Technical Barriers and R&D Opportunities for Offshore, Sub-Seabed Geologic Storage of Carbon Dioxide

Report Prepared for the Carbon Sequestration Leadership Forum (CSLF) Technical Group

By the Offshore Storage Technologies Task Force

September 14, 2015

ACKNOWLEDGEMENTS

This report was prepared by participants in the Offshore Storage Task Force: Mark Ackiewicz (United States, Chair); Katherine Romanak, Susan Hovorka, Ramon Trevino, Rebecca Smyth, Tip Meckel (all from the University of Texas at Austin, United States); Chris Consoli (Global CCS Institute, Australia); Di Zhou (South China Sea Institute of Oceanology, Chinese Academy of Sciences, China); Tim Dixon, James Craig (IEA Greenhouse Gas R&D Programme); Ryozo Tanaka, Ziqui Xue, Jun Kita (all from RITE, Japan); Henk Pagnier, Maurice Hanegraaf, Philippe Steeghs, Filip Neele, Jens Wollenweber (all from TNO, Netherlands); Philip Ringrose, Gelein Koeijer, Anne-Kari Furre, Frode Uriansrud (all from Statoil, Norway); Mona Molnvik, Sigurd Lovseth (both from SINTEF, Norway); Rolf Pedersen (University of Bergen, Norway); Pål Helge Nøkleby (Aker Solutions, Norway) Brian Allison (DECC, United Kingdom), Jonathan Pearce, Michelle, Bentham (both from the British Geological Survey, United Kingdom), Jeremy Blackford (Plymouth Marine Laboratory, United Kingdom). Each individual and their respective country has provided the necessary resources to enable the development of this work. The task force members would like to thank John Huston of Leonardo Technologies, Inc. (United States), for coordinating and managing the information contained in the report.

EXECUTIVE SUMMARY

This report provides an overview of the current technology status, technical barriers, and research and development (R&D) opportunities associated with offshore, sub-seabed geologic storage of carbon dioxide (CO_2). Specifically, the report includes:

- Existing and proposed offshore storage and enhanced oil recovery (EOR) projects.
- The current status of offshore CO_2 storage and EOR resource capacity assessments.
- Current status of transport, wellbore/well construction, and monitoring technologies, the potential challenges, and R&D opportunities.
- Existing and proposed regulatory requirements.
- Risk analysis tools and methodologies and R&D opportunities.
- Recommendations for further action.

While onshore geologic storage has been emphasized in many carbon capture and storage (CCS) projects, offshore storage provides several advantages:

- Near-offshore capacity is globally significant and information where available from oil and gas exploration and production provides a good understanding of the offshore geology.
- There is a single owner and manager of both mineral and surface rights.
- Risks to freshwater aquifers are less of a concern.
- Existing pipeline rights-of-way for oil and gas production could facilitate CO_2 pipeline infrastructure development.
- For federally-owned storage resources, revenues could be generated from offshore carbon storage activities.
- Monitoring technologies exist, but there is potential for improvement.

However, there are several challenges that exist, some of which are similar to onshore storage activities:

- Containment risks presented by existing wells.
- Protection of competing economic and environmental interests: for example, commercial fisheries, sensitive ecosystems, and existing and undiscovered gas resources need protection.
- Elevated costs: Despite existing offshore pipelines, costs of operating offshore projects are likely to be significantly higher than those onshore, as experience from decades of oil and gas extraction regionally indicate.
- Accessibility: Some near-offshore regions may have unique development challenges related to infrastructure development.
- Impact of CO_2 on marine ecosystems: Much work has identified the ongoing risks of ocean acidification via CO_2 absorption from the atmosphere, and the more localized impacts from well leakage were less understood but these are being studied and there is a growing body of knowledge.

Today, there are only a handful of offshore storage projects that are currently injecting CO_2 into saline formations: the Sleipner and Snøhvit projects in Norway, and the K-12B project off the coast of the Netherlands. There is also one CO_2-EOR project that is operational in Brazil. However, about a dozen more projects have been proposed, including projects in Japan, China, the United Kingdom, and the Netherlands. These projects play an important role in understanding the offshore storage environment and application of CCS in an offshore setting.

The key recommendations from the report can be categorized into five areas, which are storage capacity assessments, transport infrastructure, offshore CO_2-EOR potential and opportunities, understanding CO_2 impacts on the subsea environment, and monitoring technology development.

Storage Capacity Assessments: It would help prospective CCS stakeholders if public-private partnerships were developed to provide a number of pre-qualified storage locations. For such locations, all preparatory work, including the documents for a storage permit application could be made available to reduce the uncertainty regarding the availability of storage. This would support both the storage and the transport elements of CCS projects.

It is recommended that a more thorough evaluation of the geologic storage aspects of many basins be pursued. It is also recommended that an increased level of knowledge sharing and discussion be implemented among the international community to outline the potential for international collaboration in offshore storage.

Transport Infrastructure*:* The CO_2 transportation infrastructure must increase significantly and will be an important contributor to the overall costs for CCS. Hence, optimization of current practices is important, on areas such as CO_2 product specifications and sharing of infrastructure to optimize utilization.

Additionally, during the pilot and demonstration phase of CCS, CO_2 volumes will be relatively small. However, these projects could be developing the first elements of the large-scale infrastructure, if sufficient incentive is given to oversize the components of the transport infrastructure. Especially during the early phase of CCS, public-private partnership is essential to generate these large infrastructural works.

An increase in the available financial incentives for (offshore) CCS projects is needed to increase the speed of development of offshore CCS. Funding mechanisms should consider funding operational costs, as well as up-front investments.

Offshore CO_2-EOR: Offshore CO_2-EOR is seen as a way to catalyze storage opportunities and build the necessary infrastructure networks. One of the barriers reported widely for offshore CO_2-EOR projects is the investment required for the modification of platform and installations, and the lost revenue during modification. Recent advances in subsea separation and processing could extend the current level of utilization of sea bottom equipment to also include the handling of CO_2 streams. By moving equipment required to separate and condition the CO_2 to the seafloor, modifications to the platform can be minimized. It is recommended that RD&D activities explore opportunities to leverage existing infrastructure and field test advances in subsea separation and processing equipment.

Understanding CO_2 Impacts on the Subsea Environment: It is recommended to expand upon modeling efforts to understand CO_2 dispersion in an ocean environment. Whilst the primary driver of the spatial extent of detectability and impact is the leakage rate, many other factors such as depth, bubble size, current speed, tidal mixing and topography are shown to have a large influence on dispersal. Existing models are robust, but limited in that they generally cannot deal with very fine scales (≈1 meter) which are necessary for the correct treatment of small leak scenarios at the same time as accurately defining regional scale mixing processes, necessary for the correct estimation of dispersion. Model development of marine systems is required to improve their predictive capabilities. Advances are needed so that systems can simulate leakage in the context of natural variability by combing both pelagic and benthic dispersion and chemistry, including carbonate and redox processes. There is also a need to develop models that can simulate large scale dispersion of multi-phase plumes whilst simultaneously simulating tidally-induced dispersion in the near and far field.

Monitoring Technology Development: Deep-focused monitoring relies heavily on established hydrocarbon industry tools which are mature. There is scope for improving some of these technologies and related data processing and interpretation for CO_2 storage. The quantification of CO_2 distribution within a reservoir still remains a challenge.

Shallow-focused monitoring is less advanced compared with deep focused monitoring, but systems are being developed and demonstrated. New marine sensor and existing underwater platform technology such as automated underwater vehicles (AUVs) and mini-remotely operated vehicles (Mini-ROVs) enable deployment and observation over large areas at potentially relatively low cost. Seafloor and ocean monitoring technologies can detect both dissolved phase CO_2 and precursor fluids (using chemical analysis) and gas phase CO_2. AUV technology capable of long-range deployment needs to be developed so that the AUV can be tracked transmit data via a satellite communications system. Real-time data retrieval and navigation will enable onshore operators to modify or refine surveys without costly intervention using a survey vessel. Further development in integrated in situ sensors has been underway over the last 5 years. The quantification of leakage at the seabed remains a technical challenge.

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1 Introduction

1.1 CSLF Purpose

The Carbon Sequestration Leadership Forum (CSLF) is a Ministerial-level international climate change initiative that is focused on the development of improved cost-effective technologies for the separation and capture of CO_2 for its transport and long-term safe storage. The mission of the CSLF is to facilitate the development and deployment of such technologies via collaborative efforts that address key technical, economic, and environmental obstacles. The CSLF will also promote awareness and champion legal, regulatory, financial, and institutional environments conducive to such technologies.

The CSLF comprises a Policy Group and a Technical Group. The Policy Group governs the overall framework and policies of the CSLF, and focuses mainly on policy, legal, regulatory, financial, economic and capacity building issues. The Technical Group reports to the Policy Group and focuses on technical issues related to Carbon, Capture, Utilization and Storage (CCUS) and CCUS projects in member countries.

The Technical Group has the mandate to identify key technical, economic, environmental and other issues related to the achievement of improved technological capacity, and establish and regularly assess and inventory of the potential areas in need of research.

At the CSLF Ministerial meeting held in Seoul, South Korea in March 2014, the CSLF Technical Group formally moved forward with a task force to identify technical barriers and R&D needs/opportunities for offshore, sub-seabed storage of carbon dioxide, in addition to carbon capture and storage technologies that have been the main focus of CSLF efforts since its inception in 2003.

1.2 Task Force Mandate

The United States proposed to serve as chairperson and lead a Technical Group Task Force that is focused on identifying the Technical Barriers and R&D Opportunities for Offshore, Sub-Seabed Geologic Storage of CO_2. The Task Force will develop a report that will:

- Identify existing projects and characterization activities worldwide on offshore CO_2 storage and progress to date;
- Provide a current assessment or understanding (using available analyses) on the status of global offshore storage potential (including potential for offshore enhanced oil recovery [EOR]);
- Identify the technical barriers/challenges to offshore CO_2 storage (e.g., characterization, monitoring, transport challenges and R&D opportunities;
- Identify potential opportunities for global collaboration; and

- Include conclusions and recommendations for consideration by CSLF and its member countries.

1.3 Advantages and Challenges of Offshore CO_2 Storage

Much of the prospective geologic storage on Earth is found where thick sequences of sediments have accumulated on the margins of continents. These accumulations form the below-sea-level geographical features known as continental shelves. The sediments of continental shelves can be expected to contain large volumes of high quality storage related to three recurrent characteristics: (1) shallow sediments which are geologically young so that in many cases the inter-grain pores are well preserved (not filled with cement or extensively damaged by heating, compaction, and deformation), providing large volumes of storage, (2) the seal rocks in the confining system are likewise relatively young and ductile, and have not been as extensively deformed and fractured as is typical of sediments in older basins, and (3) the sediments tend to be thick with abundant sandstones due to passive margin subsidence during sediment accumulation commonly sourced by large river systems draining continental interiors. Other thick sub-sea sediment accumulations that form in settings such as carbonate platforms and rift basins may have similar geologic characteristics. The quality of the storage in these settings is demonstrated by a concentration of abundant large gas reservoirs. Storage in depleted hydrocarbon reservoirs in these sediments may also be attractive in the near term to reduce risks. To extend the possible subsea storage capacity, injection into permeable basalt sequences may also be considered.

The types of storage assessed in this review rely on injection into permeable rocks more than a kilometer below the seafloor and isolation from the surface by impermeable rocks. It is important to separate this storage type of geological CO_2 storage from a number of other types of proposed sub-sea or marine storage that lack these conditions; for example such as CO_2 storage in hydrates or as dense liquid on the seafloor, or as these phases within the upper 100s of meters of seabed sediment (e.g., House et al., 2006[1]), or storage via CO_2 dissolution in deep marine water (e.g., Herzog, 2001[2]).

Many countries are recognizing the potential of offshore geological storage. The European Union's plans to utilize the North Sea for storage are well developed and storage targets show high

[1] House, K.Z., Schrag, D.P., Harvey, C.F., and Lackner, K.S., 2006, Permanent carbon dioxide storage in deep-sea sediments, Proceedings of the National Academy of Sciences, 103(33): 12291-12295.

[2] Herzog, H.J., 2001, What future for carbon capture and storage?, Environmental Science and Technology, 35(7): 148A-153A, DOI: 10.1021/es012307j.

geologic suitability.[3,4] Academic and consultancy studies have addressed the potential of the North Sea for CCS.[5,6] Statoil's Sleipner project in the North Sea has documented the effectiveness of storage in this setting.[7] A second offshore CCS project conducted by Statoil, Snøhvit, has been operational since 2008. In 2009, Australia formally released 10 offshore acreage tracts for CCS consideration, signaling its support of offshore-project development. Studies in Victoria (Gippsland Basin) have highlighted that region's offshore storage prospects.[8] Traditional strengths in marine geosciences have allowed Japanese researchers to develop research programs related to geologic characterization and monitoring techniques for offshore CCS projects.[9] The 2010 NETL carbon sequestration atlas[10] includes estimates of storage capacity in the northern Gulf of Mexico (GOM) and offshore of the Carolinas, indicating nationally significant storage resources. Other recent work to identify storage potential has been initiated along the eastern US (New Jersey shelf and the Carolinas), and offshore Los Angeles in the Wilmington Graben.

1.3.1 Offshore advantages

In many areas, the best quality and largest volume settings for storage are offshore. The potential geologic advantages are summarized above. Offshore storage has widely-recognized public acceptance, policy, and resource utilization advantages compared to onshore. Instances of local public opposition to onshore projects in Europe (e.g., the proposed Shell project in the Dutch town of Barendrecht) have increased reliance on sub-sea resources, with European storage focus strongly on the North Sea.

Onshore, the abundance of fresh-water resources that must be protected adds to public concern, regulatory burden, and potential liability. Fresh water generally does not extend far offshore reducing concern in offshore settings. In some jurisdictions, the increase in interest in offshore

[3] Chadwick R.A., and Eiken, O., 2013, Offshore CO_2 storage: Sleipner natural gas field beneath the North Sea (Chapter 10). In: Gluyas, J. and Mathias, S. (eds) Geological storage of carbon dioxide (CO_2) – Geoscience, technologies, environmental aspects and legal frameworks. Woodhead Publishing Ltd. ISBN 978-0-85709-427-8, p. 227–250.

[4] Lu, J., Wilkinson, M., Haszeldine, R.S., and Fallick, A.E., 2009, Long-term performance of a mudrock seal in natural CO_2 storage, Geology, 37(1):35-38, doi: 10.1130/G25412A.1.

[5] Sustainable Energy Ireland, 2008, Energy in Ireland 1990-2007, 2008 Report

[6] Element Energy, 2010, One North Sea. A study into the North Sea cross-border CO_2 transport and storage: Norwegian Ministry of Petroleum and Energy and UK Foreign and Commonwealth Office- North Sea Basin Task Force, 111 p.

[7] Hermanrud, C., et al., 2009, Storage of CO_2 in saline aquifers—lessons learned from 10 years of injection into the Utsira Formation in the Sleipner area, Energy Procedia, 1: doi:10.1016/j.egypro.2009.01.260.

[8] O'Brien, G.W., et al., 2008, First order sealing and hydrocarbon migration processes, Gippsland Basin, Australia: Implications for CO_2 geosequestration, PESA Eastern Australasian Basins Symposium III, Sydney, 14–17 September.

[9] Magi, M., 2009, Evaluation study of CCS for the mitigation measure of atmospheric CO_2 and ocean acidification by the global carbon cycle model, Geochimica et Cosmochimica Acta, 73(13):A815.

[10] NETL, 2012. The United States 2012 Carbon Utilization and Storage Atlas, 4th ed. U.S. Department of Energy – National Energy Technology Laboratory – Office of Fossil Energy http://www.netl.doe.gov/technologies/carbon seq/refshelf/atlas/

sequestration results partly from perceived uncertainty for onshore sequestration in the legal framework under which CO_2 sequestration will take place, particularly issues related to pore-space ownership and long-term liability.[11] These concerns about CCS can potentially be avoided in offshore settings because the State or Federal government owns the surface, pore space, and mineral rights, thus avoiding conflict between competing ownership rights. International regulations for offshore CCS have been clarified in the context of existing marine regulations.[12] In addition, the government may have a more compelling reason to take on long-term liability for CO_2 sequestered in offshore settings.

Characterization of the geologic site is critical for selecting the properties that will accept and retain large volumes of fluids. Offshore continental shelves have been extensively explored for hydrocarbon resources globally. These data provide the needed regional characterization prior to site selection, and in favorable settings, existing data may be sufficient to locate high quality storage prospects. Because sediments on continental shelves are typically young and actively accumulating, fluids produced by compaction, shale diagenesis and hydrocarbon generation are expelled at leakage points. Seafloor expression of fluid migration is well documented in many places around the world (e.g., Judd and Hovland, 2007,[13] Huang et al., 2009,[14] Cathles et al., 2010[15]). These defined leakage points can be characterized and used to improve certainty of CO_2 retention, as compared to onshore sites where leakage paths may be relict and obscured.

Commonly the implementation of CCS includes an element of monitoring to document that the storage is effective. Offshore seismic monitoring technologies for subsurface geologic activities exist and have been shown to be effective for CCS.[16] Collecting seismic data offshore is typically lower cost per unit area and has reduced error in noise and repeatability relative to onshore, minimizing complications with acquiring time-lapse datasets for monitoring. Towed instruments

[11] Duncan, I. J., Nicot, J. P., and Choi, J. W. (2009). Risk assessment for future CO_2 sequestration projects based CO_2 enhanced oil recovery in the US. *Energy Procedia*, *1*(1), 2037-2042.

[12] Dixon, T., et al., 2009, International marine regulation of CO_2 geological storage—developments and implications of London and OSPAR, Energy Procedia, 1: 4503-4510, doi:10.1016/j.egypro.2009.02.268.

[13] Judd, A. and Hovland, M.,2007. Seabed fluid flow – impact on geology, biology and the marine environment. Cambridge University Press, Cambridge, pp 400. www.cambridge.org

[14] Huang, B., Xiao, X., Li, X., and Cai, D., 2009, Spatial distribution and geochemistry of the nearshore gas seepages and their implications to natural gas migration in the Yiggehai Basin, offshore South China Sea, Marine and Petroleum Geology, 26: 928-935.

[15] Cathles, L.M., Su, Z., and Chen, D., 2010, The physics of gas chimney and pockmark formation, with implications for assessment of seafloor hazards and gas sequestration, Marine and Petroleum Geology, 27: 82-91.

[16] Chadwick, R.A., Noy, D.J., and Holloway, S., 2009, Flow processes and pressure evolution in aquifers during the injection of supercritical CO_2 as a greenhouse gas mitigation measure, Petroleum Geoscience, 15: 59-73.

(e.g., sonar) are capable of detecting seafloor discharges and bubble columns in the seawater,[17] and effects of leakage into the water column can be modeled.[18,19]

To summarize, the potential benefits of utilizing near-offshore regions for CCS are:

1. To the degree that the continental margins are petroliferous, there generally exists a good geologic understanding of the offshore, enhanced by information available from oil and gas exploration and production.
2. The capacity of the near-offshore is globally significant, meaning the storage capacity is generally considered to be high enough to address annual emissions on a decadal timescale (i.e., meet targets and satisfy agreements).
3. There is a single offshore owner and manager of both mineral and surface rights.
4. The offshore typically has few or no economic fresh-water aquifers in the subsurface that count as underground sources of drinking water. This removes one of the most significant risks present for most onshore sequestration sites. However, risks to seawater are alternatively of concern.
5. The absence of population overlying projected CO_2 plumes eliminates broad classes of public health and safety risks (HSE), aside from operational risk to workers.
6. A large number of existing pipeline rights-of-way for oil and gas production could facilitate development of CO_2 pipeline infrastructure, and offshore infrastructure can be re-commissioned for CCS service, postponing sunset costs.
7. For federally-owned storage resources, revenues generated from offshore CCS activities could be used to return benefits to the public for utilization of publically held resources, and to establish funds for long-term monitoring and mitigation if needed. Income streams could also be considered as offsets for reduced taxation.
8. Monitoring techniques are available and may in some instance be superior offshore compared to onshore. Offshore seismic imaging is a mature technology. Other mature and novel techniques are available for monitoring shallow sediments and the water column to detect unexpected leakage.

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[17] Espa., S., Caramanna, G., and Bouche, V., 2010, Field study and laboratory experiments of bubble plumes in shallow seas as analogues of sub-seabed CO_2 leakages, Applied Geochemistry, 25: 696-704.

[18] Kano, Y., Sato, T., Kita, J., Hirabayashi, S., and S. Tabeta, 2009, Model prediction on the rise of pCO_2 in uniform flows by leakage of CO_2 purposefully stored under the seabed, International Journal of Greenhouse Gas Control, 3: 617-625.

[19] Kano, Y., Sato, T., Kita, J., Hirabayashi, S., and S. Tabeta, 2010, Multi-scale modeling of CO_2 dispersion leaked from seafloor off the Japanese coast, Marine Pollution Bulletin, 60:215-224.

1.3.2 Offshore challenges and risks

Risks of conducting CCS in offshore geologic settings need to be carefully evaluated and the range of consequences and likelihood of occurrence need to be considered. The potential challenges or risks of utilizing near-offshore regions for CCS include:

1. Containment risks presented by existing wells.[20,21]
2. Protection of competing economic and environmental interests: for example, commercial fisheries, sensitive ecosystems, and existing and undiscovered gas resources need protection (e.g., Brody et al., 2006).
3. Elevated costs: Despite existing offshore pipelines, costs of operating offshore projects are likely to be significantly higher than those onshore, as experience from decades of oil and gas extraction regionally indicate, CCS is an expensive activity anywhere, but more so offshore—unless income streams are available from EOR.
4. Accessibility: Some near-offshore regions may have unique development challenges related to infrastructure development.
5. Impact of CO_2 on marine ecosystems: Much work has identified the ongoing risks of ocean acidification via CO_2 absorption from the atmosphere, and the more localized impacts from well leakage were less understood but these are being studied and there is a growing body of knowledge.
6. Operational challenges mitigating offshore accidents: A careful and thorough approach to offshore CCS development is an anticipated part of developing offshore storage resources.

[20] Huerta, N.J., Checkai, D., and Bryant, S.L., 2009, Utilizing sustained casing pressure analog to provide parameters to study CO_2 leakage rates along a wellbore, SPE #126700.Judd, A., and Hovland, M., 2007, Seabed fluid flow: The impact on geology, biology and the marine environment, Cambridge University Press, ISBN: 9780521819503

[21] Nicot, J.-P., 2009, A survey of oil and gas wells in the Texas Gulf Coast, United States, and implications for geological sequestration of CO_2: Environmental Geology, v. 57, p. 1625–1638

2 Status and barriers of existing and proposed offshore CO_2 storage and EOR projects

2.1 Status and experience from existing offshore CO_2 storage and EOR projects

2.1.1 Offshore CO_2 storage projects

CO_2 geological storage in the offshore environment offers potentially greater opportunities than onshore in most countries globally. Notwithstanding access to more storage sites and increases in a nation's storage capacity, targeting offshore sedimentary basins avoids populated and regulated areas, eliminates risk on impacting underground sources of drinking water, and is likely to be technically easier for exploration, appraisal, and monitoring, measurement, and verification (MMV).

Experience with offshore CO_2 storage projects is reasonably well developed with nearly 20 years since the start of the first industrial-scale CCS project in 1996 at Sleipner, Norway.[22] Subsequently, in 2004 the pilot-scale project K12-B was started,[23] offshore the Netherlands, and then in 2008 CCS operations commenced at the Snøhvit site[24] in the Norwegian Barents Sea, with onshore CO_2 capture, offshore storage linked by a 150km offshore CO_2 pipeline. All these projects involve disposal of CO_2 separated from natural gas, with injection into saline formations (at Sleipner and Snøhvit) or into a depleted gas field (at K12-B).

Since the start of the Snøhvit project, progress in offshore storage has been limited. However, all currently planned large-scale CCS projects in Europe focus on using offshore options. In Asia, especially in the southeast, offshore storage seems to be the most feasible option. Figure 2-1 shows a snapshot of the offshore storage projects in operation, planned and future prospects globally.

Emerging offshore CO_2 storage projects include the Tomakomai CCS demonstration project in Japan (expected to be operational in 2016), two projects in the UK (Peterhead-Goldeneye and White Rose) and one in the Netherlands (ROAD) which are close to FID and project initiation. These are discussed in some detail below.

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[22] Baklid, A, Krobøl R, Owren G., 1996. Sleipner Vest CO_2 disposal, CO_2 injection into a shallow underground aquifer. Paper SPE 36600, presented at the SPE annual technical conference and exhibition, 6-9 October 1996.

[23] http://www.k12-b.info.

[24] Hansen, O., Gilding, D., Nazarian, B., Osdal, B., Ringrose, P., Kristoffersen, J-B., Eiken, O., Hansen, H., 2012. Snøhvit: The history of injecting and storing 1 Mt CO_2 in the fluvial Tubåen Fm. *Energy Procedia*, 37, 3565 – 357.

Figure 2-1. Offshore large-scale integrated CCS projects and the Tomakomai Project (Source: Global CCS Institute)

2.1.1.1 Operational projects

Currently, there are three CCS projects with dedicated CO_2 geological storage in operation, as mentioned above: the Sleipner Project, as well as the Snøhvit and K-12-B projects. The Sleipner Project, located about 240 kilometers [km] (149 miles [mi]) west of Stavanger, Norway in central North Sea is associated with natural gas production from primarily the Sleipner East and West gas and condensate fields. The Sleipner East field has low CO_2 content (less than 0.3 percent) but the Sleipner West reservoirs contain gasses with 4-9 percent CO_2.[25] The Sleipner West CO_2 is removed in order to meet the sales gas requirements, and driven by the Norwegian government's CO_2 tax, the CO_2 is injected into a dedicated geological storage site adjacent to the gas fields. The natural gas and CO_2 is separated using the MDEA amine process, compressed and injected from the Sleipner T platform. The CO_2 is injected at a rate of about 0.9 (million metric tonnes per annum) (Mtpa) into the Miocene Utsira Formation, around 1 km below the seafloor and by 2014 more than 15 million metric tonnes (Mt) had been injected and stored. The Project is probably best known for is extensive MMV program, including a series of time lapse (4D) seismic surveys over the storage site. These surveys have provided valuable insights into CO_2 storage behaviour by visualising the movement of the CO_2 plume through the saline formations of the Utsira Formation.

[25] Hansen, H., Eiken, A., and Aasum, T. A. 2005. Tracing the path of carbon dioxide from a gas-condensate reservoir, through an amine plant and back into a subsurface acquifer. Case study: The Sleipner area, Norwegian North Sea. Paper SPE 96742, presented at Offshore Europe 2005, Aberdeen, UK, 6-9 Sept. 2005.

The second operational project, the Snøhvit Project, is located in the Barents Sea, off Norway and began injecting CO_2 in 2008. This LNG development covers three gas fields, Snøhvit, Albatross and Askeladden, which have CO_2 contents ranging from 5 to 8 percent. This fully subsea offshore development pipes the production gas to an onshore gas processing and LNG facility where the CO_2 is separated out due to requirements for the LNG conversion process and also driven by the Norwegian CO_2 tax. The Project includes the world's first offshore pipeline for CO_2 transport which covers some 153 km (95 mi) to link the LNG facility to the subsea template where CO2 injected into saline aquifers adjacent to the Snøhvit gas field. The storage formation is the Jurassic Tubåen and Stø Formations, which are around 2.5 km (1.6 mi) depth below the sea surface. The design capacity is 0.7 Mtpa of CO_2, and by 2014 more than 2.5 Mt had been stored. This project also has an extensive MMV program based on time-lapse seismic and reservoir pressure monitoring, which has proven successful for risk management. During injection in the Tubåen Formation, a gradual increase in well pressure was detected, likely due to previously unknown compartmentalisation of the storage formation. In 2011, re-completion of the injection well was performed and further injection was diverted to the Jurassic Stø Formation.[26]

The K-12-B project, named after the project's offshore platform, also involves CO_2 separated from natural gas and then re-injected into the same reservoir as the gas field, but is smaller scale and defined as a pilot project. It is located in the Netherlands North Sea, around 150 km (93 mi) NW of Amsterdam. Gas production began in 1987 from Permian Slochteren Formation at a depth of around 3.9 km (2.4 mi) below the seafloor. The natural gas CO_2 content is around 13 percent. The CO_2 injection began operation in 2004 and around 0.02 Mtpa of CO_2 is being re-injected into the same reservoir. The project not only tests the effects of CO_2 re-injection and evaluates enhanced gas recovery, but also has an extensive MMV program focused on downhole analysis including fluid sampling and geophysics, as well as using tracers in the injected CO_2 to understand reservoir flow dynamics by sampling the re-produced CO_2.

2.1.1.2 Planned and pilot projects

All four UK/European projects which are in the advanced planning stage target offshore geological storage as part of their CCS operations. However, these new projects involve CO_2 capture from power generation. If and when these projects move to the construction phase, they will represent a dramatic shift globally towards large emission reductions via CCS in the power generation sector. These projects also use a range of capture technologies and fuel sources (gas, coal and biomass) and should help strengthen the validity of offshore CO_2 storage. The most advanced CCS project in this region, The Rotterdam Opslag en Afvang Demonstratie Project (ROAD),[27] in the Netherlands has the potential to be the conduit for emissions of Europe to the North Sea for storage. The project will capture around a quarter of the emissions from a new coal-powered plant, located in the port of Rotterdam. Around 1.1 Mtpa of CO_2 will be transported to a depleted gas field around

[26] Hansen, O., Gilding, D., Nazarian, B., Osdal, B., Ringrose, P., Kristoffersen, J-B., Eiken, O., Hansen, H., [2012] Snøhvit: The history of injecting and storing 1 Mt CO_2 in the fluvial Tubåen Fm. Energy Procedia, 37, 3565 – 357.

[27] Huizeling, E., et al., 2011. CCS project development in Rotterdam, Energy Procedia, 4, 5661-5668.

20 km (12 mi) off the coast of Rotterdam. The target reservoir will be TAQA's P18-4 gas reservoir, which will cease production in 2015. An existing well will be re-used to inject into the depleted gas field (Triassic Main Buntsandstein Subgroup) around 3.5 km (2.2 mi) below sea level and has the capacity to store around 35 Mt of CO_2. The ROAD project is the most advanced of any planned CCS projects in Europe with capture and storage permits awarded, but still requiring additional funding to proceed.

The Peterhead-Goldeneye CCS Project will focus on a natural gas fired power station. Located in Aberdeenshire, Scotland, the power station will be retrofitted for post-combustion capture in one (of three) turbines, capturing around 1 Mtpa. CO_2 will be transported 120 km (75 mi) offshore to the depleted Goldeneye gas reservoir, re-using 100 km of pipeline already in place to the existing platform at the site. The depleted field, the Cretaceous Captain Sandstone, is 2.5 km (1.6 mi) below seafloor. The Project's expected start-up is in 2019/2020. Re-using the existing infrastructure will help reduce costs. In addition, it is also expected that the demonstration of the use of a depleted gas field would improve confidence in managing risks.

Figure 2-2. Proposed route for Yorkshire and Humber CCS Country Pipeline in the UK (source: Global CCS Institute; after National Grid Carbon, 2014)

The Don Valley Power Project plans to capture CO_2 from two newly constructed integrated gasification combined cycle power units located in South Yorkshire, UK (Figure 2-2). Expected to start in 2019, approximately 5 Mtpa of CO_2 will be captured and transported to the offshore North Sea via the Yorkshire and Humber CCS Cross Country Pipeline, a common user hub and storage pipeline also to be utilised by the White Rose CCS Project. The White Rose Project is planning to capture around 2 Mtpa of CO_2 in 2019/2020 from an oxy-fuel combustion, coal feedstock (plus biomass) power station in North Yorkshire, United Kingdom. Both Don Valley and White Rose will target the same storage complex, the Triassic Bunter Sandstone Formation, located 70 km (44 mi) off the coast of Yorkshire and about 1 km (3,280 ft) below the seafloor. Utilising a multi-emitter, common-user single 'trunk line' CO_2 pipe to a dedicated storage site has the potential to reduce costs and streamline the CCS project approvals process. If the storage capacity is available, this model could be utilised in many other areas of the world with clustered high emission sources adjacent to storage sites offshore.

The Tomakomai CCS Demonstration Project is presented here as it demonstrates an alternative option to offshore CO_2 storage than detailed above.[28] The Tomakomai CCS Demonstration Project, located in southern Hokkaido, Japan is a medium-scale demonstration project currently under construction. Over 3 years starting in 2016, CO_2 will be captured from a hydrogen production facility at a rate of more than 0.1 Mtpa and piped a short distance to two onshore injection wells, targeting two different storage formations. These wells are highly deviated, extending between 2.9 km (1.8 mi) and 4.3 km (2.7 mi) offshore, to depths of 1.1 km (3,300 ft) and 2.7 km (8,900 ft) below the seabed respectively. The onshore injection to offshore storage option, if proved viable at the commercial-scale could improve the economics of a project where a near shore storage option is available.

Thus, the geological storage of CO_2 in the offshore environment is technically feasible with decades of learnings from not only the oil and gas industry but also dedicated CO_2 storage projects. Comparable to the CCS industry in general, offshore storage is not common practice with only a few projects operational, as detailed above. The exploration and appraisal of a storage site in the offshore environment would be more expensive than onshore but from social, regulatory and technical aspects may actually be easier. Moreover, through the re-use of pipelines and platforms, as well as the re-completion of wells and by targeting depleting/depleted fields or adjacent storage formations, early mover projects could benefit by lowering the overall costs and improving technical viability assurance when a commercial-scale CCS project is proposed. The UK projects in the planning phase are evidence of this and could be a repeated pattern in the offshore environment globally in the future.

2.1.2 Offshore EOR projects

Very few offshore CO_2-EOR projects exist; however, in 2011 Petrobras started the first such project offshore Brazil, as a pilot project in which the supergiant Lula oilfield uses CO_2 separated from natural gas for EOR. The field is in deep water (over 2000 m), below a thick salt formation, at a total depth between 5,000 and 7,000 m. CO_2 is separated from the hydrocarbons produced from the field and re-injected in a pilot to test the feasibility of starting CO_2-EOR early in the lifetime of the field. If successful, this would prevent expensive late-life modifications to platform and installations to accommodate CO_2 processing equipment.[29, 30]

In Southeast Asia, there have been a couple of offshore CO_2-EOR projects. In Vietnam, for example, a small-scale pilot test was conducted at the Rang Dong Oilfield, located 135 km off the coast of Vung Tau, in 2011. In the project, 111 tonnes (t) of CO_2 were injected through an existing

[28] Tanaka, Y., Abe, M., Sawada, Y., Tanase, D., Ito, T., Kasukawa, T., 2014. Tomakomai CCS Demonstration Project in Japan, 2014 Update, Energy Procedia 63, 6111 – 6119

[29] Malone, T., Kuuskraa, V., DiPietro, P., 2014. CO2-EOR Offshore Resource Assessment, report DOE/NETL-2014/1631, 2014, 90 pp.

[30] See: http://www.globalccsinstitute.com/project/petrobras-lula-oil-field-ccs-project.

production well, followed by a four-day oil recovery test with the same well 2 days later. The test was successful and an extended inter-well pilot test is under planning as a next step.[31]

In Europe, the potential for large-scale offshore CO_2-EOR projects is large. In the North Sea, field gas is used on a large scale for enhanced recovery, with total volumes of the order of 35 bcm/yr.[32] A Norwegian sector study[33] pointing to a potential demand for 12-16Mt CO_2 annually for at least 25 years. Several technical feasibility studies for CO_2-EOR, for example at the giant Gullfaks (sandstone)[34] and Ekofisk (chalk)[35] fields, have demonstrated the technical feasibility of large-scale CO_2 injection for EOR offshore. Similar technical potential for CO_2-EOR in the UK offshore sector has also been identified.[36] However, no projects have progressed past the feasibility stage mainly due to economic factors, and most essentially due to the lack of sufficient volumes of CO_2. In order to enable large-scale CO_2EOR in the offshore sector, it is clear that initiatives to initiate CO_2 capture and supply infrastructure are needed.[37]

CO_2-EOR has not yet been commercially implemented in the Gulf of Mexico due to economic (i.e., offshore drilling and pipeline costs) and operational (i.e., recycling facility large footprint) limitations. However, five CO_2-EOR pilots were carried out in Louisiana's shallow near-shore and bay waters back in the 1980s. In all pilots the CO_2 was delivered to the injection site by barges where the CO_2 was injected followed by either nitrogen or field gas in a gravity stable strategy. All pilots were considered successful.[38]

2.2 Barriers to large-scale offshore project demonstration and deployment

The oil and gas industry have been drilling, extracting and injecting in the offshore environment for decades. The technology of the offshore drilling has now been expanded to inhospitable oceans hundreds of meters deep regularly. With the background of several offshore CO_2 storage projects in operation, both at the pilot scale and at an industrial scale (c. 1 Mt CO_2 per annum), it is clear there are no major technical feasibility hurdles or barriers to further deployment. Long-term, safe and secure storage sites can be selected, characterized, operated and completed based on the oil

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[31] Ueda, Y. et al., 2013, CO_2-EOR Huff 'n' Puff Pilot Test in Rang Dong Oilfield, offshore Vietnam, Journal of the Japanese Association for Petroleum Technology, Vol. 78, No.2, 188-196

[32] Cavanagh, A., and Ringrose, P., 2014. Improving Oil Recovery and Enabling CCS: A Comparison of Offshore Gas-recycling in Europe to CCUS in North America. Energy Procedia, 63, 7677-7684.

[33] Awan, A. R., Teigland, R., and Kleppe, J., 2008. A survey of North Sea enhanced-oil-recovery projects initiated during the years 1975 to 2005. *SPE Reservoir Evaluation and Engineering*, 11(03), 497-512.

[34] Agustsson H, Grinestaf GH, 2005. A study of IOR by CO2 injection in the Gullfaks field, offshore Norway. In: The 13th European Symposium on Improved Oil Recovery

[35] Hustad, C. W., and Austell, J. M., 2004. Mechanisms and incentives to promote the use and storage of CO_2 in the North Sea. *European Energy Law Report I, Intersentia*, 355-380.

[36] Gozalpour F, Ren SR, Tohidi B., 2005. CO2 EOR and storage in oil reservoirs. *Oil and Gas Science and Technology*, 60, 537-546

[37] Markussen P, Austell JM, Hustad CW., 2002. A CO2-infrastructure for EOR in the North Sea (CENS): macroeconomic implications for host countries. In: The 6th International Conference on GHG Control Technologies, Kyoto, No. 324.

[38] Malone, T., Kuuskraa, V., DiPietro, P., 2014. CO2-EOR Offshore Resource Assessment, report DOE/NETL-2014/1631, 2014, 90 pp.

and gas industries experience in risk management principles. Moreover R&D, pilot, demonstration and operational projects continue to improve our knowledge in the offshore environment in terms of technology, risk management and in particular MMV. The main barriers concern the lack of incentives or business models needed to promote large-scale offshore CO_2 storage.

It is helpful to summarize the main barriers to large-scale offshore CO_2 storage under two classes:

1. Storage in saline formations or depleted gas fields or without any added utilization value for the CO_2 (section 2.1.1);
2. Storage as part of CO_2-EOR where there is some added value via the utilization and storage sequence (section 2.2.2).

2.2.1 Offshore CO_2 storage

The principle barriers to large-scale CO_2 storage in saline formations or depleted gas fields are:

1. Lack of progress with large-scale CO_2 capture projects;
2. Lack of investment in CO_2 transport infrastructure, either via ship or pipeline;
3. Concerns about potential impacts of CO_2 injections on the marine environment;
4. Concerns about the long-term capacity for large-scale CO_2 storage in the offshore setting.

Whilst there are some technical issues underlying these barriers (such as progress with bringing down the cost of CO_2 capture technologies or improving the confidence in monitoring and verification of long-term storage safety), the main issues are financial and societal. There is little doubt that there is a substantial capacity for CO_2 storage offshore,[39,40] where thick accumulations of suitable sedimentary formations are found on the world's extensive continental shelves and margins.

In addition to the barriers listed above, the development of storage sites in saline formations has a long lead time, with significant investment required to prove the feasibility of a storage site.[41] These investments are similar to those of an exploration effort for hydrocarbon fields, with the associated risks, but without the potential benefit of hydrocarbon production. Given the long lead time, exploration for storage sites should precede the development of a capture installation by many years. Uncertainty about the availability of sufficient and proven storage is a key uncertainty for early CCS developers.

From a non-technical or economic perspective the two barriers to the global deployment of CCS with offshore storage targets is the London Protocol and management of fluids in the subsurface across recognized boundaries. The London Protocol precludes the export of wastes, which means

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[39] Schrag, D. P. (2009). Storage of carbon dioxide in offshore sediments. Science, 325(5948), 1658-1659.

[40] Halland, E., Mujezinovic, J., Riis, F., et al., 2014. CO_2 Storage Atlas, Norwegian Continental Shelf. *Petroleum activity on the Norwegian Continental Shelf* www.npd.no/en/Publications

[41] Neele et al., *The SiteChar approach to efficient and focused CO_2 storage site characterisation*, Energy Procedia, 2013.

that CO_2 cannot move across marine borders for the purposes of geological storage. An amendment to enable export for CO_2 storage was adopted in 2009 but only Norway, the UK and The Netherlands have ratified the amendment. On the other hand, the migration of CO_2 in the subsurface, which in some places could potentially move across marine borders was addressed by revising the specific guidelines for CO_2 disposal in 2012. In policy in general, globally the regional and national policy settings of most nations are often fragmented and do not support CCS with offshore deployment.

2.2.2 Offshore CO_2-EOR

In the second class of projects, with storage as part of CO_2-EOR, there is considerable interest in potentially resolving the economic barriers to large-scale CCS, by bringing added value to projects via integrated CO_2-EOR and storage solutions. A number of barriers to the development of offshore CO_2-EOR projects can be identified.

1. Funding mechanisms for capture and transport.
2. A number of studies using different oil and CO_2 price assumptions[42,43] have shown that while CO_2-EOR can provide a positive economic business case for individual projects, the CO_2-EOR incentive still falls significantly short of providing funding mechanisms for CO_2 capture and transport. In a scenario where significant volumes of CO_2 are available from onshore CO_2 capture plants, it could well be the case that CO_2-EOR would improve the overall cost model for integrated CCUS value chain projects.
3. Availability of CO_2: The CO_2 demand of typical North Sea oilfields is of the order of 5 Mt per annum.[44] Until about 2025, the only CO_2 volumes available around the North Sea will be those from pilot and demonstration projects that produce relatively small volumes each (of the order of 1 Mt per annum). Larger volumes, from single point sources, can be expected no sooner than about one decade from today—a typical CCS project development period. Consequently, the first large-scale pipeline from (near-shore) capture locations bringing sufficient and reliable quantities to offshore oilfields are unlikely to appear before that time.
4. Cost of converting existing installations: A final important hurdle to offshore CO_2-EOR projects is that the cost of conversion of existing offshore platform facilities from water or gas injection to CO_2 injection requires a significant upgrading of topside facilities and wells. Such investments, both in terms of capital and in lost revenue from oil production during conversion, mean that other improved oil recovery methods (such as miscible gas

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[42] Hustad, C. W., and Austell, J. M., 2004. Mechanisms and incentives to promote the use and storage of CO_2 in the North Sea. *European Energy Law Report I, Intersentia*, 355-380.

[43] Cavanagh, A., and Ringrose, P., 2014. Improving Oil Recovery and Enabling CCS: A Comparison of Offshore Gas-recycling in Europe to CCUS in North America. *Energy Procedia*, 63, 7677-7684.

[44] E.g., Melzer, L. S., 2012. Carbon Dioxide Enhanced Oil Recovery (CO_2 EOR): Factors Involved in Adding Carbon Capture, Utilization and Storage (CCUS) to Enhanced Oil Recovery (http://neori.org/Melzer_CO2EOR_CCUS_Feb2012.pdf).

injection) are likely to remain the preferred option until new tax or funding incentives are applied.

5. Regulatory barriers: There are currently no regulatory barriers to using CO_2 for enhanced recovery, as illustrated by the pilot projects described in section 2.1.2. In many countries, however, it is not possible to combine CO_2-EOR with storage, with the aim to claim emission credits. The European CCS Directive does not explicitly exclude such a combination, but many European Member States have implemented the Directive into more stringent regulations, preventing a CO_2-EOR operation to be part of a CCS project.

It should be noted that where CO_2 is used for EOR, all the acquired CO_2 is ultimately stored, since produced CO_2 is recycled and re-injected both due to its economic value to the project (a business driver) and the objective of ensuring CO_2 storage (an environmental driver). This results in a decreasing demand for CO_2 during the EOR project. This practice is routine in the onshore CO_2-EOR sector in the United States, and exemplified by the large-scale CO_2-EOR and storage projects at Weyburn, Canada.[45]

2.3 Opportunities and recommendations for overcoming barriers

The major barrier to the development of offshore storage or EOR is the lack of progress with large-scale CO_2 capture projects. To resolve this situation, the development of all elements of the capture, transport and storage (or EOR) chain should be supported simultaneously. Nevertheless, the following sections highlight opportunities and recommendations that apply to transport and storage (or EOR).

2.3.1 Offshore CO_2 storage

As mentioned above, there are no significant technical barriers to offshore CO_2 storage. The barriers identified are in the areas of availability of storage capacity and of national regulations.

The high risks and long lead time involved in proving up storage capacity suggest that this could be a governmental task, especially to support the development of first-wave or even second-wave CCS projects. The long lead time (in the range of 7–10 years) means that storage qualification defines the start-up time of a CCS project. Although the unit cost of storage are lower than that of capture, one ‘dry’ hole (i.e., into a formation that proves not to be good store) would significantly increase the cost of storage. It would help prospective CCS stakeholders if governments were to provide a number of pre-qualified storage locations. For such locations, all preparatory work, including the documents for a storage permit application should be made available to reduce the uncertainty regarding the availability of storage. This would support both the storage and the transport elements of CCS projects.

[45] Aarnes JE, Wildgust N., 2012. Industry experience with large-scale CCS and similar operations. In: Hitchon, B. (Editor), *Best Practices for Validating CO_2 Geological Storage*, Geoscience Publishing, 1-7.

There could also be a role for national authorities in the development of a transport infrastructure. During the pilot and demonstration phase of CCS, separate CO_2 volumes will be relatively small. These projects could be developing the first elements of the large-scale infrastructure, if sufficient incentive is given to oversize the transport infrastructural elements. Especially during the early phase of CCS, public-private partnership is essential to generate these large infrastructural works.

An increase in the available financial incentives for (offshore) CCS project is needed to increase the speed of development of offshore CCS. Funding mechanisms should consider funding operational costs, as well as up-front investments. The CO_2 emission tax in Norway and the contract-for-difference in the UK are examples of funding mechanisms that provide certainty of funding during the lifetime of a CCS project, whether it is a demonstration or full-scale project.

2.3.2 Offshore CO_2-EOR

For offshore CO_2-EOR a number of barriers in the technical domain were identified, in contrast with offshore storage.

Current CO_2-EOR techniques, such as those used in Texas, are aimed at minimizing the volume of CO_2 stored in the oilfield and maximizing the volume of CO_2 that is circulated. This minimizes the volume of CO_2 purchased. If there is an economic benefit in storing the CO_2, for example through emission credits that can be claimed for the CO_2 stored, EOR techniques can optimized not only for enhanced oil production, but also for the stored CO_2 volume.[46] This would improve the value of CO_2-EOR operations when they form part of a capture-transport-storage project.

One of the barriers reported widely for CO_2-EOR projects is the investment required for the modification of platform and installations, and the lost revenue during modification. By moving equipment required to separate and condition the CO_2 to the seafloor, modifications to the platform can be minimized. Recent development of subsea processing offers an increasing number of new concepts and opportunities.[47] Such processing can also be applied for treating well streams resulting from CO_2 flooded offshore reservoirs. Subsea processing systems and equipment such as separators, heat exchangers and pumps have been qualified and are in use in a subsea environment today. During 2015 a subsea compressor48 cc) will be put in commercial operation on the Åsgard field on the Norwegian Continental Shelf. Such a subsea compressor unit might be a key component in an arrangement for treating a CO_2 rich well stream. By exploiting the opportunities the subsea process systems offer, it can be technically feasible to arrange a subsea based well stream process train, which could provide separation of the high concentration CO_2 well stream and reinject the compressed or liquefied CO_2 to the reservoir or into a nearby aquifer. Alternatively the compressed CO_2 could be pumped to an adjacent oil reservoir for CO_2 flooding. However, a

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[46] NETL, CO_2-EOR offshore resource assessment, 2014.

[47] Moraes, C., da Silva, F., Monteiro, A. and Oliveira, L.P.: "Subsea versus Topside Processing – Conventional and New Technologies". OTC 24519, 2013; Marjohan, R.: How to increase Recovery of Hydrocarbons Utilizing Subsea Processing Technology" OTC 24934, 2014

[48] OTC-25464-MS, 22411-MS OTC Conference Paper – 2011

complete stabilization of the oil phase at the seabed is not seen as commercially realistic, so some residual CO_2 will follow the treated well stream to the topsides facilities.

Dependent on reservoir conditions, infrastructure available on the topside and requirements to the oil and gas produced on the topsides, the subsea processing solution can be arranged in various ways. One alternative that is seen as technically feasible is to install a gas separation unit where a bulk separation of CO_2 is provided by e.g., selective membranes or other separation concepts. This concept ensures the highest possible degree of extracting commercially recoverable resources from the reservoir.

Another promising aspect of the subsea processing concept is that such arrangements are made with retrievable modules due to the need for inspection and maintenance. Since a typical EOR project has a relatively short life time, most of the subsea processing equipment can probably be reused in new projects. This would offer a commercially better solution as well.

In a final production stage of the reservoir, after the technically and commercially available hydrocarbon resources are extracted, the infrastructure of the subsea facilities can be used for permanent injection of CO_2, hence represent a considerable enabler for CCS.

Recent advances in subsea separation and processing could extend the current level of utilization of sea bottom equipment[49] to also include the handling of CO_2 streams. By moving equipment required to separate and condition the CO_2 to the seafloor, modifications to the platform can be minimized.

In the regulatory domain, an opportunity that has received attention recently is to enable CO_2-EOR projects to benefit from emission credits. The ability to combine enhanced production and storage activities would provide another incentive to utilize the potential for CO_2 storage in oilfields[50] as a driver for the development of CCS. The additional benefit of enhanced recovery could help finance the capture and transport part of the CCS project. This would probably require the EOR operator to perform more and more detailed monitoring, but the MMV technology is available and the additional cost will not significantly increase the overall cost of the EOR operations.

Further opportunities to support the development of offshore CO_2-EOR are to found in what could perhaps be termed the organizational domain.

Although CO_2-EOR is performed on a large scale in Texas, there is only one offshore project in operation and that is the Lula project in Brazil. The startup of new projects could be supported through small late-life oilfields (or a section of larger oilfields) where CO_2-EOR is developed in a demonstration project setting. These small projects could serve as stepping stones to larger-scale projects.

As mentioned above, early CO_2 capture projects are likely to produce limited volumes of CO_2. Each of these projects would not produce the CO_2 required by a single CO_2-EOR oilfield. The CO_2

[49] E.g., http://www.offshore-mag.com/content/dam/offshore/print-articles/volume-74/03/SubseaBoosting.pdf.
[50] IEAGHG, 2009.

demand curve of a typical EOR operation decreases after a peak at the start, which renders the construction of a dedicated pipeline to the field difficult. Ship transport could provide the flexibility that is required in such cases.[51] A small number of ships could link emerging capture projects to pilot and demonstration scale offshore CO_2-EOR operations. This could trigger larger EOR operations, in turn seeding the first elements of offshore CO_2 transport pipelines.

However, while such an approach could help build CO_2 volumes of required size, CO_2-EOR will only be initiated once there is certainty of supply for the typical duration of CO_2-EOR projects. During the startup phase of CCS, demonstration projects may not provide such certainty, unless the commercial phase is very likely to be the next, consecutive step in the development of CCS.

[51] Aspelund et al., 2006. Ship transport of CO_2, *Chem. Eng. Research and Design*, 84, 847-855.

3 Offshore CO_2 Storage and Enhanced Oil Recovery Resource Assessments

3.1 Status of Resource Assessments

The geologic aspects of capacity assessment are the same offshore as onshore, and future global assessment of offshore storage capacity can leverage the work that has been completed onshore, for example, the CSLF task Force Effort[52] as well as the case studies from the offshore North Sea and Gippsland basins.[53]

The largest storage volumes are found in saline storage units, which are porous sedimentary rocks occupied principally by saline water. By most definitions of storage capacity, horizontal low permeability rock layers that serve as confining systems that limit vertical migration of fluids must be identified. The second major storage subcategory is depleted hydrocarbon fields, where hydrocarbons that have been extracted have been partly replaced by injected CO_2. Depleted hydrocarbon fields can be used for storage with no intention of resource recovery, or storage can be linked to EOR or enhanced gas recovery (EGR), in which case it is classified as CCUS. Storage focused on a mineral trapping mechanism has been proposed where the rocks are highly reactive to CO_2. The major reactive rock in sub-sea settings is basalt.

Within each category, the first stage of calculating capacity is to determine the areas to be used. This determination may require defining a confining system or seal for containment in order to define a storage unit or identify areas that have structural traps (for example Brennan et al, 2010,[54] Bentham et al., 2014[55]). Another consideration is the distance between source and sink, with storage volumes distant from sources being disqualified.[56] The assessment of storage in China provides many additional variables for consideration as described by Li (2014)[57] and Jian (2014).[58]

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[52] CSLF, 2008, Comparison between Methodologies Recommended for Estimation of CO_2 Storage Capacity in Geological Media. Carbon Sequestration Leadership Forum (CSLF), Bachu, S. (Ed.)

[53] Gibson-Poole, Catherine M.; Svendsen, L. Underschultz, J. Watson, M. Ennis-King, J. P. van Ruth, P., Nelson, E., Daniel, R. and Cinar, Y., 2006, Gippsland Basin geosequestration: a potential solution for the Latrobe Valley brown coal CO_2 emissions, APPEA Journal

[54] Brennan, S.T, Burruss, R.C., Merrill, M.C., Freeman, P.A., and Ruppert, L.F., 2010, A Probabilistic Assessment Methodology for the Evaluation of Geologic Carbon Dioxide Storage, United States Geological Survey open file report 2010-1127 http://pubs.usgs.gov/of/2010/1127/ofr2010-1127.pdf

[55] Bentham, M., Mallows, T., Lowndes, J., and Green, A. (2014). CO_2 STORage Evaluation Database (CO_2 Stored). The UK's online storage atlas. *Energy Procedia*, *63*, 5103-5113.

[56] Bachu, S., Bonijoy, D., Bradshaw, J., Burruss, R., Holloway, S., Christensen, N.P., Mathiassen, O.M., 2007. CO_2 storage capacity estimation: methodology and gaps. International Journal of Greenhouse Gas Control,1, 430–443.

[57] Li, Jian, 2014, The capacity building in carbon dioxide capture and storage in China, China Australia Geological Storage workshop, CO_2 storage capacity assessment and demonstration in China, completed 2014, China Geological Survey

[58] Jian, Xiaofeng, 2014, CO_2 Geological Storage of Target Area Scale Selection and Evaluation Method, China Australia Geological Storage workshop,http://www.cagsinfo.net/pdfs/cags2-workshop3/2.1_CO2_Geological_Storage_of_Target_Area_Scale_Selection_and_Evaluation_Method.pdf

Once the storage areas to be quantified have been defined, the mass of CO_2 that can be stored in that volume is assessed by determining the fraction of the volume that can be used, and the density of the CO_2 to be stored in that volume. Quantification of capacity depends on the definition of storage adopted. Some methods are static and based an assessment of pore volume multiplied by an efficiency factor (e.g., NETL, 2012[59]). Other capacity estimations, for example the Enhanced Analytical Simulation tool (EASiTool),[60] are based on the rate at which CO_2 can be added to the system without exceeding a pressure limit. Several studies have compared capacity methods and found that the assumptions create large variation in storage capacity assessments, however these variations resolve toward similar order-of-magnitude calculations.[61,62,63]

3.1.1 Saline

The global distribution of saline storage at the coarsest level can be assessed by evaluating thickness of sedimentary cover. This method was used for the initial onshore U.S. capacity assessment[64] and is used in this report for the initial assessment of global subsea storage (Figure 3-1). Certainly not all of the volume plotted in Figure 3-1 is useable, because the existence of both reservoir and confining system must be demonstrated, however the thick areas can be considered prospective.

3.1.2 Storage related to oil and gas production

While significant experience exists in CO_2-EOR, that experience is unevenly distributed globally, with the majority occurring in the United States (specifically West Texas, since 1972). The majority of that experience is onshore due to the favorable economics in the current environment. However, the eventual development of offshore CO_2-EOR is anticipated, although it is difficult to predict when market pressures will make those projects economic. Likely the development will be incremental where projects have highest chance of success and return on investment. In addition, government financial incentives may accelerate deployment.

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[59] NETL, 2012. The United States 2012 Carbon Utilization and Storage Atlas, 4th ed. U.S. Department of Energy – National Energy Technology Laboratory – Office of Fossil Energyhttp://www.netl.doe.gov/technologies/carbon seq/refshelf/atlas/

[60] Hossieni S. A., Kim, Seunghee, and Zeidouni, Mehdi, 2014, Application of multi-well analytical models to maximize geological CO_2 storage in brine formations. Energy Procedia 63 p. 3563-3567.

[61] Szulczewski, M.L., MacMinn, C.W. Herzog, H.J., and. *Juanes, R.*, 2012, *Lifetime of Carbon Capture and Storage as a Climate-change Mitigation Technology*, Proceedings of the National Academy of Sciences, Vol 109:14, pp 5185-5189www.pnas.org/cgi/doi/10.1073/pnas.1115347109

[62] Goodman, Angela, Bromhal G., Strazisar, B., Gutherie, W. F., Allen D., 2013, Comparison of methods for geologic storage of carbon dioxide in saline formations, International Journal of Greenhouse Gas Control, v. 18, p. 329-342.

[63] Wallace, Kerstin, 2013, Use of 3-dimensional dynamic modeling of CO_2 injection for comparison to regional static capacity assessments of Miocene sandstone reservoirs in the Texas State Waters, Gulf of Mexico, University of Texas master's thesis.

[64] Bergman, M., Winter, E.M., 1995. Disposal of carbon dioxide in aquifers in the U.S. Energy Conversion and Management, v. 36, p. 523–526.

Research to facilitate CO_2-EOR focuses on improving recovery rates and reducing the costs per barrel produced. The conformance (sweep efficiency) of the floods is a primary factor governing these and miscibility, multi-phase flow, wettability, and engineered mobility (i.e., nanoparticles) are also important.

While there has been extensive offshore exploration for hydrocarbons since the 1960s in many basins throughout the world (and exploration continues with success), the opportunities for enhanced oil recovery using CO_2 are less well known. This is in part due to resource development which favors onshore enhanced oil recovery as more economic at this time. However, there are places where CO_2 is actively being used or considered to enhance offshore hydrocarbon production. The most notable of these are in the offshore of Brazil and Malaysia.

In the offshore of southeastern Brazil, exploration of the deep (pre-salt) reservoirs in the Campos and Santos Basins has indicated many of the gas reservoirs are high in CO_2 content (perhaps 10-20 percent), complicating logistics and development plans. Petrobras has repeatedly indicated it prefers not to vent the naturally produced CO_2 if it can be separated economically in the offshore environments (as is done by Statoil in the North Sea at the Sleipner development). The preferred utilization of CO_2, providing the technical challenges of deep reservoirs in heterogeneous carbonate rocks can be overcome, is to inject the CO_2 into producing hydrocarbon fields (e.g., Lula, which is currently active at ≈700 kt CO_2 per year) for enhanced recovery. There are over 35 fields in the Campos Basin that are mature and could benefit from enhanced oil recovery (e.g., Ketzer et al., 2007[65]; Almeida et al., 2010[66]; Rockett et al., 2013[67]).

In Malaysia (Sarawak), the enormous Petronas K5 Project in the southern South China Sea will produce natural gas with up to 70 percent carbon dioxide. In the region there are estimates of more than a dozen similar scale fields with similar CO_2 content. These fields hold perhaps 13 trillion cubic feet of natural gas (methane) and twice as much carbon dioxide. For perspective, this is equivalent to current national volumetric emissions of CO_2 for some countries. The concept being pursued is to boost production in depleting nearby offshore oilfields. FEED studies are anticipated to start in 2015. An additional pilot project was considered for the Dulang offshore oilfield.[68]

[65] Ketzer, J. M., Villwock, J. A., Caporale, G., da Rocha, L. H., Rockett, G., Braum, H., and Giraffa, L., 2007, Opportunities for CO_2 capture and geological storage in Brazil: The CARBMAP Project. In Sixth Annual Conference on Carbon Capture and Sequestration, Pittsburgh, Pennsylvania.

[66] Almeida, A. S., Lima, S. T. C., Rocha, P. S., Andrade, A. M. T., Branco, C. C. M., Pinto, C., and Carlos, A., 2010, January). CCGS opportunities in the Santos basin pre-salt development. In SPE International Conference on Health Safety and Environment in Oil and Gas Exploration and Production. Society of Petroleum Engineers.

[67] Rockett, G. C., Ketzer, J. M. M., Ramírez, A., and van den Broek, M. (2013). CO_2 Storage Capacity of Campos Basin's Oil Fields, Brazil. Energy Procedia, 37, 5124-5133

[68] Wilson and Hall, 2010, Tectonic influences on SE Asian carbonate systems and their reservoir development. *Cenozoic Carbonate Systems of Australasia: SEPM, Special Publication*, *95*, 13-40.

In the Gulf of Mexico, offshore EOR is not active, but anticipated.[69] Economic reasons for delayed deployment (as for most basins) include transport expense, offshore processing/compression, and higher well and facilities operations costs. Estimates of stranded oil from primary production are significant, perhaps as much as 27 billion barrels.[70] Of this, perhaps 6 billion may be recoverable using CO_2-EOR techniques. Given the royalty structure in the US offshore, the Federal government has incentive to facilitate EOR, and would also be the long-term steward for CO_2 storage projects. The Gulf of Mexico is the largest market for infrastructure decommissioning, and there is a time-sensitive motivation for re-commissioning those facilities for CO_2 injection, and thus delay expensive decommissioning processes. In the 1970s, CO_2-EOR was investigated in the Gulf of Mexico at Weeks Island, Iberia Parish, Louisiana.[71] While the location was not technically 'offshore', it was in a bay setting near the coastline in the same geological formations that are most prospective in the near offshore. Estimates of oil recovery from CO_2 injection were estimated at 26 MMBO for similar depleted reservoirs in the region. The project injected 50,000 tons of CO_2, and the extent of subsurface migration was successfully monitored with neutron well logging.

Other offshore investigations for CO_2-EOR have been performed for the North Sea (Heidrun-Draugen; Don Valley), Abu Dhabi (Persian Gulf), Vietnam (Rang Dong), and the South China Sea (SCS; Pearl River Mouth Basin; Huizhou 21-1 Field). In general, the SCS opportunities are similar in technical aspects and original recovery percentages to the North Sea Basin, Gulf of Mexico, and Brazil, although the field sizes for SCS are somewhat smaller. All basins have similar infrastructure needs, although the distances offshore vary. SCS has favorable light oil compositions (low density and viscosity), relatively high porosity and permeability, and shallow water depths.

3.1.3 Storage in subsea basalts

Development of mineral storage in subsea basaltic (mafic and ultramafic) rocks is at an early stage dominated by conceptual studies. Three complementary CO_2 trapping mechanisms are proposed. Most research focuses on trapping by reaction of dissolved CO_2 with the abundant divalent cations (Ca^{2+}, $Mg^{2+}$and Fe^{2+}) in these rocks through a naturally accelerated weathering reaction and

[69] DiPietro, J. P., Kuuskraa, V., and Malone, T. (2014). Taking CO_2 Enhanced Oil Recovery to the Offshore Gulf of Mexico: A Screening-Level Assessment of the Technically and Economically-Recoverable Resource. *SPE Economics and Management*, (Preprint).

[70] Koperna, G. J., and Ferguson, R. C. (2011, January). Linking CO_2-EOR and CO_2 Storage in the Offshore Gulf of Mexico. In *Offshore Technology Conference*. Offshore Technology Conference.Gislason S.R. and Oelkers, E.H., 2014, Carbon Storage in Basalt, Science 344, p. 373-374 doi10.1126/science.1250828

[71] Shell Oil Company, 1980, Weeks Island 'S' sand reservoir B gravity stable miscible CO_2 displacement, Iberia Parish, Louisiana, U.S. Department of Energy contract #EF-77-C-05-5232, Third Annual Report, National Petroleum Technology Office, Tulsa, OK.

subsequent precipitation as the minerals such as calcite, magnesite, and siderite.[72,73,74] Structural trapping in porous zones within the basaltic rocks beneath impermeable seals (either impermeable basalts or other impermeable strata such as mudrocks) and density trapping where injected CO_2 is more dense than seawater are also considered.[75] Testing of storage by mineralization has been conducted fairly extensively in laboratories and in three on-land field settings.[76,77,73,78] CO_2 can be dissolved in water prior to injection as is done in the CARBFix experiment in Iceland and the Lamont-Doherty Earth Observatory experiment in the Palisades sill, NY, or injected as a separate phase as has been done the Big Sky experiment in Wallula, Washington.[79]

The distribution and amount of usable storage in oceanic basalt is poorly constrained. Ocean basins typically contain kilometers of basaltic crust with various fabrics and compositions.[80] Consideration of storage in basalt may provide options for areas where porous media storage is limited, for example in the Pacific Northwest of the United States.[81] Limitations of utilization of basalt for storage have not been systematically assessed but may include excessive water depth, excessive distance from on-land CO_2 point sources, excessive depth of burial beneath sediments, and limiting properties of the basaltic rocks such as presence of porosity and a functional top seal.

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[72] Lackner, K.S., Wendt, C. H., Butt, D.P., Joyce, E.L., and Sharp, D.H., 1995. Carbon dioxide disposal in carbonate minerals: Energy, v.20, p.1153–1170.

[73] Gislason, S.R., and Oelkers, E.H., 2014. Carbon storage in basalt. Science, v. 344, no. 6182, pp. 373–374.

[74] Brown, Gordon E. et al. 2009, Geological sequestration of CO_2: mechanisms and kinetics of CO_2 reactions in mafic and ultramafic rock formations. GCEP Progress report, 27 p.

http://web.stanford.edu/~gebjr/09%20GCEP%20Progress%20Report%20%28Brown%20et%20al.2%29.pdf

[75] Marieni, Chiara, Henstock, T. J., and Teagle, D. A. H., 2013, Geological storage of CO_2 within the oceanic crust by gravitational trapping, Geophysical research Leters, v. 40, p. 6219-6224 doi:10.1002/2013GL058220, 2013.

[76] Matter, J. M., and Takahashi, Taro, and Goldberg, David, 2007, Experimental evaluation of in situ CO_2 –rock-water reactions during CO_2 injection in basaltic rocks: implications for geological CO_2 sequestration. G3 Geochemistry Geophysics Geosystems, v. 8, doi:10.1029/2006GC001427

[77] Snæbjörnsdóttir, Sandra Ó. Wiese, Frauke, Fridriksson, Thrainn, Ármansson, Halldór, Einarsson, Gunnlaugur M., Gislason, Sigurdur, R., 2013, CO_2 storage potential of basaltic rocks in Iceland and the oceanic ridges, GHGT-12, Energy Procedia, https://zenodo.org/record/12869/files/Snbjornsdottir_et_al._GHGT-12_storage_potential_2014.pdf

[78] McGrail, B.P., Spane, F.A., Amonette, J.E., Thompson, C. R., and Brown, C. F., 2014, Injection and monitoring at the Wallula basalt project, GHGT 12, Energy Procedia, (2014) 2939-2948.

[79] Big Sky Carbon Sequestration Partnership (accessed 2015) Phase II Basalt Injection Phase http://www.bigskyco2.org/research/geologic/basaltproject

[80] Wright, John and Rothery, David, 1998, The ocean basins: their structure and evolution, 2nd edition, Oxford, UK, 185 p.

[81] Goldberg, D. S., Takahashi, T., and Slagle, A. L. (2008). Carbon dioxide sequestration in deep-sea basalt. *Proceedings of the National Academy of Sciences, 105*(29), 9920-9925. Lackner, K.S., Wendt, C.H., Butt, D.P., joyce, E.L., and Sharp, D. H., 1995, Carbon dioxide disposal in carbonate minerals, Energy v. 20, p. 1153-1170 Elsevier.

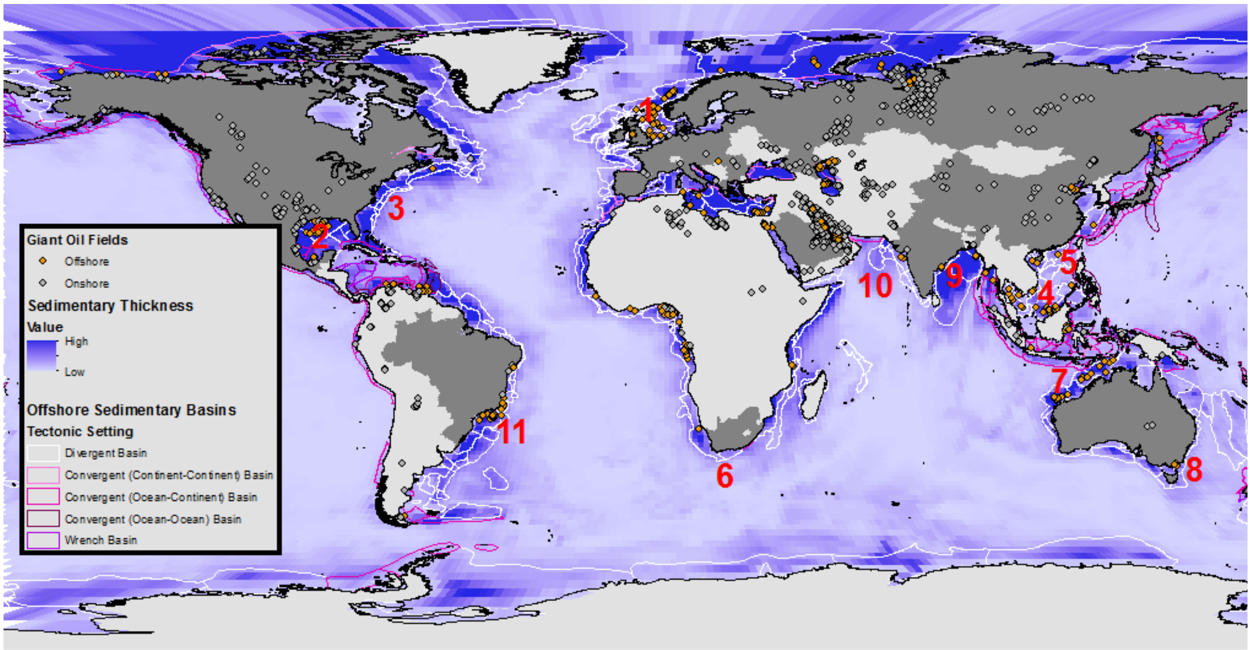

Figure 3-1. Thickness of sedimentary cover in offshore areas based on data from Divins (2003). CSLF countries are shaded. Numbers correspond to table 3-1 and to the detailed discussions in following texts. Basin outlines from AAPG (2013),[82] and supergiant hydrocarbon fields from Mann et al. (2003).[83]

More data are needed about how to assess injectivity and sealing capacity and the impact of mineralization storage processes on these key functions prior to fully understanding the distribution of suitable storage sites. Parts of the seafloor are tectonically active which may limit potential for storage in some areas. Maps of sub-sea distribution of selected basalts are presented by Brown et.al. (2009)[74] and Big Sky Carbon Sequestration Partnership[79], however maturation of the concept is needed to improve assessment of the potential global contribution of this method.

3.1.4 Status of global storage capacity assessment in subsea basins

To provide more information on the status of assessment of capacity in subsea basins globally, eleven prospective basins from Figure 3-1 were selected and a literature review conducted (Table 3-1). Status is highly variable. The best known basin is the North Sea for which a numerous regional and site-specific studies specifically targeted to assess storage have been completed and

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[82] AAPG, 2013, Robertson Tellus Sedimentary Basins of the World Map, http://www.datapages.com/Brody, S.D., Grover, H., Bernhardt, S., Tang, Z., Whitaker, B., and Spence, C., 2006, Identifying potential conflict associated with oil and gas exploration in Texas State coastal waters: A multi-criteria approach, Environmental Management, 38: 597-617.

[83] Mann, P., Gahagan, L., and Gordon, M. B. (2003). Tectonic setting of the world's giant oil and gas fields, p 15-105.

published. Other basins have significant data available about basin geology but have only a few or no studies of the suitability of the basins for geologic storage. Basins are numbered in the text, Figure 3-1 and Table 3-1.

3.1.4.1 North Sea Basin (1)

The North Sea Basin (NSB) is one of the most explored marine basins in the world, with decades of subsurface exploration summarized in the literature.[84,85] The first and longest running CO_2 storage project in the world has occurred at the Sleipner Field in the North Sea. The potential (capacity) for CO_2 sequestration is fairly well defined in regional geologic atlas format (both for the Norwegian and UK sectors of the central North Sea).[86,87,85] The storage capacity in the Norwegian sector has been estimated to have over 45 Gt of CO_2 storage, predominantly in the Utsira, Skade, Bryne, and Sandnes Formations. The UK sector of the North Sea has similar capacity. The southernmost NSB has thinner Cenozoic deposition, resulting in generally less storage capacity.[88]

Many passive continental margins initiated as rift basins during continental separation, with continued separation forming two separate shelves on opposite sides of an ocean. The North Sea Basin had a somewhat unique evolution in that rifting stalled prior to full development. This resulted in two important aspects for CO_2 storage. The first is that the basin depocenter remained in the middle of the basin (farthest from the coastline), where thick sequences of clastic sediment accumulated.[89] The second is that during this time, the basin experienced glacial advance and retreat that resulted in cyclical vertical tectonics, which is atypical for many passive margin settings (although perhaps somewhat similar to the northern Atlantic margin of the United States). These vertical isostatic basin elevation changes have caused the basin to experience dynamic cycles in pore pressure, such that the recent glacial history may be a significant influence in the structure, seal quality, and fluid history of the basin. Understanding the impact that these aspects may have for CO_2 storage is actively being pursued with the recent submission of a research proposal to the Integrated Ocean Discovery Program by an international consortium to drill a series

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[84] Chadwick, R. A., Arts, R., and Eiken, O. (2005). 4D seismic quantification of a growing CO2 plume at Sleipner, North Sea. In *Geological Society, London, Petroleum Geology Conference series* (Vol. 6, pp. 1385-1399). Geological Society of London.

[85] Bentham, M., Mallows, T., Lowndes, J., and Green, A. (2014). CO_2 STORage Evaluation Database (CO_2 Stored). The UK's online storage atlas. *Energy Procedia, 63*, 5103-5113.

[86] Gammer, D., Green, A., Holloway, S., and Smith, G. (2011). The Energy Technologies Institute's UK CO2 storage appraisal project (UKSAP).

[87] Halland, E. K., Gjeldvik, I. T., Johansen, W. T., Magnus, C., Meling, I. M., Pedersen, S., and Tappel, I. (20112013). CO_2 Storage Atlas: Norwegian North Sea. *Norwegian Petroleum Directorate, PO Box, 600*.

[88] Nilsen, H. M., Lie, K.-A., Andersen, O., 2015, Analysis of CO_2 trapping capacities and long-term migration for geological formations in the Norwegian North Sea using MRST-CO_2lab; Computers and Geosciences Volume 79, Pages 15-26.

[89] Sclater, J. G., and Christie, P. (1980). Continental stretching: An explanation of the post-mid-cretaceous subsidence of the central North Sea basin. *Journal of Geophysical Research: Solid Earth (1978–2012), 85*(B7), 3711-3739.

of wells focusing on the Cenozoic central basin fill to evaluate both the glacial stratigraphy as well as the seal characteristics. In this way, the NSB remains at the global forefront of understanding offshore basins for CCS.

3.1.4.2 Gulf of Mexico Basin (2)

Decades of exploration for hydrocarbons has provided insights into geology of the offshore portion of the Gulf of Mexico Basin.[90]. Most hydrocarbon production and concomitant data are from the northern, western and southern offshore areas of the basin. The Gulf of Mexico was formed during the Mesozoic, and accumulated a thick Jurassic sequence of shale that is important in later tectonics. The Mesozoic section contains significant carbonate with some siliciclastic depositional thickness,[91] however the most significant sediment thickness for CCS purposes are of Oligocene, Miocene and early Pliocene age.[92,93] Thick, coarse-grained clastic units provide storage reservoirs that alternate with laterally-extensive fine-grained units that serve as confining systems. Thin-skinned salt tectonics control the development of structural elements of the northwestern Gulf[94] and various structural configurations have resulted in traps that have accumulated large hydrocarbon volumes through geologic time. Such traps may also be prospective for retaining injected volumes of anthropogenic CO_2.

[90] Seni, S. J., T. F. Hentz, W. R. Kaiser, and E. G. Wermund Jr. (1997), *Atlas of Northern Gulf of Mexico Gas and Oil Reservoirs*, 199 pp., The University of Texas at Austin, Bureau of Economic Geology, Austin, Texas.

[91] Winker, C. D., and R. T. Buffler (1988), Paleogeographic evolution of early deep-water Gulf-of-Mexico and margins , Jurassic to Middle Cretaceous (Comanchean), *AAPG Bulletin-American Association of Petroleum Geologists*, *72*(3), 318-346.

[92] Galloway, W. E. (2009), Giant Fields North America: Gulf of Mexico, in *GEO ExPro - Geoscience and Technology Explained*, edited, London, UK.

[93] Galloway, W. E., P. E. Ganey-Curry, X. Li, and R. T. Buffler (2000), Cenozoic depositional history of the Gulf of Mexico basin, *AAPG Bulletin*, *84*(11), 1743-1774.

[94] Diegel, F. A., J. F. Karlo, D. C. Schuster, R. C. Shoup, and P. R. Tauvers (1995), Cenozoic structural evolution and tectono-stratigraphic framework of the northern Gulf Coast continental margin, in *Salt Tectonics; A Global Perspective*, edited by M. P. A. Jackson, D. G. Roberts and S. Snelson, pp. 109-151, American Association of Petroleum Geologists.

One focus of CCS research has been on the northern and northwestern margins of the basin.[95,96,97,98,99,100] This area is considered prospective because of the proximity of high quality storage potential, large industrial sources, extensive development of hydrocarbon resource, and demonstrated onshore EOR potential. Extensive geologic datasets from hydrocarbon exploration allow for informed regional geologic assessments. In conjunction with newer, higher-resolution technology detailed static geologic models can be generated that can then utilize hydrocarbon production histories to generate well-constrained flow simulation models of future anthropogenic CO_2 injection sites.

Research has only recently begun on evaluating offshore basins of the southern Gulf of Mexico in Mexican waters, which like the northern Gulf, are well known because of extensive hydrocarbon development.[101]

3.1.4.3 Atlantic Coast of United States (3)

The formation of the central North Atlantic Ocean began with continental rifting (separation of North America and Africa) in late Triassic to early Jurassic time followed by seafloor spreading throughout the rest of the Mesozoic and into the Cenozoic. Offshore from the East Coast of the United States, rift basins and grabens that formed during this continental breakup were subsequently filled with great thicknesses of sediment eroded from the present day Appalachian Mountains. This type of passive continental margin is known throughout the world as an Atlantic-type continental margin.[102] Major basins of interest off the Atlantic coast of eastern United States are, from north to south, the Georges Bank Basin (GBB), Baltimore Canyon Trough (BCT), Carolina Trough (CT), South Georgia Basin (SGB), the Blake Plateau Basin (BPB), and the

[95] Mickler, P. J., C. Yang, J. Lu, and K. D. Lankford (2014), Laboratory Batch Experiments and Geochemical Modelling of Water-rock-super Critical CO_2 Reactions in Gulf of Mexico Miocene Rocks: Implications for Future CCS Projects, *Energy Procedia*, *63*(0), 5512-5521.

[96] Miller, E. N. (2012), A question of capacity assessing CO_2 sequestration potential in Texas offshore lands, 119 pp, University of Texas at Austin.

[97] Nicholson, A. J. (2012), Empirical Analysis of Fault Seal Capacity for CO_2 Sequestration, Lower Miocene, Texas Gulf Coast, in *Unpublished Masters Thesis*, edited, p. 88, The University of Texas at Austin.

[98] Wallace, K. J. (2013), Use of 3-Dimensional Dynamic Modeling of CO_2 Injection for Comparison to Regional Static Capacity Assessments of Miocene Sandstone Reservoirs in the Texas State Waters, Gulf of Mexico, 152 pp, The University of Texas at Austin, Austin.

[99] Wallace, K. J., T. A. Meckel, D. L. Carr, R. H. Treviño, and C. Yang (2014), Regional CO_2 sequestration capacity assessment for the coastal and offshore Texas Miocene interval, *Greenhouse Gases: Science and Technology*, *4*(1), 53-65.

[100] Yang, C. B., R. H. Trevino, T. W. Zhang, K.D. Romanak, K. Wallace, J. M. Lu, P. J. Mickler, and S. D. Hovorka (2014), Regional Assessment of CO_2-Solubility Trapping Potential: A Case Study of the Coastal and Offshore Texas Miocene Interval, *Environmental Science and Technology*, *48*(14), 8275-8282.

[101] Jacobs, T., 2015, Bringing Enhanced Oil Recovery to Mexican Fields, JPT special issue "Uncovering Mexico", January 2015, pp 54-

[102] Bally, A. W., 1981, Atlantic-type continental margins *in* Bally, A. W., ed. Geology of passive continental margins: American Association of Petroleum Geologists Education Course Notes, series 19, p. 1-48.

Bahamas Basin (BB). Three of these (GBB, BCT, CT) are known as classic Atlantic-type marginal basins.[103]

Complexities of regional tectonics over time have resulted in big differences in geology along the U.S. Atlantic coast, including large variations in width of the continental shelf. As a result, only two of the classic Atlantic basins that are filled with clastic sediment, GBB and BCT, are located within shallower water depths of the U.S. Atlantic continental shelf. These basins have high potential for sub-seabed geologic storage (GS) of CO_2.The BCT has previously been considered for sub-seabed CO_2 GS;[104] however, more work is needed before the CO_2 sub-seabed GS potential of the GBB is known. The SGB, while not being a classic Atlantic-type basin, has thick sequences of clastic sedimentary rock that also have significant potential for CO_2 GS, especially in a section lying offshore from Georgia. A stratigraphic analysis of the SGB and preliminary capacity assessment was completed in 2011.[105]

Reconnaissance-level estimates of capacity for CO_2 GS were completed in 2008 for areas offshore from the Carolinas and landward of the Carolinas Trough.[106] These capacity estimates will need to be revisited because part of the assessed area is off the continental shelf in water up to several kilometers deep. Atlantic coastal areas south of the SGB may be less favorable for sub-seabed GS of CO_2 because they are dominated by carbonate sediments and are more tectonically active. For example, the BPB contains a shear zone that connected eastern Gulf of Mexico and central Atlantic, as well as abundant mafic intrusions. BB has strike-slip, and compressional zones near Caribbean.[107]

Early information on the offshore sub-seabed Atlantic came from hydrocarbon exploration on the continental shelf overlying GBB, BCT, and SGB starting in the late 1970s. Because of opposition from environmental groups, much of the subsequent work (drilling, seismic refraction, and gravity modeling) was completed by scientific expeditions such as JOIDES, DSDP, COST, and USGS.[108] In fact, current drilling moratoria for offshore Atlantic are in effect through 2017.

[103] Grow, J. A. and Sheridan, 1988, U.S. Atlantic continental margin: A typical Atlantic-type or passive continental margin in Sheridan, R. E. and Grow, J. A., eds., The Geology of North America, Volume I-2,The Atlantic Continental Margin: Geological Society of America, p. 1-7.

[104] Midwest Regional Carbon Sequestration Partnership characterization of offshore New Jersey - http://www.mrcsp.org/userdata/phase_II_reports/njgs_carbon_sequestration_report_web.pdf

[105] Smyth, R. C., and Carr, D. L., 2011, Continued evaluation of potential for geologic storage of carbon dioxide in the southeastern United States: UT Austin, BEG unpublished contract report, 39 p.

[106] Smyth, R. C. et al., 2008, Potential sinks for geologic storage of carbon dioxide generated by power plants in North and South Carolina: UT Austin, BEG unpublished contract report, 58p.

[107] Mattick, R. E. and Libby-French, J., 1988, Petroleum geology of the United States Atlantic continental margin in Sheridan, R. E. and Grow, J. A., eds., The Geology of North America, Volume I-2,The Atlantic Continental Margin: Geological Society of America, p. 445-462.

[108] AAPG, 2013, Robertson Tellus Sedimentary Basins of the World Map, http://www.datapages.com/

3.1.4.4 Southeast Asia (4)

The basins to the northeast of Malaysia and Indonesia are different from the more common passive margin extensional basins in that they have a prolonged compressional (convergent) history. This convergence has caused rapid subsidence of thick carbonate stratigraphic sections, causing the generation of prolific gas that has high associated CO_2 contents (Natuna: 70 percent CO_2, 200 Tcf CO_2; Kuala Langsa: 82 percent CO_2, >20 Tcf CO_2). In the North Sumatra Basin, average CO_2 content in the lower Miocene Peutu Formation is around 25 percent, and in the deeper Paleocene Tempur Formation it is typically over 50 percent. It is thought that the rapid subsidence of Cenozoic carbonates and subduction-related volcanism[109,110] generated more CO_2 than could be assimilated through natural processes in the basin (titration during migration; Cathles and Schoell (2007)[111]). Published details suggest that the most common geological circumstances for the occurrence of high concentrations of CO_2 are deep faults close to gas traps, reservoirs close to hot basement and carbonates associated with post-trap igneous activity. The prediction of CO_2 content has a major impact on exploration and production strategies. The ultimate fate of the CO_2 if these large methane accumulations were to be produced is unknown, but reinjection for storage may be guided by understanding the settings and characteristics of natural accumulations.

3.1.4.5 Pearl River Mouth Basin, offshore China (5)

According to Zhou et al. (2011),[112] the Pearl River Mouth Basin (PRMB) is "an extensional basin in the passive continental margin of the northern South China Sea" that was formed during Paleogene rifting of the South China Block and further developed through later (Neogene) subsidence. The basin contains more than 6 km of Cenozoic sediments in its continental shelf portion. The sedimentary section mostly comprises alternating units of sandstone and mudrock (shales, mudstones and siltstones) with some early Miocene limestone (reef) developed on structural highs. Hydrocarbon producing reservoirs are late Oligocene to middle Miocene in age as are potential CO_2 storage reservoirs. The prospective units are deltaic, channel, transgressional, slope and low-stand fan sandstones, and reef and platform carbonates.[112] Similarly, known hydrocarbon top seals are of early to middle Miocene age (within Hanjiang and Zhujiang formations), and they correspond to potential CO_2 confining systems, which can attain net mudstone thicknesses of 400–800 m in the Hanjiang formation.[112] Reservoirs within the Hanjiang and Zhujiang formations exhibit porosities from 16–29 percent and permeabilities from 188–1732

[109] Wilson and Hall, 2010, Tectonic influences on SE Asian carbonate systems and their reservoir development. Cenozoic Carbonate Systems of Australasia: SEPM, Special Publication, 95, 13-40.

[110] Nayoan, G. A. S., and Arpandi, M. S. (1981). Tertiary carbonate reservoirs in Indonesia.

[111] Cathles, L. M., and Schoell, M. (2007). Modeling CO_2 generation, migration, and titration in sedimentary basins. Geofluids, *7*(4), 441-450.

[112] Zhou, D., Z. X. Zhao, J. Liao, and Z. Sun (2011), A preliminary assessment on CO_2 storage capacity in the Pearl River Mouth Basin offshore Guangdong, China, *International Journal of Greenhouse Gas Control*, *5*(2), 308-317.

mD as reported by Zhou (2011)[112] after Chen et al. (2003).[113] The major carbon geo-sequestration uncertainties in the PRMB are the distribution of reservoirs and confining systems. The PRMB is adjacent to one of the most highly industrialized regions of China (Guangdong Province),[114] where several petrochemical plants have been producing high-concentration CO_2 and where two units in the coal-fired Haifeng power plant are designed to be capture-ready.

3.1.4.6 Offshore storage capacity of South Africa (6)

South Africa's total emission of carbon dioxide is over 400 Mt/y according to estimation in 2010.[115] More than ninety percent of South Africa's electricity is generated from coal.[116] Clean coal technology is vital to South Africa's coal industry in a low carbon future.[117] CCS has been identified as one of the technical approaches to reduce carbon dioxide emissions in government's long-term mitigation plan. South Africa Centre for CCS has prepared a roadmap towards full commercial operation of geological storage of in 2025.

The Atlas on Geological Storage of Carbon Dioxide in South Africa released in 2010 determined that 98 percent of the country's ≈150 Gt storage capacity lies in three offshore Mesozoic basins, the Outeniqua Basin (south coast), Orange Basin (west coast), and Durban and Zululand Basin (east coast) (Figure 3-2). The potential for storage in the depleted oil and gas fields is limited, estimated 62 million tons of CO_2. Total storage capacity of the known oil and gas reserves in the Orange and Outeniqua Basin is estimated 15 million tons of CO_2 after depletion.[118,115] The majority of the estimated storage capacity is from deep saline formations.

In these offshore basins, multiple storage/confining intervals occur in the thick strata of rift-drift sediments. Fluvial marginal-marine and shelf sandstones in the syn-rift sequences and slope/marine fan sandstones in the drift sequences provide storage intervals, while drift and younger deep marine shales provide good confining units. Among them, the Outeniqua Basin is the most explored with existing oil and gas infrastructure, while the Durban/Zululand Basin has

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[113] Chen, C., Shi, H., Xu, S., Chen, X., et al (2003), *Formation Conditions of Tertiary Oil/Gas Reservoirs in Pearl River Mouth Basin (East)*, 266 pp., Beijing.

[114] Bai, B., X. C. Li, Y. P. Yuan, D. Zhou, and P. C. Li (2014), Preliminary assessment of CO_2 transport and storage costs of promising source-sink matching scenarios in Guangdong province, China, *Acta Geotech.*, *9*(1), 115-126.

[115] Viljoen, J.H.A., Stapelberg F.D.J., Cloete, M., 2010, Technical report on the geological storage of carbon dioxide in South Africa. South Africa Council for Geoscience, 238 p. http://www.sacccs.org.za/wp-content/uploads/2011/02/CO2%20Technical%20Report%20on%20the%20geological%20storage%20of%20carbon%20dioxide%20in%20South%20Africa.pdf. Last accessed on February 23, 2015.

[116] South African Department of Environmental Affairs. 2010. National Climate Change Green Paper, 38 p. https://www.environment.gov.za/sites/default/files/legislations/national_climatechnage_response.pdf. Last accessed on February 20, 2015.

[117] Glazewski, J., Gilder, A., Swanepoel, E. 2012. Carbon Capture and Storage (CCS): Towards a regulatory and legal regime in South Africa. Institute of Marine and Environmental Law (IMEL) and African Climate and Development Initiative (ACDI), University of Cape Town, Cape Town. 42 p. http://www.imel.uct.ac.za/usr/law/imel/downloads/CCS_Report.pdf. Last accessed on February 20, 2015.

[118] Cloete, M. 2010. Atlas on geological storage of carbon dioxide in South Africa. Council for Geoscience, Pretoria, South Africa, 60 pp. http://www.sacccs.org.za/wp-content/uploads/2010/11/Atlas.pdf. Last accessed on February 20, 2015.

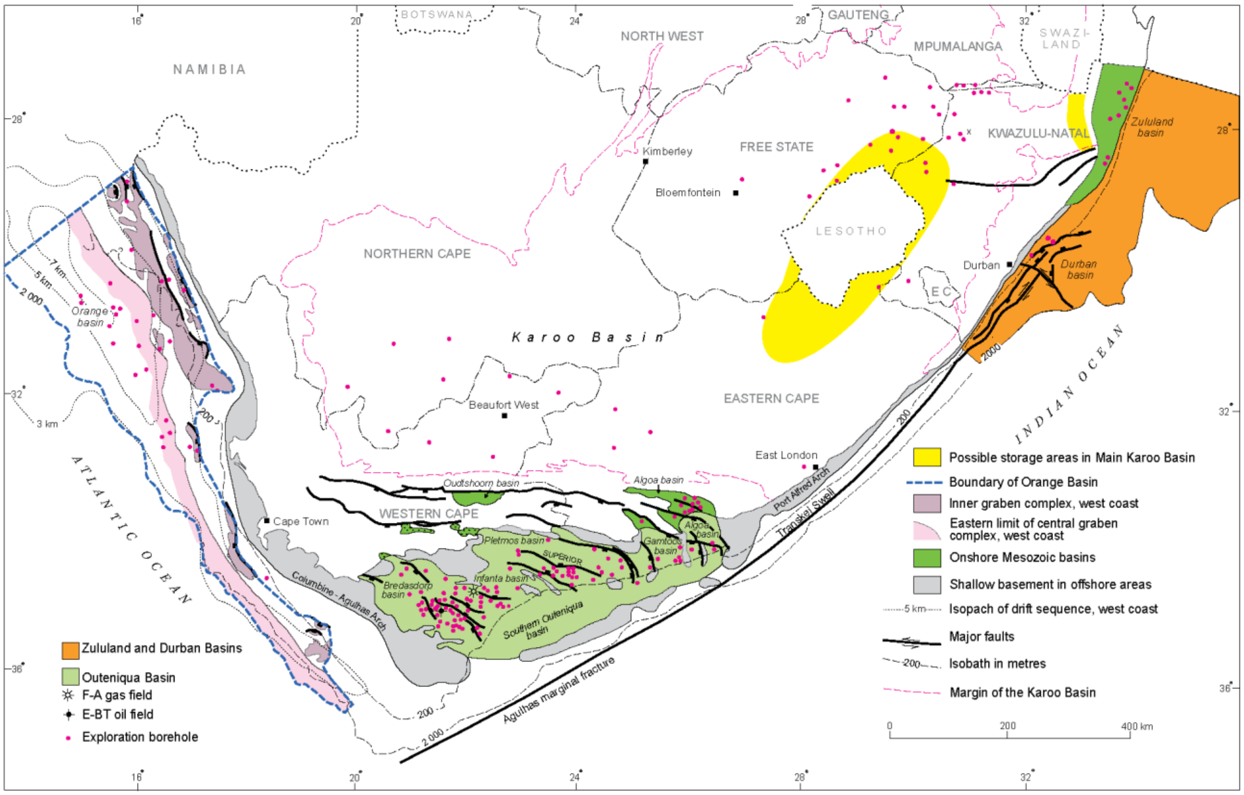

Figure 3-2. Offshore Mesozoic basins along the coast of South Africa[115]

scant data, but is nearest to the major CO_2 sources. The major challenges for carbon geological storage are the overall lack of geological data and the extensive presence of faults and dolerite sills and dykes.

3.1.4.7 NW shelf of Australia (7)

The major continental shelves of North West shelf -Timor Sea area of Australia is underlain by sedimentary basins (e.g., Carnarvoran, Canning, Browse, Bonapart, Yampi) of Australia are in the northwest side of the continent, offshore the state of West Australia. Dense publically accessible seismic data means that this complex stratigraphy is well documented in the public domain as well as in the oil and gas industry (e.g., Longley et al, 2003[119]).

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[119] Longley, L. M., Buessenschuett, C., Clydesdale, L., Cubitt, C. J., Davis, R.C., Johnson, M.K., Marshal, N.M., Murray, A. P., Somerville, R., Spry, T. B., and Thompson, N.B., 2003, The North West Shelf of Australia - A Woodside Perspective, AAPG Search and Discovery article #10041 (2003) ww.searchanddiscovery.com/documents/longley/

Complex Paleozoic basement stratigraphy (2-6 km) impacts the structure and sedimentology of Neogene—Recent basins. Convergent plate setting, dominated by normal faults.[120]

These areas were recognized early as having high storage potential for CO, but questions arose how this areas, distant from populations centers should be evaluated in terms of global potential, as this volume might be too far to be of pragmatic utility.[121] However, the area is highly productive of gas and the Gorgon Project, storing CO_2 stripped from gas, is under construction by a consortium led by Chevron. Although the separation facility as well as the storage project is located on Barrow Island, the project will provide a demonstration of the storage resource of the region. It also continues the theme of early project related to sequestration of CO_2 stripped from gas prior to sending it to market.

3.1.4.8 Gippsland Basin, eastern Australia (8)

During assessment of the storage resource of Australia, the Gippsland Basin was identified as a favorable target[122,123] One of Australia's hydrocarbon–producing areas, it lies in the near offshore (<100 km to shoreline) of a major brown coal mining and use area in the Latrobe Valley, Victoria, in southeastern Australia.[124] A fault-bounded rift basin with anticlinal structures has undergone a fairly complex evolution from the upper Cretaceous through the Tertiary. The sedimentary basin thickness is >6km,[124] however the characterization for geologic storage has focused on a 400-900 m-thick wedge of Paleocene—Eocene sandstones, shales and coals that form the Latrobe Group.[125] Numerous stacked sandstone reservoirs have mineralogically mature composition sand retain good porosity and permeability. Shale seals of the Lakes Entrance Formation average 395 m thick.[126]

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[120] Keep, Myra and Harrowfield, Mathew, 2008, Elastic flexture and distributed deformation along Australia's North West Shelf: Neogene tectonics of the Bonaparte and Bowse basins. Geological Scarcity of London Special publications, v. 306, p. 185-200.

[121] Bradshaw, John and Rigg, Andy, 2011, The GEODISC Program: Research into Geological Sequestration of CO_2 in Australia Environmental Geosciences, September 2001, v. 8, p. 166-176, doi:10.1046/j.1526-0984.2001.008003166

[122] Bradshaw, John and Rigg, Andy, 2011, The GEODISC Program: Research into Geological Sequestration of CO_2 in Australia Environmental Geosciences, September 2001, v. 8, p. 166-176, doi:10.1046/j.1526-0984.2001.008003166.

[123] Root. R.S., Gibson-Poole, C.M., Lang, S.C., Streit, J. E., Underschultz, J. R., and Ennis-King, J.,2004 Opportunities for geological storage of carbon dioxide in the offshore Gippsland Basin, SE Australia: an example from the upper Latrobe Group. In Boult, P.J., Johns, D.R. and Lang, S.C., (eds) Eastern Australia Basins Symposium II PESA, 367-388.

[124] Rahmanian, V.D., Moore, P. S., Mudge, W.J., Spring, D.E., 1990, Geological Society of London Special Publication, v. 50, p. 525-544

[125] Gibson-Poole, Catherine M.; Svendsen, L. Underschultz, J. Watson, M. Ennis-King, J. P. van Ruth, P., Nelson, E., Daniel, R. and Cinar, Y., 2006a, Gippsland Basin geosequestration: a potential solution for the Latrobe Valley brown coal CO_2 emissions, APPEA Journal

[126] Gibson-Poole, Catherine M.; Svendsen, L. Underschultz, J. Watson, M. Ennis-King, J. P. van Ruth, P., Nelson, E., Daniel, R. and Cinar, Y., 2006b, Regional Characterization of a Major Storage System: Gippsland Basin, Southeast Australia, CO2SC 2006, Berkeley CA.

Complex basin evolution result in a long, baffled, predicted regional migration path for buoyant CO_2.

Depleted oil reservoirs are considered as the major target, and EOR is not considered economically viable. Because exploration is currently active and production of known reservoirs is predicted to be ongoing for several decades, a plan for injecting in saline formations down-dip of active producers is proposed, so that CO_2 migration into traps will be delayed until the end of production. Faults are identified on 3D seismic and cut through the prospective reservoir intervals of the Eocene Latrobe Formation.[124] Fault reactivation risk has been considered a significant risk which should be mitigated through management.[128,126,125]

Figure 3-3. Geometry of the Bengal and Indus fans. From Woods Hole Oceanographic Institute.[127]

3.1.4.9 Indus (9) and Ganges-Brahmaputra-Meghna (10) Basins

Starting in the late Eocene, the collision of the India Plate with the Eurasian Plate began uplifting continental crust into the Himalaya Mountains that continues today. Weathering and erosion that counteract mountain building forces supply enormous sediment loads to two composite drainage basins along the Indian Margin (Ganges-Brahmaputra and Indus). Both the Ganges-Brahmaputra and Indus rivers drain over 1 million km^2 that supply sediment to enormous fan accumulations in the Bay of Bengal and Arabian Sea respectively (Figure 3-3). Both fan's stratigraphy is generally characterized by turbidity currents through canyon complexes on the marine shelf that eventually deposit channel-levee features along the length of the fan.[129,130] While these fans are kilometers thick at their thickest part (Indus: 9km; Ganges-Brahmaputra: 16km), Eocene and Oligocene mudrocks in the lower third of the sedimentary column are separated by an unconformity from coarser grained

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[127] Woods Hole Oceanographic Institute. (accessed Mar, 2015. http://www.whoi.edu/oceanus/v2/article/images.do?id=2510

[128] Swierczek, E., Backe, G., Holford, S.P., Tehthorey, E., and Michell, A, 2015, 3D seismic analysis of complex faulting patterns above the Snapper Field, Gippsland Basin: Implications for CO_2 storage. Australian Journal of Earth Sciences: and International Geoscience Journal of the Geological Society of Australia, 62:1, 77-94 DOI 10.1080/08120099.2015.978373

[129] Curray, J. R., and Moore, D. G. (1974). Sedimentary and tectonic processes in the Bengal deep-sea fan and geosyncline. In The geology of continental margins (pp. 617-627). Springer Berlin Heidelberg.

[130] Kolla, V., and Coumes, F. (1987). Morphology, internal structure, seismic stratigraphy, and sedimentation of Indus Fan. *AAPG Bulletin*, *71*(6), 650-677.

Miocene and younger rocks with sediment sourced from Himalaya erosion.[131,132] In terms of CCS potential, reservoir candidates include turbidities 10s of meters thick from levee collapse or kilometer scale channels containing coarse infill.

Novel issues to be evaluated in these large active fans are depth and slope stability, as well as source-sink matching.

3.1.4.10 Campos and Santos Basins, offshore Brazil (11)

The most prospective portion of offshore Brazil for CO_2-related activities is in the Campos and Santos Basins in the southeast. The Campos Basin is a primary candidate for CO_2 storage, given its geology and proximity to coastal CO_2 sources. In the Campos Basin, there is significant potential for CO_2 storage (ca. 950Mt) as assessed for 17 oilfields in the basin, and 75 percent of this storage capacity is found in sandstone reservoirs.[133] Static volumetric estimates of storage for the Campos and Santos Basins suggest they may be able to receive 30 and 80 Mt CO_2 (respectively) per year for decades.[134]

3.2 Opportunities and Recommendations

CSLF countries have access to offshore storage. Those settings are predominantly passive margin extensional clastic basins with Cenozoic age fill, representing high porosity and permeability and ductile seals, with broadly similar extensional faults dominant. Storage opportunities are similar in style and quantity/capacity for many countries. While some aspects are unique, geologic and technologic advances undertaken in one area are more likely to be applicable to other countries. It is recommended that a more thorough evaluation of the geologic storage aspects of many basins (i.e., those in Figure 3-1) be pursued. It is also recommended that an increased level of knowledge sharing and discussion be implemented among the international community to outline the potential for international collaboration in offshore storage to overcome challenges such as cost, and building technical expertise.

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[131] Clift, P. D., Shimizu, N., Layne, G. D., Blusztajn, J. S., Gaedicke, C., Schlüter, H. U., and Amjad, S. (2001). Development of the Indus Fan and its significance for the erosional history of the Western Himalaya and Karakoram. Geological Society of America Bulletin, 113(8), 1039-1051.

[132] Curray, J. R., Emmel, F. J., and Moore, D. G. (2002). The Bengal Fan: morphology, geometry, stratigraphy, history and processes. Marine and Petroleum Geology, 19(10), 1191-1223.

[133] Rockett, G. C., Ketzer, J. M. M., Ramírez, A., and van den Broek, M. (2013). CO_2 Storage Capacity of Campos Basin's Oil Fields, Brazil. Energy Procedia, 37, 5124-5133.

[134] Ketzer, J. M., Villwock, J. A., Caporale, G., da Rocha, L. H., Rockett, G., Braum, H., and Giraffa, L., 2007, Opportunities for CO_2 capture and geological storage in Brazil: The CARBMAP Project. In Sixth Annual Conference on Carbon Capture and Sequestration, Pittsburgh, Pennsylvania.

Table 3-1 Properties of example basins evaluated for this study are summarized

Map Number	Region	Basin	Avg. water depth (m)	Max water depth (m)	Min sediment thickness (km)	Max sediment thickness (km)	Structural type	Structural comparment-alization	Siesmic Risk	Target formation age (my)	Target formation rock type	Target formation depositional system/facies	Target formation heterogeneity	Confining system type	Confining system age (my)	Major confining system risks	Level of information	Major uncertainties for storage target
1	North Sea	North Sea	~100	330	1	2	Extension	Low	Low	Miocene-Pliocene	Sandstone	Basin-restricted marine lowstand deposits	Medium	Clay-rich shale	Upper Pliocene	Faults from isostatic rebound, wells	High	Leakage potential of faults
2	North America	GoM - nearshore	50	1000	2	8	Extension	Medium	Low	3-30	Sandstone	Progradational continental wedge	Medium	shale-sandstone	3-30	Faults & gas chimneys	High	Closed vs. open reservoir systems
3	North America	US East Coast	100	500	1	10	Passive	Medium	Low	65 - 150	Sandstones	Synrift fluvial, deltaic and shallow marine	Medium	shale, shale-sandstone	50-80	Faults, dike and salt domes	Low	Offshore transport distances, migration along faults
4	SE Asia	South China Sea	70	2000	1.4	9.3	Extension	Medium?	Medium	Tertiary	Sandstones and carbonates	Shoreline, delataic, and reef deposits	High	Marine mudstone with interbedde	Lower-Middle Miocene	Normal faults	Low	Offshore transport distances, migration along faults
5	China	Pearl River Mouth Basin	50	2000	6	14	Extension	High	Medium	5-30	Sandstone with reef carbonates on local structural highs	Marine	High	Transgres-sional mudstone	9-16	Lateral extent and fault leakage	Low	Confining system integrity; reservoir quality
6	South Africa	Outenique, Orange, Durban and Zululand	65	2000	1	7	Extension, assymetrical grabens	High	Medium	Cretaceous	Sandstone	Synrift fluvial, deltaic, shallow and deep marine submarine fan	Medium to high	Multiple synrift and transitional shales	Cretaceous	Faults, dyke penetration	Medium to low	Porosity/ permeability, compartmentaliza tion
7	Australia	NW Shelf	100	200	???	10	Extensional	High	Medium?	Cretaceous	Sandstone	Fluvial-deltaic and marginal marine sandstones	High	Anticlines and fault blocks at base of	Cretaceous	Faults and seeps	Medium	Evidence of hydrocarbon seepage along faults
8	Australia	Gippsland	45	70	3.4	2.9	Compressed rift basin	High	Medium	Paleocene-Eocene	Sandstones	Alluvial plain, Coastal plain, shoreface	Medium	Glauconitic, slighlty calcareous, mud-rich sediments	Oligocene	Faulted, but sealing to hydrocarbons	High	Intersection with still-active production (started 1960)
9	India	Ganges-Brahmaputra	500	2500	1	16	Compression	Medium	High?	20	Sandstones	Local Thickening & Uplift of SS	???	Shale-sandstone	10	Faults/Pinch Out	Low	Lack of Info/ Seismicity
10	India	Indus	500	3000	Pinches Out	12	Compression	Medium	High?	21	Sandstones	Turbidite/ Channel SS	???	Carbonate	11	Faults/Eroded Unconformity	Low	Lack of Info/ Seismicity
11	Brazil	Santos and Campos	2100	2400	1	2	Extension	High	Low	Lower Cretatceous	Sandstones	Carbonate microbialites, turbidites	High	Pre-salt	Cretaceous	Faults	High	Deep water and deep stratigraphy; monitoring

4 CO_2 transport for offshore storage

4.1 Introduction

For offshore storage, CO_2 source and sink are rarely co-located, and when they are, typically it is for offshore hydrocarbon production. Cost-efficient and safe solutions are needed in order to realize large scale value chains for CO_2 capture and transport. Similar to capture and storage of CO_2, methods for transporting CO_2 exist, and have been proven to work. Currently, more than 6,800 km of CO_2 pipelines have been constructed world-wide, most of these are onshore in North America. Small volumes of food grade CO_2 are also transported by ship and by truck.

According to the IEA 2 degree scenario (2DS), CCS has to be scaled up from a few tens of Mtpa today to more than 6 gigatonnes per year in 2050.[135] In comparison, the current natural gas production amounted to approximately 2.5 gigatonnes in 2012.[136] Hence, in order to realize the 2DS, a massive investment in transportation infrastructure is needed. A significant part of the infrastructure will be offshore, both to reach attractive offshore storage sites and to avoid public acceptance issues related to transportation through populated areas.

The long industrial experience with natural gas transportation systems both onshore and offshore will certainly be of great help in achieving this goal, but in some aspects CO_2 behaves quite differently than natural gas, and this has to be taken into account when designing transport system. When optimizing the design of a transport system, it is important to take into account the whole chain. Currently, there are some uncertainties in predicting the properties of CO_2 mixed with typical impurities from CO_2 capture processes.

Hence, most transportation specification tends to be conservative, which could lead to a value chain that is off the optimum in terms of costs and efficiency.

4.2 Transport Methods

The main modes of CO_2 transport are by pipeline, ship or truck. Given the volumes required to meet the 2DS scenario, and the report focus offshore storage, this chapter will only discuss transport by pipeline and ship.

4.2.1 Pipeline transport

Pipelines are expected to be the backbone of a future CCS transport system in all regions. No other technology will be capable of handling the large transportation needed to mitigate global warming caused by anthropogenic emissions at an acceptable cost in terms of capital and efficiency.

[135] *Energy Technology Perspectives 2014*. (2014). Paris, France: International Energy Agency.
[136] *World Energy Outlook 2014*. (2014). Paris, France, www.worldenergyoutlook.org: International Energy Agency.

Pipeline infrastructure for CO_2 transport will have many similarities with natural gas infrastructure, with conditioning and compression[137] at the source upstream and pipelines of similar materials and design and possibly hubs and booster stations before the terminus. Significant experience has been built over the decades with regards to offshore natural gas pipelines, summed up in standards such as the DNV standard for submarine pipeline systems.[138] Offshore pipelines are more expensive to install, operate, and maintain, but on the positive side they usually operate in a more predictable physical environment, especially in terms of temperature, and the public acceptance issues related to perceived safety seen especially with European CCS projects are not expected to apply for offshore CCS pipelines.

Under normal steady-state operating conditions, the natural gas offshore pipeline wisdom is expected to be readily applicable also for CO_2 for pipelines of similar dimensions and operating pressure with regards to offshore specific installation and impact from the environment. However, just like for onshore pipelines, the differences properties from natural gas have to be considered when designing CO_2 pipeline transportation systems. These specifics of CO_2 pipeline transport are fairly well covered in a number of high-level publications and recommendations.[139,140,141,142]

For instance, different gaskets materials and designs have to be used to cater for CO_2's high solubility in polymers, and CO_2's relatively low lubricity compared with hydrocarbons have to be taken into account when selecting rotating equipment and designing pigs for interior pipeline inspections. More importantly, CO_2 is most efficiently transported in dense phase, and in order to avoid two-phase flow, the pressure needs to be kept above the phase boundary during operation. Liquid water with CO_2 is corrosive, and like natural gas CO_2 forms hydrates with water. Hence, the impurity level of the CO_2 to be transported must be optimized. For these reasons, startup and

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[137] Aspelund, A. and Jordal, K. (2007). Gas conditioning—The interface between CO_2 capture and transport. *International Journal of Greenhouse Gas Control, 1*(3), 343-354.

[138] DNV, Det Norske Veritas AS. (2013). *Submarine Pipeline Systems* (Offshore Standard No. OS-F101). www.dnv.com.

[139] Doctor, R. and Palmer, A. (2005/2006). Transport of CO_2 *Carbon Dioxide Capture and Storage* (pp. 179-194). Geneva, Switzerland: IPPC (online) / Cambridge University Press.

[140] DNV, Det Norske Veritas AS. (2010). *DESIGN AND OPERATION OF CO2 PIPELINES* (RECOMMENDED PRACTICE No. DNV-RP-J202). www.dnv.com.

Pershad, H., et al. (2010). Development of a global CO_2 pipeline infrastructure Retrieved from http://decarboni.se/publications/development-global-co2-pipeline-infrastructure

[141] Forbes, S. M., et al. (2008). *CCS Guidelines: Guidelines for Carbon Dioxide Capture, Transport, and Storage*. Washington, DC: World Resources Institute (WRI).

[142] *CO_2 Transportation - Is it Safe and Reliable?* (2010). Carbon Sequestration Leadership Forum.

Engebø, A. and Ahmed, N. (2012). *Activity 5: CO_2 transport*. Norway, http://www.gassnova.no/no/Documents/5.%20DNVFinalReportAct5CO2transport2012.pdf: Gassnova

Oosterkamp, A. and Ramsen, J. (2008). *State-of-the-Art Overview of CO_2 Pipeline Transport with relevance to offshore pipelines*. Haugesund, Norway: Polytec.

depressurization need more attention, particularly because rapid pressure drops are associated with strong cooling. Section 4.4 will provide a more detailed account of these topics.

To sum up, solutions for transporting CO_2 by pipeline exists. Compared with other modes of transport, such as shipping, the main advantage is potentially very large capacity and low operational costs, especially over relatively short distances and for high volumes, whereas the drawbacks are the investment costs and lack of flexibility.

4.2.2 Ship transport

Although transportation of CO_2 by ship has been common practice for more than 20 years, this mode of transportation has not been implemented in a CCS project yet. Up until now, there have only been small tonnage ships (approx.1000 tons) for supplying CO_2 to the food industry and other relatively small scale purchasers. Most of them were converted from liquefied petroleum gas (LPG) carriers. CO_2 transportation for CCS purposes will face different requirements, and there will be other challenges in terms of the design of the ships. The existing fleet transports CO_2 with a pressure of 15-20 bar and a temperature of about -30 °C. For larger volumes, current studies tend to use values for pressure and temperature in the neighbourhood of 8 bars and -50 °C (close to the triple point).[143]

Building pipelines over longer distances in combination with uncertain or smaller volumes of CO_2 can be quite expensive. In this case CO_2 transportation by ship can be a competitive solution, assuming the technology and systems are available. Ships can carry CO_2 far below their design capacity and has therefore a higher adaptability to fluctuation in CO_2 supply. This offers an option of collecting CO_2 from multiple sources and also injecting CO_2 at multiple storage sites. Their mobility and reusability increase flexibility in project planning, making it easier to expand or shrink the size of a project and to alter storage sites. But due to its nature of discrete services, the transportation mode generally needs additional facilities in comparison with pipeline systems: intermediate storage facilities and loading infrastructure at a port; and an unloading facility and intermediate storage facilities at or near a CO_2 storage site.

Currently, ship transport is foreseen as a potential kick-starter of offshore CO_2 transport and storage by fulfilling the need for reliable supply at the early stages of CCS or CO_2-EOR projects. Several studies into the technical feasibility of ship transport have been performed in recent years and a demonstration project is urgently needed to address some of the remaining uncertainties. Only a few technical issues remain, which are partly specific to each different storage location.

4.2.3 Hybrid solutions and value-chain perspectives

As discussed above, pipeline transport is most suitable for transportation of high volumes over many years and relatively short distances, whereas shipping is an attractive option for smaller

[143] *The Costs of CO_2 Transport*. (2011). http://www.zeroemissionsplatform.eu: European Technology Platform for Zero Emission Fossil Fuel Power Plants (ZEP).

sources / sinks, longer distances, and its higher flexibility. In particularly in the early days of CCS, such flexibility could be very important. Compared with shipping, point to point links are particularly risky as the business case depends on the operation of a single source and single sink. For optimized operation, the transported volume should be close to capacity, but for sinks such as EOR fields, the demand will be far from constant. Hence, just like for natural gas, the CO_2 pipeline infrastructure should evolve into networks which will improve the flexibility and provide a more predictable transportation demand. Such networks could also include shipping hubs to connect marginal smaller industrial sources to the pipeline grid.[144] Similar to a natural gas network, a CO_2 network has to adhere to some CO_2 product standards. Here requirements from the storage operator might be given, whereas quality specifications for transport in some aspects will be a trade-off between transport cost and capabilities and conditioning costs at the capture site.

4.3 Current Status

4.3.1 CO_2 pipelines

4.3.1.1 Existing and planned infrastructure

A number of CO_2 pipeline projects are documented in the literature.[145,146,147] The largest CO_2 pipeline infrastructure in the world today exists in North America, chiefly in the US south-west/high plains region. This network has been constructed since the 1970s, partly financed by government incentives for enhanced oil recovery. The network was 6600 km long in 2010[145], including only high-pressure pipelines of length 16 km and longer with diameters varying between 4 and 30". The network is continuously under expansion.[148] Offshore there are significantly less pipelines deployed. Currently the only two operating projects are Sleipner[149,150] and Snøhvit[150,151]

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[144] Jordal, K., Morbee, J., and Tzimas, E. (2012). *ECCO strategies for CO_2 value chain deployment*. http://www.sintef.no/globalassets/project/ecco/results---deliverables/d2.3.7-ecco-strategies-for-co2-value-chain-deployment-sintef-er.pdf: ECCO Consortium.

[145] Bliss, K., et al. (2010). A Policy, Legal, and Regulatory Evaluation of the Feasibility of a National Pipeline Infrastructure for the Transport and Storage of Carbon Dioxide. Retrieved from http://www.sseb.org/downloads/pipeline.pdf

[146] Noothout, P., et al. (2014). *CO_2 pipeline infrastructure*. http://ieaghg.org/docs/General_Docs/Reports/2013-18.pdf: Global CCS Institute, IEA Greenhouse Gas R&D Programme (IEAGHG).

CO_2 Pipelines (online database). from IEA Greenhouse Gas R&D Programme (IEAGHG): http://www.ieaghg.org/ccs-resources/co2-pipelines

[147] CO_2 Transportation - Is it Safe and Reliable? (2010). In Carbon Sequestration Leadership Forum, (CSLF) (Ed.), *inFocus - Carbon Capture and Storage*.

[148] Energy Pipelines CRC. (2014). Transport *The Global Status of CCS: 2014* (Ch. 8). Melbourne, Australia: Global CCS Institute. Retrieved from http://decarboni.se/publications/global-status-ccs-2014/8-transport

[149] Hansen, H., Eiken, O., and Aasum, T. O. (2005). *The path of a carbon dioxide molecule from a gas-condensate reservoir, through the amine plant and back down into the subsurface for storage. Case study: The Sleipner area, South Viking Graben, Norwegian North Sea*. Paper presented at the Offshore Europe 2005. Retrieved from http://dx.doi.org/10.2118/96742-MS

[150] Eiken, O., et al. (2011). Lessons learned from 14 years of CCS operations: Sleipner, In Salah and Snøhvit. *Energy Procedia, 4*, 5541-5548.

[151] Hansen, O., et al. (2013). Snøhvit: The History of Injecting and Storing 1 Mt CO_2 in the Fluvial Tubåen Fm. Ibid., *37*, 3565-3573.

in Norway. Sleipner, in the North Sea, has been operating since 1996, but is a special case since the pipeline from the amine plant to the injection point is less than 1 km and made of stainless steel.

Figure 4-1: Left: Melkøya LNG plant, starting point of the world's only major existing offshore CO_2 pipeline[150,151]. Photo: Harald Pettersen / Statoil. Right: Installation of natural gas pipeline at the Sleipner field. Photo: Kim Laland/Statoil.

The Snøhvit project, located in the Barents Sea at 70° northern latitude, operates a 153 km long 8" pipeline from a coastal gas processing plant to the submarine injection point. Further European projects for offshore CCS pipeline transport are however in extended planning phase,[148,152] most notably:

- ROAD project,[153] Netherlands: Permitted / awaiting funding, 25 km 16" new offshore pipeline
- Peterhead project,[154] UK: FEED-phase, reuse of existing 100 km offshore natural gas pipeline
- Yorkshire and Humber project,[155] UK: FEED-phase, up to 24" new pipeline, 90 km offshore

4.3.1.2 Operation

The natural gas pipeline grid has been developed for decades. In Europe these pipelines have shown a remarkably low failure rate of 0.08 per 1000 km·years for pipelines of diameter 5 to 11"

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[152] Hetland, J., et al. (2014). CO2 Transport Systems Development: Status of Three Large European CCS Demonstration Projects with EEPR Funding. Ibid., *63*(0), 2458-2466.

[153] http://road2020.nl/en/

[154] http://www.shell.co.uk/energy-and-innovation/the-energy-future/peterhead-ccs-project.html

[155] http://www.ccshumber.co.uk/the-pipeline.aspx

in the period 2004-2013, and even lower for larger diameter pipelines.[156] The primary cause of 35 percent of the incidents was external interference whereas corrosion caused 24 percent of the failures. Similar safety records are found in other developed regions, and have been used as a starting point also to analyze reliability of CO_2 onshore pipelines.[157,158]

For the US onshore pipelines, the Department of Transportation maintains a database of pipeline incidents.[159] Many groups have studied these data, and the results from some of these studies are summarized by Duncan and Wang.[158] The indication from these studies is that the failure rates are somewhat higher than for natural gas pipelines, up to a factor 2 or so. It has also been reported that different from natural gas pipelines, the largest cause of failures are corrosion.[160] It should be noted though, that in the United States the length of CO_2 pipelines is of the order of 1 percent of the natural gas pipelines, and with the small failure rates seen, the number of incidents is not statistically significant. So far no injury or fatality has been reported from CO_2 transportation, and most reported failures are minor leaks.

Due to the limited length and operational experience with offshore CO_2 pipelines, it should come as no surprise that no major incident has been reported publicly. Compared with onshore pipelines, it should be clear that offshore pipeline constitute an even smaller risk for public health. During operations of Snøhvit and Sleipner, experience with for instance shut-ins has been gained,[151] which could have impact also for the CO_2 transportation[161] due to transient effects.

4.3.1.3 CO2 transport specifications

It should be noted that the different CO_2 pipeline operators differs when it comes to CO_2 product specifications and pressure. For instance, the water content specifications vary between < 50 ppm to < 630 ppm [146]. From the information provided by Eiken et al.[149], the water content seems to be more than 1000 ppm at Sleipner, which could lead to hydrate formation or even water-rich liquid phase at prolonged shut-ins. From a corrosion perspective this example has less general relevance due to the use of stainless steel. Most of the US EOR pipelines are transporting gas from geological CO_2 sources.

Future CCS transport streams will have different impurities and composition depending on the capture and conditioning process. During the last decade, various CO_2 quality specifications for

[156] *9th Report of the European Gas Pipeline Incident Data Group (period 1970 – 2013)*. (2015). Groningen, Netherlands, http://www.EGIG.eu: European Gas Pipeline Incident Data Group (EGIG).

[157] *Technical Guidance on Hazard Analysis for Onshore Carbon Capture Installations and Onshore Pipelines - A guidance document*. (2010). London, UK, http://www.energyinst.org: Energy Institute.

[158] Duncan, I. J. and Wang, H. (2014). Estimating the likelihood of pipeline failure in CO2 transmission pipelines: New insights on risks of carbon capture and storage. *International Journal of Greenhouse Gas Control, 21*, 49-60.

[159] http://www.phmsa.dot.gov/pipeline/library/data-stats

[160] *Mapping of potential HSE issues related to large-scale capture, transport and storage of CO_2*. (2008). Stavanger, Norway, http://www.ptil.no/getfile.php/PDF/Ptil%20CCS%202008.pdf: Det norske veritas (DNV).

[161] de Koeijer, G., Hammer, M., Drescher, M., and Held, R. (2014). Need for experiments on shut-ins and depressurizations in CO_2 injection wells. *Energy Procedia, 63*, 3022-3029.

pipeline transport have been proposed.[162] These standards vary a great deal in terms of for instance content of water (50 to 500 ppm) and other impurities and CO_2 overall purity (95 to 99.5 percent).

4.3.2 CO_2 Ship Transport

Although there is no existing example of CO_2 transport by ship in relation to a CCS project, there have been at least six small CO_2 tankers for businesses such as carbonated beverage, food chilling/ freezing and greenhouses in northern Europe. There is one ship designed as a CO_2 carrier. The ship, operated by a Dutch shipping company Anthony Veder since 1999, carries up to 1,250 m^3 of CO_2 at 18 barg and -40 °C.[163] The rest of the ships were all converted from LPG tankers. These ships, including two retired, are/ were owned by a Norwegian company Yara International and operated by Larvik Shipping, and capable of carrying CO_2 of up to 900 to 1,800 tonnes at 15–20 bara and around -30 °C.[164,165,166]

There have been multiple proposals, studies and designs for shipping solutions executed mainly in Europe in and East Asia. These include a shipping solution developed by TEBODIN, Anthony Veder and VOPAK[167] for the development of a liquid logistics shipping concept between Rotterdam and various storage locations in the Netherlands and Denmark. Other examples include studies published by SINTEF,[168] IFPEN, Chiyoda Corp.,[169] and DSME,[170] Knudsen et al. and

[162] de Visser, E., et al. (2008). Dynamis CO2 quality recommendations. *International Journal of Greenhouse Gas Control, 2*(4), 478-484.

Buit, L., et al. (2011). *Standards for CO_2*. Netherlands, http://www.co2europipe.eu/: Towards a transport infrastructure for large-scale CCS in Europe (CO2Europipe).

Matuszewski, M. and Woods, M. (2012). *CO_2 Impurity Design Parameters*. United States, http://www.netl.doe.gov//research/energy-analysis/publications/: National Energy Technology Laboratory (NETL).

Høydalsvik, H. (2013). *Gassnova CO_2 Capture, Transport and Storage - Mongstad CO_2 product specification*. Norway: Gassnova.

[163] http://www.anthonyveder.com/fleet/coral-carbonic/

[164] http://www.yara.com/media/news_archive/Yara_co2_ships.aspx

[165] http://www.larvik-shipping.no/

[166] Peter Brownsort (2015). Ship transport of CO_2 for Enhanced Oil Recovery – Literature Survey, SCCS

[167] Vermeulen, T. (2011). *Knowledge sharing report – CO_2 liquid logistics shipping concept (LLSC): overall supply chain optimization.* The Hague, The Netherlands, http://www.globalccsinstitute.com/publications/co2-liquid-logistics-shipping-concept-llsc-overall-supply-chain-optimization: Global CCS Institute.

[168] Aspelund et al., 2006. Ship Transport of CO_2: Technical Solutions and Analysis of Costs, Energy Utilization, Exergy Efficiency and CO_2 Emissions, *Chem. Eng. Research and Design*, 84, 847-855.

[169] Omata, A. (2011). *Preliminary feasibility study on CO_2 carrier for ship-based CCS*. http://www.globalccsinstitute.com/publications/preliminary-feasibility-study-co2-carrier-ship-based-ccs: Global CCS Institute.

Omata, A. (2012). *Preliminary feasibility study on CO_2 carrier for ship-based CCS. Phase 2: unmanned offshore facility*. http://www.globalccsinstitute.com/publications/preliminary-feasibility-study-co2-carrier-ship-based-ccs-phase-2-unmanned-offshore: Global CCS Institute.

[170] Yoo, B.-Y., Lee, S.-G., Rhee, K.-P., Na, H.-S. and Park, J.-M. (2011). New CCS system integration with CO_2 carrier and liquefaction process. 10th International Conference on Greenhouse Gas Control Technologies, 2011, Amsterdam. Energy Procedia, 4: 2308-2314. Elsevier Science

others. Furthermore, there is ongoing or recently-completed research on CO_2 shipping within several national research programs like CATO (Netherlands), CLIMIT (Norway) , MOE (Japan) and European research programs such as CO2Europipe[171] and Cocate[172] (completed). These examples provide a solid scientific basis to further development of CO_2 transport by ship.

Furthermore, operational experience exists on individual elements of the liquid logistics chain. For example, commercial activities like Yara's Sluiskil (The Netherlands) fertilizer industry demonstrate CO_2 onloading and offloading systems.

4.3.3 Costs

Some cost figures for CCS pipeline projects are collected in the IEAGHG CO_2 pipeline database[146]. Generally, cost estimates for the CO_2 transport vary greatly, from a few dollars to several tens of dollars per CO_2 tonne transported, greatly dependent on factors such as terrain, transport length, capacity, and utilization rates.[139,173,174,175] The transportation can hence be a significant part of both the cost and energy use of a CCS system, especially when offshore transport is needed. Hence, it is important to optimize the efficiency and investment and operational costs of the transport system while ensuring safety in order to lower the threshold of large-scale CCS deployment.

All the studies cited above were mainly using corresponding costs for hydrocarbon transport as a starting point. The NETL study[173] is generally concerned with onshore transport in the United States, but provided a handy formula to calculate the costs in terms of whereas other studies also consider offshore pipelines and shipping in more detail. A thorough study should also calculate the cost per avoided amount of CO_2, rather than transported. Generally speaking, pipeline has a rather high capex cost which scale approximately proportionally with distance, and small operational cost. Shipping, on the other hand, has much lower investment costs, but higher operational cost with a minimum per trip due to loading/liquefaction and unloading/heating/compression. Hence, shipping is favored by long distances and smaller volumes, whereas pipelines are favored by short distances and large volumes. For short distances the choice will always be pipelines, whereas for large volumes the jury seems to be out in terms

[171] www.co2europipe.eu.

[172] http://projet.ifpen.fr/Projet/jcms/c_7861/fr/cocate.

[173] Grant, T., Morgan, D., and Gerdes, K. (2013). *Carbon Dioxide Transport and Storage Costs in NETL Studies*. USA, http://www.netl.doe.gov/research/energy-analysis/quality-guidelines-qgess: United States Department of Energy, National Energy Technology Laboratory (NETL).

[174] *The Cost of CO_2 Transport*. (2011). http://www.zeroemissionsplatform.eu: European Technology Platform for Zero Emission Fossil Fuel Power Plants (ZEP).

Roussanaly, S., Bureau-Cauchois, G., and Husebye, J. (2013). Costs benchmark of CO_2 transport technologies for a group of various size industries. *International Journal of Greenhouse Gas Control, 12*, 341-350.

[175] Roussanaly, S., Brunsvold, A. L., and Hognes, E. S. (2014). Benchmarking of CO_2 transport technologies: Part II – Offshore pipeline and shipping to an offshore site. Ibid.*, 28*, 283-299.

Geske, J., Berghout, N., and van den Broek, M. (2015). Cost-effective balance between CO_2 vessel and pipeline transport. Part I – Impact of optimally sized vessels and fleets. Ibid.*, 36*, 175-188.

of break-even distance between shipping and pipelines[175]. It can be noted that since pipelines require a large up-front investment, the alternative constitute a large financial risk than shipping, and that the cost calculations both are affected by the ship capacity and pipeline lifetime and ramp-up time.

4.4 Technical Challenges or Technology Gaps

4.4.1 Pipeline transport - challenges/gaps

It should be noted, that most of the technical challenges discussed below are just as relevant for onshore pipeline. In many aspects, offshore pipelines could be at an advantage, due to their more stable temperature, perhaps higher heat transfer to the surroundings, and higher external hydrostatic pressure. Aspects related to dynamic phenomena and impurities are however also highly in other parts of the CO_2 value chain, such as injection[161]. Most of the challenges can be avoided by conservative design and sufficient safety margins for instance in terms of pipeline design, level of impurities and compression level. For a more optimized and cost efficient transportation system, additional targeted research is however recommended.

4.4.1.1 CO_2 properties and impact of impurities

The thermodynamic properties of pure CO_2 are well described by the Span-Wagner equation of state[176] and illustrated in the phase diagram of Figure 4-2 and can be compared with natural gas in Figure 4-3. Different from natural gas, the critical point of CO_2 is above the typical environmental range relevant for offshore pipelines between approximately 0 and 25 °C, meaning there is a phase boundary between liquid and gas. For better efficiency and smaller volumes, the preference will usually be to transport gas in the liquid state, although gas phase transport has also been proposed for storage sites with low pressure. Hence, unlike natural gas pipeline systems, pumps are often used to boost the pressure of the CO_2 fluids[137,141]. Two-phase flow is usually undesirable, as it could lead to slug flow and destroy compressors or pumps that are not designed for it. In order to avoid two-phase flow, the operation point should be away from the phase boundary, meaning that there is a theoretical lower limit for the operational pressure in the pipeline, unlike commercial natural gas pipelines which operate at a large range of pressures.

In some cases, for instance when the CO_2 storage field has low pressure, it is not possible to be above the dew point pressure all the way to the injection point. In the ROAD project where the plan is to use a depleted gas field as a storage site, it is proposed to avoid this problem by heating the CO_2 far above the critical temperature at the pipeline inlet such that the pressure is below phase boundary as the temperature passes the critical point as the gas is being cooled.[177] This will lower

[176] Span, R. and Wagner, W. (1996). A new equation of state for carbon dioxide covering the fluid region from the triple-point temperature to 1100 K at pressures up to 800 MPa. *Journal of Physical and Chemical Reference Data*, *25*(6), 1509-1596.

[177] Uilenreef, J. and Kombrink, M. (2013). *Flow Assurance and Control Philosophy ROAD - Special Report for the Global Carbon Capture and Storage Institut*. http://decarboni.se/sites/default/files/publications/114746/road-

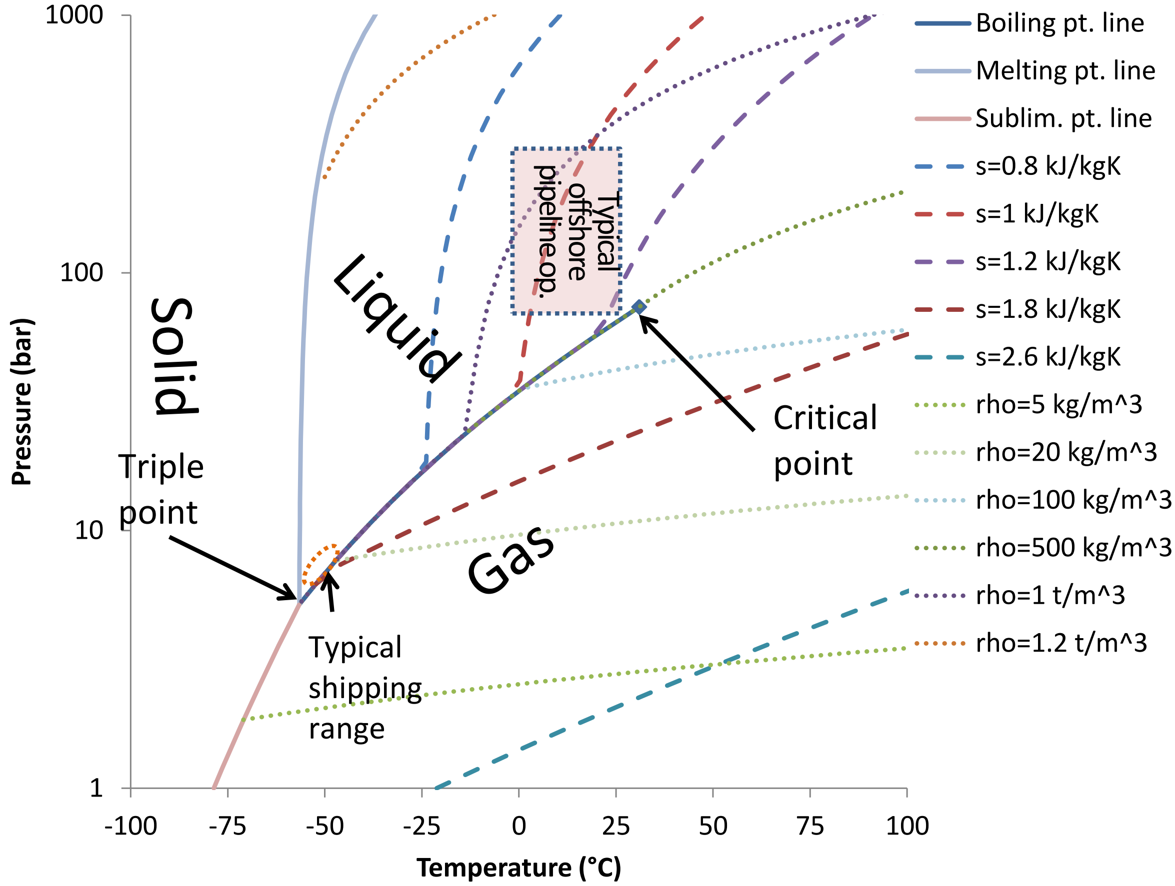

Figure 4-2: Phase diagram of pure CO_2, including curves for constant density (ρ) and entropy (s), calculated from the Span-Wagner equation of state.

CO_2 density inside and hence capacity of the pipeline, but the injection will take place in the liquid phase as the reservoir pressure has increased.

project-flow-assurance-and-control-philosophy.pdf: ROAD | Maasvlakte CCS Project C.V. / Global Carbon Capture and Storage Institute.

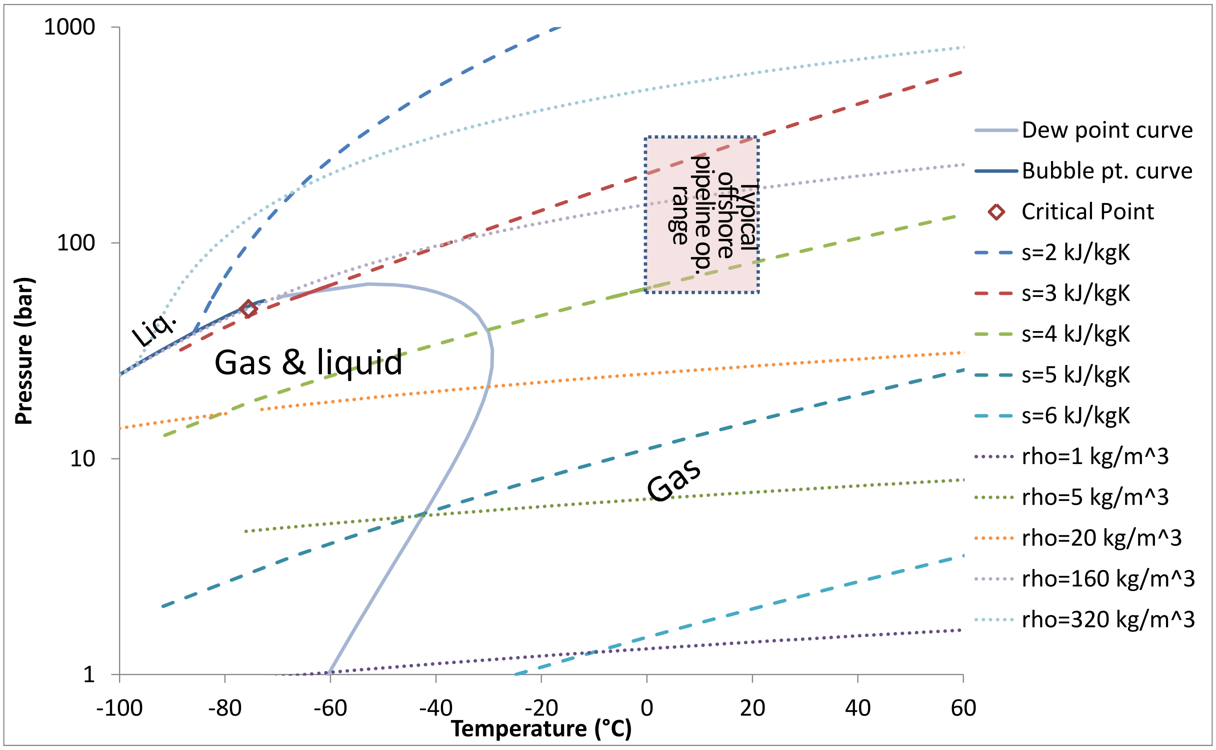

Figure 4-3: Typical phase diagram of natural gas within pipeline spec., including curves for constant (ρ) and entropy (s).

With impurities present, the phase boundary will split and form a two-phase envelope and complicate the diagram. Typically the upper pressure for which two phases form, the cricondenbar, may increase with the presence of non-condensable impurities such as nitrogen.[178] Other challenges exist with other impurities. For instance, water may form hydrates with CO_2 at lower water concentrations than needed for a water rich-phase,[179] a behavior which can be enhance by other impurities such as methane.[180] Impurities are also seen to have large impact on important properties such as density.[178]

There is currently a lack of accurate experimental data for CO_2 mixed with impurities regarding important properties such as phase behavior, density (needed for dimensioning and metering), viscosity (needed for pressure loss calculations), and thermal conductivity (needed e.g., to

[178] Løvseth, S. W., et al. (2013). CO_2Mix Project: Experimental Determination of Thermo Physical Properties of CO_2-Rich Mixtures. *Energy Procedia*, *37*, 2888-2896.

[179] de Koeijer, G., et al. (2011). CO_2 transport–Depressurization, heat transfer and impurities. Ibid., *4*, 3008-3015.

[180] Song, K. Y. and Kobayashi, R. (1990). The water content of a carbon dioxide-rich gas mixture containing 5.31 Mol% methane along the three-phase and supercritical conditions. *Journal of Chemical and Engineering Data*, *35*(3), 320-322.

calculate dynamic phenomena).[181] Hence, awaiting these experimental data and corresponding reference models,[182] current standards on impurities tend to be very conservative.

4.4.1.2 Corrosion

A problem of less importance in natural gas pipelines is the well-known fact that CO_2 dissolved in water forms carbonic acid which could cause serious corrosion. Hence, since stainless steel is ruled out due to costs for a large scale transportation system, a water-rich liquid phase should be avoided in CO_2 pipelines at all times. Unfortunately, the water solubility is much lower in the gas phase than in the liquid phase.[183] To complicate matters more, the presence of other impurities, like methane, SO_2, and NO_x is known to lower the solubility further,[184] and chemical reactions between impurities may have a negative effect.[185]

4.4.1.3 Dynamic phenomena

During an operation of a CCS pipeline, transient changes in pressure and flow must be expected, usually planned during startup, well shut-ins etc., but an operator should also be prepared for unintentional rapid depressurizations. Just like natural gas, rapid pressure changes are associated with changes in temperature. During depressurization of a CO_2-pipeline, the state point of the fluid fairly quickly falls down to the boiling point line,[179] in the ideal case following one of the isentropic lines shown in Figure 4-2, at which point the liquid will start to boil and temperature continues to fall towards the triple point. At the same time, the shock wave velocity will slow down, dependent

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[181] Li, H., Jakobsen, J. P., Wilhelmsen, Ø., and Yan, J. (2011). PVTxy properties of CO_2 mixtures relevant for CO_2 capture, transport and storage: Review of available experimental data and theoretical models. *Applied Energy, 88*(11), 3567-3579.

Li, H., et al. (2011). Viscosities, thermal conductivities and diffusion coefficients of CO_2 mixtures: Review of experimental data and theoretical models. *International Journal of Greenhouse Gas Control, 5*(5), 1119-1139.

Gernert, G. J. (2013). *A NEW HELMHOLTZ ENERGY MODEL FOR HUMID GASES AND CCS MIXTURES.* Fakultät für Maschinenbau, Ruhr-Universität Bochum, Bochum, Germany.

[182] Gernert, J., Jäger, A., and Span, R. (2014). Calculation of phase equilibria for multi-component mixtures using highly accurate Helmholtz energy equations of state. *Fluid Phase Equilibria, 375*, 209-218.

[183] Spycher, N., Pruess, K., and Ennis-King, J. (2003). CO_2-H_2O mixtures in the geological sequestration of CO_2. I. Assessment and calculation of mutual solubilities from 12 to 100°C and up to 600 bar. *Geochimica et Cosmochimica Acta, 67*(16), 3015-3031.

[184] Austegard, A., Solbraa, E., Koeijer, G. D., and Mølnvik, M. J. (2006). THERMODYNAMIC MODELS FOR CALCULATING MUTUAL SOLUBILITIES IN H_2O–CO_2–CH_4 MIXTURES. *Chemical Engineering Research and Design, 84*(A9), 781–794.

Ahmad, M. and Gersen, S. (2014). Water Solubility in CO_2 Mixtures: Experimental and Modelling Investigation. *Energy Procedia, 63*, 2402-2411.

Xiang, Y., et al. (2012). The upper limit of moisture content for supercritical CO_2 pipeline transport. *The Journal of Supercritical Fluids, 67*, 14-21.

[185] Halseid, M., Dugstad, A., and Morland, B. (2014). Corrosion and Bulk Phase Reactions in CO_2 Transport Pipelines with Impurities: Review Of Recent Published Studies. *Energy Procedia, 63*, 2557-2569.

on the degree of phase equilibrium[186] and impurity level.[187] Hence, such sudden drop in pressure is associated with formation of liquid phase, and in the worst case in the presence of water, hydrate plugs. These are complex phenomena involving coupling between fluid dynamics and thermodynamics.[187]

One example where understanding of transient phenomena in CO_2 pipelines are needed, is the study of running fractures. Such fractures can propagate due to the inner pressure of the pipeline, and is hence dependent on the relation between the propagation velocity of the fracture and the pressure wave front. Due to the drop in the shock wave velocity associated with the phase boundary, running fractures may be a more likely scenario in CO_2 pipelines than in natural gas pipelines. Occurrence of running fractures could constitute a major setback for CCS, and be can be prevented by ensuring sufficient pipeline wall thickness or material quality or introduce crack arrestors. Large decreases in temperatures due the Joule-Thomsen effect and boiling has to be taken into consideration when evaluating the material parameters, and steels with low ductile-brittle transition temperature.[188] The current industry standard is to use the empirical uncoupled models such as Battelle method and HLP approach.[189] Unfortunately, these methods are not necessarily conservative, and a more rigorous approach should probably be applied.[190]

4.4.2 Ship transport

Several studies into the technical feasibility of ship transport have been performed in recent years. Only a few technical issues remain, which are partly related to the storage location itself. The remaining technical challenges are related to offshore unloading (interface between ship and well head), injection conditions, CO_2 processing on the platform in case of an EOR project and onshore unloading at a pipeline terminal. In order to remove these barriers a real demonstration project is needed.

4.4.2.1 Offshore unloading

The offshore offloading system can be viewed as the interface between the ship and the field. This implies that a conversion needs to be made from the CO_2 conditions within the ship (typically, liquid CO_2 at a pressure of around 8 bar and temperature of around -50 °C) and the conditions acceptable to the reservoir (pressure, temperature, flow rate). In order to match these requirements,

[186] Flåtten, T. and Lund, H. (2011). Relaxation two-phase flow models and the subcharacteristic condition. *Mathematical Models and Methods in Applied Sciences, 21*(12), 2379-2407.

[187] Munkejord, S. T., Jakobsen, J. P., Austegard, A., and Mølnvik, M. J. (2010). Thermo- and fluid-dynamical modelling of two-phase multi-component carbon dioxide mixtures. *International Journal of Greenhouse Gas Control, 4*(4), 589-596.

[188] Nordhagen, H. O., et al. (2012). A new coupled fluid–structure modeling methodology for running ductile fracture. *Computers and Structures, 94–95*, 13-21.

[189] Maxey, W. (1974). *Fracture initiation, propagation, and arrest*. Paper presented at the Fifth Symposium on Line Pipe Research.

Sugie, E., et al. (1982). A study of shear crack propagation in gas-pressurized pipelines. *Journal of Pressure Vessel Technology, 104*(4), 338-343.

[190] Aursand, E., et al. (2014). CO_2 Pipeline Integrity: Comparison of a Coupled Fluid-structure Model and Uncoupled Two-curve Methods. *Energy Procedia, 51*, 382-391.

the flow properties in hoses, pipelines and well(s) will have to be analyzed. This will in turn allow determining pressurization and heating capabilities needed on board the vessel. The design of the offshore offloading facility is likely to be dependent on the reservoir properties (depth, pressure), as well as the maximum period level of intermittency allowed for the injection. In addition to pressurization and heating requirements on the ship, an important aspect of this optimization work will also be to maximize the offloading rate in order to minimize the offloading time of the vessel.

Depending on these parameters, temporary storage near the platform may be required. A solution for offshore offloading may need to be developed for each different storage location. Several engineering studies have been executed to further detail offshore offloading systems, which may include additional systems (compressors, heaters) on the ship itself, or a temporary storage barge.[191] The challenge is to design a system that provides enough flexibility to be connected to different storage locations with different requirements.

4.4.2.2 Injection conditions and temperatures

The injection of cold CO_2 from the ship into a reservoir could cause ice formation in the riser including a possible phase transition in the CO_2. Various combinations of pressure, temperature and flow rate should be analyzed to see how typical reservoirs respond during injection and also during the periods between the injections. It is expected that the temperature of the CO_2 at the well head should be above zero, to avoid freezing of the near-well area at depth (followed by thawing during interruptions in the injection). Further research needs to be done in order to improve the understanding of the allowed ranges of well-head temperatures.

4.4.2.3 CO_2 separation offshore

Studies of transport of CO_2 by ship often consider a connection to EOR projects. Onshore EOR, as in the United States, is typically done as WAG flooding. That means that the injection of gas alternates with that of water. If applied offshore such practice may benefit from CO_2 transportation by ship. This is because WAG flooding will not need a continuous flow of CO_2, but rather a batch flow, at least as seen from the individual well.

Once the injected CO_2 breaks through to the producing well, any gas injected afterwards will follow that path, reducing the overall efficiency of the injected fluids to sweep the oil from the reservoir rock. This means that the full (maximum) supply of CO_2 to an EOR field will only be needed for a limited period of time, before the volumes of supplementary CO_2 will be reduced. It is expected that, typically, the demand for CO_2 in an EOR project is at a maximum at the start, steadily decreasing until the end of the project.

[191] E.g., see Vermeulen, T. (2011). *Knowledge sharing report – CO_2 liquid logistics shipping concept (LLSC): overall supply chain optimization.* The Hague, The Netherlands, http://www.globalccsinstitute.com/publications/co2-liquid-logistics-shipping-concept-llsc-overall-supply-chain-optimization: Global CCS Institute.

4.4.2.4 Onshore unloading at a pipeline terminal

The design, safety, and practicality of CO_2 import by ship into onshore (near-shore) pipeline terminals need to be further developed, especially on the design and costs of equipment and installations (re-gasifiers, re-heaters, pumps, temporary storage).

4.5 R&D Opportunities

With the technical challenges and knowledge gaps discussed above, there are certainly areas that call for more research, and several groups around the world have started the job.[192] As already indicated above and in CLSF 2013 Technology Roadmap,[193] there is a need for accurate measurements of phase behavior and other properties of CO_2 mixed with impurities at relevant conditions and develop correspondingly accurate models. There is also a need to advance the current flow models, which include non-equilibria thermodynamics. Such models needs to be tuned with accurate transient flow measurements.[161,194] In addition to these fundamental aspects to optimize the operation of CO_2 pipelines, it is probably also room for improving associated equipment and processes, for instance relating to compression, gaskets, pipe inspections, metering etc.

For ship transport, only a few technical issues remain, which are partly related to the storage location itself. The remaining technical challenges are related to offshore loading, injection conditions, CO_2 processing on the platform in case of an EOR project and onshore unloading at a pipeline terminal. In order to remove these barriers a real demonstration project is needed.

Most likely, the main barrier for CO_2 offshore transportation is not of technical nature, but a matter economics and organization. Hence, there will still be need to work on benchmarking and cost estimates. Future CCS chains will be complex, with a variety of sources and storage sites which will have different types of requirements. In such a chain, it is important to realize that cost saved in one process, e.g., conditioning, could lead to additional costs at another place, e.g., transport.

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[192] Some research programs and larger projects on CCS transport around the world include
BIGCCS: http://www.bigccs.no
CO_2PipeTrans2: https://www.dnvgl.com/oilgas/innovation-development/joint-industry-projects/co2pipetrans.html
UKCCRS: https://ukccsrc.ac.uk/
Energy Pipelines CRC: http://epcrc.com.au/
Pipeline Research Council International: http://prci.org/index.php/about/
IMPACTS: http://www.sintef.no/projectweb/impacts/
CO_2Quest: http://www.co2quest.eu/

[193] *Carbon Sequestration Leadership Forum Technology Roadmap 2013*. (2013). Washington DC, USA, http://www.cslforum.org/publications/documents/CSLF_Technology_Roadmap_2013.pdf: Carbon Sequestration Leadership Forum (CSLF).

[194] Drescher, M., et al. (2014). Experiments and modelling of two-phase transient flow during pipeline depressurization of CO_2 with various N_2 compositions. *Energy Procedia, 63*, 2448-2457.
Botros, K. K., et al. (2010). Transferability of decompression wave speed measured by a small-diameter shock tube to full size pipelines and implications for determining required fracture propagation resistance. *International Journal of Pressure Vessels and Piping, 87*(12), 681-695.

Hence, optimization must be performed on a chain level. Further, methodology for large scale infrastructure design criteria and planning will have to be developed further, building on existing tools.[195] Such a work should include evaluation of global/regional/national government incentives and legal issues.

4.6 Regulatory Requirements

4.6.1 Existing national and regional codes

Most markets currently accommodate CO_2 pipeline transport by adjusting existing regulations relating to other pipeline transport, for example:

- United States: 49 Code of Federal Regulations (CFR) part 195.[196] CO_2 added to "Transportation of hazardous liquids by pipeline" in 1989, associated standard ASME B31.4.[197]
- Canada: Parts of CSA Z662.
- Europe: CCS directive 2009/31/EC established a framework for regulatory regime for pipeline transport,[198] member state to implement specific codes regarding safety standards.

A recommended practice document has been developed by DNV for CO_2 pipeline transport[138], and DNV has also written a standard for submarine pipeline systems.[199] Currently, an ISO standard is being developed for CO_2 transportation,[199] apparently supplementing the existing ISO standards for gas pipelines and building on the recommended practices by DNV.[148]

For shipping, regulations should be international, and existing frameworks such as UN Recommendations on the Transport of Dangerous Goods - Model Regulations should be a good starting point.[200] The design and construction of CO_2 tankers should comply with the IGC Code adopted by International Maritime Organization (IMO). The Code is to provide an international

[195] E.g.: Jakobsen, J. P., Tangen, G., Nordbø, Ø., and Mølnvik, M. J. (2008). Methodology for CO2 chain analysis. *International Journal of Greenhouse Gas Control, 2*(4), 439-447.

Løvseth, S. W. and Wahl, P. E. (2012). ECCO Tool: Analysis of CCS value chains. *Energy Procedia, 23*, 323-332.

Jakobsen, J. P., Roussanaly, S., Mølnvik, M. J., and Tangen, G. (2013). A standardized Approach to Multi-criteria Assessment of CCS Chains. Ibid., *37*, 2765-2774.

Eickhoff, C., et al. (2014). IMPACTS: Economic Trade-offs for CO_2 Impurity Specification. Ibid., *63*, 7379-7388.

Business models for commercial CO_2 transport and storage - Delivering large-scale CCS in Europe by 2030. (2014). Retrieved from http://www.zeroemissionsplatform.eu/library/publication/252-zepbusmodtransportstorage.html

[196] https://www.law.cornell.edu/cfr/text/49/part-195

[197] https://law.resource.org/pub/us/cfr/ibr/002/asme.b31.4.2002.pdf

[198] http://eur-lex.europa.eu/ , see also:

Haan-Kamminga, A. and Roggenkamp, M. (2010). CO_2 Transportation in the EU: Can the Regulation of CO_2 Pipelines Benefit from the Experiences in the Energy Sector? Retrieved from http://dx.doi.org/10.2139/ssrn.1701126

[199] International Organization for Standardization, (ISO). (2015). *Carbon dioxide capture, transportation and geological storage* (Approved for registration as draft international standard No. ISO/CD 27913).

[200] http://www.unece.org/?id=3598

standard for the safe transport by sea in bulk of liquefied gases and certain other substances, by prescribing the design and construction standards of ships involved in such transport and the equipment they should carry so as to minimize the risk to the ship, its crew and to the environment, having regard to the nature of the products involved.[201]

However there is one legal issue on the transboundary transportation of CO_2 that need still need to be resolved. The London protocol (global agreement on regulating dumping of wastes at sea) prohibits countries to export their CO_2 to another country for storage in the marine environment (see chapter 8.2 for a detailed explanation). Therefore the export amendment was adopted in 2009 in order to allow export of CO_2 for geological storage. Two thirds of member states need to ratify before it comes into force. This currently means 30 countries need to ratify it. To date just two have: Norway and UK. The exception is if the CO_2 is a purpose other than dumping, such as for enhanced oil recovery. The slow ratification process can have a negative impact on the development of transboundary CCS projects the coming years.

CO_2 export by pipeline or ships for CO_2 dumping at sea is currently prohibited under the London Protocol. To allow this, its Article 6 had amended in 2009 but the amendment has not come into force yet. The detail is discussed in 8.2.1.1 in this report.

To conclude, regulations exist for CO_2 transport, but these should be optimized as the technology and market mature.

4.7 Recommendations

Just like CO_2 capture and offshore storage, technology and solutions for CO_2 transport exists and have shown to be robust during decades of operation. Offshore CO_2 transportation is more limited, but can benefit from substantial operational experience from natural gas pipelines. Compared with onshore pipeline transportation, offshore CO_2 transport will probably be more expensive, but also there are also some distinct advantages:

- Less exposed to political controversy related to perceived public risk and routing
- Shipping is a mode of transport with large flexibility in a start-up phase and to tie in smaller CO_2 sources and/ or smaller CO_2 sinks
- More stable physical environment.

To realize the international ambitions to mitigate global warming, the CO_2 transportation probably has to increase by a factor of approximately 100, and transportation of CO_2 will be an important contributor to the overall costs for CCS. Hence, optimization of current practices is important, on areas such as CO_2 product specifications and sharing of infrastructure to optimize utilization. Specific areas of research to achieve these goals have been described.

[201] http://www.imo.org/OurWork/Environment/PollutionPrevention/ChemicalPollution/Pages/IGCCode.aspx

5 Risk analysis for offshore CO_2 storage

The risk management process for the geological storage of CO_2 would be implemented systematically for each storage project (Figure 5-1).[202] In the process, risk assessment can be performed using the three stage approach consisting of identification, analysis and evaluation. Risk analysis is the process to comprehend the nature of risk and determine the level of risk.

Proposals for an offshore CO_2 storage license ought to be subjected to the completion of appropriate risk analysis as part of a required environmental impact statement, including potential amelioration of risk by safety monitoring equipment.

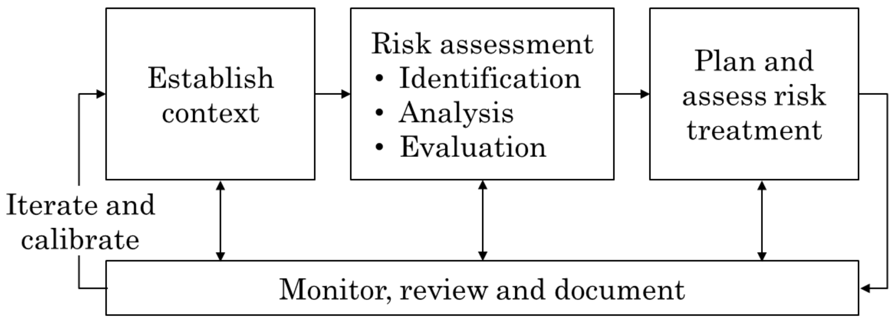

Figure 5-1. Recommended risk management process for CO_2 geological storage.[1] Risk assessment consists of risk identification (the process of finding, recognizing and describing risks), risk analysis (the process to comprehend the nature of risk and to determine the level of risk), and risk evaluation (the process of comparing the results of risk analysis with the risk criteria to determine whether the risk and/or its magnitude is acceptable and tolerable).

5.1 Potential Risks

General potential risks and their consequences associated with CO_2 storage operations are shown in Table 5-1. Among the potential consequences, issues concerning the marine environment and resources would be specific to offshore storage. Issues regarding induced seismicity are the same for both onshore and offshore storage, but monitoring tools and techniques would be different. Thus monitoring technology for passive and induced seismicity is described in Chapter 7.

Public concern regarding the environmental risks associated with CCS, in particular the possibility of CO_2 leakage from a reservoir into the marine environment, has the potential for stalling the wide-scale industrial deployment of CCS.[203] While it can be argued that the likelihood of CO_2

[202] DNV, 2012. RECOMMENDED PRACTICE, DNV-RP-J203, Geological Storage of Carbon Dioxide. Available online: https://exchange.dnv.com/publishing/Codes/download.asp?url=2012-04/rp-j203.pdf. Last accessed 23/2/2015

[203] Van Noorden, R., 2010. Carbon sequestration: buried trouble. Nature 463, 871–873.

leakage from a reservoir is extremely small,[204] secure scientific and public acceptance of offshore CO_2 storage is needed for the wider deployment of this technology.

Table 5-1 Potential risks associated with CO_2 storage operation

Risk Category	Potential risk	Potential Consequence
Injection	Deformation of rock stratum	Degradation of storage performance by unexpected CO_2 migration
		Damages resulting from induced seismicity
Leakage	Human health	Acute or chronic CO_2 impacts on employees or the general public
	Environmental	Impacts on groundwater or seawater
		Impacts on surface or near-surface ecosystem
	Property	Damages to natural resource rights (mineral, water, agriculture, forestry and fisheries)
		Diminution of properties value in the vicinity of storage sites
		Business interruption for CCS operator or for neighboring properties if remediation is required
	Financial	Entailing potential for return on investment, contractual liabilities in the carbon market
		Entailing credit risk related to obligations for long-term operations and maintenance at CCS sites

5.2 Monitoring Tools for Risk Control

Potential continuous leakage of CO_2 into the water column may occur from a pipeline, an injection well, an abandoned well and through the seabed sediments following escape via a geologic pathway such as permeable fault.

[204] IPCC, 2005: IPCC Special Report on Carbon Dioxide Capture and Storage. Prepared by Working Group III of the Intergovernmental Panel on Climate Change [Metz, B., O. Davidson, H. C. de Coninck, M. Loos, and L. A. Meyer (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 442 pp.

When gaseous CO_2 ($CO_2(g)$) dissolves in seawater reacting with water through a series of four chemical equilibria (below) that increase the concentrations of the carbon species: dissolved carbon dioxide ($CO_2(aq)$), carbonic acid (H_2CO_3) and bicarbonate (HCO_3^-):

$$CO_2(g) \leftrightarrow CO_2(aq)$$

$$CO_2(aq) + H_2O \leftrightarrow H_2CO_3$$

$$H_2CO_3 \leftrightarrow H^+ + HCO_3^-$$

$$HCO_3^- \leftrightarrow H^+ + CO_3^{2-}$$

These reactions lead to a net increase in hydrogen ions (H^+). This results in a reduction in pH, or an increase in acidity of the seawater (acidification).

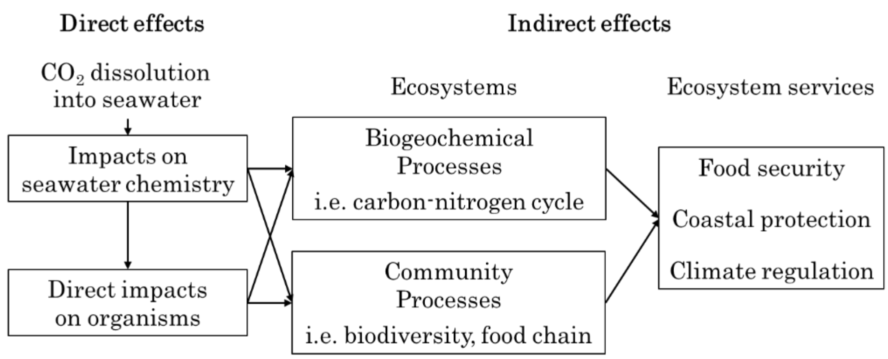

Figure 5-2. Impacts of potential CO_2 leakage on marine organisms, ecosystems and ecosystem services. Direct impacts on organisms are summarized in Table 5-2

A decline in seawater pH is associated with a fall in both carbonate ion (CO_3^{2-}) and the saturation states (Ω) of various calcium carbonates ($CaCO_3$). Hence, the seawater solubilities of three forms of calcium carbonates, namely calcite, magnesium-calcite, and aragonite, increase, making it harder for some marine biota to maintain heathy shells and other structures.

These chemical alterations of seawater resulting from CO_2 dissolution impacts on marine organisms in several ways[205,206](Table 5-2). While understanding the physiological impacts of CO_2 is important when assessing the potential survival or mortality of individuals or species, it is also important to consider whether species loss will also lead to reductions in the key ecological or biogeochemical functions needed to maintain a healthy ecosystem. Ecosystem robustness then supports ecosystem services such as climate regulation and food security (Figure 5-2).

It should be noted that rising atmospheric CO_2 over the last century and into the future not only causes ocean warming but also changes carbonate chemistry in a process termed ocean

[205] Secretariat of the Convention on Biological Diversity, 2014, An Updated Synthesis of the Impacts of Ocean Acidification on Marine Biodiversity (Eds: S. Hennige, J.M. Roberts and P. Williamson). Montreal, Technical Series No. 75, 99 pages.

[206] Widdicombe, S., Blackford, J.C., Spicer, J.I., 2013. Assessing the environmental consequences of CO_2 leakage from geological CCS: generating evidence to support environmental risk assessment. Mar. Pollut. Bull. 73, 399–401.

acidification. This acidification will affect marine ecosystems for centuries if emissions continue.[207] Considerable amounts of biological data that can be utilized in CCS leakage assessments are available from ocean acidification studies.

Table 5-2 Direct biological impacts associated with high CO_2 conditions in seawater

Direct impacts on:	Description
Growth and survival	Reduction of growth and survival is apparent especially for corals, mollusks and echinoderms. However, the responses are variable, and some species can tolerate substantial high CO_2 conditions.
Acid-base regulation and metabolism	Organisms may need extra energy to maintain their internal acid-base balance when external hydrogen ion levels substantially increase. This can lead to reduced growth and fitness.
Fertilization	Fertilization of some species is highly sensitive to high CO_2 conditions, whilst others are tolerant. Intra-specific variability indicates the scope for a multigenerational, evolutionary response.
Calcification	Early life stages of many of calcifying organisms seem to be particularly sensitive to high CO_2 conditions, with impacts including decreased larval size, reduced morphological complexity, and decreased calcification.
Sensory system and behavior	Some fish and invertebrates show loss of ability to discriminate between important chemical cues. This may lead to behavioral alteration important for their reproduction process.
Photosynthesis	Many macroalgae, seagrass, phytoplankton species can show increased photosynthesis and growth under high CO_2 conditions. Calcifying macroalgae and phytoplankton are, however, negatively impacted.

5.2.1 Analytical tools for seawater CO_2 monitoring

There are four parameters that can be reliably measured for the seawater CO_2 system, namely total dissolved inorganic carbon (DIC), total alkalinity (AT), pH and partial pressure of CO_2 that is in

[207] Pörtner, H.-O., Karl, D.M., Boyd, P.W., Cheung, W.W.L., Lluch-Cota, S.E., Nojiri, Y., Schmidt, D.N., Zavialov, P.O., 2014: Ocean systems. In: Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part A: Global and Sectoral Aspects. Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Field, C.B., V.R. Barros, D.J. Dokken, K.J. Mach, M.D. Mastrandrea, T.E. Bilir, M. Chatterjee, K.L. Ebi, Y.O. Estrada, R.C. Genova, B. Girma, E.S. Kissel, A.N. Levy, S. MacCracken, P.R. Mastrandrea, and L.L. White (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, pp. 411-484.

equilibrium with a water sample (pCO_2).[208] It is possible to obtain a complete description of the acid-base composition of a seawater sample at a particular temperature and pressure provided the following are known:

- The salinity and temperature, and hence the solubility constant of CO_2 in the seawater as well as the equilibrium constant for each of the acid dissociation reactions that is assumed to exist in the solution;
- The total concentrations for each of these non-CO_2 acid-base systems;
- The values for at least two of the CO_2-related parameters: DIC, AT, pH, pCO_2.

Measurement of a combination of DIC and AT can be recommended for the most accurate monitoring on natural seawater as samples for these can be preserved easily and the measurements made with low uncertainty. As an alternative, combination of pH and DIC is also recommended. However it should be noted that the calculated CO_2 system parameters are typically dominated by the uncertainty in the pH measurement.

For the calculation of seawater CO_2 system including saturation states (Ω) of $CaCO_3$ the most acknowledged program is CO2SYS[209] which is available at http://cdiac.ornl.gov/oceans/co2rprt.html.

Practical technology for marine and seabed monitoring is in Chapter 7.

5.2.2 Simulation tools for leakage scenarios

There is no dissimilarity in simulation tools for leakage from reservoir to surface between onshore and offshore. The final key element in understanding potential consequence of CO_2 leakage is to understand the sea area impacted by harmful high CO_2 conditions for given leakage scenarios. It is useful to model hypothetical leakage scenarios for estimating potentially impacted areas. If deleterious impacts are spatially restricted then environmental concerns diminish and vice versa.

Once leakage rates at the seafloor are given by leakage simulations in subsea geological formations, CO_2 fate in seawater can be predicted by numerical simulations. Leaked CO_2 can occur in both gas and dissolved phases when it seeps out from the seafloor. The bubble CO_2 rises in the water column forming bubble plumes and rapidly dissolves into the seawater during its ascent.

[208] European commission, 2010, EUR 24328 – Guide to best practices for ocean acidification research and data reporting. Luxembourg: Publications Office of European Union, 260pp.

[209] Pierrot, D., Lewis E., Wallace D.W.R., 2006. MS Excel Program Developed for CO_2 System Calculations. ORNL/CDIAC-105a. Carbon Dioxide Information Analysis Center, Oak Ridge National Laboratory, U.S. Department of Energy, Oak Ridge, Tennessee. http://dx.doi.org/10.3334/CDIAC/otg.CO2SYS_XLS_CDIAC105a.

Dissolved CO_2 disperses in the sea by water currents and tidal mixing. The sequence of CO_2 dispersion in the sea have been modeled in detail to predict the impacted area.[210,211,212]

5.3 R&D Opportunities and recommendations

Over the last decade or so a significant body of research into the impacts of high CO_2 on marine systems has matured, driven directly by CCS but also by concerns regarding ocean acidification. Much of this work has concentrated on physiological impacts and has utilized laboratory scale manipulations. However both natural analogues, typically where volcanic CO_2 is emitted at the seafloor,[213] and more recently a controlled release experiment, where CO_2 was deliberately injected into the seabed,[214] have been used to study the synergistic impacts driven by a combination of hydrodynamics, ecosystem interactions, behavior and physiological responses. These systems also provide highly realistic environments in which to test a variety of monitoring tools and strategies (q.v. Marine and seabed monitoring, Chapter 7.2 Offshore Monitoring Technology) and are very well suited to communicating realistic impact scenarios to concerned parties including the general public. The main outcome from these real world experiments is a glimpse of the complexity of impacts and the challenges to efficient monitoring, in particular the requirement for a comprehensive understanding of natural variability necessary to correctly identify and quantify non-natural change. Natural analogue sites are geographically diffuse, and due to their volcanic nature never associated with candidate storage sites and controlled release experiments are expensive to develop. Nevertheless the knowledge gain is so significant that more such experiments, in diverse storage sites can only be recommended. Specific challenges arising from existing work are to understand the buffering potential of sediments, and the impact of longer term exposures. In the short term it has been observed that carbonates, naturally present in some sediments undergo dissolution in the presence of excess CO_2, reducing the presence of gas at the seafloor, some of the chemical parameters and biological impacts. However sediment carbonate is finite and once exhausted a step change in detectability and impact is likely.

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[210] Mori, C., Sato, T., Kano, Y., Oyama, H., Aleynik, D., Tsumune, D., Maeda, Y., 2015. Numerical study of the fate of CO_2 purposefully injected into the sediment and seeping from seafloor in Ardmucknish Bay. Int. J. Greenhouse Gas Control, http://dx.doi.org/10.1016/j.ijggc.2014.11.023

[211] Sellami, N., Dewar, M., Stahl, H., Chen, B., 2015. Dynamics of rising CO_2 bubble plumes in the QICS field experiment Part 1 – The experiment. Int. J. Greenhouse Gas Control, http://dx.doi.org/10.1016/j.ijggc.2015.02.011

[212] Dewar, M., Sellami, N., Chen, B., 2014. Dyanamics of rising CO_2 bubble plumes in the QICS field experiment Part 2 – Modelling. Int. J. Greenhouse Gas Control, http://dx.doi.org/10.1016/j.ijggc.2014.11.003

[213] Caramanna, G., Voltattorni, N. and Maroto-Valer, M. M. (2011), Is Panarea Island (Italy) a valid and cost-effective natural laboratory for the development of detection and monitoring techniques for submarine CO_2 seepage?. Greenhouse Gas Sci Technol, 1: 200–210. doi: 10.1002/ghg.28

[214] Blackford, JC; Stahl, H; Bull, JM; Bergès, BJP; Cevatoglu, M; Lichtschlag, A; Connelly, DP; James, RH; Kita, J; Long, D; Naylor, M; Shitashima, K; Smith, D; Taylor, P; Wright, I; Akhurst, M; Chen, B; Gernon, TM; Hauton, C; Hayashi, M; Kaieda, H; Leighton, TG; Sato, T; Sayer, MDJ; Suzumura, M; Tait, K; Vardy, ME; White, PR; Widdicombe, S. 2014. Detection and impacts of leakage from sub-seafloor deep geological carbon dioxide storage. *Nature Climate Change* 4, 1011-1016. DOI: 10.1038/NCLIMATE2381

Models of hydrodynamics or bubble plume behavior, often coupled with CO_2 speciation equations have been used to address a wide range of leakage scenarios.[9,11,215] Whilst the primary driver of the spatial extent of detectability and impact is the leakage rate, many other factors such as depth, bubble size, current speed, tidal mixing and topography are shown to have a large influence on dispersal. Whilst these existing models are robust, they are limited in that they generally cannot deal with very fine scales (≈1m), necessary for the correct treatment of small leak scenarios at the same time as accurately defining regional scale mixing processes, necessary for the correct estimation of dispersion. Further these models do not simultaneously deliver detailed estimates of natural variability of carbonate chemistry, as driven by biological processes, with leakage predictions. Models that aspire to such a multi-scalar multi-process functionality are under development, limited mainly by computational demands, rather than fundamental lack of understanding. The existing modelling provides clear evidence that no two leakage scenarios are alike and a recommendation for any storage site is to commission a bespoke model analysis to inform both the range of potential leakage extents and the potential variability in the natural environment.

The majority of work to date has focused on the detectability and impacts of high CO_2 reaching the seafloor including the mobilization of other chemical species under low pH conditions. A scenario that has not been adequately investigated is the potential for hyper-saline anoxic formation water expulsion as a precursor at storage complexes situated in saline aquifers. Natural analogues or even controlled release experiments addressing this phenomenon would be a potentially valuable addition to the research base, presuming that expulsion of formation water is geologically realistic.[216]

[215] Phelps, J.J.C, Blackford, J.C., Holt, J.T., Polton, J.A. Modelling Large-Scale CO_2 Leakages in the North Sea. Int J Greenhouse Gas Control, (in press). doi:10.1016/j.ijggc.2014.10.013

[216] Hannis S., Bricker S., Goater A., Holloway S., Rushton J., Williams G., Williams J. Cross-international Boundary Effects of CO_2 Injection**.** *Energy Procedia, Volume 37, 2013, Pages 4927-4936*

6 Wellbore management

6.1 Well construction technologies

The construction of an offshore well can be divided into a five main phases:

1) Planning
2) Drilling
3) Completion and commissioning
4) Operation
5) Plug and abandon

6.1.1 Pre-drilling activities

The main planning activities consist of:

- Identifying reservoir targets and possible infrastructure locations
- Site investigation
- Detailed well and facilities planning (drilling, completion and commissioning)
- Well risk assessment and mitigation planning

An important part of the site investigation is the identification of potential hazards. The geohazard assessment is recommended for every well drilled. The shallow hazards evaluation should contain the following.

- Shallow Gas Classification
- Shallow water flow
- Soil stability issues such as landslides
- Depth to all interpreted formations
- structural closures
- Faults
- Shallow sediments
- Anchoring conditions
- Boulders
- Neighboring well geohazards

Furthermore, for the geotechnical investigation a shallow gas interpretation needs to be available prior to execution of geotechnical investigations.

Important planning aspects when constructing an injection well:

- The pressure operational window needs to be set early in the planning stage to ensure sufficient design parameters, i.e., minimum and maximum pressures and temperatures, formation strength, formation fluid types and salinities, etc.
- Drilling fluids: One of the main purposes of the drilling mud is to remove drill cuttings from the hole by keeping the particles in suspension. Another main function is to control the formation pressure, at the same time as it must not cause damage to the formation by reducing its injectivity.
- Ensure hydraulic isolation between formation and all casing strings
- Instrumentation should be installed to detect any potential future leaks.
  - Bottom-hole pressure and temperature
  - Wellhead pressure and temperature
  - Fluid injection rate
  - Annulus pressures

Sensors can be used to monitor pressures and temperatures outside the casing

A shallow gas pilot may need to be drilled if shallow gas is a potential concern. The shallow gas pilot well is typically drilled to 800-1000 m.

6.1.2 Drilling phase

For carbon storage there are three types of wells: characterization (or exploration), injection, and monitoring wells. Characterization wells are used to evaluate the site suitability for safe carbon storage, mainly focused on reservoir and caprock properties. Utilizing existing data from oil exploration wells can greatly decrease the need for characterization wells. Injection wells are drilled to be used in disposal operations. The wells are optimally located for injection technical reasons. While production wells in an oil reservoir are drilled in the oil zone, injection wells are usually drilled to a gas or water zone, and only exceptionally in the oil zone. Monitoring wells are used strictly to monitor the CO_2 plume and the effect it is having on the subsurface.

In order to be usable from a central platform, injection wells are generally deviated wells. Wells added to existing infrastructure are drilled from fixed installations. However, subsea-completed wells and pre-drilled wells are drilled from floating facilities or jack-up platforms.

Offshore wells are often drilled with small pressure margins and advanced techniques. These margins mean that drilling operators are challenged to keep pressures across the entire well high enough to avoid formation collapse while not exceeding the formation fracturing pressures.

Drilling and well operations are high risk activities with regards to safety, environmental and economic exposure. The activities involve cooperation between many participating parties, work with over-pressured formations that may contain hydrocarbons, and use highly specialised equipment. The ultimate risk is uncontrolled hydrocarbon flow with the possible loss of life, damage to property and environment and subsequent harm to the company's reputation.

A typical injection well is first spudded (drilled) using a 36"-hole opener. If the seabed is soft or uneven, a temporary guide base is installed on the seabed. The 36" holes are typically drilled to around 60-80 metres under the seabed. Seawater is used to circulate out sand and silt, which flow onto the seabed. The hole is filled with a viscous liquid which prevents it from collapsing before the drillstring is retracted. Afterwards, a 30" conductor casing is run through a permanent guide base and run in the hole. The casing functions to prevent the hole from collapsing and prevents contamination of the ground water in the upper formations. The conductor casing is then cemented to the formation all the way up to the seafloor.

Subsequently, the drilling of a 26" hole often commences without risers. Return of the drill cuttings is to the seabed. When drilling on a subsea template using several slots, the drill cuttings are moved 50-100 metres away. In some cases of pre-drilling of wells, the 26" holes are drilled with risers to circulate drill cuttings back to the rig. A pilot hole can be drilled if shallow gas is considered an issue. A blow-out preventer is often not used, only a diverter valve at the top, and the drilling fluid is seawater with a little added weighting material to obtain a density of approximately 1.1g/cc. A likely depth for 26" holes is in the region of 400- 500 metres below the seabed, but this depends on geological conditions and well target depth. Then a 20" surface casing is run. Normally, the 20" surface casing is cemented up to the surface (seabed). After the wellhead is in place, a blowout preventer is used for all subsequent drilling operations. The blowout preventer is connected to the top of the wellhead.

After the 20" casing is in place, a 17½" hole is usually drilled using a blowout preventer and risers. The blowout preventer comprises a system of valves on top of the wellhead. Its function is to secure the well in the event that downhole fluids start flowing into the well due to a high-pressure zone, or if the drilling mud is too light. After the 17 ½" holes is drilled 13 3/8" casing is run and cemented. The casings is cemented above all permeable zones, or in many cases, up to the 20'' casing.

Afterwards, drilling is carried out using a 12¼" bit. This section is often drilled to just above the reservoir. In some cases, this section is drilled through the reservoir. The 12¼" hole is usually cased with 9 5/8" casing and cemented up to the previous casing string. The cement is required to be above the proposed packer depth and verified by logs. Hydraulic isolation is essential for ensuring outer well integrity. This is especially important in injection well operations.

If the 12¼" hole is not drilled through the reservoir, an 8½" bit is used for drilling through the reservoir. The hole is cased with a 7" casing. This is often suspended from the lower part of a 9 5/8" casing, but sometimes run in all the way up to the surface. It is particularly important to cement this section, as a leak could result in fluids rising to the surface through migration up the annulus.

Characterization wells are drilled to gather detailed information on the reservoirs and caprocks. Much of the time they are not designed for any other use, and are plugged and abandoned after the information is gathered. The data is gathered by taking many meters of formation core, running multiple logging suites, and performing fluid injection or extraction tests. Although the well design can be simpler due to the lack of the final string of casing, there is usually a lack of experience drilling in the area and thus protections need to be put in place to mitigate the risk of unanticipated hydrocarbon accumulations, higher than expected pressures, or other geohazards.

Since monitor wells do not need to allow for fluid to be pumped through them, they can usually be designed for smaller diameters. The size will depend on the technologies to be deployed in or through them. If there will not be perforations through the casing, there is no need to run a packer and tubing. Technologies can be run outside of the casing, between the casing and tubing, and on wireline inside the tubing. These technologies are discussed in detail in the next chapter.

6.1.3 Well completion and commissioning

Completion involves running in the tubing, installing monitoring equipment, packers, liner/tubing hanger systems, valves and tree. Any string, including all connections and down-hole equipment, should be of such diameter, wall thickness, material quality and strength, and installed in such a manner, that it will withstand the structural and pressure restraining loads.

The completion can be divided into the lower and upper completion.

The lower completion refers to the portion of the well across the injection zone in the reservoir. Typically, the lower completion is set across the reservoir using a liner hanger system, which anchors the lower completion to the casing string. Several types of lower completion designs have been used for injection wells i.e., open hole, cemented and perforated liner, predrilled liner and screens. The recommended lower completion design will depend on factor like formation properties (formation stability, porosity/permeability) and type of fluid to be injected. Formations with low strength and good porosity and permeability should consider using screens unless a lot of particles will be injected.

The upper completion refers to all components from the bottom of the injection tubing upwards.

The tubing provides isolation of fluids and pressures from the casing, well control, injection control, stimulation control, and a retrievable "replaceable" pipeline to the reservoir. When selecting the tubing it is necessary to evaluate material quality relative to the planned use (strength and corrosion). For CO_2 injectors where the fluid can be corrosive, 13Cr or better should be considered. This material selection will also depend on the desired lifetime. The tubing should have a size that enable sufficient flow and allow for anticipated tool passage during future workovers or logging operations.

All offshore wells should have a subsurface safety valve installed in the tubing below the level of the seafloor. These valves, whether surface- or subsurface-controlled, operate in a failsafe mode, meaning in any upset condition they automatically close, sealing off all vertical flow in the well.

Placement of the packer is critical for safe injection operations. A leak above the packer will be detected on the annulus pressure. A leak below the packer can be more difficult to detect. The packer should also be placed in well-cemented casing.

The well can be perforated either before, during, or after the lower and upper completions are run.

Well commissioning takes the completed well and prepared it to accept the injection fluid (CO_2). It consists of two tasks:

1. Connecting and verifying the accuracy of all instrumentation
2. Placing the proper fluid in the wellbore.

After the completion of the injector wells, there is a possibility that the wells will not have been cleaned up sufficiently. A remedial action will often be required to decrease the skin damage on the well. A breaker is then often spotted across the reservoir section, which should dissolve the filter cake built up during the drilling of that section. However there is the possibility that the wells may not clean up sufficiently and then conventional coiled tubing will be required to carry out remedial action to decrease the skin damage on the well.

When CO_2 injection starts whatever fluid is in the wellbore will be pushed ahead of the injectate and into the reservoir. Some formations, due to their mineralogy, are easily damaged by water, the wrong salinity of water, or the presence of certain chemicals in the fluid. In some cases the well will need to be circulated and pressurized with CO_2 in order to not damage the reservoir at the initiation of injection.

6.1.4 Well operation

During the injection operations key parameters are continuously or periodically monitored to ensure no damage to the well, reservoir, or caprock. Alarm points are set for these parameters and mitigation actions are pre-determined for each scenario. Since the well is downstream of the pumps and pipeline, and problems with the well could cause damage to all equipment upstream of it, the monitoring of the well operation should be performed by the same control room as the pipeline, which will most probably be onshore.

Common measurements made include:

- Injection well downhole pressure and temperature
- Injection well surface pressure and temperature
- Injection well tubing/casing annular pressure
- Injection well flow rate
- Monitoring well in-zone pressure
- Above-caprock formation pressure (injection well, monitoring wells, or both)
- Microseismic activity (from any well or permenent ocean-bottom sensor)
- Time-lapse logs in all wells

Most of the mitigation actions would require mobilization of equipment and/or a rig to the site, thus causing a delay in remediation, and could also be quite expensive to perform. Thus offshore storage demands that the wells be engineered to be operable under as many conditions as economically possible in order to minimize the number of interventions.

6.1.5 Plug and Abandonment

The proper procedures for P&A of all wells will be specified by the regulatory agency. Specific to carbon storage wells will be the requirement that plugging materials be resistant to carbonic acid. Multiple plugs will be required in each well to ensure permanent sealing of the well. Since the injection interval will probably be at a much higher pressure than it was originally, extra care will need to be taken to guarantee well control during the entire plugging operation.

6.2 Wellbore Construction Materials and Integrity

The basis for injection wells is designing a fit for purpose well ensuring safe and effective injection of the planned fluids. The injection well also needs to be equipped with instrumentation enabling sufficient monitoring.

Considerations within the well design and monitoring include:

1. *Well design* and construction materials are site specific and will depend on factors such as:

- local geological setting (depth, fluid chemistry, pressure, temperature)
- expected design life of the injection well
- injection and reservoir fluid characteristics
- formation chemistry
- injected fluid chemistry
- Pressure (formation and injected fluid)
- Temperature (formation and injected fluid)
- injection rates

2. *Material quality:* Material selection for CO_2 injection requires input related to physical and chemical composition of reservoir an injected fluid in addition to pressure and temperature the well will be exposed to during the well lifetime. Additionally, there are various materials that are part of a well, including cement and polymers/rubbers. For CO_2 injectors the liner and liner hanger system should be corrosion resistant material such as 13CrS110 material to resist corrosion. The parts in the lower completion contact with formation water should also be corrosion-resistant material.

Under standard atmospheric conditions CO_2 is always in the gas state. For pressure above 73 bar and 31 °C the CO_2 goes into single phase—supercritical phase. For some rubbers the supercritical phase has been shown to influence more than pure gas exposure. The main effects of CO_2 in gas and liquid form on rubbers are:[217]

- Physical swelling—with associated loss in mechanical properties.

[217] Reidar Stokke, CO2PIPETRANS – Technical study: Material compatibility for polymers and elastomers,2008-12-01, SINTEF Report

- Explosive decompression (ED)—dissolved gas trapped in rubber that expands when the pressure drops.
- Chemical degradation

It was concluded that the chemical degradation from CO_2 on its own is minimal for the standard oilfield rubbers.[218] From the literature[218] it seems that the two main parameters for a successful use of rubbers are:

- The rubbers should show minimal swelling (at operating conditions).
- The resistance to explosive decompression should be good minimal for the standard oilfield rubbers. The main challenge with CO_2 exposure is the ED damage.

Rubber quality should be evaluated in relation to dynamic, static and shear ram seal of the BOP and other critical components in the well.

3. *Injection pressures* should not be higher than the fracture closure at the packer setting depth. The reason for this is that a leaking casing below the packer will not be detected on annulus pressure.

4. *The cement* must provide hydraulic isolation above the target reservoir to prevent out of zone injection.

5. *Well Instrumentation needs.* Instrumentation is of critical importance ensuring optimal and safe injection operations. Chapter 7 on monitoring technologies provides more details, but the importance of well instrumentation needs are defined below.

- Injection pressures operating within predefined operating window based on topside design, well design and formation limitations.
- Early detection and stop of injection with abnormal well behaviour
- Use of high and low alarms defined by well design and formation limitations in the operations phase enabling detection of abnormal well behavior.
- Annulus pressures monitoring to detect leaks in injection tubing and annulus monitoring to detect abnormal pressure buildup in formation outside casing that can be caused by out of zone injection (OOZI). Leaks into overburden can significantly increase the P&A cost when permeable overpressured zones need to be isolated.

6.3 Well Remediation

Well remediation can take many forms depending on the problem being corrected. In the offshore environment mobilization to the well can take quite a bit of time, and working space at the well is at a premium. So any remediation will take careful planning and close coordination.

[218] Morris Roseman, Rod Martin, Developing new elastomers from compound to downhole tool demonstrator for steam, supercritical CO_2, and H_2S injection for enhanced oil recovery, Merl Ltd., Wilbury Way, Hitchin, Hertfordshire, SG4 0TW, *MERL Oilfield Engineering with Polymers 2010 20-22 September 2010 – London, UK*

The easiest treatment is when a fluid is pumped down the well to dissolve some kind of blockage. Typical problems could be scale plugging the tubing or perforations, fines plugging the sandface, or hydrates in the interval from the wellhead to the mudline. Diagnosing these problems to select the correct fluid can be the hardest part, and many times require the mobilization of a wireline or slickline unit to run measurements inside the well. In some cases the wireline unit can fix the problem itself by adding perforations, spotting fluid with a bailer, shifting a sliding sleeve, setting a plug, or many other tasks.

If these methods do not work, the next level of effort requires a coiled tubing unit to be mobilized to the well to spool a continuous tube down the inside of the well. The many potential usages include using a drill bit and motor to drill out a blockage, a jetting tool to cut scale off the sides, a grapple or bailer to fish debris out of the well, various downhole assemblies to spot chemicals at specific points in the well, or squeezing cement or other sealants into leaks. Again, diagnosing the problem could include the use of other techniques such as wireline or slickline.

If the tubing and/or packer needs to be removed from the well, a workover unit or rig will need to be mobilized. The type of rig will depend on the type of well being remediated. It could vary from a small unit on a barge, a platform rig, a jackup, or a semisubmersible. The uses would be to replace a joint of tubing or leaking packer, squeeze a hole in the casing, replace downhole hardware, or recomplete the well in another interval.

Well remediation is a complex process that requires close cooperation among many disciplines. Installed hardware does not always come free as designed. Squeeze jobs do not always plug the leak. The organization needs to be nimble enough to react to unforeseen results by changing the remediation plan on the fly. Thorough brainstorming of possible scenarios and mitigation actions will pay off in less surprises and reduced down time. This will keep cost to a minimum while enabling the highest odds of success.

6.4 Technical Challenges or Technology Gaps

Offshore wells that receive CO_2 from a subsea pipeline will have much colder temperatures through the wellhead and the shallow sections of the well than any experience in the oilfield. It is poorly understood what effect this will have on well integrity and material durability.

Modeling has shown that an uncontrolled CO_2 blowout (such as the wellhead getting knocked off by a ship) could cause extremely low temperatures in a shallow-set subsurface safety valve. It is not yet demonstrated that the metallurgy and response systems could withstand these low temperatures.

When cold CO_2 from a subsea pipeline is injected into a depleted offshore field, especially a shallow one, the reservoir may not present enough backpressure to the wellhead and pipeline to keep the fluid in dense phase. Pure CO_2 at 5 °C will boil when the pressure drops below 600 psia. We do not know what effect this will have on the stability of the flow and the ability of the elastomers to maintain their sealing properties.

CO_2 sequestration wells will need to be permanently plugged with material guaranteed to last. Normal well plugging materials are susceptible to degradation by carbonic acid. Unlike onshore wells, plugged offshore wells are very hard to re-enter if they develop a leak.

6.5 R&D Opportunities

Research is needed for materials and procedures that are used to construct, complete, monitor, and plug carbon storage wells. With the high cost of offshore well intervention the long-term durability of metals, elastomers, and electronics will be critical.

The materials used and how they are assembled to combat any negative effects from cold CO_2 entering a wellhead.

- Verify that subsurface safety valves will perform in worst-case scenarios
- Develop probes and electronics that enable accurate monitoring for decades
- Develop well plugging materials that do not degrade when exposed to carbonic acid
- Understand the surface and system implications of injecting into low-pressure reservoirs

As was discussed in Section 4.5, (R&D Opportunities for Transportation, dynamic flow models) for wells also suffer from poor understanding of phase equilibria and equations of state in CO_2 mixtures with small amounts of impurities. Transient flow models require a much better understanding of these conditions in order to accurately predict the conditions wells will be subjected to. Fluid viscosities could swing wildly if trying to operate near phase transition boundaries, as at present small amounts of impurities can cause the equations of state to become unstable.

6.6 Recommendations

Safe and dependable offshore CO_2 sequestration wells will depend on proper data gathering (characterization) and risk management. While the costs will be higher than onshore sequestration fields, it may be much easier to permit and operate. Care will need to be taken to fully evaluate the economics through the entire CCS system so that proper decisions can be made on site selection, CO_2 cleanup, material selection, and monitoring activities. The design and operation of the wells will be very site specific. The above technology gaps and R&D areas could greatly reduce the uncertainties, risks and costs associated with offshore storage.

7 Monitoring, verification and assessment tools for offshore storage

7.1 Offshore monitoring overview

7.1.1 Context

In this chapter we review the current status of technology and methods for monitoring, verification, and accounting (MVA) for offshore CO_2 storage. We focus on summarizing recent experience and identifying important lessons learned for the offshore context. CO_2 storage monitoring and approaches for MVA have been widely addressed in previous reports.[219,220] More recently the IEAGHG[221] has reviewed offshore monitoring for CCS projects and main of the key conclusions from the IEAGHG report are also summarized in this chapter.

7.1.2 The offshore setting

Offshore CO_2 storage is attractive given the large estimated storage capacity, reduced risks to protected groundwater resources and population centers, generally simpler storage resource ownership aspects, and proximity to sources of large industrial CO_2 emissions. The offshore settings also allow for efficient collection of continuous 3D subsurface seismic imaging data over prospective storage sites which can be used for characterization and monitoring.

Monitoring for offshore CO_2 storage has some general characteristics which makes it distinct from monitoring onshore projects. The main differences are that:

- Wells and well interventions are more expensive offshore;
- Geophysical surveys are generally less expensive and often give much better imaging quality;
- The regulatory requirements differ in several respects;
- The marine ecosystem is quite different from the onshore surface environment.

Monitoring for offshore CO_2 storage is quite a mature technology, having been applied since the start of the first industrial-scale CCS project at Sleipner,[222] offshore Norway, in 1996. Since then similar approaches have been applied at the Snøhvit site[223] in the Norwegian Barents Sea (since 2008), at the K12-B pilot site offshore Netherlands (since 2004) and at the Tomakomai CCS

[219] NETL, 2012. Best Practices for Monitoring, Verification, and Accounting of CO_2 Stored in Deep Geologic Formations 2012 Update, DOE/NETL-2012/1568 Report, October 2012.

[220] Cooper, C. (Ed.), 2009. A technical basis for CO_2 storage. CO_2 Capture Project, CPL Press, UK. www.co2captureproject.org

[221] IEAGHG, 2016. Offshore Monitoring for CCS Projects, Report 2015/02, May 2015.

[222] Arts, R.J., Chadwick, A., Eiken, O., Thibeau, S., Nooner, S., [2008] Ten years' experience of monitoring CO_2 injection in the Utsira Sand at Sleipner, offshore Norway. *First Break* 26(1), 65-72.

[223] Hansen, O., Gilding, D., Nazarian, B., Osdal, B., Ringrose, P., Kristoffersen, J-B., Eiken, O., Hansen, H., [2012] Snøhvit: The history of injecting and storing 1 Mt CO_2 in the fluvial Tubåen Fm. Energy Procedia, 37, 3565 – 357.

Demonstration Project[224] in Japan (under construction, to be operational in 2016). Two planned offshore CO_2 storage projects at Peterhead-Goldeneye (UK) and ROAD (Netherlands) have also performed extensive scoping studies for offshore monitoring. Figure 7-1 and Table 7-1 summarize monitoring technologies deployed at offshore CO_2 storage site to date.

Time-lapse 3D seismic monitoring has proven to be a highly valuable tool in the offshore setting, with repeat survey intervals of 2–3 years being applied at Sleipner and Snøhvit giving excellent plume monitoring capabilities.[225] The Sleipner project has also successfully applied time-lapse gravity monitoring [226] (Alnes et al. 2011) and tested the potential for controlled source electromagnetic monitoring (CSEM).[227] At the Snøhvit CO_2 storage project, permanent down-hole pressure and temperature gauges were deployed demonstrating the value of downhole gauges in understanding pressure development. Down-hole gauges have also been successfully tested at the K12-B project, where the use of tracers has also been successfully tested, demonstrating their value in understanding CO_2 storage in an offshore depleted gas field. In Tomakomai, the initial 3D and 2D surveys have been conducted and down-hole pressure and temperature measurements are planned for collection of baseline data in early 2015. Microseismicity and natural earthquakes have been already observed continuously with an ocean bottom cable (OBC) equipped with 72 seismometers and four independent ocean bottom seismometers. The OBC will also be used for future repeated 2D surveys.

Marine and seabed monitoring approaches are generally less mature than reservoir monitoring methods, but the technology is rapidly developing and a range of methods have now been successfully tested and applied in the Sleipner area.

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[224] Tanaka, Y., Abe, M., Sawada, Y., Tanase, D., Ito, T., Kasukawa, T., 2014. Tomakomai CCS Demonstration Project in Japan, 2014 Update, *Energy Procedia* 63, 6111 – 6119

[225] Eiken, O., Ringrose, P., Hermanrud, C., Nazarian, B. and Torp, T., 2011. Lessons Learned from 14 years of CCS Operations: Sleipner, In Salah and Snøhvit. 10th International Conference on Greenhouse Gas Technologies. *Energy Procedia,* Volume 4, 5541-5548.

[226] Alnes, H, Eiken, O., Nooner, S., Sasagawa, G., [2011] Results from Sleipner gravity monitoring: updated density and temperature distribution of the CO2 plume. *Energy Procedia* 4, 5505-5511.

[227] Park, J. Vanneste, M. Waarum, I. K., Sparrevik, P. M. and Sauvin, G., 2014, In Situ Resistivity of CO_2 Plume at Sleipner from CSEM and Gravity Data, Near Surface Geoscience 2014 - First Applied Shallow Marine Geophysics Conference

Table 7-1 Summary of offshore monitoring technologies applied at offshore CO_2 storage projects to date

Monitoring Technology	Sleipner	Snøhvit	K12-B	Tomakomai
High-resolution 2D seismic	*	*		*
Time-lapse 3D seismic	*	*		*
Gravity surveys	* (4D)	* (4D)		* (continuous)
CSEM	*			
Seabed surveys and marine monitoring	*			*
Permanent down-hole gauges		*		*
Tracers			*	
Downhole well-testing during operations		*	*	
Wellbore integrity monitoring		*	*	*
Downhole fluid sampling	*	*	*	
Wellhead monitoring	*	*	*	*

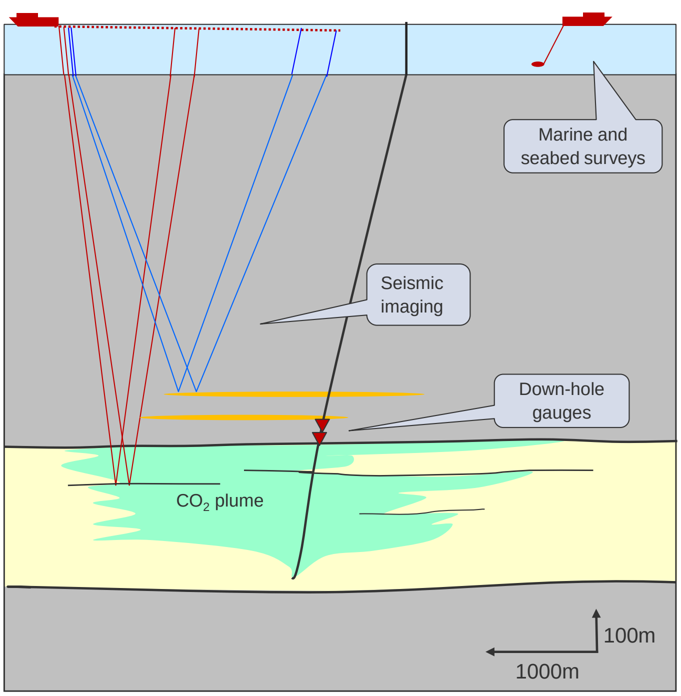

Figure 7-1 Overview of monitoring technologies applied at offshore CO_2 storage projects

7.1.3 Offshore regulation and monitoring objectives

The first overall question for CO_2 storage monitoring is what type of monitoring is needed? There are two aspects to this question:

a) What monitoring is required from a regulatory perspective?

b) What monitoring is cost-effective from an operational point of view?

The regulatory requirements are the overriding factor, but generally leave room for choice and optimization depending on the site context. The operational perspective is therefore often critical as it involves specific choices of technologies and survey intervals that are necessary to achieve certain MVA objectives.

There are two key over-arching regulations that cover offshore CO_2 storage, as reviewed by the recent IEAGHG Report,[228] the London Protocol and the OSPAR Convention. The London Protocol, which is a global agreement to protect the marine environment by regulating waste disposal at sea, was amended in 2006 to include CO_2 storage. Both of these conventions have similar two-stage monitoring guidelines. The first stage covers the performance of monitoring of CO_2 within storage formations and the second deals with the environmental impact in the event that leakage is suspected. The implications are that impacts on the seafloor and marine communities need to be ascertained.

It is in Europe that the regulatory framework is most mature but offshore storage regulations also exist and are developing elsewhere, notably in Japan, Australia and the Unites States. Although drafted at differing levels of detail, the regulatory documents from the different national jurisdictions all emphasize the key role of monitoring and the range of objectives it should serve. These can be broadly distilled as demonstrating that the storage site is performing effectively and safely and that it will continue to do so into the future. This approach can therefore be expressed as providing assurance of containment and conformance.

Since 2007 the international regulatory framework has been evolving notably in Europe with the introduction of the European Storage Directive for CO_2 in 2009. These regulations will be particularly pertinent to the planned projects at Peterhead-Goldeneye, White Rose and ROAD. Sleipner, Snøhvit and K12-B predate current EU legislation. The Sleipner and Snøhvit projects were licensed under Petroleum legislation in Norway, but have been used as case studies for informing the EU Directive, which has been recently adopted into Norwegian law. The EC Storage Directive specifically addresses monitoring for the purposes of assessing whether injected CO_2 is behaving as expected, whether any migration or leakage occurs, and if this is damaging the environment or human health.

OSPAR is primarily focused on detecting and avoiding leakage and emissions and therefore identifies the following objectives for a monitoring program:

- Monitoring for performance confirmation;
- Monitoring to detect possible leakages;
- Monitoring of local environmental impacts on ecosystems;
- Monitoring of the effectiveness of CO_2 storage as a greenhouse gas mitigation technology.

The following essential elements of monitoring and control are stated as required to help achieve these objectives:

- The injection rate;
- Continuous pressure monitoring;
- Injectivity and pressure fall-off testing;

[228] IEAGHG, 2016. Offshore Monitoring for CCS Projects, Report 2015/02, May 2015

- The properties of the injected fluid (including temperature and solid content, the presence of incidental associated substances and the phase of the CO_2 stream);
- Mechanical integrity of seals and (abandoned) wells;
- Containment of the CO_2 stream including performance monitoring and monitoring in overlying formations to detect leakage;
- Control measures, overpressure and emergency shutdown system.

It is clear from the wide range of regulatory requirements that have been developed, that regulation has reached different stages of maturity across the world. There are, however, two relatively consistent monitoring-related themes:

a) The requirement to demonstrate that a storage site is performing effectively and safely;

b) The need to ensure that it continues to do so via the provision of information supporting robust prediction of future performance.

These requirements for monitoring offshore storage can be distilled into a number of necessary actions, which fall within two main monitoring objectives: containment assurance and conformance assurance. A third category, contingency monitoring may be required in the event that containment and/or conformance requirements are not met.

In terms of the types of monitoring tools used, it is sometimes convenient to categorize them as deep-focused (providing surveillance of the reservoir and deeper overburden) and shallow-focused (providing surveillance of the near seabed, seabed and water-column) as described in the IEAGHG report[229] and summarized in Table 7-2.

[229] IEAGHG, 2016. Offshore Monitoring for CCS Projects, Report 2015/02, May 2015

		OSPAR	EU Directive	EU ETS	
Deep-focussed monitoring actions	Migration in overburden				Containment
	Containment integrity				Containment
	Migration in reservoir				Conformance
	Performance testing and calibration and identification of irregularities				Conformance
	Calibration for long-term prediction				Conformance
	Testing remedial actions				Contingency
Shallow-focussed monitoring actions	Verification of no leakage				Containment
	Leakage detection				Containment
	Emissions quantification				Contingency
	Environmental impacts				Other
	Testing remedial actions				Contingency

Table 7-2 Objectives for Deep and Shallow-focused monitoring (as proposed by the authors of the IEAGHG report).

7.1.4 Monitoring experience at Sleipner

The Sleipner CO_2 injection project was the world's first offshore industrial CO_2 storage project and emerged at a time when there were no regulations for monitoring CO_2 injection (the project was licensed under Norwegian petroleum regulations). Consequently, the project has served as a full-scale "laboratory" for testing and developing monitoring techniques, being extensively used as a case study in the 2005 IPPC special report on CCS[230] and numerous research projects. Figure 7-2 shows an overview of monitoring techniques tested and used at the Sleipner CO_2 injection site.

Seismic 3D monitoring was from the start the main monitoring technique at Sleipner.[231] It has been very successful, despite the fact that the seismic surveys were designed mainly for monitoring the deeper gas condensate production in the area. The main reason for the success is the high porosity of the reservoir, promoting large velocity and density contrasts between the injected CO_2 and the original brine in the pore space. CO_2 at Sleipner is injected close to the base of the Utsira sandstone Formation at an injection point at a depth of 1010 m (TVD MSL). The 200-300 m thick sand-rich Utsira Fm. with porosities of 35-40 percent and permeability values mainly over a Darcy (10^{-12}

[230] Metz, B., Davidson, O., De Coninck, H. C., Loos, M., and Meyer, L. A., 2005. IPCC special report on carbon dioxide capture and storage: Prepared by working group III of the intergovernmental panel on climate change. IPCC, Cambridge University Press: Cambridge, United Kingdom and New York, USA.

[231] Arts, R.J., Chadwick, A., Eiken, O., Thibeau, S., Nooner, S., 2008. Ten years' experience of monitoring CO_2 injection in the Utsira Sand at Sleipner, offshore Norway. *First Break* 26(1), 65-72.

m^2) provides an excellent storage domain with good capabilities for testing monitoring techniques.[232] Since injection start in 1996, the CO_2 plume has gradually spread laterally and vertically, within a series of stacked sandstone layers separated by thin shale layers, gradually rising to the top Utsira/caprock interface at a depth of around 820 m. The time-lapse seismic observations have provided both containment monitoring (confirming that the CO_2 has not migrated out of the Utsira storage unit), and conformance monitoring (providing a better understanding of the CO_2 flow behavior in the reservoir). Other technologies tested at Sleipner have been time-lapse gravity,[233] seafloor mapping (sonar and echo beam),[234] water and sediment sampling,[235] and a test of the feasibility of monitoring using CSEM.[236]

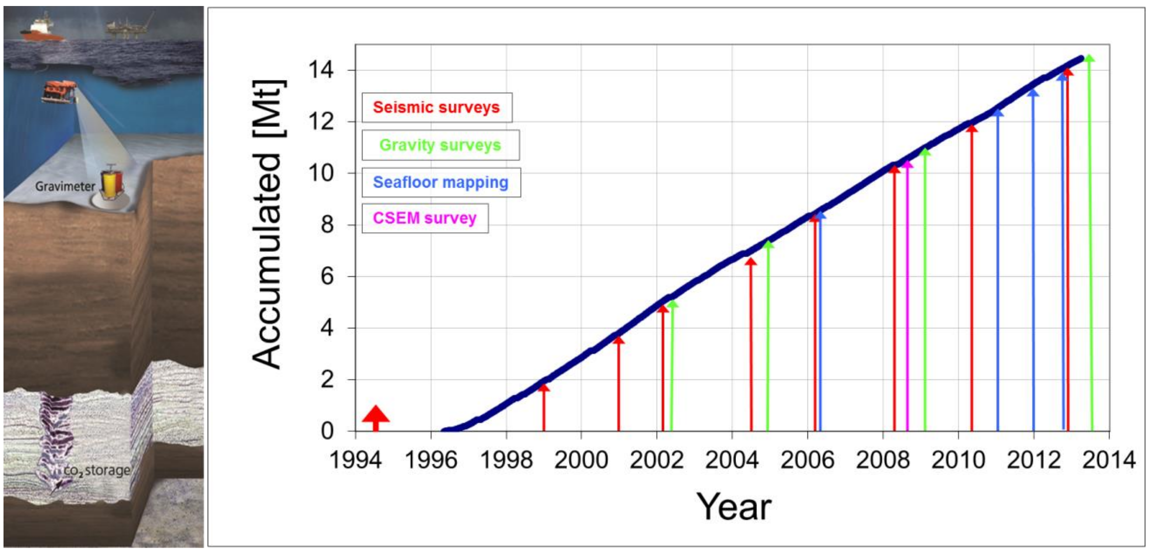

Figure 7-2 Illustration of seismic, gravimetry and sonar measurements at Sleipner (left) and monitoring techniques employed at Sleipner as a function of CO_2 stored (right)

232 Eiken, O., Ringrose, P., Hermanrud, C., Nazarian, B. and Torp, T., 2011. Lessons Learned from 14 years of CCS Operations: Sleipner, In Salah and Snøhvit. 10th International Conference on Greenhouse Gas Technologies. *Energy Procedia,* Volume 4, 5541-5548.

233 Alnes, H, Eiken, O., Stenvold, T., 2008, Monitoring gas production and CO_2 injection at the Sleipner field using time-lapse gravimetry. *Geophysics,* 73(6), WA155-WA161.

234 Linke, P., ed . (2011) RV ALKOR Fahrtbericht / Cruise Report AL374; 29.05.-14.06.2011, Kiel - Kiel; ECO_2 - Sub-seabed CO_2 Storage: Impact on Marine Ecosystems IFM-GEOMAR Report, 51 . IFM-GEOMAR, Kiel, 55 pp. DOI 10.3289/IFM-GEOMAR_REP_51_2011.

235 Pedersen, R. B. and Reigstad, L. J. and Centre for Geobiology, UiB (2011) Cruise Report GS11B: The Sleipner area, North Sea ; R/V G.O. Sars, Expedition No. 2011108/CGB2011, June 24th– July 1st 2011, Bergen, Norway – Bergen, Norway Centre for Geobiology, UiB, Bergen, Norway, 38 pp. DOI 10.3289/CR_ECO2_20594.

236 Park, J. Vanneste, M. Waarum, I. K., Sparrevik, P. M. and Sauvin, G., 2014, In Situ Resistivity of CO_2 Plume at Sleipner from CSEM and Gravity Data, Near Surface Geoscience 2014 - First Applied Shallow Marine Geophysics Conference

In general, the repeat seismic monitoring at Sleipner has proved most valuable, being able to address multiple MMV issues, including the spatial extent of the CO_2 plume, the vertical migration of the plume between sand layers within the Utsira, and the containment of the CO_2 plume beneath the Nordland shale. Gravity field monitoring has also been very valuable as a control on mass distribution, and has provided a constraint on the rate of CO_2 dissolution in brine. The seafloor mapping techniques have been valuable in helping to define how monitoring methods can be applied in the offshore setting.

Routine wellhead monitoring of pressure, temperature and flow rate have confirmed a very stable injection history with the wellhead temperature held at 25ºC and the pressure remaining stable at 62-65 bar (close to the gas-liquid phase transition point). Permanent downhole gauges were not deployed at the Sleipner CO_2 injection well.

7.1.5 Monitoring experience at Snøhvit

The Snøhvit CCS project which started CO_2 injection in April 2008, adopted a similar monitoring strategy to Sleipner with a base-line seismic survey acquired in 2003 followed by three repeat seismic surveys so far (in 2009, 2011 and 2012) and a gravity field survey (baseline and 1 repeat so far). Furthermore, the successful deployment of a down-hole pressure and temperature gauge in the injection well proved especially valuable. In 2011 the injection strategy was modified by changing the downhole injection completion, closing off the lower Tubåen Fm. completions and switching to injection in the higher Stø Fm.[237] By the end of 2014 the project had injected 9 Mt CO_2 with a little over 1 Mt having been injected into the Tubåen Fm.

By combining down-hole gauge data with 4D seismic monitoring (Figure 7-3), Snøhvit project was able to optimize the injection strategy in response to operational challenges related to reservoir uncertainties. The expected formation permeabilities around the injection well were in the range of 100mD to 8D. However, analysis of pressure gauge data during the first 3 years of injection showed that the effective permeability away from the wellbore was significantly lower than this, due to the effects of geological barriers. This led to a gradual rise in the injection well pressure, eventually leading to a limit on the injection period as the operational pressure limits was approached (Figure 7-3). Analysis of the first time-lapse seismic survey (2009) also revealed a limited degree of injection into the upper two perforations (Tubåen 2 and 3), with most of the CO_2 being injected into the lowermost perforation (Tubåen 1). These monitoring observations were then used to design a well intervention operation in April 2011—the world's first such operation for a CO_2 injection well from a subsea template.

[237] Hansen, O., Gilding, D., Nazarian, B., Osdal, B., Ringrose, P., Kristoffersen, J-B., Eiken, O., Hansen, H., [2012] Snøhvit: The history of injecting and storing 1 Mt CO2 in the fluvial Tubåen Fm. Energy Procedia, 37, 3565 – 357.

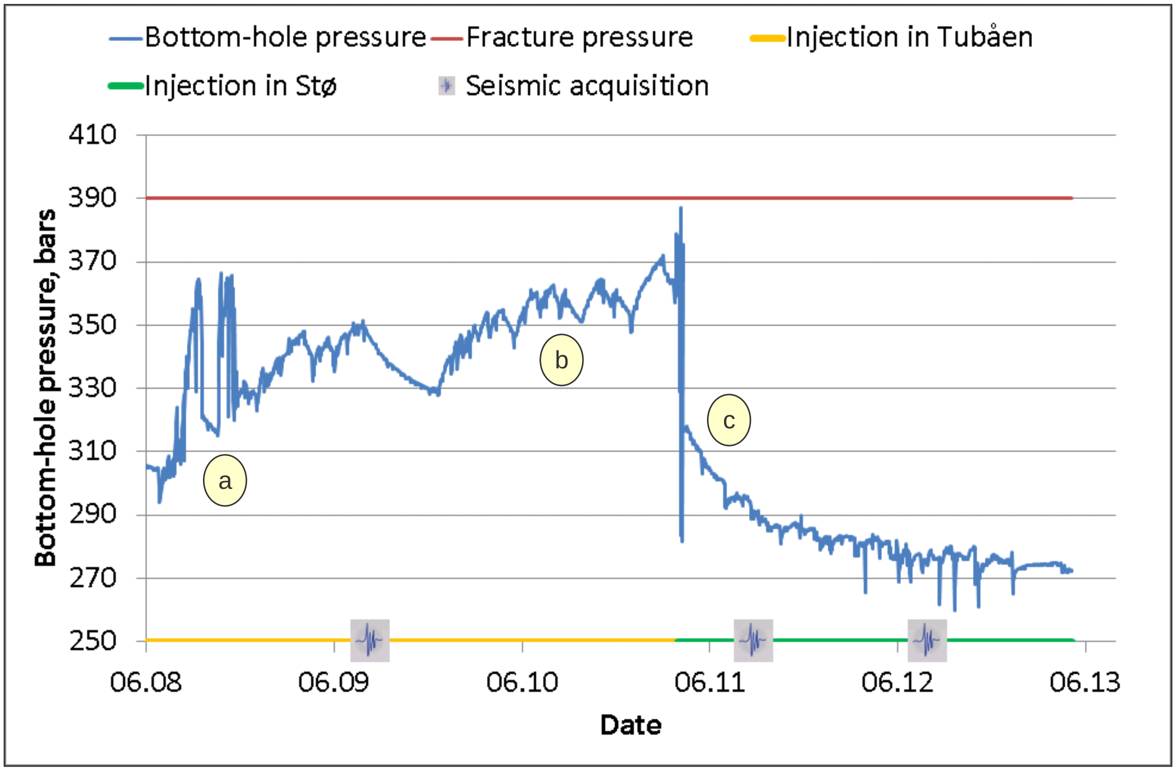

Figure 7-3 Pressure history at the Snøhvit CO_2 storage site (2008 to 2013) with time-lapse seismic acquisition surveys. Three main features of the injection pressure history are: a) early rise in pressure due to near-wellbore effects related to salt drop-out, b) a gradual rising trend in pressure due to geological flow barriers in the Tubåen Fm., and c) pressure decline to a new stable level following diversion of the injection into the overlying Stø Fm.

Following formation testing of the existing CO_2 perforations, the decision was made to deploy a back-up injection solution by isolating the Tubåen interval and switching the injection to the overlying Stø Formation. Subsequent CO_2 injection into the Stø Fm (since 2011) has continued without interruption and with pressure falling to a stable level (Figure 7-3) due to the better lateral continuity of the Stø Fm.[238] It should be noted that this change in the Snøhvit injection plan was within the expected range of uncertainty identified at the start of the project, and that the alternative injection option was deployed using a well designed to be flexible. By combining surface geophysical and downhole monitoring data, the project was able to successfully respond to operational challenges related to geological and reservoir uncertainties. The Snøhvit project is planning a second CO_2 injection well (to be drilled in 2016) as part of the long-term strategy to ensure continued CO_2 storage as part of this large gas development project.

[238] Osdal, B., Zadeh, H. M., Johansen, S., Gonzalez, R. R., and Wærum, G. O., 2014. Snøhvit CO_2 Monitoring Using Well Pressure Measurement and 4D Seismic. Extended abstract presented at Fourth EAGE CO_2 Geological Storage Workshop, 22-24 April 2014, Stavanger, Norway.

7.1.6 Monitoring experience at K12-B

The K12-B gas field is located in the Dutch sector of the North Sea, some 150 km northwest of Amsterdam. Since 2004, produced CO_2 has been re-injected into the field for storage and enhanced natural gas production. Injection is still ongoing and so far about 90kT of CO_2 have been injected. Different monitoring technologies have been deployed, with the overall aim of studying relevant processes for underground CO_2 storage in depleted gas fields, but with the primary aim of establishing wellbore integrity and assessing the potential for EGR.

Downhole and wellhead measurements of temperature, pressure and flow rate have been acquired for the gas production and CO_2 injection wells, and provide the input data for reservoir simulations. At the start of CO_2 injection in 2004 this data was updated on an hourly basis, but later the frequency was changed to daily updates.

Since the injected CO_2 originates from the same reservoir into which it is being re-injected, it cannot be chemically distinguished from naturally occurring CO_2 in the reservoir. Two perfluorocarbon chemical tracers were therefore injected to investigate the CO_2 migration patterns and EGR potential of the reservoir, as well as the partitioning behavior of the CO_2 and CH_4 (Figure 7-4).

Downhole sampling of water samples took place in 2010. Analysis of these samples gave an insight into the downhole conditions of the CO_2 injection well during shut-in. Downhole pressure and temperature gauges have been temporarily installed to perform pressure fall-off tests. These tests along with the results of reservoir modelling work have been used demonstrate that CO_2 injection at K12-B has performed successfully and has not lead to complications related to changes of reservoir permeability, increasing skin factors or wellbore storage. Samples from the gas production stream were taken at regular intervals and the composition of the produced gas was analyzed in order to support reservoir simulations and confirm interpretations of the reservoir dynamics.

All tests along with the results of reservoir modelling work have been used to demonstrate that CO_2 injection at K12-B is successful and has not lead to complications related to changes of reservoir permeability, increasing skin factors or wellbore storage.

Since the injected CO_2 originates from the same reservoir into which it is being re-injected, it cannot be chemically distinguished from naturally occurring CO_2 in the reservoir. Two perfluorocarbon chemical tracers were therefore injected to investigate the CO_2 migration patterns and EGR potential of the reservoir, as well as the partitioning behavior of the CO_2 and CH_4 (Figure 7-4).

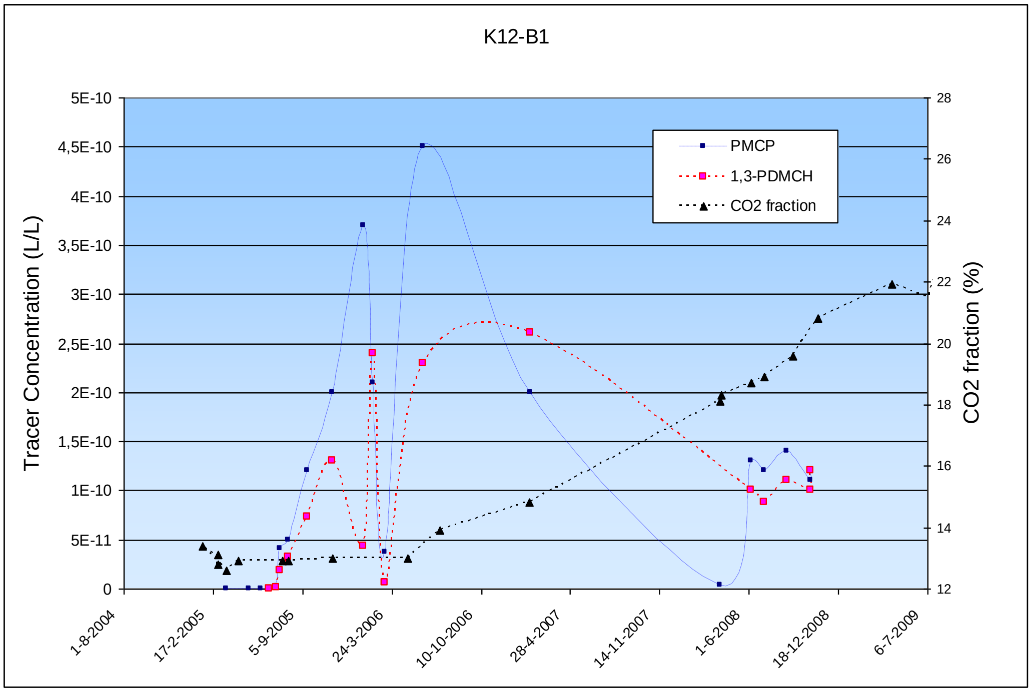

Figure 7-4 Tracer concentrations and CO2 fractions at the K12-B1 production well. Tracer concentration data for both tracers show tracer breakthrough after 130 days (August 2005) for the K12-B1 well and after 463 days for the 12-B5 well (June 2006).

Additional tracer tests are being planned for 2015. The objectives of these tracer tests are (a) to identify and test new chemical tracers specifically for (Dutch) gas field conditions and (b) to provide insights into the flow of CO_2 in the reservoir. The results will be useful for the assessment of the potential for Enhanced Gas Recovery. The project has identified and characterized suitable chemical tracers that are expected to migrate more closely with CO_2 as compared with previously injected tracers. Future plans at this site include co-injection of the tracers with the CO_2 stream, with monitoring for breakthrough times and concentration. Composition data from the production stream in combination with well head data will then be used to constrain reservoir simulations, leading to an improved understanding of processes relevant to CO_2 storage and EGR.

7.1.7 New offshore CO_2 storage projects in the planning phase

The planned CCS project at Peterhead-Goldeneye, offshore Scotland, involves injection into a depleted gas field and has a monitoring program designed to meet European offshore requirements and covering both deep and shallow focused monitoring. The deep-focused component will include surveillance of the reservoir and overburden and utilizes a number of proven technologies, including time-lapse 3D seismic, down-hole pressure and temperature, geophysical logging and fluid sampling. A comprehensive shallow environmental monitoring program is also planned, including seabed imaging, seabed sampling and seawater sampling technologies. Contingency monitoring is also addressed, for example a P-Cable seismic survey is planned to help image and understand shallow migration in the event of leakage being detected at the top of the storage complex.

The Dutch ROAD project is the first project to be permitted under the EU Storage Directive. The permit is subject to updates and the inclusion of more detail. Around 1.1 Mtpa of CO_2 is planned to be transported to a depleted gas field 20 km (12 miles) off the coast of Rotterdam. The target reservoir will be the P18-4 gas reservoir (operated by TAQA). Further work is underway to assess specific local pressure build-ups, pressure barriers and later-stage fault leakage. Results will be used to update the risk assessment which will feed into the updated monitoring plan to provide evidence for containment and to demonstrate integrity of seals, faults and wells.

The Japanese Tomakomai CCS project is a large scale demonstration project located 3-4 km off the coast of Hokkaido. The monitoring program includes 2D and 3D seismic surveys. These will be deployed via OBCs because greater repeatability is achievable and the busy port and shallow water setting precluded streamer deployment. The 2D survey line aligns with the two injection wells and uses a buried OBC for similar reasons. Heavy emphasis has been placed on the detection of natural earthquakes and microseismicity which also uses the OBC equipment, in addition to four dedicated ocean bottom seismometers (OBS) and downhole sensors in the observation wells. Various kinds of marine environmental monitoring are also scheduled, as required by Japanese regulation.

7.2 Offshore monitoring technology

7.2.1 Time-lapse seismic methods

Time-lapse seismic is a mature technology used to monitor gas and oil production worldwide, and it has also been successfully employed for monitoring many saline aquifer CO_2 injection sites, both onshore and offshore. The technology is based on the acoustic contrast between the low velocity and density of CO_2 compared to the higher velocity and density of the *in situ* brine. Both repeated 2D and 3D seismic have been employed for CO_2 monitoring and the results typically give a detailed image of the lateral and vertical distribution of CO_2 in the pore space. The method is best employed at sites where the injected CO_2 properties give a good contrast with the in situ pore fluid—generally good within saline aquifers but less favorable for CO_2 injection into produced gas fields. Although the level of detail possible with seismic imaging is relatively high, it is restricted by the seismic wave length and there is a lower resolution limit beneath which time-lapse changes will not be resolved (typically around 10-15m). The method depends on a precise repetition of the seismic surveys, and it is particularly important to reproduce the position of the seismic source and receivers. Marine 3D seismic acquisition and time-lapse seismic monitoring is constantly improving, e.g., using guided and steerable streamer technology. These improvements lead to a paradox in any time-lapse monitoring project. Although there is a desire to always use the most updated technology, the base line survey is often the limiting factor when taking advantage of the newer technology available for repeat surveys. In recent years there has been a development towards broadband seismic technologies, aimed at expanding the frequency range for seismic acquisition. Time-lapse processing is used to make these newer surveys backward compatible with the (typically poorer) base line survey.

Time-lapse seismic has been the main monitoring technology employed from the start at the Sleipner injection site, and has provided a detailed overview of the CO_2 behavior in the reservoir.[239,240] (Figure 7-5) shows the typical time-lapse response at Sleipner, between the 1994 (base survey) and the repeat 2010 survey. In total, nine different layers were identified at Sleipner from the 4D seismic monitoring. These imaged layers are interpreted as being due to CO_2 partially trapped beneath thin mudstone layers within the Utsira sandstone storage unit (due to capillary forces), and then migrating upwards towards the top of the storage unit. These thin shales were identified in wells at the outset of the project[241] but their effect was unknown as the shales could not be correlated from well logs alone or seen on the baseline seismic data. Time-lapse seismic imaging has therefore revealed which geological units actually control the dynamics of CO_2 plume movement, leading in turn to an improved appreciation of the physics and dynamics of CO_2-brine multiphase flow systems.[242,243,244]

[239] Arts, R.J., Chadwick, A., Eiken, O., Thibeau, S., Nooner, S., [2008] Ten years' experience of monitoring CO_2 injection in the Utsira Sand at Sleipner, offshore Norway. First Break 26(1), 65-72.

[240] Furre, A. K., and Eiken, O. (2014). Dual sensor streamer technology used in Sleipner CO_2 injection monitoring. *Geophysical Prospecting*, 62(5), 1075-1088.

[241] Zweigel P, Arts R, Lothe AE and Lindeberg EBG, 2004. Reservoir geology of the Utsira Formation at the first industrial-scale underground CO_2 storage site (Sleipner area, North Sea). In: Baines SJ editor. Geological Storage of Carbon Dioxide. Geological Society special publication no. 233, p. 165-180.

[242] Singh, V., Cavanagh, A., Hansen, H., Nazarian, B., Iding, M. and Ringrose, P., 2010. Reservoir modeling of CO_2 plume behaviour calibrated against monitoring data from Sleipner, Norway. SPE 134891, presented at the SPE Annual Technical Conference and Exhibition held in Florence, Italy, 19–22 September 2010.

[243] Chadwick, R. A., and Noy, D. J., 2010. History-matching flow simulations and time-lapse seismic data from the Sleipner CO_2 plume. In Geological Society, London, Petroleum Geology Conference series (Vol. 7, pp. 1171-1182). Geological Society of London.

[244] Cavanagh, A., 2013. Benchmark Calibration and Prediction of the Sleipner CO_2 Plume from 2006 to 2012. Energy Procedia, 37, 3529-3545.

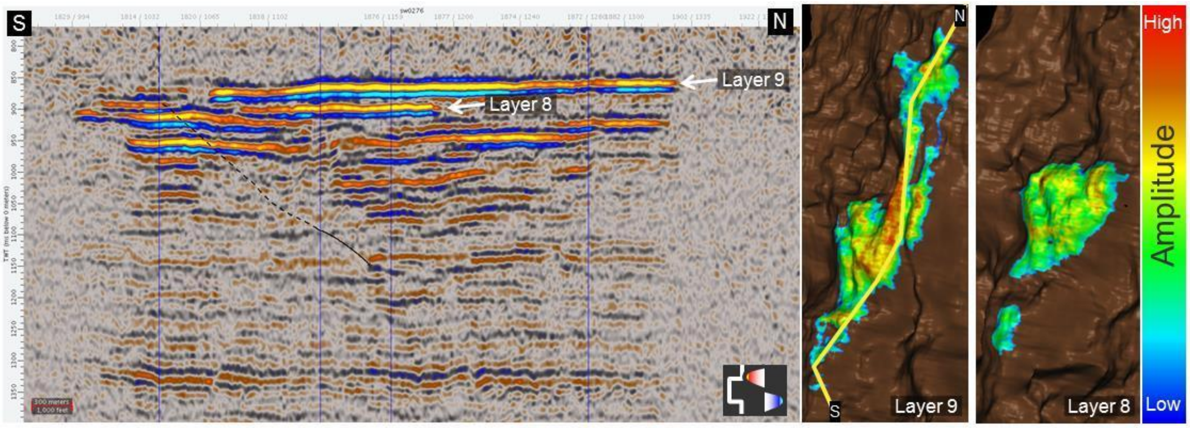

Figure 7-5 Time-lapse response (1994 to 2010). Left: seismic difference section, right: map view of the two uppermost layers.

The time-lapse seismic response is potentially influenced by changes in saturation, pressure or rock strain, or more generally a combination of all these factors. While at Sleipner the response is mainly related to saturation (since pressure changes are very small), at the Snøhvit site it seems that the observed response is related to both pressure and saturation changes.[245] Although this can complicate the interpretation of time-lapse seismic, it also brings the potential for resolving both the pressure footprint and the spread of the CO_2 plume itself from seismic monitoring datasets.

7.2.2 Other geophysical methods

The most successful alternative geophysical monitoring technique has probably been time-lapse gravity, which has been employed both at the Sleipner and Snøhvit injection sites.[246,247,248] Time-lapse gravity monitoring is based on accurately measuring the difference in the Earth's mass attraction when the *in situ* brine is replaced by lower density CO_2. The methodology was developed for offshore monitoring by Statoil in co-operation with the Scripps Research Institute during the late nineties and was first successfully used in monitoring gas production from the Troll field. The success of the method depends on the instrument precision and position accuracy. Typically concrete benchmarks are placed on the seafloor in a grid covering the injection site and the gravimeter is deployed using an ROV and then retrieved from the benchmark after sufficient time to correct for tidal effects and long-term drift. This allows a precision in the range of 2-5

[245] Grude, S., Landrø, M., and Osdal, B. (2013). Time-lapse pressure–saturation discrimination for CO_2 storage at the Snøhvit field. *International Journal of Greenhouse Gas Control*, 19, 369-378.

[246] Nooner, S. L., Eiken, O., Hermanrud, C., Sasagawa, G. S., Stenvold, T. and Zumberge, M. A., 2007. Constraints on the in situ density of CO_2 within the Utsira formation from time-lapse seafloor gravity measurements. *International Journal of Greenhouse Gas Control*, 1, 198 – 214.

[247] Alnes, H, Eiken, O., Stenvold, T., 2008, Monitoring gas production and CO_2 injection at the Sleipner field using time-lapse gravimetry Geophysics, Vol 73, no 6 (November-December 2008), P. WA 1555-WA 161.

[248] Alnes, H, Eiken, O., Nooner, S., Sasagawa, G., 2011. Results from Sleipner gravity monitoring: updated density and temperature distribution of the CO_2 plume. *Energy Procedia*, 4, 5505-5511.

microgalileos (μGals), (which is a unit of acceleration defined as one-millionth of a Gal, which is 1 cm/s^2) comparable to the best onshore gravimetric surveys.

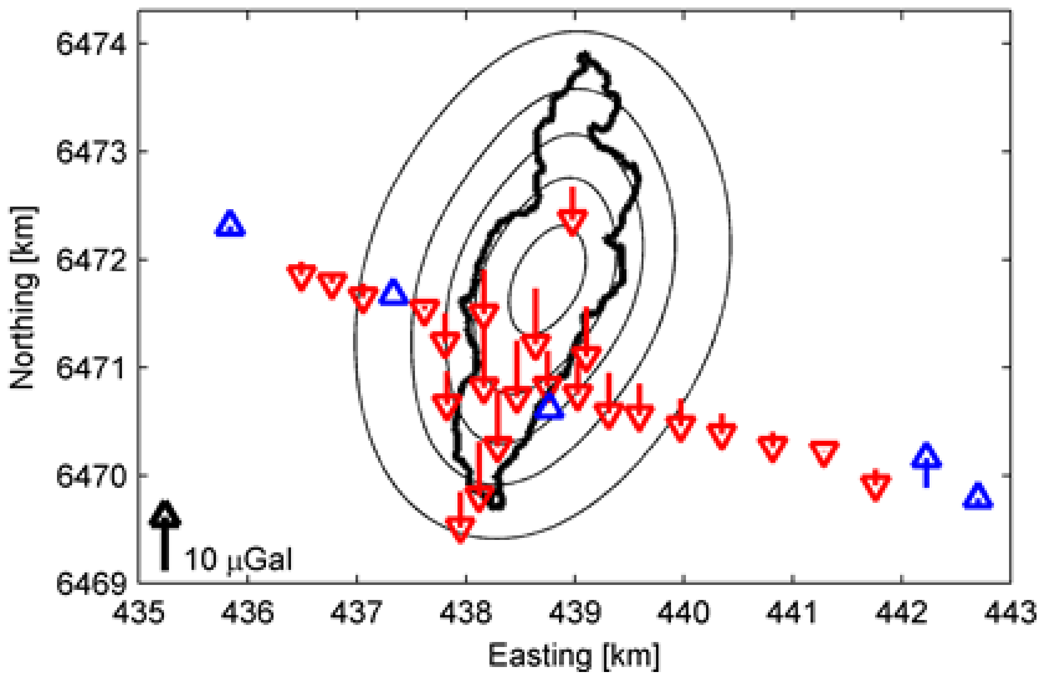

Figure 7-6 Map of observed gravity changes at Sleipner between 2002 and 2009 (corrected for measured benchmark settling, and after water influx signal has been subtracted), redrawn from Alnes et al 2011. Red arrows denote a reduction in seafloor gravity (scale i s shown in the bottom left hand corner). Contours show modelled gravity response from the CO_2 plume (contour spacing is 2 μGal). Thick black outline shows the outline of the CO_2 plume estimated from the seismic response in 2008.

Figure 7-6 shows the gravimetric layout over the Sleipner field, together with the gravimetric time-lapse response from 2002 to 2009. The advantage of the gravimetric method is that it provides a direct estimate of the CO_2 density change in the reservoir (as opposed to seismic which is a mixed response of density and velocity); however, the disadvantage is that gravimetric measurements have much less resolution than seismic measurements. In practice, gravity surveys are most useful when used in combination with time-lapse seismic, allowing density changes to be more precisely calibrated.

Repeated resistivity measurements downhole have been used successfully for monitoring resistivity changes at the onshore Ketzin CO_2 injection test site.[249] In the offshore setting, where downhole monitoring in wells is much more limited, an attractive alternative is to use CSEM waves with sources and receivers towed close to the seabed. CSEM has had a rapid development as a

[249] Bergmann, P., Schmidt-Hattenberger, C., Kiessling, D., Rücker, C., Labitzke, T., Henninges, J., and Schütt, H. 2012. Surface-downhole electrical resistivity tomography applied to monitoring of CO_2 storage at Ketzin, Germany. Geophysics, 77(6), B253-B267.

supplement to seismic for oil exploration purposes and relies on measuring the resistivity difference between a more resistive oil or gas bearing rock formation compared to the formation filled with saline brine. CSEM surveys also provide relatively low resolution measurements. A feasibility test was conducted at the Sleipner CO_2 storage site in 2006, but did not give conclusive results, however the method shows some potential especially when combined with gravity field monitoring.[250]

7.2.3 Downhole monitoring

Onshore CO_2 storage sites, such as the demonstration projects at Ketzin,[251] Decatur,[252] Bell Creek,[253] and Cranfield[254] have tended to have a stronger focus on downhole monitoring, including use of downhole gauges, distributed fiber-optic measurements, repeat saturation logging, downhole electrical resistivity tomography, and downhole seismic measurements. In the offshore setting, where well construction and operations costs are significantly higher, downhole monitoring for CO_2 storage has so far been more limited. However, following significant technical advances in down-hole fiber-optic deployed measurement devices,[255] downhole monitoring in the offshore setting has become a more practical and cost-effective option.

Permanent downhole monitoring approaches recently applied in the oilfield setting include:

- Permanent quartz gauges with a range of acoustic, copper or fiber-optic transmission systems;
- Distributed temperature sensing (DTS) systems where the fiber optic cables are used to measure temperature changes along the fiber;
- Distributed acoustic sensing (DAS), where the fiber optic cables are used to measure strain.

These permanent downhole sensors are most commonly deployed attached to the injection (or production) tubing with transmission to surface via single-mode fiber or multiple fibers in a single tube. Fiber optic cables and downhole gauges may also be placed behind the well casing or in dedicated monitoring wells. At the Citronelle (United States) test site, a DAS cable was deployed

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[250] Park, J., Vanneste, M., Waarum, I. K., Sparrevik, P. M. and Sauvin, G., 2014. In Situ Resistivity of CO_2 Plume at Sleipner from CSEM and Gravity Data. Extended abstract presented at the First Applied Shallow Marine Geophysics Conference, 14-18 September 2014 (EAGE).

[251] Bergmann, P., Schmidt-Hattenberger, C., Kiessling, D., Rücker, C., Labitzke, T., Henninges, J., and Schütt, H. 2012. Surface-downhole electrical resistivity tomography applied to monitoring of CO_2 storage at Ketzin, Germany. Geophysics, 77(6), B253-B267.

[252] Finley, R. J., 2014. An overview of the Illinois Basin–Decatur project. Greenhouse Gases: Science and Technology, 4(5), 571-579.

[253] Gorecki, C. D., Hamling, J. A., Ensrud, J., Steadman, E. N., and Harju, J. A. (2012). Integrating CO_2 EOR and CO_2 Storage in the Bell Creek Oil Field. Carbon Management Technology Conference. doi:10.7122/151476-MS

[254] Meckel, T. A., and S. D. Hovorka, 2009. Results of continuous downhole monitoring (PDG) at a field-scale CO_2 demonstration project, Cranfield, MS. In SPE International Conference on CO_2 Capture, Storage, and Utilization. San Diego, California, pp. 4-9.

[255] Eck, J., Ewherido, U., Mohammed, J., Ogunlowo, R., Ford, J., Fry, L., and Veneruso, T., 1999. Downhole monitoring: the story so far. *Oilfield Review*, 11(3), 18-29.

as part of a Modular Borehole Monitoring (MBM) system alongside electrical cables for geophone and P/T data, and a u-tube for fluid sampling.[256] Improvements in the reliability of the installation process and in the long-term stability of the gauges and fibers at high temperatures and pressures have taken the performance lifetime from a few months to several years, meaning that the systems can now be considered as permanent for the lifetime of most projects (10–30 years). The value of permanent downhole gauges for CO_2 storage monitoring has now been demonstrated at several sites, both onshore[257] and offshore (at the Snøhvit and K12-B sites). Distributed temperature and acoustic sensing has been field tested at several onshore CO_2 storage sites including Otway (Australia), Ketzin (Germany), Decatur and Citronelle (United States),[258] where the value of DAS for acquiring vertical seismic profile (VSP) datasets shows great potential as an advanced and cost effective approach for MMV. Field trials for acquiring VSP data from distributed acoustic sensing systems deployed in offshore gas production wells have also been recently demonstrated,[259] such that use of DAS and DTS systems is likely to be an important part of future offshore CO_2 storage projects.

Interpretation of downhole monitoring data will always require integration with other subsurface data, including geological data, surface seismic data, and fluid characterization and modelling. The value of this integrated approach to monitoring and verification of CO_2 storage sites is clear from many case studies, and nicely illustrated for the offshore setting by Snøhvit CO_2 injection project, where downhole pressure gauge data were interpreted alongside time-lapse surface seismic data to design a well intervention operation.[260,261] Figure 7-7 illustrates how the time-lapse seismic response at Snøhvit was subsequently confirmed by downhole flow logging data, confirming the value of combining a range of monitoring data (in this case surface seismic data with downhole pressure gauge and flow logging data) in order to optimize and manage CO_2 storage in an offshore setting.

[256] Daley, T. M., Freifeld, B. M., Ajo-Franklin, J., Dou, S., Pevzner, R., Shulakova, V., and Lueth, S., 2013. Field testing of fiber-optic distributed acoustic sensing (DAS) for subsurface seismic monitoring. *The Leading Edge*, 32(6), 699-706.

[257] Couëslan, M. L., Smith, V., El-Kaseeh, G., Gilbert, J., Preece, N., Zhang, L., and Gulati, J., 2014. Development and implementation of a seismic characterization and CO_2 monitoring program for the Illinois Basin–Decatur Project. *Greenhouse Gases: Science and Technology*, 4(5), 626-644.

[258] Daley, T. M., Freifeld, B. M., Ajo-Franklin, J., Dou, S., Pevzner, R., Shulakova, V., and Lueth, S., 2013. Field testing of fiber-optic distributed acoustic sensing (DAS) for subsurface seismic monitoring. *The Leading Edge*, 32(6), 699-706.

[259] Nørgaard Madsen, K.,Thompson, M., Parker, T., Finfer, D., 2013, A VSP field trial using distributed acoustic sensing in a producing well in the North Sea, First Break 31 (11) pp. 51 – 56.

[260] Hansen, O., Gilding, D., Nazarian, B., Osdal, B., Ringrose, P., Kristoffersen, J-B., Eiken, O., Hansen, H., [2012] Snøhvit: The history of injecting and storing 1 Mt CO_2 in the fluvial Tubåen Fm. Energy Procedia, 37, 3565 – 357.

[261] Osdal, B., Zadeh, H. M., Johansen, S., Gonzalez, R. R., and Wærum, G. O., 2014. Snøhvit CO_2 Monitoring Using Well Pressure Measurement and 4D Seismic. Fourth EAGE CO_2 Geological Storage Workshop, April 2014.

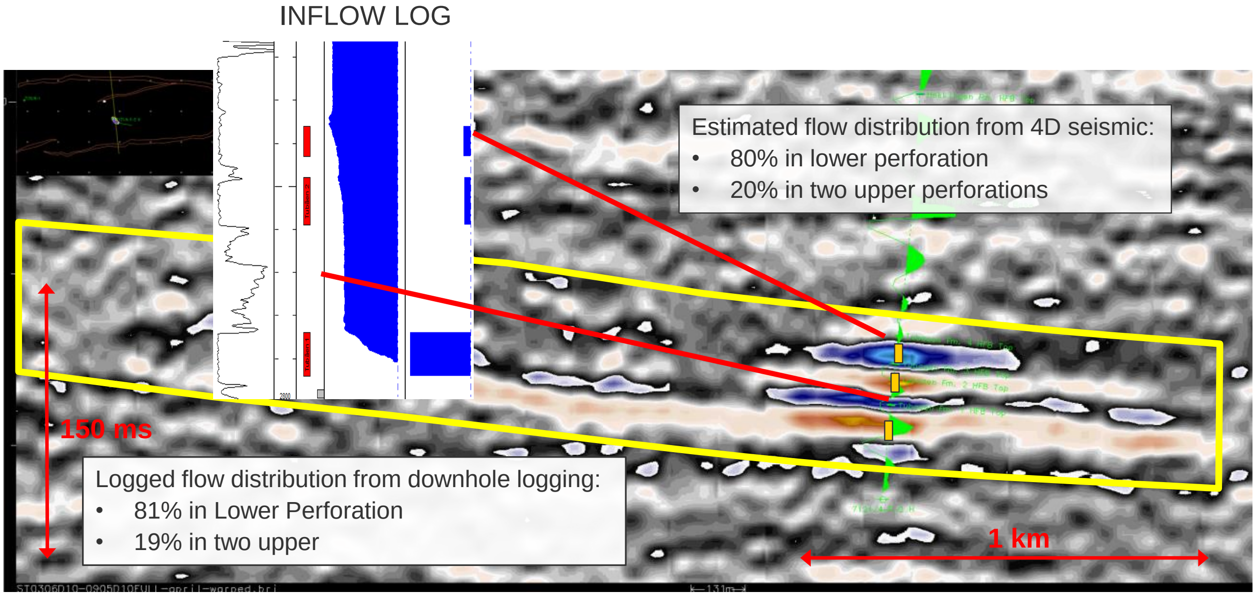

Figure 7-7 Comparison of downhole flow logging at the Snøhvit CO_2 storage site with flow distribution estimate from time-lapse (4D) seismic (yellow box indicates the Tubåen storage unit).

7.2.4 Shallow-seismic monitoring

Various technologies currently exist for investigating the shallow sub-seabed, the sediment-water interface and overlying water column. These include shallow seismic methods, acoustic methods (swath bathymetry, sonar), coring, underwater imagery, and chemical sampling. Near-seafloor monitoring techniques are undergoing rapid development and are now being applied to CO_2 storage issues; including establishing baseline datasets, understanding spatial and temporal sampling requirements, and improving detection thresholds. Figure 7-8 illustrates the various methods available for addressing monitoring, risk assessment and site selection issues. Here we will first review shallow seismic monitoring methods and then passive seismic and seabed monitoring in the following sections.

There is a wide range of offshore seismic acquisition and monitoring technologies available for subsurface geologic characterization, which need only minor modification adaptation for CCS. In heavily explored hydrocarbon basins, baseline 3D seismic surveys are widely available, and for other offshore basins new 2D and 3D seismic data can be easily acquired. Newer high resolution 3D (HR3D) seismic technologies [262], [263] (e.g., the P-cable) are especially valuable for characterization of the overburden stratigraphy Figure 7-9. Such acquisition systems have been deployed for the Snøhvit site in the Barents Sea Basin as well as for the potential CO_2 storage site

[262] Planke, S., F.N. Eriksen, C. Berndt, J. Mienert, and D.G. Masson, 2009, P-cable high-resolution 3D seismic, *Oceanography*, 22, 81.

[263] Steeghs, P., Vandeweijer, V.P., Mosher, C.C., Ji, L. and De Kleine, M.P.E., Acquisition and Processing of a High Resolution 3D Seismic Survey – Offshore Netherlands, 77th EAGE Conference and Exhibition, 2015

P18, offshore the Netherlands. When integrated with deeper regional conventional 3D seismic data and petroleum exploration data, HR3D becomes a valuable tool for characterizing regional seals and mapping faults that may extend vertically from hydrocarbon and CO_2 storage reservoir depths through confining systems.

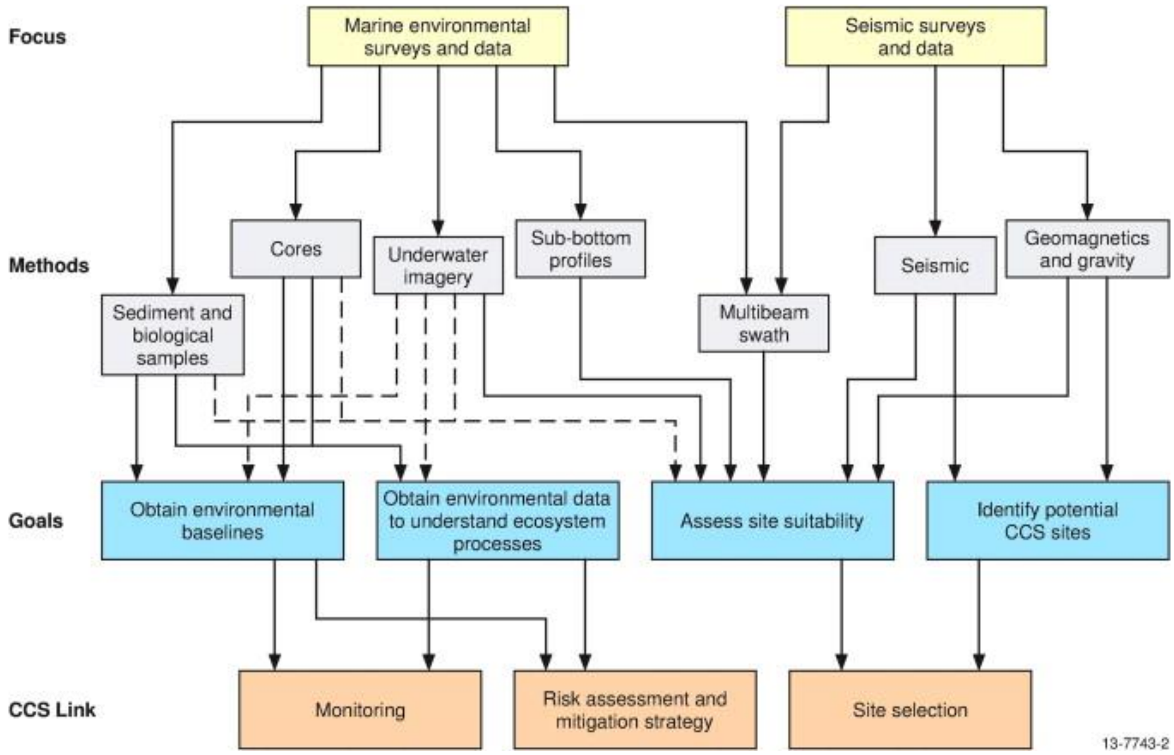

Figure 7-8 Diagram showing the roles of environmental (seabed and shallow sub-seabed) and deep geological (seismic) data to sub-seabed storage of CO_2. Solid lines indicate likely relationships, and dashed lines indicate potential relationships. [264]

From 2012 to 2014, three HR3D surveys have been conducted on the inner shelf (<10 miles) offshore Texas in the Gulf of Mexico as part of a project to characterize CO_2 storage potential. During 2014 another type of HR3D survey was executed just offshore the Netherlands in the vicinity of the P18 gas field, a potential CO_2 storage location for the ROAD project. These surveys have identified gas migration pathways and shallow re-accumulations, providing insight into CO_2 storage and long-term fate of buoyant mobile phases. HR3D data can identify stratigraphy and faults in the overburden in unprecedented resolution (well below conventional seismic resolution (Figure 7-9), and provide crucial information for proving up storage prospects (seal continuity and potential migration pathways). Observations from these surveys indicate the value of HR3D data for discriminating between favorable and unfavorable storage settings with

[264] Carroll, A.G., P. Przeslawski, L.C. Radke, J.R. Black, K. Picard, J.W. Moreau, R.R. Haese, and S. Nichol, 2014, Environmental considerations for sub-seabed geological storage of CO_2: A review, Continental Shelf Research, 83: 116-128.

respect to long-term containment, as well as potential for time-lapse monitoring for leakage from engineered injections.

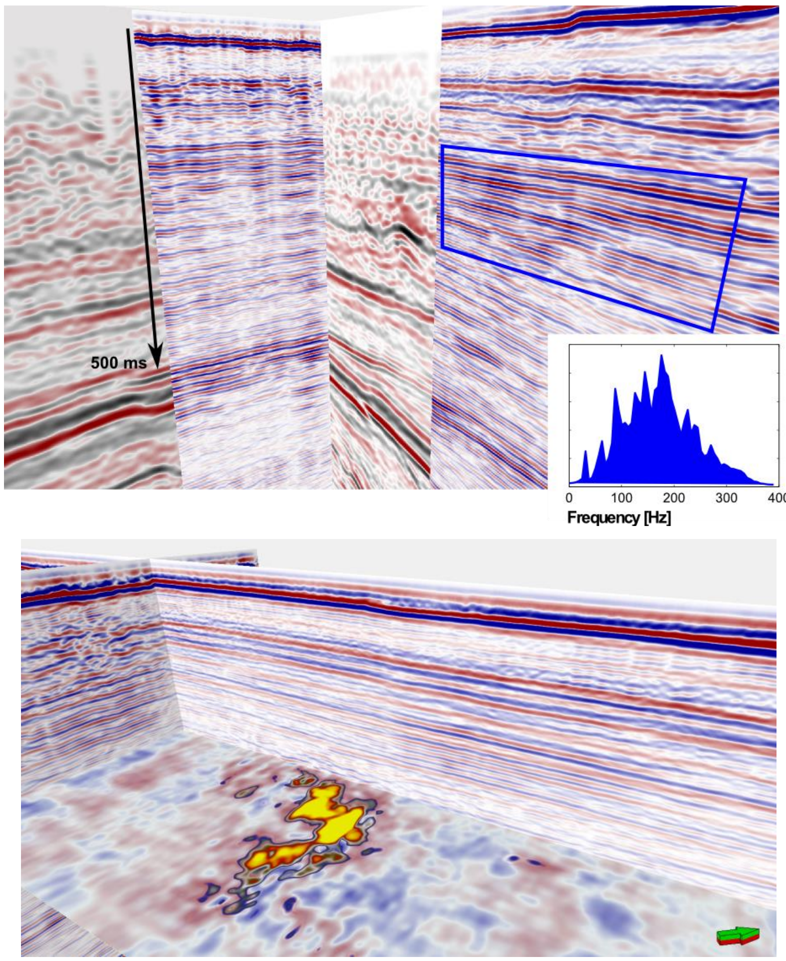

Figure 7-9 (Top) Comparison of data from a conventional seismic survey with HR3D data. Conventional data has poor shallow coverage and resolution. (Below) shallow gas pocket delineated in HR3D survey near the ROAD project's candidate storage location.

7.2.5 Passive and induced seismic monitoring

One particular concern for CO_2 storage security is the potential risk of induced seismicity.[265,266] A major technical challenge is that induced seismicity needs to be differentiated from a background of natural seismicity. In general, land-based seismic monitoring networks are much better

[265] Zoback, M.D., Gorelick, S.M., 2012. Earthquake triggering and large-scale geologicstorage of carbon dioxide. PNAS 109, E3624–E3624.

[266] Verdon, J.P., 2014. Significance for secure CO_2 storage of earthquakes induced by fluid injection. Env. Rev. Lett 9, 064022.

developed than offshore networks, such that the starting point for understanding background seismicity is generally poor.

Seismic events offshore can be monitored by seismographs such as OBS. Offshore reservoir monitoring tools such as OBCs and ocean bottom nodes (OBN) can also be used for event hypocenter determination of microseismic events around a reservoir zone or storage unit. The combination of OBS and OBC/OBN monitoring should be useful for distinguishing induced seismic events from natural events, but is currently an emerging technology and will be demonstrated in the Japanese Tomakomai Project (Figure 7-10), where CO_2 injection is planned for 3 years, starting in 2016. Some onshore CO_2 storage sites, including Weyburn,[267] In Salah[268,269] and Decatur[270] have successfully tested microseismic monitoring for CO_2 storage revealing the potential for using the approach to monitor microseismicity associated with CO_2 injection. A key issue emerging from these studies is that detected events are generally controlled by pressure and stress changes and only indirectly associated with CO_2 injection. Development of high quality velocity and geomechanical models is therefore essential for successful application of this technology.

[267] Verdon, J. P., Kendall, J. M., White, D. J., and Angus, D. A. (2011). Linking microseismic event observations with geomechanical models to minimise the risks of storing CO_2 in geological formations. Earth and Planetary Science Letters, 305(1), 143-152.

[268] Oye, V., Aker, E., Daley, T. M., Kühn, D., Bohloli, B., and Korneev, V. (2013). Microseismic monitoring and interpretation of injection data from the In Salah CO_2 storage site (Krechba), Algeria. Energy Procedia, 37, 4191-4198.

[269] Stork, A.L., Verdon, P.J., Kendall, J.-M., 2015. The microseismic response at the In Salah Carbon Capture and Storage (CCS) site. Int. J. Greehouse Gas Control 32, 159–171.

[270] Couëslan, M. L., Smith, V., El-Kaseeh, G., Gilbert, J., Preece, N., Zhang, L., and Gulati, J., 2014. Development and implementation of a seismic characterization and CO_2 monitoring program for the Illinois Basin–Decatur Project. Greenhouse Gases: Science and Technology, 4(5), 626-644.

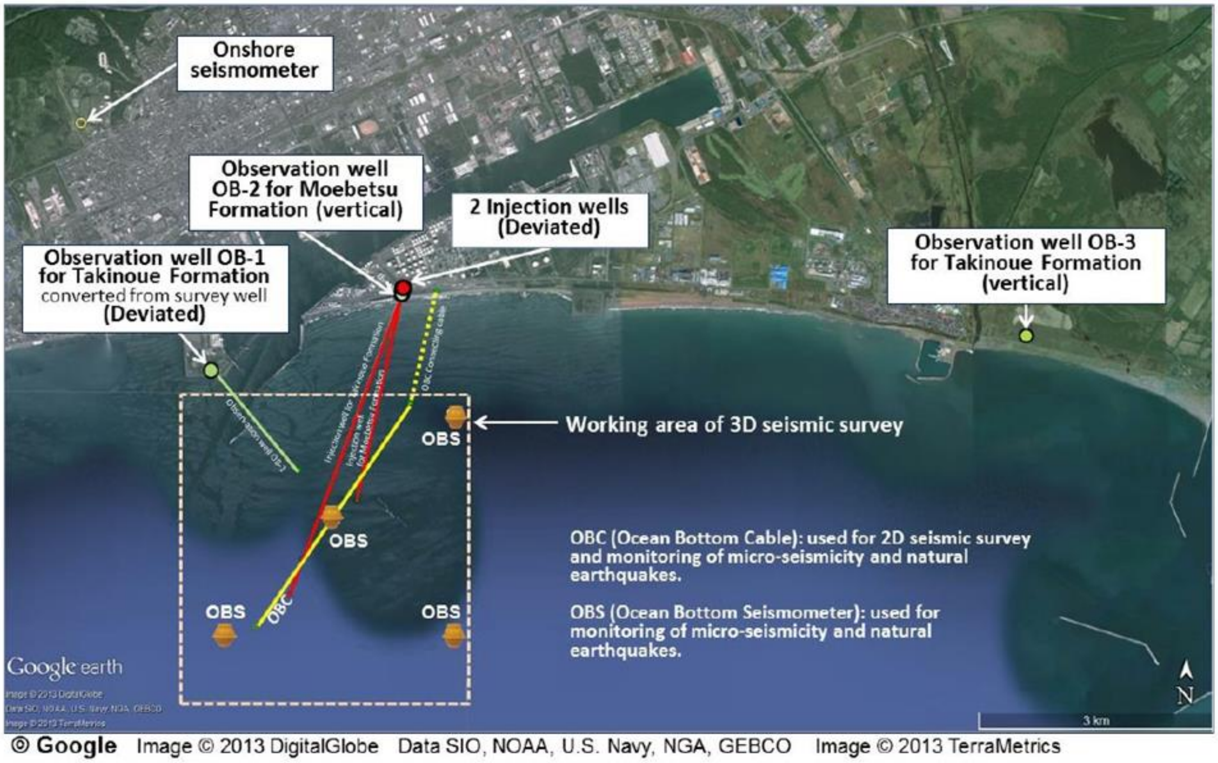

Figure 7-10 Layout of the monitoring facilities at the Tomakomai CCS Demonstration Project.

7.2.6 Marine and seabed monitoring

A number of studies have looked at natural leakage of CO_2 from the seabed[271] as an analogue for understanding possible leakage of CO_2 into the marine environment, while others have conducted controlled release experiments in the shallow marine environment.[272,273] In both cases the objective has been to understand how CO_2 leakage to the seabed might be detected and what the potential impacts could be to the marine environment.

An important research site is the QICS artificial CO_2 test injection experiment in Ardmucknish Bay off the west coast of Scotland. CO_2 was released beneath 11m of sediment over a period of 37 days. Although bubbles occurred soon after injection, CO_2 was retained within sediments and trapped in pore waters. The QICS experiment also clearly revealed the influence of cyclical hydrostatic pressure induced by tides. By using dispersed transponders it is possible to detect the location of bubble streams by triangulation. Although the system allows continuous measurement

[271] Pearce, J. M. (2006). What can we learn from natural analogues?; Advances in the geological storage of carbon dioxide (pp. 127-139). Springer Netherlands.

[272] Tait, K., Stahl, H., Taylor, P., and Widdicombe, S., 2014. Rapid response of the active microbial community to CO_2 exposure from a controlled sub-seabed CO_2 leak in Ardmucknish Bay (Oban, Scotland). International Journal of Greenhouse Gas Control, doi:10.1016/j.ijggc.2014.11.021

[273] Kita, J., Stahl, H., Hayashi, M., Green, T., Watanabe, Y., and Widdicombe, S., 2014. Benthic megafauna and CO_2 bubble dynamics observed by underwater photography during a controlled sub-seabed release of CO_2. International Journal of Greenhouse Gas Control. doi:10.1016/j.ijggc.2014.11.012

it is susceptible to biofouling, suspended sediment and trawler damage. One of the main challenges encountered with passive acoustic measurements is the extent of background noise from artificial and natural sources which can mask a specific acoustic signal.

The controlled release experiments conducted by the QICS research project demonstrate that leaks of CO_2 gas can be detected by monitoring acoustic, geochemical and biological parameters within a given marine system. However the natural complexity and variability of marine system responses to (artificial) leakage strongly suggests that there are no absolute indicators of leakage or impacts that can unequivocally and universally be used for all potential future storage sites. These studies suggest that a multivariate, hierarchical approach to monitoring is needed, escalating from anomaly detection to attribution, quantification and then impact assessment, as required. Proposed optimal spatial and temporal criteria for baseline surveys relating to each category of monitoring approach are detailed in Table 7-3. The particular choice of approaches will have some site specificity. QICS suggested that acoustic and geochemical methods will be the primary detection methodologies and therefore identify the most pressing aspects of baseline generation. Given the spatial heterogeneity of many marine ecosystems it is essential that environmental monitoring programs are supported by a temporally (tidal, seasonal and annual) and spatially resolved baseline of data from which changes can be accurately identified.

Table 7-3: Optimal spatial and temporal criteria for baseline surveys relating to each category of monitoring approaches suggested from QICS controlled release experiment

Methodology	Variables	Temporal sampling interval	Spatial sampling scale	Notes
Active acoustics	Seafloor bathymetry, including pockmarks.	In shallow waters where the seafloor sediments are exposed to storm-driven resuspension and biological sedimentation a seasonal discrimination, in the first instance. In deeper waters where sediments are disconnected from weather driven events an initial survey, followed by a repeat survey 1–2 years later.	The spatial extent of the storage reservoir in addition to allowing for lateral movement of migrating CO_2.	Assists identification of existent natural seeps.
	Free gas in surface sediments and water column.	An initial survey, followed by a repeat survey 1–2 years later.		Useful for attribution.
Passive acoustics	All noise at relevant frequencies.	Seasonal in addition to targeted short-term deployments to assess event driven noise.	Targeted to known fixed installations or shipping routes.	Necessary for quantification, not essential for detection.
	Acoustics of existent natural gas seeps.	Seasonal and targeted short term deployments to account for intermittent gas flow.	Spatial extent of the storage reservoir as well as allowing for lateral	Required for detection.

Methodology	Variables	Temporal sampling interval	Spatial sampling scale	Notes
			movement of migrating CO_2.	
Geochemistry	Water column pH, pCO_2, temperature, salinity, pressure. TA or DIC and O_2 if possible.	Hourly measurements for at least part of the seasonal cycle, corresponding with periods of biological or physical activity. Weekly for entire annual cycle. Repeated for at least one subsequent year to assess inter-annual variability and then on an approximately decadal repeat to assess longer term trends.	For high frequency data, if the storage site is large or includes significant changes in water depth or other hydrodynamic properties, at least a pair of landers deployed across the site. Spatial extent of the storage site via AUV deployment.	Required for detection.
	Isotope composition ratios: e.g., C^{13}:C^{12}	Occasional (not dynamic)	Occasional (not dynamic)	Addresses attribution
Biology	Community structure, indicator species and related indices.	Weekly during periods of intense biological activity, otherwise monthly. Repeated for at least one subsequent year to assess inter-annual variability and then on an approximately decadal repeat to assess longer term trends.	Significant differences in water depth and-or different sediment types within the complex would need separate characterization. Multiple replicates are required for statistical certainty.	Principally for impact assessment.

Natural CO_2 seepage sites are prevalent in several areas around the world and especially in geothermally active areas. The hydrothermally driven seeps off the island of Panarea in the Aeolian Islands are a good example. Observations near these seeps show that the local biology has adapted to the presence of these seeps, but this adaptation is in distinct contrast to conditions in colder, deeper and more turbid sites. The Hugin Fracture is another example of a natural seepage, in this case in the central North Sea. Here, a 3 km long seabed structure is covered by soft sediments with wide patches of methanotrophic bacteria which metabolize methane from a natural seep. There is no evidence of CO_2 at this location.

The use of high-resolution seismic reflection using chirp and boomer technology is a valuable technology for near-surface monitoring, and proved highly effective during the QICS experiment. The technique produced clear images of gaseous CO_2 trapped in sediments above the release point (Figure 7-11).

The experience being gained from experimental and natural seepage sites highlights some key issues that affect offshore monitoring programs. Monitoring strategies need to be devised to cover large areas, typically tens to hundreds of km^2 and yet also achieve accurate measurement and

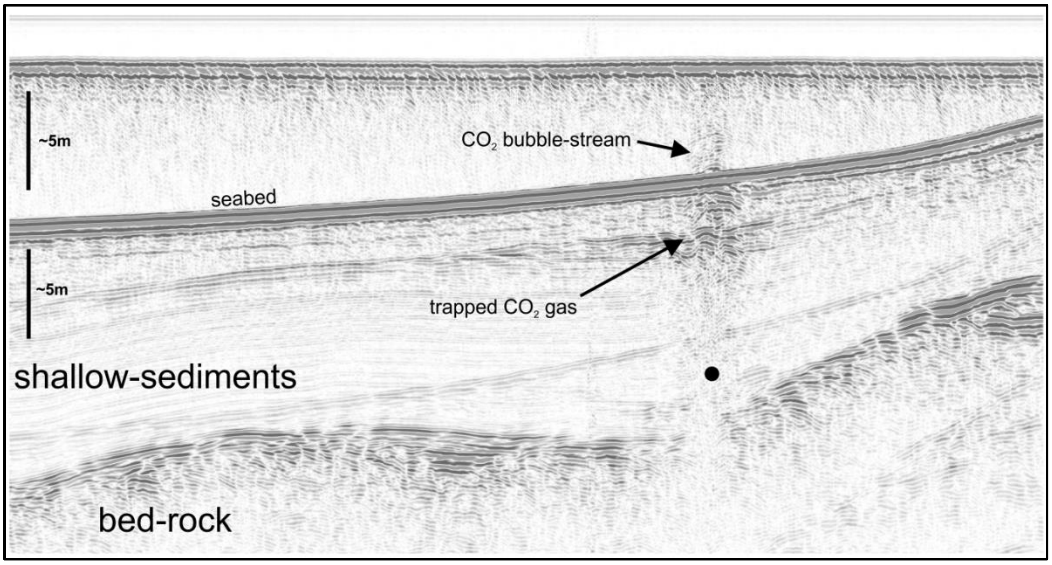

Figure 7-11 Seismic profile at the QICS site showing gaseous CO_2 trapped in shallow sediments and a bubble stream above the release point.

characterization over sufficiently long periods in order to understand temporal fluctuations. Limited spatial coverage could increase the risk that anomalies remain undetected. Monitoring data should be used to build a robust baseline but data interpretation can be used to improve the knowledge of storage sites and where anomalies could occur. A combination of point sampling and large spatial surveys should help to improve the quality of monitoring. Search areas could be narrowed down by the integration of information from deeper-focused monitoring such as 3D seismic, which can identify migration pathways, with shallow surface monitoring such as acoustic detection.

Seasonal variability, seawater chemistry variability and other features such as the presence of shallow gas (CH_4, CO_2, H_2S) in marine sediments need to be considered in any monitoring program. Other factors such as seabed recycling and sediment transport and anthropogenic activities such as trawling also need to be taken into account.

7.3 Technical challenges and technology gaps

7.3.1 Importance of data integration

Based on the recent record of monitoring technology development, we can expect further steady progress with novel monitoring approaches, improved detection and resolution, and more cost-effective survey methods. Despite these improvements, it is important to emphasize that measurement of CO_2 in the subsurface will always carry inherent uncertainties. Detection of changes in fluid saturation or pressure must always be compared to a background signal. This is clearly the case with time-lapse seismic monitoring of CO_2 plumes, where the “fluid signal” needs to be differentiated from the “rock signal”, but it is also the case apparently more direct downhole measurements. The successful track record of CO_2 storage monitoring at Sleipner and Snøhvit, clearly illustrates the importance of using multiple datasets (e.g., seismic, gravity and well data) in order to understand the nature of the monitoring data being interpreted.

Furthermore, it is increasing clear that CO_2 storage modeling and monitoring activities have to function in an iterative loop, with improved monitor data used to refine models[274] and improved model understanding used to improve the accuracy of monitoring data.[275,276] Using this experience from the early offshore CCS demonstration projects, we can develop realistic expectations on what can be detected from monitoring data, and use this insights to guide the implementation of the appropriate monitoring regulations.

7.3.2 Challenges for monitoring

This need for data integration and realistic expectations from monitoring data gives a good framework for understanding the main challenges for MMV, which can be summarized as follows:

1. Understanding the requirements for baseline datasets versus monitoring surveys: Technology evolves with time, and baseline datasets will typically have less advanced content than the latest survey data.
2. Marine and seabed surveys need to assess the range of natural variation, spatially and temporally, in order to establish a reference for detection of possible anomalies.
3. CO_2 storage monitoring requires some knowledge of the whole storage complex, including the overburden sequence and a fairly large volume around the storage site, leading to the question of how much data is really needed and over what volume?
4. Rock strain and the geomechanical response to CO_2 injection is relatively poorly understood and so the basis for differentiating natural (passive) seismicity from induced seismicity is challenging.
5. The interests of different stakeholders (e.g., the public, the regulator, the site operator) leads to challenging demands on the monitoring datasets, which will always have some inherent uncertainties.

7.3.3 Emerging technology

Many new and improved monitoring technologies have emerged in the last decade, and these are being tested and applied at the several industrial and pilot-scale CO_2 storage projects currently in operation. We can expect this trend to continue. It is useful to highlight some of these

[274] Cavanagh, A. 2013. Benchmark calibration and prediction of the Sleipner CO_2 plume from 2006 to 2012. *Energy Procedia*, 37, 3529-3545.

[275] Furre, A. K., and Eiken, O. 2014. Dual sensor streamer technology used in Sleipner CO_2 injection monitoring. *Geophysical Prospecting*, 62(5), 1075-1088.

[276] Furre, A. K., Kiær, A., and Eiken, O. 2015. CO_2-induced seismic time shifts at Sleipner. *Interpretation*, 3(3), SS23-SS35.

developments as a pointer to what technology might emerge in the near future. These technologies include:

1. Improved time-lapse seismic imaging using steerable streamer technology and broadband seismic technology;
2. Improvements in the accuracy of time-lapse gravimetric monitoring to resolve density changes;
3. Use of high-resolution 3D seismic technologies (e.g., P-cable) to obtain improved imaging of overburden sequences;
4. Use of high-resolution seismic reflection chirp and boomer technology for near-surface marine monitoring;
5. Use of OBS and OBC and OBN to monitor natural and induced seismic events;
6. Use of fiber optic cables for downhole monitoring, including systems with permanent quartz gauges, DTS systems and DAS systems.
7. Interpretation of tracers co-injected the with the CO_2 stream to monitor breakthrough times and concentrations;
8. A range of improved acoustic techniques (e.g., multibeam echosounders) for monitoring the seabed, including detection of gas fluxes.

7.4 Summary and Recommendations

1. Monitoring technology for offshore CO_2 storage can be considered as mature, with many emerging technologies potentially bringing higher quality surveillance at an acceptable cost level.
2. The long history of monitoring at the Sleipner and Snøhvit sites in Norway and the pilot-scale K12-B site in the Netherlands, can be used to demonstrate the value of several key technologies, including 4D seismic, gravity-field monitoring, downhole gauges, and the use of tracers, alongside routine wellhead monitoring.
3. The portfolio of monitoring techniques available for CO_2 geological storage offshore can be classed in terms of deep-focused (providing surveillance of the reservoir and deeper overburden) and shallow-focused (providing surveillance of the near seabed, seabed and water-column).
4. Deep-focused operational monitoring systems are dominated by the use of 3D seismic surveys which have been highly effective for tracking CO_2 plume development in Sleipner and Snøhvit reservoirs. Measurement of downhole pressure is also highly valuable, and the availability of reliable down-hole gauges and fiber-optic systems indicates that this will be important technology for the future.
5. Shallow-focused monitoring systems are less mature but are currently being developed and demonstrated. New marine sensor and existing underwater platform technology such as

AUVs and mini-ROVs enable deployment and observation over large areas at potentially relatively low cost. Seafloor and ocean monitoring technologies can detect dissolved phase CO_2, precursor fluids (using chemical analysis) and gas phase CO_2.

6. Developments in geophysical techniques (such as the P-Cable seismic system for higher resolution 3D data collection in the overburden) have shown that successful and effective integration of these shallow subsurface technologies with the seabed monitoring data can help to understand shallow migration processes.
7. Assessment of the results from both the operational (predominantly deep-focused) and research (predominantly shallow-focused) monitoring activities from Sleipner and Snøhvit indicates that many elements of the European storage requirements have been met at these large-scale sites which were both initiated before the CCS Directive was introduced.
8. There are currently several emerging offshore CO_2 storage projects, such as the Tomakomai in Japan, ROAD in the Netherlands and Peterhead-Goldeneye offshore Scotland, which are designing and adopting state-of-the art monitoring strategies for offshore storage.

It is important to maintain the momentum in technology development for monitoring of offshore CO_2 storage, especially via data and experience exchange, along with focused international knowledge-sharing workshops.

8 Summary of regulatory requirements for offshore storage

8.1 Introduction

There have been significant developments in the regulation of CO_2 geological storage offshore. This section will describe the main developments, starting with the international coverage of the London Convention, the regional coverage of OSPAR for the EU and North East Atlantic, the regulation implemented by Japan, and the regulatory situation in the United States. These have created an enabling regulatory situation for CCS offshore whilst ensuring the protection of the marine environment and other resources.

From 2004 to 2007, a considerable amount of both legal and technical work on the storage of CO_2 in sub-seabed geological formations was developed under the London Convention and its 1996 Protocol and the OSPAR Convention. The technical and legal work included consideration of the risks and benefits to the marine environment within the context of increasing atmospheric CO_2 absorption by the oceans. The conclusion of this work was that the Conventions should move to remove their prohibitions that applied to certain CO_2 geological storage project configurations, so as to facilitate and to regulate environmentally safe CO_2 geological storage. In timescales faster than most anticipated, the London Protocol was amended in November 2006 and OSPAR was amended in June 2007. The actual amendments include various provisions, conditions and restrictions so as to only allow environmentally sound CO_2 storage. In this process, three detailed guidelines were produced for risk assessment and management of CO_2 storage. Much of the material below is taken from Dixon (2009 and 2015).[277,278]

8.2 International Regulatory Requirements (Existing and Proposed)

8.2.1 London Protocol

The London Convention (1972)[279] and the London Protocol (1996)[280] are the global agreements regulating dumping of wastes at sea, with the intention of protection of the marine environment. The Convention consists of 87 countries, and the Protocol 45 countries (as of November 2014). The Protocol is an updated and more rigorous version of the Convention. The secretariat of the London Convention and the London Protocol is provided by the IMO. The London Protocol was ratified by sufficient countries so as to come into force in March 2006, and is intended to replace the Convention in time. The Protocol prohibits dumping of wastes or other matter except those specified in its Annex 1, and these require permitting and regulation. Examples of wastes or other

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[277] Dixon T, Greaves A, Thomson J, Christophersen O, Vivian C. International Marine Regulation of CO_2 Geological Storage. Developments and Implications of London and OSPAR. GHGT-9. Energy Procedia 1 (2009) 4503-4510.

[278] Dixon T, Garrett J, Kleverlaan E.2015. Update on the London Protocol – Developments on Transboundary CCS and on Geoengineering. *Energy Procedia, Volume 63, 2014, Pages 6623-6628 (Jan 2015)*

[279] London Convention 1972. Convention on the Prevention of Marine Pollution by Dumping of Wastes and other Matter (London Convention 1972).

[280] Protocol to the London Convention 1996. Convention on the Prevention of Marine Pollution by Dumping of Wastes and other Matter – protocol thereto.

matter which may be dumped include dredged material, fish waste and inert geological material. However, it appeared that the Protocol, because it included the sub-seabed in its scope, could prohibit CO_2 geological storage in several CCS project scenarios including CO_2 from an onshore source to an offshore platform for injection into a sub-seabed geological formation.

An amendment to the Protocol to the London Convention was proposed in April 2006 by Australia and supported by UK, Norway, France and Spain. This was voted on and agreed in November 2006 and came into force on 10 February 2007. All of this was in timescales far faster than most anticipated, due to the newly recognized impacts of atmospheric CO_2 upon the oceans with ocean acidification. The key elements of this amendment are as follows: added to the list of substances that can be dumped is:

"CO_2 streams from CO_2 capture processes for sequestration"

With the important caveats that*:*

"Carbon dioxide streams may only be considered for dumping, if:

1 disposal is into a sub-seabed geological formation; and

2 they consist overwhelmingly of carbon dioxide. They may contain incidental associated substances derived from the source material and the capture and sequestration processes used; and

3 no wastes or other matter are added for the purpose of disposing of those wastes or other matter." (IMO 2006a)[281]

This meant that the geological storage of CO_2 had its prohibition uncertainty removed, so long as it is geological storage, and the CO_2 can contain impurities but this cannot be used as route for dumping other wastes.

In addition, the Scientific Group for the Convention and the Protocol produced two sets of detailed guidelines on geological storage of CO_2 in the marine environment. For risk assessment and management of such activities, they produced the Risk Assessment and Management Framework for CO_2 Sequestration in Sub-seabed Geological Structure (known as the RAMF) (IMO 2006b),[282] which also helped them understand the processes and risks better themselves. They then produced Specific Guidelines for Assessment of CO_2 Streams for Disposal into Sub-seabed Geological Formation (known as the CO_2 Specific Guidelines or sometimes as the CO_2 Waste Assessment Guidelines—WAG) (IMO 2007).[283] Both these guidelines provide an environmental impact assessment process, with factors to be considered specifically for CO_2 storage activities. These

[281] IMO 2006a. International Maritime Organisation. Report of The 28th Consultative Meeting And The First Meeting Of Contracting Parties. LC 28/15. 6 December 2006. Annex 6.

[282] IMO 2006b. International Maritime Organisation. Report of The Meeting Of The SG Intersessional Technical Working Group On CO_2 Sequestration. LC/SG-CO2 1/7. 3 May 2006. Annex 3

[283] IMO 2007. International Maritime Organisation. Report of the 30th Meeting of the Scientific Group of the London Convention. LC/SG 30/14. 25 July 2007. Annex 3

guidelines drew upon the best available knowledge from scientific experts and guidance from IPCC sources, including the IPCC Special Report (IPCC 2005)[284] and the IPCC Guidelines for GHG Inventories (IPCC 2006).[285]

The basic structure of the RAMF guidelines is as follows, with a brief summary of the content:

1. ***Problem Formulation****—scope, scenarios, boundaries*

2. ***Site characterization****—capacity, integrity, leakage pathways, monitoring options, surrounding area, modelling of CO_2 behavior*

3. ***Exposure assessment****—properties of CO_2 stream, exposure processes and pathways, likelihood, scale*

4. ***Effects assessment****—consequences - sensitivity of species, communities, habitats, other users*

5. ***Risk characterization****—integrates exposure and effects - environmental impact, likelihood*

6. ***Risk management****—leak prevention, monitoring of CO_2 streams within and above formations—linked to performance monitoring and migration detection, and monitoring seafloor, water and biological if leakage is suspected - mitigation*

Regarding monitoring, the RAMF guidelines draw upon the information contained in the IPCC guidelines (2006).[286] It places monitoring techniques into two categories - those for measuring performance within the geology, and those for monitoring when leakage is suspected. The latter are more detailed and also can measure impacts, and include monitoring of sea water chemistry and ecological effects. Emphasis is made that the monitoring activities have to be revised in the light of monitoring results, and following the IPCC GHG guidelines (IPCC 2006),[286] the frequency of monitoring can be reduced as confidence grows in the security of storage. Also following the IPCC guidelines, the RAMF recognizes that each storage site will be different and so site characterization and risk assessments should be on a site-by-site basis. Overall, the primary focus of the RAMF is on geological storage in depleted hydrocarbon reservoirs and saline aquifers. They explicitly do not cover coal beds, basalts and salt caverns. Also they recognize that storage in geological formations under deeper waters, e.g., 500m, would require revised guidelines.

The CO_2 Specific Guidelines (IMO 2007)[284] are the transposition and refinement of the RAMF into the standard structure of London Convention waste assessment guidelines to assist regulators in their permit decisions. These require an 'impact hypothesis' to be produced as a statement of the expected consequences of disposal. The basic structure of the Specific Guidelines is as follows, with a summary of the content:

1. ***Introduction—****purpose and scope*

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[284] IPCC 2005. Carbon Dioxide Capture and Storage. Cambridge University Press

[285] IPCC 2006. Guidelines for National Greenhouse Gas Inventories. Vol 2 Energy, Chapter 5, Carbon Dioxide Transport, Injection and Geological Storage. Published: IGES, Japan IPCC.

*2. **Waste Prevention Audit**—not directly pertinent to CCS*

*3. **Consideration of Waste Management Options**—not directly pertinent to CCS*

*4. **Chemical and Physical Properties**—characterization of the CO_2 stream*

*5. **Action list**—screening for acceptability of substances to be disposed, in this case the CO_2 stream including impurities.*

*6. **Site selection and Characterization**—both of the storage formation and of the marine area, drawing upon the IPCC SR, including evaluation of potential exposure to CO_2 and other substances mobilized by the CO_2, identification of leakage pathways and probabilities, modelling of the CO_2 behavior.*

*7. **Assessment of potential effects**—bringing all the above together into a risk assessment and producing an impact hypothesis.*

*8. **Monitoring and risk management**—to verify the site management and that permit conditions are being met, a detailed monitoring program defined from the results of the impact hypothesis, including a mitigation plan in the event of leakage.*

*9. **Permit and permit conditions**—the information required for and in a permit.*

Refinements added to the CO_2 Specific Guidelines included a further definition of the CO_2 stream which clarifies that substances can be added to assist CCS. "*the CO_2 stream, consisting of: .1 CO_2; .2 incidental associated substances derived from the source material and the capture and sequestration processes used: .1 source- and process-derived substances; and .2 added substances (i.e., substances added to the CO_2 stream to enable or improve the capture and sequestration processes)"* [IMO 2007, section 1.3].[284]

On CO_2 stream purity, the Scientific Group concluded that, rather than stipulating a generic standard for stream purity, given that the overall requirement is for environmental safety the levels of these impurities should be related to potential impacts on the integrity of storage and transport, and assessed on a case-by-case basis recognizing the natural variation in storage site characteristics (as in IPCC (2005)[285] and IPCC guidelines (2006)[286]) and different transport constructions. This principle is described in the Specific Guidelines (IMO 2007)[284] and is why the general phrase "*consist overwhelmingly of carbon dioxide"* is used in the legal amendment.

The Specific Guidelines provide guidance on permitting and permit contents. A key requirement identified is that permits (and permit applications) should contain information on the CO_2 stream composition, and a risk management plan which has itself to include: a monitoring plan (operational and long term) and reporting requirements; a mitigation and remediation plan (for in the event of leakage): and a site closure plan with post-closure monitoring (IMO 2007 section 9.1).[284] Permits should be reviewed at regular intervals and should take into account any changes identified from the monitoring and updated risk assessments.

8.2.1.1 Transboundary Issues under the London Protocol

The main issue for CCS at the London Protocol since the 2006 amendment is the topic of transboundary export of CO_2 for sub-seabed geological storage. The London Protocol Article 6 prohibits exports of wastes for dumping in the marine environment.

ARTICLE 6. EXPORT OF WASTES OR OTHER MATTER.

"Contracting Parties shall not allow the export of wastes or other matter to other countries for dumping or incineration at sea." (London Protocol 1996)[280]

This is intended to stop Parties exporting their waste to non-Parties so as to get around the London Protocol controls. However, this prohibits transboundary transport, i.e., export, of CO_2 for sub-seabed geological storage. There may well be a need for such export in the situations where a Party does not have sufficient suitable geological storage capacity but they still wish to use CCS to reduce emissions. In the 4th meeting of contracting parties to the Protocol (LP4) in October 2009 an amendment was adopted to remove this restriction (IMO 2009 resolution LP.3(4)).[286] The amendment requires that an agreement or arrangement has been entered into by countries concerned, which should include permitting responsibilities and, for export to non-parties, equivalent provisions as those required of Protocol Parties.

AMENDMENT TO ARTICLE 6 OF THE LONDON PROTOCOL

"2 Notwithstanding paragraph 1, the export of carbon dioxide streams for disposal in accordance with Annex 1 may occur, provided that an agreement or arrangement has been entered into by the countries concerned. Such an agreement or arrangement shall include:

2.1 confirmation and allocation of permitting responsibilities between the exporting and receiving countries, consistent with the provisions of this Protocol and other applicable international law; and

2.2 in the case of export to non-Contracting Parties, provisions at a minimum equivalent to those contained in this Protocol, including those relating to the issuance of permits and permit conditions for complying with the provisions of annex 2, to ensure that the agreement or arrangement does not derogate from the obligations of Contracting Parties under this Protocol to protect and preserve the marine environment.

A Contracting Party entering into such an agreement or arrangement shall notify it to the Organization." (IMO 2009)[286]

Work commenced to revise the CO_2 Specific Guidelines for the assessment of carbon dioxide streams for disposal into sub-seabed geological formations to take into account transboundary activities (export and migration). Through this work, it was decided that sub-seabed migration across national boundaries does not constitute export, and so was not prohibited by Article 6, but

[286] IMO 2009. On the Amendment of Article 6 of the London Protocol [CO_2 export amendment]. Resolution LP.3(4). 2009

was not covered by the CO_2 Specific Guidelines. The revised CO_2 Specific Guidelines were finalized and adopted on 2 November 2012 (IMO 2012 annex 8).[287]

The other transboundary aspect to be resolved is the development of guidance to determine the responsibilities of Parties in the case of export of CO_2, in particular if exported to a country that is not a party to the London Protocol. A new document "Guidance on the Implementation of Article 6.2 on the Export of CO_2 Streams for Disposal in Sub-seabed Geological Formations for the purpose of Sequestration" was produced (IMO 2013).[288] This sets out the responsibilities of Parties and the requirements of the agreements and arrangements which must be entered into by Parties who wish to undertake export of CO_2, including if to non-Parties, so as to ensure that the standard of requirements of the London Protocol on permitting CO_2 geological storage are maintained. In the case of a breach of an agreement or arrangement by a non-Contracting Party, the Contracting Party should "*engage in consultations to rectify*". In the case of a "*significant ongoing breach*" the Contracting Party is required to terminate the export (IMO 2013).[288] This new Guidance was adopted at the Annual Meeting on 18 October 2013, for use when the export amendment comes into force.

However there is one significant remaining transboundary aspect to be resolved. The export amendment adopted in 2009 to allow export of CO_2 for geological storage requires two thirds of Parties to ratify before it comes into force. This currently means 30 countries need to ratify it. To date just two have: Norway and UK. Emphasis and concern on the rate of this ratification was expressed by Mr. Koji Sekimizu, the IMO Secretary-General in his opening speech to the 2013 annual meeting of the London Convention and London Protocol (held at the International Maritime Organization in London from 14-18 October 2013 (LC35 and LP8).

"*The London Protocol currently is also the only global framework to regulate carbon capture and sequestration in sub-seabed geologic formations… …. However, it remains a serious concern that, to date, only two of the 43 London Protocol Parties have accepted the 2009 amendment, which is a long way from satisfying the entry-into-force requirements. The importance of securing its entry-into-force cannot be over-emphasized, if the threat from acidification of the oceans from climate change is to be minimized.*"[289]

It is understood by the authors' informal enquiries that just five further countries are working on their ratification at the moment, so at this rate it will take many years to come into force, and in the meantime London Protocol countries cannot export their CO_2 to another country for storage in

[287] IMO 2012 Specific Guidelines for the Assessment of Carbon Dioxide for Disposal into Sub-seabed Geological Formations.LP.7. LC 34/15, Annex 8. 2012 [aka Revised CO_2 Specific Guidelines or Revised CO_2 Sequestration Guidelines]

[288] IMO 2013. Guidance on the Implementation of Article 6.2 on the Export of CO_2 Streams for Disposal in Sub-seabed Geological Formations for the Purpose of Sequestration. LC 35/15 Annex 6. 2013

[289] Sekimizu, K., 2013. Address of the IMO Secretary-General at the opening of the thirty-fifth meeting of Contracting Parties to the London Convention and the eighth meeting of Contracting Parties to the London Protocol, London, 14 October, 2013. http://www.imo.org/en/MediaCentre/SecretaryGeneral/Secretary-GeneralsSpeechesToMeetings/Pages/LC35LP8.aspx

the marine environment. The exception is if the CO_2 is a purpose other than dumping, such as for enhanced oil recovery.

8.2.2 OSPAR

OSPAR (1992)[290] is the convention protecting the marine environment in the North East Atlantic, with 15 nations and the EC as Parties. Similarly to the London Protocol, OSPAR was drafted without CCS in mind. Like the London Protocol, OSPAR specifies what is allowed to be dumped in its Annexes, and is considered more restrictive than the London Protocol. In the light of the work on the London Protocol amendment, in 2006 OSPAR started legal work to consider its own amendment, and started a technical group to assess and refine for OSPAR purposes the London RAMF. This work resulted in guidance called the OSPAR Framework for Risk Assessment and Management of Storage of CO_2 Streams in Geological Formations (known as the FRAM) (OSPAR 2007a).[291]

The structure of the OSPAR FRAM mirrors that of the London RAMF, with the same purpose. The principles established for CCS in London were also repeated in the FRAM. Again, the focus was on geological storage and explicitly not on storage in coal beds, basalts, oil and gas shales, or salt caverns. Refinements included the addition of an 'impact hypothesis' in the risk characterization, providing more information on monitoring requirements, and identification of areas benefiting from further research.

Two amendments were required, for OSPAR's Annex II dealing with dumping and for Annex III dealing with offshore sources. These amendments were proposed in 2007 by Norway and co-sponsored by UK, Netherlands, and France. As well as the FRAM, guidelines were produced on how to use the FRAM, these were the OSPAR Guidelines for Risk Assessment and Management of Storage of CO_2 Streams in Geological Formations (known as the OSPAR Guidelines), which included the FRAM as an integral annex (OSPAR 2007b).[292]

OSPAR was amended in June 2007 by consensus. The legal amendments were similar to London's but with an additional condition:

"CO_2 streams from CO_2 capture processes for storage...provided:

- *Into a sub-soil geological formation*
- *Consist overwhelmingly of CO_2. May contain incidental associated substances derived from the source material and capture and sequestration processes used*

[290] OSPAR (1992). Convention for the Protection of the Marine Environment of the North-East Atlantic. (OSPAR). 1992. More information available at www.ospar.org

[291] OSPAR 2007a. Framework for Risk Assessment and Management of Storage of CO_2 Streams in Geological Formation (FRAM). Annex 7 in OSPAR Guidelines for Risk Assessment and Management of Storage of CO_2 Streams in Geological Formations. Summary Record OSPAR 07/24/1-E Annex 7 (2007).

[292] OSPAR 2007b. Guidelines for Risk Assessment and Management of Storage of CO_2 Streams in Geological Formations. Summary Record OSPAR 07/24/1-E Annex 7 (2007)

• *No wastes or other matter are added for the purpose of disposal*

• *They are intended to be retained permanently and will not lead to significant adverse consequences for the marine environment, human health and other users "(OSPAR 2007c)*[293]

The permanent retention point means that sites with even low enough levels of leakage for climate benefit cannot be used.

At the same time, OSPAR Parties adopted a 'Decision' (a legal decision) to make use of the OSPAR Guidelines obligatory (OSPAR 2007d)[294] when issuing permits for geological storage of CO_2. In the London Protocol, the similar guidelines are for guidance only (though the London Protocol includes more detailed provisions on the issuing of permits within an overarching annex). This OSPAR Decision 2007/2 (OSPAR 2007d)[294] includes permit requirements similar to those in the London Specific Guidelines, but in more detail.

Any permit or approval issued shall contain at least:

1. a description of the operation, including injection rates;

2. the planned types, amounts and sources of the CO_2 streams, including incidental associated substances, to be stored in the geological formation;

3. the location of the injection facility;

4. characteristics of the geological formations

5. the methods of transport of the CO_2 stream;

6. a risk management plan that includes:

i. monitoring and reporting requirements ;

ii. mitigation and remediation options <u>including</u> the pre-closure phases; and

iii. a requirement for a site closure plan, including a description of post-closure monitoring and mitigation and remediation options; monitoring shall continue until there is confirmation that the probability of any future adverse environmental effects has been reduced to an insignificant level. [OSPAR 2007d Section 3.2.6][294]

The point in part 6.iii on monitoring means that monitoring may cease when confidence exists in the security of the CO_2 storage, reflecting the IPCC GHG Guidelines (IPCC 2006). The OSPAR Decision also included the requirement for reporting, including post-closure reports, and a reporting template (OSPAR 2007d Appendix 1).[294]

In addition, at the same meeting, OSPAR adopted another Decision to adopt a German proposal to prohibit ocean storage *"The placement of carbon dioxide streams in the water column or on the*

[293] OSPAR 2007c. Amendments of Annex II and Annex III to the Convention in relation to the Storage of Carbon Dioxide Streams in Geological Formations. Summary Record OSPAR 07/24/1-E Annex 4. (2007)

[294] OSPAR 2007d. OSPAR Decision 2007/2 on the Storage of Carbon Dioxide Streams in Geological Formations. Summary Record OSPAR 07/24/1-E Annex 6. (2007)

seabed is prohibited" (OSPAR 2007e).[295] Thus ruling out ocean storage for OSPAR countries, unless for experimental purposes.

In terms of timescales, the OSPAR Decision to use the OSPAR Guidelines, and the Decision on ocean storage, came into force on 15 January 2008, for all CO_2 geological storage projects in the marine environment except those for enhanced oil recovery or from normal operations or experimental purposes, which fall outside the OSPAR cover. The legal amendments to remove the prohibitions came into force after seven OSPAR Parties ratified them, which was achieved on 23 July 2011.

Note that OSPAR does not have the export prohibition on wastes. Note also that both these marine treaties do not deal with long term liability.

8.3 Examples of Specific National Regulatory Requirements

8.3.1 Japanese regulations

Prior to her ratification of the London Protocol in 2007, Japan amended the Act on Prevention of Marine Pollution and Maritime Disaster to set out a regulatory framework for CO_2 sub-seabed storage in a way of complying with the Protocol. The amendments prohibit dumping in the sub-seabed in addition to that in the water column and exempt CO_2 sub-seabed disposal or storage if permitted by the Environment Minister. The Act regulates CO_2 disposal not only at sea but also from the land, for example, through an inclined well with its wellhead onshore, which is beyond the Protocol. To obtain a permit, those who plan to dispose CO_2 under the seabed are required to submit to the Minister such documents as a project plan and a CO_2 monitoring plan. The Minister may issue a permit if determining, for example, that the way of storing CO_2 stream will not harm the conservation of the marine environment around the storage site and that there are no other appropriate ways of disposal available. More detail requirements are set out in a cabinet order, ordinances and a notification of the Ministry of the Environment (MOE).

The major documents of an application are, as mentioned above, a project plan and a CO_2 monitoring plan. The MOE ordinance for dumping permits requires the monitoring plan to be developed for three cases: for normal times, for CO_2 leak possibly taking place and for leaking or nearly leaking. The MOE notification categorizes those to be monitored, which are the same for the three cases: injected/ stored CO_2, reservoirs, seawater chemicals, marine organisms and ecosystems, and marine utilization such as marine leisure and fishery. The ordinance also requires applicants to submit an environmental impact assessment (EIA) report as an attachment to a permit application. To complete the EIA report, applicants need to set up CO_2 leak scenarios; project locations, spatial extent and volume of CO_2 leakage based on the scenarios; identify those to be affected by the projected leakage such as marine organisms and the marine ecosystems; acquire

[295] OSPAR 2007e. OSPAR Decision 2007/1 to Prohibit the Storage of Carbon Dioxide Streams in the Water Column or on the Sea-bed. Summary Record OSPAR 07/24/1-E Annex 5. (2007)

baseline data of the potentially affected; and assess the potential impacts of the assume leakage on those.

The Act and its related legal orders were set out under a concept not to promote CCS but to regulate CCS. There are, therefore, a couple of stipulations which may need to be amended for wider CCS deployment in future. An example is that the regulations require an applicant to renew a permit every 5 years or less, but do not specify the end of the renewals. This implies that the storage operator should continue the renewals forever and keep on monitoring the injected CO_2 and the marine environment for an indefinite period. MOE has investigated appropriate conditions to allow operators terminating monitoring but such conditions are not incorporated legally at present. Another example is specifications for CO_2 stream allowed to be injected. The orders provides that CO_2 should be captured by amine and be a concentration of 99 vol% or more (the threshold of concentration is relaxed to 98 vol% for hydrogen production for oil refinery) on the assumption that amine is the capture technology most likely to be adopted in Japan. The regulator claims that they will amend stipulations when other promising technologies emerge, but anyway the current law does not allow oxyfuel combustion capture and widely-used pre combustion capture such as Selexol and Rectisol in Japan.

The regulations will be applied for the first time to a full-chain demonstration project funded by the Ministry of Economy, Trade and Industry (METI). The project takes place in Tomakomai, Hokkaido and plans to capture more than 100 thousand t of CO_2 per year from a hydrogen plant and inject the CO_2 to offshore reservoirs for 3 years, commencing in 2016. The project is exempted from the London Protocol in that CO_2 will be injected onshore with inclined wells. However, because the Japanese Government intends to report the project as that complying with the CO_2 Specific Guidelines under the Protocol to IMO and the contracting parties, the project will be recognized as the world-first CCS project to be operated under the framework of the Protocol once operated.

8.3.2 U.S. regulations

Regulation of future offshore sub-seabed GS of CO_2 in the United States will be the responsibility of two federal entities, the U.S. Department of Interior (DOI) and the U.S. Environmental Protection Agency (EPA). The area under DOI jurisdiction is the Outer Continental Shelf (OCS), which is that portion of the United States offshore from the seaward boundary of State submerged lands to the outer edge of the Exclusive Economic Zone (200 nautical miles [nmi] [370 km]). EPA will have jurisdiction over sub-seabed CO_2 GS in State submerged lands; these extend from shore line seaward to a distance of either 9 nmi (16.7 km) (Texas and west coast of Florida) or 3 nmi (5.6 km).

The DOI will have jurisdiction over sub-seabed CO_2 GS within the largest offshore portion of the United States, meaning those portions of the OCS not under drilling moratoria.[296] However, regulations specific to CO_2 sub-seabed GS have not yet been written. Through the Bureau of Safety

[296] U.S. Drilling Moratoria: http://www.boem.gov/Areas-Under-Moratoria/

and Environmental Enforcement (BSEE) and Bureau of Ocean Energy Management (BOEM) DOI already regulates offshore oil and gas activity on the OCS under the authority of the Outer Continental Shelf Lands Act.[297] This regulatory responsibility includes secondary and tertiary oil recovery, and by default EOR using CO_2. The current rules focus on resource recovery operations; regulations for monitoring to demonstrate that CO_2 injected for EOR is remaining in the deep sub-seabed will be needed if operators want to claim CO_2 storage credit.

The OCSLA was amended in 2005 to also give DOI authority to establish regulations for renewable energy resource recovery and other forms of energy and marine related uses of the OCS. DOI and BOEM have determined that they have authority to regulate GS of CO_2 generated from coal-fired power plants. They have not yet issued an opinion on whether they will also have authority to regulate GS for CO_2 generated by and captured from other types of industrial sources.

The Bureau of Economic Geology (BEG) at The University of Texas at Austin is working with the BOEM under funding from the National Oceanic Partnership Program[298] to provide (1) an analysis of existing BSEE and BOEM regulations that could be adapted to sub-seabed CO_2 GS, (2) an online EndNote database of pertinent existing manuals and guidance documents, and published literature, and (3) a report on Best Management Practices and Data Gap Analysis for Sub-seabed Geologic Carbon Dioxide Sequestration. This report is nearly ready for external review and will be finalized and submitted to BOEM in September 2015. Further discussion of how existing BSEE and BOEM regulations may be adapted to offshore GS, is contained in an interim report associated with BEG's BOEM project.[299]

The EPA has jurisdiction over onshore GS of CO_2 through two U.S. federal laws, the Clean Air Act (CAA)[300] and the Safe Drinking Water Act (SDWA).[301] The EPA, through its Office of Air and Radiation, is responsible for regulations to protect the public from air pollution. In 2007, the U.S. Supreme Court included CO_2 as an atmospheric pollutant the EPA must regulate. As a result EPA established the Greenhouse Gas Reporting program and in 2009 published regulations for industrial emitters of CO_2.[302] The association of this program to offshore CO_2 GS is through rules in its Subpart RR—Geologic Sequestration of Carbon Dioxide.[303] Certain Subpart RR rules require operators seeking to avoid future CO_2 emissions penalties through geologic sequestration

[297] OCSLA: http://www.boem.gov/Outer-Continental-Shelf-Lands-Act/

[298] National Oceanic Partnership Program: http://www.nopp.org/

[299] Smyth, R. C. and Thomas, P. G., III, 2013, Analysis of applicability of existing BOEM/BSEE regulations to offshore sub-seabed geologic sequestration of carbon dioxide: unpublished BEG interim contract report, 30 p.

[300] Clean Air Act: http://www.epa.gov/air/caa/

[301] Safe Drinking Water Act: http://water.epa.gov/lawsregs/rulesregs/sdwa/index.cfm

[302] Greenhouse Gas Reporting Program: http://www.epa.gov/ghgreporting/

[303] Subpart RR of the GHGRP: http://www.epa.gov/ghgreporting/reporters/subpart/rr.html

to follow an approved plan for monitoring, reporting, and verification (MRV). Such operations located on State submerged lands will be subject to EPA GHGRP Subpart RR.

Under the SDWA, EPA's Office of Water regulates protection of drinking water resources. The program most applicable to CO_2 GS is Underground Injection Control (UIC).[304] UIC has defined multiple classes of injection wells, each with their own set of rules. For example, EPA UIC Class I well rules apply to industrial and municipal waste disposal wells. Injection of CO_2 for EOR falls under EPA UIC Class II rules. In 2010, EPA published regulations for newly established UIC Class VI wells, which are wells used to inject CO_2 for long-term geologic storage without EOR. Class VI well rules include specific requirements for MVA of injectate-CO_2. Again, the purpose of EPA's UIC program is to protect drinking water resources. These regulations should apply in State submerged lands underlain by underground sources of drinking water (USDW),[305] or where sub-seabed stratigraphic units in hydraulic connection with onshore USDWs are present.

8.4 Implications of Regulatory Requirements on Technology Development

The international regulations were drafted in consultation with technical expertise on CO_2 geological storage, with the intention that they did not place unrealistic requirements on the science, the operators or the regulators. This means that they are based upon the level of knowledge and technology development that existed in 2004-2008. With the emphasis on protection of the marine environment, there is an emphasis on monitoring techniques for both leak detection and impact assessment, as well as for environmental baseline measurements. There has since been much work in developing such techniques, and some have been demonstrated at offshore sites such as in Europe.

Monitoring strategies may need to be devised to cover large areas, typically tens to hundreds of square km and also achieve accurate measurement and characterization possibly over lengthy periods. Limited spatial coverage could lead to the risk that anomalies remain undetected or are only detected after a lengthy period of time. Search areas could be narrowed down by the integration of information from deeper-focused monitoring, such as 3D seismics which can identify migration pathways, with shallow surface monitoring such as acoustic detection.

Deep-focused monitoring relies heavily on established hydrocarbon industry tools which are mature. There is scope for improving some of these technologies and related data processing and interpretation for CO_2 storage. The quantification of CO_2 within a reservoir still remains a challenge.

Shallow-focused monitoring is less advanced compared with deep focused monitoring, but systems are being developed and demonstrated. New marine sensor and existing underwater platform technology such as AUVs and mini-ROVs enable deployment and observation over large areas at potentially relatively low cost. Seafloor and ocean monitoring technologies can detect both dissolved phase CO_2 and precursor fluids (using chemical analysis) and gas phase CO_2. AUV

[304] Underground Injection Control Program: http://water.epa.gov/type/groundwater/uic/index.cfm

[305] Underground sources of drinking water definition: http://water.epa.gov/type/groundwater/uic/glossary.cfm

technology capable of long-range deployment needs to be developed so that the AUV can be tracked transmit data via a satellite communications system. Real-time data retrieval and navigation will enable onshore operators to modify or refine surveys without costly intervention using a survey vessel. Further development in integrated in situ sensors has been underway over the last 5 years. The quantification of leakage at the seabed remains a technical challenge.

The capabilities to predict the behavior of marine systems using models need to be improved. Advances are needed so that systems can simulate leakage in the context of natural variability by combining both pelagic and benthic dispersion and chemistry, including carbonate and redox processes. Models that can simulate large scale dispersion of multi-phase plumes whilst simultaneously simulating tidally-induced dispersion in the near- and far-field also need to be developed.[306]

8.5 Implications of Technology Development on Regulations (i.e., better modeling/simulation tools, etc. and influence on regulations)

There have been significant developments in the regulation of CO_2 geological storage offshore. This section has described the main developments internationally and for Japan and the United States. These regulations have created an enabling regulatory situation for CCS offshore whilst ensuring the protection of the marine environment and other resources.

These regulations, particularly the international ones, were among the first dedicated CCS regulations to be developed. Experience and assessment of their suitability with application with projects would be beneficial. There have also been significant developments in technologies and knowledge since the period these regulations were developed, particularly in the areas of monitoring and environmental assessment, with testing and demonstration of these developments in Europe, Japan, and the United States. It is recommended that the knowledge gained through the development and application of these regulations, and the relevant technical knowledge and developments since, are shared with other countries who may be interested in offshore CCS.

[306] IEAGHG, "Offshore Monitoring for CCS Projects", Report 2015/02.

9 Summary and Recommendations

Offshore storage has been demonstrated by the Sleipner project for nearly 20 years and much has been learned from this effort. Additionally, the oil and gas industry has developed significant toolsets and capabilities for offshore hydrocarbon recovery and transport. However, there are also significant opportunities to increase our understanding of offshore CO_2 storage. Some of these opportunities include: storage capacity assessments, infrastructure, monitoring and modeling, and understanding of environmental impacts and dynamics of CO_2 dispersion in ocean environment.

There is a growing wealth of research, development and practical experiences that are specific to, or relevant for, CO_2 storage offshore, as described in the preceding chapters, but this expertise is familiar only to a few specific countries around the world. However there is also significant global potential for offshore CO_2 storage, and countries who are not yet active but may become interested in offshore storage, would benefit from knowledge sharing from these existing experiences and expertise. Such international knowledge sharing would be facilitated by international workshops and by international collaborative projects. The CSLF is very well-positioned to encourage and support such knowledge-sharing activities.

Storage Capacity Assessments

Global storage capacity assessments at the national level are currently inadequate. These assessments are typically high risk and involve long lead times to prove storage capacity and support the development of first-wave or even second-wave CCS projects. The long lead time (in the range of 7–10 years) means that storage qualification defines the start-up time of a CCS project. There are also cost implications. For example, although the cost of storage is typically considered to be lower than that of capture, one ‘dry’ hole (i.e., into a formation that proves not to be a good storage resource) would significantly increase the cost of storage.

Recommendation: It would help prospective CCS stakeholders if public-private partnerships were developed to provide a number of pre-qualified storage locations.[307] For such locations, all preparatory work, including the documents for a storage permit application could be made available to reduce the uncertainty regarding the availability of storage. This would support both the storage and the transport elements of CCS projects.

It is recommended that a more thorough evaluation of the geologic storage aspects of many basins be pursued. It is also recommended that an increased level of knowledge sharing and discussion be implemented among the international community to outline the potential for international collaboration in offshore storage.

Transport Infrastructure

Technology solutions for CO_2 transport exist and have shown to be robust during decades of operation. Offshore CO_2 transportation is more limited, but can benefit from substantial

[307] This is sometimes referred to as ‘bankable’ storage capacity.

operational experience from natural gas pipelines. Compared with onshore pipeline transportation, offshore CO_2 transport will probably be more expensive, but there are also some distinct advantages, such as less exposure to issues around routing, shipping is a mode of transport with large flexibility in a start-up phase and to tie in smaller CO_2 sources, and a more stable physical environment.

***Recommendation**:* To realize the international ambitions to mitigate global warming, the CO_2 transportation infrastructure must increase significantly and will be an important contributor to the overall costs for CCS. Hence, optimization of current practices is important, on areas such as CO_2 product specifications and sharing of infrastructure to optimize utilization.

Additionally, during the pilot and demonstration phase of CCS, CO_2 volumes will be relatively small. However, these projects could be developing the first elements of the large-scale infrastructure, if sufficient incentive is given to oversize the components of the transport infrastructure. Especially during the early phase of CCS, public-private partnership is essential to generate these large infrastructural works.

An increase in the available financial incentives for (offshore) CCS project is needed to increase the speed of development of offshore CCS. Funding mechanisms should consider funding operational costs, as well as up-front investments.

Offshore CO_2-EOR

Currently, the only offshore CO_2-EOR project that exists is the Lula project in Brazil. However, offshore CO_2-EOR is seen as a way to catalyze storage opportunities and build the necessary infrastructure networks. One of the barriers reported widely for offshore CO_2-EOR projects is the investment required for the modification of platform and installations, and the lost revenue during modification.

Recommendation: Recent advances in subsea separation and processing could extend the current level of utilization of sea bottom equipment to also include the handling of CO_2 streams. By moving equipment required to separate and condition the CO_2 to the seafloor, modifications to the platform can be minimized. It is recommended that RD&D activities explore opportunities to leverage existing infrastructure and field test advances in subsea separation and processing equipment.

Understanding of CO_2 Impacts on the Subsea Environment

Over the last decade, a significant body of research into the impacts of high CO_2 concentrations on marine systems has matured, driven directly by CCS but also by concerns regarding ocean acidification. Much of this work has concentrated on physiological impacts and has utilized laboratory scale manipulations. However both natural analogues, typically where volcanic CO_2 is emitted at the seafloor, and more recently a controlled release experiment, where CO_2 was deliberately injected into the seabed, have been used to study the synergistic impacts driven by a combination of hydrodynamics, ecosystem interactions, behavior and physiological responses. The main outcome from these real world experiments is a glimpse of the complexity of impacts and the challenges to efficient monitoring, in particular the requirement for a comprehensive understanding of natural variability necessary to correctly identify and quantify non-natural change. For example, it has been observed that carbonates, naturally present in some sediments undergo dissolution in the presence of excess CO_2, reducing the presence of gas at the seafloor, some of the chemical parameters and biological impacts. However sediment carbonate is finite and once exhausted a step change in detectability and impact is likely.

Recommendation: Leverage the existing body of knowledge to expand R&D efforts to diverse geologic storage sites. Specific challenges arising from existing work are to understand the buffering potential of sediments, and the impact of longer term exposures.

It is also recommended to expand upon modeling efforts to understand CO2 dispersion in an ocean environment. Whilst the primary driver of the spatial extent of detectability and impact is the leakage rate, many other factors such as depth, bubble size, current speed, tidal mixing and topography are shown to have a large influence on dispersal. Existing models are robust, but limited in that they generally cannot deal with very fine scales (≈1m) which are necessary for the correct treatment of small leak scenarios at the same time as accurately defining regional scale mixing processes, necessary for the correct estimation of dispersion. Model development of marine systems is required to improve their predictive capabilities. Advances are needed so that systems can simulate leakage in the context of natural variability by combing both pelagic and benthic dispersion and chemistry, including carbonate and redox processes. There is also a need to develop models that can simulate large scale dispersion of multi-phase plumes whilst simultaneously simulating tidally-induced dispersion in the near and far field.

Monitoring Technology Development

Monitoring strategies may need to be devised to cover large areas, typically tens to hundreds of square km, and also achieve accurate measurement, characterization and repeatability possibly over lengthy periods. Limited spatial coverage could lead to the risk that anomalies remain undetected or are only detected after a lengthy period of time. Search areas could be narrowed down by the integration of information from deeper-focused monitoring, such as 3D seismic which can identify migration pathways, with shallow surface monitoring such as acoustic detection.

Recommendation: Deep-focused monitoring relies heavily on established hydrocarbon industry tools which are mature. There is scope for improving some of these technologies and related data processing and interpretation for CO_2 storage. The quantification of CO_2 distribution within a reservoir still remains a challenge.

Shallow-focused monitoring is less advanced compared with deep focused monitoring, but systems are being developed and demonstrated. New marine sensor and existing underwater platform technology such as AUVs and mini-ROVs enable deployment and observation over large areas at potentially relatively low cost. Seafloor and ocean monitoring technologies can detect both dissolved phase CO_2 and precursor fluids (using chemical analysis) and gas phase CO_2. AUV technology capable of long-range deployment needs to be developed so that the AUV can be tracked transmit data via a satellite communications system. Real-time data retrieval and navigation will enable onshore operators to modify or refine surveys without costly intervention using a survey vessel. Further development in integrated in situ sensors has been underway over the last 5 years. The quantification of leakage at the seabed remains a technical challenge.

10 Appendix

Tables from IEAGHG Offshore Monitoring Report

Table A1 Surface seismic methods

Method	**Capabilities**	**Practicalities**	**Deployment**	**Containment Monitoring**	**Conformance**	**Cost**	**Limitations**
Streamer—3D seismic	High detection and resolution capabilities. Data suitable for advance analysis especially the investigation of reservoir properties and plume tracking	Routine deployment, robust and mature but requires large unobstructed areas of sea Detection threshold depends on geometry of CO_2 accumulation	Sleipner, Snøhvit. Planned for Goldeneye, ROAD, Tomakomai* (Retrievable OBC 3D seismic)	Can provide robust and uniform spatial surveillance of storage complexes. Can detect small changes in fluid content and therefore useful for leakage detection. Changes in time-lapse seismic images can detect small quantities of CO_2.	Ability to track CO_2 plumes is useful to corroborate model predictions and can be used to refine or modify them. Plume mobility and storage efficiency can be checked. Measured time-shifts can reveal indicative pressure changes in reservoirs.	£10M+ depending on survey area, specification, and locality. Processing time up to £1M in computing time	Lack of significant azimuthal variation in wave propagation which limits azimuthal analysis for evaluation of anisotropy and geomechanical integrity. Interpretation and detection of CO_2 relies on good repeatability which may not always occur.

Method	Capabilities	Practicalities	Deployment	Containment Monitoring	Conformance	Cost	Limitations
Streamer 2D seismic	High detection and resolution capabilities similar to 3D seismic. Star survey configuration can provide image of plume spread.	More compact compared to 3D. Time-lapse is reputedly poor.	Sleipner, Tomakomai (OBC 2D seismic)			<£1m depending on survey area, specification, locality	Lack of 3D migration in processing precludes optimum imaging of some subsurface structures.
Streamer—P Cable seismic	High resolution 3D seismic system suited to shallow sections (<1,000 m) therefore useful for imaging shallow overburden. High spatial and temporal resolution possible Useful for 3D mapping of structures especially faults.	Relatively compact and short than 3D and 2D configurations gives high maneuverability.	Snøhvit, Gulf of Mexico	Useful for containment risk assessment and leakage monitoring by tracking CO_2 migration above storage complexes		<£1m depending on survey area, specification, locality	Sea bed multiple can obscure important features. Vulnerable to reduced performance in poor sea conditions.

Method	Capabilities	Practicalities	Deployment	Containment Monitoring	Conformance	Cost	Limitations
Chirps, boomers and pingers	Designed for very high resolution surface seismic surveys direct detection of bubble-streams may be possible in favorable circumstances.	Can be deployed from small site-survey vessels. AUV systems can be equipped with Chirp transducers. AUV survey has detected clear images of natural gas pockets in central North Sea	Sleipner, planned for Goldeneye			<£100k	Designed for shallow surface surveys. AUV based systems have limited penetration due to lower power availability.

Table A2 Ocean bottom seismic methods

Method	Capabilities	Practicalities	Deployment	Containment Monitoring	Conformance	Cost	Limitations
OBN and OBC	As static observation data recorders these devices can provide full azimuth coverage with multicomponent sensors with p and s-wave recording for geomechanical and isotropy characterization. Long-term recording is useful for detecting natural and induce seismicity	Can provided information in close proximity to platforms	OBN planned at Goldeneye OBC planned at Tomakomai			£10M+ but unlike streamer surveys there is a high initial cost to set up the system and relatively low costs for repeat surveys.	Vulnerability to trawling operations. Limited spatial sampling density compared with streamer surveys.

Table A3 Downhole seismic methods

Method	Capabilities	Practicalities	Deployment	Containment Monitoring	Conformance	Cost	Limitations
4D VSP (Vertical seismic profiling)	High resolution imaging of near-wellbore region 10s–100s meters radius	Permanent downhole sensors allow for cost-effective time-lapse imaging. Data processing can be complex. Fiber-optic acoustic cable might improve reliability.	Goldeneye (under consideration)				Coverage is non-uniform (spatially variable offsets and azimuths) which can make interpretation difficult. Time-lapse repeatability is uncertain. Reliability of sensors is a key issue.
Passive seismic monitoring	Allows continuous monitoring for microseismic events	Deployment in one or more shallow wells (<200m). Microseismic events can be used to identify structures such as faults and fractures. Important to establish natural background seismicity to distinguish events related to CO_2 injection and migration.	Planned for ROAD and Tomakomai Considered for Goldeneye		Important to establish natural background seismicity to distinguish events related to CO_2 injection and migration.	High initial costs required for deployment. Maintenance costs could also be high	Sensor reliability can make the method vulnerable leading to potentially limited signal records.

Table A4 Potential field methods

Method	Capabilities	Practicalities	Deployment	Cost	Limitations
Sea bottom gravimetry	Directly measures mass change within reservoirs which is a conformance-related parameter	Offshore deployment is logistically complex requiring ROV and boat support to emplace concrete benchmarks	Sleipner	Low compared to 3D streamer surveys. A 50 station near-shore survey would cost ≈£1M.	
CSEM	Can provide complementary information to seismics. Method is sensitive to fluid saturation at higher CO_2 saturation levels	Offshore deployment is logistically complex	Sleipner	Costs high and comparable with offshore 3D seismics.	The technique is severely hampered in shallow water (<300m).

Table A5 Downhole measurements

Method	**Capabilities**	**Practicalities**	**Deployment**	**Containment Monitoring**	**Conformance**	**Cost**	**Limitations**
Downhole pressure and temperature	Downhole gauges are capable of detecting very small temperature and pressure changes which are a primary method for monitoring injected CO_2 physical properties and reservoir performance. Position of gauge across permeable units can give indications of out-of-reservoir migration.	Deployment is a requirement under the EU Storage Directive, Long-term surveillance needs to take account of instrument drift and reliability.	Snøhvit, K12-B. Planned for Goldeneye, ROAD, Tomakomai	Key for controlling geomechanical integrity of the reservoir and caprock. Any unexpected pressure reduction in the reservoir could indicate potential leakage.	Essential for monitoring fluid flow performance and model calibration demonstrating reservoir permeability, storage capacity and geomechanical stability.	Relatively low <£100 plus installation and retrieval of gauges	

Method	Capabilities	Practicalities	Deployment	Containment Monitoring	Conformance	Cost	Limitations
Geophysical logging	Standard oilfield technique used for calculating CO_2 saturation. Provided there is a good baseline survey, repeat surveys can be used to calculate CO_2 saturations	Downhole logging is dependent on access to wellbores which might be restricted. Obstructions such as scale accumulation may preclude logging.	Planned at ROAD and Goldeneye		Pulsed neutron capture logging is planned for Goldeneye to acquire a good baseline and quantify CO_2 thickness interval.	Cost varies depending on the suite of logs run	

Table A5 Downhole measurements

Method	Capabilities	Practicalities	Deployment	Containment Monitoring	Conformance	Cost	Limitations
Wellbore integrity monitoring	Standard oilfield technique including cement bond logs used to check integrity of the cased wellbore. Quality and availability of legacy data from abandoned wells may limit effectiveness of integrity checks. Ultrasonic imaging, Multi-finger calliper and Electromagnetic imaging, downhole video and real time borehole stress and tubing/ casing deformation imaging are used to check casing and tubing integrity.	Techniques is reliant on access to wells and different operations. Build-up of scale can cause problems by obstructing logging tools.	K12-B, planned at ROAD and Goldeneye		Wellbore integrity is essential for long-term CO_2 storage security by preventing leakage. At Goldeneye logs will be run prior to injection to establish a baseline. Integrity will be checked initially in year three and then every 5 years until injection is completed.	Cost varies depending on the suite of logs run	

Method	**Capabilities**	**Practicalities**	**Deployment**	**Containment Monitoring**	**Conformance**	**Cost**	**Limitations**
Downhole fluid sampling.	Analyses of reservoir fluids can yield pCO_2,pH HCO_3^-, dissolved gases, stable isotopes and tracers	Sampling should be carried out at ideally at reservoir pressure. Requires access to specific reservoir zones. U-tube is deployed onshore but does not have safety certification for offshore deployment.	K12-B planned at Goldeneye		At K12-B analyses of gas samples from two production wells revealed heterogeneous nature of the reservoir. Wireline downhole sampling proposed for Goldeneye.	Onshore cost per sample ≈£5-10k per sample.	Accuracy of breakthrough timing depends on temporal sampling frequency.

Method	Capabilities	Practicalities	Deployment	Containment Monitoring	Conformance	Cost	Limitations
Chemical tracers and gas analyses	Tracers and isotopic signatures can help to identify CO_2 origin and monitor migration or potential leakage.	Tracers can be injected in a pulse or continuously. Tracers can be detected in extremely small quantities using gas chromatograp hy or mass spectrometry.	K12-B planned at Goldeneye	At Goldeneye use of tracers is being considered to distinguish between natural CO_2 being emitted from the sea bed and CO_2 from the storage complex.	Tracer studies at K12-B showed breakthrough occurred at two producer wells after 130 days and 463 days depending on distance from the injector. Differing CO_2 and CH_4 solubilities and insoluble tracers mean these breakthrough rates may not reflect real CO_2 migration rates.	Noble gases analyses are ≈£350 compared with £125 for SF_6	

Table A6 Sub-sea monitoring

Method	Capabilities	Practicalities	Deployment	Containment Monitoring	Conformance	Cost	Limitations
Seabed and water column imaging.	Active acoustic techniques can be effective at detecting gas fluxes. Multibeam echosounders (MBES) can be used for 3D bathymetric surveys. In time-lapse mode method could be used to detect slight changes in seafloor that might be caused by CO_2 leakage. Acoustic bubble detection can identify bubble releases	These are established techniques that can be carried out by a survey vessel with multiple imaging systems. This is a cost-effective means of surveying large areas of sea bed. AUV and ROV systems can operate closer to the seabed, the scale and operational duration of surveys is limited the size of the device.	Pervious side-scan sonar, single beam and multibeam echosounding and pinger sea bottom profiles were conducted. Surveys at Sleipner and Snøhvit. Pockmarks were clearly identified but no bubble streams. Acoustic bubble detection is planned at ROAD. A MBES plus side-scan sonar is planned for Goldeneye			Surveys 10 km2 cost ≈£100k - £200k but cost efficiencies are possible if multiple techniques are carried out.	There is a trade-off between the scale of the survey area and the ability to survey the seafloor from an AUV. Static seabed sensors can achieve high resolutions but over smaller fixed areas. However, they are generally more costly to install, maintain and retrieve compared to mobile equipment.

Method	Capabilities	Practicalities	Deployment	Containment Monitoring	Conformance	Cost	Limitations
Underwater video	Detection and recording of high definition images of bubbles and other features such as bacterial mats and biota behaviors which may give an indication of CO_2	Image quality can vary depending on water quality and height above seabed.	Sleipner			≈£1k-10k	A highly qualitative technique with a poor ability to resolve the size and shape of bubbles.
Seabed displacement monitoring	Vertical displacements of the seabed can be indicative of pressure changes in reservoirs. GPS system could measure rates with a accuracy range of 1-5mm.	Sensor networks on seafloor that use acoustic ranging techniques, pressure gauges or tiltmeters can give very accurate measurements of seabed movement	Planned for Goldeneye. Single GPS station mounted on a platform.	Monitoring subsidence or uplift can provide evidence of containment and conformance.		≈£1k-10k for single GPS station mounted on a platform.	

Table A6 Sub-sea monitoring (cont.)

Method	Capabilities	Practicalities	Deployment	Containment Monitoring	Conformance	Cost	Limitations
Geochemical water column sampling.	Water column measurements using Conductivity, Temperature and Depth (CTD) probes in combination with pH pCO_2, dissolved O_2, inorganic and organic carbon, nitrogen, phosphate, Eh, salinity can be sued to detect anomalous chemistry.	CTD probes can be conducted from survey ships. Continuous measurements can be made. Interpreting a leakage signal above background measurements can be extremely challenging. Baseline measurements ideally need to reflect a degree of natural variability.	Sleipner and Snøhvit, and planned at Goldeneye (permanently attached to platform) and Tomakomai. A survey over a period 2011 -2013 above Sleipner found no evidence of CO_2.			≈£1k–10k for a survey when deployed from a vessel conducting other surveys	The density, timing and the vertical spacing separation of surveys may mean small leakage plumes could remain undetected depending on plume dispersion.

Method	**Capabilities**	**Practicalities**	**Deployment**	**Containment Monitoring**	**Conformance**	**Cost**	**Limitations**
Sediment sampling	Time-lapse sediment sampling can be used to detect changes in sediment, pore fluid that could indicate CO_2 leakage. Detecting CO_2 leak induced changes above background requires a good understanding of natural variability	Quality of sample depends on substrate and whether core has retained pore fluid at the original in situ pressure. Specialist vibrocorer equipment is required.	Sleipner and Snøhvit, and planned at Goldeneye) and Tomakomai. Repeat surveys will be conducted to detect possible changes induced by CO_2 leakage.		Seabed sediment samples from Goldeneye will be analyzed for a suite of dissolved gases to provide a background baseline.	£5k / day for equipment deployment and excluding ship time.	
Ecosystem response monitoring	Time-lapse sediment sampling can be used to detect changes in benthic flora and fauna caused by elevated CO_2 concentrations either as a gas phase or by a reduction in pH. Avoidance behavior needs to be distinguished by changes induced by natural variability	Species density and variety can be recorded with underwater video.	At Goldeneye ecosystem sampling using Van Veen Grab is planned.			≈£100s per sample excluding processing and organism identification	Most effective biomarker species have not yet established.