilling data and leak-off tests may be useful to examine caprock properties. The use of these data may reduce the need for additional seismic and well data acquisition. This could shorten the development timeline by 2 to 4 years (COSTAIN et al. 2016) and reduce the appraisal costs. The availability of data and information is not considered to be an issue if the future storage operator is the same entity as the HC operator, even though hydrocarbon production and CO_2 storage activities may be organised in separate legal entities within the wider mother company.

The transfer of data and licenses between operators is common practice. However, as an operator may be concerned that another party will end up with their storage licence opportunity, they may be hesitant to share data and information. This holds in particular for a 3rd party which has acquired an exploration licence for an existing producing hydrocarbon field. For example. according to Dutch mining law a 3rd party may get priority access to the storage prospect instead of the current production operator. The latter has no legal obligation to provide data. Good arrangements are thus necessary so that existing data will be shared (see also Section 4.5.1 on “1st right of refusal”).

Current storage projects in depleted fields tend to be developed by the operator that produced the hydrocarbon. Examples include The Porthos consortium, that worked closely with production operator Taqa in the conversion of the P18 fields; Shell prepared a storage permit application for their Goldeneye gas field offshore UK and Pilot Energy submitted an application to declare a greenhouse gas storage formation over its oil production licence offshore Western Australia (see Appendix 1). A notable example is the Snøhvit project in Norway, where CO_2 separated from produced gas is injected into the water leg of the gas field (in a downfaulted segment that is in communication with the producing segments). Table 3-1 shows a selection of currently developing CO_2 projects using depleted fields for storage. In all cases, gas or oil was produced by a joint venture (JV) and at least one of the production JV partners is in the JV for the storage of CO_2. This ensures the flow of data, knowledge and experience from the production phase to the storage project. Not shown in the table is the recently awarded Phoenix project of Projeo Corporation, who intend to convert a mature oil and gas field in the Permian basin for CO_2 storage[13].

Table 3-1 Selected CCS projects developing depleted fields for storage. All projects are operated as joint ventures (JV), it is noted only where considered relevant here.

Project	Production operator	Storage operator
Snøhvit	Equinor	Equinor
Goldeneye – offshore gas field (UK)	Shell	Shell
ROAD – offshore gas field (NL)	Taqa	ROAD; Taqa involved in storage project development
Porthos – offshore P18 gas fields (NL)	Taqa	Porthos; Taqa involved in storage project development
Offshore K14 field (NL)	NAM, in JV, (NAM is partly Shell owned)	Shell, in JV
Offshore L4 field (NL)	TotalEnergies	TotalEnergies
HyNet – offshore gas fields (UK)	Eni	Eni

[13] See https://www.energy.gov/fecm/project-selections-foa-2711-carbon-storage-validation-and-testing-round-2

Ravenna CCS – offshore gas field (IT)	Eni	Eni, in JV with SNAM
Viking – offshore gas fields (UK)	ConocoPhillips, in JV with BP	Harbour Energy, in JV with BP
Greensand – offshore oil fields (DK)	DONG, in JV with WDEA	INEOS, in JV, with WDEA
Bifrost – offshore gas fields (DK)	TotalEnergies, in JV	Bifrost JV, with TotalEnergies
Prinos – offshore oil field (GR)	Energean	Energean
Donghae – offshore gas field (South Korea)	KNOC	KNOC
Mid-West Clean Energy Project (Cliff head CO_2 Storage project)	Triangle Energy (Operations) Pty Ltd – 50% owned by Pilot Energy Limited	Triangle Energy (Operations) Pty Ltd – 100% owned by Pilot Energy Limited

Available data and evaluations will need to be updated. Relatively simple evaluation tools may have been sufficient in the production phase, which most likely will not suffice for the storage project. This applies as well to the subsurface static and dynamic modelling concepts. Gas fields in the Dutch offshore have been producing for decades, and sometimes are in decline. The decommissioning or the abandonment of the fields is currently going faster than the CCS market can develop. The models will need updating and revamping to incorporate the latest behaviour of the field in the history matching and injection modelling.

Static modelling used in the production phase typically needs to be expanded so that the storage complex which may be larger than the production model, is well represented including the overburden. This may require additional interpretation of well data and reprocessing of seismic data. Dynamic modelling will look into repressurizing the reservoir during CO_2 injection and the stability of faults. Destabilisation may occur due to the injection of cold CO_2, especially when reservoir pressure is low.

The collection and restructuring of data and information sometimes can be a difficult, in particular for hydrocarbon fields that have already been abandoned. Depending on when abandonment happened, these fields can be quite old and a CO_2 storage exploration licence may be needed for the fit-for-purpose collection of new data.

3.3 Delay of decommissioning, mothballing and hibernation

Existing oil and gas infrastructure with re-use potential may not be directly repurposed for CO_2 storage after cessation of hydrocarbon production. In that case one may consider mothballing the installations with subsequent hibernation. Mothballing refers to the activities to stop operations which includes safeguarding, cleaning, removal of obsolete equipment and conservation. After mothballing the installations get put into a stage of hibernation and operational costs are reduced to a very minimum awaiting future plans for redeployment (DHV & TNO 2008; 2009).

Offshore, capital expenditures for mothballing and hibernation would amount to about 10% of the platform abandonment costs (DHV & TNO 2008; 2009). This is equivalent to about 2.6 M€ for a satellite platform and 4.6 M€ for an export platform with an assumed reference year 2009 (Jansen et al 2011). Operational costs of hibernation would amount to about 0.7 M€/year for a satellite platform and 1.5 M€/year for an export platform. For a typical situation in the Dutch offshore mothballing and hibernation would be about 3 to 5% of the total costs of a new transport and storage system (EBN & Gasunie 2017).

Operators indicate that platforms should be reused as soon as possible to avoid maintenance costs and integrity issues. Costs of requalifying installations which are in bad shape, may become so high and so might warrant building a completely new installation after dismantling the old equipment. For the Dutch offshore a maximum duration of a hibernation period was assumed to be 10 years (EBN & Gasunie 2017). This study proposed to evaluate how the availability of suitable infrastructure can be secured and what types of mothballing can be deployed.

Another driver for the re-use of depleted fields as CO_2 stores is the possibility of avoiding decommissioning of the facilities directly after the production phase. Decommissioning costs have been estimated to be about 15% of the total CAPEX (IEAGHG & ZEP 2011). Delaying decommissioning was a recognized additional benefit of the business case of the ROAD project (Wildenborg et al. 2018), although it was difficult to quantify. As mentioned in the previous section, the Mining Act in The Netherlands offers the possibility of delaying decommissioning and removal by several years, to give operators the time to consider potential re-use for CO_2 storage.

4 Regulatory considerations

This section discusses regulatory and legal aspects of making the transition from hydrocarbon production to CO_2 storage. Experience around permitting CO_2 storage is described in Section 4.1. The safeguarding and handover of field data to the storage operator is discussed in Section 4.2. Section 4.3 discusses current regulations related to enhanced recovery; the topic of re-use of production facilities for storage is dealt with in Section 4.5, and transfer and mothballing (suspension) of assets and decommissioning is discussed in Section 4.6.

In Europe, 25 countries have transposed the EU Directive for CO_2 geological storage into national law, which provides the legal basis for CCS. These are all Member States, Iceland, and Norway except for Austria, Cyprus, Estonia, Finland, Germany, Ireland, and Slovenia. In particular, CCS is prohibited in Lithuania since July 2020. Many countries still lack the regulatory framework to handle projects dealing with CO_2 transport, storage or both impeding their development. In Australia (see IEA 2024), the Commonwealth regulates offshore CCS activities under the Offshore Petroleum and Greenhouse Gas Storage Act 2006 (Cth), also called the Offshore Act. The states of Victoria, South Australia and Queensland have passed legislation to regulate CCS. Western Australia is drafting a Greenhouse Gas Storage and Transport Bill, its Gorgon project was permitted under the project specific Barrow Island Act 2003. Northern Territory, New South Wales and Tasmania do not have regulations[14]. In the US a different set of regulations applies, with CCS projects being regulated under the Underground Injection Control (UIC) program. In the US the general attitude towards onshore storage of CO_2 is more positive than in Europe (possibly also due to lower cost onshore); consequently, in the US offshore regulation is developing later than the onshore one (Hannis et al. 2017; IEAGHG 2017).

A database of laws and regulations that support a framework for CCUS development is maintained by the IEA[15]. The database covers the US and Canada (in both cases also selected States), the European Union, the UK, Norway and Australia.

4.1 Permitting

Hydrocarbon field operators are familiar with the legal and practical activities of commissioning, management, and testing of infrastructure, but are less likely to be familiar with the conversion to injection, adaptation and implementation of CO_2-compatible hardware (Akhurst et al. 2021). Linked to the still relatively new field of CO_2 storage is an uncertainty that the first wave of projects is likely to solve, which is related to the level of detail that is to be reached in a storage feasibility study that will result in a storage permit application and award.

When writing a storage permit application a balance must be found between the level of detail that the competent authorities wish to see and the detail that the operator can provide. For example, at the time of writing a storage license application, there is uncertainty about the precise location and type of sensors in the monitoring system, which makes it impossible

[14] https://www.kwm.com/au/en/insights/latest-thinking/ccs-in-australia-a-legal-guide.html
[15] The database can be accessed at https://www.iea.org/data-and-statistics/data-tools/ccus-legal-and-regulatory-database

to set up a final monitoring plan containing operational parameters. Such parameters can be provided only when the set-up of the monitoring system is available.

During the preparation of the storage license application for the P18-4 depleted field, the ROAD project convinced the European Commission that draft plans may be submitted in the application and final plans provided when the required information would be available (Jonker et al 2018). In The Netherlands, these final plans are to be submitted to the competent authority three months prior to the start of injection.

With the first storage license applications being submitted, evaluated and published, clarity is emerging about the level of detail that is to be covered. In the USA, Class VI permit documents are published on the EPA website[16] after the permit is granted; the documents include the monitoring plan, well plugging plan, emergency and remedial response plan, etc. Once the first wave of licenses is approved, it can be expected that industry recommended practice can be defined. This will support the development of storage projects in other parts of the world, where competent authorities are beginning to acquire the required expertise to evaluate license application from local projects.

Examples of the evolving requirements for storage permit applications are the ROAD and Porthos projects in The Netherlands. The first permit application was submitted in 2011, by the ROAD project, for storage in the offshore P18-4 field. This was the first application submitted in Europe under the CCS Directive. During the two-year permit preparation process, the interpretation of the CCS Directive and the accompanying Guidance Documents were discussed frequently between ROAD, Taqa (the field operator) and the competent authorities, with the result that a draft permit was granted almost immediately after the permit submission. The permit was issued in 2013. The two-year period between submission (in 2011) and granting of the permit (in 2013) was partly taken up by the European Commission to draft its opinion.

Then, after the ROAD project was cancelled in 2017, the Porthos project took over ROAD's legacy by developing a storage project involving again the P18-4 depleted field. A new storage permit application was prepared for the P18-2 depleted field (a field in the same cluster of fields as the P18-4 field), at first following the template provided by the already granted P18-4 storage permit. However, despite the discussions with the competent authorities around the interpretation of the CCS Directive held in 2010 – 2011 for the P18-4 application, due to changed societal views on the use of the subsurface, the government required substantially more analysis. A change of the already granted storage permit for the P18-4 field also required a more detailed analysis than was provided in 2011. A key element that required more detail in the license application for the Porthos project was that of the risk of induced seismicity.

This is an illustration of how new insights – on the side of the regulator – and changing societal attitude – in this case towards exploitation of the subsurface – lead to changing requirements on the contents of a storage permit application. More specifically, there was a need to perform a more detailed and deeper risk assessment.

4.2 Field data

In The Netherlands, a large number of offshore gas fields is expected to reach the end of production (CoP) in the period until 2030 (EBN-Gasunie 2017). The Dutch Mining Act requires

[16] See https://www.epa.gov/uic/table-epas-draft-and-final-class-vi-well-permits

that facilities (platforms, wells) are removed or plugged and abandoned, within a period of two years after CoP; similar regulations exist in other countries, such as in the United Kingdom. Only a small number of these fields are likely to be re-developed for CO_2 storage. Other fields will be abandoned and re-entry for storage may take many years (see, e.g., Wildenborg et al. 2022). The access to production data many years later is a concern, as is the availability of staff who have operated the field. As offshore gas production decreases and fields are abandoned, operators are likely to leave the country or cease to exist. As that happens, the risk of data getting lost is increases.

A national data repository would be helpful in keeping all data from the production phase until future use. An important issue is the question of which data should be collected and stored. Operators operate their fields in different ways, collecting more or less detailed data, depending on the complexity of the field and of the production process. As an example, not all fields require the construction of a 3D geological model. Also, the concept of 'all data' is unclear and could lead to unmanageable amounts of data. Therefore, a list of data that should be collected as a minimum should be created. Ideally, these data should be collected and stored in the repository as part of the decommissioning activities. The repository should allow open access to parties interested in investigating the feasibility of re-using the subsurface pore space. See also Section 1.3.4, which reports the absence of an automatic procedure for data availability to a storage project developer.

If the period between development of a CO_2 store and the end of production is not too long, the field's production staff could be involved in the storage development, ensuring that their knowledge of and experience with the field is used to ensure the best approach. While data and models can be collected and maintained in data repositories for future re-use, safeguarding such knowledge and experience will prove to be a major challenge.

A data repository that ensures data availability and transfer from the production operator to the storage operator would respond to the requirements set forth in the Net Zero Industry Act (NZIA), proposed by the European Commission. The Net Zero Industry Act (NZIA, Article 17) requests that data pertaining to decommissioned production sites or to sites that have been announced to be decommissioned are made publicly available. For the UK offshore it has been recommended to include well by well production rates and pressure data from HC production in a national archive as well as detailed well abandonment records (COSTAIN et al. 2016).

Analyses of the feasibility of redeveloping hydrocarbon fields for storage, such as referred to in Section 2.7, could become part of the data requested by the NZIA.

4.3 Enhanced hydrocarbon production and CO_2 storage

While there is some debate around the view that CO_2 emissions from the incremental oil or gas production negate the purpose of permanent CO_2 storage, there are no legal or regulatory barriers – although some Member States in Europe do not yet have clear regulations on enhanced recovery with permanent CO_2 storage.

In Europe, enhanced recovery is not explicitly addressed by the EU CCS Directive (2009/31/EC), although it is mentioned in Recital 20, which states that enhanced recovery combined with storage should fall under the Directive. A process to update the Guidance Documents to the

Directive[17] is ongoing and new Guidance Documents will be published early 2024. The Guidance Documents provide non-binding clarification to the stipulations of the Directive. One of the topics that is likely to be updated in the new Guidance Documents is that of the combination of enhanced recovery of hydrocarbons and CO_2 storage.

During a public stakeholder workshop in June 2023[18] a proposed guidance regarding the combination of CO_2 storage and enhanced production under the Directive was presented. The guidance was to allow enhanced hydrocarbon recovery with CO_2 if storage is the primary goal of the combined activity. In addition, the overall CO_2 stored should exceed the life-cycle emissions of the operations, including those from the combustion of the incremental production.

In Europe, clarification is needed whether incidental storage during enhanced production is accountable or that permanent storage only relates to the CO_2 injected after cessation of hydrocarbon production. All site characterisation and assessment work described under the CCS Directive needs to be performed if a CO_2-EOR operation is transferred into an activity with permanent CO_2 storage. The Directive prescribes that other parties (parties other than the EOR operator) are allowed to apply for a exploration permit (IEA 2022a), but not directly for a storage permit.

While this is a proposal that is yet to be endorsed by the European Commission, this explanation of the position of enhanced hydrocarbon production within European emission reduction regulations provides some support to project developers to consider EOR or EGR as part of their CO_2 storage project. The combination of storage with hydrocarbon production remains a sensitive one, where clear reporting and accounting of CO_2 will be required to demonstrate its value in the toolbox of emission reduction technologies.

In Europe, there are currently no enhanced production projects that include a storage component under the Directive. Conventional CO_2-EOR projects are ongoing in Hungary, Turkey and Croatia. In several other Member States the feasibility of CO_2-EOR using captured CO_2 has been investigated (e.g., CO2Geonet 2021), but to date no projects exist. An important reason for this is that the major funding sources in Europe, such as the Innovation Fund, do not allow projects to have an enhanced production component. The same is true for some of the national funding mechanisms in Member States. In addition, the target of 30 Mtpa set forth in the NZIA specifically excludes CO_2 stored as part of enhanced recovery.

In the US, CO_2-EOR has been ongoing for decades in the Permian Basin (Section 2.5.1). The CO_2-EOR wells require a Class II permit for the incidental injection of CO_2. For dedicated geological storage, Class VI permits are needed, which require additional study and measures to prevent contamination of drinking water sources. However, transfer from conventional CO_2-EOR to CO_2-EOR with permanent storage is complicated due to different regulation, ownership and operator mindsets (IEAGHG 2017; Hannis et al. 2017). In 2014 EPA published a memorandum with principles on the transition from Class II to Class VI wells. Still more detailed requirements may be needed (IEA 2022). The Denbury project in South Dakota is an example of a Class II CO_2-EOR project that benefits from tax credits from the storage of CO_2 (Leroux et al. 2021). A list of Class II and Class VI well permits, both current and pending, can be found on the EPA site[19].

[17] The Guidance Documents can be found at https://climate.ec.europa.eu/eu-action/carbon-capture-use-and-storage/implementation-ccs-directive_en#documentation.
[18] See, for background information, https://climate.ec.europa.eu/eu-action/carbon-capture-use-and-storage/implementation-ccs-directive_en#guidance-documents
[19] https://www.epa.gov/ghgreporting/subpart-rr-geologic-sequestration-carbon-dioxide

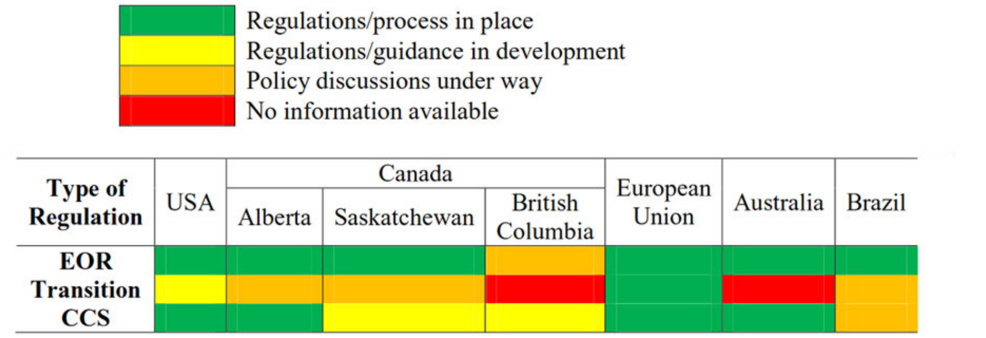

Table 4-1 Overview of the status of regulatory development of conventional EOR (‘EOR’), pure CO_2 storage (‘CCS’) and the transition from EOR to CO_2 storage (‘Transition’) in various regions around the world (Allinson et al. 2017).

Table 4-1 shows that regulations for conventional EOR (‘EOR’) and for pure CO_2 storage (‘CCS’) are reasonably well developed throughout the world. This is in contrast to CO_2-EOR combined with permanent storage of CO_2 (‘Transition’) (Allinson et al 2017), where in most regions the regulation for a transition is still being developed. In other areas overarching policies for the transition are under way. The working group ISO TC 265 is writing a technical report on the transition from EOR to storage, which is expected to be published soon (ISO TC265, in prep). The focus of this report will be on potential technical, policy, and regulatory barriers (ERM 2016; Carpenter 2022).

Overall, there is a need for a pathway with clear and practical requirements to transfer conventional CO_2-EOR projects to permanent CO_2 storage projects. No serious technological issues exist in transferring CO_2-EOR operations to operations dedicated to permanent CO_2 storage (IEA 2022).

4.4 Well abandonment

Legacy wells offer the potential for reuse, but they also increase risk. Fields are likely to have exploration wells, some of which were plugged and abandoned at times when decommissioning guidelines were different. Such wells tend not to be easily accessible, and remediating wells that may not have been adequately plugged to be safe in the presence of CO_2 may be expensive. In such cases, an operator may wish to develop a storage site away from such problematic wells.

The appropriate abandonment of wells before storage starts (legacy wells that are accessible) or after storage (wells used during the injection operation) is not clearly regulated in all countries. An overview of (offshore) well plugging and abandonment regulations is given by IOGP (2017), but no mention is made of wells that could see CO_2 after abandonment. Industry best practice for well decommissioning is emerging (e.g., OEUK 2022), but regulations are lacking. When considering the risk of leakage from depleted fields, it should be considered that the CO_2 mix with hydrocarbons and cause hydrocarbon leakage; the impact of which is different from that of leaking CO_2.

An operator in the Dutch offshore points out that at the moment there is no guideline from authorities on abandonment with consideration of future storage. The status of abandonment of legacy wells is up for interpretation and operators lack a clear reference or target for the selection of P&A concepts. The UK government is working on a CCS abandonment strategy which accepts a limited amount (ALARP) of leakage through the legacy wells, which could be a useful and practical way forward.

The storage permits of the Porthos project in The Netherlands mention full-bore formation plugs to be set in wells that are abandoned, both before (legacy wells not reused) and after injection. It is not clear whether such relatively expensive measures will be required for all CO_2 wells.

The practical issue is for authorities to decide which method of decommissioning is considered good enough, to provide clarity to operators, as well to all CCS stakeholders. The choice should be based on scientific and engineering experience.

4.5 Hydrocarbon field facilities re-use

Policy recommendations to support the re-use of transport infrastructure for CO_2 transport have been provided elsewhere (e.g., ZEP 2020). Guidelines for the assessment of re-use of hydrocarbon production facilities are yet to be developed in most countries. The first wave of projects is building experience in assessing the feasibility of re-use, which will feed into such guidelines. Considerations for the re-purposing of pipelines have been outlined by DNV (2022).

Removal of the production platform (for offshore sites) and decommissioning of the wells is part of the production license. The HC production operator is required to remove facilities after the end of the production within a period of time specified in regulations that also inform how to plug and abandon open or suspended wells (ZEP 2022a). However, these regulations may not consider a future use of the subsurface reservoir for the storage of CO_2, and different abandonment procedures could be preferred to create higher confidence of integrity of the P&A'd wells during and after CO_2 injection.

When a HC operator wants to stop their activities in the current production license area, smart decommissioning of infrastructure is crucial and must be done in a cost-effective matter. When the current HC operator stops, decommissioning obligations need to be taken over, the HC operator needs to be reimbursed for the value of their assets and they might need to pay the latest estimates of decommissioning cost (ZEP 2022a). A clear plan must be made for future storage operators to be able to access information required for site appraisal activities (ZEP 2022a); in Europe, such plans could well fall under the requirements set forth in the Net Zero Industry Act (NZIA, Articles 17, 18).

When a HC operator continues with a CCS project in the current production license area, existing joint-venture (JV) partners need to be informed and have to agree to return the production license or become partners on the new project (ZEP 2022a). Subsequently, plans on costs and reimbursements will be made. When none of the existing partners agrees to participate, it must be determined who will take over their shares. When there are no other interested parties, the State might need to step in to ensure further progress in CCS (ZEP 2022a). When potential third parties also wish to start CCS in the same license area, all project plans need to be evaluated and permits can be granted based on objective, transparent and non-discriminatory views (ZEP 2022a).

To prevent a HC operator from blocking the current license it has been recommended that operators be requested to annually publish their plans for CO_2 storage for every field (suitable for CO_2). Guidelines on how to manage a field and its abandonment should be available (ZEP 2022a). As above, the NZIA requirements for sharing of data related to CO_2 storage capacity and for preparation of plans for CO_2 storage by operators could well support such developments.

To promote the reuse of existing infrastructure for oil and gas exploitation the UK initiated the development of a strategy to remove a number of barriers. Relevant data for the evaluation of re-use potential is not always readily available. Infrastructure data and information from operators need to be gathered and compiled to enable assessment for re-use. Timing of the conversion of oil and gas assets to be used for CO_2 transport and storage is key. For that purpose the following priorities are defined (Greenhalg et al. 2019):

- To define and implement an approach for the identification of existing infrastructure with re-use potential and an aligned integrated planning;
- To deal with the consequences of a possible time gap between the end of production and the start of CO_2 injection including the need for maintenance and ownership; and
- To manage decommissioning liabilities.

Regarding the timing issue, CO_2 injection and hydrocarbon production can be combined on a single platform. The Bifrost project (Denmark) plans to gradually convert the Harald platform from production to injection; production and injection will occur from different reservoirs (Prevost et al. 2022). This approach makes it possible to start with injection as early as the storage reservoir (and storage project development) allows.

A consultation of the UK Department for Business, Energy and Industrial Strategy (previously BEIS and currently called Department for Energy Security and Net Zero, DESNZ) resulted in the proposal to define an organisational entity which would coordinate the transition of oil and gas infrastructure to CCUS[20]. Detailed, site-specific evaluations of the infrastructure integrity are needed before they can become part of a future national network of CO_2 transport and storage. The assessment should tackle legal and commercial aspects as well (Greenhalg et al. 2019). The evaluation is to be undertaken early in the planning stage of decommissioning to avoid additional costs and integrity issues. The transition needs to consider continuity in the generation of revenues from the stage of production, and potentially enhanced recovery to CO_2 storage.

4.5.1 Overview of legislation for re-use in selected countries

Not all countries have clear regulations regarding re-use of wells (or other infrastructure) in CO_2 storage operations. The most advanced in this field seem to be Norway, the UK and the US. Other countries, such as France, the Netherlands and Romania, do not yet have specific regulations and standards for CO_2 wells or for the re-use of wells. The UK policies regarding the re-use of infrastructure for CO_2 storage are the most advanced; they must be considered in the decommissioning plan (Dudu et al. 2020).

France
Re-using a hydrocarbon field for CO_2 storage needs a new authorization from the local authority (Dudu et al., 2021a). It is possible to re-use surface and subsurface petroleum facilities under economical and administrative obligations, such as the prior granting of a mining title for the new use (Dudu et al. 2020).

[20] https://www.gov.uk/government/consultations/carbon-capture-usage-and-storage-ccus-projects-re-use-of-oil-and-gas-assets

Netherlands
Hydrocarbon well re-use was permitted for CO_2 operations in the Porthos project (Dudu et al. 2021a). Currently CO_2 specific legislation and standards for new build or re-use are lacking (Dudu et al., 2020). This gap may need a regulatory solution.

Two storage permits have been issued for the re-use of wells for the offshore P18-2 and P18-4 depleted gas fields, as part of the Porthos CO_2 storage project (Phase 1). Injection in both fields will involve re-using (including workover) existing production wells. The P18 license application represents a blueprint that other companies in the Dutch offshore can use as reference. CO_2 was injected at the K-12B field from 2004-2017 for a pilot project on enhanced gas recovery and re-used gas production wells for the injection (Dudu et al. 2020). While the Porthos project plans to re-use platform and wells, in other cases the approach is to build new facilities, e.g. the Aramis project. Although the Dutch Government has shown interest in utilizing offshore oil and gas infrastructure and repurposing for use in CO_2 storage projects, there is currently no policy incentive to encourage industry to pursue the reuse of offshore infrastructure (Dudu et al. 2020).

For decommissioning wells, the Dutch organisation of oil and gas producers NOGEPA (currently Element NL) has developed standards on Well Decommissioning, but storage of CO_2 is currently outside the scope (NOGEPA 2021). There is a requirement for standards to address best practices for CO_2 wells, as well as the re-use of existing oil and gas wells to safely handle CO_2 (Dudu et al. 2020).

Current Dutch Mining Law provides the opportunity to ask for temporary exemption of dismantling to investigate the option of permanent CO_2 storage. The expectation of operators in The Netherlands is that many requests will be submitted; this is expected to be further encouraged by the EU Net-Zero Industry Act (NZIA) (see Section 1.1).

A 3rd party, which is not the production operator nor the production licence holder, may apply for an exploration licence for storage in the same target field. Such an exploration licence will give the right to the 3rd party to characterize the storage prospect. After seismic exploration and drilling of an exploration well, the 3rd party can be given priority in acquiring a storage permit, even if the production operator has more data and knowledge of the storage prospect. This seems not to be desirable according to operators in the Dutch offshore.

Current legal rules in The Netherlands state that once a party has submitted a storage licence (not an exploration license) application, other parties have a period of up to 13 weeks to submit a “competing” application (provided that they are aware of the submission of the first application). This term is quite short. Even if the production operator/production licence holders succeed in a timely submission, the holder of the storage exploration licence will have priority. Operators in the Dutch offshore propose that the production operator/production licence holder could have the “*right of first refusal*” for the storage licence, meaning that the operator/production licence holder will get the opportunity to submit an application for a storage licence within a predefined time frame before the submission of other parties will be processed.

The Dutch Mining law allows simultaneous production and injection into the same reservoir, which opens the possibility of combining enhanced production with dedicated storage. This is a legacy of the ROAD project, which selected the small near-shore Q16-Maas field as the storage reservoir for a downscaled version of the CCS project (see also Section 5.1). This version of the ROAD project planned to start injection into the Q16-Maas field when production would still be ongoing. Text Box 3 describes the impact of the regulatory system on the development of the CCS project, as well as vice versa.

Text box 3: The Q16-Maas field – regulatory modifications to allow simultaneous storage and production

The Q16-Maas storage prospect is an example of re-use for permanent CO_2 storage with simultaneous HC production. This was the down-scaled storage opportunity considered in the ROAD CCS project in 2014.

The Q16-Maas field is a condensate-rich gas field, located just offshore of the Maasvlakte in the Rotterdam harbour area. The field was discovered in 2011 and production started in April 2014 from the well MSG-03X. Production was planned to cease by the end of 2022. While the production was planned to use natural depletion only, a benefit of injecting CO_2 into the field could be enhanced production of gas and condensate.

The development of this site and preparation for permitting led to a number of interesting insights (Jonker et al. 2018).

- The Q16-Maas permitting process should account for agreements with the Government on the concept of permanent CO_2 storage in an active reservoir, the contents of the new and modified permits and the permitting trajectory. Furthermore the production plan (Dutch: winningsplan) needs to be adjusted.
- At the time of developing the Q16-Maas storage site for the ROAD CCS project the injection of CO_2 would not be eligible for carbon emission credits as the production of hydrocarbons would still be ongoing during the start phase of injection. This is because in the original Dutch Mining Act one and the same reservoir could not have a production permit and a permanent CO_2 storage permit at the same time. For this particular reason the Mining Act has been amended to enable simultaneous HC production and permanent CO_2 storage, which was enforced from 1 January 2017 (Jonker et al. 2018).
- At the same time another provision was included in the Mining Act that promotes cooperation between the production operator and storage operator to avoid risky practices. This is to be ascertained in an agreement between both parties and may include specific requirements from the Ministry.
- The storage complex of the Q16-Maas gas reservoir and its environment has been characterized and evaluated on the basis of existing data from the production phase. No *exploration permit* was required. In case the current operator would apply for an exploration permit, this would give the operator also priority in the subsequent storage permit application. The drawback of this could be that in future situations an exploration permit application could lead to the neglect of a wealth of already existing data with other parties. In case of the ROAD CCS project, which was cancelled during the development stage, this did not lead to problematic situations. This particular linkage between exploration and storage permits would need to be evaluated (Jonker et al. 2018).
- In order to acquire a permit according to the Dutch Mining Act the operator has to show evidence of their technical competence and reliability to operate a storage site, which includes the necessary training and development of staff. A hydrocarbon production operator has a clear advantage here because a large part of the competence for CO_2 storage is comparable to that required for E&P activities.

- It is not likely that an operator will apply for a permit if they are not sure of operating a storage site prudently. Problems may arise for the applicant in case they would be completely unknown to the competent authority (Jonker et al. 2018).
- The existing *spatial zoning plan* needs to be adjusted so that the previous production location is now earmarked as a gas production and a CO_2 injection location.
- There is one operator of the Q16-Maas production and CO_2 injection location who planned to submit the application for the *environmental permit* (Wabo, in Dutch). The existing permit for the production installation would also include the CO_2 injection facilities and the adjusted production well with a CO_2 separator (Jonker et al. 2018). Part of the injected CO_2 may end up in the hydrocarbon production stream (condensate and gas) in the Q16-Maas storage project. For this purpose a device was planned to separate the produced CO_2 from the hydrocarbon stream and re-inject it with the CO_2 from the ROAD power plant.

Norway
There is no specific procedure referring to re-use of infrastructure for CO_2 storage. A permit including re-use will have to follow general provisions in the petroleum and CO_2 storage legislation (Dudu et al. 2021a). The HC field or the area of the continental shelf must be relicensed for CO_2 storage, and the ownership must be transferred to the legal entity running the CO_2 injection operation. If CO_2 injection is a part of the petroleum operation the holder of a petroleum licence may re-use wells for CO_2 injection (Dudu et al. 2020).

Romania
No permitting procedure is specified enabling re-use of hydrocarbon wells for CO_2 storage (Dudu et al. 2021). The guide for abandonment of offshore wells specifies that offshore infrastructure can be temporary abandoned and kept for other types of activities, including for the operation of CO_2 reservoirs (Dudu et al. 2020).

UK
Hydrocarbon well re-use is specifically permitted for CO_2 operations (Dudu et al. 2021). The Department for Energy Security & Net Zero (DESNZ) is the regulator for offshore oil and gas infrastructure decommissioning in the UK. DESNZ works with other agencies including the North Sea Transition Authority (NSTA, formerly Oil and Gas Authority, OGA), HSE, and waste regulators (e.g. the Environment Agency) to ensure that decommissioning is executed in a safe, environmentally sound and cost-effective manner. All installations should be completely removed from the marine environment unless an exemption is granted (Dudu et al. 2020).

Re-use of infrastructure is the preferred decommissioning option where practically feasible. It must be demonstrated in the decommissioning programme that re-use of the installations has been considered in conjunction with the NSTA (Dudu et al. 2020).

US
In the US, hydrocarbon well re-use is specifically permitted for CO_2 operations. Re-permitting of existing wells is allowed when the owner/operator can demonstrate that the well is engineered and constructed in an appropriate manner for CCS. The owner/operator needs to consider well material strength, material compatibility with CO_2 and formation fluids, injection well design and mechanical integrity (Dudu et al. 2020).

4.6 Transfer of assets, decommissioning

4.6.1 Decommissioning of hydrocarbon assets

One of the key challenges is to ensure that reuse is considered in the decommissioning plans of depleted fields, and when necessary, to allow for the postponement of decommissioning. Decommissioning of hydrocarbon production infrastructure is often required within a certain timeframe after Cessation of Production (CoP), which may prevent re-use. This facility removal obligation is a complex topic, in particular, in combination with the option of future re-use. The UK North Sea Transition Authority (NSTA, formerly Oil and Gas Authority, OGA) is upholding responsibility to consider re-use before decommissioning (COSTAIN et al. 2016).

Oil and gas operators should consider the re-use potential of their oil and gas infrastructure, before decommissioning the facilities. In case of potential re-use, oil and gas wells could be decommissioned in a way suitable for re-use for CCS (BEIS 2020); existing regulations may, of course, already prescribe methods of plugging and abandoning wells that lead to CO_2-tight wells. Data and technical records on well condition and how wells were plugged and abandoned should be made available for a future CCUS project. The reuse of wells may lead to cost associated with significant re-design and re-completion, depending on their state after CoP, when developing a CO_2 store (BEIS 2020).

Transfer of data from production operator to storage operator is highly relevant in case the storage operator is not the same entity as the production operator. Transfer of the data from the exploration and production phases to the storage operator requires oversight in case the storage activities do not directly start upon the Cessation of Production. A data repository should be set up (see Section 4.2).

4.6.2 Mothballing or suspending facilities

Mothballing is an activity to stop operations, with the objective to reduce OPEX and includes cleaning, conservation and safeguarding of facilities with the intention of later re-use (Cronenberg et al. 2009). The challenge in this regard is the liability and responsibility during the period of suspension. At present, it is unclear whether governments will take the cost of and liability during periods of suspension. The UK consultation on decommissioning suggested that when postponing decommissioning of offshore hydrocarbon assets to a date that would increase the likelihood of an asset being transferred to a CCUS project, this would be accompanied with essential ongoing monitoring and maintenance costs being incurred by the asset owner, although these could be partly offset by the delay of the cost of decommissioning (BEIS 2019); a period of up to 10 years of suspending assets was mentioned.

Oil and gas platforms might cease production before there is a large-scale demand for CO_2 storage. The risk exists that platforms may be abandoned and removed, unless there is clear prospect for reuse for CO_2 storage. Shareholders of the existing joint ventures in hydrocarbon exploration projects have voting rights with respect to mothballing and other strategic decisions that need to be taken by the current gas exploration entities (Haffner et al. 2018).

Long-term mothballing to preserve installations for future CO_2 storage will be costly, thus a trade-off must be made whether to construct new infrastructure or to mothball them for a longer period until the infrastructure can be adapted for CO_2 storage. If reuse is an option, platforms should be reused as soon as possible after CoP for CO_2 storage in order to avoid maintenance and integrity problems. Mothballing is likely to be feasible for short periods of time, especially in case the facilities are located offshore. Given the scale of re-use of facilities in projects currently being developed on the North Sea, the actual level of re-use may be limited.

4.6.3 Transfer of assets before CO_2 injection

Transfer of assets for a field is generally permitted between hydrocarbon operators inside the hydrocarbon licences. There are specific procedures for this transfer. Transfer of assets from hydrocarbon operations to storage operations is an issue poorly resolved in current regulatory frameworks (Dudu et al. 2021b). Table 4-2 shows the regulatory status for various countries based on the REX-CO2 project (Dudu et al. 2021a). For countries such as France and Romania CO_2 storage is not regulated inside hydrocarbon blocks (Dudu et al. 2020). In Norway licensing specifically for CO_2 storage is considered outside of areas licensed to petroleum operations, although the legislation allows concurrent licensing of the same area both for CO_2 storage and petroleum production, if one activity is not causing unreasonable disadvantages for the other (Dudu et al. 2020).

In the UK, conversion of a hydrocarbon field into a storage field is permitted and even encouraged. At present only the UK has a policy proposal for re-use of oil and gas infrastructure for potential future CO_2 transport and storage (Dudu et al. 2020). In the US, conversion of a hydrocarbon field into a storage field is permitted. There are multiple policy drivers and tax incentives for CO_2 geological storage. However, no policy explicitly encouraging hydrocarbon well re-use exists (Dudu et al. 2020).

Previous hydrocarbon asset owners are liable for the costs associated with decommissioning infrastructure. However, it is unclear how these obligations will fit into existing frameworks if assets are intended to be transferred for re-use. The removal of these decommissioning obligations for the asset owners could allow for the smooth transfer of infrastructure to a CCUS project (IEA n.d.).

Pore space ownership is not always clear and often an unsettled area of property rights law. In the US, the person who owns the surface estate is generally the person who owns the pore space in the ground and who has the right to sell (Newburn Law 2022). In the US the Mineral Estate owns the underground minerals (but not the geological formation including the soils). The Mineral Estate has the right to use the pore space during mineral extraction (Newburn Law 2022).

In the transfer of ownership one may distinguish three scenarios, according to Gazendam & Roggenkamp (2020): 1. Storage licence awarded during production, 2. Licence awarded directly after production ceases, and 3. CO_2 storage starts several years after cessation of production. In the first situation one and the same party could hold both licences, whereas in the second scenario it is more likely that different parties hold the production and storage licences. In both situations assets and financial reservations for decommissioning need to be transferred.

Scenario 3, in the above list, with a temporal gap between production and storage is the most problematic. Two possible solution directions can be considered. In the first, the production licence is extended for the period after the end of production and before the start of injection. The competent authority will approve that the infrastructure is not decommissioned during the extended period of the production licence. A second, possibly more viable option is to introduce an interim operator or ‘operator of last resort’ (Gazendam & Roggenkamp 2020) which will be responsible for the maintenance of the installation after the end of production and before the start of injection. The latter solution will require more extensive legislative action:

1. Developing a regional strategy for infrastructure selection,
2. Appointing an operator of last resort,
3. Defining a business model likely depending on financial government support, and 4. Securing final decommissioning.

The Zero Emission Platform (2022) identified three cases for the transition from production to storage accompanied with separate sets of recommendations. These cases overlap the 3 scenarios describe above. The three cases are:

1. The operator stops production in the current license area. It is recommended that the current operator (and JV partners) reports its intentions upfront, the competent authority needs to decide on liabilities of asset and license holders and a clear pathway to access information for site evaluation activities.
2. The operator continues and intends to start permanent CO_2 storage operations in the current license area. The existing joint-venture partners are asked if they want to join the new storage project or resign, and if needed the State may step in. In case of competition a transparent license granting process would be required.
3. The operator blocks a license because the operator has no clear priority in the storage application process. This could be overcome by asking production license holders to annually publish their plans for CO_2 storage, and annually publish their estimated production cessation date. Furthermore, they would be asked to ensure that all relevant data is appropriately archived.

An ETI study (COSTAIN et al. 2016) recommends to upgrade UK standards for abandonment of wells. In the abandonment of depleted gas fields particular attention is to be directed to these fields as strategic storage resources. If suitable for storage they could be made re-use ready with usable pipeline infrastructure. Each depleted field is recommended to undergo an independent assessment of CO_2 storage potential before decommissioning. An industry-led guideline for well abandonment considering CCS has been published by OEUK (2022).

Liability over wells put into hibernation is an issue that should be regulated in such a way as to encourage re-use of wells in a fair manner for the hydrocarbon operator. Liability during hydrocarbon well hibernation currently rests with the hydrocarbon operator, which comes with the responsibility of financing the hibernation. Liability of the hydrocarbon operator can be transferred to the CO_2 storage operator, when this new storage operator assumes ownership of infrastructure. This could take place during the appraisal phase for storage. This ownership transfer can be made only when the HC operator shows that the well is suitable for re-use and when the new storage operator is fully aware of the wells' status (Grimstad et al. 2021).

Clarity on the transfer of liabilities with the handover of assets from the production operator to the storage operator would be very helpful for making contractual agreements, though they might be overruled by private law. Change of ownership of existing infrastructure is permitted in Norway, but the original owner will maintain secondary liability for decommissioning of the infrastructure at ownership change. Transferring ownership of plugged but not abandoned wells requires parties to seek a new license and transfer of liabilities (Dudu et al. 2020). Operators in the Dutch offshore pose that it needs to be ascertained that no liabilities will be left with the producer (last known operator) after transfer of the assets to the storage operator.

The financial responsibility (e.g. in case of bankruptcy or other hazards) is covered by insurance. In the North Sea region, when the current CO_2 storage operator of an infrastructure cannot fulfil the decommissioning obligations, the competent authorities can impose the obligations on previous owners. This could discourage hydrocarbon operators to consider re-use for CO_2 storage projects, as they could be liable when the CO_2 storage operator fails to meet decommission obligations. In the US, the current owner is always liable and is expected to be aware of the status of the infrastructure. When the operator is bankrupt or in financial difficulty, then the insurance covers these expenses (Grimstad et al. 2021).

Table 4-2 Regulatory and legal aspects for transitioning to CO_2 storage for selected countries (Dudu et al 2021a).

Country	France	Netherlands	Norway	Romania	UK	USA
Permit/procedure to re-use hydrocarbon well for CO_2 storage	None	Existing	None	None	Existing	Existing
Safety standards for CO_2 storage wells	Unknown	Unknown	Existing	Unknown	Existing	Existing
Permit/procedure for the transfer of permits/assets between hydrocarbon license holders (related to hydrocarbon operations)	Existing	Existing	Existing	Existing	Existing	Existing
Permit/procedure for transfer of assets (wells) from hydrocarbon operation to storage operation	None	Proposed	None	None	Proposed	Existing
Procedure for transfer of CO_2 storage assets and fields to the state	Existing	Existing	Existing	Existing	Existing	Unknown

5 Commercial considerations

Following the assessment of technical, economic and regulatory needs in Sections 2, 3 and 4, this section discusses some practical commercial issues when looking at utilising depleted hydrocarbon fields. Although it may be technically possible to re-use hydrocarbon fields, in many countries the practical logistics of doing so and managing the uncertainties, liabilities and transfer of knowledge prevents projects from developing at the pace needed.

The UK Department for Energy Security and Net Zero (DESNZ, previously BEIS) has noted that a lack of experience with decommissioning CCUS installations acts as barrier to the development of CCS. The lack of experience disincentivises the transfer of assets from the oil and gas industry as the government is not able to transfer decommissioning liability to a future CCUS project (BEIS 2019). A policy on the preservation of oil and gas assets for future re-use is to be developed. The Head of Terms agreement between UK authorities and Eni may serve as start in this regard, as it is the first agreement on a regulated asset base on a depleted gas field[21].

Section 5.1 presents examples from the ROAD project in The Netherlands, which is summarised in a series of close-out reports[22]. The section outlines the different entities that emerged in the planning of the transition from production to storage, to handle ownership, cost and responsibility for production platform and wells, for a project that would involve simultaneous production and injection on the same platform changing relative importance over time. Section 5.2 discusses some aspects of the residual hydrocarbons in a gas or oil field.

5.1 Example: commercial framework proposed in the ROAD CCS project

Defining commercial arrangements for CO_2 storage projects in depleted hydrocarbon reservoirs can become quite complex, in particular for projects in the early stage of development. The ROAD CCS project (Wildenborg et al 2018) is used as an example here. At the time of development of the ROAD CCS project, around 2010, business models were not yet defined and the limited commercial incentives were not aimed at the storage operator. Furthermore, the business cultures of hydrocarbon and power producers, both sectors being part of the ROAD CCS project team, are quite different, as the exploitation of hydrocarbons is a high-reward, high-risk business whilst for the power sector this is the opposite. CCS operations involve many different actors, which may change over time and thus result in a complex ownership structure. The ROAD CCS demonstration project reached an advanced development stage but did not mature, unfortunately. In 2017 the project was cancelled mainly due to political reasons. Nevertheless, the project resulted in important lessons for the future development of CCS projects and the use of depleted hydrocarbon reservoirs as CO_2 storage media in particular (Read et al. 2019).

[21] https://www.eni.com/en-IT/media/press-release/2023/10/pr-eni-uk-government-agree-first-asset-based-regulated-ccs-business-model.html
[22] https://www.globalccsinstitute.com/resources/publications-reports-research/road-project-close-out-report/

In the ROAD project there was no strategic interest of the gas production operator in developing CO_2 storage. The operator required a commercial incentive to use their facilities and licence area for CCS. Regulatory risk was considered to be significant because of its uncertainty; in addition, the lack of strategic interest for the current field operator to become a CO_2 storage operator represented a risk in itself. The production operator required that the storage licence could be transferred to a storage operator after hydrocarbon production ceased.

In developing the commercial framework for the ROAD CCS project two main contractual parties were discerned, the ROAD legal entity (Maasvlakte CCS Project, MCP) and the Offshore Group, the latter consisting of the Platform Group and the P18-4 Group (Figure 5-1). The Platform Group consisted of the platform owners, while the P18-4 Group held the production licence and was the applicant of the CO_2 storage license.

The following cost Items were identified in the commercial agreements:

- Direct costs for construction and decommissioning of the platform modification according to normal industry standards, which was passed on as a direct charge;
- Common facility costs for operating and maintaining the platform according to the value of the fluid handled. It was agreed that the sharing of costs between production and storage was made dependent on the number of wells used for both activities[23]. With change of well usage over time, this split in costs would change consequently.
- Risk management costs were dealt with according to normal industry practice for shared facilities

The above would result in a modest reward for the Offshore Group. Three other rewards were included for the Offshore Group: the benefit of delaying decommissioning, the inclusion of a commercial tariff for keeping the facility available, and a payment per tonne of CO_2 linked to the CO_2 price. Arranging this tariff took a lot of effort.

A considerable number of agreements were set up between the various parties (Figure 5-1, see also Wildenborg et al. 2018):

- The Project Development Agreement (PDA) between the Offshore Group and MCP for construction, commissioning and CO_2 handling equipment;
- The Transporting, Processing and Operating Services Agreement (TPOSA) between both parties for operation and decommissioning the multi-user shared facility; the agreement offers the possibility for adding 3rd party CO_2.
- The Storage Services Agreement (SSA) between the P18-4 Group and MCP for operation and decommissioning; with enforcement of the PUT agreement (see below) the SSA would not be applicable. A PUT agreement arranges the option to sell assets at a fixed price.
- The optional PUT agreement between the Offshore Group and MCP to transfer the storage licence to MCP before start of injection or transfer the platform to MCP; eventually this could make MCP the owner of the complete CCS chain.
- The Master Services Agreement (MSA) between the P18-4 and the Platform Group for operation and decommissioning of the reservoir. The MSA would replace the SSA if MCP would become the storage license holder before start of injection.

[23] The platform provided access to the P18-4 gas field, the intended storage reservoir, as well as to the P18-2 and P18-6 gas fields, from which gas production was to continue during CO_2 storage operations.

Operating committees were planned for the PDA and TPOSA.

The ROAD project considered a second potential storage reservoir as an alternative to the P18-4 gas reservoir, which is the Q16-Maas condensate gas reservoir (Wildenborg et al. 2018). At the time, the Q16-Maas field was producing natural gas and condensates. One option was to simultaneously inject CO_2 and enhance hydrocarbon production in the same reservoir. However, the original Dutch Mining Law did not allow for simultaneous production from and storage in one and the same reservoir. To solve this issue, the Mining Law was amended so that simultaneous production and storage from one and the same reservoir became legally acceptable.

For a CCS project in the Q16-Maas reservoir two contractual entities were identified:

- The Q16-Maas Group, a consortium owning the condensate gas reservoir, and
- The ROAD legal entity (MCP).

The Q16-Maas Group had no strategic interest in developing CCS and would act as a facilitator of the CCS project rather than a co-investor. The Group would participate on a neutral-value basis. The benefits of accelerated gas production and enhanced recovery of condensate would outweigh the additional capital and operating costs of production. The additional costs and risks of CO_2 injection would rest solely with MCP. The costs, risk and obligations connected to the storage licence were covered by a "CO_2 storage fund" paid for by the acquired emission trading scheme (ETS) credits. It is unclear whether this was an acceptable way forward to the Dutch regulators as the ROAD project was stopped before formal discussions were possible.

A strong decrease in the carbon price undermined the business case and in 2012 the ROAD project was put on hold. A scaled-down version of the project was developed in the period 2014 – 2016, with the Q16-Maas field to be developed for storage. The emitter and the operator of the Q16-Maas field established an MoU for the cooperation on CO_2 injection into the gas-condensate reservoir. Based on this MoU a detailed commercial agreement was developed at the end of 2016 (Jonker et al 2018). However, in 2017 the project was again put on hold and the project was terminated.

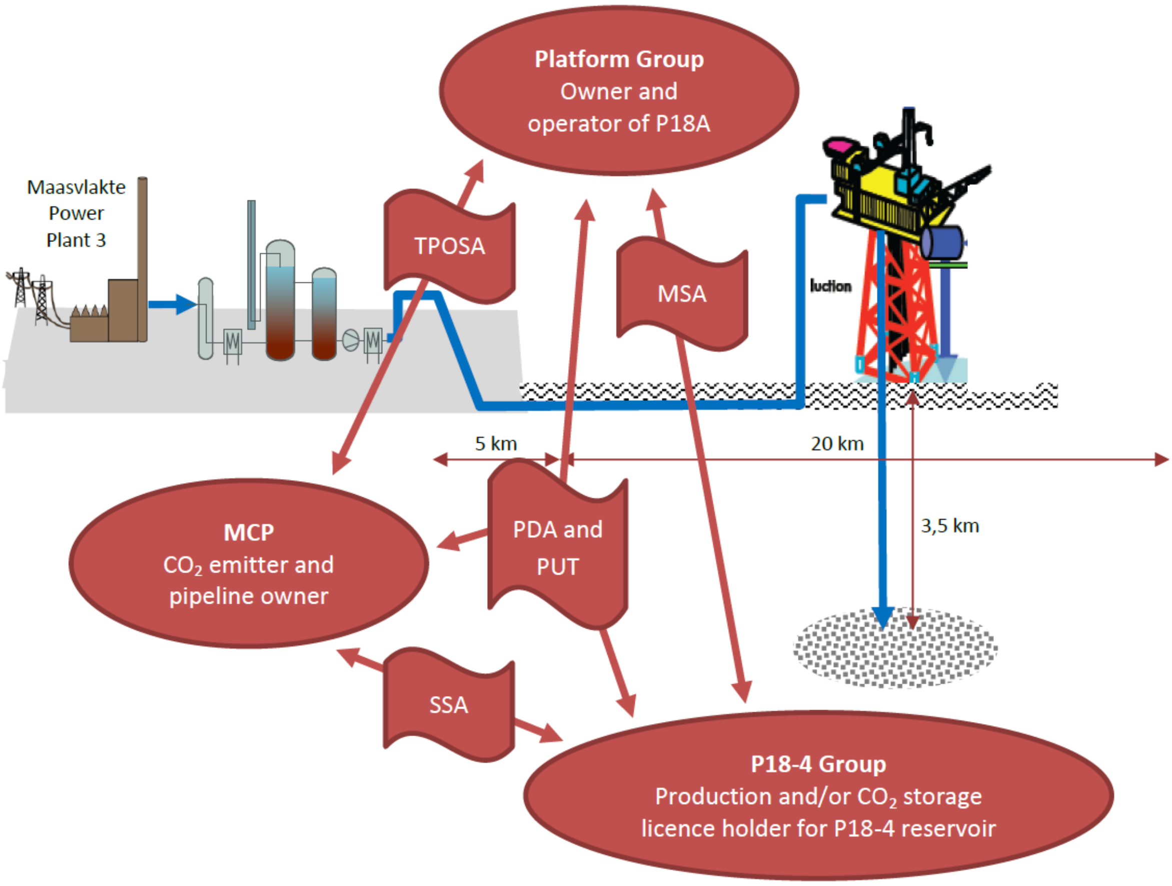

Figure 5-1. Scheme of the commercial parties involved in the CCS demonstration project ROAD and agreements between the various parties (Wildenborg et al., 2018); abbreviations are explained in the main text.

5.2 Residual hydrocarbons

The residual hydrocarbon volume in a reservoir (i.e., the volume of hydrocarbons remaining in place after the end of production) represents a potentially commercial value that needs be agreed on between production operator and storage operator, much like the facilities that are re-used. The value of the residual hydrocarbons will be as volatile as the market price of natural gas or oil, and will be negotiated between the production operator and the entity that is developing the storage project. Even if these are subsidiaries of the same mother companies, negotiations can take a long time to complete. This can really have an impact on the commerciality of the storage project.

Hydrocarbon JVs will also benefit from CO_2 storage if they can show they store a certain amount of emissions into a depleted reservoir somewhere else in Europe. If hydrocarbon production JV partners all move to the storage JV, negotiations can be expected to be more efficient.

This issue does not play a role in case of a reservoir that is re-opened after abandonment. No example of a gas reservoir developed for storage after the field has been decommissioned exists at this time; there are examples of oil fields that have been revitalised for EOR with associated storage (see, for the example of the Bell Creek oil field: Hamling et al. 2017). However, in mature oil and gas regions, such as the North Sea and the Gulf of Mexico, where fields approach the end of their lifetime, this can be expected in the period 2030 – 2050. In the Dutch offshore region, a large number of the 100+ offshore gas fields that are assumed suitable for storage (EBN-Gasunie 2017) will be abandoned before the need for CO_2 storage capacity requires their re-development.

Current developments suggest that hydrocarbon production operators that are planning CO_2 storage projects organise their storage activities in a separate legal entity. Cost, risk and benefits from storing CO_2 are then isolated from the hydrocarbon production business. If enhanced production would be pursued in parallel with storage, the revenue from the incremental recovery may not be on the same company as the cost of the injection operations.

In exploiting HC fields for permanent CO_2 storage one may consider an intermediate recovery phase enhanced by CO_2 injection (CO2-EOR). Different types of commercial contracts for an integrated CCS EOR project were analysed in Agarwal & Parsons (2011). They studied the example of integrated CCS-EOR with CO_2 capture at a coal-fired powerplant, transport via a dedicated pipeline to an oil field and injection for EOR. Two parties are considered in the commercial contracting, the owner of the powerplant responsible for capture and the oil field operator responsible for injection and permanent storage. The pipeline is assumed to be jointly owned by the power plant owner and the EOR operator. Two types of contracts were considered, one with a fixed price for CO_2 (USD per tonne of CO_2) and one with an indexed price for CO_2 per tonne. The indexed price is expressed as a percentage of the oil price (USD per barrel of oil).

The analyses showed that an indexed price contract is attractive for both parties and can accommodate a larger range of future CO_2 price changes without creating insolvencies with both parties. In this way the risk of future variations in the oil price is distributed better between the two companies with optimal contingent decision making on changing the capture rate and injection rate (Agarwal & Parsons 2011).

6 Summary and Conclusions

This report presents an analysis of the transition of depleted hydrocarbon fields to storage of CO_2. The attraction of re-developing depleted fields into CO_2 stores lies in the existence of a structure that has held in place hydrocarbons, pressurised and over geological timescales, in the availability of data and existence of understanding of the hydrocarbon field, and in the potential for cost reduction through the re-use of production facilities.

This attractiveness has led to a significant number of CO_2 storage projects being developed in depleted fields, in the North Sea and the Mediterranean, as well as in other parts of the world. Most of these projects plan to become operational before or around 2030 and prove that their developers are confident that the challenges discussed in this report and summarised below can be met. Operators in the North Sea realm emphasize that current uncertainties in project development, such as those described in this report, have been assessed and that mitigation plans for upset cases are in place.

Identified challenges are not prohibitive in reaching financial investment decisions (FID) or subsequent development steps; yet, solving these challenges will streamline the various phases of storage in depleted gas and oil fields and make storage more attractive, more efficient and less costly. The wide range of CO_2 concepts adopted by currently developing projects in depleted fields suggests that new projects will have the opportunity to customise their project concept, taking the solution to addressing challenges that best fits their project.

Table 6-1 summarises the challenges discussed in this report. The table, in the third column, also gives an indication of the group of stakeholders that is expected to take the lead in resolving the issues: industry (black font), governments (blue font) or the R&D community (green font). Standardisation organisations, such as ISO, are included in the industry stakeholder group. It is clear from the table that many of these challenges are expected to be resolved by the operators of the first wave of projects, that together will build a body of experience and operational evidence that will be the basis for industry best practices. Examples of these challenges include the injection of CO_2 from high-pressure transport systems into low-pressure reservoirs, the conversion of production wells (or other facilities) for storage, and the definition of suitable and sufficient monitoring systems.

Continued research and development will be required, to decrease cost and increase efficiency, as well as to resolve some of the issues listed in the table. A key issue, although not specific to depleted fields, is the definition of CO_2 specifications for CO_2 transport and storage operations. Knowledge development is needed to better understand the risks associated with impurities in the captured CO_2. Another area where R&D activity can provide support is that of suspension of facilities in the period between CoP and start of construction of storage facilities. Transport and storage projects currently in development suggest that re-use may take place at a smaller scale than perhaps expected, partly because of the age of facilities. This will be even more relevant for future projects. Using experiences from first-wave projects, recent studies on reuse potential could be updated, which may also support legislation and regulation around reuse (see below).

Knowledge sharing among CO_2 transport and storage projects will be essential for making full use of the experience gained by early projects and speeding up the development of sufficient storage capacity. Of equal importance is building up knowledge of competent authorities, who will have to understand the technical issues underlying the best practices to be able to accept them as the basis for, for example, storage license applications.

Some issues in Table 6-1 will require competent authorities taking the lead, which are:

1. Data repository. The availability of data, models and knowledge from the production phase is perhaps the strongest driver for the use of depleted fields for storage. Governments should take the lead in setting up a repository for this data, and develop guidance or rules for data to be transferred. This transfer preferably takes place directly after hand-over from production to storage operator (in the case that storage development immediately follows production) or after decommissioning and abandonment of the production facilities (in case no storage initiatives are developed when a field reaches the end of production). This data repository would be in line with the Article 17 of the Net Zero Industry Act. The data involved will form the starting point for the storage developer to build the models required for the CO_2 storage project.
2. Re-use of production facilities. The opportunity of cost savings through repurposing production facilities for storage is another attraction of depleted fields for storage developers. A clear policy and regulatory basis for assessing the feasibility of re-use of assets will provide the basis for an assessment of the cost involved in re-use and redevelopment of production assets. An assessment of the state of facilities and the feasibility of re-use could be part of the decommissioning of production assets and become part of the data transfer as discussed under the previous point.
3. Combined storage and production. Although currently not widely developed, concurrent storage and hydrocarbon production could be an attractive option. Initiating CO_2 storage during tail-end production could support the transition from hydrocarbon production to dedicated CO_2 storage. To provide clarity, governments should develop policy and regulations regarding the combination of storage and tail-end production.
4. Liability (and ownership) during suspension of production facilities. Currently developing storage projects present a mixed image with respect to re-use. On a national scale, studies could be performed to investigate the cost, risk and scale of potential re-use. Governments could step in in specific cases of key infrastructure or facilities, to maintain such facilities during the period between end of production and start of injection.

Table 6-1 Summary of challenges identified in the transition from production to storage in depleted hydrocarbon fields. In the column 'Way forward' coloured fonts indicate the stakeholder group who are expected to take the initiative for resolving the issues is expected: industry (black), governments (blue), or the R&D community (green). Relevant section numbers given in brackets in first column.

Topic	Challenge, issue	Way forward
Availability of data from production period for permit application (3.2, 4.2)	Availability and accessibility of subsurface data after abandonment of field, or after cessation of production	Set up data repository at country level
	Adapting hydrocarbon production workflows to CO_2 injection	Develop industry best practices
Risk assessment for permit application (2.3.1, 4.1)	Find appropriate level of detail in the analysis of risks, e.g. related to existing wells	Develop industry best practices Define metrics in permit application requirements coherent with scientific and engineering knowledge base
Re-use production facilities (2.3.4, 3.1, 4.5)	Balance risk profile and requalification of production facilities with cost savings	Develop industry best practices
	Regulations and standards for re-use	Develop policy and regulatory basis for the re-use of production assets for storage adjusted to current decommissioning rules
Design injection scenarios (2.2)	Manage conditions of CO_2 during injection to minimise operational and containment risks	Develop industry best practices
Set up storage license application (4.1)	Find appropriate level of detail in license application	Develop industry best practices Define metrics in permit application requirements coherent with scientific and engineering knowledge base
Transport (2.4.1.5)	Define CO_2 specifications for entire CCS chain	Continue knowledge development on the impact of impurities on transport risk level; set industry standard
Monitoring (2.3.5)	Set up site specific, adequate monitoring system	Develop industry best practices Define metrics in permit application requirements coherent with scientific and engineering knowledge base
Enhanced hydrocarbon recovery as an initial phase of dedicated storage operations (2.5, 4.3)	Approve projects transitioning from conventional CO_2-EOR to CO_2-EOR with storage	Develop policy and regulations to enable combined storage and tail-end production, to support the transition from production to dedicated storage

Mothballing (suspending) production facilities (3.3)	Liability, responsibility during suspension period	Perform study to investigate cost, risk and scale of probable re-use Governments to step in in specific cases of key infrastructure or facilities

7 References

ACORN, 2021. ACORN CCS project: Deliverable D10 Well Operating Guidelines. Acorn CCS Project: D10 Well Operating Guidelines (publishing.service.gov.uk)

Akhurst M, Kirk K, Neele F, Grimstad A-A, Bentham M, Bergmo P, 2021. Storage Readiness Levels: communicating the maturity of site technical understanding, permitting and planning needed for storage operations using CO_2, *Int J Greenhouse Gas Control* 110, 103402.

Agarwal A & Parsons J, 2011. Commercial Structures for Integrated CCS-EOR projects, *Energy Procedia*, 4, 5786-5793.

Allinson K, Burt D, Campbell L, Constable L, Crombie M, Lee A, Lima V, Lloyd T, Solsbey L, 2017. Best Practice for Transitioning from Carbon Dioxide (CO_2) Enhanced Oil Recovery EOR to CO_2 Storage. GHGT-13, *Energy Procedia* 114, 6950 – 6956.

Becker, B.W., Baldino, F. and A. Aleandri, Liverpool Bay are CCS: an advanced case study to achieve UK's carbon neutrality, ADIPEC conference, Abu Dhabi, November 2021, *SPE-207418-MS.*

BEIS, 2019. Reuse of oil and gas assets for carbon capture usage and storage projects – *Consultation*, 21p. https://assets.publishing.service.gov.uk/media/5d36e613ed915d0d083f29cf/reuse-oil-gas-assets-ccus-projects.pdf.

BEIS, 2020. Carbon capture, usage and storage, a government response on re-use of oil and gas assets for carbon capture and storage projects, https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/909642/CCUS-government-response-re-use-of-oil-and-gas.pdf.

Bifrost, 2023. CCS: bridging the transition to the energy of the future, https://bifrost-ccs.com/ccs/.

Bui M, Adjiman CS, Bardow A, Anthony EJ, Boston A, Brown S, and 24 more authors, 2018. Carbon capture and storage (CCS): the way forward, *Energy and Environ Sci* 11, 1062, 115 pp.

CarbonNet, 2016. Development of a CO_2 specification for a CCS hub network https://www.globalccsinstitute.com/archive/hub/publications/199363/carbonnet-project-development-co2-specification-ccs-hub-network.pdf

Carpenter S, 2022. Eliminating Non-Cash Flow Risks to Full Scale-Up of Geologic Storage (GS) Once Commercial Deployment Has Been Achieved. EFI Foundation, 42p, https://efifoundation.org/wp-content/uploads/sites/3/2023/02/5-Carpenter-CCS-Template-FINAL.pdf.

Cerasi P, Huiskes T, de Borst K, Opedal N. Todorovic J, Wollenweber J, Amro M, Bartosek M, 2022. RETURN – re-sue of depleted oil and gas fields for CO_2 sequestration, a new ACT project. Proc. 16th Greenhouse Gas Control Tech Conf (GHGT-16), 11pp. https://papers.ssrn.com/sol3/papers.cfm?abstract_id=4273106.

Clennel MB, Hovland M, Booth JS, Henry P, Winters WJ, 1999. Formation of natural gas hydrates in marine sediments. 1. Conceptual model of gas hydrate growth conditioned by host sediment properties. *J Geophys Res* 104/B10, 22985-23003.

CO2GeoNet, 2021. State-of-play on CO_2 geological storage in 32 European countries — an update, CO2GeoNet Report, 325 p.; DOI: 10.25928/co2geonet_eu32-o21u

Conner, A., Place, M., Chace, D. and N. Gupta, 2020. Pulsed Neutron Capture for Monitoring CO2 Storage with Enhanced Oil Recovery in Northern Michigan, Midwestern Regional Carbon Sequestration Partnership (MRCSP) Phase III (Development Phase), Volume II.F, https://www.osti.gov/servlets/purl/1773351.

COSTAIN, ETI, Pale Blue Dot, Axis Well Technology, 2016. Progressing Development of the UK's Strategic Carbon Dioxide Storage Resource – A Summary of Results from the Strategic UK CO_2 Storage Appraisal Project, 48p, https://ukerc.rl.ac.uk/ETI/PUBLICATIONS/CCS_CC1026_14.pdf.

CSRC 2022. CO_2 storage resources catalogue, *Cycle 3 report.* https://www.ogci.com/wp-content/uploads/2023/04/CSRC_Cycle_3_Main_Report_Final.pdf.

DHV & TNO, 2008. R van der Velde, J Mieog, J Breunese, G Remmelts. Potential for CO_2 storage in depleted gas fields on the Dutch Continental Shelf – Phase 1: Technical assessment. *Report DHV B3157 / MD-MV20080582, TNO 2008-U-R0674/A*, 79p.

DHV & TNO, 2009. C Cronenberg, R Rottier, R van der Velde, J Breunese, G Remmelts. Potential for CO_2 storage in depleted gas fields on the Netherlands Continental Shelf – Phase 2: Costs of transport and storage. *Report C2051 / MD-MV20090186*, 45p.

DNV, Safely re-using infrastructure for CO_2 transport and storage, 2022, https://www.dnv.com/Publications/safely-re-using-infrastructure-for-co2-transport-and-storage-229979.

Dudu AC, Rycroft L, Muriel T, Grimstad A-A, Pawar R, Williams J, 2020. Report on the assessment of policy, legal and environmental framework in participating countries, REX-CO_2 Deliverable D6.1, https://rex-co2.eu/documents/REX-CO2-D6.1%20Report%20on%20the%20assessment%20of%20policy,%20legal%20and%20environmental%20framework.pdf.

Dudu AC, Wildenborg T, Pagnier P, Grimstad A-A, Kvassnes A, Pawar T, AJS, Williams, J, 2021a. Comparative analysis of regulatory frameworks, REX-CO_2 D6.2, https://rex-co2.eu/documents/REX-CO2-D6.2-v2021.04.01-Comparative-analysis-of-regulatory-frameworks-public.pdf.

Dudu A-C, Grimstad A-A, Pagnier P, Pawar R, Rycroft L, Wildenborg T, Pearce J, Williams J, 2021b. Recommendations for Improvement of Legal and Environmental Framework. REX-CO_2 Deliverable D6.3, 17p, https://rex-co2.eu/documents/REX-CO2-D6.3-v2021.08.31-Recommendations-Legal-Environmental-Framework-public.pdf.

EBN & Gasunie, 2017. Transport en opslag van CO_2 in Nederland, 88p. (in Dutch) Studie-Transport-en-opslag-van-CO2-in-Nederland-EBN-en-Gasunie.pdf

Ennis-King, J, et al., 2011. The role of heterogeneity in CO2 storage in a depleted gas field: history matching of simulation models to field data for the CO2CRC Otway Project, Australia, Energy Procedia, 4, 3494-3501, doi:10.1016/j.egypro.2011.02.276

EPA, 2021. Petra Nova West Ranch Oil Field CO2 Monitoring, Reporting and Verification (MRV) Plan, https://www.epa.gov/system/files/documents/2021-09/wru_mrvplan.pdf.

ERM, 2016. Best Practice in Transitioning from CO2 EOR to CO_2 Storage – Report for CCP4 Policies and Incentives Working Group, 54p, https://www.co2captureproject.org/xt457PuN/report/CCP4_Transitioning_EOR_to_CCS_Report.pdf

EU, European Commission, 2023. An Interoperable CO_2 Transport Network – Towards Specifications for the Transport of Impure CO_2 https://circabc.europa.eu/ui/group/75b4ad48-262d-455d-997a-7d5b1f4cf69c/library/13c2a475-c705-432d-8ca3-17ce799ba502/details.

Furre AK, Eiken O, Elnes H, Vevatne JN, Kiaer AF, 2017. 20 years of monitoring CO_2 injection at Sleipner, Energy Procedia, 114, 3916-3926, doi: 10.1016/j.egypro.2017.03.1523

Gazendam J & Roggenkamp M, 2020. Legal aspects of reuse of offshore hydrocarbon infrastructure for CCS. ALIGN CCUS Deliverable D3.3.4, 60p.

GCCSI, 2020. Global Status of CCS 2020. Global Status of CCS Report: 2020 - Global CCS Institute

GCCSI, 2022. Global status of CCS 2022.GCCSI_Global-Report-2022_PDF_FINAL-01-03-23.pdf (globalccsinstitute.com)

GCCSI, 2023. Global status of CCS 2023 – scaling up through 2030. Global-Status-of-CCS-Report-1.pdf (globalccsinstitute.com)

Godec M, Kuuskraa V, Van Leeuwen T, Melzer LS, Wildgust N, 2011. CO_2 Storage in Depleted Oil Fields: The Worldwide Potential for Carbon Dioxide Enhanced Oil Recovery. GHGT-10, *Energy Procedia* 4, 2162–2169.

Godec M, Koperna G, Petrusak R, Oudinot A, 2014a. Enhanced Gas Recovery and CO_2 Storage in Gas Shales: A Summary Review of its Status and Potential. *Energy Procedia* 63, 5849 – 5857, GHGT-12.
doi: 10.1016/j.egypro.2014.11.618.

Godec M, Koperna G, Gale J, 2014b. CO_2-ECBM: A Review of its Status and Global Potential, *Energy Procedia*, 63, 5858-5869, doi:10.1016/j.egypro.2014.11.619.

Greenhalgh E, Randles T, Goldthorpe W, Akhurst MC, 2019. Re-use of infrastructure United Kingdom, ALIGN-CCUS project, Deliverable D3.3.2, 39p.

Greensand, 2023. What is Project Greensand? https://www.projectgreensand.com/en/hvad-er-project-greensand.

Grimstad, A-A, Ringstad C, Greenhalgh E, Randles T, Neele F, Gazendam J, Goldthorpe W, Avignon L, 2019. Methodology for mapping possibilities of infrastructure re-use. ALIGN-CCUS project, Deliverable D3.3.5, 54p.

Grimstad A, Pagnier P, Pawar R, Rycroft L, Wildenborg T, Pearce J, Williams J, 2021. Recommendations for Improvement of Legal and Environmental Framework, REX-CO_2https://rex-co2.eu/documents/REX-CO2-D6.3-v2021.08.31-Recommendations-Legal-Environmental-Framework-public.pdf

Gupta N, Cumming L, Sminchak J, Pasumarti A, Ganesh PR, Van Voorhees RF PLLC, 2016. Combining CO_2 Enhanced Oil Recovery with Permanent Storage in Mexico – Review of Current Status and Identification of Key Issues. *Final Report*, World Bank Selection No. 1158524, Battelle Project #100062989, 89p.

Haffner R, Bolscher H, van Til H, Vermeulen, J., 2018. Marktontwikkeling en Marktordening CCS, Ministerie van Economische Zaken en Klimaat, https://trinomics.eu/wp-content/uploads/2019/04/MarktontwikkelingenmarktordeningCarbonCaptureandStorageCCS-1.pdf

Hamling, JA, et al 2017. Monitoring 3.2 million tonnes of CO_2 at the Bell Creek oil field, *Energy Procedia*, 114, 5553-5561, doi: 10.1016/j.egypro.2017.03.1695.

Hannis S, Lu J, Chadwick A, Hovorka S, Kirk K, Romanak K, Pearce, J, 2017. CO_2 storage in depleted or depleting oil and gas fields: What can we learn from existing projects?, *Energy Procedia*, 114, 5680 – 5690.

Hill IB, Li XC, Wei N, 2020. CO_2 in China: a comparative review, *Int J Greenhouse Gas Control* 103, 103173, 13pp.

IEA, 2015. Storing CO_2 through enhanced oil recovery – combining EOR with CO_2 storage (EOR+) for profit, https://iea.blob.core.windows.net/assets/bf99f0f1-f4e2-43d8-b123-309c1af66555/Storing_CO2_through_Enhanced_Oil_Recovery.pdf.

IEA, 2020. Energy Technology Perspectives, Special Report on Carbon Capture, Utilisation, and Storage, CCUS in clean energy transitions, 174pp Energy Technology Perspectives 2020 – Analysis - IEA

IEA, 2022a. CO_2 transport and storage, https://www.iea.org/energy-system/carbon-capture-utilisation-and-storage/co2-transport-and-storage

IEA, 2022b. Legal and regulatory frameworks for CCUS, an IEA Handbook, 111pp. Legal and Regulatory Frameworks for CCUS (windows.net)

IEA, 2024. CCUS Legal and Regulatory Database – Data Tools – IEA, https://www.iea.org/data-and-statistics/data-tools/ccus-legal-and-regulatory-database

IEAGHG & ZEP, 2011. The costs of CO_2 storage: post-demonstration CCS in the EU, Zero Emission Platform. The costs of CO2 storage: post-demonstration CCS in the EU - Global CCS Institute

IEAGHG, 2009. CO_2 Storage in Depleted Oil Fields: Global Application Criteria for Carbon Dioxide Enhanced Oil Recovery, Report, 165 pp. Microsoft Word - IEA_CO2 storage in oil fields 8-31-09 FINAL _ARI approved_ (ieaghg.org).

IEAGHG, 2015. Review of offshore monitoring for CCS projects, International Energy Agency Greenhouse Gas R&D Program, *Report* No. 2015/02, 185pp.

IEAGHG, 2017. Case Studies of CO_2 Storage in Depleted Oil and Gas Fields., International Energy Agency Greenhouse Gas R&D Program, Report No. 2017/01, 172pp.

IEAGHG, 2022. Criteria for Depleted Reservoirs to be Developed for CO_2 Storage, January 2022.

ISO TC265 (in prep). Carbon dioxide enhanced oil recovery (CO_2-EOR) – Transitioning from EOR to storage. ISO/AWI TR 27926

Jafari A and Faltinson J, 2013. Transitioning of Existing CO_2-EOR Projects to Pure CO_2 Storage Projects. SPE 167180. *SPE Unconventional Resources Conference Canada*, Society of Petroleum Engineers.

Jansen F, Steinz R, van Gelder B, 2011. Potential for CO_2 storage in depleted fields on the Dutch Continental Shelf – Cost estimate for offshore facilities. GHGT-10, *Energy Procedia* 4, 3079–3086.

Jonker T, van Onna J, Read A, Kombrink M, 2018. Close-Out Report Permitting & Regulation – Rotterdam Opslag en Afvang Demonstratieproject, 61p. https://www.globalccsinstitute.com/wp-content/uploads/2019/09/ROAD-Close-Out-Report-on-Permitting-Regulation-final.pdf

Kearns D, Liu H, Consoli, C, 2021. Technology readiness and costs of CCS, Global CCS institute report, 50pp. CCE-CCS-Technology-Readiness-and-Costs-22-1.pdf (globalccsinstitute.com).

Koning M, Dudu A, Opedal N, Pawar R, Rycroft L, Williams J, Zikovic V, 2022. Final report REX-CO_2 project, Deliverable 1.7, 42p.

Lacy R, Serralde C, Climent M, Vaca M, 2013. Initial assessment of the potential for future CCUS with EOR projects in Mexico using CO_2 captured from fossil fuel industrial plants, *Int J Greenhouse Gas Control* 19, 212-219.

Le Goff T-H, Lagardea F, Bousqué M, Santanach-Carreras E, 2022. A Microfluidic Experimental Approach to Assess CO_2 Hydrate Risk for CO_2 Storage into Depleted Gas Reservoirs, *16th International Conference on Greenhouse Gas Control Technologies* (GHGT-16), 11pp. http://dx.doi.org/10.2139/ssrn.4284971.

Leroux, KM et al, 2021. First North Dakota CCS Project: Advancing North Dakota Ethanol Economics, Proceedings of the 15th Greenhouse Gas Control Technologies Conference 15-18 March 2021. http://dx.doi.org/10.2139/ssrn.3812021.

Liu S-Y, Ren B, Li H-Y, Yang Y-Z, Wang Z-Q, Wang B, Xu J-C, Agarwal R, 2022. CO_2 storage with enhanced gas recovery (CSEGR): A review of experimental and numerical studies, *Petroleum Sci.,* 19, 594-607. https://doi.org/10.1016/j.petsci.2021.12.009.

Luderer G, Vrontisi Z, Bertram C, Edelenbosch OY, Pietzcker RC, Rogelj J, et al. ,2018. Residual fossil CO_2 emissions in 1.5-2°C pathways. *Nat. Clim. Change* 8, 626–633. Doi: 10.1038/s41558-018-0198-6.

Maslin E, 2021. Decommission or repurpose? – Could there be a CCS afterlife for old platforms? https://www.maritimemagazines.com/offshore-engineer/202201/decommission-or-repurpose/

Mazumder S, Karnik AA, Wolf K-H, 2006. Swelling of coal in response to CO_2 sequestration for ECBM and its effect on fracture permeability. *SPE Journal* 11/3, 390-398. Doi: 10.2118/97754-PA.

Melzer, LS, Carbon Dioxide Enhanced Oil Recovery (CO_2-EOR): Factors Involved in Adding Carbon Capture, Utilization and Storage (CCUS) to Enhanced Oil Recovery, *Report* for the National Enhanced Oil Recovery Initiative, Center for Climate and Energy Solutions, https://carboncapturecoalition.org/wp-content/uploads/2018/01/Melzer_CO2EOR_CCUS_Feb2012.pdf.

MidWest, 2023. The Mid West Clean Energy CCS project in Western Australia. Mid West Clean Energy Project | Pilot Energy

Min B, Sun AY, Wheeler MF, Jeong H, 2018. Utilization of multiobjective optimization for pulse testing dataset from a CO2-EOR/sequestration field, J. Petr. Sc. Eng., 170, 244-266, https://doi.org/10.1016/j.petrol.2018.06.035

Miri R, Hellevang H, 2016. Salt precipitation during CO_2 storage – a review, *Int J Greenhouse Gas Control* 51, 136-147.

Morland BH, Dugstad A, Svenningsen G, 2022. Experimental based CO_2 transport specification ensuring material integrity, *Int J Greenhouse Gas Control*, 119, 103697. https://doi.org/10.1016/j.ijggc.2022.103697.

Mourits F, Kulichenko-Lotz N, Hernández González G, Mota Nieta J, 2017, Overview of World Bank CCUS program activities in Mexico, *Energy Procedia* 114, 5916 – 5932. Doi: 10.1016/j.egypro.2017.03.1729

Neele F, Hewson C, Loeve D, Eyvazi F, Hegen D, Hofstee C, 2018. CO_2-EGR: Using CO_2 to Enhance Gas or Condensate Recovery. 14th Greenhouse Gas Control Technologies Conference (GHGT-14), https://ssrn.com/abstract=3366064.

Neele F, Wildenborg T, Geel K, Loeve D, Peters L, Kahrobaei S, Candela T, Koenen M, Hopmans P, van der Valk K, Orlic, B, Vandeweijer, V, 2019. CO_2 storage feasibility in the P18-6 depleted gas field, *TNO report* 2019 R11212.

Negrais Seabra P., 2020, Lula Oil Field CO2-EOR Project Update, Presented at the 4th International Workshop on Offshore Geologic CO_2 Storage, University of Bergen, Norway, https://gccc.beg.utexas.edu/files/gccc/media/4th international workshop on offshore geologic co2 storage/13-12_1121 Paulo Negrais Seabra Lula v1.pdf.

NETL, 2010. Carbon Dioxide Enhanced Oil Recovery: Untapped Domestic Energy Supply and Long Term Carbon Storage Solution, The Energy Lab, https://www.netl.doe.gov/sites/default/files/netl-file/CO2_EOR_Primer.pdf.

NOGEPA, 2021. Industry standard nr 45 – decommissioning of wells, https://www.nogepa.nl/download-file/31

Núñez-López V, Holtz MH, Wood DJ, Ambrose WA, Hovorka SD, 2008. Quick-look assessments to identify optimal CO_2-EOR storage sites: *Environ Geol,* 54/8, 1695–1706, doi:10.1007/s00254-007-0944-y.

Newburn Law, 2022. Pore space ownership and use in the carbon capture industry, https://www.newburnlaw.com/pore-space-ownership-and-use-in-the-carbon-capture-industry.

OEUK, 2022. OEUK Well Decommissioning for CO_2 Storage Guidelines https://oeuk.org.uk/product/oeuk-well-decommissioning-for-co2-storage-guidelines/.

OnePetro, 2024. Online library accessed March 2024 CO_2 enhanced recovery | Page 1 | Search Results | OnePetro.

OGA, Oil and Gas Authority, 2020, UKCS Energy Integration Final Report. https://www.nstauthority.co.uk/media/6625/ukcs_energy_integration_phase-ii_report_website-version-final.pdf.

Pagnier H, van Bergen F, Krzystolik P, Skiba J and 21 co-authors, 2006. RECOPOL reduction of CO_2 emission by means of CO_2 storage in coal seams in the Silesian coal basin of Poland, final report, *IAEGHG report* 2006/10, 102 pp.

Porthos, 2023. Porthos project, https://www.porthosco2.nl/en/project/

Prevost, M., et al., BIFROST, an innovative CO_2 transportation and storage project in Denmark, GHGT-16 paper, 2022, http://dx.doi.org/10.2139/ssrn.4287094.

Rebscher D, Oldenburg CM, 2005. Sequestration of carbon dioxide with enhanced gas recovery – Case Study Altmark, North German Basin, Lawrence Berkeley National Laboratory Report LBNL-59033. https://escholarship.org/content/qt7sj2g8mc/qt7sj2g8mc.pdf?t=li51tc.

Read A, Gittins C, Uilenreef J, Jonker T, Neele F, Belfroid S, Goetheer E, Wildenborg T, 2019. Lessons from the ROAD project for future deployment of CCS. *Int J Greenhouse Gas Control*, Volume 91, 102834. https://doi.org/10.1016/j.ijggc.2019.102834.

Rempel AW & Buffet BA, 1997. Formation and accumulation of gas hydrate in porous media, *J Geophys Res* 102/B5, 10151-10164.

Sachde D, Dombrowski K, Davis D, McKasle R, Lundeen J, 2022. Offshore Oil and Gas Infrastructure Reuse for CCS: Opportunities and Challenges in the U.S. Gulf of Mexico, *Proc 16th International Conference on Greenhouse Gas Control Technologies* (GHGT-16).

Sacuta N, Young A, Worth K, 2015. International Energy Agency (IEA) Greenhouse Gas (GHG) Weyburn-Midale CO_2 Monitoring and Storage Project, *Report* Petroleum Technology Research Centre. https://www.osti.gov/servlets/purl/1235550.

Saini, D., Monitoring of injected CO2 at two commercial geologic storage sites with significant pressure depletion and/or re-pressurization histories: A case study, *Petroleum*, 3, 138-143, 2017.

Sahin S, Kalfa U, Celebioglu D, 2008. Bati Raman field immiscible CO_2 application – status quo and future plans, SPE-1065750PA, *SPE Res Eval & Eng* 11/4, 778-791.

Sharma, S., Cook, P., Jenkins, C., Steeper, T., Lees, M., and N. Ramasinghe, The CO2CRC Otway Project: Leveraging experience and exploiting new opportunities at Australia's first CCS project site, *Energy Procedia*, 4, 5447-5454, 2011.

Shell U.K. Limited, 2014. Peterhead CCS project: Abandonment concept for injection wells. PVT Modelling Report for CO2 in Goldeneye Project (publishing.service.gov.uk)

Sloan ED & Koh CA, 2008. *Clathrate Hydrates of Natural Gases*, 3rd ed. CRC Press, 730pp.

Smith, S., Sorensen, J.A., Steadman, E.N., J.A. Harju, and D. Ryan, Zama acid gas EOR, CO_2 sequestration, and monitoring project, *Energy Procedia*, 4, 3957-3962, 2011.

Spangenberg E, Kulenkampff J, Nauman R, Erzinger J, 2005. Pore space hydrate formation in a glass bead sample from methane dissolved in water, *Geophys Res Lett* 32/L24301, 4pp, doi: 10.1029/2005GL024107.

Steeghs P, Neele F, Gittins C and Ros M, 2014. Drafting a monitoring plan for the ROAD project under the EU CCS Directive, *Energy Procedia*, 63, 6680-6687, https://doi.org/10.1016/j.egypro.2014.11.702.

Sun X. Alcalde J, Gomez-Rivas E, Struth L, Johnson G, Travé A, 2020. Appraisal of CO_2 storage potential in compressional hydrocarbon-bearing basins: Global assessment and case study in the Sichuan Basin (China), *Geoscience Frontiers*, 11, 6, 2309-2321.

Tamáskovics A, Kummer N-A, Amro M, Alkan H, 2023. Experimental investigation on the stability of gas hydrates under near-welbore conditions during CO_2 injection for geologic carbon storage, Gas Sci Eng, 118. https://doi.org/10.1016/j.jgsce.2023.205101.

The CCUS Hub, 2023, CCUS Basics: State of Play, https://ccushub.ogci.com/ccus-basics/state-of-play/.

Thibeau, S., Chiquet, P., Prinet, C. and M. Lascanne, Lacq-Rousse CO_2 Capture and Storage Demonstration Pilot: Lessons Learnt from Reservoir Modelling Studies, *Energy Procedia*, 37, 6306-6316, 2013.

Total, Carbon capture and storage – the Lacq pilot, project and injection period 2006-2013, and 2015. https://www.globalccsinstitute.com/archive/hub/publications/194253/carbon-capture-storage-lacq-pilot.pdf.

Trupp M, Ryan S, Barranco I, Leon D, Scoby-Smith L, 2021. Developing the world's largest CO_2 injection system – a history of the Gorgon Carbon Dioxide Injection System, *Proc. 15th Int. Conf Greenhouse Gas Control Technologies*, 13 pp.

Upstream news, 2020. ENI sees CCS as 'key pillar of decarbonisation strategy' with Europe hub in its sights,https://www.upstreamonline.com/energy-transition/eni-sees-ccs-as-key-pillar-of-decarbonisation-strategy-with-europe-hub-in-its-sights/2-1-902281.

Vujasin M, 2023. Energean to store CO_2 in depleted oil wells off Greek coast, https://balkangreenenergynews.com/energean-to-store-co2-in-depleted-oil-wells-off-greek-coast/.

Waite WF, Spangenberg E, 2013. Gas hydrate formation rates from dissolved-phase methane in porous laboratory specimens, *Geophys Res Lett* 40, 4310-4315, doi:10.1002/grl.50809.

Wallace M, 2021. The U.S. CO_2 Enhanced Oil Recovery Survey: An interim update of enhanced oil production totals and CO_2 supplies for active CO_2-EOR projects in the U.S. as of end-of-year 2020, Advanced Resources International. DRAFT 2021 EOY 2020 CO2-EOR Survey OCT_21_2021 V2.pub (adv-res.com).

White, D. (2009). Monitoring CO_2 Storage during EOR at the Weyburn-Midale Field. *The Leading Edge*, 28, 838-842.

Wildenborg T, Brunner L, Read A, Neele F, Kombrink M, 2018. Close-Out Report on CO_2 Storage (P18-4 and Q16-Maas) – Rotterdam Opslag en Afvang Demon-stratieproject, 100p. https://www.globalccsinstitute.com/wp-content/uploads/2019/09/ROAD-Close-Out-Report-on-CO2-Storage-final.pdf

Wildenborg T, Loeve D, Neele F, 2022. Large-scale CO_2 transport and storage infrastructure development and cost estimation in the Netherlands offshore, *Int J Greenhouse Gas Control*, 118, 103649. https://doi.org/10.1016/j.ijggc.2022.103649.

Zapantis A, Townsend A, Rassool D, 2019. Policy priorities to incentivise large scale deployment of CCS, Global CCS institute.

Zero Emissions Platform, 2020, A Trans-European CO_2 Transportation Infrastructure for CCUS: Opportunities & Challenges, https://zeroemissionsplatform.eu/wp-content/uploads/A-Trans-European-CO2-Transportation-Infrastructure-for-CCUS-Opportunities-Challenges-1.pdf

ZEP, 2022a. Experience in developing CO_2 storage under the Directive on the geological storage of carbon dioxide, Zero Emission Platform.

ZEP, 2022b. Guidance for CO_2 transport by Ship, Zero Emissions Platform, ZEP/CCSA Network Technology report, 50 pp. ZEP-CCSA-Report-on-CO2-transport-by-ship-March-2022.pdf (zeroemissionsplatform.eu)

Appendix 1: Case studies

1.1 Selection of case studies

Three case studies are presented below. In the Netherlands the Porthos project has recently taken FID and is in the construction stage. It is the result of more than a decade of studies. The Mid-West project in Australia has entered pre-FEED/FEED stage. An lastly, consideration of the transition from EOR to storage in North Dakota as well as a CCUS project are described.

1.2 Case Study: PORTHOS (Netherlands)

1.2.1 Launching the first CCS project in the Netherlands

The case study of the Porthos (Port of Rotterdam CO_2 Transport Hub and Offshore Storage) project in the offshore Dutch North Sea illustrates the main risks of storing CO_2 in depleted gas fields. Here, the way in which these risks were approached is discussed. The project has taken Final Investment Decision in October of 2023. The history of this' project development is laid out and its concept for re-use of platforms and wells is described.

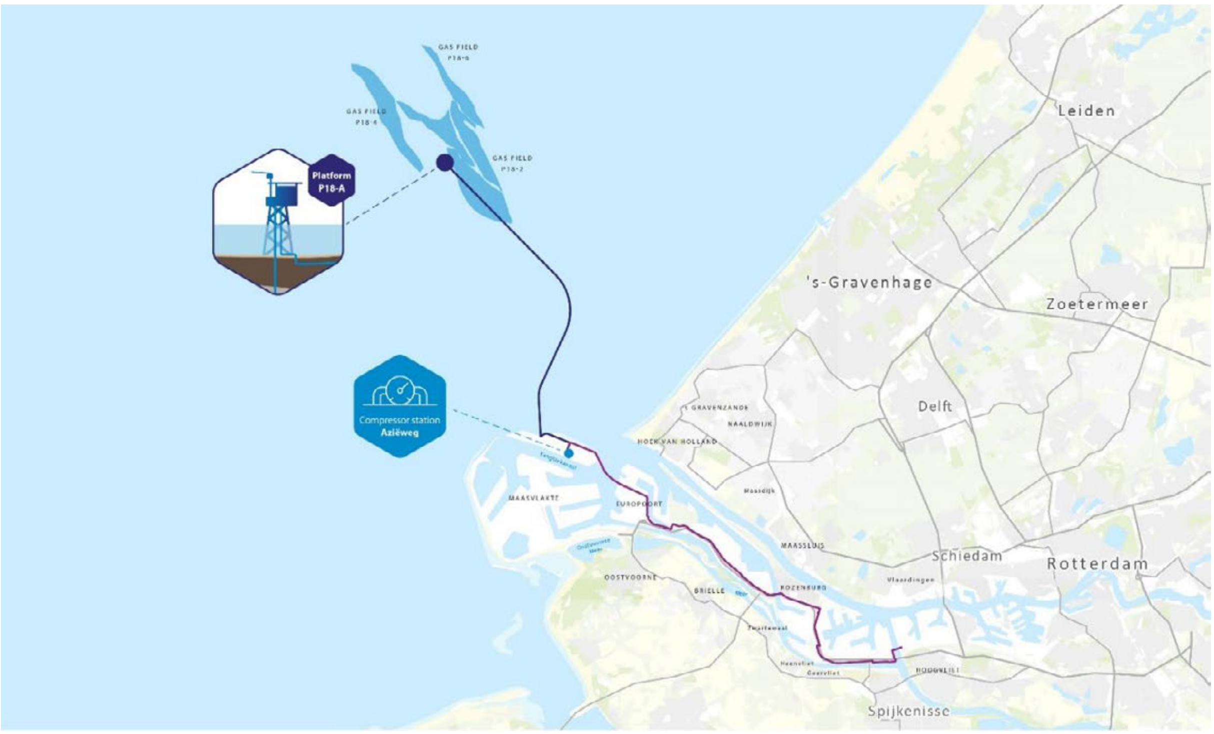

Figure A-1. Location of the Porthos infrastructure and offshore field in the Rotterdam Port area, The Netherlands (see Project - Porthos (porthosco2.nl)).

Porthos is a collaboration of the Dutch state shareholdings Port of Rotterdam Authority, Gasunie and EBN[24]. The project aims to transport CO_2 captured from industry in the Port of Rotterdam and store it in depleted gas fields 20 km offshore Rotterdam (see Figure A-1).

The four launching customers for storage are Air Liquide, Air Products, ExxonMobil and Shell. Together, they will capture approximately 2.5 Mt/a of CO_2 for 15 years (a total of 37.5 Mt). The onshore collection pipeline is designed for a larger capacity (up to 10 Mt/a CO_2) and 10 entry points, to ensure that in the future additional clients will be able to access the CO_2 transport and storage infrastructure.

The CO_2 will be transported via the onshore pipeline to a compressor station to be pressurised (Figure A-2) and then travel through an offshore pipeline to an offshore platform and injected in depleted gas fields at a depth of more than 3 km. Porthos will initially transport and store around 37 million tonnes CO_2 in these fields.

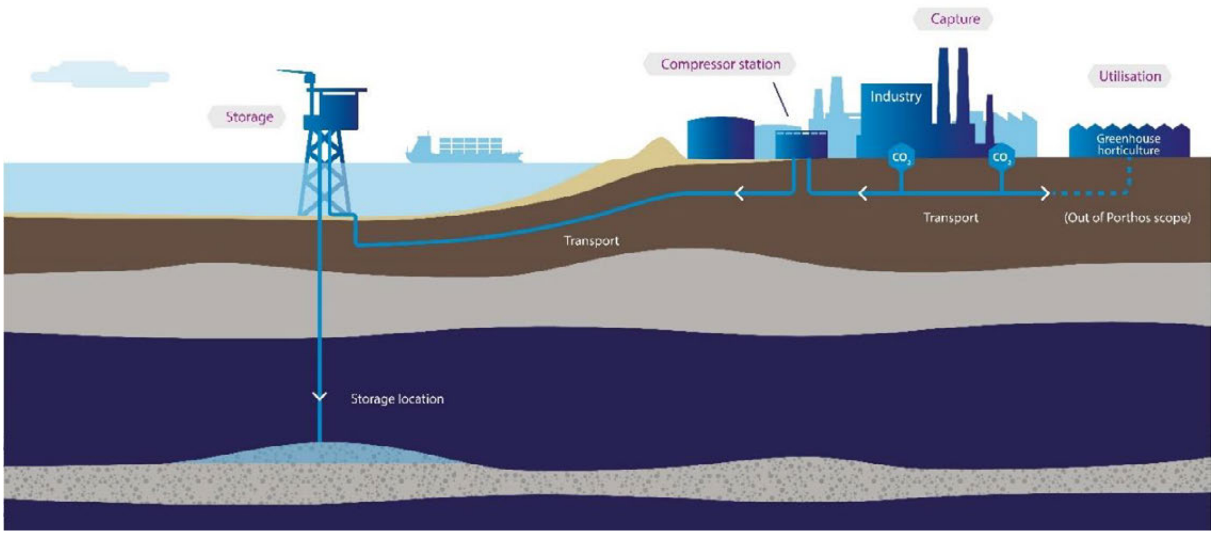

Figure A-2. Schematic overview of the Porthos system (see Media - Porthos (porthosco2.nl))

Whilst previous injection into depleting gas fields were small scale pilots, Porthos is the first large-scale CCS project in the Netherlands, and one of the first to source CO_2 from multiple companies, adopting an open access approach. As a result, Porthos has a significant cost advantage over stand-alone projects (one source/customer to storage). It is to date also the first full scale storage of CO_2 in depleted gas fields.

Porthos has been developing since 2017 with step-by-step commitments on technical design concomitantly with the maturation of commercial agreements. Currently, activities focus on permit procedures, technical details, contracting contractors and purchasing system components to start construction of infrastructure. It is expected to be operational by 2026.

[24] See also https://www.porthosco2.nl/

1.2.2 Reducing CO_2 emissions rapidly to slow down climate change

The Netherlands aims for a reduction in emissions of 55% of the 1990 emissions by 2030 and ultimately reach net-zero by 2050[25]. Numerous solutions are needed: the transition to renewable energy sources, energy conservation, reuse of materials and the capture, transport and storage of CO_2 (CCS). The Dutch Climate Agreement underlines the importance of CCS for the energy transition to aid decarbonising the hard-to-abate emissions from industries, both in the short term and in the long term.

The Netherlands is ideally suited for CCS, for a number of reasons[26]:

- Energy-intensive industry with large CO_2 emissions is concentrated in a few clusters.
- These clusters are close to the coast, which is favourable for offshore storage.
- The Netherlands have considerable storage capacity under the North Sea in the form of depleted oil and gas fields. Many of the gas and oil fields are at the end of their economic life and therefore potentially available for CO_2 storage.
- The oil and gas infrastructure (platforms and wells) can potentially be reused for transport and storage of CO_2, if deemed suitable after the appropriate engineering studies.
- The Netherlands has excellent logistical conditions for CO_2 transport in the form of infrastructure of pipeline lines, waterways and ports for transport of CO_2 via ships.

All this makes CCS cost-effective (euros per avoided tonnes of CO_2) compared to alternative techniques for reducing CO_2 emissions. Together with the fact that CCS can be realized quickly and in large volumes, CO_2 storage can be considered an indispensable instrument to achieve the Dutch climate goals by 2030. Consequently, the Dutch government has granted a subsidy to the four launching customers to overcome the dilemma of investing in carbon capture installations with respect to the market conditions of the European Trading System prices for carbon emission rights. This unique governmental support system helps to bridge gaps in the business case.

1.2.3 Main findings in the transition of hydrocarbon fields from production to injection

As first-of-a-kind project Porthos has run into several issues that had to be solved such as:

- Porthos has identified the main risks for system safety and is putting in place all required measures to store CO_2 in a safe manner.
- Porthos has successfully obtained permits for storage of CO_2 in depleted gas reservoirs, based on extensive technical studies and modelling work to substantiate injection and monitoring plans.
- Porthos has overcome the investment dilemma by successful matchmaking between CO_2 emitters and geological storage providers.

Here, the focus is on how Porthos has created confidence that CO_2 storage in offshore gas fields can take place in a safe manner.

[25] See, e.g., government goals presented in the coalition agreement of 2022: https://www.rijksoverheid.nl/onderwerpen/klimaatverandering/klimaatbeleid#:~:text=Om%20uiterlijk%20in%202050%20klimaatneutraal,2023%20een%20aanvullend%20klimaatpakket%20gepresenteerd. (in Dutch)

[26] S Akerboom, S Waldmann, A Mukherjee, C Agaton, M Sanders and GJ Kramer, 2021, Different This Time? The Prospects of CCS in the Netherlands in the 2020s, Frontiers in energy research, doi: 10.3389/fenrg.2021.644796.

1.2.4 Findings on system safety: main risks and adequate measures

Porthos has mapped the risks of CO_2 storage and which mitigation measures need to be put in place (Table A-1).

Table A-1 Overview of the main risks for the Porthos system

Type	Risk	Mitigating measures
Geological risks	CO_2 leaves the storage complex vertically	- Selection of gas fields with a robust sealing rock layer - Pressure in the gas fields should not exceed hydrostatic during and after injection
	CO_2 leaves the storage complex horizontally	- Pressure in the gas fields should not exceed hydrostatic during and after injection
	Seismicity	- Selection of gas fields where no seismic activity was observed during gas production - Avoid severe cooling of the reservoir during injection
Integrity risks	CO_2 leaves the storage complex along the wells	- Prior assessment of well integrity - Robust sealing of the wells - The pressure in the gas fields should not exceed hydrostatic during and after injection
	Loss of well integrity	- CO_2 specifications of the well stream - Pre-assessing well integrity - Use of CO_2 resistant materials in the wells
	Integrity loss of (reused) infrastructure	- CO_2 specifications of the well stream - Use of CO_2 resistant materials - Pre-confirming the integrity of the reused infrastructure
Injectivity risks	Reduced injection flows	- Choice of gas fields with demonstrated good injectivity - CO_2 specifications of the source stream - Robust operational procedures to prevent hydrate formation - Build buffer into injection plan - Well stimulations or drilling of new wells
	Reduced storage capacity	- Choice of gas fields with demonstrated good injectivity - ‘Base case’ does not use all capacity of gas fields

In the next sub-sections, more detail is given on five focus areas of concern:
1. The composition of the source stream (section 1.2.4.1)
2. The geological field selection (section 1.2.4.2)
3. The well integrity (1.2.4.3)
4. Proper operating procedures (section 1.2.4.4)
5. Monitoring (section 1.2.4.5)

Note that all these topics also apply to storage in saline aquifers, albeit possibly with different parameter ranges.

1.2.4.1 The composition of the source stream

It is important to establish precisely the acceptable composition of the CO_2 mixture that emitters supply, because components can affect the behaviour of the CO_2 mixture, with may lead to corrosion or to a toxic fluid. The CO_2 specifications for Porthos can be found on their website[27].

The Porthos specifications are based on ISO-27913, the International Standard for Carbon dioxide capture, transportation and geological storage – Pipeline transportation systems, first edition 2016-11-01. This standard "specifies additional requirements and recommendations not covered in existing pipeline standards for the transportation of CO_2 streams". Porthos has tightened these to, inter alia, the requirements in the storage permit with the aim to minimize condensation and corrosion and reduce toxicity of the CO_2 mixture.

The following criteria were also considered when developing the Porthos specification:

- The gas should be suitable for injection into the gas field.
- The integrity of the transport and storage system is guaranteed.
- Project costs are optimised for both Porthos and the emitters, specifically considering the composition of the source stream at the emitters.
- Compatibility with the adjacent OCAP network and with future reuse of CO_2.
- Process and occupational safety and environmental aspects.

The components that have a major impact on the criteria above are measured and monitored continuously. These are CO_2, water, non-condensing gases, sulphur components, NO_x, aliphatic hydrocarbons, ethanol, methanol, amines and glycols. Dew point temperature is also measured and monitored. Components with a lower impact are monitored via lab measurements.

1.2.4.2 The gas field selection

In the selection of gas fields for CCS not only the risks should be considered but also the potential to reduce emissions. Selection criteria are:

- There is enough capacity to store the CO_2 throughout the project period at the rate required.
- The rocks in the gas field and the sealing top layer are of sufficient quality.
- Integrity of the existing wells and absence of wells at high risk of leakage is assured.

Aspects that are not related to safety but are important when choosing a storage field:

- Timing of cessation of production of the depleting field.
- Distance from the coast or from central infrastructure, as greater distance means higher costs.

Based on the above criteria Porthos chose the P18-2 and P18-4 reservoirs as storage locations. In determining capacity, Porthos used dynamic models, which simulate the flow of injected CO_2 in the reservoir. These models are calibrated using historic data of the natural gas production. A history spanning several decades will provide for reliable models. Using the calibrated models, the total amount of CO_2 that can be safely injected over the course of a project is determined. Hysteresis (the rise of the gas-water contact) or compaction (the compression of rock) could reduce the storage capacity. In the Porthos gas fields, no reduction

[27] https://www.porthosco2.nl/wp-content/uploads/2021/09/CO2-specifications.pdf

in capacity due to hysteresis is expected. In almost thirty years of production time, the water level has not reached the wells. Moreover, pressure measurements indicate that there is no active aquifer and therefore no inflow of water is to be expected. Porthos also expects hardly any reduction in capacity due to compaction; field observations indicate the reduction of the pore volume of the rock is about one per cent at the end of gas production.

The injectivity of the wells were evaluated based on well test data, production data and field observations. The injectivity of the Porthos wells is such that three of the four wells can deliver adequate flow rates to maintain a plateau rate of 2.5 Mt/a over the project duration. The conclusion is therefore that the injectivity of the wells is more than sufficient for an effective and safe operation.

Containment of the CO_2 in the reservoir is secured since there is a ~600 m thick sealing cap rock present above the reservoir. The sealing character is indicated by the presence of natural gas. Lateral containment is provided by sealing faults.

Three risks have been identified that can yet cause loss of containment:

- *Leakage due to seismic activity.* Fault reactivation may result in caprock breaches or altering sealing properties of the faults. Studies concluded that the risk of induced seismicity is deemed highly unlikely, hence loss of containment due to seismicity is highly unlikely for the P18 reservoirs;
- *Leakage due to thermal induced fractures.* Injection of CO_2 results in cooling of the reservoir which could result in thermally induced fractures. These fractures may grow in the direction of faults and/or reach the overlying caprock. Expanding of the thermally induced fracture system is mitigated by limiting maximum injection rates and by limiting minimum injection temperatures. Furthermore, geomechanical modelling work showed that the anticipated fractures are limited to the bottom few meters of the caprock.
- *Leakage along (legacy) wells.* Cooling of an injection well might result in the creation of micro annuli in the cement. Dependent on the expected pressure difference between reservoir and wellbore, and depending on the size of the micro annuli, leakage might occur. The risk of loss of containment along a well bore is mitigated by limiting the maximum reservoir pressure to the hydrostatic pressure.

1.2.4.3 Well integrity

All new well components will be made of CO_2 resistant material. For the new casings and Christmas trees 25 Chrome and S13 Chrome alloys will be used. Specific attention is paid to the Subsurface Safety Valve (SSSV), which prevents uncontrolled outflow of CO_2. In the event of such an outflow, the temperature cools down considerably, to –78°C (the Joule-Thomson effect). Therefore, SSSV's are needed that can withstand such low temperatures. For Porthos, such a valve was developed and successfully tested.

The integrity of the wells will be monitored continuously during and after injection, the Christmas tree will be regularly tested, the pressure in the well is continuously measured and, in addition, vibration monitoring takes place through distributed acoustic sensing (DAS). Wall thickness measurements of the tubing will be taken every five years.

Finally, flow measurements, together with temperature, pressure and composition of the CO_2 mixture, will be used to perform a mass balance analysis. Deviations may indicate a CO_2 leakage.

1.2.4.4 Proper operating procedures

Adequate operational procedures are a prerequisite for safe CO_2 storage under the North Sea. The challenges are:

- *Freezing of the liquid in the annuli.* The fluid present in the well casings (annuli) can freeze due to the cooling effect of CO_2. This is prevented by ensuring that the temperature in the well cannot fall below 0°C. In this case, the CO_2 mixture leaves the compressor station at 80°C. During transport through an insulated pipeline the CO_2 cools, but on the platform the temperature remains above 30°C.
- *Hydrate formation in the wells.* To prevent hydrates in the bottom of the well the minimum down hole temperature should be above 15°C. Extensive flow assurance work has resulted in the definition of operating envelopes for all wells under all conditions that can be expected. For any combination of field pressure and flow rate, a feasible combination of wells is defined that will not result in excessively low temperatures.
- *Hydrate formation in pipelines.* To prevent this from happening – for example at the distribution valves on the platform – methanol can be injected. The use of methanol as hydrate inhibitor is well established in the oil and gas industry. The risk of hydrate formation is the greatest when the pressure in the gas field is lowest, i.e. at the beginning of injection. At Porthos, the CO_2 is therefore initially injected into the field in gaseous state. The pressure in the pipeline can therefore be low (less than 65 bar), so the pressure drop to the low-pressure gas field is minimal and the temperature drop limited. The moment the reservoir pressure reaches more than 50 bar, the injection will change from gaseous to dense (liquid) phase, which also increases the injection rates.
- *Two-phase behaviour of CO_2 in pipelines.* CO_2 can be present in gaseous or liquid phase, depending on pressure and temperature in the pipeline. Two-phase behaviour must be avoided in the offshore pipeline for two main reasons. On the one hand because of the risk of physical forces arising during the phase change, on the other hand because of the risk of precipitation of liquid impurities in the CO_2 stream (e.g. triethylene glycol (TEG) and amines). Two-phase behaviour could potentially occur in the pipeline between the compressor station and the wells, and in the wells themselves. Porthos prevents two-phase behaviour by operating within precisely defined operational windows. During the gas phase, the operational pressure from the compressor station remains below 65 bar until the pressure in the gas fields has risen to 50 bar. When this point is reached, pipeline pressure will be increased to a minimum of 85 bar to ensure the CO_2 will remain in dense phase (Table A-2 and Figure A-3).
- The transport of CO_2 to the compressor station takes place at low pressure (maximum 35 bar) and will always be in gas phase. Here, cyclones are used to remove liquids and solids from the CO_2 stream and siphons to collect precipitated liquids. Porthos also creates a buffer of four 400-800 hundred tonnes CO_2 in the low-pressure pipeline. This will guarantee a more constant flow to the wells independent of variations in inflow from the emitters into the collecting pipeline.

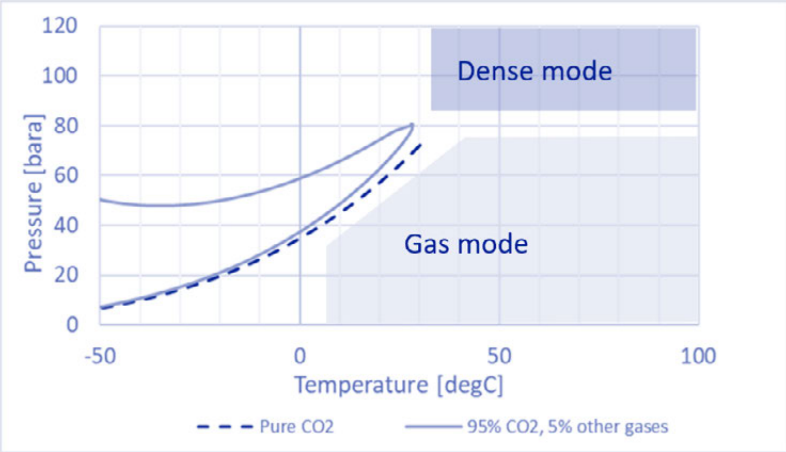

Figure A-3. Illustration of Porthos operating modes for the offshore pipeline

Table A-2 Simplified injection plan for the Porthos reservoirs

Phase	CO_2 state	Reservoir Pressure (bar)	Time (years)	Flow Rates (t/hr)	Minimum # of wells used	Description
Technical Operations	Gas	17 – 50	< 2 years	0 – 220	4	Careful ramp up; Porthos controls flow rates; this phase ends when both reservoirs reach 50 bar pressure
Commercial Operations	Dense	50-310 (P18-2) 50 – 295 (P18-4)	~14 years	80 – 360	Up to 3	Flow rates are controlled within the operational windows

1.2.4.5 Monitoring

During and after injection, Porthos will monitor the CO_2 in the system and in the gas field to ensure safe operations and containment. Porthos monitors three areas:

- *Monitoring for leakage.* As described above, Porthos monitors the wells for the purpose of detecting leakage. In addition, measurements at the seabed, e.g. pockmark surveys, are planned to be conducted.
- *Monitoring the distribution of CO_2 in the gas field.* Porthos monitors whether the CO_2 behaviour in the reservoir matches with predictions. If the operator can demonstrate that the CO_2 mixture behaves as predicted by the models, it can be assumed that the CO_2 remains trapped within the complex. At Porthos, temperature along the borehole, pressure at the bottom of the well, injection flows and unexpected downtime are all measured to measure compliance. Corrective measures will be put in place in case of a lack of conformance, as described in the plan for corrective measures. This plan is a requirement under the storage license.
- *Monitoring seismicity.* Because the Porthos field is close to the coast, the onshore Koninklijk Nederlands Meteorologisch Institute (KNMI) network can be used to measure seismic activity at the P18-2 and P18-4 fields. Corrective measures may be taken when seismic activity is observed, again as described in the plan for corrective measures. Once all the CO_2 has been injected and the wells have been plugged, a further monitoring phase of twenty years for leakage and seismicity will start. After that, the license holder must provide the state government with sufficient funding to enable another thirty years of monitoring. Once that is done, the license is revoked and liability passes to the Dutch government.

1.2.4.6 Conclusion

CO_2 storage is an indispensable to realise the Dutch climate goals in time. The Netherlands has a unique combination of clustered industrial emitters of CO_2 close to the coast, an extensive and reusable infrastructure that is has been built for the production of natural gas, as well as the presence of substantial storage capacity in depleted gas fields.

In this case study, the example of Porthos, as the first large-scale CCS project in the Netherlands, illustrated briefly how a project for injection of CO_2 in to a depleted (low pressure) reservoir is developed. The main technical risks of CO_2 storage in low-pressure gas fields are outlined and the kind of measures developed so that storage can be done safely and efficiently.

To deal with different types of risks (geological risks, integrity risks and injectivity risks), Porthos has identified five main types of measures that need to be taken to deal with these risks in an adequate manner.

1. The composition of the source stream needs to be as pure as possible. Other components than CO_2 can affect the behaviour of the CO_2 gas mixture and cause corrosion or be toxic. The CO_2 specifications can be retrieved from the Porthos website[28].

2. In the process of selecting suitable depleted reservoirs, the following items need to be considered for system safety: capacity of the reservoir, injectivity, geological containment, absence of seismic activity, integrity of the existing wells integrated in a risk identification, assessment and management system including mitigation measures. For economic reasons a good match of timing between cessation of gas production and intended start of CO_2 injection and a short distance from the coast are preferable.

3. With the repurposing of depleted gas fields, existing production wells can be used for injecting the CO_2 after they have been deemed to be suitable. Therefore well integrity is critically important. Some components will need to be replaced or added to the wells, such as a new completion, SSSV and Christmas trees.

4. During operations, adequate monitoring is needed to ensure smooth and safe operations and fast response to anomalies in operations. At Porthos, temperature along the borehole, pressure at the bottom of the well, injection flows and unexpected downtime are measured. The monitoring activities for seismicity and leakage are put in place both during the injection phase and after injection.

5. The implementation of proper mitigation measures.

With this robust understanding of the potential risks, combined with the implementation of proper mitigations, Porthos is confident that CO_2 storage in offshore depleted gas fields can take place in a safe manner.

[28] See https://www.porthosco2.nl/wp-content/uploads/2021/09/CO2-specifications.pdf

1.3 Case study: Mid-West Clean Energy CCS Project (Australia)

This contribution was provided by Pilot Energy.

1.3.1 Project overview

Pilot Energy Limited (PE Ltd) is an Australian oil and gas company transitioning to clean energy. Its flagship Mid-West Clean Energy Project (MWCEP) aims to develop an integrated CO_2 storage service and produce clean ammonia leveraging existing oil and gas infrastructure as well as renewable energy resources. It is currently in the Pre-FEED/FEED stage. CO_2 storage operations are anticipated to commence in 2026 followed by blue ammonia production from 2028. Here the focus is the CO_2 storage aspect of the project. The information source for this section is MidWest (2023).

Pilot Energy has encountered numerous technical, regulatory and commercial challenges which have shaped project development.

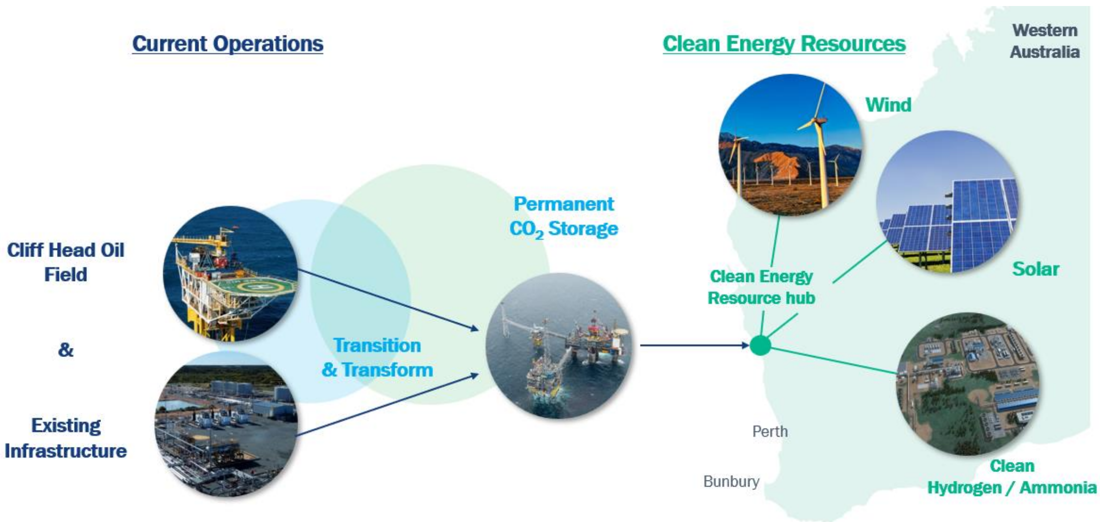

Figure A-4. Lay-out and location of the Mid West Clean Energy project, West Australia [MidWest 2023)

1.3.2 Location

The project is situated in Western Australia (Figure A-4, Figure A-5). Existing operations at the Cliff Head Oil Field (Cliff Head) are approximately 270 km north of Perth and 10 km off the coastal town of Dongara at a water depth of 15-20 m (Figure A-5). The production licence WA-31-L covers 72 km² and the oil field extends over 6 km².

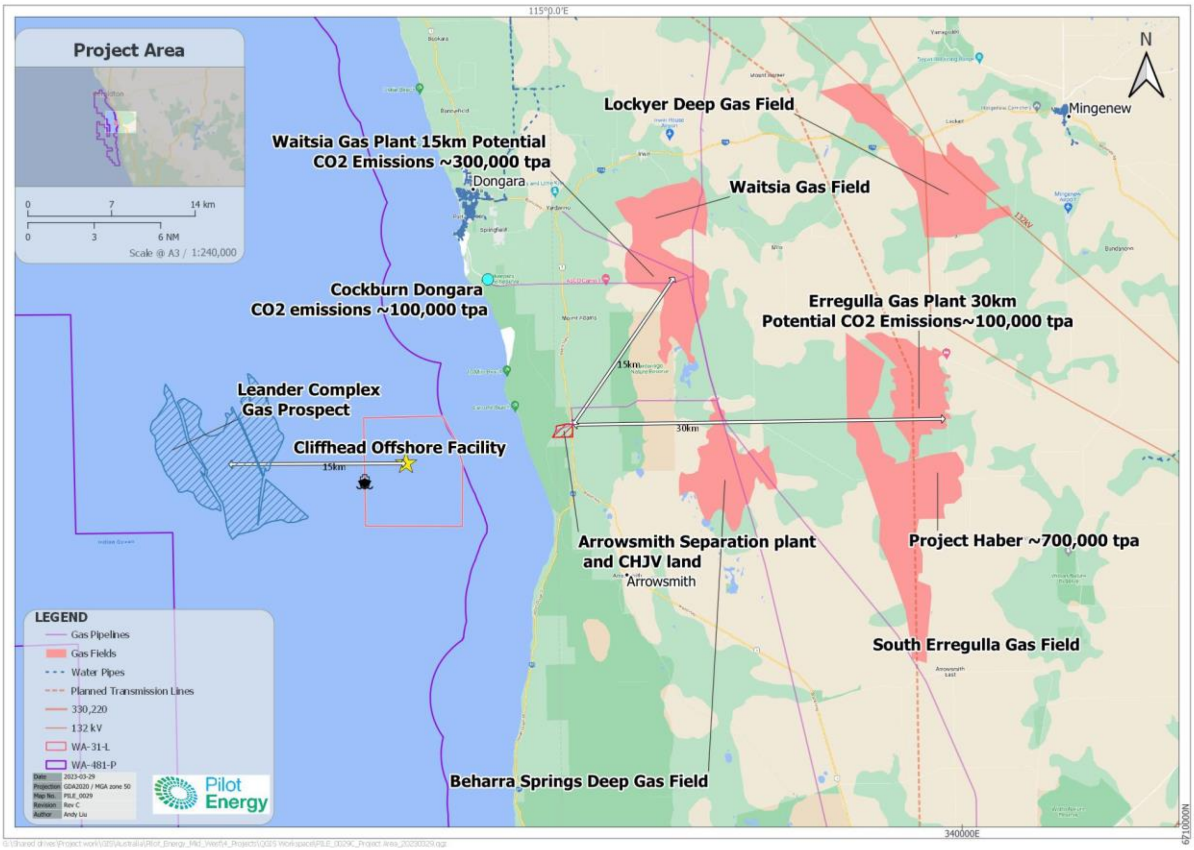

Figure A-5. Location of the Mid West Clean Energy project (MidWest 2023).

Cliff Head was the first commercial oil discovery developed in the offshore Perth Basin with first oil production commencing in May 2006. The two 14 km, 250 mm diameter pipelines connect the offshore platform to the onshore crude stabilisation plant at Arrowsmith. The conversion to a CO_2 storage project is supported by Pilot's detailed understanding of the CO_2 storage formation derived from the geological mapping and reservoir simulations underpinned by the operational data set acquired from oil production since 2006.

The project will be repurposing Pilot Energy's existing assets at Cliff Head and Arrowsmith, and will located within the existing disturbed footprint of the current oil production and processing facilities. This operating footprint will be used as far as possible to minimise the environmental impact on native flora and fauna, coastal landscapes and the seabed. The near depleted Cliff Head oil reservoir along with existing pipelines and onshore infrastructure supports Pilot Energy's view that the MWCEP deliver cost competitive carbon management services and clean ammonia production.

Table A-3 Key Mid West Western Australia Tenements.

Tenement	Location	Pilot Energy interest
WA 31L	WA Offshore Commonwealth Waters	21.25% (increasing to 100% and operated from ~ Q2 2024 following receipt of the Declaration of Greenhouse Gas Storage Formation)
WA 481P	WA Offshore Commonwealth Waters	100% operated

1.3.3 Site Development Plans

Site infrastructure will consist of pipelines (existing and new), processing infrastructure (existing and new), hydrogen and ammonia production facilities, CO_2 hub and processing infrastructure, offshore platform (existing), offshore wind farm (new), onshore wind farm (new), onshore solar farm (new). The project's offshore jetty-less terminal may be expanded to facilitate the import of CO_2 within the same footprint as the ammonia export point (Figure A-4).

Most of the project's infrastructure will be located on existing tenure held by Pilot and on additional freehold properties. Pilot is in advanced discussions with landholders to secure access to strategic parcels of land and will aim to secure access (via option agreements) for project land during 2024. Site access during construction and operation will be via existing road infrastructure.

The mature, end-of-life oil production and processing facilities consist of:

- Cliff Head A unmanned offshore platform (CHAP);
- Onshore Arrowsmith Stabilisation Plant (ASP);
- Twin 250 mm offshore/onshore production and water injection pipelines connecting CHAP to ASP;
- 1.5 MW power & control umbilical from ASP to CHAP;
- 5 oil production wells with artificial lift;
- 3 water injection wells; and
- Additional well slot.

Onshore supercritical CO_2 will be transported to CHAP via conversion of the existing oil production pipeline to a CO_2 pipeline. CO_2 will be aggregated onshore at ASP from multiple third-party sources and MWCEP clean hydrogen & ammonia plant.

Installation of offshore infrastructure for direct offshore liquified CO_2 receipt and injection as well as the export of ammonia is being considered. CO_2 received via the offshore jetty-less terminal will be integrated into, and managed by, the same infrastructure that handles CO_2 received from onshore sources.

1.3.4 Technical Aspects

Technical feasibility assessment for CO_2 storage requires a different approach to the traditional reservoir modelling techniques applied to an oil and gas development. Broader considerations and skillsets are needed to delineate the CO_2 storage opportunity. It is not a straightforward application of skillsets from oil and gas (including enhanced oil recovery).

Pilot's existing oil and gas infrastructure is examined for CO_2 storage. Pilot Energy's plans to re-purpose legacy wells for either pressure management or plume monitoring. Well integrity is an important consideration when planning the re-use of existing wells as part of future CO_2 storage operations. Pilot Energy will conduct workovers to meet mechanical and geologic seal integrity requirements, respectively, to ensure CO_2 can be permanently sequestered. Pilot's offshore wells have been constructed and planned for abandonment at a higher standard compared to onshore wells.

An enabling factor for successful CO_2 storage development is the availability of data in Australia via open file regulations. The National Offshore Petroleum Titles Administrator (NOPTA) makes available well and seismic data including the name, location, type or purpose, and other general information relating to the activity being undertaken. NOPIMS is the repository for new well and seismic data captured by NOPTA since 1 January 2012, which is generally available two years after the end of operation. While there is no automatic process or requirement to transfer data between the owner of the oil and gas assets and CO_2 storage assets, third party proponents of CO_2 storage projects can enter into commercial arrangements to ensure transfer of information. As the existing owner of the Cliff Head oil producing assets and the proponent of the CO_2 storage project, data availability has not been an issue for Pilot Energy.

The operation will consist of supercritical CO_2 transported via existing and new infrastructure from the Arrowsmith Separation Facility into Pilot Energy's offshore Cliff Head CO_2 storage reservoirs. Subsurface modelling incorporated numerous considerations: heterogeneity of the sub-surface geology (e.g., structural form, existence and location of faults, porosity) which affects flow pathways and storage for buoyant CO_2; differences in temperature and pressure throughout the reservoir; long-term stability of injected CO_2; condition of existing oil wells and future well abandonments; and likelihood and severity of events (e.g., earthquakes) which could lead to a failure case. Initial studies using the Cliff Head oil production model assessed storage capacity to be ~6.4 Mt CO_2 with an annual injection rate of ~0.5 Mtpa. Subsequent regional static and dynamic modelling informed an optimised injection strategy and delineated regional constraints. This resulted in the identification of a substantially higher potential storage capacity of up to 100 Mt capable of potentially accepting up to 5 Mtpa of CO_2. Key attributes that led to the increase in injection rate and capacity were an optimised injection plan across the Cliff Head storage formation's two reservoir intervals that delayed the plume migration increasing the capacity and expansion into a third sector of the licence area. The 100 Mt storage potential results from the contribution of three areas within WA31L – Cliff Head, Mentelle and Illawong. Figure A-6 depicts the modelled CO_2 plume within the Cliff Head and Mentelle storage areas at the end of the injection period and 50 years post-injection. The modelled injection volume in this area is ~58 Mt; Illawong is not illustrated.

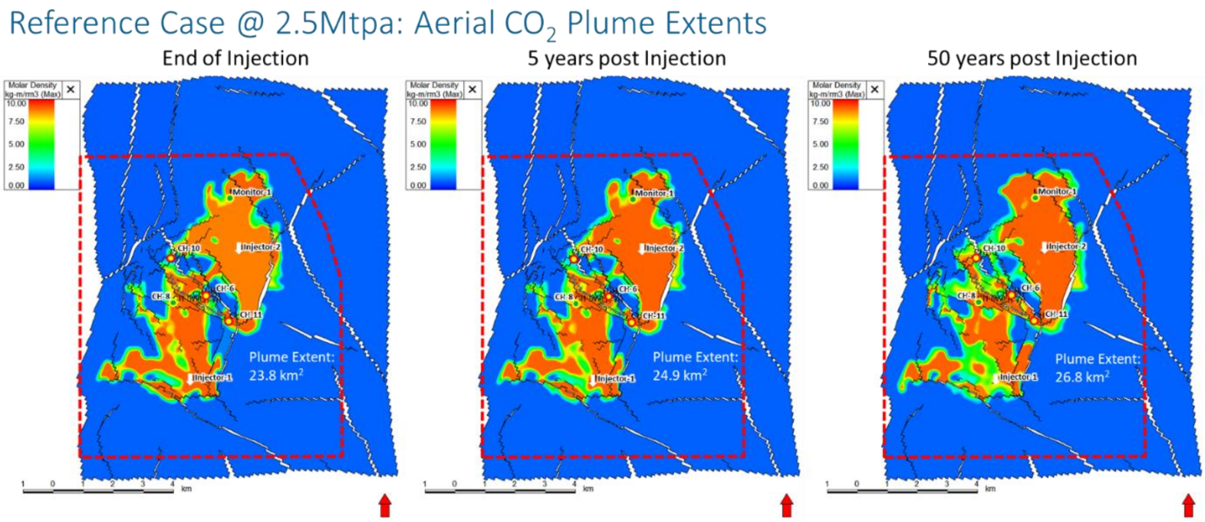

Figure A-6. CO_2 plume in the Cliff Head and Mentelle storage areas at the end of injection (left), 5 years post end of injection (middle) and 50 years post end of injection (right). Injected volume is 58 Mt.

A key learning from modelling the behaviour of buoyant supercritical CO_2 was the identification of alternate strategies to optimise storage such as injection on flanks. This is quite different to a depleted gas field and affirms the value of detailed modelling including considering alternative approaches to maximise CO_2 storage potential.

A technical advantage of the Cliff Head project is the extended injection and production history. Reservoir pressure has been maintained close to original reservoir pressure during the project's oil production phase. Produced water has been continuously re-injected through the project's life, providing detailed insights into reservoir behaviour materially de-risking the future injection performance of CO_2 and containment. Further, maintaining the reservoir pressure near original level has ensured limited changes to the subsurface stress regime, reducing the risk of fault re-activation during the CO_2 injection phase. A key objective of ongoing pressure management operations is to hold pressure around current levels and ensure stability. The Cliff Head project has an advantage over projects utilising a pressure depleted gas (or oil) reservoir as injection operations can commence and continue in a stable pressure regime avoiding a period of re-inflation/re-pressuring.

The final consideration is how to transition from existing oil and gas production to CO_2 storage. A smooth transition avoids the potential for interim mothballing or to incur decommissioning and commissioning efforts which would negatively affect the economic value of the project. Pilot Energy has undertaken a review of its oil resources to determine the optimal timing for closure. The planned operational commencement for CO_2 storage reflects this timeframe. If, however regulatory approvals are met and the CO_2 storage project is ready for delivery, Pilot Energy sees potential additional value in an earlier transition.

1.3.5 Regulatory Aspects

CO_2 storage projects face regulatory hurdles on two fronts. The first hurdle relates to the approvals process. The second is a broader regime around carbon obligations. Pilot Energy's CO_2 storage project is among the first to test legislation in Australia (Commonwealth Offshore Petroleum and Greenhouse Gas Storage Act 2006).
Key regulatory approvals for the Cliff Head CO_2 Storage include:

a. Declaration of Greenhouse Gas Storage Formation
b. Greenhouse gas injection licence
c. Sea Dumping permit
d. Federal and State environmental approval
e. Infrastructure licences

Pilot undertook a period of pre-lodgement consultation with the key regulator NOPTA and with National Offshore Petroleum Safety and Environmental Management Authority (NOPSEMA) to ensure the project was correctly understood. Pilot Energy also engages in broader consultations with the Commonwealth Department of Climate Change, Energy, the Environment and Water (DCCEEW); Department of Industry, Science, Resources; the Western Australian Government and the Department of Mines, Industry Regulation and Safety (DMIRS), and Department of Jobs, Tourism, Science and Innovation (DJTSI).

Additional enabling legislation is required for onshore/state water infrastructure (draft legislation under review by Western Australia Government).

A key focus area is the transfer of existing approved oil and gas project wells and infrastructure to CO_2 storage operations. Where there is potential for conversion to CO_2 storage operations, Pilot Energy suggests the regulatory regimes be adapted to facilitate the transfer of rehabilitation obligations from the oil and gas producer to CO_2 storage operator. Under existing legislation, obligations for decommissioning and rehabilitation rests with the oil and gas producer who must decommission when (or within a "period" after) production ceases. If the decommissioning can be replaced with re-use of infrastructure for CO_2 storage, both the oil and gas producer and CO_2 storage project owner can benefit. This avoids unnecessary decommissioning and recommissioning, provides a clean exit for the oil and gas producer and potentially improves the time and cost efficiency of CO_2 storage projects.

The broader regime around carbon obligations influences the development of CCS projects. Australia's Safeguard Mechanism reforms which came into effect as of 1 July 2023 provide much needed certainty to emitters and proponents of CO_2 storage projects. Key reforms included:

- Applies to emitters facilities with >100,000 t of CO_2 emissions (scope 1 emissions).
- Baseline emissions calculated in line with Australia's climate targets. Emission limits tighten over time.
- Facilities which exceed their baseline are required to buy and surrender Australian Carbon Credit Units (ACCUs) or Safeguard Mechanism Credits (SMCs). Failure to do so attracts a pecuniary penalty.
- International credits cannot be used.
- Creates a revenue opportunity for emitters with actual emissions below baseline emissions through the creation and sale of SMCs.

Australia's carbon market is currently dominated by offset credits (ACCUs) rather than abatement solutions. Market supply and demand dynamics are driven by the release of low-cost offset contracts into a voluntary market. Safeguard Mechanism reforms are likely to drive up demand for ACCUs as the current oversupply of ACCUs allows emitters to satisfy near term obligations with offsets and not direct abatement.

An independent review in 2022 highlighted the lack of transparency in the ACCU scheme. Current restrictions on data sharing and disclosure in the scheme's governing legislation go further than required to protect privacy and commercial-in-confidence information, and the blanket nature of these restrictions is undermining transparency, trust and confidence in the scheme. The review advocated for more transparent data and information sharing arrangements that would enable communities and carbon market stakeholders to assess, understand and manage potential project impacts and opportunities more effectively.

The creation of financial incentives for emitters to outperform further supports the business case for developing CO_2 storage projects. By reducing emissions faster than their safeguard obligations, emitters can generate safeguard mechanism credits thereby turning an operating cost into revenue. This revenue stream may convince otherwise cautious emitters to consider abatement solutions and enter in a CO_2 storage service agreement.

1.3.6 Commercial Aspects

The CCS ecosystem in Australia is still in its infancy. Pilot Energy is pioneering the development of a business model shaped by discussions with partners and customers. Pilot Energy is engaging with customers to build its demand book. Potential customers include domestic customers who can co-locate in the vicinity of the ASP to deliver CO_2, domestic customers willing to deliver CO_2 via onshore gas pipelines, or international/domestic customers exporting via shuttle based marine transport solutions. Pilot Energy is also engaging with overseas customers who are interested in sequestering CO_2 and/or participating in the production of clean ammonia. Each of these customers is at different stages of readiness and commitment to long-term abatement solutions. They also have varying appetite for risk and profit sharing. Discussions are continuing to shape whether Pilot Energy develops a centralised hub capable of accepting CO_2 from several customers. In doing so, Pilot Energy will consider specifications of CO_2 (e.g., pressure, temperature, purity) received from customers. Preference will be to standardise CO_2 specifications where possible.

Furthermore, it is important that the business model being developed considers carbon accounting requirements. Pilot Energy will develop CO_2 storage solutions to ensure customers can satisfy their emission reduction obligations. Potential customers exhibit varying levels of risk appetite, which opens a revenue sharing model and opportunity; a combination of capacity and volumetric charges with the option for profit-sharing based on carbon prices for customers.

Pilot's partners and customers along with standardised CO_2 specifications are key enablers of the CCS ecosystem and the development of CO_2 storage at scale. Developing CO_2 specifications which align operational and customer requirements is crucial. Large-scale foundational customers together with marine transport solutions are key influences of the projects CO_2 specification. CO_2 source and transportation vectors represent unique characteristics and constraints for consideration.

1.4 Case study: the transition from CO_2-EOR to dedicated storage in North Dakota (USA)

This contribution is provided by the Energy & Environmental Research Centre, University of North Dakota.

Underground injection and storage of CO_2 is a process to mitigate CO_2 emissions into the atmosphere from large stationary sources. In this process, CO_2 is compressed into a supercritical fluid and injected underground for enhanced oil recovery (EOR) (associated storage) or for dedicated geologic storage in a deep saline formation. Both approaches use wells to place the CO_2 into deep geologic formations but are regulated differently by the U.S. Environmental Protection Agency (EPA) and states.

Through the Safe Drinking Water Act (SDWA), the EPA regulates underground injection activities to prevent the endangerment of underground sources of drinking water (USDWs). To date, the EPA has issued regulations for six classes of underground injection wells based on the type of fluids injected or produced and the potential for endangerment of USDWs. The injection of fluids related to oil and gas production, including injection of CO_2 for EOR (and the incidental storage of CO_2) is covered under EPA Underground Injection Control (UIC) Class II well regulations.

Under EPA UIC Class II regulations, EOR wells require a permit and must comply with standards for construction, operation, financial responsibility, mechanical integrity, and corrective action. Regulations for UIC Class VI dedicated CO_2 storage wells also require individual permits but specify additional requirements and technical standards to protect USDWs from potential CO_2 leaks under conditions unique to dedicated CO_2 storage, such as the often elevated reservoir pressure and higher risk of leakage due to geological storage. Thus, Class VI regulations include more specific and more comprehensive permitting requirements than EPA Class II requirements.

To protect USDWs from injected CO_2 or the movement of other fluids between underground formations, CO_2-EOR wells must transition to Class VI dedicated storage wells when there is an increased risk to USDWs compared to prior Class II operations using CO_2. The Class VI program director (EPA or primacy state) determines whether a Class VI permit is required based on site-specific risk factors associated with USDW endangerment.

Within the state of *North Dakota*, the following regulation guides the transition from enhanced oil or gas recovery to dedicated geologic storage.

A storage operator injecting carbon dioxide for the primary purpose of geologic sequestration into an oil and gas reservoir shall apply for and obtain storage facility and injection well permits when there is an increased risk to underground sources of drinking water compared to enhanced oil or gas recovery operations.

In determining if there is an increased risk to underground sources of drinking water, the commission shall consider the following factors:

1. *Increase in reservoir pressure within the injection zone;*
2. *Increase in carbon dioxide injection rates;*
3. *Decrease in reservoir production rates;*
4. *Distance between the injection zone and underground sources of drinking water;*
5. *Suitability of the enhanced oil or gas recovery area of review delineation;*
6. *Quality of abandoned well plugs within the area of review;*
7. *The storage operator's plan for recovery of carbon dioxide at the cessation of injection;*
8. *The source and properties of injected carbon dioxide; and*
9. *Any additional site-specific factors as determined by the commission.*

For either dedicated or associated CO_2 storage, the entity that owns the capture equipment and physically or contractually ensures the disposal, utilization, or use as a tertiary injectant of the CO_2 can claim the IRS 45Q tax credit.

The new (2022) Denbury (now Exxon) CO_2-EOR project in southwestern North Dakota / Montana is using CO_2 brought in via pipeline from southwestern Wyoming. Over 1.4 Mt of CO_2 have been injected since March 2023[29]. Denbury intends to pursue 45Q tax credits for CO_2 incidentally stored in the CO_2-EOR process.

Existing legal and regulatory frameworks lack a clear guidance on the transition from CO_2-EOR to dedicated storage and will therefore impede a smooth transition from CO_2-EOR to CO_2 storage. These challenges have been touched upon in the existing literature to a greater or lesser extent[30]. For example, a unit operating agreement governing a CO_2-EOR operation in jurisdictions where unitization is allowed will likely have a clause that dictates when the agreement will terminate (no longer producing oil at a level that can cover operating expenses). This former pooling agreement with the multiple mineral owners may not suffice as a pooling agreement (amalgamation agreement[31]) with the pore space owners. This misalignment is the result of the pore space being owned by the surface owner, whereas the mineral rights may have been severed from the surface estate and are now owned by another party. There will be hydrocarbons remaining in the target reservoir after the CO_2-EOR process

[29] https://s201.q4cdn.com/317576541/files/doc_presentation/2023/02/DEN-March-Presentation-vFINAL.pdf
[30] Legal and Regulatory Frameworks for CCUS An IEA CCUS Handbook. 2022. https://iea.blob.core.windows.net/assets/bda8c2b2-2b9c-4010-ab56-b941dc8d0635/LegalandRegulatoryFrameworksforCCUS-AnIEACCUSHandbook.pdf
[31] North Dakota has established statutory law for compulsory unitization, like those used in oilfield development, known as pore space amalgamation.

is completed, and future technologies and/or higher oil/gas prices could once again make production from the target reservoir profitable. This potential will generate hesitancy in the mineral owners to relinquish their mineral rights for the sake of dedicated CO_2 storage. Additionally, there may be regulatory challenges in convincing the State oil and gas agency. Oil and gas-producing States typically have a legal mandate to promote the development of oil and gas resources, protect the correlative rights of mineral owners, and maximize the greatest ultimate recovery of oil and gas resources. The long-term storage of CO_2 in hydrocarbon-bearing zones may be in direct competition with these existing mandates.

There are no CO_2-EOR operations in the northcentral area of the United States that have attempted to make the transition from EOR to storage, thus there is no direct knowledge of the challenges faced or the strategies used to address the technological or regulatory hurdles encountered.

Another project is the North Dakota Ethanol with CCS project. Red Trail Energy (RTE) aims to reduce CO_2 emissions from their ethanol facility. The Broom Creek Formation underlying the facility has been extensively studied and a preliminary technical and economic feasibility has been achieved. Field studies are being conducted to obtain a pre-injection baseline of the near surface environments to comply with permit requirements. A 3D seismic survey and a stratigraphic test well enhanced the geologic characterisation of the site. The intension is to transition this well into a UIC Class VI compliant well.

The project economics can benefit from incentive programs such as the California Low-Carbon Fuel Standard and opportunities provided by the U.S. Internal Revenue Service for smaller scale fuel production companies.

Public outreach and engagement has been conducted throughout the development of this project. There was no significant opposition to the project.

A more detailed description of this project is given by Leroux et al. (2021) and references therein.

Appendix 2: Glossary

CCS	Carbon capture and storage
CO_2-EOR	Enhanced oil recovery through injection of CO_2 into an oil field
EC	European Commission
ETS	Emission trading scheme in the EU
EU	European Union
JV	Joint venture
MMP	Minimum miscible pressure (in CO_2-EOR)
Mt	Megatonne (million tonnes)
Mtpa	Megatonne per year
NZIA	Net Zero Industry Act (in Europe)
P&A, P&Ad	Plug and abandon, or plugged and abandoned (of wells)
PI	Productivity index (units: (kg/s)/bar)
USD	US dollar
WAG	Water alternating gas injection (secondary oil production)

Energy & Materials Transition

Princetonlaan 6
3584 CB Utrecht
www.tno.nl

IEA Greenhouse Gas R&D Programme

ieaghg.org
+44 (0)1242 802911
mail@ieaghg.org

IEAGHG, Pure Offices, Cheltenham Office Park,
Hatherley Lane, Cheltenham, GL51 6SH, UK

IEAGHG