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Norway's Sleipner and Snøhvit CCS: Industry models or cautionary tales?

Unexpected subsurface geology developments in the two projects call into question the world's offshore CO_2 storage ambitions

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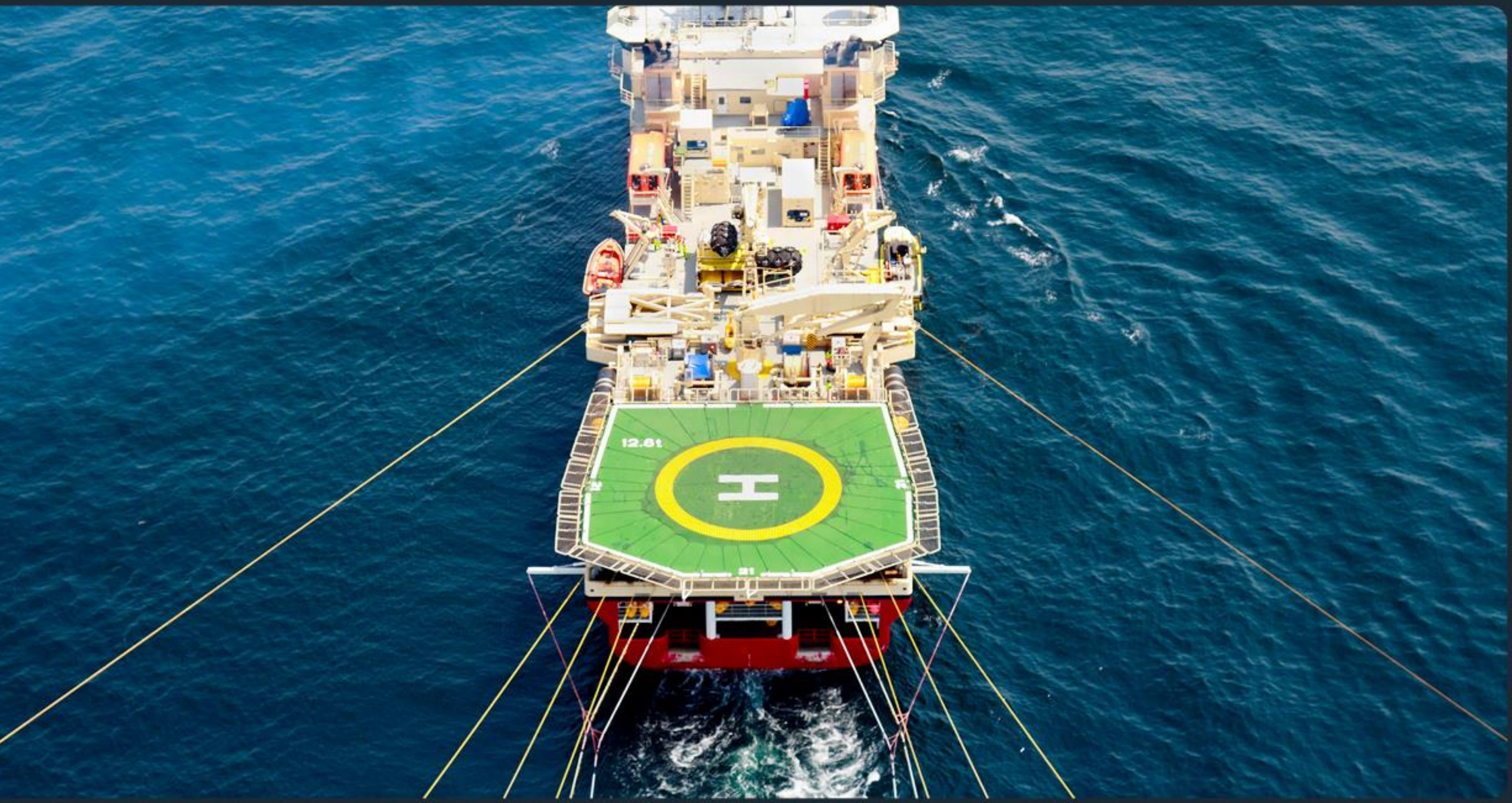

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Sleipner and Snøhvit demonstrate carbon capture and storage is not without material ongoing risks that may ultimately negate some or all the benefits it seeks to create.

Every project site has unique geology, so field operators must expect the unexpected, make detailed plans, update the plans and prepare for contingencies.

Ensuring storage is securely maintained implies a high level of proactive regulatory oversight, activities for which governments may not be adequately equipped.

Sleipner and Snøhvit cast doubt on whether the world has the technical prowess, strength of regulatory oversight, and unwavering multi-decade commitment of capital and resources needed to keep carbon dioxide sequestered below the sea – as the Earth needs – permanently.

Executive Summary

The oil and gas industry, along with a host of high carbon-emitting companies and hopeful governments, are looking at offshore carbon capture and storage (CCS) as a panacea to reducing anthropogenic carbon dioxide (CO_2) emissions. Leading CCS proponents consistently cite two projects in Norway as proof of the technology's viability: Sleipner and Snøhvit. These offshore fields have been operating since 1996 and 2008 respectively. The facilities separate CO_2 from their respective produced gas, then compress and pipe the CO_2 and reinject it underground. Between Sleipner and Snøhvit, an average of 1.8 million metric tonnes per year of CO_2 are disposed of in this manner, accumulating 22 million tonnes in storage so far.

Following from Sleipner's and Snøhvit's purported success, there are now nearly 200 proposed offshore CCS projects worldwide seeking to sequester hundreds of millions of tonnes of CO_2 annually – potentially billions over their operating lives. These proposals represent hundreds of billions of dollars in capital investment and billions of dollars in ongoing operating costs. More importantly, they are said to be the key to making a material dent in the over 37 billion tonnes of CO_2 emitted globally each year.

> **Can these two Norwegian projects be relied upon as fully successful models for global decarbonization?**

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Research conducted by the Institute for Energy Economics and Financial Analysis (IEEFA) has revealed that storing carbon dioxide underground is not an exact science. It may carry even more risk and uncertainty than drilling for oil or gas, given the very limited practical, long-term experience of permanently keeping CO_2 in the ground.

Oil and gas exploration companies rely on their geophysical survey prowess and analytic capabilities in identifying and updating reserves. However, even in what are thought to be reserve-rich areas, drilling sometimes comes up with dry holes. This is because exploration is an inexact science. There can be no clairvoyance as to what lies below the ground, but rather indications. While exploration is increasingly based on data derived from the most advanced technologies, its outcomes necessarily remain estimates drawn from interpretations and interpolations of subsurface data.

The subsurface areas of Sleipner and Snøhvit are among the most studied geological fields in both oil and gas and CO_2 storage globally. More seismic and other forms of subsurface study and monitoring of these two fields have been conducted than nearly any other place on the planet. Over 150 academic papers have been published. Their seismic datasets have been downloaded more than a thousand times.

Despite the studies, experience and passage of time, the security and stability of the two fields have proven difficult to predict. In 1999, three years into Sleipner's storage operations, CO_2 had already risen from its lower-level injection point to the top extent of the storage formation and into a previously unidentified shallow layer. Injected CO_2 began to accumulate in this top layer in unexpectedly large quantities. Had this unknown layer not been fortunate enough to be geologically bounded, stored CO_2 might have escaped.

At Snøhvit, problems surfaced merely 18 months into injection operations despite detailed pre-operational field assessment and engineering. The targeted storage site demonstrated acute signs of rejecting the CO_2. A geological structure thought to have 18 years' worth of CO_2 storage capacity was indicating less than six months of further usage potential. This unexpected turn of events baffled scientists and engineers while at the same time jeopardizing the viability of more than US$7 billion of investment in field development and natural gas liquefaction infrastructure. Emergency remedial actions and permanent long-term alternatives needed to be, and were, identified on short notice and at great cost.

> **In the context of CCS projects and proposals worldwide, Sleipner and Snøhvit account for only a tiny fraction of the intended carbon capture capacity.**

In the context of CCS projects and proposals worldwide, Sleipner and Snøhvit account for only a tiny fraction of the intended carbon capture capacity. The hub proposals – from Malaysia to the North Sea to the Gulf of Mexico – are larger by factors of 10 or more, and potentially entail CO_2 storage fields measuring in the thousands of square kilometers. Applying a similarly intense level of technical study, monitoring and resources as allocated to the CO_2 storage operations of Sleipner and Snøhvit may prove to be a cost and resource challenge for larger, more complex CCS projects.

Yet unpredicted deviations in how Sleipner's and Snøhvit's injected CO_2 was interacting with targeted strata underground, including unexpected behaviors that evolved years into operations, indicate that such monitoring is indeed required. What the Norwegian projects demonstrate is that each CCS project has unique geology; that geologic storage performance for each site can change over time; and that a high-quality monitoring and engineering response is a constant, ongoing requirement. Every proposed project needs to budget and equip itself for contingencies both during and long after operations have ceased.

Globally, regulation of CCS projects is both nascent and uneven. Australia, the European Union and Norway have perhaps the most advanced rules governing CO_2 injections, but their efficacy of scope and level of detail remains untested. The common features are requirements for pre-implementation plans; collection and disclosure of operational data; and post-closure containment monitoring and mitigation plans spanning decades. CCS field operators must post financial bonds and have emergency remediation plans to address contingencies if the CO_2 leaks. However, bonding requirements vary considerably among jurisdictions, from 10 years in Australia to potentially 50 years in the United States. Including long post-closure bonding periods appears to acknowledge that storage sites may not have the permanence proponents assume. Yet, at the regulator's discretion, those periods can be shortened, potentially transferring uncapped risk to the public.

While these regulations are imperfect, most of the rest of the world lacks any CCS regulation. This exposes people and the planet to considerable long-term risk.

Sleipner and Snøhvit, rather than serving as entirely successful models for CCS that should be emulated and expanded, instead call into question the long-term technical and financial viability of the concept of reliable underground carbon storage. They cast doubt on whether the world has the technical prowess, strength of regulatory oversight, and unwavering multi-decade commitment of capital and resources needed to keep CO_2 sequestered below the sea – as the Earth needs – permanently.

An Overview of Geology and Subsurface Investigations Appears in Appendix A

This report investigates technical matters pertaining to the subsurface geology of offshore, carbon dioxide (CO_2) storage. There are numerous references to subsurface geology terms and methods of studying what may lie underground. The paper also summarizes some of the risks field developers might encounter when planning for and implementing storage projects. Many of the concepts those professionals address are highly complex scientific topics which may not be readily comprehended by lay readers. Indeed, this is likely why debate on storage risks in public discourse has been limited.

The bulk of research for the current report was sourced from technical journals, university papers, and industry documents. It attempts to synthesize key points from that material and present the information in a more accessible way. Accordingly, the main body of the report will not go in depth into technical details.

Appendix A is meant to familiarize readers with what geophysicists and engineers are studying through their investigations, designs and operations oversight for CO_2 storage. It also provides a sampling of techniques used by scientists to analyze the nature of potential storage sites. The Appendix is merely a summary, not an exhaustive treatment of the science or technology used.

A Note on Units

The current paper designates volumes of CO_2 using metric quantities; this is the global standard when referring to carbon emissions. To avoid confusion with imperial measurement in "tons," the metric mass of CO_2 is denoted by the word "tonnes", thus:

- tonnes = metric tonnes of CO_2
- mtpa = million metric tonnes of CO_2 per annum
- Mt = million metric tonnes of CO_2, which is the same as one megatonne of CO_2

Introduction

In the world's urgent effort to reduce greenhouse gas emissions, many oil and gas companies, heavy industry owners, industry advocates, and policymakers are looking at carbon capture and storage (CCS) as a means to rapidly abate carbon dioxide (CO_2) emissions from their industrial and energy processes.

The "capture" part of CCS requires stripping CO_2 from a mixture of produced hydrocarbons, typically comprising primarily methane gas, or removing it from industrial processes post-combustion before it reaches a venting stack. It is then compressed into a supercritical state – somewhere between gas and liquid – for transportation via pipeline.

The next and most important step of CCS from a climate change perspective is the "S" part: storage. CO_2 is injected at high pressure into wells that deliver it deep underground in quantities that range from thousands up to one million tonnes per annum. The injection release point should be located at least 800 meters below the surface such that ambient temperatures and pressures keep the CO_2 supercritical, reducing the chance that it all turns back to gas and more readily percolates to the surface.

That storage needs to be permanent if the aim of reducing atmospheric CO_2 is to progress. But how can engineers and advocates of CCS assure the world that the CO_2 will stay in the ground? As this paper will explore, it is a proposition fraught with high technical complexity, inherent unknowns and, as a result, material risks of failure.

> **As this paper will explore, it is a proposition fraught with high technical complexity, inherent unknowns and, as a result, material risks of failure.**

Decades of research have gone into trying to improve CO_2 removal, handling, and use or disposal. Still, the successes of CCS, as proponents would define it, have been limited for the most part to the oil and gas industry.[1] Currently, 24 of the 30 operating CCS projects globally are associated with oil or gas production.[2] And, in that application, the industry nearly exclusively pumps the stripped CO_2 back into the ground to produce more oil and gas through a process called enhanced recovery, rather than permanently sequestering it.

[1] IEEFA. Carbon capture has a long history. Of failure. Robertson. September 2, 2022.
[2] Global CCS Institute. The Global Status of CCS 2022. October 17, 2022.

Even within those "successes," there have been numerous cases of below-expected performance leading to above-expected amounts of CO_2 vented to the atmosphere.[3]

CCS proponents claim two offshore projects in Norway have changed that paradigm: Sleipner in the North Sea and Snøhvit in the Barents Sea, both managed by state-owned energy firm Equinor ASA. The pair are routinely cited as both the proof of concept and a model upon which the world's CCS aspirations can be built. The facilities are designed to strip CO_2 from their respective gas fields, then compress, pipe and inject it deep below the seafloor to permanently store it.

Sleipner, operating since 1996, is the world's most established and most consistently performing CO_2 storage project.[4] Spurred by the Norwegian government's high carbon taxes starting in 1991, the Sleipner gas production field could be financially viable only if the CO_2 separated from the produced gas was sequestered. To monetize the gas field, Equinor's former self, Statoil ASA, built a dedicated, first-of-its-kind offshore CO_2 stripping and processing platform next to its gas production platform in the North Sea to dispose of the CO_2 on-site.

The Snøhvit (or "snow white") gas production field was established in 2008, some 1,000 kilometers north of the Arctic Circle, to supply the multibillion-dollar onshore Hammerfest liquefied natural gas (LNG) project. Produced gas is piped 143km to Hammerfest, Norway, where the CO_2 is separated from the gas. This by-product is then compressed and pumped back out the same distance to the subsea injection point. The gas extraction wells and CO_2 injection well infrastructure are completely submerged, sitting on the seafloor, and are remotely operated. Snøhvit's fields supply about 6.5 billion cubic meters of gas each year, which is exported from Hammerfest as 4.65 million tonnes of LNG.[5]

Combined, Sleipner and Snøhvit separate and inject 1.45 to 1.7 million tonnes of CO_2 per annum (mtpa) hundreds of meters below the ocean floor. To date, the cumulative CO_2 stored between the two projects exceeds 22 million tonnes. The facilities continue to operate and are slated to run well into the 2030s.

Governments, in a quest to meet their Paris Agreement commitments,[6] and industries, seeking to comply with net-zero targets, eye CCS as a fix for high-emitting operations, whether in electric power, steel, cement, or petrochemicals. Subsurface carbon storage areas suitable in size and integrity are being sought, particularly in offshore oil and gas fields that are depleting.

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[3] IEEFA. Carbon capture has a long history. Of failure. Robertson. September 2, 2022.
IEEFA. The ill-fated Petra Nova CCS project: NRG Energy throws in the towel. Mattei and Schlissel. October 5, 2022.
IEEFA. 'Carbon capture' model at Exxon's Shute Creek CCUS reveals a questionable technology and uncertain economic viability. Robertson and Mousavian. March 24, 2022.
Energy Procedia. The In Salah CO_2 storage project: Lessons learned and knowledge transfer. Ringrose et al. Volume 37. June 2013, p. 6226-6236.
[4] Equinor Research and Technology. The CCS hub in Norway: Some insights from 22 years of saline aquifer storage. Ringrose. July 2018.
[5] Equinor. High gas exports and emissions cuts from Hammerfest LNG. December 20, 2022.
[6] "Paris Agreement commitments" refers to the legally binding international treaty, agreed by 196 nations at the 21st Conference of Parties to the United Nations Framework Convention on Climate Change on December 12, 2015, and governs reductions in carbon emissions per nationally determined contributions from each signatory.

Petronas, Malaysia's nationally owned oil and gas company, in November 2022 approved a project that intends to pump 3.3mtpa of CO_2 underground, aimed at monetizing a subsea gas deposit with an enormous 40% CO_2 content.[7] Indonesia is looking to employ CCS in more than a dozen high CO_2 content oil and gas fields.[8] Japan plans to effectively surround itself with subsea CCS to serve industrial CO_2 disposal.

In the U.S., a consortium of high-emitting industries on the Houston Ship Channel seeks federal government support to invest US$100 billion in collecting CO_2 onshore and depositing it under the Gulf of Mexico.[9,10] And in Europe, every country bordering the North Sea is proposing to send tens of millions of tonnes of CO_2 per year into depleted offshore oil and gas fields.[11]

Nearly 200 CCS project proposals are now under consideration globally.[12] Given the scope and scale of these projects, knowing whether subsurface storage of CO_2 is safe, secure, cost-effective and permanent is imperative.

The Institute for Energy Economics and Financial Analysis (IEEFA) has assessed the overall costs, benefits and challenges of CCS projects in great detail.[13] We provided a global compendium of CCS projects in the September 2022 paper, "The carbon capture crux."[14] Issues arising from the pursuit of CCS, focused on particular challenges in Southeast Asia, were explored in the April 2022 paper, "Carbon capture in the Southeast Asian market context."[15] These reports provide insights into CCS on a project level; the focus of the current paper is on subsurface geology.

Although governments and industry advocates alike cite Sleipner and Snøhvit as proof that the technology is viable and safe,[16,17] success depends on how it is defined. Both Norwegian projects have experienced unexpected subsurface behaviors once in operation, where risks were realized and remedial actions needed. In one situation, the CO_2 deposited moved rapidly and unexpectedly to a previously unidentified area. In another, CO_2 storage space meant for years of sequestering turned out to be insufficient. Such developments raise questions about whether two data sources the size of Sleipner or Snøhvit are sufficient to form a reliable basis for secure storage of greenhouse gases on a scale hundreds of times their size, and do so permanently.

[7] Petronas. Petronas Carigali reaches final investment decision for Kasawari CCS project offshore Sarawak. November 29, 2022.
[8] Argus Media. Indonesia's Pertamina, ExxonMobil to advance CCS hub. November 14, 2022.
[9] Houston CCS Alliance.
[10] Houston Chronical. Exxon seeks $100 billion for Houston carbon capture plan. November 2, 2021.
[11] Refer to Appendix B for a list of European CCS project plans.
[12] International Energy Agency (IEA). CCUS Projects Database. March 24, 2023.
[13] IEEFA. CCS search results. Accessed on April 12, 2023.
[14] IEEFA. The carbon capture crux: Lessons learned. Robertson and Mousavian. September 1, 2022.
[15] IEEFA. Carbon capture in the Southeast Asian market context: Sorting out the myths and realities in cost-sensitive markets. Adhiguna. April 1, 2022.
[16] United States Congress. Oversight hearing on the opportunities and risks of offshore carbon storage in the Gulf of Mexico. Subcommittee on Energy and Mineral Resources of the Committee on Natural Resources, U.S. House of Representatives, 117th Congress, Series 117-19. April 28, 2022.
[17] Ibid, footnote 2.

IEEFA has deepened its research into Sleipner and Snøhvit to better understand their performance history and suitability as models. The key aspects of a CCS project that make it qualify as a proof of concept include:

- Effective capture, compression and transportation of CO_2 to the injection site
- Sustained, well-managed and reliable injection of CO_2 into well sites
- Predictable, consistent and safe uptake of CO_2 by the targeted geological formations
- The security and sequestered status of that CO_2 in the storage area

Although engineers for Sleipner and Snøhvit believe the above conditions have been achieved, certain material deviations from their plans may lead investors, financiers, policymakers and the public to come to different conclusions. The CO_2 behaved in unexpected ways requiring unplanned-for actions and capital investments.

Long-term maintenance and oversight costs must be considered. The need for continuous monitoring, evaluation and planning indicates storage site developers must commit substantial amounts of financial, human and technical resources to CCS operations, including for decades beyond eventual closure. In parallel, ensuring storage is securely maintained implies a high level of proactive regulatory oversight, activities for which governments may not be adequately equipped. Policymakers and the public may not understand these requirements well. Even CCS geophysicists and engineers acknowledge that the technology has unique, sometimes costly and potentially unpredictable outcomes. Putting something back in the ground can be far more challenging than extracting it.[18]

This paper will elaborate on key developments over the course of Sleipner's and Snøhvit's operational experience. The lessons learned will be placed in the context of challenges the global oil and gas industry faces in exploration and production, and why CCS operations are showing an increasing need robust regulatory oversight. Sleipner and Snøhvit demonstrate that CCS is not without material ongoing risks that may ultimately negate some or all the benefits it seeks to create.

[18] First Break. Why CCS is not like reverse gas engineering. Ringrose et al. Volume 40, Issue 10. October 2022, p. 85-91.

Summary of Findings

Sleipner and Snøhvit are among the most studied CO_2 storage projects in the industry. Few projects in the development or operations phases have undergone more initial or repeated seismic, gravimetric measurement, and monitoring studies.[19] The Norwegian sites have attracted hundreds of detailed reviews and studies from companies, institutions, and academia. Seismic datasets from Sleipner alone have been downloaded over a thousand times.[20]

In researching this paper, IEEFA reviewed scores of technical studies and academic papers spanning from the 1990s to the 2020s. Despite the extensive literature, most of the publicly available information on Sleipner and Snøhvit is mostly confined to scientific journals and technical industry publications, with little in the way of readily digestible content for the public.

What this literature review reveals is that field operators must expect the unexpected, make detailed plans, continually update those plans and prepare for contingencies.

What this literature review reveals is that field operators must expect the unexpected, make detailed plans, continually update those plans and prepare for contingencies. But, most of all, the literature fails to call out the fact that neither the performance nor the integrity of storage sites can be guaranteed, whether up front or over time; at most, the studies tend to undermine certainty when it comes to CO_2 storage.

- ***CO_2 storage has not behaved as geologists initially expected for either project.*** To date, the two projects have been successful in sequestering their intended annual CO_2 deposit volumes, since 1996 for Sleipner and since 2008 for Snøhvit. However, *both* have also experienced **unexpected subsurface storage behaviors** that could have led to CO_2 leakage and, in the case of Snøhvit, potential subsurface geological failure.

- ***Every project site has unique geology.*** The biggest lesson from studying Sleipner and Snøhvit is that every CCS storage site's geology is going to be unique, requiring bespoke solutions. Even with extensive subsurface seismographic and gravimetric study, there is no way to definitively and exhaustively identify strata boundaries, faults or variations within those boundaries. Nor can one accurately forecast how the formations will perform in the presence of CO_2, as introduced

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[19] Appendix A. Overview of Geoscience in CCS provides an overview of technical terminology and practices used to identify and maintain CCS storage sites.
[20] IEA Greenhouse Gas R&D Program. Sharing CO_2 data with the world. March 13, 2023.

or over time. While each project offers many lessons, the pair ***cannot serve as definitive models*** for the future of CCS due to the size and unique subsurface conditions of the individual proposed hubs.

- ***Even extensive repeated study, using the most modern methods, is not foolproof.*** Both Sleipner and Snøhvit underwent extensive amounts of survey and engineering before implementation, far more than is typical in the oil and gas industry. Those enhanced efforts continued at regular intervals during operation. Even then, with the wealth of information in hand, the operators could not predict what would happen.

- ***Ongoing study and monitoring during operation is imperative to track deviations.*** Sleipner and Snøhvit have required – and will continue to require – extensive monitoring and survey throughout their life at material cost. Changes in how CO_2 behaves and where it migrates can happen even years into operations, and engineers must continually monitor storage evolution, planning for contingencies.

- ***Monitoring must run for decades after closure.*** The requirement of ongoing monitoring applies to any CCS project but would assume greater importance – and cost – for the scale of the proposed hub projects. Given that the Earth and its strata are continually moving and the long-term impacts of man-made storage are unpredictable and currently unknown, monitoring programs would need to continue indefinitely to assure the *permanent* sequestration of CO_2 long after the field's closure. Such requirements will warrant assured funding for years and monitoring and maintenance conducted to high standards without fail.

- ***Remedial actions are always a possibility and must be anticipated and budgeted for.*** No matter how mature the CO_2 storage field, conditions could change over time, potentially rapidly. Those changes may, as was the case with Snøhvit, require timely intervention. Contingency plans should always be at the ready. That means the engineering teams, drilling, and specialty vessel resources – and the money to pay for those – must remain available not only throughout the facility's operational years but also *after* the storage site is sealed at the end of its life.

- ***The scale of the two Norwegian projects is far smaller than most CCS projects being proposed globally.*** The injection rates and total capacity – 0.85mtpa to 1.0mtpa for Sleipner and 0.7mtpa for Snøhvit –

are smaller than many of the CCS proposals.[21] To develop a hub of envisaged capacity, multiple subsurface formations need to be identified, studied, monitored and managed. Given that CCS cluster projects will require subsurface storage space many times the size of Sleipner or Snøhvit, they may face magnified risks arising from geophysical deviations. For many of the larger proposals, particularly those in Norway and the United Kingdom, the infrastructural configurations and sizes of Sleipner and Snøhvit do not provide reasonable proxies for scope, scale or risk. It raises valid questions about equipment and field sizes, redundancy, the need for contingency planning, and the funding available to pay for this – all on a greater scale than anything previously considered. It is not clear that CCS projects can be scaled safely and efficiently.

- ***In Norway, a substantial carbon tax was the economic impetus for CCS.*** The primary driver of CCS for both projects was avoidance of the Norwegian Carbon Tax (1991). The price point of the tax is such that oil and gas producers, even with extensive development costs and ongoing operating costs for the CCS system, saved money by undertaking the investment. That savings margin has only grown since. Unless that fundamental cost element exists in a given market – and persists – that economic drive will be missing. It is unclear whether subsidies alone will create an equivalent result.

- ***Even the experts admit that CCS entails many risks, unknowns and learning while operating.*** Geophysicists and engineers involved in storage projects acknowledge that the unique challenges of handling, injecting and stabilizing CO_2 subsurface require advanced geophysical study and engineering, beyond that used to identify and extract oil and gas.[22] This creates unique conditions for CCS that do not parallel any other subsurface activity.

[21] Refer to Appendix B for a listing of Asian and European CCS hub projects and their proposed capacities.
[22] Ibid, footnote 18.

The Sleipner Project[23]

In 1991, the Norwegian government began applying a carbon tax to most hydrocarbon sources of emissions.[24] While Finland, which in 1990 introduced the world's first carbon tax, placed its rate at less than US$2 per tonne of CO_2, Norway went bold, setting a price over US$41 per tonne.[25] The new policy sent the message that reducing greenhouse gas emissions was a national priority that must be integrated into any sector with energy-intensive investment decisions.

At that same time, Norwegian state-owned oil company Statoil – now renamed Equinor – was looking to develop its Sleipner gas field. The gas being extracted had CO_2 content ranging from 4% to 9%, and Statoil needed to reduce it to below the 2.5% level required to make it marketable.[26] Former practices would have vented that CO_2 to the atmosphere, but the new carbon tax meant it would have been so costly that it might have scuttled the field development.[27]

Thus, CO_2 removal and permanent subsea disposal was considered as a solution. It was unprecedented at the time. The government, as the golden shareholder in Statoil and also highly vested in the CO_2 avoidance policy, backed the decision to advance the project. After all, if it proved successful, other fields in Norwegian waters could be monetized using the same approach.

Summary of Sleipner

The Sleipner project is located about 250km offshore from Norway in the North Sea. Two gas fields, Sleipner East and Sleipner West, are tapped to produce gas (Figure 1). The project installed a separate, first-of-its-kind self-contained platform to strip CO_2 from the gas next to the production platform. The CO_2 is compressed and pumped about 12.5km via subsea pipeline to an injection site more than 1,000m below the seafloor (Figure 2). Depending on gas production rates and the level of CO_2 in the extracted gas, the project sequesters between 0.85mtpa and 1mtpa of CO_2. Sleipner has

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[23] This summary of the Sleipner project is compiled from data and explanations described in the following source documents:
Society of Petroleum Engineers. Sleipner vest CO_2 disposal, CO_2 injection into a shallow underground aquifer. Baklid et al. Paper 36600. October 6, 1996.
Bellona. Carbon dioxide storage: Geological security and environmental issues – case study on the Sleipner gas field in Norway. Solomon. May 1, 2007.
Energy Procedia. Lessons learned from 14 years of CCS operations: Sleipner, In Salah and Snøhvit. Eiken et al. Volume 4. 2011, p. 5541-5548.
International Journal of Greenhouse Gas Control. The Sleipner storage site: Capillary flow modeling of a layered CO_2 plume requires fractured shale barriers within the Utsira Formation. Cavanagh and Haszeldine. Volume 21. February 2014, p. 101-112.
Energy Procedia. The CCS hub in Norway: Some insights from 22 years of saline aquifer storage. Ringrose. Volume 146. July 2018, p. 166-172.

[24] Organization for Economic Cooperation and Development. How carbon taxation can help deploy CCS in natural gas production. 13th Plenary Meeting of the Policy Dialogue on Natural Resource-based Development. November 25, 2019.

[25] Proceedings of the 7th International Conference on Greenhouse Gas Control Technologies. September 2004. CO_2 underground storage costs as experienced at Sleipner and Weyburn. Torp and Brown. Volume 1. 2005, p. 531-538.

[26] Norwegian Petroleum Museum. CCS on Sleipner – back where it came from. Lindberg. Accessed on June 7, 2023.

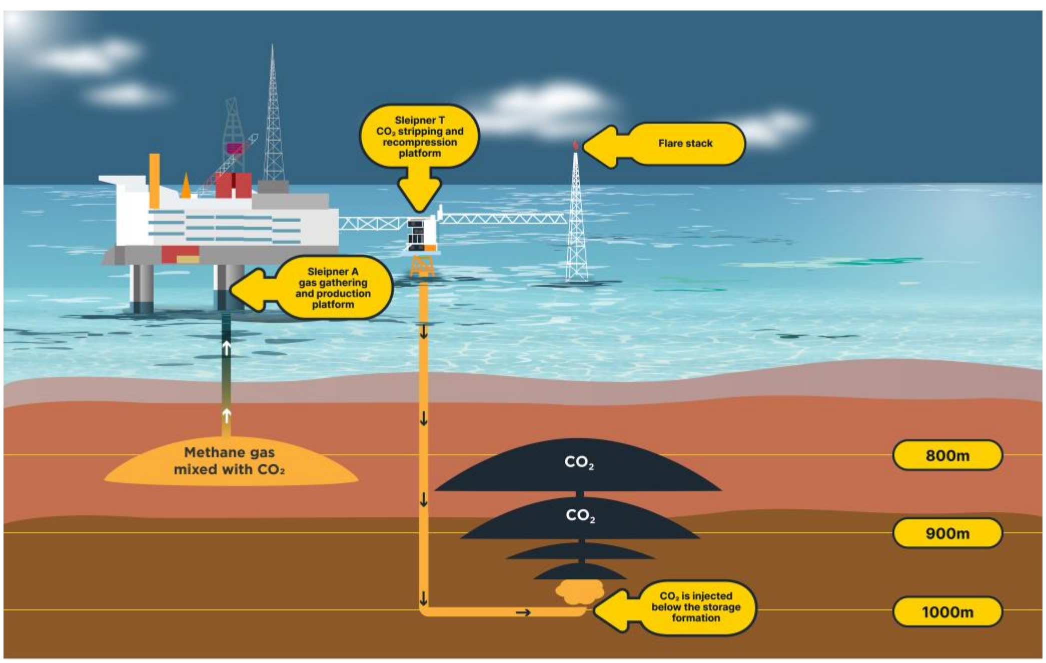
[27] IEA. 20 years of carbon capture and storage – Accelerating future development. November 15, 2016, p. 20-22.

been operational since 1996. The investment cost for Statoil was US$92 million in 1996, or about US$181 million in 2022 dollars.[28,29]

Figure 1: Sleipner Project Location Map

Source: Zhu Laboratory, Indiana University Bloomington. IEEFA

Figure 2: Sleipner's Self-contained Offshore CO_2 Processing Platform



Source: Geological storage of CO_2: project design and global scale-up. Ringrose. March 29, 2021. IEEFA

[28] Coordinating Committee for Geoscience Programmes in East and Southeast Asia (CCOP). Workshop on development of natural gas resources with high CO_2 and CCS in CCOP. CCS Case Studies. Kaarstad. March 18, 2009.
[29] Ibid, footnote 25.

The Original Information

Statoil undertook extensive surveys of the subsurface conditions around Sleipner using three-dimensional (3D) seismic survey techniques. This allowed geophysicists and reservoir engineers to predict which subsurface geological layers had the potential to store CO_2. The area they identified, the Utsira formation, appeared to have a series of eight layers, ranging from a depth of about 1,050m to around 850m below the surface.[30]

This was deemed technically appropriate because, at those depths, CO_2 had the potential to remain in supercritical form. Supercritical CO_2 exists in a state between liquid and gas when under correct pressure and temperature conditions, making it more likely to remain sequestered in the pore spaces within the rocks where it is introduced. Those conditions are maintained when CO_2 is stored typically 800m below the surface or deeper.[31,32]

The Sleipner project drilled a single well for CO_2 injection that traveled horizontally at a level of nearly 1,050m, so as to provide the best chance for percolating introduced supercritical CO_2 into the layers above.

With this configuration, injection operations began in August 1996, delivering between 0.85mtpa and 1mtpa of CO_2.[33] Additional seismic surveys were conducted about every two years to track how CO_2 uptake into the various subsurface layers was progressing. Such frequent surveys were costly but were deemed important so that scientists would be able to prove the storage capabilities of this first-of-a-kind project.

Deviation from Plan: Unexpected Shallow Subsurface Layer

In 1999, about three years into CO_2 injections and after the second of the 3D seismic studies was completed, scientists noticed an unexpected artifact in their seismic imaging: an indication of CO_2 starting to accumulate in a shallower, previously unidentified layer.[34] The layer was situated 800m below the seabed in about 250m of water. That placed it right at the upper limit of what is considered to be the minimum preferred depth for CO_2 storage, the depth required to keep CO_2 in a supercritical state.[35]

Pre-injection studies of the injection site had indicated only eight layers of shale rock. This made the presence of what was quickly referred to as the ninth layer (Layer 9) a surprise. However, what was perhaps more surprising was that the CO_2 had migrated so quickly through the eight deeper layers,

[30] Society of Petroleum Engineers. Sleipner Vest CO_2 disposal, CO_2 injection into a shallow underground aquifer. Baklid et al. Paper number SPE-36600-MS. October 6, 1996, p. 269-277.
[31] International Journal of Greenhouse Gas Control. The Sleipner storage site: Capillary flow modeling of a layered CO_2 plume requires fractured shale barriers within the Utsira Formation. Cavanagh and Haszeldine. Volume 21. February 2014, p. 101-112.
[32] Ibid, footnote 30.
[33] Equinor. Sleipner area. Accessed on June 6, 2023.
[34] Ibid, footnote 31.
[35] Ibid, footnote 30.

to Layer 9, moving upward 220m in just three years. This implied that the eight layers were potentially far more fractured and/or thinner than previously thought.[36]

The ability of the CO_2 to travel so quickly and easily from its initial deposition point to Layer 9 raised questions. The depth and horizontal extent of Layer 9 was completely unknown. How far would the CO_2 spread out inside it? Would that layer be geologically contained at its perimeter? This was a concern since, as the CO_2 moved to shallower elevations, its volume would expand due to changes in pressure and/or temperature.

A need arose to conduct regular 3D seismic surveys of the storage site in order to determine how the CO_2 was moving over time. Accordingly, follow-up work ensued at a minimum of every two years – 2001, 2002, 2003, 2006, 2008 and so on, thus creating a "4D" seismic series. These surveys yielded observations of Layer 9's horizontal coverage growing extensively between 2006 and 2008 and continuing into 2010. Rates of filling increased from what was estimated to be 135m^3/day in 2001 to 540m^3/day by 2006.[37] As the rate of gathering grew in Layer 9, it became imperative to more accurately model plume behavior in an attempt to predict how stable or secure the storage would be. It was a challenge at this first-of-its-kind site. As some researchers have pointed out, 4D geophysical surveys have limitations that do not provide full insight into CO_2 plume density or the ability to measure with reasonable accuracy all nine layers' thicknesses and, therefore, how much CO_2 is being stored.[38] One researcher noted that, even with regularly conducted surveys, differing approaches to collecting and processing seismic data done by different service providers could render comparisons across time-based datasets challenging or unreliable.[39]

Hampering the monitoring efforts was a lack of instrumentation. Temperature is a key factor in determining the state and characteristics of the migrated CO_2. The Sleipner CO_2 injection well had no downhole sensors.[40] Other wells in the area were located at material distances from the deposition site and at different depths, meaning that any information obtained would need to be interpolated.

Following from Layer 9's development, geophysicists throughout Europe began conducting modeling studies of the site. They employed a wide array of methods to see if one could accurately model the characteristics of the CO_2 in the formation and predict the extent the plume might travel.

Between Sleipner's 2008 and 2010 seismic studies in the 10th to 12th year of operations, CO_2 plume growth began accelerating. Statoil highlighted this growth in Layer 9 development in its presentation to the Carbon Capture and Storage Association at an event titled "Sleipner: 20 years of successful storage operations" in 2016.[41] The extent of Layer 9's rapid growth is shown clearly in Figure 3.

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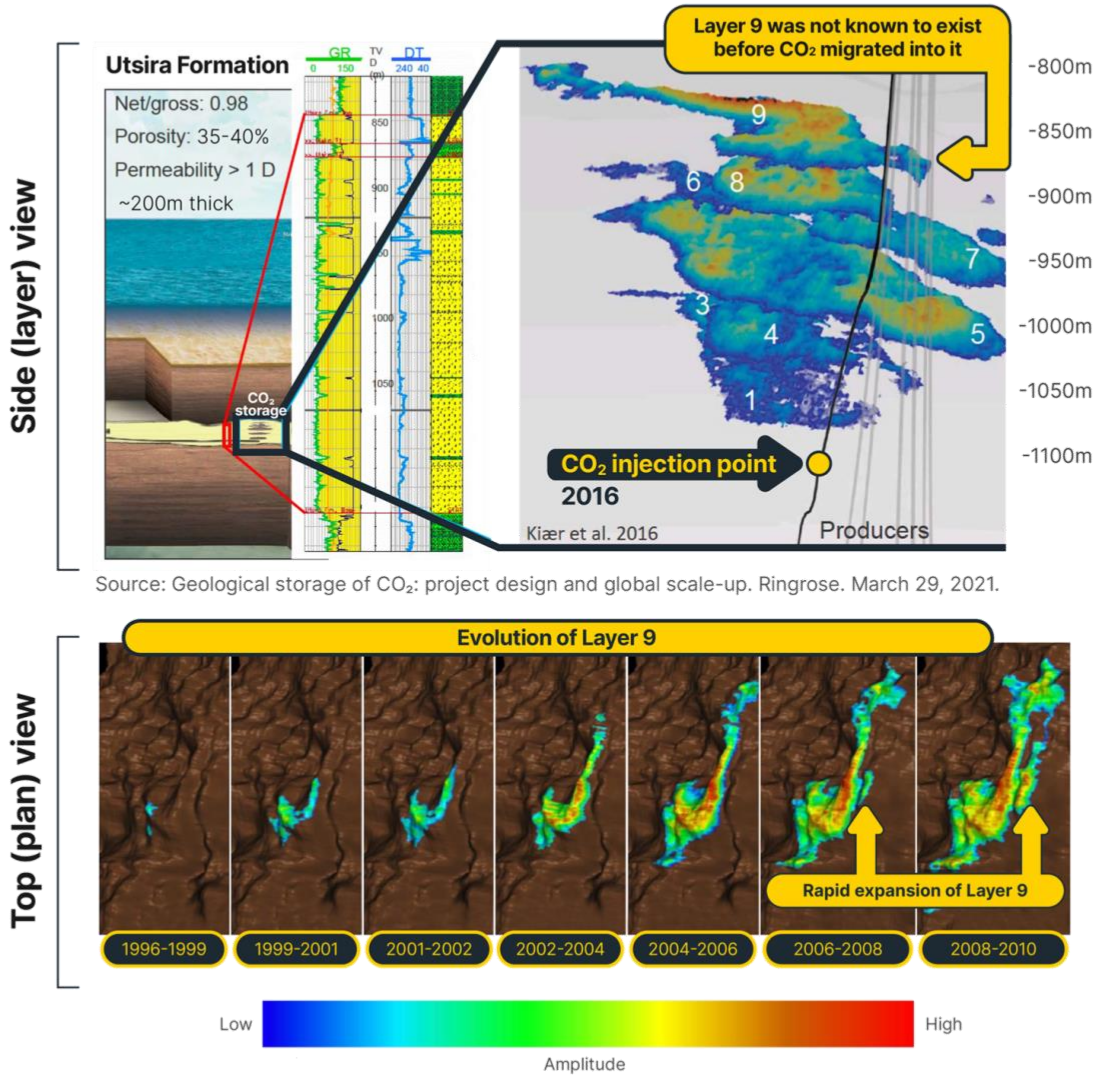
[36] Ibid, footnote 31.
[37] Energy Procedia. Latest time-lapse seismic data from Sleipner yield new insights into CO_2 plume development. Chadwick et al. Volume 1. February 2009, p. 2103-2110.
[38] Ibid, footnote 31.
[39] Journal of Geophysical Research. Spatial and temporal evolution of injected CO_2 at the Sleipner Field, North Sea. Boait et al. Volume 117, B03309. March 13, 2012.
[40] Ibid, footnote 39.
[41] Statoil. Sleipner: 20 years of successful storage operations and key learning for future projects. Skalmeraas. June 29, 2016.

Figure 4 provides a vertical section profile of the Sleipner storage field across its depth, from the CO_2 injection point up to Layer 9. Subsequent independent study and modeling of that data provided an even clearer illustration of the extent of growth.[42]

Figure 3: Sleipner Development of CO_2 Storage Layer 9

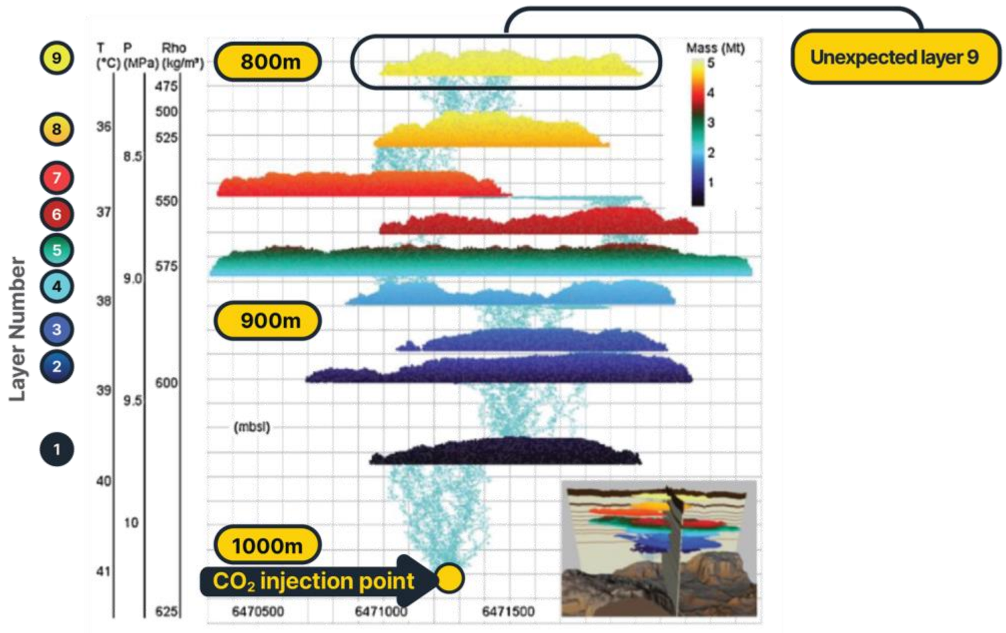


Source: Geological storage of CO_2: project design and global scale-up. Ringrose. March 29, 2021.

Source: Statoil ASA. Sleipner – 20 years of successful storage operations and key learning for future projects. Skalmeraas. June 29, 2016. IEEFA

[42] Ibid, footnote 39.

Figure 4: Depths of Sleipner's Nine CO_2 Storage Strata



Source: International Journal of Greenhouse Gas Control. Cavanagh and Haszeldine. 2014. IEEFA

To combat the unknowns of Layer 9 while operations continued, Statoil had to create a new and more detailed model of Sleipner's subsurface formations, called the Sleipner Benchmark. Released in 2011 granting researchers open access, the Sleipner Benchmark 2011 was a 3D numerical mesh model but only of Layer 9, as it was the layer of greatest concern. The model was calibrated using the 4D seismic data series collected through 2010 and sought to provide sufficiently detailed information for researchers to help model the future of storage buildups and boundary conditions, particularly within the top layer.[43]

Equinor updated the Sleipner Benchmark in 2014 and again in 2019, fed by each successive round of seismic data acquisition. Benchmark 2014 added a storage layer 8 to the 2011 model to facilitate analysis of the two topmost storage structures.[44] Benchmark 2019 covered all nine storage layers to provide a more comprehensive dataset for analysis.[45] Figure 5 compares the 2011 and 2019 Sleipner Benchmarks and illustrates the type of data researchers can access.

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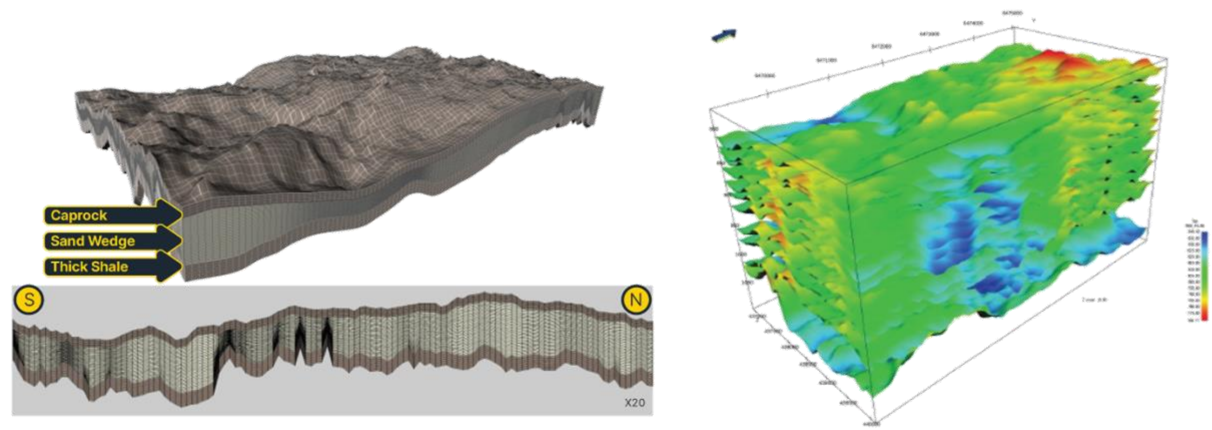
[43] Energy Procedia. Benchmark calibration and prediction of the Sleipner CO_2 plume from 2006 to 2012. Cavanagh. Volume 37. 2013, p. 3529-3545.
[44] Energy Procedia. A new and extended Sleipner Benchmark model for CO_2 storage simulations in the Utsira Formation. Cavanagh and Nazarian. Volume 63. 2014, p. 2831-2835.
[45] Equinor. Sleipner 2019 Benchmark Model. CO_2 DataShare. Released January 17, 2020, and updated October 13, 2022.

Figure 5: Comparison of Sleipner Benchmark Datasets

Sleipner Benchmark 2011
Model only of Layer 9

Sleipner Benchmark 2019
Model of all nine layers



Source: Energy Procedia. Benchmark calibration and prediction of Sleipner CO_2 plume from 2006 to 2012. Cavanagh. Volume 37. 2013, p. 3529-3545.

Source: Equinor. Sleipner Benchmark 2019. CO_2 DataShare. October 2022.

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Sleipner Modeling and Prediction Struggles Continue

The key to whether Layer 9's CO_2 would be contained was the nature and extent of the caprock on top of it. Pre-operational investigations conducted in 1994 indicated that the caprock was thick and lacking significant fractures.[46] What was and remained unknown at the time of Layer 9's discovery and subsequent years of CO_2 filling were the edge boundaries of the caprock and whether those boundaries were confined to the geographic limits of Sleipner's operating license.

Equinor made efforts to crowdsource research support; however, it appears scientists still struggle to predictively model the storage formation's behavior.[47] Academic studies released since the presence of Layer 9 became known up to the 2020s continue to highlight modeling challenges.[48] What this struggle indicates is the monumental science behind CCS – the need for continual improvement of modeling and monitoring techniques in order to get a better handle on the envelope of risks and potential behaviors.

To date, the caprock formation above Layer 9 has contained further migration of CO_2. Had this not been the case, the "success" of Sleipner's storage operations may have turned out differently. Yet, despite near continual study, the precise extent of Layer 9's capacity for containment remains unknown.

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[46] Ibid, footnote 30.
[47] International Journal of Greenhouse Gas Control. Sleipner: The ongoing challenge to determine the thickness of a thin CO_2 layer. White et al. Volume 69. February 2018, p. 81-95.
Earth and Planetary Science Letters. Benchmarking of vertically-integrated CO_2 flow simulations at the Sleipner Field, North Sea. Cowton et al. Volume 491. June 2018, p. 121-133.
[48] Greenhouse Gases: Science and Technology. Analysing the role of caprock morphology on history matching of Sleipner CO_2 plume using an optimisation method. Ahmadinia and Shariatipour. 2020.

Sleipner's subsurface storage area has been under continual, intensive study from the point of site selection through to the current day. The site, and the specific strata chosen for CO_2 injection, was picked based on the reservoir engineers' conclusions from analysis performed to determine how the CO_2 might behave in the long term and to assure minimal chances of release. Despite upfront study, engineers could not identify the presence of Layer 9. They could not predict how rapidly Layer 9 would fill and expand.

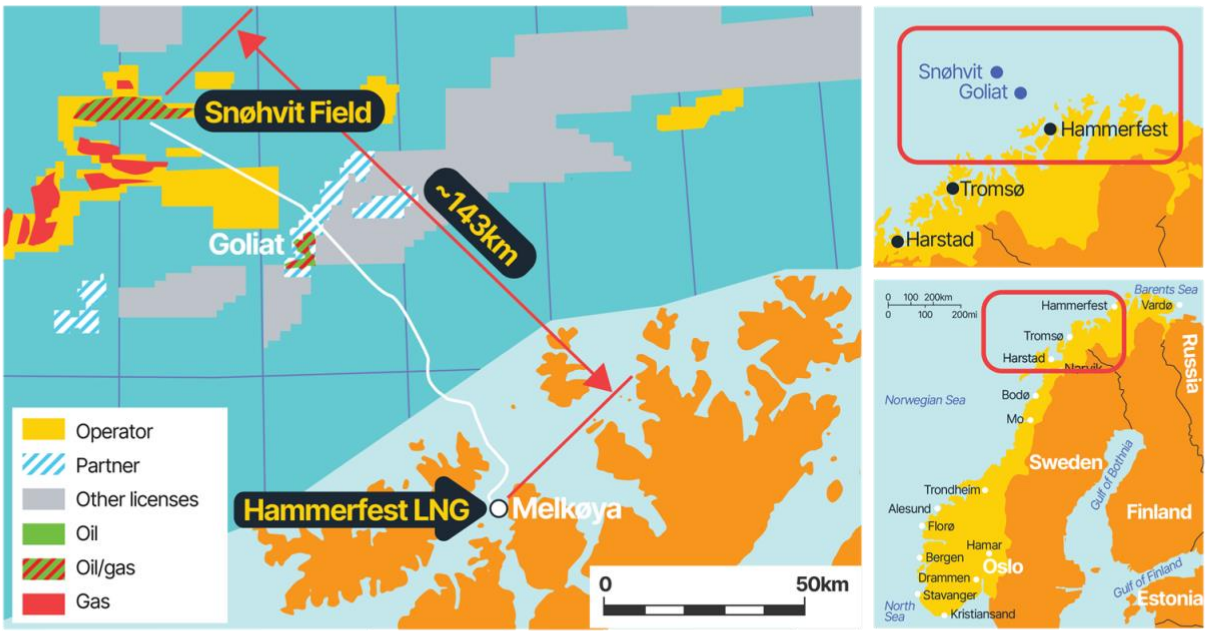
Even now, with the benefit of a dozen sets of seismic data collected using the latest technology and techniques, a state-of-the-art benchmark model, and the efforts of scores of researchers producing large volumes of scientific models and assessments, still it remains a challenge to predict how Sleipner's subsurface storage area will behave from year to year, let alone from decade to decade.

Sleipner, in the scheme of things concerning CCS, is a small project. As this paper will discuss later, projects being considered worldwide are of an order of magnitude larger in their CO_2 injection rates, requiring storage areas many times the size of Sleipner's. A larger project is likely to multiply challenges. Getting the science right – or at least better – may be the difference between CO_2 staying in the ground or not. Sleipner's monitoring and modeling struggles are a bellwether of what could be in store for proposed CCS projects globally.

The Snøhvit Project[49]

Snøhvit is a gas field situated in the Barents Sea supplying the 4.65mtpa Hammerfest LNG export project in the far northern reaches of Norway. It is located about 800km north of the Arctic Circle and 143km offshore northwest of Melkøya, Norway, where the Hammerfest project is sited (Figure 6).

Figure 6: Snøhvit Project Location Map



Sources: Snøhvit location map - Adapted from Statoil as referenced in the article, Statoil announces giga-investment in northernmost ever oil field. The Barents Observer. December 5, 2017.
General Norway map – WorldMap1.com. https://www.worldmap1.com/map/norway/hammerfest-map.asp IEEFA

The Snøhvit gas field sits under 300m of water, where engineers felt it impractical to build platforms. Accordingly, all well infrastructure is submerged and affixed to the seafloor. Pipelines carry the raw produced gas to shore-based facilities at Hammerfest where the CO_2 is stripped from the methane, compressed to supercritical state and pumped again about 143km back offshore to the injection well site (Figure 7). The pipeline is made of a special high chromium steel to mitigate against the

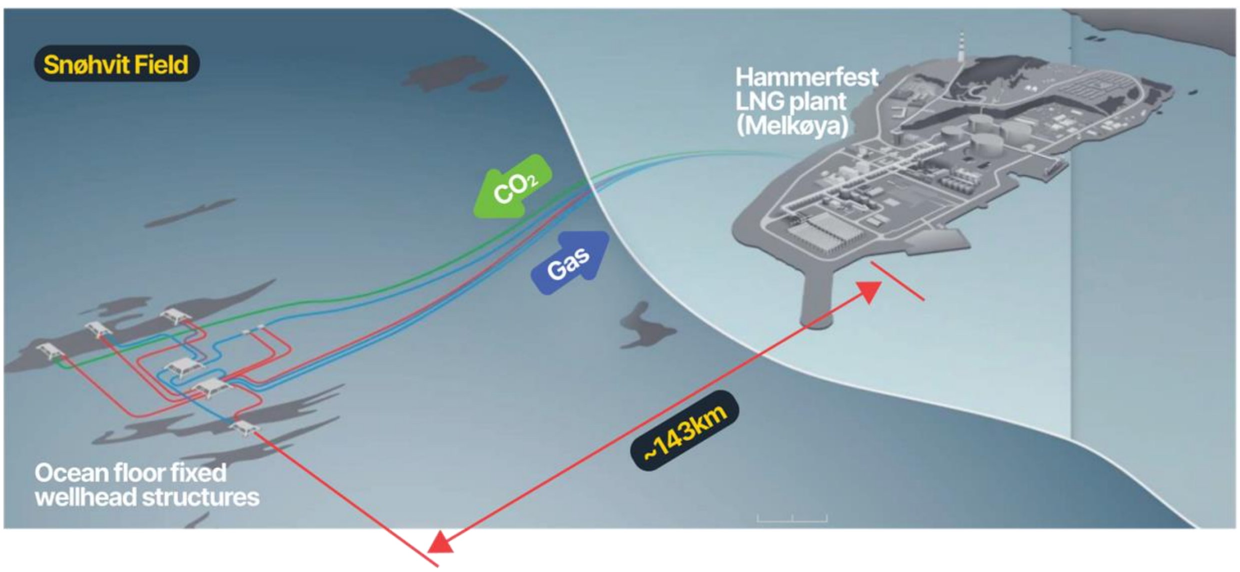
[49] The information provided in this section is derived from the following studies and reports:
Statoil. Light well intervention, Snøhvit Well 7121/4-F-2 H, results and evaluation. August 22, 2011.
Energy Procedia. Snøhvit: The history of injecting and storing 1 Mt CO_2 in the fluvial Tubåen formation. Hansen et al. Volume 37. 2013, p. 3565-3573.
Lawrence Livermore National Laboratory. Snøhvit CO_2 Storage Project FWP-FEW0174 Task 4. Chiaramonte et al. August 20, 2013.
Statoil. Offshore monitoring lessons learned: Sleipner and Snøhvit storage projects. Ringrose et al. August 22, 2013.
Lawrence Livermore National Laboratory. Probabilistic geomechanical analysis of compartmentalization at the Snøhvit CO_2 sequestration project. Chiaramonte et al. March 25, 2014.
Energy Procedia. The CCS hub in Norway: Some insights from 22 years of saline aquifer storage. Volume 146. July 2018, p. 166-172.
Equinor and Norwegian University of Science and Technology (NTNU). Ensuring safe storage operations: Learning from Sleipner and Snøhvit. Ringrose. October 14, 2020.

corrosive nature of the CO_2 fluid. Snøhvit's produced gas contains between 5% and 8% CO_2 gas that must be separated from the methane gas; production rates yield about 0.7mtpa of CO_2 for injection.

The initial target for CO_2 injections was a formation named Tubåen, located at 2,600m below the seafloor. This placed the CO_2 injection point far below the 800m phase-change point for supercritical CO_2. Geophysicists, following a similar process to Sleipner's, conducted extensive 3D seismic studies of the subsurface formations in order to identify Tubåen. By evaluating that strata's geology, they predicted the rock was porous enough to hold about 18 years of Snøhvit's CO_2 production. While the projected life of the gas field was at least up to 2035, engineers felt 18 years provided sufficient time to identify other strata in the area for supplemental CO_2 storage in the latter years.

The project was commissioned in 2008 with a cost of US$191 million, or US$311million in 2022 dollars.

Figure 7: Snøhvit Project Configuration



Source: Equinor and Norwegian University of Science and Technology. Ensuring safe storage operations: learning from Sleipner and Snøhvit. Ringrose. Baltic Carbon Forum 2020. October 14, 2020. IEEFA

Snøhvit's Storage Challenges Manifested Early

Like Sleipner, Snøhvit's CCS component was meant to monetize a large methane gas deposit in Norwegian waters. Its financial success hinged on the reliable stripping and disposal of excess CO_2 from feedstock gas. The stakes for Equinor were far larger due to its concurrent US$6.9 billion investment in the Hammerfest LNG liquefaction facility, so the CCS had to work. The chain of projects was commissioned in April 2008 and is slated to continue operating through at least 2035. Due to the high stakes of investment, extensive subsurface seismic study of the Snøhvit field gas and CO_2 storage sites was conducted to ensure proper and sufficient CO_2 storage potential.

As noted in Hansen et al (2013), while field developments can have extensive and well-intended engineering designs, often the physical implementation may not go as planned.[50] It is not possible to accurately predict all physical conditions at the time of design. Snøhvit realized this uncertainty almost immediately.

From Snøhvit's initial CO_2 storage stratum assessment, engineers expected to have nearly 80m of perforated well casing at the base of Tubåen's 2,600m deep injection site, which would allow a large surface area for CO_2 injection. However, during the 2008 primary drilling, the rock conditions encountered allowed for only 30m of the 80m to be perforated, thus shrinking the injection surface area by two-thirds.[51] While engineers deemed this smaller area workable, it reduced the comfort margin at the Tubåen interface in the event of complications.

Then, in 2010, less than two years into operations, trouble in the CO_2 injection well was detected. Pressures were rising far faster and higher than the reservoir engineering predicted. By the third quarter of 2010, pressures at the injection site had risen by more than a third, from their initial 290 bar to 390 bar.[52] Either the CO_2 inflow was being impeded or the deposition stratum was having problems accepting the CO_2. As noted above, the original design studies had indicated that Tubåen was of ideal porosity for CO_2 deposit and could hold an estimated 18 years' worth of targeted production. However, at the rate pressures were rising, engineers projected in 2010 that, at the prevailing injection rates, the project might be able to continue CO_2 storage only for an additional half a year. That would put the entire Snøhvit-Hammerfest project in jeopardy.

Flashbacks to In Salah, Algeria

At the time Snøhvit's woes became apparent, Equinor was taking stock of the nearly concurrent failure of its land-based In Salah CCS project in Algeria.[53] There, CO_2 was being deposited at a similar injection rate to Sleipner, about 3,000 tonnes per day. However, the storage site at In Salah was considered to be a "relatively simple anticline" geologic structure. Such "simplicity" inspired confidence. As early as 2005, just one year into the project's operations, the Intergovernmental Panel on Climate Change (IPCC), in Chapter 5 of its seminal CCS report, included In Salah as a model for CCS globally.[54] The report noted that the project's 3D seismic data were validated by production well data which confirmed the viability of the simple formation, and thus posed "minimal structural uncertainty or risk."[55]

Injections at In Salah began in 2004. Starting 2009, CO_2 pressure in the deposit strata had built up to extremely high levels. Despite this rise, injections continued into early 2011, while more monitoring

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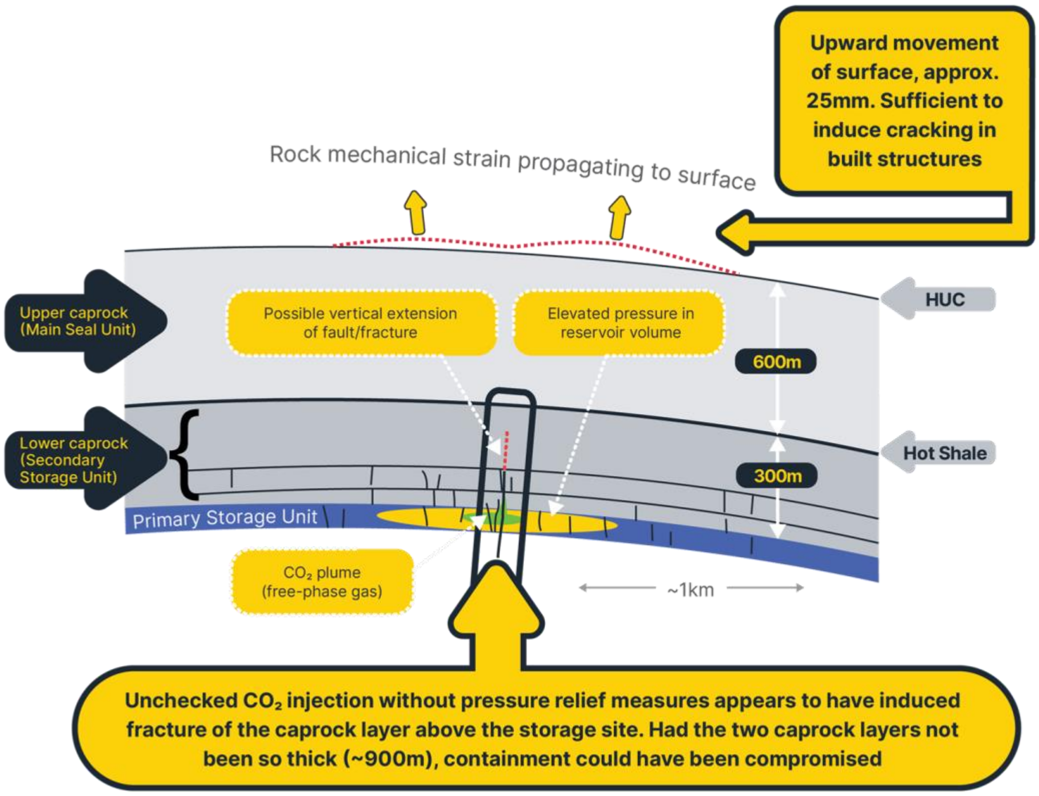
[50] Energy Procedia. Snøhvit: The history of injecting and storing 1 Mt CO_2 in the fluvial Tubåen formation. Hansen et al. Volume 37. 2013, p. 3565-3573.
[51] Statoil. Offshore monitoring lessons learned: Sleipner and Snøhvit storage projects. Ringrose et al. August 22, 2013.
[52] Ibid, footnote 51.
[53] Energy Procedia. The In Salah CO_2 storage project: Lessons learned and knowledge transfer. Ringrose et al. Volume 37. 2013, p. 6226-6236.
[54] IPCC. Carbon dioxide: Capture and storage. Chapter 5, Box 5.2. Metz et al. 2005.
[55] Ibid, footnote 54.

and studies were conducted. Eventually, the pressures grew strong enough that the injected CO_2 appeared to have fractured the caprock containment strata above the storage formation.

Fortunately, due to the caprock layer being extremely thick, of around 950m, CO_2 did not escape from the subsurface. However, the pressure was great enough that it caused a surface-level ground swell of 20-25 millimeters even though the storage formation was 1km underground (Figure 8). A movement of that scale is significant enough that it could have caused structures on the ground to crack. Fortunately, the site was located in unoccupied desert land.

CO_2 injection was indefinitely suspended. Since 2011, stripped CO_2 from In Salah's continuing natural gas well production has been vented to the atmosphere. As Algeria does not tax CO_2 emissions, this continued venting is not a regulatory violation.

Figure 8: In Salah CO_2 Storage Site Failure Mode



Sketch illustrates main geomechanical observations around injection well KB-502

IEEFA

Source: Energy Procedia. The In Salah CO_2 storage project: lessons learned and knowledge transfer. Ringrose et al. No 37, 2013, p. 6226-6236.

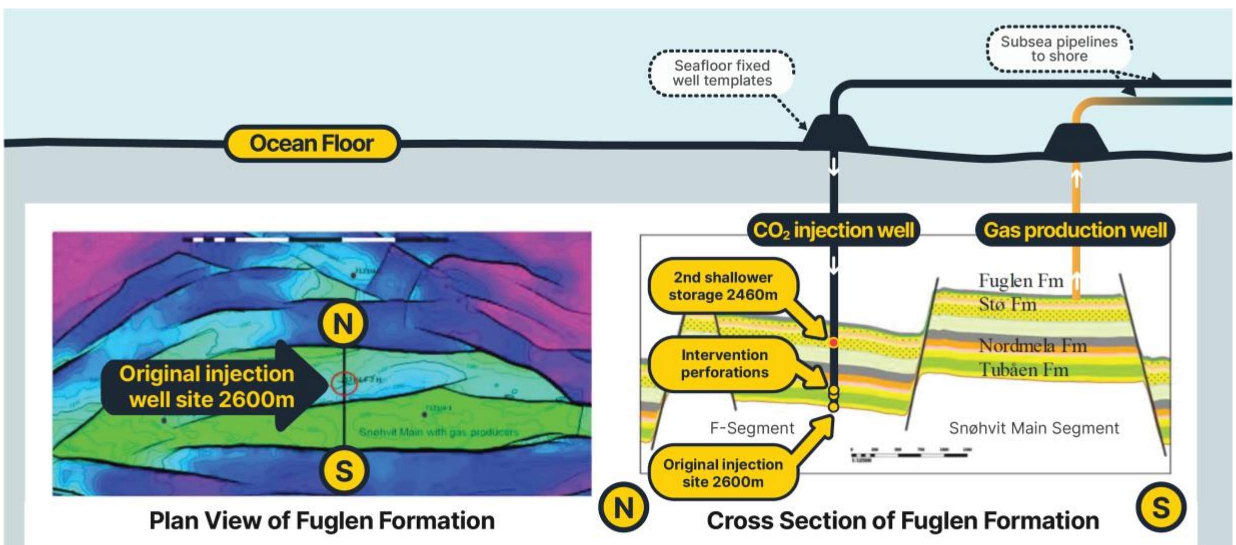
Immediate Remedial Intervention at Snøhvit

Back at Snøhvit, CO_2 injection site pressures were continuing to rise. As little other sensor data than pressure was available, what was causing the increase was unknown. To get to the bottom of the constrained CO_2 uptake, reservoir engineers scheduled an emergency well intervention. This required:

- Immediate remedial engineering work to develop actionable options
- Hiring a specialized, self-positioning intervention drillship and crew
- The right seasonal conditions in the Barents Sea needed to safely launch an intervention
- Stoppage of Snøhvit gas production during the investigations
- A diagnosis of what was wrong in real time based on the data obtained from downhole well monitors and samples
- The execution of all possible remedial or supplementary downhole drilling while the ship was in place.

Engineers and scientists considered the possibilities. The cause might have been as straightforward as a blockage in the well line. Salt or other mineral deposits could have been building up at the interface between the well perforation and the storage stratum because of the CO_2 interacting with other fluids. Or there might have been an issue with formation chemistry or porosity not identified during initial drilling. Not until the chartered intervention vessel was deployed and connected to the well would engineers be able to diagnose the conditions. Only after such research could solutions, if any, be applied. Many contingency plans were required as running through this checklist would need to take place while an intervention vessel was in position and connected to the well.

Figure 9: Well Intervention at Snøhvit's Initial CO_2 Injection Site



Source: Energy Procedia. Snøhvit: The history of injecting and storing 1mt CO_2 in the fluvial Tubåen formation. Hansen et al. No 37, 2013, p. 3565-3573. Annotated by IEEFA. IEEFA

The checklist intervention steps did not yield improvements.[56] The well casing was not found to be blocked. Salt-dissolving chemicals in the injection stream did not improve flow; therefore, mineral deposits downhole were ruled out.[57] Reperforation of the Tubåen formation just above 2,600m failed to ease pressures during test injections.

The conclusion, after sampling the rock at the injection interface, was that Tubåen was not sufficiently porous and therefore not as receptive to CO_2 storage as pre-operation studies had indicated. The deep, 2,600m formation was plugged and abandoned as data clearly indicated it was unable to accept the injections for much longer.

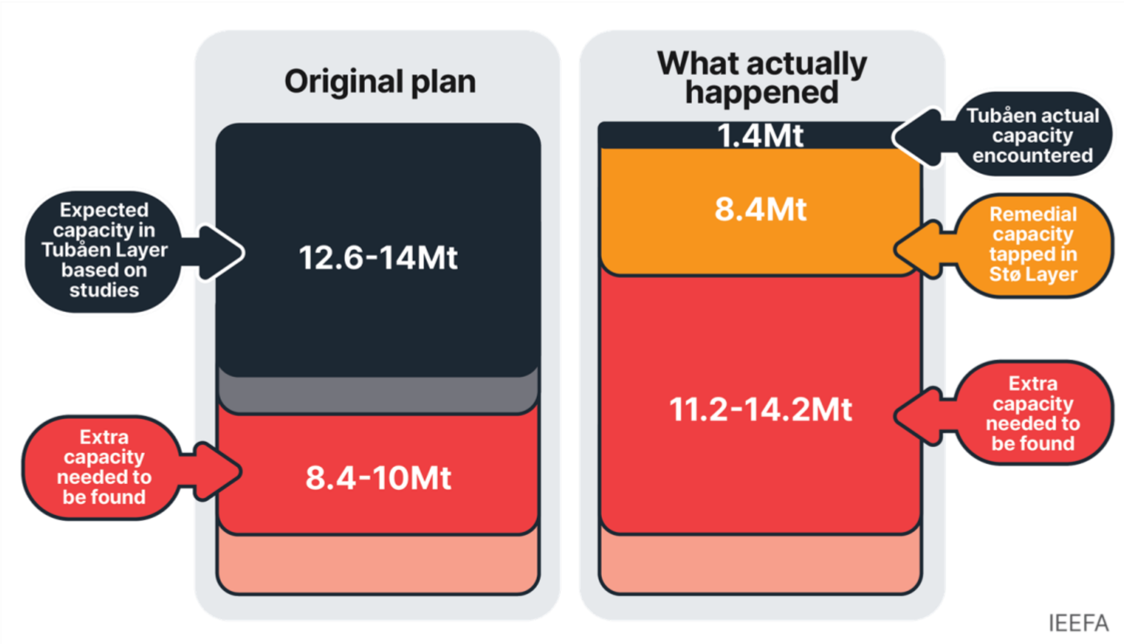
The engineers started exploring the storage potential of a shallower stratum, called Stø, on the same well bore. This stratum ran from a depth of about 2,480m to 2,400m. With the deep part of the well bore now plugged, new perforations were opened at around the 2,460m level of Stø. Well engineers needed to tread carefully as within the shallower range of Stø, above 2,435m, gas production was taking place, thus there was a very small comfort margin. After a number of failed CO_2 injection attempts, eventually test flows and pressures from this shallower Stø formation demonstrated CO_2 storage viability. Re-evaluating past seismic data allowed engineers to create a new estimate of storage potential for Stø. Satisfied that appropriate conditions could be met for the time being, Equinor resumed CO_2 deposit operations.

However, a new hurdle arose; Stø had a smaller storage potential than the original deeper Tubåen stratum. This volume was insufficient for Snøhvit's targeted production life. Further, given the minimal separation between the CO_2 injection well level and the gas-producing areas of the Stø formation (2,460m versus 2,435m), there was heightened potential for injected CO_2 to push into gas-producing wells.[58] Engineers needed to identify a *third* potential CO_2 storage stratum at a different location. The new perforations at Stø's 2,460m level had bought time, but not until 2035.

The original design had intended to deposit 12.6Mt to 14Mt of CO_2 during the first 14-15 years of operations, based on initially projected production rates.[59] While this was not sufficient storage space for the entire operating life of Snøhvit, it provided engineers with sufficient time and buffer capacity to undertake exploration to find a supplemental 8Mt to 10Mt of CO_2 storage. Thus, with the storage limitations of Tubåen (about 1.4Mt) and the smaller storage space of Stø (8Mt-9Mt), the search for additional storage took on greater urgency. Exploration for a new CO_2 storage site needed to be undertaken expediently to keep both Snøhvit and Hammerfest LNG operational. A summary of the storage situation Snøhvit faced is shown in Figure 10.

[56] The following four paragraphs paraphrase the Completion Report for Snøhvit's CO_2 injection well intervention contained in: Statoil. Light Well Intervention Snøhvit Well 7121/4-F-2 H Results & Evaluation. Document AU-SNO-00037. August 22, 2011.
[57] International Journal of Greenhouse Gas Control. Pressure effects caused by CO_2 injection in the Tubåen Fm., the Snøhvit field. Grude et al. Volume 27. August 2014, p. 178-187.
[58] JWN Energy. Statoil begins drilling for CO_2 sequestration and replenishment of Snøhvit gas in Norwegian Arctic. August 10, 2016.
[59] These aggregate levels are based on the targeted CO_2 injection rates of 0.75mtpa to 1mpta over the originally intended operating period.

Figure 10: Snøhvit CO_2 Storage Design Plan versus Implementation Outcome



Between 2011 and 2015, more seismic studies were carried out, leading to a new CO_2 injection well site being selected closer to Snøhvit's gas production wells. It was part of the same Stø formation as the 2,460m secondary site, albeit separated by faulting. Engineers could be relatively certain that the second Stø location would perform similarly to the first.

By 2016, Equinor had spent about US$225 million to charter a drillship for project expansion, sinking a new CO_2 injection well and an additional three production wells plus constructing subsea infrastructure to connect the new wells to existing gas and CO_2 pipelines.[60] It was not disclosed what percentage of the additional capital expenditure was associated with the new CO_2 injection site and connections. Snøhvit is now using the third CO_2 injection site.

Questions arise as to how connected the new storage site is to gas production areas, and whether the CO_2 will remain where it has been deposited or migrate elsewhere. The performance of the site will require repeated 3D seismic and gravimetric monitoring while its operation matures. As the Snøhvit project has demonstrated, continual monitoring, study and evaluation is a requirement of the CO_2 injection and storage process.

Snøhvit's challenges demonstrate that there is no finality to plans or operations in CCS. Had monitoring not been continuous and operators not been as cautious, subsurface pressures could

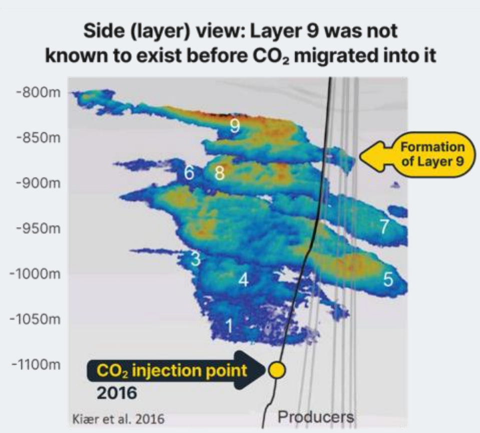
[60] Offshore Magazine. GE to expand Snøhvit subsea injection capacity. June 19, 2013.
Offshore Magazine. Statoil adds more wells at Snøhvit offshore northern Norway. August 3, 2016.
LNG Industry. Statoil to drill new Snøhvit field wells. August 9, 2016.

have exceeded limits, leading to either well failure or, like In Salah, cracking of geologic containment formation. Had studies, equipment or even reasonable weather conditions been unavailable – given the short service season on the Barents Sea – the project would have had to suspend operations. But even with the availability of those resources, it was not outside the realm of possibilities that investigations may have determined no other geologic formation on the well bore could have substituted for the loss of Tubåen and/or that no other suitable storage site near the field was available. CCS operations are an amalgamation of probabilities and risks, some of which can be identified, others remaining unknown until the risk materializes.

Summary of Unexpected Developments in Norway’s Model CCS Projects

As Sleipner and Snøhvit have demonstrated, offshore CCS storage projects offer a variety of potentially unforeseen challenges thrown up by variations in geology and in how CO_2 will interact with that geology. A summary of unexpected developments from each project is provided in Table 1.

Table 1: Unexpected Developments in Norway’s Model CCS Projects

Sleipner Project	
CO_2 migrated unexpectedly within the subsurface. Three years into operations, ***CO_2 moved unexpectedly and rapidly*** to the top of the storage formation and into a ***previously unknown and unidentified*** geological stratum. The stratum, at 800m, was at the very upper elevation limit appropriate for keeping CO_2 in supercritical form. Despite the migration into the shallow Layer 9, the caprock structure above appears geologically resilient.[61] This prevented further CO_2 migration or release. However, the perimeter extent of the caprock formation remains yet to be determined, posing risk for continued injections. Despite detailed subsurface geology studies before operations began, ***engineers missed the existence of Layer 9***. Now, even with tremendous amounts of seismic data gathered and investments made in 3D benchmark models, projecting how the CO_2 will behave and how far it will spread remains a challenge.	**Sleipner CO_2 Storage Plume: Emergence of New Storage Layer**  Source: Geological storage of CO_2: project design and global scale-up. Ringrose. March 29, 2021. IEEFA

[61] See Appendix A for an overview of geoscience in CCS.

Snøhvit Project

***Storage capacity was <u>far lower</u> than studies and engineering expected*.**

Just a year and a half after CO_2 injections commenced, pressure in the deposit formation rose rapidly to alarming levels. The storage stratum was not porous enough to accept the CO_2. **Storage capacity estimates dropped from 18 years of production to less than two years**.

Well intervention was required.
Additional perforations in the target stratum failed to relieve the rapid pressure buildup. An alternate deposit stratum was identified along the same well bore, but at a shallower depth and with lower overall capacity. The intervention incurred unplanned costs but was necessary to address a realized risk.

A third, new CO_2 storage formation had to be identified. For backup, a search for a third CO_2 storage field became necessary in case the second field proved deficient or if performance was similarly subpar. In 2016, Equinor invested in a new CO_2 injection well site as part of an extra US$225 million capital expenditure campaign to enhance production and storage operations.

Snøhvit CO_2 Storage Plan Evolution

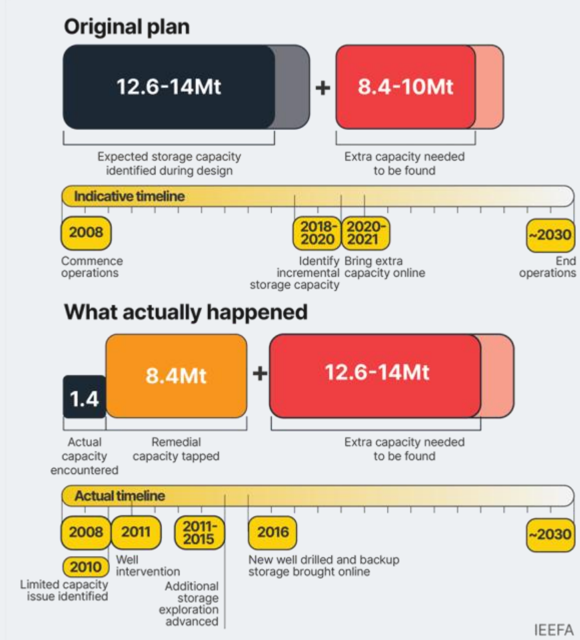


Table 2: Norwegian CCS Project Comparison

Project	Sleipner[62]	Snøhvit[63]
Configuration	Strips out, compresses and injects CO_2 atop remote offshore platform built solely for this purpose. Shoreside facilities for stripped natural gas connect directly to piped gas network.	Pumps raw gas to onshore processing facility, which strips out, compresses and pipes CO_2 back to gas extraction site for injection and storage. Part of the larger, remote Hammerfest LNG export project.
Start of commercial operations	August 1996	April 2008
Gas CO_2% content	4%-9%	5%-8%
CO_2 production	0.85mtpa-1mtpa	0.7mtpa
CO_2 processing location	Offshore, on-platform	Onshore
CO_2 transportation distance	12.5km	143km
Pipeline	Unknown material	World's first offshore CO_2 pipeline. Uses special high-chromium steel alloy to avoid corrosion from CO_2* in supercritical state.
Injection depth	800m-1,000m	2,600m initial; well plugged and abandoned 800m current
Subsequent well intervention / investment	Not applicable	2011 – made additional perforations at 2,600m, then new perforation at 800m. 2016 – drilled new CO_2 well for third storage formation access.
Capital cost (US$)	$92m in 1996 [$181m in 2022 dollars]	$191m in 2008 [$311m in 2022 dollars] $225m in 2016 for new CO_2 well plus 2 new production wells
Operating cost (US$)	$7m/year in 1996 [~$13.2m/year in 2022 dollars]	Not disclosed
Estimated CO_2 sequestration cost (US$ per tonne)	~$17-$20	Not disclosed
Norway carbon tax: At final investment decision (2022 US$-equivalent per tonne)	$41 ($78)	~$45 ($65)
Projected field closure	Not disclosed	2035

* Snøvhit uses gas-drying processes and pipes with high chromium to avoid long-term corrosion from CO_2 transport.

[62] Statoil Research Centre, Norway, and Petroleum Technology Research Centre, Canada. CO_2 underground storage costs as experienced at Sleipner and Weyburn. Torp and Brown. December 2005.
[63] IPCC. Carbon Dioxide Capture and Storage. Chapter 5: Underground Geological Storage. 2005.

Global Push for CCS Projects: Uncertainty Increases with Scale

Sleipner and Snøhvit are repeatedly cited in parliaments, committees, and boardrooms globally as justification for looking to undertake CCS at much larger scale. Worldwide, according to the Global CCS Institute, nearly 200 CCS projects have been proposed in roughly 30 countries, representing an annual indicated deposit capacity of 244mtpa.[64] The IEA has begun tracking these undertakings as well and, in March 2023, it published a database of current and proposed CCS projects.[65]

The projects are targeting an accumulation of tens of billions of tonnes of CO_2 in reservoir storage volumes over their life cycles. Hundreds of billions of dollars will be required in upfront capital investment, and many billions of dollars more to meet operating costs stretching over at least 20 years, with post-closure monitoring periods extending equally as long. Many of the projects are based on a hub or cluster model involving extensive CO_2 gathering infrastructure, consolidation and compression systems, transportation pipelines, and injection sites.

In Asia, ambitious ideas for deploying CCS are afoot. Japan's Tomakomai CCS demonstration project, running since 2019, has sequestered a modest 300,000 tonnes of CO_2. Injections have ceased and the storage formation is being monitored for leakage. However, using relatively short-term conclusions drawn from Tomakomai, the country wants to launch a massive CCS program, taking CO_2 from industrial processes, power generation, and the manufacture of hydrogen for storage offshore at multiple sites at a scale a hundred times greater than this single small-scale demonstration.[66]

Petronas, Malaysia's nationally owned oil and gas company, approved the Kasawari CCS offshore project in the South China Sea, 180km north of Bintalu, Sarawak, last November.[67] The SK316 block from which Petronas is planning to draw gas has an extraordinarily high CO_2 content of 40%. This creates an unprecedented volume of CO_2 to strip out, transport and store. Kasawari's RM4.5 billion (US$1 billion) CCS component will feature the world's largest offshore CO_2 processing platform. At a targeted 3.3mtpa of CO_2, Kasawari will also be among the largest by proposed annual injection volume, second only to Chevron's underperforming Gorgon CO_2 storage project in Australia, at 3.5mtpa to 4mtpa.[68] Accordingly, system integrity and injection well and storage performance are going to be critical if the CO_2 reduction goals are to be met and maintained in the long term. It is worth noting that Malaysia does not have CCS regulations yet.

Similarly, across Europe, about 20 major CCS hub-based projects are in planning and development, aiming to deposit more than 90mtpa of CO_2. In the U.S., high greenhouse gas-emitting industries

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[64] Global CCS Institute. Global Status of CCS 2022. 2022.
[65] IEA. CCUS Projects Database. March 2023.
[66] Reuters. Japan sets carbon capture roadmap with 6-12 mln tonne/year target by 2030. January 26, 2023.
[67] Ibid, footnote 7.
[68] The Guardian. Emissions from WA gas project with world's largest industrial carbon capture system rise by more than 50%. April 20, 2023.

clustered around the Houston Ship Channel in Texas are trying to partner up to create a US$100 billion mega-$CO_2$ storage hub.[69,70] Their site of choice is in the deep waters of the Gulf of Mexico, making use of depleted oil and gas formations. Appendix B provides an overview of CCS project ambitions in Asia and Europe.

The scale and complexity of these projects is unprecedented. Sleipner and Snøhvit would be tiny by comparison. Very real questions can be raised regarding the technical viability and risk associated with developing and managing these proposed undertakings which, after all, are meant to permanently store CO_2. Are governments truly prepared to oversee, regulate and potentially operate these complex projects?

Discussion: Implications for Global CCS From Sleipner and Snøhvit

Several important implications arise from the Sleipner and Snøhvit experience. There are technical implications, scale implications, regulatory implications and, of course, climate implications to these developments. These matters are all the more important in a world that is seeing hundreds of larger and more intensive CCS projects proposed.

Advocates for global adoption of subsurface CO_2 storage systems point to Norway's "CCS success story" as definitive proof of concept. The two fields' ongoing operations mean that they are not fraught with speculation or argument like many other proposed projects. However, the challenges highlighted in this paper beg the question of whether Sleipner and Snøhvit are indeed representative models for global CCS ambitions.

The variances encountered in their operations over time point out issues that might cast doubt on the reliability and security of the concept of CCS itself, especially at scale. The experience clearly illustrates the necessity of extensive upfront subsurface studies; similar levels of study, monitoring and measurement during injection operations; and a post-closure monitoring regime using extensive, repeated studies and instrumentation backed by actionable contingency plans. The need for implementing these plans, at times on short notice, and at any point during or after the operating life implies significant cost. All of this needs to be well regulated.

We present below a number of key takeaways and considerations when looking at offshore CCS and, in particular, when attempting to extrapolate from the Norwegian project pairs' experience to bigger and more complex undertakings.

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[69] ExxonMobil. Industry support for large-scale carbon capture and storage continues to gain momentum in Houston. January 20, 2022.
[70] Ibid, footnote 10.

Overarching CCS Technical Takeaways

Why Permanent CO_2 Storage is a Challenge

CCS technology development derives from the oil and gas exploration and production (E&P) industry. Many of the same techniques used to identify hydrocarbon-bearing strata are employed to discover strata for CO_2 storage.

Experience shows that oil and gas E&P exists in a perpetual state of geologic and technical uncertainty. Field development is based on a statistical distribution of expected outcomes arising from well-considered, yet inherently incomplete, subsurface information. The best technology and processes notwithstanding, assessments yield ranges of potential outcomes across implementation and operational risk scenarios. These are statistical expectations, not certainties. CCS is no different.

Further complicating matters, initial state analyses and resulting designs are subject to change during operations as the subsurface response also shifts over time. Geological structures will present differently in practice than expected during design. A certain percentage of wells will fail. This will lead to deviations from plan. Some of those deviations will be containable while others will result in abandonment, and still others may end up with losses, some potentially substantial.

The Geophysics: CCS May Pose Far Greater Challenges Than Oil and Gas Extraction

Subsurface structures behave differently when materials are put back into them than when things are taken out. To make room for deposition, something has to be displaced or transformed, often under varying temperatures and very high pressures.

Further, CO_2 storage geologic structures are targeted at significant depths in order for the compressed gas to remain in a gel-like supercritical state, which allows for better uptake in the subsurface formation. Introducing this gel to subsurface structures consistently over long periods of operations can lead to unpredictable outcomes.

As seen from Sleipner and, especially, Snøhvit's well performance, variables can present themselves unexpectedly. Even the world's premier subsurface geophysicists and engineers freely admit this. A 2022 paper titled, "Why CCS is not like reverse gas engineering," jointly published by a team of Norwegian scientists, including some of Equinor's most prominent geophysicists, provides a useful discussion of the issues.[71] The paper clearly states many possible unknowns may be encountered and changes may occur over a field's life – and beyond. That leads to the need to:

- Employ the best, most experienced scientists and engineers
- Make use of the most advanced data acquisition, computational, and analytic techniques
- Continually monitor, assess and update plans during operations

[71] First Break. Why CCS is not like reverse gas engineering. Ringrose et al. Volume 40. October 2022, p. 85-91.

- Use more advanced, technical well designs in concert with high specification materials in order to maintain well integrity
- Continually assess storage field integrity before, during and long after CO_2 injection.

Their perspective, garnered over years of working on the CO_2 storage challenge, implies the need to employ, in comparison to regular oil and gas extraction, extraordinary levels of talent, resources, equipment, monitoring and, therefore, money to assure the safe, reliable and secure storage of CO_2. This greater intensity of focus comes at much greater cost. Taken together, though, these resource allocations are commensurate to the challenge and to the risk.

Technical Implications

- Storage sites require extensive ongoing exploration, engineering and contingency planning. CO_2 storage in geologic structures is technically complex and fraught with unknowns and risks. The use of multiple types of modern subsurface investigation techniques provides the best possible assessment but cannot achieve more than an estimate of what may be under the surface. Sleipner and Snøhvit have demonstrated that formations have a material likelihood of performing or behaving differently than assessed, whether up front or over time. As the geophysicists involved have stated, true conditions and behaviors can be seen only after operations commence; there is a risk those conditions are not conducive to storage. These unknowns require contingency planning and, potentially, urgent physical intervention during operations to prevent catastrophic failures.

- ***Multiple forms of survey and modeling are required at regular intervals, representing a material recurring operating cost.*** Geophysical monitoring and modeling of the fields is done using a number of measurement techniques. Despite yielding only an estimation of what is underground, such studies are valuable and need to be implemented repeatedly. Ocean conditions must be favorable to obtain consistent, useable data. The cost of these programs is consequential. Seismic survey requires contracting for these services from providers operating specialized vessels, staffed by geophysicists. These must be booked far in advance. Competition is growing for such vessels, given the ongoing demands of oil and gas E&P and now compounded by the raft of offshore CCS projects contemplated.

- ***Continuous monitoring is required both during and after operations.*** Both Sleipner and Snøhvit, being pioneers in CO_2 storage, had massive amounts of money and technical assistance, and benefited from extensive, detailed, and repeated geological studies.

Experience shows that, to prove the efficacy of the CO_2 storage arrangements, a steady program of confirmation surveys is needed. This includes seismic and gravimetric mapping exercises requiring specialized ships, equipment, and experts. For Sleipner and Snøhvit, had this program not been in place, deficiencies and deviations from the planned storage might not have been detected or addressed in a timely manner – or may have been missed entirely until catastrophic failures occurred.

Scale Implications

- ***For all the effort and monies expended on Sleipner and Snøhvit, the CO_2 volumes being addressed at those sites are small.*** All the planning, studies, active monitoring, investment and ongoing risk combined go into addressing a mere 1.45mpta to 1.7mtpa of CO_2. Global energy-sector CO_2 emissions in 2019, pre-Covid, were 33,000Mt.[72] There needs to be 1,000 times Norway's level of achievement to address the CO_2 problems in the energy sector alone at an appropriate scale.

- ***Both government and industry are proposing storage sites with capacities in multiples of Sleipner and Snøhvit.*** The fact of the matter is, nothing of the scale being proposed for the Houston Ship Channel, the UK CCS clusters program,[73] Norway's Northern Lights,[74] Malaysia's Kasawari, or elsewhere has ever been done. Geologic experience is site specific and non-transferrable.

- Exploration, analysis and monitoring programs for proposed hubs will be massive undertakings that, for reasons of safety and geologic deviations, require CO_2 storage redundancy. As Snøhvit has demonstrated, sometimes storage needs to shift to alternative locations due to a failure or underperformance of the original plan. Thus, on a global scale, given the variations of formation performance over time exist everywhere, it is highly likely that multitudes of backup subsurface structures will need to be identified, analyzed and risk-ranked for integrity and leakage as part of any one CCS hub project. Like Sleipner, Snøhvit or In Salah, each of those identified subsurface

[72] IEA. Global Energy Review 2021. 2021.
[73] Government of Great Britain and Northern Ireland, Department for Business and Trade. Carbon capture, usage and storage. Accessed on April 20, 2023.
[74] Northern Lights JV DA. How to store CO_2 with Northern Lights. Accessed on April 14, 2023.

structures has the potential to see unexpected layers, substandard uptake performance or even failure.

- ***The scope and scale of global CCS aspirations means that failures become likely.*** Undertaking CCS at a global scale as a major contributor to decarbonization would require thousands of wells perforating fields covering tens of thousands of square kilometers of seabed and land. The scale of assessment and management is daunting. Geological strata on Earth are more varied than the proposed fields and, as has been discussed in this paper, the potential for deviations or losses somewhere, at some point in the life cycle, is high. Variations of subsurface strata are evident even at the comparatively small Sleipner and Snøhvit. Such variances signal that each proposed CO_2 storage site would require proportionally similar studies and monitoring as the Norwegian pair, using arrays of sensors and recurring gravimetric and seismic surveys before, during operations and after storage field closure. Even then, statistically speaking, there will be failures, and failures could mean loss of containment, which in turn is a regression from climate change goals.

Regulatory Implications

- ***CCS requires comprehensive, proactive life-cycle regulation.*** Rulemakers must seriously take stock of the deviations-to-plan encountered by Sleipner and Snøhvit. Getting both the realities of subsurface science and the appropriateness of long-term storage regulations correct is becoming imperative on a climate-challenged planet. The experience of Sleipner and Snøhvit demonstrates that full life-cycle regulation is firmly needed. Laws should mandate comprehensive plans that set out realistic expectations for performance variations, properly maintained and monitored operations, and provisions for contingencies to be executed in a specified timely manner. Data on planning, operations and performance needs to be collected and systematically disclosed so that the public and industry are suitably informed when deviations occur, as well as how deviations are managed and CCS integrity maintained. Self-regulation is likely inappropriate as there are too many unknowns in subsurface conditions and potential deviations from plans or operations. Robust regulatory oversight will be particularly important given the veritable explosion in the number and size of storage proposals globally. Appendix C provides a survey of the few existing regulatory environments globally and the status of international technical standards for CCS.

- The Norwegian government was a partner in Sleipner and Snøhvit; any future project will require similar extensive public oversight and involvement. Norway's pioneering CCS projects benefited from a partnership with government. Indeed, Equinor itself is a state-owned entity. In comparison, the hundreds of proposed CCS projects are by and large private-sector ventures serving private-sector clients. Their motivations will be to minimize costs and time, and maximize benefits. While the proponents will likely be experienced operators in the oil and gas sector, the proposals must be subject to vigorous oversight, risk management-oriented regulations and strong compliance requirements to store carbon safely, reliably and permanently. Governments will likely have to increase staffing and resources to be able to rise to the regulatory challenge effectively.

- ***Carbon taxes made the Norwegian pair financially worthwhile; finite subsidies might not.*** The driving force behind sequestering CO_2 was Norway's carbon tax, established in 1991. The Norwegian government set the price and the companies did the math. For E&P companies, the difference was between paying more than US$41 per tonne of CO_2 emitted versus a sequestering cost of about US$17/tCO2. It was a no-brainer. That sequestering cost was based on the nature of the field, knowledge of its properties and, foremost, having other infrastructure in place for production; add to that the unforeseen expenses due to deviations in CO_2 storage field performance, and the cost still remains well below the prospective CO_2 tax. If the viability of a CO_2 storage site depends on a government reliably and continually providing subsidies, there is risk, if those monies run out, that resources will be insufficient to maintain CCS sites, potentially creating a ticking time bomb of greenhouse gases.

Sleipner and Snøhvit Conclusions: What is Proven, What is Unproven, and What is Unknown

What **Sleipner has proven** is that, even after steadfast study and monitoring using top-level technology and engineers, injected CO_2 can move to unexpected places and behave in unexpected ways even years after what appears to have been nominal operations.

What **Snøhvit has proven** is that, even after steadfast study and monitoring using top-level technology and engineers, actual behavior of what has been studied can turn out to be substantially different and replacement plans may need to be implemented with speed in order to avoid catastrophe.

What both projects, **Sleipner and Snøhvit, have proven** is that, to assure long-term secure CO_2 storage, ongoing monitoring and verification of storage site integrity is imperative. Backup plans must always be available in case storage formations do not behave as anticipated. The companies that invest in and operate these fields need to have the financial and technical resources at the ready to address deficiencies, deviations and unexpected performance. Above all, clear regulations and requirements are necessary across the entire CCS life cycle to maintain integrity.

What is **unproven** is whether the techniques employed in Sleipner and Snøhvit can safely and reliably be scaled up five times, 10 times or, in some proposals, more than 25 times across a multitude of subsurface formations accessed by thousands of CO_2 injection well sites covering tens of thousands of square kilometers. Will each and every one of those wells receive the same level of seismic and gravimetric study and monitoring? Can the care and attention provided to a single well's operation – like in the cases of Sleipner and Snøhvit – be repeated within a given field containing hundreds of such wells?

What is **unproven** is the long-term management of storage sites after their injection wells are sealed. In the absence of permanent caretakers, those wells and formations will join the hundreds of thousands of "orphaned" wells present in the U.S., operation and responsibility abandoned.

What is **unproven** is whether CO_2 will remain sequestered with 100% reliability such that none of those sites leak what is supposed to be permanently buried CO_2 back into an already strained environment.

What is **unknown** is the long-term viability of any subsurface storage formation. Will the gas migrate over time? Will the formations fault or deform in ways that allow the gas to escape? Are the formation's boundaries sealed, or faulted such that the CO_2 has a path to move? The truth is that no engineer or scientist, let alone corporate executive or politician, can answer the question definitively. That is because, even using the best technology and techniques available today, the hard science is limited to statistically based expectations derived from costly and resource-intensive samples of subsurface data that are, by their nature, conjectures of what is going on underground. Subsurface assessment technologies are improving, but they likely will never provide a complete and foolproof picture of what nuances, exceptions, deviations, inclusions, or limits are above and within subsurface structures.

Then there is the relentless march of time. Snapshots taken now are subject to change, year by year. The Earth is constantly moving, evolving, changing. Something that was open one year may be sealed up the next; worse, something that was thought to be tightly sealed today may open up tomorrow. Even with improved technology, better resolution, artificial intelligence and machine learning techniques, the data remains interpolated and, by definition, gaps in knowledge exist. And where there are gaps in knowledge, the potential exists that there are gaps through which captured CO_2 could escape.

Appendix A. Overview of Geoscience in CCS

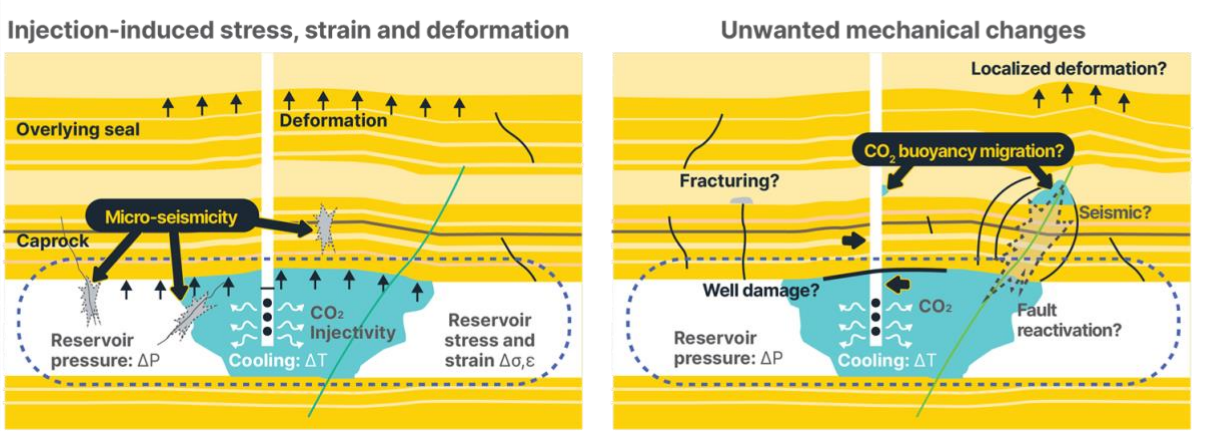
To understand subsurface study and monitoring, it is helpful to identify what aspects of subsurface geology are of concern when choosing and maintaining a CO_2 storage site. This appendix introduces the parameters that experts study. It also provides an overview of the range of technical methods and equipment employed to undertake that exploration, modeling and monitoring.

Subsurface Geology: Characteristics to be Investigated

The Earth's surface is characterized by a complex matrix of rock and soil, liquids and solids, with varying temperatures and pressures, all constantly moving and changing. These changes create pockets where oil and gas accumulate. They also create spaces and conditions where, theoretically, CO_2 can be stored. Movements in the subsurface can open faults that bridge gaps, degrade strata integrity, and produce weak or high-stress areas.

Human intervention can induce further change. Wells tapping hydrocarbons, brine, water or other fluids can release pressure. Conversely, injections of fluids may induce stresses, creating cracks in capstone strata or even causing localized seismic activity. Buildup of pressure in subsurface strata that are receiving injections can deform those layers to the extent that the changes may be detectable on the surface. Figure A1 summarizes many of the conditions geoscientists must study up front to assure a subsurface formation both possesses the characteristics necessary to accept CO_2 and is safe to use.[75] These same conditions must then be monitored to make sure operations are stable and CO_2 is contained over a long time.

Figure A1: Subsurface Geotechnical Risks to be Studied and Monitored



Source: Springer Nature. The Geomechanics of CO_2 Storage in Deep Sedimentary Formations. Rutqvist. 2012. IEEFA

It is important to keep in mind that subsurface conditions which exist at the point of storage strata identification are only a snapshot in time. Even then, despite using the most advanced study

[75] Springer Nature. The geomechanics of CO_2 storage in deep sedimentary formations. Rutqvist. 2012.

techniques, these are necessarily just approximations of what exists subsurface due to the limitations of seismic measurement. Faults change in dimension across space, pockets may not reflect seismic waves, nor stresses in strata manifest until disturbed to a critical point. These conditions are continuously evolving, some rapidly and others over the course of years.

Subsurface Study and Monitoring Techniques

Assessing subsurface geology takes teams of highly specialized geophysicists, petroleum reservoir engineers, and scientists. They use fleets of specially designed vessels and equipment as well as huge amounts of computational power. As such, the entire process is costly and time-consuming.

The oil and gas industry has been using seismic studies for years to prospect for, assess and refine estimates of oil and gas deposits. This approach has been adapted to estimate the potential of subsurface formations for CO_2 storage and security. Based on the experience gained from Sleipner and Snøhvit, accurately assessing and monitoring CCS reservoirs requires access to the most advanced subsurface survey techniques employed in the oil and gas industry.

Modern ocean-going seismic survey vessels are expensive, each requiring capital investment of between US$200 million and US$300 million, depending on size and rigging.[76] Up to two-thirds of that cost are associated with seismic sensing and process hardware. These vessels must be crewed with not just expert geophysicists and engineers but also highly experienced seafarers. Keeping bearing and speed constant is a critical component in gathering quality data.

This is made all the more challenging given that the research vessel is towing seismic streaming and sensing cables which can extend from 5km to as long as 12km for the most accurate measurements. The vessel may be towing as many as 12-24 seismic streamers in an array, thus deployment logistics and stability management are critical. Handling seismic sounding and telemetry equipment can be delicate work, even in the potentially rough waters these ships ply, and maintenance is constant. Global 3D survey provider Petroleum Geo-Services (PGS) estimates that it spends around US$100 million annually to maintain seismic equipment.[77]

There are limited seismic data acquisition systems within the world's oceans. According to Rystad, a company that tracks the global seismic fleet, more than 100 active ships are collecting such data.[78] However, fewer than 15 possess the most modern sensory and acquisition systems needed for high-resolution 3D surveys appropriate for CCS storage assessment.

In addition, the waters need to be calm such that vertical displacements of equipment due to waves are kept to a minimum. Calm seas permit a more constant steaming speed, which is important in keeping streaming cables and the sensors attached to them taut and at the proper spacing. Similarly, vertical and horizontal displacements due to waves and currents should be minimized. Any variations

[76] PGS. Annual Report 2011. Accessed in April 2023.
[77] PGS. PGS Capital Markets Day presentation – Our fleet: status and scaling. January 26, 2023, p. 83.
[78] Keyfacts Energy citing Rystad Energy. Seismic vessel utilization recovers to pre-Covid level. September 23, 2021.

can introduce noise into the data collection; if that disruption is material, the run may need to be redone.

Seismic surveys collect petabytes of data that have to be stored and processed. Final analyses can take months to complete. Due to the protracted and demanding nature of seismic study, multi-client assessment campaigns are being increasingly used in order to share costs across multiple beneficiaries.

These 3D survey campaigns are costly for another reason: the large areas of ocean floor to cover. Costs also depend on subsurface complexity; highly varying terrain or complex subsurface strata may require multiple passes over the same area or more intense sensor scans, which will be slower. As such, costs per km^2 range widely, from US$15,000 up to US$1 million, with an average of around US$35,000.[79,80] However, given the limited number of vessels, crew and scientists, the laws of supply and demand apply. The global push to identify subsurface structures suitable for CCS requires ever more detailed and resource-intensive study, therefore costs are likely to increase.

The regulatory Norwegian Petroleum Directorate is taking a proactive approach to this need by helping organize and fund comprehensive seafloor studies of Norway's waters in the Norwegian Sea and Barents Sea.[81] This investment will go toward establishing a base level of subsurface knowledge of these areas. The studies will be made available to companies investigating storage projects, providing excellent starting points for assessing what could lie beneath and informing how geophysicists and engineers might proceed with their assessment and design. However, placing complete reliance on this data, when the risks, costs and stakes are so high, is unlikely to placate corporate executives or their financial backers. Accordingly, specific CCS projects may require more focused and specially ordered follow-up surveys; again, this incurs high cost but helps mitigate uncertainties.

As experience from Sleipner and Snøhvit has shown, surveys must be repeated over time to verify CO_2 depositing and to accurately monitor its behavior and containment in subsurface formations. In certain regions, more permanent sensor installations known as ocean bed nodes (OBNs) are preferred to hiring seismic study vessels. OBNs are combined seismic wave inducers and geophone receivers affixed to the ocean floor and connected by cables to a central data acquisition and monitoring center. Such arrays allow for continuous monitoring of subsurface strata both during and after operations are complete.

However, OBN networks are also costly. Specialized sensors, personnel and remote-operated subsea equipment are required to install the sensor array, sometimes working at extreme depths. The spacing and configuration of the array affect not only the cost but also the accuracy of data. The more remote and deeper the array, the more challenging the infrastructure and the higher the cost of

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[79] Ibid, footnote 77.
[80] BN Americas. Cost of offshore studies could limit Mexican O&G investment. October 7, 2019.
[81] Norwegian Petroleum Directorate. Overview of all the geophysical surveys that are started. Accessed in April 2023.

failure. Thus, there are critical tradeoffs to consider. These factors are what lead many exploration projects to favor hired seismic study vessels.

Seismic technology overview. A variety of technologies and techniques are used to acquire subsurface data. Box A1 summarizes some of the more common methods to give a quick reference. For a more thorough yet still accessible overview of how seismic surveys work, the techniques used and the typology of approaches, we would recommend An Overview of Marine Seismic Operations co-published by the International Association of Oil & Gas Producers and the International Association of Geophysical Contractors.[82]

Data reinterpretation, reprocessing and interpolation. Advancements are being made in data collection and processing. Geophysical survey companies now offer services to reprocess older data. New computational techniques can squeeze more informative results and imaging out of these older streams.[83, 84] More cutting-edge approaches are applying artificial intelligence (AI) and machine learning to process these datasets.[85, 86] The goal is to attempt to fill in data visualization or interpretation gaps from the images produced. It must be kept in mind, however, that while AI and other computational techniques can interpolate between data points in an iterative way to create a range of indications as to what might be there, they cannot fabricate missing data. If the original data acquisition missed signs of a significant surface anomaly, it is quite possible that AI processing would not generate a result showing it. Thus, interpolation and inferences could generate misleading results or be flat out wrong, leading to missed critical information that impacts project design or operations, and is indeed the key point of this paper.

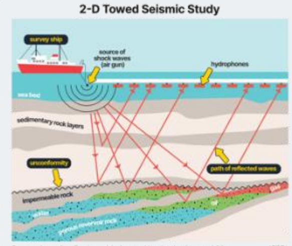
[82] International Association of Oil & Gas Producers and the International Association of Geophysical Contractors. An overview of marine seismic operations. April 2011.
[83] Shearwater GeoServices. Case study: adding value to data through reprocessing. Accessed in April 2023.
[84] PGS. Reprocessing to extract more details. Accessed in April 2023.
[85] Allerin Tech. How AI is helping seismic interpreters. March 30, 2020.
[86] Geoteric. Improve your decisions with Geoteric AI. Accessed in April 2023.

Box A1: Overview of Sea-based Subsurface Seismic Survey Types

Large Area Studies

To investigate very large areas, particularly during exploration, mobile towed systems are employed. These make use of specialized seagoing vessels towing seismic and sonar detection equipment to measure sound-wave reflections off the subsurface strata beneath the seabed. The accuracy and detail of this data depend on the type and configuration of equipment used:

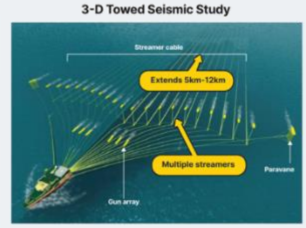
2-D Towed Seismic Study



Source: Learning Geology. Marine and land seismic acquisition. June 16, 2015. IEEFA

2D. ($) Two-dimensional seismic studies capture data from a single data collection strand towed behind a survey vessel. Such studies can act as a "first pass filter" to determine areas with possible subsurface structures of interest suitable for further study.

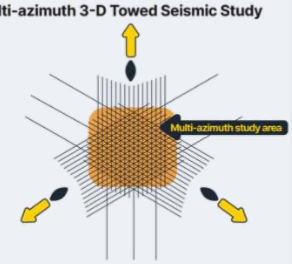
3-D Towed Seismic Study



Source: Analysis of Seismic Methods Used for Subsea Hydrocarbon Exploration. Birin and Maglić. February 2020. IEEFA

3D. ($$) A three-dimensional seismic survey sees a specialized study vessel towing an array of sounders and sensors behind the ship to bounce sound waves off subsurface strata and record the returns across a field of sensors. This provides far greater detail on the composition of subsea strata.

Multi-azimuth 3-D Towed Seismic Study



Source: Cambridge University Press. Ocean Bottom Marine Seismic Methods. Jack. November 25, 2021. IEEFA

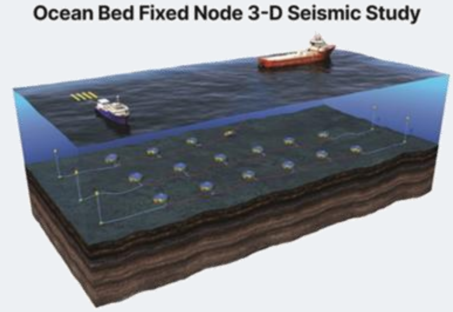
MAZ 3D. ($$$) Multi-azimuth 3D seismic surveys pass the survey vessel multiple times over a specific area of study. The passes are made at certain angles to one another to better process data and increase subsurface strata resolution. Multiple passes require more vessel time and computing time, and, therefore, are more expensive than single-directional studies.

4D. ($$$ recurring) Four-dimensional analysis adds a time element to study results by repeating a 3D study over the same study area at some point in the future. This allows geologists to see a time series of data points to detect any changes in the field structure. It is particularly useful in active fields where oil or gas is being produced or where CO_2 is being injected, to see how the structures are performing with changes of volume

Fixed Site Studies

Ocean Bed Nodes. ($$$$) This method either temporarily or permanently installs seismic sounding and receiving sensors on the seabed to continuously monitor specific geologic strata. It provides much greater accuracy and detail of formation performance in a specific area. This is particularly useful to track changes during extraction or injection. It is costly because specialized equipment and installation techniques are required to affix the sensors to the seabed and the cables that connect them for data collection.

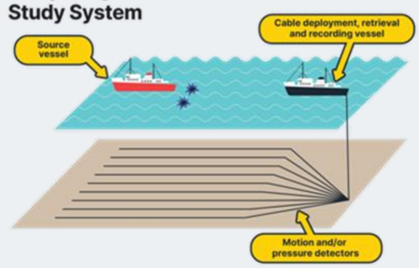
Ocean Bed Fixed Node 3-D Seismic Study



Source: The American Oil & Gas Reporter. Seismic Technology Advances ‘Scale Up’ Nodal Acquisition. 2018. IEEFA

Downhole sensors. ($) Downhole methods insert sensors into a well to obtain horizontal characteristics of specific strata encountered along the depth of the bore. Sensor installation typically piggybacks on well establishment or well maintenance. Most permanent sensors measure temperature, pressure, or tilt. Downhole seismic measurements can also be made while the well is being serviced. This approach can provide high-accuracy strata profiles within a more confined radius relative to the borehole.

Temporary Ocean Bottom Cable Seismic Study System



Source: Cambridge University Press. Ocean Bottom Marine Seismic Methods. Jack. November 25, 2021. IEEFA

2D towed seismic study:

Learning Geology. Marine and land seismic acquisition. June 16, 2015.

3D towed seismic study:

University of Rijeka. Analysis of seismic methods used for subsea hydrocarbon exploration. Birin and Maglić. February 2020.

Multi-azimuth 3D towed seismic study:

Cambridge University Press. Ocean bottom marine seismic methods. Jack. November 25, 2021.

Ocean bed fixed note 3D seismic study:

The American Oil & Gas Reporter. Seismic technology advances “scale up” nodal acquisition. 2018.

Appendix B. Proposed CCS Projects in Asia and Europe

This appendix provides an overview of proposed CCS projects in Asia and Europe. Table B1 provides a listing of Asian CCS projects, while Table B2 offers a list of CCS projects under consideration for Europe. These represent a sampling of proposals worldwide, a subset of the nearly 200 such projects being considered. For a more comprehensive listing of global projects, we recommend visiting the IEA's CCS Projects Explorer.[87] The website provides links to IEA's CCUS Project Database, which is available for download and should have the most current information on projects.[88]

Asian CCS Project Proposals

Malaysia

Petronas, the nationally owned oil and gas company, in November 2022 approved the Kasawari CCS offshore project in the South China Sea, 180km north of Bintalu, Sarawak. The SK316 block from which Petronas is planning to draw gas has an extraordinarily high CO_2 content of 40%. This creates an unprecedented volume of CO_2 to strip out, transport via pipeline and store subsurface.

At 3.3mtpa, the project will have the highest CO_2 injection rates per cubic meter of gas production globally. Kasawari will also be among the largest by proposed annual injection volume, second only to Chevron's Gorgon project in Australia, at 3.5mtpa to 4mtpa. Accordingly, system integrity and injection well and storage performance are going to be critical if the CO_2 reduction goals are to be met and maintained in the long term.

Given the CO_2 volumes Kasawari will handle, combined with its distance offshore, Petronas is opting for a Sleipner-like approach, doing all gas processing and CO_2 recompression offshore on a dedicated platform. In the case of Kasawari, however, the platform and the equipment it holds will be four to five times the size of Sleipner's, thus making it the world's largest dedicated CO_2 processing platform.[89]

Because of the unprecedented size and complexity of Kasawari, Petronas is entering into an unusual "alliance contracting" risk-sharing structure with its prime contracting partner, Malaysia Marine and Heavy Engineering. It is due to the project's unique conditions, massive scale, and risks – both known and unknown – associated with start-up commissioning. This contracting approach, while conservative, will likely add costs to what is already an RM4.5 billion (US$1 billion) component of the overall development.

Petronas is also considering approval for another CCS project, of 2mtpa, in peninsular Malaysia.[90]

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[87] IEA. CCUS Projects Explorer. March 24, 2023. Accessed on April 25, 2023.
[88] IEA. CCUS Projects Database. March 24, 2023.
[89] Rigzone. Construction of world's largest offshore CCS project underway. November 30, 2022.
[90] Petronas. Petronas Carigali, JX Nippon enter into heads of agreement for BIGST cluster, offshore peninsular Malaysia. December 12, 2022.

Indonesia

Pertamina, the Indonesian national oil company, is looking at CCS investments to help transform its preponderance of highly sour (high-percentage CO_2 content), in-ground hydrocarbons into a marketable commodity. In October 2022, Pertamina, in partnership with the Japanese state-owned Japan Organization for Metals and Energy Security (JOGMEC), inaugurated Indonesia's first carbon capture, utilization and storage (CCUS) project at the Jatibarang field in West Java.[91] This onshore facility is being used to demonstrate CO_2-enabled enhanced oil recovery (EOR). The partners say the project has the ability to "increase production while reducing emissions." Should this be successful, the Pertamina subsidiary that runs the field, Pertamina Hulu Energi, has six more proposed developments at Sukowati, Gundih, Ramba, Subang, Acacia Bagus and Betung which, taken together, hold the potential to yield 15 million tonnes of CO_2 per year that could be used for EOR.[92]

Following closely on these developments are Indonesia's two largest proposals, both onshore in Sumatra. The Rokan project in central Sumatra sees Pertamina teaming up with Japan's Mitsui & Co to develop an onshore CO_2 hub supporting the Duri and Minas gas fields, among the largest in the country. It would gather CO_2 from the fields, which are spread across the province, by pipe and truck. The identified subsurface formation has a projected storage capacity of 25 million tonnes and project designs are targeting a 2mtpa injection rate. Separately, Spain's Repsol would make use of gas delivered to its Sakakemang refinery via CO_2 enhanced gas recovery (EGR) from the adjacent Gelam and Dayung fields. It would yield 2mtpa of CO_2 in the EGR process, looking to avoid a cumulative 30mt of emissions.[93]

Japan

Japan's Tomakomai CCS demonstration project, running since 2019, has sequestered a modest 300,000 tonnes of CO_2. Injections have ceased and the storage formation is being monitored for leakage.[94] However, the country wants to launch a massive CCS program, taking CO_2 from industrial processes, power generation and hydrogen manufacture for storage offshore at a scale thousands of times greater than this single small-size demonstration.

Chevron's Gorgon in Australia: Another warning for CCS

In Australia, Chevron's Gorgon project is struggling to get its massive 3.5mtpa to 4mtpa CCS facilities to meet its targets of 80% CO_2 capture and reinjection for storage. The promised capture rate is stipulated in its operating license from Australian authorities.

Like Snøhvit, a material portion of Gorgon's challenge is related to unexpected subsurface conditions. High volumes of sand infiltration in injection balancing wells have restricted flows. As a result, the CCS facility has never run to its planned design capacity. It has experienced repeated shutdowns and plant failures while reaching only about half of its removal target during sporadic operating runs. Chevron's reports from the 2021-2022 operating year show total CO_2 emissions from

[91] Pertamina. CCUS technology implementation, Pertamina injects CO_2 in Jitabarang field. October 26, 2022.
[92] Ministry of Energy and Mineral Resources, Indonesia. Progress of CCS/CCUS Implementation in Indonesia. September 30, 2022.
[93] Ibid, footnote 8.
[94] Japan CCS Co., Ltd. Tomakomai CCUS Demonstration Project Monthly Report. April 2023.

gas production yielded 5.04Mt. Meanwhile, Gorgon injected only 1.65Mt of CO_2 over the same period, clearly far below the promised 4mtpa capture rate target.[95,96,97]

Gorgon's troubles arise from a source gas that is 14% CO_2, a fraction of the 40% content Petronas is looking to reliably process at its proposed Kasawari development. To learn more about Gorgon's challenges in operationalizing its CCS elements, refer to IEEFA's 2022 paper, "Gorgon carbon capture and storage: The sting in the tail".[98]

Major implications for gas supplies in Southeast Asia and Australia

Southeast Asia and northwest Australia have among the world's largest concentrations of sour gas, or gas with high CO_2 content, accounting for about half of identified reserves.

With CO_2 in the extracted gas ranging from 15% to 80%, and the need to reduce it below 1% for marketed gas, CO_2-related operations, whether storage or EOR/EGR, are going to be a major issue spelling great expenses for all prospective gas field operators. Developing these gas resources is a potentially pricey gamble. The high CO_2 content requires robust gas processing, which comes at great cost. At Australia's Gorgon project, CCS infrastructure cost and remedial investment has required about US$2.2 billion equivalent to date.[99] For Malaysia's Kasawari project, that additional investment may add 40% to 45% to the breakeven cost.[100]

However, if the engineering goes wrong, whether in the petroleum geology or the CO_2 processing, the cost to the environment may be even higher. And all the countries in the region have some level of Paris Agreement net-zero target set for the coming decades, the achievement of which increasingly depends on such uncertain pursuits.

[95] Chevron. Gorgon gas development and Jansz feed gas pipeline environmental performance report 2022. Chapter 7: Carbon dioxide injection project. November 4, 2022.
[96] Chevron. Gorgon gas development and Jansz feed gas pipeline greenhouse gas annual report FY 2022. March 28, 2023.
[97] The Guardian. Emissions from WA gas project with world's largest industrial carbon capture system rise by more than 50%. April 20, 2023.
[98] IEEFA. Gorgon carbon capture and storage: The sting in the tail. Robertson and Mousavian. April 29, 2022.
[99] Ibid, footnote 98.
[100] Journal of Petroleum Technology. What you should know about offshore and sour gas CCS: High cost, leak mitigation and transportation. Jacobs. June 1, 2022.

Table B1: Selected Asian CCS/CCUS Project Proposals
As of March 1, 2023

Country	Project Name	Sponsor	Capacity	Projected Start of Operation	Notes
Indonesia					
	Rokan	Pertamina Mitsui & Co (Japan)	2mpta	2025	Central Sumatran onshore production block. Considering a CO_2 gathering hub to collect CO_2 from fields spread across central Sumatra using pipelines and trucks. Considering a CO_2 import terminal to add scale and volume to storage
	Sakakemang	Repsol (Spain)	2mpta	To be determined (TBD)	To store up to 30mt of CO_2 stripped from Repsol's Sumatra-based refinery production. Feedstock gas has 28% CO_2 content
	Tangguh LNG (Train 3)	BP (UK) Mitsubishi Inpex CNOOC JX Nippon KG Mitsui LNG Japan	~3.1mtpa	2027	Propose conducting West Papua production and modifying LNG liquefaction facility. Targeting 90% CO_2 reduction from 23% CO_2 content feedstock gas at LNG facility by using 25mt of CO_2 for EGR operations. Final investment decision expected in 2023. About US$3bn investment
	Abadi LNG	Japan Impex 65% Shell 35% (although Shell has been seeking exit for years; Pertamina considering stake)	~2.3mtpa	Early 2030s	To develop greenfield offshore deepwater gas with 9.7% CO_2 content. Abadi LNG targeting 9.5mtpa LNG exports through its US$20bn investment. CCS expected to add US$1.4bn to that cost
	Jatibarang EOR CCUS demonstration	Pertamina JOGMEC (Japan)	Not stated	October 2022 (launched)	Located onshore in West Java, it is Indonesia's first CO_2 injection project for EOR purposes. Extracted gas has 23% CO_2 content. Depending on its success, Pertamina E&P subsidiary Pertamina Hulu Energi is looking to apply CCUS to fields in Sukowati, Gundih, Ramba, Subang, Acacia Bagus and Betung having CO_2 content ranging from 20% to 60%. If applied to all fields, an estimated 15mtpa of CO_2 would be stripped and used for EOR/EGR
	Gundih CCUS /EGR demonstration	Pertamina JGC J-Power Janus Bandung IoT	0.3mtpa	2026-2027	Onshore in Central Java. To strip CO_2 from produced gas and reinject it to enhance further gas production

Country	Project Name	Sponsor	Capacity	Projected Start of Operation	Notes
Japan					
	Tomakomai CCS Demonstration Project	Japan CCS Japan's Ministry of Economy, Trade and Industry (grantee)	0.1mtpa, 0.3mt total	2016-2019	Nationally funded pilot project to show viability of CO_2 capture from a refinery, CO_2 offshore well injection and monitoring of subsurface stability. Stored 300,000t CO_2, which has been monitored since November 2019. Aims to demonstrate ability to replicate this approach throughout Japan
Malaysia					
	Kasawari	Petronas	3.3mpta	2024	World's largest offshore CCS project approved for development, located 180km north of Bintalu, Sarawak. Final investment decision taken in November 2022. Requires world's largest offshore CO_2 processing and compression platform to help process 40% CO_2 content extraction gas
	BIGST	Petronas JX Nippon	TBD	TBD	Located in the South China Sea on eastern shore of peninsular Malaysia, BIGST stands for a chain of five proximate gas fields: Bujang, Inas, Guling, Sepat and Tujoh. Collaboration agreement signed in December 2022. Targets stripping of gas with CO_2 concentrations ranging from 28% to 80%. Studying possibility of a centrally located offshore CCS processing platform

Table B2: Selected European CCS Project Proposals
As of March 1, 2023
Note: hyperlinks to project websites or corporate information on projects provided for reference

Country	Project Name	Sponsor	Capacity	Projected Start of Operation	Notes
Norway					
	Northern Lights CCS. "Providing carbon storage as a service." The master project comprises the following four components:				
	Errai (formerly Polaris)	Neptune Energy Horisont Energi Vår Energi	4-8mtpa Phase 1: 1.5mtpa	2024-2026	To make blue ammonia from gas sourced from adjacent Hammerfest LNG site. Integrated with CO_2-receiving terminal that blends received CO_2 with industrial CO_2 captured from sites around Norway
	Smeaheia	Equinor	20mtpa	2027-2028	Slated to become Norway's primary CO_2 storage site
	Luna	Wintershall Dea 60% Cape Omega 40%	5mtpa	Not disclosed	120km offshore from Bergen, awarded by GoN on October 5, 2022
	Langskip (Longship)	Government of Norway (GoN) Norcem AS Fortum Oslo Verme AS	Not applicable		Approved by Parliament on September 21, 2020. GoN operates project through Gassnova SF; and provides state sponsorship for design, construction and testing of CO_2 transport fleet, inclusive of CO_2 gathering and compression facilities. Cost estimate is NOK17.1bn (US$1.59bn) for capital expenditure, and NOK8bn (US$0.75bn) for 10 years of operating expenditure, two-thirds of which would be funded by GoN and one-third from private-sector participants, Fortum and Norcem.
	Trudvang	Sval Energi AS Storegga Geotechnologies Neptune Energy Norge AS	9mtpa	2029	Open-source CO_2 repository with projected total storage capacity of 225mt
United Kingdom					
	Acorn	Storegga 30% Shell 30% Harbour Energy 30% North Sea Midstream Partners 10%	5-10mtpa	2030	Based in Scotland. To develop CO_2 gathering network, both onshore and via ship from other parts of UK, consolidating and compressing, then transporting by repurposed gas pipelines to depleted North Sea gas fields
	Viking CCS	Harbor Energy	10mtpa Phase 1: 2mtpa	Phase 1: 2027	

Country	Project Name	Sponsor	Capacity	Projected Start of Operation	Notes
	Northern Endurance	BP (lead) National Grid Equinor Shell TotalEnergies	20mtpa	2030	Combines two CO_2 "hubs": Teesside and Humberside. To pump compressed CO_2 145km from Teesside and 103km from Humberside to depleted gas fields offshore
	Hynet North West		10mtpa Phase 1: 4.5mtpa	2030 Phase 1: 2025	
Netherlands					
	Porthos	Air Liquide Air Products Shell Exxon Mobil	2.5mtpa	2025	Dutch waters of North Sea Project overview
	L10	Neptune Energy Rosewood Exploration Exxon Mobil EBN (state-owned enterprise)	4-5mtpa	2026	Dutch waters of North Sea Overview presentation
Denmark					
	Project Greensand	INEOS Energy Wintershall Dea	8mtpa Phase 1: 1.5mtpa	2030 Phase 1: 2025	
	Project Bifrost	TotalEnergies Orsted, TUD	3mtpa	2027	
Sweden					
	Slite CCS	Heidelberg Materials	1.8mtpa	2030	Part of a "carbon-neutral" cement plant project undertaken by Heidelberg Materials
Bulgaria					
	ANRAV	Petroceltic Heidelberg Materials	0.8mtpa	2028	Recipient of EU Innovation Fund monies on July 13, 2022, to demonstrate CCUS in Eastern Europe. To sequester CO_2 in Black Sea fields
France-Spain					
	PYCASSO	Avenia – European Cluster Collaboration Platform	1mtpa	2030	Regional CO_2 gathering and disposal demonstration project

Country	Project Name	Sponsor	Capacity	Projected Start of Operation	Notes
Germany					
	Wilhelmshaven LNG terminal		1mtpa	2026	To create a CO_2 liquefaction facility and use new LNG terminal to load CO_2 ships for disposal at fields being developed in Norway and elsewhere in the North Sea
Italy					
	CCS Ravenna Hub	ENI	4mtpa Phase 1 testing 0.1mtpa	2027 Phase 1: 2023	To expand to 10mtpa in 2030 if initial commercial operations prove successful
Iceland					
	Project Silverstone	CarbFix	0.025mtpa	2025	EU-funded project to demonstrate CarbFix technology's ability to take externally sourced CO_2, process it and create solid-phase underground storage
	Coda Terminal	CarbFix	3mtpa	2031	Commercial-scale terminal for receiving, processing and storing CarbFix-based technology for CO_2 disposal

Appendix C. Policymaking, Standards and Regulations: How Governments Should Address CCS Uncertainty

Just as prospective underground CO_2 deposit formations are varied, so too is the global regulatory map for CCS. Very few national regulations govern the complete CCS technical value chain. Most focus on oil and gas E&P processes but are not tailored for the complexities of CCS. Laws and policies regarding CCS investment and incentives exist in a number of countries, but few possess detailed protections on planning, operations, closure, or highly important post-closure monitoring.

Four regions led the creation of CCS-specific regulations: Australia (2006, updated 2022),[101] the EU (2009),[102] the U.S. (2010, updated 2016),[103] and the Province of Alberta in Canada (2011, updated 2016).[104] Norway, despite its leadership in modern offshore CO_2 storage, put in place CCS-specific regulations only in 2014;[105] however, those promulgated fall in line with the aforementioned peers. The United Kingdom, after exiting the European Union, established CCS regulations in 2022 under UK laws. These are nearly identical to the EU regulations from which they were derived, and in certain clauses there is cross-referencing with the EU regulations.[106] It is worth noting that Indonesia adopted its first carbon capture, utilization and storage (CCUS) regulations on March 2 this year; given the rules' nascent status, they remain untested.[107]

In Australia, the EU and Norway, the regulations focus on *offshore* CO_2 storage, while Canadian and U.S. regulations are terrestrially based. Responsibility for U.S. offshore areas rests with the U.S. Department of the Interior's Bureau of Ocean Energy Management. This bureau allocates and regulates leases for offshore oil and gas as well as offshore wind. As the same offshore waters are being considered for CCS, regulation falls to the bureau. At the time of publishing this paper, the bureau is soliciting public input for proposed regulations overseeing offshore CO_2 injections.[108] They draw heavily from the U.S. Environmental Protection Agency's Class VI well framework for underground injection control of CO_2.[109]

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101 Federal Register of Legislation, Australia. Offshore Petroleum and Greenhouse Gas Storage Act 2006. June 17, 2022.
102 Official Journal of the European Union. Directive 2009/31/EC of the European Parliament and of the Council of 23 April 2009. 2009.
103 U.S. Environmental Protection Agency. Class VI – Wells used for Geologic Sequestration of Carbon Dioxide. December 9, 2022.
104 Government of Alberta, Canada. Alberta Regulation 68/2011, Carbon Sequestration Tenure Regulation. Amended on April 26, 2016.
105 Norwegian Petroleum Directorate. Regulations relating to exploitation of subsea reservoirs on the continental shelf for storage of CO_2 and relating to transportation of CO_2 on the continental shelf. October 31, 2017.
106 North Sea Transition Authority. UK carbon dioxide storage. April 28, 2023.
The Government of the United Kingdom of Great Britain and Northern Ireland. The Storage of Carbon Dioxide (Licensing etc.) Regulations 2010, as amended through December 12, 2022. No. 2221.
107 Government of Indonesia. Ministry of Energy and Mineral Resources Regulation No. 2 of 2023 concerning Implementation of Carbon Capture and Storage, as well as Carbon Capture, Utilization and Storage in Upstream Oil and Gas Business Activities (in Bahasa Indonesia only). March 2, 2023.
108 Bureau of Ocean Energy Management, U.S. Carbon sequestration. Accessed on April 14, 2023.
109 U.S. Environmental Protection Agency. Final Class VI Guidance Documents. November 7, 2022.

Common Characteristics of CCS Regulation

The referenced CCS regulations share common features which are summarized in Table 3. The details of these regulations vary, although, for the most part, they are comprehensive and provide full life-cycle coverage. All are supported by and/or refer to other environmental and/or petroleum-sector regulations and permitting requirements.

Table 3: Common Features of CCS Regulations

Planning Phase	Operational Phase	Post-closure Phase
Site characterization • Survey and assessment methods • Minimum details required • Geological data collection • Capacity assessment	**Operations plan** • Operational procedures • Maintenance plans • Management oversight • Health, safety and environment	**Shutdown plan** • Procedures in sealing injection site for good • Materials to be used to maintain quality, monitoring and inspection
Process design • Proposed processes, infrastructure • Proposed operating parameters (volume, pressure) • CO_2 quality • Design parameters	**Operations monitoring** • Comparison of anticipated site behavior to actual behavior • Migration monitoring • Capacity and pressure monitoring • CO_2 storage integrity • Documentation and explanation of deviations • Duty to inform regulator • Regulator's right to access • Data acquisition, measurement and reporting to authorities	**Decommissioning plan** • Scope of decommissioning • Environmental protection • Plugging and abandonment specifications • Environmental contingency plan • Risk assessment and management • Scenario assessment • Remedial action plan • Cost assessment
Risk assessment, management and contingency plan	**Risk management** • Risk assessment matrix • Contingency plans for identified risks	**Monitoring plan** • Reservoir migration and pressure monitoring • Seismic and gravimetric survey • Cost assessment

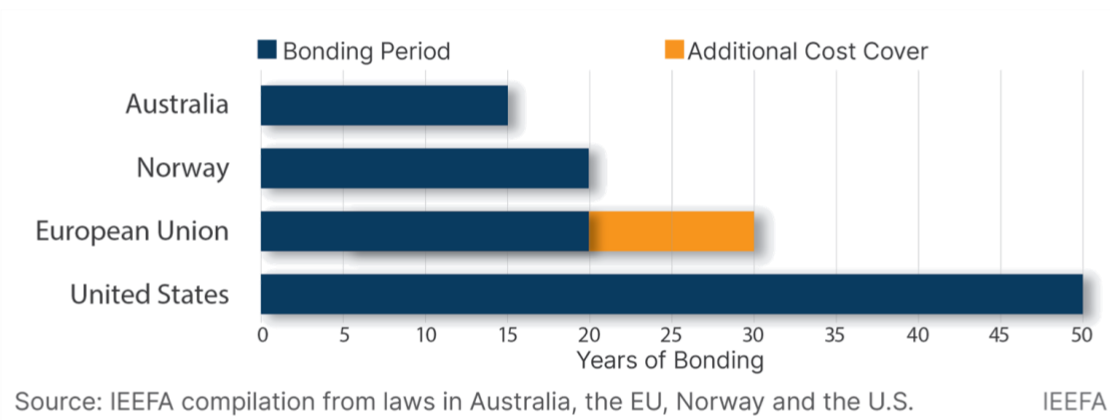
Financial credentials	Financial bond and insurance	Financial bond
• Proof of financial capacity to undertake the investment and operations • Demonstrated ability to post required security	• Posting of bond during operations to cover a minimum number of years of monitoring and contingency intervention costs • Minimum insurance coverage	• Posting of bond to cover monitoring and contingency costs for statutory minimum period

Source: IEEFA compilation from laws in Australia, the EU, Norway and the U.S.

In 2022, the IEA published a handbook on the development of legal and regulatory frameworks for CCS in recognition that if CCS is to expand globally, it must be well regulated.[110] The publication covers areas similar to those summarized in Table 3.

Regulators across Australia, the EU, Norway and the U.S. recognize that CO_2 storage integrity is of utmost importance. The post-closure monitoring responsibility, contingency action plan and financial bond to pay for integrity monitoring and remedial actions extend up to 15 years in Australia,[111] 20 in the EU and Norway,[112,113] and up to 50 in the U.S.[114] The EU requires financial bonding for 30 years of costs, despite the potential for release of obligation after only 20 years (Figure 9).

Figure 11: Contingency Responsibility Period After CCS Site Closure



[110] IEA. Legal and Regulatory Frameworks for CCUS: An IEA CCUS Handbook. July 2022.
[111] Ibid, footnote 101.
[112] Ibid, footnote 102.
[113] Ibid, footnote 105.
[114] Ibid, footnote 103.

Under each cited regulatory regime, if the storage proponent can prove its site is compliant, secure and stably storing CO_2, the regulatory authority has the discretion to shorten the bonding period. On the other hand, these terms are not necessarily long-stop dates; should complications materialize, the storage field operators remain responsible for remediation work until the regulator is satisfied stable storage has been achieved. This requirement holds the potential of extending beyond the stated liability period.

The regulator faces a challenge when deciding to truncate the operator's performance bonding period, as once the original operator's bonding has been released, liability for the storage sites reverts to the state. This means the taxpayer is responsible for remedying any deviations that threaten site safety or CO_2 storage integrity. Absent dedicated money and resources to address any deviations under state management, CO_2 has the potential to return to the atmosphere.

It is important that all countries considering CO_2 storage operations take into account comprehensive and risk management-oriented regulations for CCS. Governments and their constituents must understand the full set of risks and costs that may be involved.

Getting Partway There: ISO CCS Technical Standards

In the absence of widespread national-level CCS regulations, the International Standards Organization (ISO) has sought to bring some degree of uniformity to the *technical* side of CCS processes. ISO places CCS under the category 13.020.40, "Pollution, pollution control and conservation, including ecotoxicology and greenhouse gas emissions." In 2011, it formed a technical committee to develop operational standards.[115] Using the ISO27900 series, ISO began issuing CCS standards in 2016 and, to date, has addressed 12 areas of CCS operations, running from injection site identification through end-of-life closedown.[116] More ISO standards and improvements to current standards are under development.

While these technical standards will help to harmonize the planning and operational implementation of CCS globally, they are not legally binding. ISO does not have regulatory authority over how a given country might apply or enforce its standards.

[115] ISO. Carbon dioxide capture, transportation, and geologic storage. Accessed on April 14, 2023.
[116] ISO. Standards by TC/265: carbon dioxide capture, transportation and geologic storage. Accessed on April 14, 2023.

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