Technology Collaboration Programme
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Evaluating technology options to mitigate greenhouse gas emissions

IEAGHG Technical Report 2023-04

Components of CCS Infrastructure - Interim CO_2 Holding Options

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IEA GREENHOUSE GAS R&D PROGRAMME

Disclaimer

Acknowledgements & Citations

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This report describes work undertaken by TNO, SINTEF and Vopak on behalf of IEAGHG. The IEAGHG manager for this report was Samantha Neades. The principal researchers were: Lydia Rycroft (TNO), Filip Neele (TNO), Ragnhild Skagestad (SINTEF), Coen Ponsioen (Vopak - Expert Advisor).

To ensure the quality and technical integrity of the research undertaken by IEAGHG each study is managed by an appointed IEAGHG manager. The report is also reviewed by a panel of independent technical experts before its release. The expert reviewers for this report were: Richard Parker & Jeff Lee - Battelle, Ceri Vincent & Helen Taylor-Curran - BGS, Robert Yarlett & Chris Quarton - UK Department for Energy Security and Net Zero (DESNZ) (was UK Department for Business, Energy & Industrial Strategy, BEIS), Silvian Baltac, Elian Pusceddu & Enrique Garcia-Calvo Conde - Element Energy an ERM Group, Marcus Fathi - Equinor.

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About IEAGHG

Blazing the way to net zero with leading CCS research. *We advance technology to accelerate project development & deployment.*

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

About the IEA

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

COMPONENTS OF CCS INFRASTRUCTURE - INTERIM CO_2 HOLDING OPTIONS

(IEA/CON/21/282)

This work, undertaken on behalf of IEAGHG by TNO, SINTEF and Vopak, provides an overview of temporary / interim CO_2 storage, or 'holding', options (also called buffers) and investigates the role of buffer storage and its potential to create flexible and robust carbon capture and storage (CCS) chains. The report looks at current and emerging buffer technologies, conducts simulations to demonstrate the temporary storage required for given flow-rate scenarios and discusses the impact of buffer capacity on transport costs. In the report, the storage requested in the chain for normal operation is presented as " temporary storage" and storage to give buffer capacity is presented as " buffer storage". This report has focussed on buffering at the emitter site. The results of this study will benefit CO_2 storage site project developers, operators, financiers and regulators.

Key Messages

- It is important for the transport of CO_2 to be flexible due to variations in the production of CO_2 and availability in the storage part of the chain; a buffer, or interim storage, may be needed to make up for the batch-like nature of a ship-based transport chain as well as to assist with varying transport and storage (T&S) availability and to absorb variations in CO_2 supply and / or demand.
- The choice of buffer solutions depends on the capacity needed and the cause for the variation to be dealt with and is best done with dense phase (liquid) CO_2 to minimise volume requirements.
- Current technology options for buffering include quayside facilities and on-site tanks, geological gas storage, and pipeline system line-packing.
- Emerging technology options may include offshore storage in salt and other caverns, and floating storage and injection units.
- Costs will be incurred when designing extra / interim CO2 storage capacity into a CCS chain and as an estimate for cases in Europe, the cost for buffer storage will be in line with approximately 5-10% of the transport costs.
- The most likely solution for buffer capacity is onshore facilities designed for shipping. It is unlikely that geological storage will be developed for these changes given the longer timescales for storage and injection cycles. Man-made underground storage tanks are likely to become more common as energy storage becomes more widely used.
- Line-packing is unlikely to provide interim storage for more than a few hours and will incur extra compression and costs.
- In the scenarios investigated in this study, the cost is between 1 to 2.7 € per tonne of CO_2 buffer storage provided.
- These buffer storages should be located close to the capture site to minimise costs.
- It will be more cost effective to design some level of flexibility into a T&S system through spare capacity in pipelines and wells, allowing some freedom to redirect CO_2 flows in cases of T&S downtime and an ability to handle flowrate variations.
- It will be more cost effective to group CO_2 sources together because when sources are connected in a T&S network, the inherent need for buffer capacity to prevent shutdowns is reduced.
- To assess whether a project should incorporate buffer storage, a full understanding is needed of the likelihood of having to close down specific wells due to the lack of CO_2 (including the time

a shut-down may be needed for and the impact this will have on the well and reservoir) and also the impact of releasing CO_2 to the atmosphere (i.e. impact on project costs, climate and public perception).

Background to the Study

The construction and operation of carbon capture and storage (CCS) infrastructure is crucial for the widespread deployment of CCS projects. In 2020 the IEAGHG Strategy Group recognised that infrastructure for transport and storage (T&S) needs to be enabled and until now has not been given enough focus. The technology is established but there is a lack of incentives. In addition, the 2020 IEAGHG report, 'Review of Constructability and Operational Challenges Faced by CCUS Projects'[1] noted that 'T&S and full-chain integration has been repeatedly cited as an essential part of the planning and failure to achieve optimal interfacing between capture and T&S has been a reason for cancelling several potential projects'.

The infrastructure process brings with it several risks, such as construction timing mismatches between capture plants and transport and storage networks, and both planned and unplanned outages of the T&S network. When these events occur, the emitter may have to operate unabated, resulting in CO_2 emissions venting to atmosphere until the supply chain is fully restored.

One approach to mitigating the risk of CO_2 emissions during these events is to install 'interim', also known as 'temporary', CO_2 storage facilities between the capture plant and the T&S network. Power and industrial CO_2 emitters will require approaches to prevent CO_2 emissions where there are potential temporary 'breaks' in the CCS supply chain between the capture plant and the storage site. The findings of this study may help to prevent these excess emissions and the need to rely on natural or man-made greenhouse gas removal approaches, whilst also looking into accounting metering issues measuring CO_2 export and injection.

There is little widely available information on what interim / temporary CO_2 storage options are available and approaches to prevent CO_2 emissions with temporary breaks in the supply chain, and this work seeks to provide more information on the potential options.

Scope of Work

The objective of this study was to look at the interim / temporary CO_2 storage options that emitters can feasibly use during periods when they are unable to access the usual T&S network with the aim of providing important information to the CCS technical community, policy makers and project operators. This work aims to identify and explain the various methods of interim / temporary storage options and uses case studies to detail the key elements. Technical details are investigated along with a cost assessment for various scenarios modelled, aiming to provide more information and recommendations for different applications and industries interested in such interim storage options for CO_2.

Findings of the Study

It is important for the transport of CO_2 to be flexible due to variations in the production of CO_2 and availability in the storage part of the chain; a buffer, or interim storage, may be needed to make up for the batch-like nature of a ship-based transport chain as well as to assist with varying T&S availability and to absorb variations in CO_2 supply and / or demand. A simple CCS chain (i.e., one or two sources with transport to storage) is vulnerable to changes and may benefit from buffer storage to reduce risks

[1] IEAGHG, '**Review of Constructability and Operational Challenges faced by CCUS projects**', September 2020, Report number 2020-12

such as not being able to transport the CO_2 or not having access to CO_2 when the reservoir requires continuous injection, such as to prevent well shut-ins.

A network with multiple sources and storage options is more flexible, with less sensitivity if there is unplanned interruption of delivery of the CO_2 (for example). The choice of buffer solutions depends on the capacity needed and the cause for the variation to be dealt with and is best done with dense phase (liquid) CO_2 to minimise volume requirements. The below section summarises the buffering technology options, both currently in operation and those emerging. The report itself offers more detail and information on each option.

Buffering technology options

Current Technologies

The current technology options in terms of buffering / interim CO_2 storage are defined as those current in commercial deployment, either for natural gas, petroleum gas or CO_2 systems. It is noted that buffering technologies for CO_2 are not yet widely deployed, because the majority of commercial CO_2 transport to date is for utilisation rather than storage purposes, and many of the current CO_2 projects are fairly simple chains with minimal number of sources and just one sink with little need for buffers. Hence, analogues are looked at in this report, such as the natural gas industry, to provide an insight as they would be ready for large-scale CCS deployment.

Quayside facilities / on-site tanks: CO_2 is already transported and temporarily stored for commercial process (i.e., for use in the food industry) and so onshore storage tanks are at a high technology readiness level (TRL) and would be suitable for CO_2 storage. Due to the intermittent nature of ship transport where CO_2 is transported in batches, there is already an inherent need for temporary CO_2 storage, such as at quayside locations. At these storage facilities, the liquid volume in the tanks / ships can be used to stabilise flow rates in a T&S system so are good buffer candidates. The temporary storage should be able to store at least the same volume as the ship to allow for minimal loading times and although various volume capacities have been proposed, research has shown that a size factor (the ratio of the temporary storage volume to the ship storage volume) of 1.2 is the most suitable for a commercial CO_2 operation. Of course, the CAPEX and OPEX increase with the deployment of larger storage tanks and these costs dominate, but the unavailability cost decreases as there is less downtime. Temporary quayside storage for shipping is being utilised at the Northern Lights CCS project where CO_2 will be shipped to a receiving terminal where buffer storage tanks will be utilised, and being investigated for the development of the CO2nnect Terminal in the Port of Rotterdam.

Geological gas storage: Temporary storage of natural gas happens in geological formations such as aquifers, depleted hydrocarbon reservoirs and salt caverns and provides a good analogue for temporary CO_2 storage.

- Salt caverns are considered the most flexible option given their ability to withdraw and accept large quantities of gas more rapidly; they can undergo monthly cycles of injection and reproduction, but have smaller capacities compared to depleted fields / saline aquifers so would be better suited to provide short demand requirements rather than longer periods of gas delivery. They are however more expensive to develop than depleted fields and the costs of disposing saline water will need to be considered. Salt caverns can therefore potentially be used to allow for temporary storage needed for 10–20 day supply, but at a relatively large capital investment cost.
- Depleted hydrocarbon fields / saline aquifers are more suited to seasonal storage due to longer withdrawal periods.
    - Depleted fields are likely the cheapest option for longer-term temporary CO_2 storage due to the infrastructure already available and amount of existing

geological and operational knowledge. Storage capacities and injection rates will be site-specific, but generally dry gas reservoirs are preferred over depleted oil reservoirs as they require less maintenance. The use of depleted fields for temporary CO_2 storage has been assessed in research but not yet implemented.
    - Saline aquifers have been utilised for temporary natural gas storage. Usually there is less geological data available at such locations and so characterisation may be more expensive than at depleted fields. Pressure management with water production, if needed, will also increase costs. One of the biggest limiting factors to utilising an aquifer for temporary storage is the large volumes of cushion gas required.
- It is likely that temporary CO_2 storage will only be utilised in stores that already have ongoing permanent storage operations.

Pipeline system line-packing: Line-packing is used in the natural gas industry for providing short-term (hourly and daily) gas storage. The line-pack refers to the total volume of gas contained in a pipeline system. Line-packing (increasing the total volume of gas in the pipeline system) lowers the pressure drop at either end of the system during periods of high demand by maintaining higher pressure in the middle of the network. A pipeline with dimensions considered typical for CCS schemes can provide short-term storage for around 10 hours and in dense phase, times of up to 8 hours could be achieved, indicating that this method does not represent a long-term temporary storage option. Line-packing has been utilised in CO_2 pipelines in the OCAP system in The Netherlands, which uses a low-pressure pipeline to absorb the diurnal variation in CO_2 demand from greenhouses.

Emerging Technologies

There are emerging future technologies that could be appropriate for temporary / buffer CO_2 storage that are not yet deployed, be it in the potential for increasing the capacity of currently deployed technologies, or for repurposing existing technologies for use with CO_2.

Offshore storage in salt caverns: In addition to the onshore salt caverns mentioned above, offshore settings could also be considered. Research in Brazil on the use of salt caverns for storage of CO_2 proved to be technically feasible and met with good safety margins and research in Europe has investigated the potential of temporary hydrogen storage in offshore salt caverns. The main cost for temporary geological CO_2 storage is driven by the cost of site development, which is much higher for cavern excavations and especially in offshore settings.

Other caverns: Rock caverns in other structures such as disused mines, man-made hard rock caverns, lined rock caverns or gravity-based structures (e.g., large reinforced concrete tanks) could also be considered for temporary CO_2 storage. The high cost of hard-rock caverns has to date meant they are not yet extensively used for gas storage, but they are under development for use as temporary stores of natural gas and for compressed air energy storage (CAES).

Floating storage & injection unit (FSI): For ship transport, there is the potential to transfer CO_2 from a tanker to an offshore FSI. Compared to onshore facilities, this system remains unproven and is in general more costly and less understood., but they could be designed to provide an overcapacity and be able to either store extra CO_2 that could be utilised to prevent shut-ins or provide extra capacity should the injection need to be temporarily suspended. The potential for offshore FSIs was investigated in the CO2LOS II R&D project, which found it was the most expensive option modelled compared to batch-wise injection or continuous injection from ships. FSIs will also be included in the logistics chain for the Stella Maris CCS project, which will provide a large-scale, flexible, scalable maritime logistics solution for captured CO_2 from industrial sources near the North Sea.

Modelled scenarios

Simulations have been conducted to demonstrate the temporary storage required for given flow-rate scenarios. It is noted that injection wells have both a minimum and maximum injection rate; the minimum flow rate is critical in the discussion on the requirements for intermediate storage or buffering. To avoid shutting in wells for short periods, the total flow rates to the injection site must be maintained above the sum of the minimum rates of the open wells. Key well behaviour aspects must be considered for the simulations: well bottomhole pressure, wellhead pressure, and choking. The report looks in detail at these aspects by modelling flowrates required to prevent well shut-ins, pipeline simulations and buffering requirements, using three separate case scenarios to demonstrate at what point well shut-ins would be required.

With regards to line-packing and buffering requirements, the findings show:

- One of the critical operational limits in the CO_2 injection is a limit on the wellhead temperature. At pressures less than 35 bar, the fluid wellhead temperature drops below 0°C which means that wellhead pressures need to be higher than 25-35 bar or single-phase conditions need to be ensured.
- In addition, projects must ensure avoidance of hydrate formation.
- Both above conditions lead to a minimum flowrate requirement. The typical minimum CO_2 flowrates at the well are in the order of 10-15 kg/s (40-60 tonnes /hr). This is the flowrate which buffer capacity needs to be designed to maintain.
- If a drop in total flow rate occurs, to keep the wellhead and bottomhole temperature within a safe operational window, a buffer or well shut-in will be required relatively quickly (in a matter of hours) to prevent temperatures becoming too low to operate the well safely.
- Line-packing cannot provide enough buffering beyond this short timeframe: the buffer capacity in the pipelines is limited. In high-pressure networks the capacity is often less than a few hours. The capacity in low pressure networks is often higher due to the often large-diameter pipes. However, even in these networks the capacity is limited by the operational window which is defined by the requirement to operate with CO_2 in gas phase.

Cost assessment

Several possibilities for intermediate storage of CO_2 are available, including vessels, geological storage and pipeline storage and the most common way today to store liquefied CO_2 is in insulated steel vessels. Costs for these vessels are defined based on parameters as pressure, material, temperature, size and wall thickness. The installed cost may vary quite a lot based on the ground characteristics and location factors, and if the vessel is horizontally or vertically oriented, if the vessel is welded / built at site and also on the local costs of where it was built.

This section of the report looks at the impact of buffer capacity on the transport costs showed in three different scenarios. In this work, cost data for the buffer vessels are estimated using AspenTech software and a total installation cost factor is estimated by means of SINTEF's much-used proprietary estimation tool. The vessels used for estimations are horizontal low temperature steel tanks, and in normal operation there is no buffer storage / extra capacity in the transport chain; the buffer storage accommodates for the extra capacity if the chain meets unexpected issues and normal operation is disturbed. The buffer capacity is estimated based on these possible failures in the chain:

- The capture plant cannot deliver CO_2
- The injection well cannot receive CO_2
- The ship cannot receive CO_2
- The ship cannot deliver CO_2
- The pipeline cannot receive CO_2

An empty buffer storage is needed to be able to collect the CO_2 produced from the industrial plant if the injection well or transport network cannot receive CO_2. A full buffer storage is needed before the injection well to secure continuously injection if the emitters, capture plant or transport network cannot deliver CO_2.

Three scenarios are analysed to demonstrate the need for buffering in different networks and to investigate how buffer / interim storage could be used in each system.

Scenario 1: Single source and storage chain

In this system, a cement plant has a facility to capture CO_2 (producing 1000 kt CO_2 per year) and transport it via pipeline to a geological storage reservoir, as shown in the figure below.

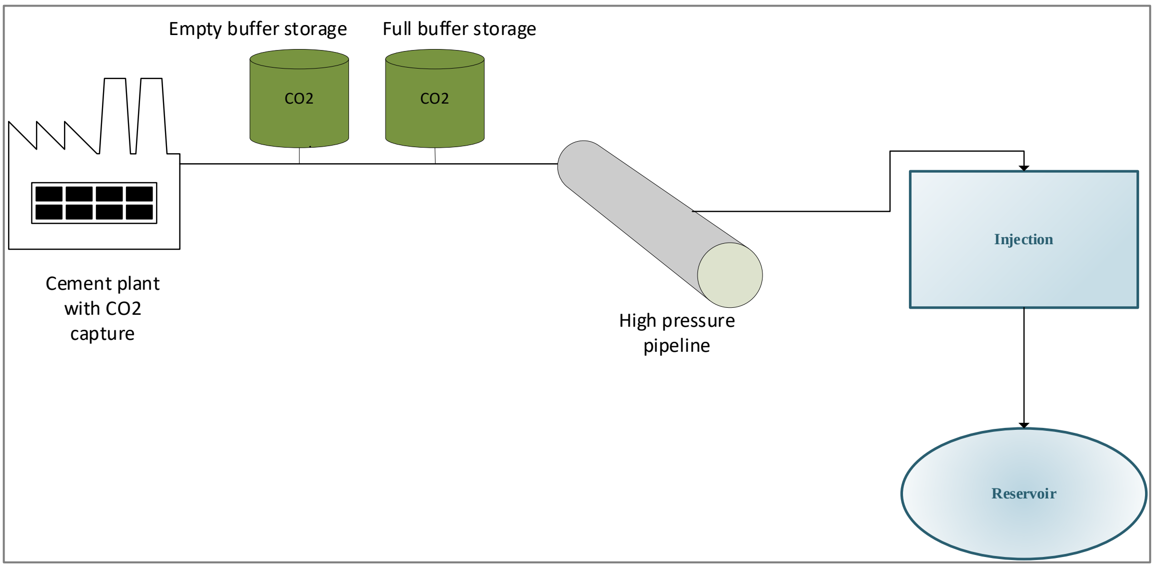

Figure 1. **Scenario 1, single source and storage chain including buffer storage**

As the pipeline transport is a continuous process as opposed to ship transport, no temporary capacity is needed during normal operation, but if there is a failure then buffer capacity may be required. To be able to keep a continuous injection rate of 54 t/h, a buffer storage before the injection well of approx. 2 days production of CO_2 is suggested (that equals the product of the injection rate and the 2 day stoppage time, 54 t/h * 48 h = 2.6 kt of CO_2). If the pipeline or injection well cannot receive CO_2, two days' production of CO_2 equal to 5.1kt (106 t/h * 48 h) from the capture plant, should be stored in a buffer storage. This buffer storage is empty during normal operation and is only in use if the source or capture plant cannot deliver CO_2 to the transport chain.

If buffer capacity is included, the cost of the two vessels is approx. 23,200 k€. A rough calculation of the CAPEX for both buffer storages over a project lifetime of 20 years, and with 7.5% discount rate, shows that the cost for the buffer storage is 2.7 €/t. The operational cost is difficult to estimate but would include maintenance costs, staffing and energy to keep the temperature low.

Numbers here and in other research show that the suggested buffer capacity has a high cost compared to the total investment of the chain, and it should be discussed if the cost of the buffer storage justifies the risk avoided.

Scenario 2: Multiple supplier and storage site network

This system is a network that connects multiple CO_2 sources (a cement plant producing 1000 kt CO_2 /year, a power plant producing 500 kt, and a steel plant producing 2500 kt CO_2 per year) with a single storage reservoir, with the CO_2 transported by ship to a collection hub (a common terminal, where it is compressed) before being transported via pipeline to the reservoir. This scenario includes intermediate storage in the ship transportation (figure 2, below). In scenario 2, as the ship transport is a batchwise system and the sources/ capture plant produce CO_2 continuously, there is a need for buffer capacity during normal operation both before and after the ship transport. The buffer capacity varies with the volume of the flow from the emitters. Even if the power plants have lower yearly amounts of CO_2 produced, the buffer capacity and the transport chain are designed for maximum flow.

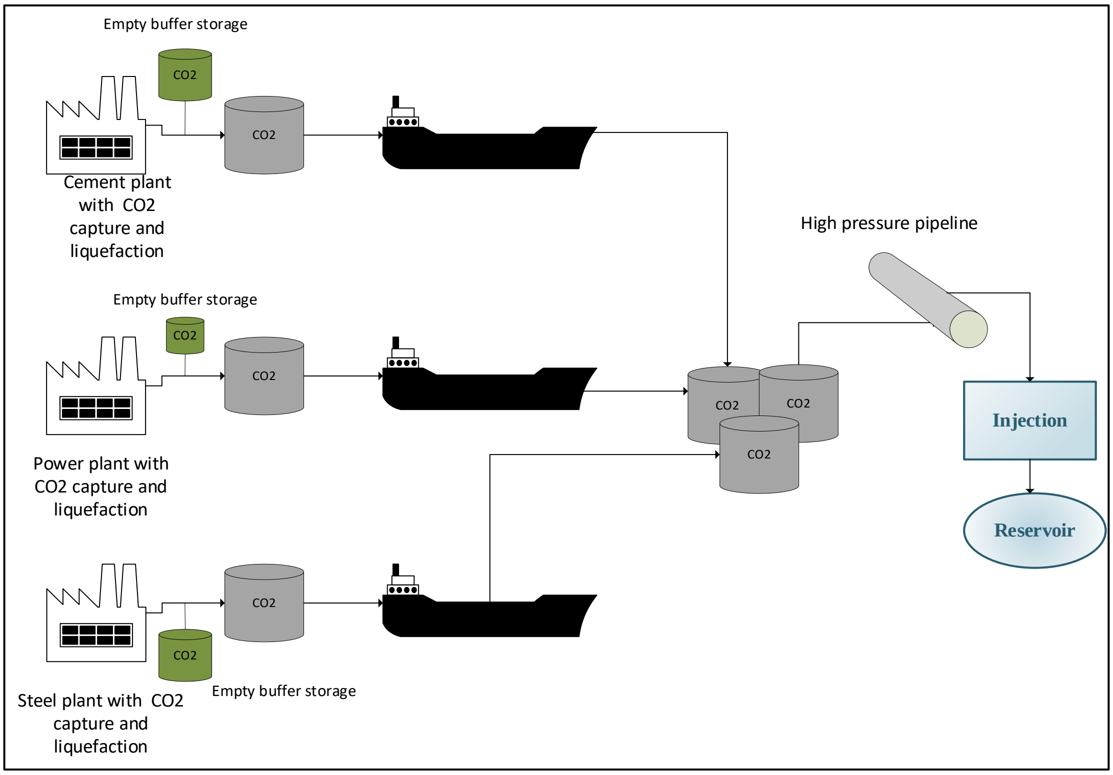

Figure 2. **Scenario 2, multiple supplier and storage site network including buffer storage**

The extra buffer capacity in the chain has an estimated cost of approx. 58,000 k€. That includes the three buffer storages before transport and the small buffer storage before the injection well. The cost for the extra buffer capacity is estimated to be (at 20 year life time and 7.5 % discount rate) 1.5 €/t. Again, OPEX is not included but maintenance will be required as will energy to maintain low temperatures in the tanks.

Scenario 3: Low pressure network

This system involves two CO_2 sources (a cement plant and a steel plant) and a single reservoir, as detailed in the below figure. The cement plant transports the captured CO_2 through a low-pressure pipeline and the CO_2 is compressed into a high-pressure pipeline before being injected into the reservoir. The steel plant transports the captured CO_2 via ship to a collection hub, where the CO_2 is compressed into the same high-pressure pipeline as the cement plant before being injected into the reservoir. The cement plant network does not require any buffer capacity in normal operation, but the steel plant transport network requires intermediate storage before and after the ship transport.

In the figure below, it shows the interim storage in grey vessels for the steel plant. The buffer storage is shown in the green tanks, those that may be required to keep the flow into the injection well if there are issues with delivering CO_2 from the plants or if the well cannot receive the CO_2.

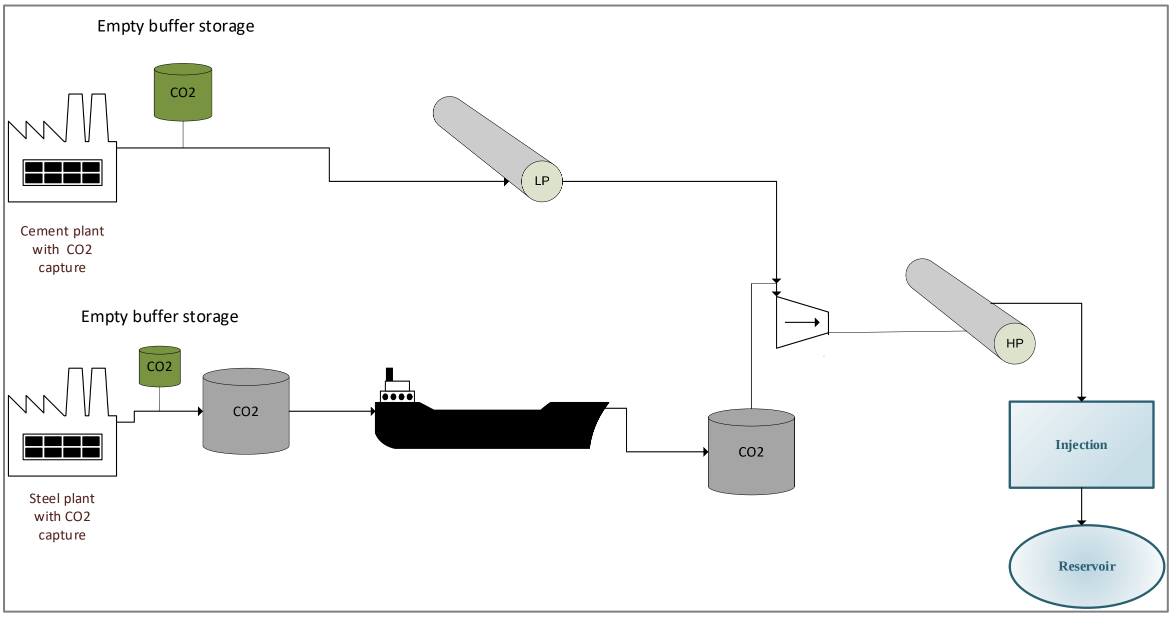

Figure 3. **Scenario 3, low pressure network including buffer storage**

The steel plant produces 2,500 kt CO_2 per year, and with a capture rate of 85% the capacity of the capture plant is 2,125 kt per year. The transport is by ship and temporary storage before and after transport is required during normal operation. In addition, a buffer storage of 2 days production is needed in case the T&S system cannot receive the CO_2. The size of this buffer storage is estimated to be 12.1 kt. (252 t/h * 48hr = 12,096 t).

The total buffer capacity increases the cost for intermediate storage with approx. 36,000 k€. That includes the two empty storage vessels before the transport. As the network consist of both ship and pipeline logistics, there are no need for extra buffering to avoid shut down of the well if one source fails. The cost for the extra buffer capacity is estimated to be (20 year lifetime and 7.5% discount rate) 1.0 €/t (CAPEX only).

Geological gas storage

A common option for the storage of natural gas, these costs would be highly site-specific and vary according to parameters such as volume, depth, type of storage, wells, injection cost, infrastructure needed, platform operation and maintenance costs. Generally, onshore storage is cheaper than offshore; depleted oil and gas fields are cheaper than deep saline aquifers; larger reservoirs are cheaper than smaller ones and the cost of wells increases with depth. These storage options could be used if there is a need for buffering large amounts of CO_2; for smaller volumes, steel tanks will normally be more cost-effective.

Floating buffer storage

Floating buffer tanks could be located at the industry site or close to shore on barges, which can be reused at other sites if needed. Reuse may reduce the risk of investing in buffer storage capacity but requirements (i.e., tie-ins and size of buffer storage) will be different at different locations; one size does not fit all.

The section demonstrates that the cost of buffers is generally high, but the risk of not including buffers in a CCS chain is that CO_2 will be emitted to air if failures occur. The design of and need for buffer storage should reflect the risks of emitting CO_2 and public perception issues of this. Operators must weigh up the costs of having CO_2 available in part of the chain and having extra capacity with empty buffer available with the risks. It will be more cost effective to group CO_2 sources together because when sources are connected in a T&S network, the inherent need for buffer capacity to prevent shutdowns is reduced. The buffer storage to prevent CO_2 loss from the T&S network if storage cannot receive CO_2 is not affected if sources are connected, and should be included close to the capture plant.

Future projections

Many future CCS projects will likely follow a hubs and cluster approach, with several emitters utilising a single collection network joined to a hub with one or more storage locations. More emitters will increase the likelihood of unplanned variation in the CO_2 supply but the chances of two or more sources stopping supply at the same time is relatively low, so the requirement for buffering is not likely to increase as a CCS chain becomes larger with more complex networks. More emitters may add more flexibility to the chain with the ability to accelerate CO_2 production if needed, and multiple wells / storage sites involved may increase the capacity of the system to compensate for additional flow.

As CCS chains become bigger with networks of hubs and clusters, the costs of buffering will be shared between more parties, but if the project is small, the buffer storage may become a more significant part of the overall T&S costs. Different industries and the size of the plants will have different requirements for the configuration of any buffer storage.

With more emitters joining a CCS chain, projects will also need to address the issue of intra-cluster management of CO_2 supply, for example to minimise the potential impact on supply rates, routine maintenance and planned downtime could be managed between the various sites to dramatically reduce the need for well shut-ins. Buffer storage could be shared where all the emitters feed into, which will need management and planning between the different sources and storage sites, but could be a valuable way of improving system flexibility. However, given the commercial needs of the capture site downtime may be difficult to plan to incorporate the needs of other sites, especially if there is no financial incentive for the capture site undergoing the maintenance to plan this around the CCS network as a whole.

Enhanced hydrocarbon recovery (EHR) projects may benefit from the temporary holding of CO_2. These systems operate differently to CCS projects (different financial drivers, back production of CO_2 etc.), and many existing projects will have dealt with temporary storage. It is unknown how these projects are affected by supply intermittency or how buffering is specifically integrated into such systems.

Conclusions

Costs will be incurred when designing extra / interim / temporary CO_2 storage capacity into a CCS chain and as a rough estimate from research in this study, the cost for buffer storage will be in line with approximately 5-10% of the transport costs. There are several benefits of having buffer storage as an option, including to prevent well shut-in and to prevent unplanned venting of CO_2 to the atmosphere.

Any buffer capacity is likely to be designed for short-term changes in the CCS chain because the volumes of CO_2 produced on a daily basis are likely to be large, meaning long periods of downtime which would require very large storage capacity and very high costs.

The most likely solution for buffer capacity is onshore facilities designed for shipping (e.g. onshore tanks), which could be built slightly over capacity to accommodate unplanned short-term changes. It is unlikely that geological storage will be developed for these changes given the longer timescales for storage and injection cycles. Man-made underground storage tanks are likely to become more common as energy storage becomes more widely used in the hydrogen industry, for example, due to the increase in renewable energy deployment. Although for CO_2 this technology is currently at a low TRL, increased use in other industries will lead to more widespread understanding and a higher TRL.

Providing an overcapacity of onshore CO_2 storage in quayside facilities means an unplanned downtime of the T&S network or CO_2 supply could be compensated for. However, as more projects come online that will likely be linked in networks, the buffer capacity is unlikely to be increased and it will be easier to keep the minimum flowrates needed so this may reduce the need for buffering options.

Line-packing is unlikely to provide interim storage for more than a few hours and will incur extra compression and costs.

Shipping is being increasingly used in CCS projects and as the need for temporary storage is inherent in such circumstances, there is potential to oversize the needed loading / unloading terminals and for longer trips to consider whether buffering will be required. Pipeline based projects will incur significant extra costs to incorporate onshore interim storage.

The costs of buffer storage are unlikely to change dramatically in the near future; most of the facilities (i.e., shipping tanks, quayside facilities and on-site tanks) are already commercially deployed. There may be minor changes to material costs, but general costs are unlikely to change. As more emitters come online in a project, more ship capacity may be required.

As with most technologies, processes and practices, the reader is reminded that cost estimates can be site-specific and dependant on availability of infrastructure in the region.

Expert Review

Five external expert reviewers examined the draft report, and all agreed this could be a useful study on the potential for the use of interim storage for CO_2. There was a reasonable number of comments on the report, with many asking for more explanation and clarity throughout the report. Where appropriate, sections were re-written to provide clarity and more detail, and a list of abbreviations and list of units used to help readability.

Some reviewer comments asked for better explanations within the cost assessment section in particular and noted that more be provided on project financing and investment mechanisms. The contractors added more detailed explanations as requested but noted that financing and investing was out of the scope of this particular work. One reviewer asked for a discussion on the link between variation of buffer storage size and frequency of ship visits when an emitter is exporting CO_2 at peak export capacity; it was noted that this is very dependent on the sea conditions, specific vessels and shipping distance and so the contractors refrained from commenting on this in detail in the report.

It was asked whether there should be detail added on concerns about leakage for pressurised CO_2 tanks; this is discussed only very briefly in the report as there are no particular concerns for CO_2 in comparison to LPG – mitigating actions would be different but there would be no extra safety concerns. One reviewer asked for the report to include an estimation of energy requirements and an estimation of the reduced climate benefits of CCS (e.g., due to energy use for interim storage). It was noted that the cost assessment in this study is just an indication of how much the buffer storage may cost, and not a complete cost analysis. The main point is to show that the extra capacity is costly, and that should be taken into account when designing CCS chains and therefore the energy cost has not been included in this study. To find the climate benefits a lifecycle analysis should be performed, but that was not included in the scope of this work.

Finally, the IEAGHG Executive Committee asked for the title of this report to be edited slightly to 'Components of CCS Infrastructure – Interim CO_2 Holding Options' (was originally '*Components of CCS Infrastructure – Interim CO_2 Storage Options*').

Recommendations

The following recommendations are made by IEAGHG following publication of this report:

- It would be interesting to consider the cost of buffer storage withing the context of the risk and consequences of not having buffer capacity,
- Further work on project financing and investment mechanisms for temporary storage would provide a new insight,
- One specific scenario not yet considered is the temporary storage of CO_2 during enhanced hydrocarbon recovery projects (EHR). Future work could look at existing projects using temporary storage and model for not-yet existent scenarios with EHR to look at supply intermittency, how buffering is specifically integrated into such systems, and cost assessments of such activities,
- It would be useful to do an in-depth analysis looking at the regulatory and public perception implications of the different technologies for buffer storage / holding options,
- A complete lifecycle analysis of buffer / temporary CO_2 storage options is recommended and would benefit project operators, investors and regulators.

TNO report

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Components of CCS Infrastructure: Interim CO_2 Storage Options

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Contents

List of abbreviations

ASTM	American Society for Testing and Materials
CAPEX	Capital expenditures
CCUS	Carbon capture, utilisation, and storage
CCS	Carbon capture and storage
CO_2	Carbon dioxide
FEED	Front-end engineering design
FSI	Floating Storage and Injection unit
LCC	Life cycle cost
LPG	Liquified petroleum gas
OPEX	Operating expenses
T&S	Transport and storage
TVD	Total vertical depth

List of units

°C	degree Celsius
Bar	used for pressures sufficiently high to make the difference between bara and barg insignificant
Bara	bara = barg+atmospheric pressure (Atm), if 1 Atm = 1 bar, bara = barg+1
Barg	gauge pressure
kg	kilograms
k	formation permeability
k€	thousand euros
h	formation thickiness
hr	hour
ktpa	Kilatonnes per annum
mDm	millidarcy-meters
Mtpa	Megatonnes per annum
M€	Million euros
PI	Injectivty
s	seconds
t	tonnes
“	inches

Executive Summary

Carbon capture, utilisation and storage (CCUS) is one of the key technologies needed to reach the goals of the Paris Agreement and the infrastructure for transport and storage (T&S) is vital to be able to connect the emitters with the CO_2 storage and/or users. In this study, commissioned by IEAGHG, temporary storage has been investigated regarding its ability to create flexible and robust carbon capture and storage (CCS) chains (i.e. to be utilised as a 'buffer'). (CO_2 utilisation has not been explicitly covered in this study).

The need for interim or temporary storage of CO_2 (referred to in this report as a 'buffer' storage when utilised to provide overcapacity and flexibility in the system) arises from several factors. A continuous and consistent supply of CO_2 is important to prevent emissions of CO_2 to the atmosphere which could be caused by intermittent or over-supply along the CCS chain. Another key challenge is that the storage reservoir is sensitive to large changes in supply and a discontinuous flow could lead to shutting in the wells which should be avoided when possible. Conversely, an over-supply of CO_2 may lead to venting being required along the transport chain. This should also be avoided as it will prevent CCS providing the climate mitigation solution it fundamentally delivers. Venting may therefore incur costs (e.g. associated with paying back emissions allowances) and may also negatively impact public perception of CCS. Variations in both the production of CO_2 and availability in the storage part of the chain can cause variations in flow. In the CO_2 shipping chain buffer storage is often required to bridge the gap between the (semi-)continuous process of CO_2 capture and the batch-wise process of ship transportation. However, even a chain based on pipeline transportation is likely to require buffer capacity to manage varying CO_2 volumes and also any unexpected changes in capacity throughout the CCS chain. Buffers would therefore provide the ability to make up for the discontinuous flow of CO_2 related to 1) batch processes (e.g. shipping and rail) as a transport options, 2) to supplement strongly varying T&S availability, and 3) to absorb strong variations in CO_2 supply (capture) or CO_2 demand (utilisation).

This study provides an overview of temporary CO_2 storage options (which can be used as buffers) that are currently in commercial deployment, either for natural gas or for CO_2 systems. Technologies that have yet to be deployed at a large scale (named emerging technologies) are also reviewed. When looking at potential buffering options an appropriate analogue for CO_2 T&S is the oil and gas industry. Hence, when looking at technologies such as quayside facilities or temporary geological storage, liquefied petroleum gas (LPG) technologies have also been investigated as part of this study. Buffer storage options for gas generally have high technology readiness levels given they have already been deployed at commercial scale in the natural gas industry and are ready for large-scale CO_2 deployment.

Quayside buffers (i.e. storage in tanks) are a standard component of a shipping terminal (to ensure fast loading or unloading) and are the most likely technology to be utilised to provide buffer capacity for projects in the near-term. This study reviewed three scenarios with different requirements. All concluded that installing a buffer to accommodate disruptions to flow in the T&S network, on the order of magnitude of a stoppage for a couple of days, will require tanks of significant volume and that the cost of installing and operating such tanks is likely to be financially prohibitive as the cost for the buffer capacity is generally high..

In the scenarios investigated in this study, the cost is between 1 to 2.7 € per tonne of CO_2 buffer storage provided. These buffer storages should be located close to the capture site to minimise costs. It should also be noted that a buffer tank to accommodate an intermittent supply should be full, while a buffer that is to accommodate outage on the T&S side should be empty. It is probably more cost effective to design some level of flexibility into a T&S system through spare capacity in pipelines and wells, allowing some freedom to redirect CO_2 flows in cases of T&S downtime and an ability to handle flowrate variations.

The cost of buffer storage should be considered within the context of the risk and consequences of not having buffer capacity. Given the high cost of buffering a more detailed risk analysis is needed at a project level. To assess whether a project should incorporate buffer storage, a full understanding is needed of the likelihood of having to close down specific wells due to the lack of CO_2 (including the time a shut-down may be needed for and the impact this will have on the well and reservoir) and also the impact of releasing CO_2 to the atmosphere (i.e. impact on project costs, climate and public perception).

1. Introduction

CCS is one of the key technologies needed to reach the Paris Agreement goals and the infrastructure for transport and storage is vital to be able to connect emitters to a CO_2 storage facility or a user store. In this report buffer storage is investigated regarding its potential to create flexible and robust CCS chains. Buffer storage is often required in the CO_2 shipping chain to bridge the gap between the continuous process of CO_2 capture and the batch-wise process of ship transportation. However, even a chain with pipeline transportation needs buffer capacity to accommodate any changes in the volume of CO_2 being transported or any unexpected changes in capacity along the chain. One important aspect is that the reservoir is sensitive to large changes in supply and a discontinuous flow could lead to shutting in the wells which should be minimised.

Buffer storage is typically carried out in pressure vessels although other technologies such as underground geological storage can also be utilised. The buffer type will depend on:

- the amount of CO_2 variation expected;
- the properties (pressure, temperature and composition) of the CO_2 to be stored;
- the cost of the technology to be deployed;
- health and safety regulations in the local area;
- public acceptance concerns (especially for onshore CO_2 storage).

This report will also analyse the effect of linepacking and see how much additional capacity pipelines may offer if pressure is temporarily increased. To provide some context on temporary storage needs and buffering, a high-level overview is provided here on CO_2 transport options, and the volumes and conditions CO_2 is transported in.

Information Box 1: CO_2 Transport Conditions

To prevent unwanted pressure and temperature effects during CO_2 transport, it must be transported in conditions which allow it to remain in phase equilibrium. As shown in Figure 1, different parts of the CCS chain operate with CO_2 in different phases.

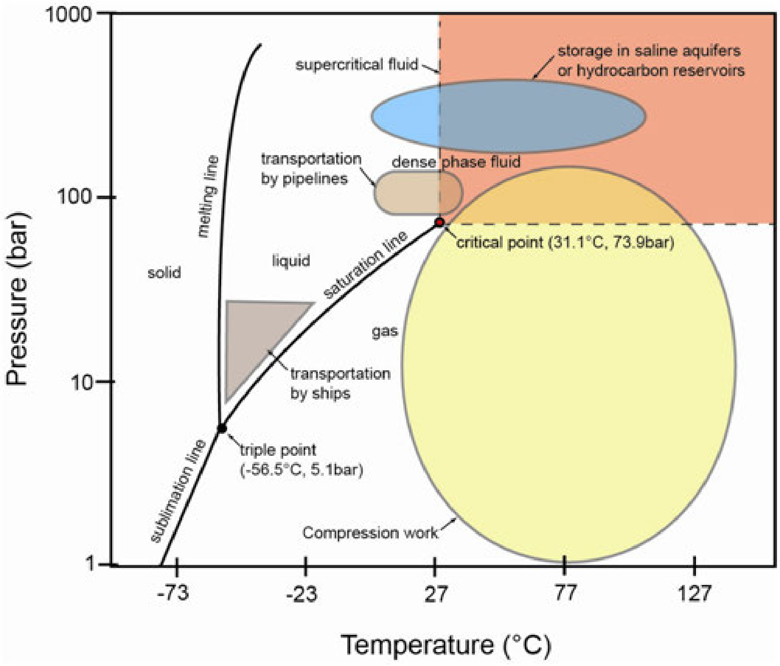

Figure 1 Various operations involved in the CCS chain showing the pressure and temperature domains superimposed on the CO_2 phase diagram (TWI Website, 2022)

As shown in Figure 1, transportation by ship is typically at much lower temperatures and pressures than pipelines. Before CO_2 can be stored, compression is also required somewhere along the CCS chain to allow for injection of CO_2 as a dense phase fluid into the storage location. An overview of typical CO_2 conditions for transport, including representative volumes and applications, are provided in Table 1.

Table 1 Overview of CO_2 transport options and characteristics (Al Baroudi, Awoyomi et al. 2021).

Transport Type	Typical Volumes	CO_2 Conditions	Current applications
Pipeline	Flow for a CO_2 temperature of 10 °C at 120 bar = 935.23 kg/m and at 85 bar = 907.76 kg/m^3.	Phase: Vapour, dense phase. 4.8–20 MPa, 10 to 34 °C.	Extensively deployed (approx.. 6500 km in operation) e.g. for EHR use.
Ship	Currently <10000m^3 but envisioned to become larger-scale in future. Food industry currently 800 – 1000m^3 .	Phase: Liquid. 0.65–4.5 MPa, -50 to 10 °C. Low pressure minimum is the CO2 triple point = 7 barg (approx. 0.65Mpa) and -50°C. Optimal pressure currently considered 15 barg, -30˚C. This is current standard for small-scale food industry shipping. For larger volumes (and in the future) it is envisioned that the pressure is going to be decreased as ongoing studies suggest a decreasing cost per ton for the whole supply chain for lower transport pressures.	Currently applied in food and brewery industry for smaller quantities and different conditions.
Road	2-30 tonnes per batch.	Phase: Liquid. 1.7–2 MPa, -30 to -20 °C.	Not economical for large-scale CCUS projects.
Rail	Small batches, < 100 tonnes.	Phase: Liquid. 0.65–2.6 MPa, -50 to -20 °C.	No large-scale systems in place.

As this study focuses on the commercial large-scale application of CO_2 storage, only pipeline and ship transport are considered in terms of their temporary storage and buffering requirements.

1.1. Overview of Buffering Requirements

CO_2 transport systems need to be flexible to be able to accommodate variations in CO_2 volumes which can occur through a CCS project's operational lifetime. Alongside inherent temporary storage needs (e.g. due to the batch-wise nature of a ship-based CO_2 chain) a buffer is also typically needed to supplement strongly varying transport and storage (T&S) availability, absorb strong variations in CO_2 supply (capture) or changing CO_2 demand. These variations can arise from: a need for fast ship loading or offloading, daily and seasonal swings in supply or demand rates, or injection wells that need minimum supply rates to prevent frequent shut-in (see Information Box 2).

A simple CCS chain with one or just a few CO_2 sources and then transport to a single storage site is vulnerable to changes and would benefit from a buffer storage to reduce the risk of not being able to transport the CO_2 or the risk of not having access to a source of CO_2 if the reservoir requires continuous injection. A network with multiple sources and storage alternatives gives more flexibility and will be less sensitive if sources experience unplanned interruption in their delivery, or a reservoir has issues with injection.

The choice of buffer solutions will depend both on the capacity needed and on the cause of the variation to be dealt with. Buffering is best done with liquid CO_2, to increase CO_2 density (and as a result increase storage efficiency by minimizing volume requirements). Although increasing pressure often increases the cost due to the need for liquefaction facilities. The design capacity of the buffer storage before ship transport is an important parameter and is dependent on the ship size and logistics cycle. The buffer storage should carry at least the volume of the produced CO_2 at the source for one round trip of the ship. There is also some flexibility in relation to the speed of the ship, as should delays or over supply be experienced elsewhere in the chain a ship can be temporarily be slowed or sped up (at cost) to compensate for this . The speed is typically 12 knots (Adland, Cariou et al. 2020) but can be higher or lower if there are issues at the receiver end of the chain.

Information Box 2: Well Shut-ins

The main reason buffering (temporary storage) may be required is to prevent a drop in CO_2 flow rate which may lead to the injection wells needing to be shut-in. If the flowrate drops below the minimum required threshold (i.e. which is required to prevent temperature or pressure in the well becoming too low) wells are shut-in to stabilize conditions in the well.

Well Integrity

Well shut-ins are undesirable as it will lead to a sudden decrease of pressure at the wellhead which ultimately causes an unwanted drop in temperature. This low pressure is because of "*the downward inertial flow of CO_2 and a decrease in the magnitude of the frictional pressure drop in the wellbore, both of which will result in transient effects and a drop in the temperature of CO_2 due to Joule–Thomson (J–T) cooling*." (Li, Xu et al. 2015). This variation of wellbore temperature is undesired as it can lead to damage of the injection wells as it may cause debonding along the cement-casing or cement-rock interfaces.

Start-Up and Shut-Down

Shut-ins also require the start-up of injection again which also impacts wellbore dynamics. During a shut-in "*a gas cap can develop at the wellhead (depending on depth and pressure of the reservoir). When passing through this state of the system during start-up and shut-down, CO_2 will flash across the wellhead choke valve, which comes along with the strong J-T cooling effect that can endanger the integrity of the well*." (Spitz, Chalmers et al. 2017). One of the biggest factors impacting this is the time between the shut-in and restart of injection. The more time the well has to reach the ambient temperature of the reservoir the greater the temperature change will be when injection recommences (Torsæter, Todorovic et al. 2017).

Impact

The risks associated with these temperature cycles can be reduced in two ways. Firstly by designing the wells to accommodate these lower temperatures and secondly by minimising the number of well shut-ins required. Buffering is therefore a potential way to mitigate this risk, if it can help prevent drops in CO_2 flow that would otherwise require a well shut-in. Case studies of the Porthos and Snøhvit projects are provided below which discuss the risks associated with well shut-in.

Case Study 1: Porthos, Netherlands

The P18-2 storage permit application from Porthos (in the Netherlands) discusses well integrity in detail, because of the potentially low temperatures that may occur at the bottom of the well. This is due to the low pressure of the depleted gas field being used as the storage reservoir. The P18-2 permit application mentions that debonding is (very) likely to occur, creating micro-annuli (example shown in Figure 2). It is currently thought that these annuli will grow in number and length, not in size, meaning that the network of annuli will become larger after each low-temperature cycle (Vrålstad, Skorpa 2020).

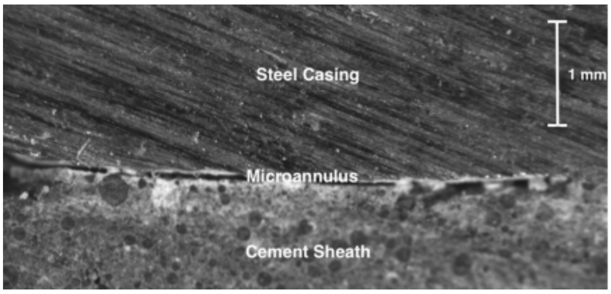

Figure 2 Photograph of micro-annulus at steel (above) and cement (below) contact (Gomez, Sobolik et al. 2016)

On the other hand, the P18-2 permit application (Netherlands Enterprise Agency (RVO) Website, 2022 April) argues that the low pressure (below hydrostatic) in the reservoir actually prevents leakage through the annuli, except for the very last phase of injection, when pressure in the well needs to be above hydrostatic to be able to inject at all. Leakage rates are estimated and are negligible. This approach appears to be supported by the regulator.

For saline formations, a similar line of reasoning could be followed. Annuli size is expected to be smaller, as the bottomhole temperature during shut-in is higher, but pressure will always be above hydrostatic. In summary, although well shut-ins may increase the risk of well integrity being compromised, they are also likely to be manageable without significant risk of leakage as and when they are required. The requirement for buffering should therefore also be considered within this context.

Case Study 2: Snøhvit, Norway

During the CO_2 injection operations at the Snøhvit CCS Project, short periods of stoppage have taken place regularly. Data collected at the site allowed the measurement of well pressure over these shut-in periods, as well as during CO_2 injection to be analyzed (Shi, Imrie et al. 2013).

Shut-ins occurred regularly (lasting only a few minutes) to allow for fall-off analysis to be undertaken. Alongside this almost monthly during unplanned stoppages occurred during the 32 month assessment. The longer stoppages varied in length and occurred due to operational challenges at the LNG plant associated with the project. A long 4.5 month shut-in also occurred as a major plant maintenance workover was undertaken at the LNG plant in the autumn of 2009.

During the shut-ins some changes in pressure occurred that had not been expected (i.e. slower pressure drops at the start and quicker pressure build ups as injection re-started) however, no problems occurred at the site associated with these shut-ins and injection and storage operated as planned once the capture plant was providing continuous CO_2 supply.

1.2. Scenarios Analysed

In this report three different scenarios are investigated to demonstrate the need for buffering in different networks and how temporary storage could be integrated into each system. Each scenario begins with the capture of CO_2 and ends at the storage site. The scenarios will include both ship and pipeline transport and also the potential buffer capacity needed during the logistic chain.

For all the scenarios are these conditions present:

- From capture plant the CO_2 is at 1 bar, 20 °C.
- Close to the capture plant, a compression/liquefaction unit is present.
- Ship transport at 15 bar, -28 °C.
- For high pressure pipeline 130 bar, ambient temperature.
- For low pressure pipeline 35 bar, ambient temperature.
- Buffer storage at 20 bar, -18 °C.

Scenario 1: Single source and storage chain

This system illustrates the varying need for buffer capacity in a one-to-one system. A cement plant has a facility to capture CO_2, compress it and transport it via pipeline to a reservoir for storage (Figure 3). This 1-1 system represents the lowest buffering potential.

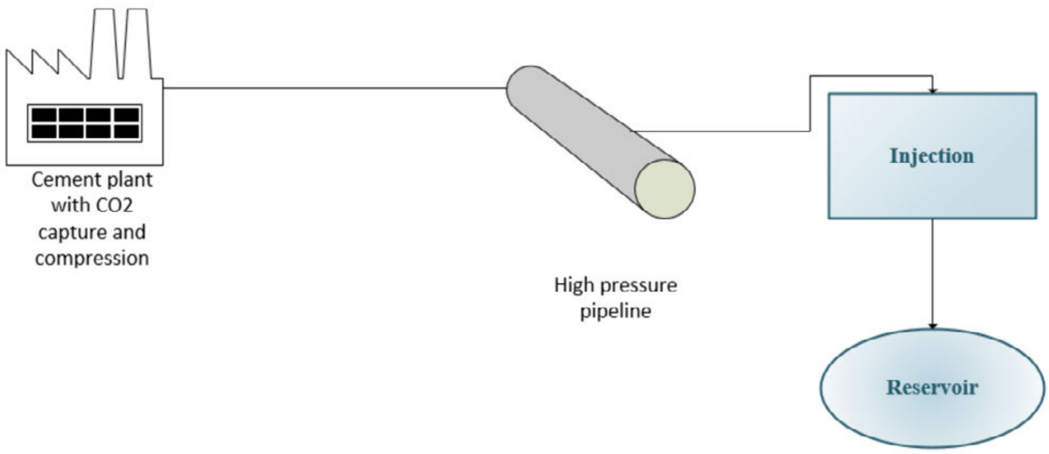

Figure 3 Scenario 1 with a single CO_2 source, pipeline and single injection site.

Scenario 2: Multiple supplier and storage site network

This scenario is a network that connects several emitters of CO_2 which have installed CO_2 capture facilities with a single storage reservoir. CO_2 is transported by ship to a collection hub and a pipeline brings the CO_2 to the reservoir (see Figure 4). This scenario includes some temporary storage due to the ship transportation, both before and after shipping. However, there is no extra buffer capacity included, as the temporary storage tanks are completely filled up and emptied during normal operations. In this scenario the size of the temporary storage means there is no extra capacity if the ship transport or production of CO_2 is interrupted.

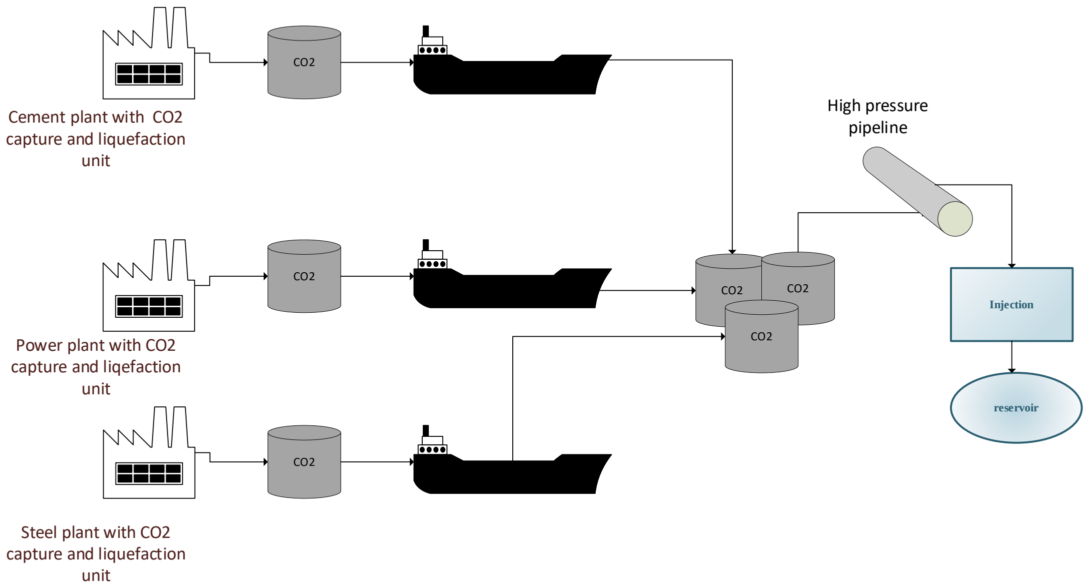

Figure 4 Scenario 2 with a several CO_2 sources, ship transport to a single collection point and a high-pressure pipeline to a storage location.

Scenario 3: Low pressure network

This system has two sources of CO_2, one cement plant and one steel plant. The cement plant transports the captured CO_2 through a low pressure pipeline, and then the CO_2 is further compressed and introduced into a high pressure pipeline before it is injected into a reservoir. The steel plant transports the captured CO_2 via ship for the first part of the transport chain to a collection hub, where the CO_2 is compressed into the same high pressure pipeline as the CO_2 from the cement plant, and then injected into the reservoir for permanent storage. The cement plant transport network does not require any temporary storage during normal operation, but the transport chain from the steel plant requires temporary storage before and after the ship transport. The system is sketched in Figure 5.

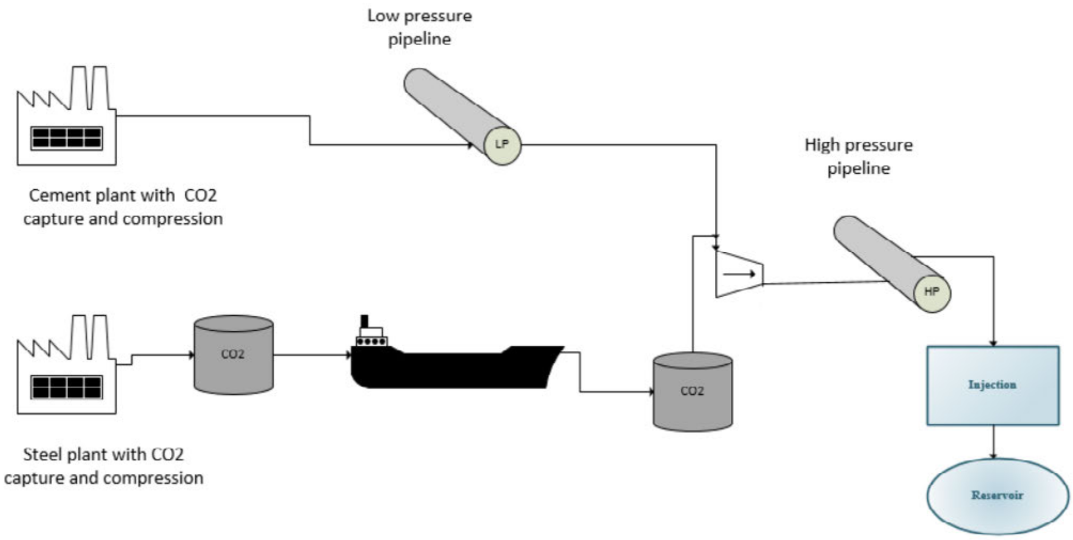

Figure 5 Scenario 3 with two CO_2 sources, transport by ship and low-pressure pipeline to a collection point and high-pressure pipeline to a single storage location.

It should be noted that supply variability is also an important factor for the stability and uptime of the T&S system. The T&S system will require a more or less constant and continuous supply of CO_2 to avoid shutting in wells. Buffers could be needed when the T&S system is not available or if the capture plant do not capture CO_2. Both of these variations will lead to a need for buffering but require very different solutions. By having CO_2 from several sources into the T&S system may strongly reduce the need for buffering at the supply side.

The system-level buffer capacity is a summary of the capacity in pipelines and storages. Having them in a system there are four different aspects that needs to be considered:

- pipeline length/size and pressure variability;
- tank storage capacity;
- operational redundancy (ship sizes, frequency, inclement weather allowance etc); and
- design redundancy (pipe oversize, extra tank).

1.3. Variability

In a CCS chain where the captured CO_2 is transported and injected into a reservoir for permanent storage it is of importance to know the operational time of the source when the CO_2 is produced. If the CO_2 is coming from a facility operating at variable loads, that will lead to large variations in quantity of the CO_2 stream that is fed to the pipeline. This can be dealt with partly by turning down the compressors but there is a point at which the compressors or pumps cannot be turned down any further. In this case, it would be useful to have multiple CO_2 compressors or variable frequency drives. Another option is to build buffer capacity in the chain, to balance the risk of being out of CO_2 at the reservoir. The need for buffering of CO_2 arises from: 1) the need to include shipping as a transport option, 2) to supplement strongly varying T&S availability, 3) to absorb strong variations in CO_2 supply (capture) or CO_2 demand (CCU). Examples include: requirements for fast ship loading or offloading, daily and seasonal swings in supply and demand rates, or injection wells that need minimum supply rates (to prevent frequent shut-in, which may damage the well). Buffer solutions will depend on the capacity needed and on the cause for the variation to be dealt with. Buffering is best done with liquid CO_2 to minimize volume requirements, although this increases the cost due to the liquefaction facilities.

Gas power plants are often used as a "swing producer" in the grid system. This leads to very unstable flows of CO_2 and it should be considered if the CCS system should be designed for maximum flow, or a more reduced flow. Coal power plants are more complicated to turn on and off, but the CO_2 flows from these plants also vary.

Industries like cement, steel, aluminium, and ammonia will typically have a steadier flow. Their operation time is based primarily on the demand for and access to raw material, and it is possible to store the final product if needed. That gives less variation in the production and thereby also the CO_2 flow. All of these industries may have planned stops in the production over a period of time, but occasionally there are also unplanned production stops. The planned stops are often caused by the need for maintenance and upgrade and some industries, like cement and ammonia, they may stop their production for a few weeks . Steel and aluminium sites do not normally have complete production stops due to their processes, instead maintenance is carried out while production is still running.[1] Other stops may occur for short periods of time, and that is where the buffer capacity is needed. To keep up with small changes in the CO_2 flow, line packing, frequency of ship trip, or utilizing eventual extra capacity in tanks may be possible. For larger changes in the production of CO_2, buffer storage is needed. In this study, we have investigated both the buffer capacity needed if the sources cannot deliver CO_2 to the transport network (if the industry site do not produce CO_2) or if the transport chain/storage cannot receive the captured CO_2.

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[1] Personal communication with personal at Norcem Cement plant in Brevik, SSAB steel plant in Luleå, Yara ammonia plant in Porsgrunn, Hydro R&D center in Porsgrunn, March-April 2022.

2. Buffering Technology Options

2.1. Current Technologies

Section 2 provides an overview of temporary CO_2 storage options which can provide buffering capacity that are currently in commercial deployment, either for natural gas / petroleum gas or for CO_2 systems. Technologies that are yet to be deployed at a large-scale or are still under research and development are included in Section 2.2 regarding Emerging Future Technologies.

A majority of commercial CO_2 transport to date is for utilisation purposes (e.g. in the food industry) and not for storage. Transportation of CO_2 is also currently occurring at much smaller scales than would be required for CCS deployment. The majority of CCS projects to date are also simple systems with one source and one sink, with little need for buffering capacity. Hence, buffering technologies for CO_2 are not yet widely deployed.

When looking at potential buffering options an appropriate analogue for CO_2 T&S is the liquified petroleum gas (LPG) industry. Technologies such as quay-side facilities or temporary geological storage are therefore considered as 'current technologies' since they have already been deployed at commercial scale in the LPG industry and are ready for large-scale CO_2 deployment.

2.1.1 *Quayside facilities or on-site tanks*

The temporary storage of CO_2 can take place onshore in on-site tanks. This can be as part of quayside facilities for shipping or on a smaller scale for further transport by rail or road. CO_2 is already transported and stored for commercial purposes, for example for industrial processes or for use in the food industry, and hence temporary onshore storage tanks are already at commercial deployment. Even though Yara / Nippon Gases have transported CO_2 by ship for decades from the ammonia plant in Porsgrunn to the Netherlands, a majority of CO_2 to date is transported by road and rail, therefore temporary storage of CO_2 at quayside facilities for shipping is a more innovative process already at a high technology readiness level (TRL) and ready for commercial deployment.

Due to the intermittent nature of ship transport, where CO_2 is transported in batches, there is already an inherent need for temporary CO_2 storage locations. An interesting application of quay-side storage locations for transport by ship is their potential secondary use as a buffer in transport and storage (T&S) systems. In these quayside storage facilities the liquid volume in the tank or tanks can be used to stabilize flow rates in a T&S system. Temporary storage tanks could also be used to add buffer capacity to pipeline transport systems.

Onshore Tank Design

The tank design and specifications will vary based on the conditions the CO_2 needs to be stored in, and this is usually defined by the incoming or outgoing transportation requirements. Most pressurized steel tanks are typically suited to provide CO_2 storage vessels, see Table 2.

Table 2 CO_2 and storage tank proprieties based on liquefaction pressures (Fraga, Nie et al. 2020)

Liquefaction Pressure (Bar)	Liquefaction Temperature (°C)	CO_2 Density (kg/m^3)	Maximum size (m^3)	Material (ASTM)
6	-52.3	1,159	5,000	A537
15	-27.7	1,064	5,000	A517

25	-11.4	990	1,550	A517
35	0.5	926	570	A517
45	10.2	846	270	A517

ASTM (American Society for Testing and Materials) A517 refers to a quenched and tempered alloy steel plate intended for use in fusion welded boilers and other pressure vessels. This is a standard material already used for pressure vessels and has already been used commercially to store CO_2.

The maximum volume per cylindrical tank up to pressures of 15 bar is 5,000 m^3, the maximum storage volumes then decrease with greater pressures (shown in Table 2). Storage tank material requirements vary for different pressures, and increased wall thickness is needed at greater pressures to meet the A517 specification. Therefore an increase in storage pressure *“demands greater number of tanks which, combined with demanded space for inspection, can result in either lower transportation capacity or bigger ship sizes and weight*” (Fraga, Nie et al. 2020) Given the maximum pressure requirements, and increased wall thickness, storage at higher pressures tends to result in higher costs for onshore tanks.

For onshore storage both cylindrical and spherical tanks are feasible. Standards for pressured gas storage are well documented given their commercial deployment (International Maritime Organization (IMO) 2000, DNV 2011, American Society of Mechanical Engineers (ASME) 2010). Details on materials and design, e.g. how the wall thickness increases with increasing pressure, can be calculated in accordance with guidelines of the Pressure Vessel Handbook (Megyesy 2008). Given the size of the tanks required for CCS purposes, cost (CAPEX) is also likely to be a major consideration for material choices.

Another factor which will impact the design of the temporary storage is the amount of space available onshore and the volume capacity of temporary storage required. Depending on the amount of onshore space available the temporary storage can either be located onshore or on a floating barge depending on the specific project requirements and space available in the harbour (Element Energy 2018).

The design of a floating barge type temporary storage is discussed by Yoo et al. based on semi-refrigerated typed already utilised for LPG carriers (Yoo, Choi et al. 2013).

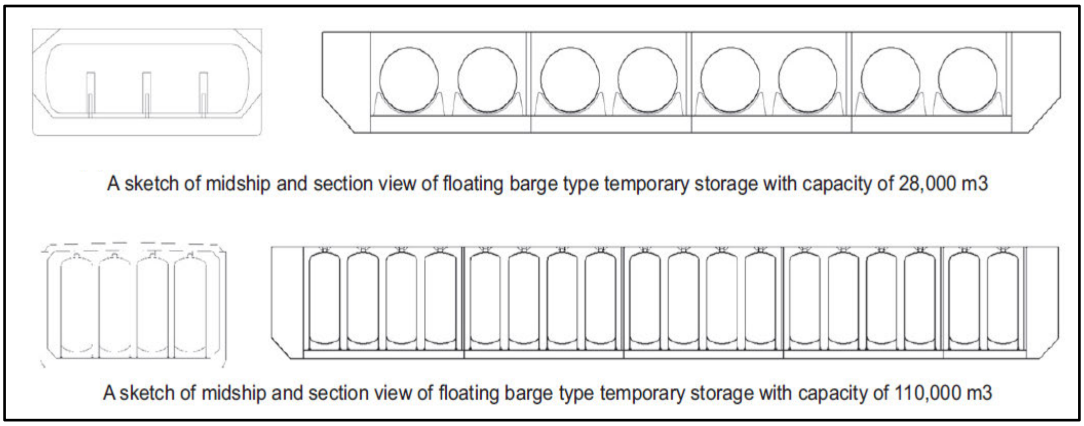

Figure 6 Sketches from Yoo et al. 2013 showing potential designs temporary CO_2 storage facilities on a floating barge.

Horizontal tanks are utilised for relatively small storage capacities and vertical tanks provide more flexibility in terms of arrangement options for larger scale storage. For this specific design the maximum tank size was 36 m length and 11 m diameter (Yoo, Choi et al. 2013).

Case Study 3: Northern Lights, Norway

Temporary quayside storage for shipping is being utilised in the Northern Lights project, shown in Figure 7. At Northern Lights CO_2 will be shipped to a receiving terminal located in Øygarden (specifically the Naturgassparken industrial area) on the west coast of Norway. Construction of this onshore terminal started January 2021 where there will be a temporary buffer storage facility (storage tanks) along with the import quay, unloading equipment, and injection pumps. This will then be connected to a 110 km, 12 inch diameter pipeline to the offshore location where the CO_2 is injected in to a saline reservoir.

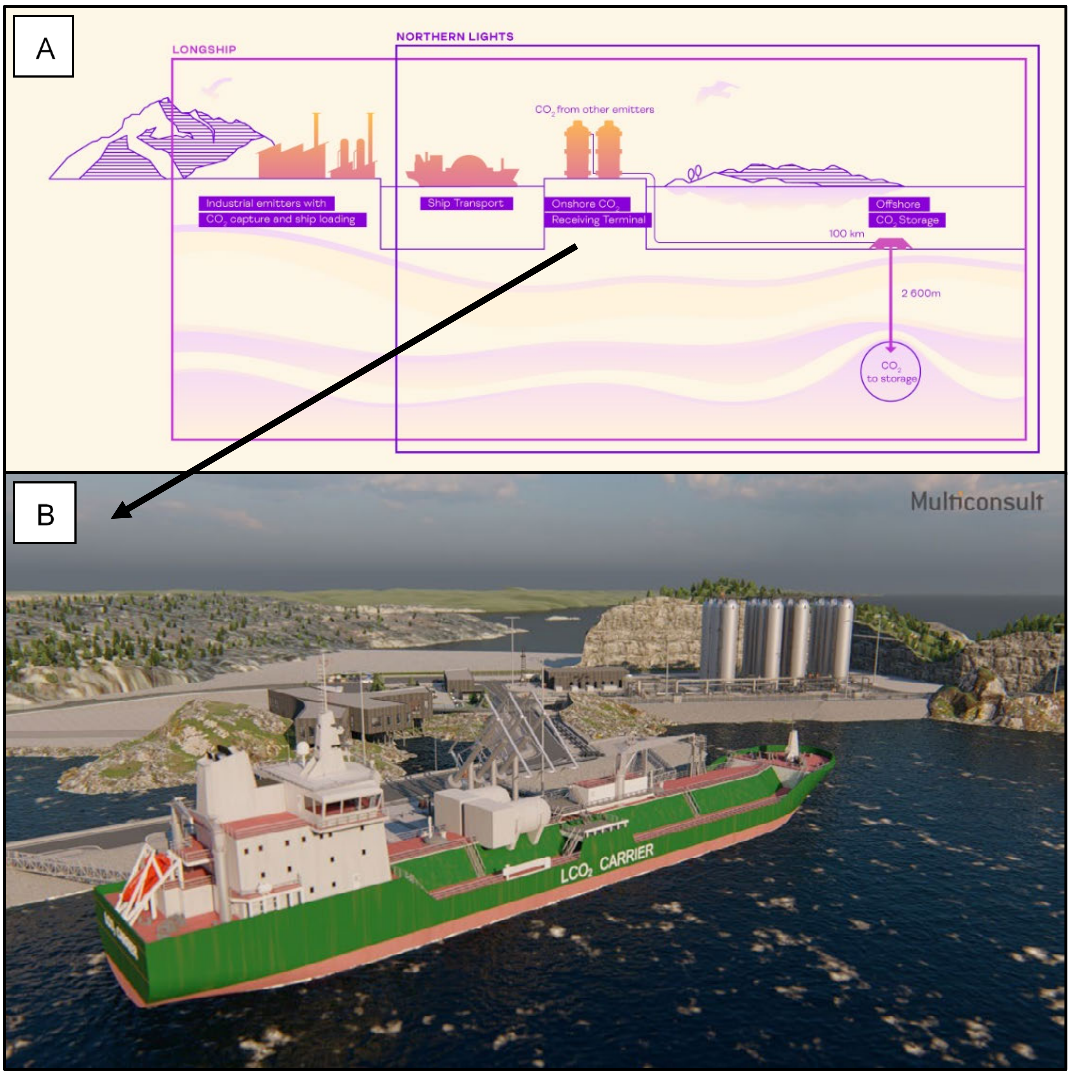

Figure 7 A Schematic of the full-chain Longship and Northern Lights project**. B** digital design for the CO_2 receiving terminal at the premises of Naturgassparken industrial area in the municipality of Øygarden in western Norway. Source: (Northern Lights Website, 2022)

CO_2 will be brought to the Naturgassparken terminal by ships with a 7500 m^3 capacity at pressures of 13-18 barg (and equilibrium temperature). The jetty will then allow for shop mooring and importing of the CO_2 into the temporary storage tanks. After temporary storage the CO_2 then goes through an export pump and heater to allow injection into a pipeline for further transport to the offshore storage site (100 km pipeline, 12.75 inch diameter), see Figure 8.

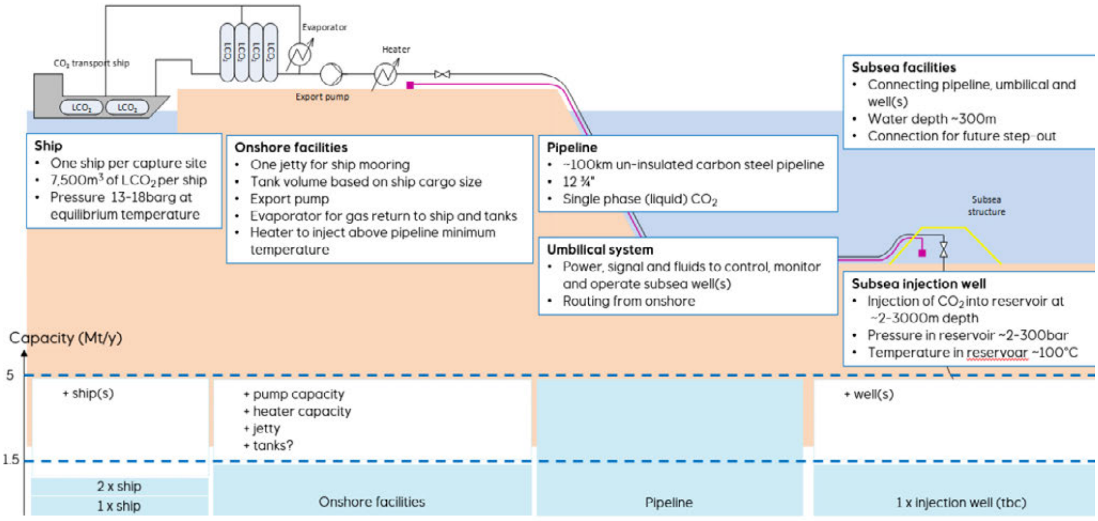

Figure 8 Northern Lights concept building blocks with capacities in the first phase shown with blue shading.

The FEED report for Northern Lights (Equinor 2020) provides details on the temporary storage tanks planned at the Naturgassparken site. As shown in the background of Figure 7B, the site will comprise 12 vertical pressurized cylindrical storage tanks, the specifications of which are given in Table 3.

Table 3 Specification for temporary storage tanks planned at Northern Light's onshore receiving terminal (Equinor 2020).

Total operating volume	8250 m³ (in 12 pressurized cylindrical tanks)
Tank sizing	6.1 m inner diameter, 24.5 m height
Design P&T	21.8 barg -46°C to +50°C
Planned Operational P&T	13 to 18 barg -30.8°C to 20.8°C
Materials	Low Temperature Carbon steel (LTCS) with 2.5mm corrosion allowance and insulated to avoid external ice build-up.

Low Temperature Carbon Steel (LTCS) was chosen for this design due to the large size of the tanks and the high material costs associated with their construction. Stainless steel (such as SS316 or 316L) was considered too expensive and instead LTCS was selected with a 2.4 mm corrosion allowance accounted for in the design. The 2.5 mm allowance will require close monitoring, as accounted for in the FEED study and operational design, to detect any significant changes in chemical composition. Potential concerns include the formation of free water or the potential accumulation of corrosive chemicals, both of which could increase corrosion rates (Equinor 2020).

Northern Lights is a-first-of-a-kind demonstration project both with regards to large-scale CO_2 shipping but also with numerous emitters utilising a single temporary storage CO_2 import hub. The current project timeline is for the storage tank installations to be completed by December 2022 ready for CO_2 export by September 2023.

Case Study 4: Rotterdam Terminal, CO2NNECT

Gasunie, Vopak and Gate Terminal are jointly investigating the development of CO2nnect (CO2nnect Project Website, 2022) an independent terminal for liquid CO_2 on the Maasvlakte in the Port of Rotterdam. The independent hub terminal will be able to receive and deliver liquid CO_2 via ships (or trucks or railcars) and will be connected to the depleted gas fields in the North Sea as shown in Figure 9. The technical feasibility and development of a CO_2 terminal is being explored independently and also as part of the Aramis CCS project. The CO2nnect terminal is envisaged to be developed with additional (stand-alone) functionalities, such as re-loading of vessels, railcars and trucks for CCU.

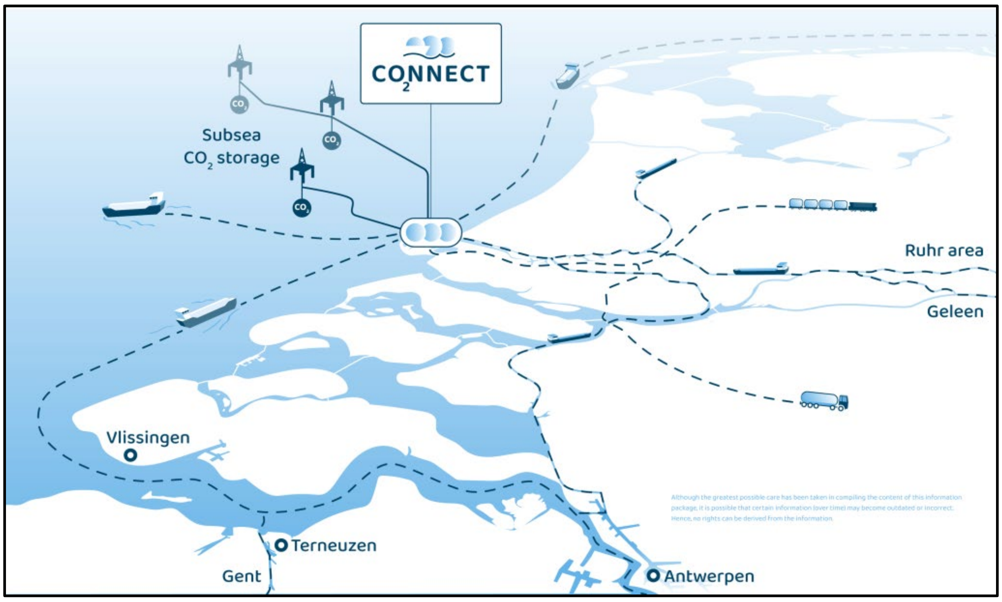

Figure 9 Overview of the CO2NNECT project (Source: CO2nnect Project Website, 2022)

CO2nnect's scope involves the technical and commercial development of the terminal for the unloading of vessels including temporary storage and compression and send out of CO_2 for storage. The terminal configuration for the initial phase of the project includes jetties to receive sea-going vessels, coasters and river barges. The approximate annual throughput capacity is expected to be expandable up to 7 million tonnes, with temporary onshore storage capacity expandable up to 88,000 m^3. Temporary storage is currently planned in spherical tanks (Figure 10). The project is currently collecting expressions of interest and plans to have a signed terminal service agreement in place by October 2023.

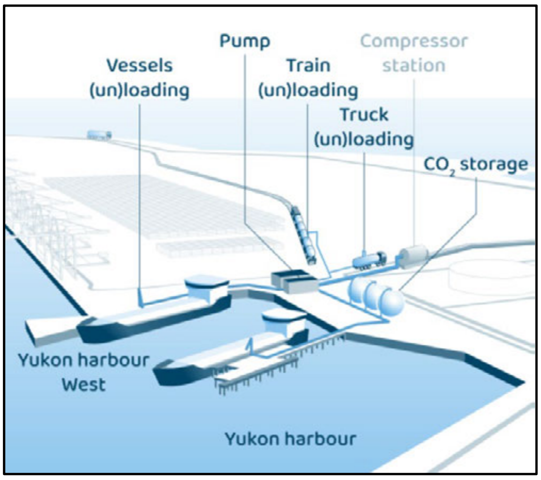

Figure 10 Configuration of the terminal planned for CO2nnect (Source: CO2nnect Project Website, 2022)

Regarding the amount of CO_2 that should be stored at these onshore hub facilities to provide suitable buffer capacity, a review of CO_2 shipping commissioned by Department for Business, Energy and Industrial Strategy (BEIS , UK) stated that: "*to enable fast loading of the ship, the storage should have at least the capacity of the ship in tonne of CO_2. On the other hand, if the ship is unexpectedly delayed, the storage should be sufficient that it does not meet capacity, resulting in a halt to the CO_2 capture and subsequent liquefaction*" (Element Energy 2018). Such a process can also be utilised for buffering delays that occur in other parts of the full-chain network, and not only for project's which might experience ship delay. Therefore, if the temporary storage facilities are oversized in comparison to the ship capacity, or are incorporated into projects without ship transport, they could also be used to buffer the full CCS chain's capacity. The specific capacity requirements of onshore buffering via tanks are discussed below.

Tank capacity for ship transport
As discussed, the temporary storage should be able to store at least the same volume as the ship to allow for minimal loading times. Various other volume capacities have also been proposed in literature to accommodate elements such as:

- Unplanned delays in the CO_2 transport system: e.g. due to extreme weather events;
- Varying project logistics: e.g. round trip duration, frequency of each ship, dedicated service, diversity of sources, seasonal peaks in the port's traffic; or
- To accommodate future plans: e.g. to accommodate elements such as future shipping industry expansion.

These temporary storage volumes are often discussed as 'size factors', which is a ratio of the 'temporary storage volume' to 'ship storage volume' (i.e. a size factor of 1 means the volumes of both the ship and temporary storage are the same, 1.5 means the temporary storage capacity is 50% larger than the ship volume). One of the largest size factors utilised in logistics studies is 1.5 times the ship capacity (Barrio, Aspelund et al. 2005) which was incorporated to increase the system's flexibility, although this was only an assumption used for logistics modelling purposes. In a more recent study (Yoo, Choi et al. 2013) size factors from literature regarding both CO_2 and LNG transport were reviewed and the study concluded a size factor of 1.2 to be the most suitable for a commercialized CO_2 market. For LNG storage factors of 1.18-1.48 were recorded as operational margins, but "*since CO_2 is a less hazardous fluid than LNG, less or equal margin is enough for buffer volume of temporary storage*". The temporary storage requirements at the export and import ports may vary and are dependent on the requirements of the buffer on the export side (i.e. the flow from the emitters), and on the buffer requirements on the import side (i.e. what kind of stability is required in the flow to the field).

In the Northern Lights project (see Case Study 3 below for more details) a ship cargo capacity of 7500 m^3 is included in the FEED design with onshore temporary storage tanks having a volume of 8250 m^3. This is therefore a size factor of 1.1. Overall a design margin with a 1.1 size factor for buffer capacity is considered relatively small, and often only valid for a dedicated terminal with a dedicated jetty (as in Northern Lights). For terminals with such marginal capacity the buffer capacity is often moved to the shipping vessels to provide the flexibility required in the system, i.e. the ships transport less CO_2 (utilise fewer tanks) or sail faster/slower to level delays elsewhere in the supply chain. In the Northern Lights case the numerous emitters being brought online at the same time may also reduce the size of buffering potential needed. In each project the total tank capacity should be assessed for the specific case and shipping vessel size.

The optimal volume for temporary storage tanks in a ship-based CCS project in Korea has also been studied based on a life-cycle cost (LCC) analysis (Seo, Lee et al. 2017). In the study the trade-off between increased CAPEX and OPEX costs due to including temporary storage in comparison to the cost of "loss of production" due to not having temporary storage (i.e. CO_2 not traded, referred to here as the "unavailability cost") was investigated. A summary of the findings is given in **F**igure 11.

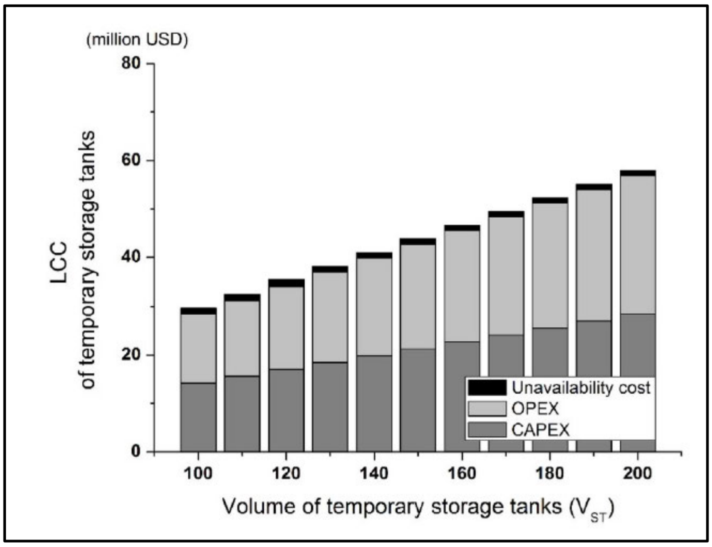

Figure 11 Life-cycle cost of temporary storage tanks (in-terms of CAPEX, OPEX and unavailability cost) for different storage volumes. (Trade cost of CO_2 = 20USD) (Source: Seo et al. 2017)

As expected, the analysis showed that CAPEX and OPEX increase with the deployment of larger temporary storage tanks, but the unavailability cost decreases (a there is less down-time). Even though the 'unavailability cost' decreases as the storage tank volume increases the overall price continues to increase as the CAPEX and OPEX dominate. The study also took into consideration the potential variation in CO_2 trade costs with estimates used in the analysis ranging from 20 to 100 USD per ton (note: 1 imperial ton is equal to 0.907 metric tonnes).

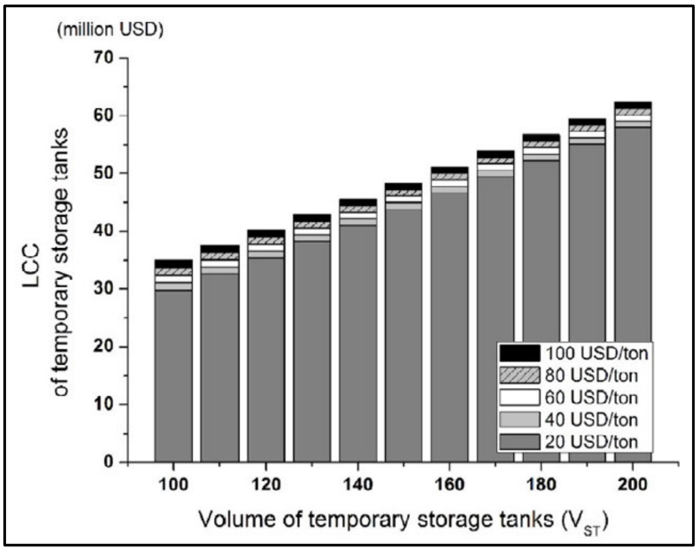

Figure 12 Variation of life-cycle cost (LCC) for different 'unavailability costs' associated with varying CO_2 trade price. (Source: Seo et al. 2017)

Overall it was concluded that the total LCC "*grew with the volume of the temporary storage tanks because the CAPEX and OPEX were dominant in the LCC. The CAPEX and OPEX contributed ~96% to the LCC*". Therefore, even with the trade cost of CO_2 varying from 20 to 100 USD per ton, the impact on the total LCC was limited given it represents approximately 4% of the total cost.

The temporary storage capacity in onshore tanks is therefore likely to be driven by cost. Beyond a size factor of 1 (100% of the ship volume being covered), a risk assessment is needed to ascertain what the temporary storage needs are. In order to fully assess whether the added value of 1.1 or 1.2 size factor (10 or 20% additional storage) is worth the additional CAPEX and OPEX an assessment is needed of the predicted delays and logistical elements that need to be accommodated in the system. This will be case specific and for the above study typhoon occurrence was taken into account as this is specific for South Korea (Seo, Lee et al. 2017).

Tank capacity for pipeline transport
For CCS projects only utilising CO_2 transport by pipeline there is no inherent need for temporary CO_2 storage. The amount of onshore tank storage incorporated in these cases is purely based on what the desired flexibility to be incorporated into the system is. This is discussed further in Section 4 with regards to the cost impact of incorporating buffering into a pipeline system.

2.1.2 *Geological gas storage*

The temporary storage of natural gas has been undertaken in geological formations including aquifers, depleted hydrocarbon reservoirs and salt caverns. This provides a good analogue for the temporary storage of CO_2 in the same types of geological formations. Developing a geologic store carries high cost but can be a strategic option for certain circumstances and locations. Salt caverns are considered the most ‘flexible’ storage reservoirs given their ability to withdraw and accept large quantities of gas more rapidly compared to other storage types (NETL 2019) as shown in Table 4:

Table 4 Underground storage reservoir type cycling comparison (Source: NETL, 2019)

Storage Type	Injection Period (days)	Withdrawal Period (days)
Aquifer	200 to 250	100 to 150
Depleted Oil/Gas Reservoir	200 to 250	100 to 150
Salt Cavern	20 to 40	10 to 20

Salt Caverns
As salt caverns are easier to move gas in and out of, they have more commonly been utilized for temporary natural gas storage as they can undergo monthly cycles of injection and reproduction. Depleted hydrocarbon and saline aquifers are more suitable for seasonal storage given their longer withdrawal periods. Salt caverns have other benefits including lower risks associated with leakage due to their self-healing quality and having lower acreage minimising surface space requirements. Given the impermeable nature of the salt cavern walls they also require less cushion gas than an aquifer or depleted field.

On the other hand, salt caverns often have much smaller capacities in comparison to depleted fields and aquifers which means they are better suited to provide short demand requirements rather than longer periods of gas delivery. They are also more expensive to develop as costs include (NETL 2019):

1. The need to build surface facilities to handle gas storage (which may be present at depleted fields);
2. Solution-mining is required which uses millions of gallons of water; and
3. Produced brine needs transporting and treating.

Salt caverns can therefore potentially be used to allow for temporary storage needed for a 10-20 day supply, but at a relatively large capital investment cost.

Economic assessments for salt cavern storage are mainly available for hydrogen, which focus on the cushion gas element since hydrogen is a commodity. Depleted fields require significant volumes of cushion gas, making them less economically feasible for hydrogen in comparison. This is not equally problematic for CO_2 storage, as often keeping CO_2 underground is the main cost driver. Therefore the main cost for temporary geological CO_2 storage is driven by the cost of site development, which is much higher for cavern excavations.

Depleted Fields

The use of depleted gas fields for temporary storage is only relevant where costs can be minimised by developing relatively small and easy-to-access fields. Onshore depleted fields with infrastructure that can be re-used are likely to be the cheapest to utilize for longer-term CO_2 storage given the infrastructure already available and the amount of prior geological and operational knowledge already developed, see Figure 13.

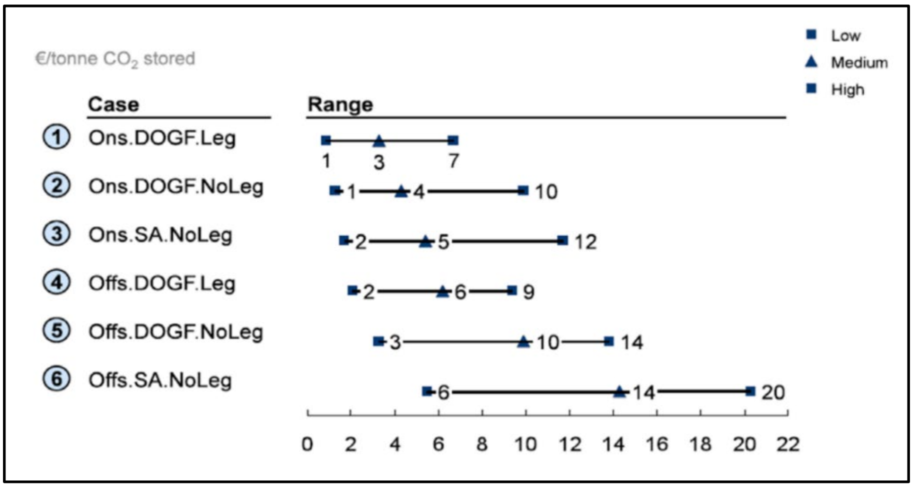

Figure 13 Storage cost ranges for different scenarios (Ons: Onshore, Offs: Offshore, DOGF: Depleted Oil or Gas field, SA: saline formation, Leg: re-use infrastructure, Noleg: no re-use of infrastructure) (Zero Emissions Platform 2013)

However, it should be noted that this will not apply in all cases as costs can greatly vary across sites and also the economics may be significantly different for temporary storage in comparison to permanent storage, given the additional costs of extraction post-injection. In comparison to saline aquifers though, the costs of developing a temporary store in depleted oil and gas fields are likely to vary as shown in Figure 13.

The properties of depleted oil and gas fields, such as storage capacity and maximum injection rates, will be highly site specific but in general, dry gas reservoirs are preferred over depleted oil reservoirs as they generally require less maintenance. Legacy wells are also a risk elements for depleted fields compared to other stores, as they can pose potential fluid migration pathways. This risk is minimised for temporary storage in depleted fields though, in comparison to large-scale permanent storage sites, as the capacities will be smaller and as the pressure in the field will be below that of neighbouring formations.

The use of depleted gas fields as a temporary CO_2 storage site has been assessed in one R&D study to date (Koenen, Neele et al. 2018), but has not yet been implemented. As part of the H2020 ENOS project, in collaboration with OCAP (a CO_2 supplier for greenhouses in the Netherlands) and ONE-Dyas (a Dutch oil and gas company), the facilities to support a seasonal CO_2 buffer were investigated. OCAP currently has a mismatch between supply and demand of CO_2 with surplus supply in winter and a shortage in the summer. This buffering system analysed in ENOS was designed to help bridge the mismatch and included the design of an injection-production scheme to maximize buffer capacity and support growth in CO_2 offtake during the summer period.

In the study by Koenen et al. 2018, the potential contamination of CO_2 during its residence in the reservoir prior to back-production and the requirements for purification to OCAP specifications (for greenhouse and agricultural use) were investigated. The study concluded that the back-produced CO_2 will "*be contaminated with hydrocarbons, primarily CH_4, with a concentration as high as 20% in the first injection cycle, decreasing with each consecutive cycle*." The hydrocarbons can however easily be separated from the CO_2 by the use of a condenser and flash separator. The proposed chain for CO_2 buffering is shown in Figure 14.

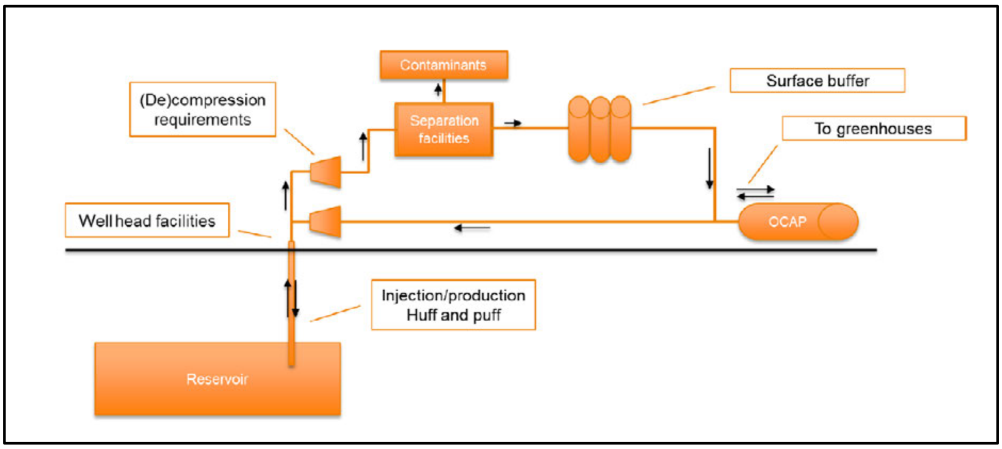

Figure 14 Schematic of a proposed buffer chain for seasonal temporary CO_2 storage for OCAP from the ENOS project (Koenen, Neele et al. 2018)

The Q16-Maas gas and condensate field, operated by ONE, was identified as being of suitable size and location as a hypothetical storage site for this buffering purpose. The study concluded that 500 to 815 thousand tonnes of additional CO_2 could be supplied to the greenhouses in the summertime by using the Q16-Maas field as temporary storage during the winter. It was also concluded, through rough cost estimates, that is could also be an economically viable option assuming a levelized purification cost of 2.7 €/tonne for the back-produced CO_2, shown in Table 5.

Table 5 Overview of purification costs for back-produced CO_2 from a depleted oil and gas field (Source: Koenen et al. 2018)

Equipment	Costs (€)
Condenser and heat exchangers	
Adsorption and flash separator	3.4 M€
Buffer storage (without external cooling)	1.4 M€
Operating costs (withoutexternalcooling)	0.14 M€
Levelized cost	2.7 €/tonne

The study also ran several scenarios to assess the need for cushion gas. Results showed that a single injection cycle immediately followed by back-production (i.e., no cushion) would be possible, in the sense that gas production can be done but would result "*in a high concentration of hydrocarbon species in the back-produced CO_2 due to mixing with the remaining gas and extraction of hydrocarbons from the condensates*." The scheme with two injection cycles prior to back-production (to provide a cushion gas) was therefore considered as optimal.

Saline Aquifers

Saline aquifers have also been utilized for temporary natural gas storage, e.g. in the Mid-Western United States, as it has the benefit of potential pressure support if the aquifer has an active water drive (NETL 2019). Usually less geological data is available for these sites compared to operating oil and gas fields, and as a result they are commonly viewed as being more expensive to characterize than depleted fields (Zero Emissions Platform 2013). However, saline aquifers are often considered more secure given the lack of legacy wells completed to depleted wells which can provide an increased risk of leakage. Costs can also be larger for saline aquifers if water production is required to relieve pressure during storage which would incur additional processing costs.

One of the biggest limiting factors to utilizing an aquifer for temporary storage is the large volumes of cushion gas required. This can be "*upwards of 80 to 90 percent of the total gas volume since there is no naturally occurring gas in the formation*" (NETL 2019). However, this may not be problematic if permanent storage is also associated with the sites where temporary extraction is also possible. This is also the case for cushion gas requirements in depleted oil and gas fields, as shown by Koenen et al. 2018 where two gas cycles were recommended prior to back-production.

Summary of Geological Storage Options

Given the largest capital costs of developing a geological store for storage, alongside the cushion gas requirements, it is likely that temporary CO_2 storage is only going to be utilised in stores that already have ongoing permanent storage operations. Once a storage has been characterised and developed and reached operational phase, it will be most effective to also utilise the site for permanent CO_2 storage operations. A comparison of geological storage properties for each storage type is provided in Table 6.

Table 6 Summary of qualities for temporary storage in each type of geological formation (Source: Zero Emissions Platform 2013, Koenen et al., 2018, and NETL 2019)

	Salt Caverns	Depleted Fields	Saline Aquifers
Total gas storage capacity	Typically $10^5 – 10^6$ m^3 - therefore 0.06 - 0.6Mt CO_2 storage capacity (Assuming a pressure of 200 bar and temperature of 80 °C)	Mt scale capacity	Gt scale capacity
Efficiency (storage as % of bulk pore volume)	100%	Typically 1–4%	Typically 1–4% storage
Cushion gas	Very low - as saturated brine required acts as cushion	Base gas requirement approx. 50% of total reservoir capacity	Large volumes required (80-90% of total storage volume)
Deliverability	Monthly withdraw cycles possible	Seasonal withdrawal	Seasonal withdrawal (but higher reservoir pressures = quicker deliverability rates)
Capital costs per tonne of CO_2 stored	High (1600 €/tonne quoted for hydrogen but limited cost information on CO_2) (Lord, Kobos et al. 2011)	Low (1 – 9 €/tonne)	Medium (2 – 20 €/tonne)

Salt caverns provide the only solution to very short-term (<1 month) temporary CO_2 storage given the much larger withdrawal periods for depleted hydrocarbon fields and saline aquifer storage. They are also much more likely to allow for higher injection rates. Their costs are likely to be prohibitive for CO_2 storage though given their constructed nature and the costs of disposing of saline water produced. Although these costs will vary largely by country, for example, in some countries where desalination is already common place this costs are likely to be more viable.

2.1.3 *Pipeline System Linepacking*

Linepacking is a method already used in the natural gas industry for providing short-term (daily and hourly) gas storage. Linepack refers to the total volume of gas contained in a pipeline system. To protect the exit pressure of a system (i.e. prevent it from varying) the flexibility of the whole natural gas pipeline system needs to accommodate changing diurnal demand profiles. This is done in most national gas grids by increasing the total volume of gas in the pipeline system (referred to as linepacking). This linepacking lowers the pressure drop at either end of the system during periods of high demand by maintaining higher pressure in the middle of the network.

This linepacking is possible due to the significant compressibility of gas, and is therefore more effective (i.e. the total volume of gas in the pipeline can have large variations) in gas pipeline systems. The capacity of a pipeline to linepack can be increased by increasing the internal volume of the pipeline, reducing the mass flow rate into the pipeline, increasing the wall thickness, increasing the yield stress properties of the pipeline material and by managing the inlet pressure and outlet pressures (Wetenhall, Race et al. 2017). A pipeline with dimensions considered typical for CCS schemes (i.e. 15 km length, 10 mm wall thickness and 437 mm internal diameter) can provide short-term storage for around 10 hours (with a mass flow rate of 105 kg/s) (Aghajani, Race et al. 2017, Wetenhall, Race et al. 2017). The magnitude of linepacking potential is dependent on the operational window of the pipeline which will be dictated by the full-chain design and well and reservoir conditions. An introduction to potential linepacking scenarios is given in Information Box 3.

Linepacking has already been utilised in CO_2 pipelines, for example the OCAP system in The Netherlands (OCAP Website, 2022), shown in Figure 15 The OCAP network currently uses a low-pressure pipeline to absorb the diurnal variation in CO_2 demand from greenhouses.

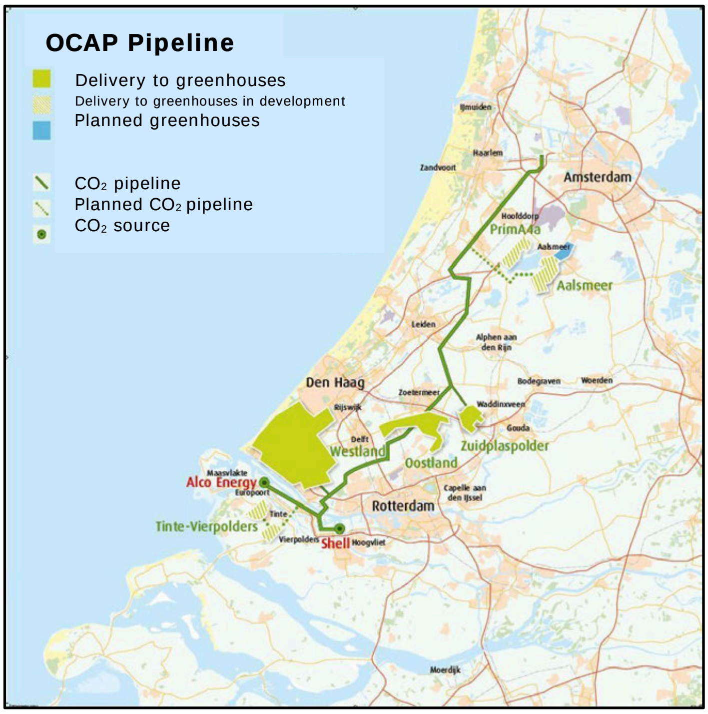

Figure 15 Route of OCAP pipelines in the Netherlands (dark green line). OCAP is a subsidiary of Linde plc. (Source: OCAP Website, 2022)

Information Box 3: Typical Linepacking Values

For high pressure pipelines a common mean pressure is 85 bar, with a maximum of 120 bar. This to ensure single phase conditions even in case of some impurities within the CO_2 stream. Given a CO_2 temperature of 10°C:

- CO_2 density at 120 bar = 935.23 kg/m^3
- CO_2 density at 85 bar = 907.76 kg/m^3

This means for each 1m^3 of pipe volume and additional 27.47 kg of CO_2 can be 'stored' via linepacking by increasing the pressure from 85 to 120 bar. Given a 10" pipeline has a volume of 50.67 m^3/km this means an additional potential storage via linepacking of 1392 kg/km (i.e. 1.4 tonnes per km), see Figure 16.

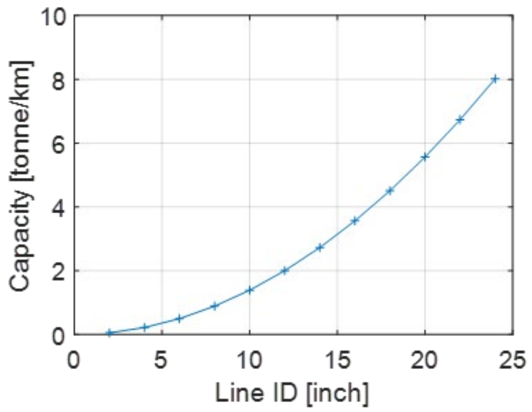

Figure 16 Buffering capacity potential of a high-pressure pipeline given potential pressure change of 85-120 bar, given for different diameters.

If buffering is required to accommodate an increased CO_2 flow rate, this can therefore be maintained for a short time. For example, using the calculations above, in a 50 km 10" pipeline there is a linepacking capacity of 69600 kg (69.6 tonnes). Therefore, at an increased rate of 100 tonnes/hr the buffer capacity is therefore less than one hour.

In general the temporary storage capacity via linepacking in a high-pressure pipeline is very limited. Increasing the pipeline pressure from 85 to 120 bar also impacts the well performance which for simplicity has not been taken into account in this example.

Note: the capacity in the pipeline to accommodate reduced CO_2 flow rates is limited as normally the pipeline will be operated at its lowest safe pressure.

Pressures of 25-35 bar are typical for currently operational low pressure pipelines. For this pressure range the linepacking potential is 31.8 kg/m^3 . A 24" line of 25km has a buffer capacity of 232 tonnes, see Figure 17.

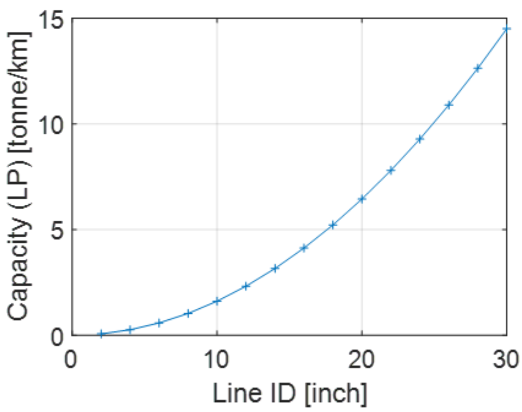

Figure 17 Buffering capacity potential of a low-pressure pipeline given potential pressure change of 25-35 bar, given for different diameters.

The simulations conducted for this study (see Section 3) also support the findings of the studies by Aghajani et al. (2017) and Wetenhall at al. (2017) that the pipeline does not represent a long-term storage option for CCS systems. However, as previously stated, the linepacking capacity of a pipeline can be increased by changing the design parameters. Therefore, if linepacking as a potential buffer is considered at the design stage (for example by changing the maximum operating pressure or lines size) then the level of flexibility for buffer capacity could be increased.

2.2. Emerging Future Technologies

New solutions may be needed in the future to match potentially increasing temporary storage demands as CCS reaches more large-scale commercial deployment. This section will describe emerging future technologies that are not currently deployed. The scope for this section includes the potential for increasing the capacity of currently deployed technologies, or for repurposing existing technologies for use with CO_2.

2.2.1. Offshore Storage in Salt Caverns

As discussed in Section 2.1.2, CO_2 could be temporarily stored in onshore salt caverns. In addition to onshore caverns recent studies have also proposed to deploy salt caverns in offshore settings. This has been most extensively researched in Brazil where the use of deep offshore salt caverns has been investigated for the storage of liquified natural gas and CO_2. Research here on the use of giant salt caverns for storage of CO_2 proved to be technically feasible and at the same time meets with good safety margins for the logistics of natural gas in Brazil (Costa, Costa et al. 2017, Maia da Costa, V.M. Costa et al. 2019). The study investigated offshore giant salt caverns of 450 m high x 150 m in diameter, and showed that one cavern could store about 4 billion Sm^3 or 7.2 million tonnes of CO_2.

The offshore storage potential of salt caverns in Europe has also been investigated for potential temporary hydrogen storage. In these analyses, a minimum salt thickness of 200 m and a range of minimum to maximum depth of 500 m to 2000 m were selected as being suitable for salt cavern construction (Caglayan, Weber et al. 2020). This study focussed on all potential salt deposits at a basin level, as geological information regarding salt thicknesses was limited. From this high-level assessment approximately 27% of the sites identified in Europe were onshore. In this study only sites within 5 km of the shore were considered feasible due to the high costs of offshore temporary storage.

2.2.2. Other caverns

Rock caverns in structures other than salt could also be considered, for example in disused mines or constructed hard rock caverns. Such caverns would need to be excavated by means of well-known techniques such as the use of explosives. Gravity based structures (for instance large reinforced concrete tanks) could also be considered. Caverns are already under development for use as temporary stores of both natural gas as well as compressed air energy storage (CAES).

The high cost of hard rock caverns has to date meant they are not yet extensively used for gas storage. The concept of ‘lined rock caverns’ (LRCs) has been researched in Sweden since the 1980s to create a solution to changes in demand for natural gas production within the year. A field test was conducted in a Pilot Plant at Grängesberg, Sweden (1988-1993) and one of the test caverns withstood a pressure of over 50 MPa (Mansson, Marion et al. 2003). In this pilot the facilities consisted of one storage cavern with a vertical shaft, and a system of tunnels connecting the cavern with the ground surface. The storage cavern (Figure 18) was excavated in rock as vertical cylinders with a half spherical top cupola and a flattened half spherical bottom. The cavern was located about 115 meters below ground.

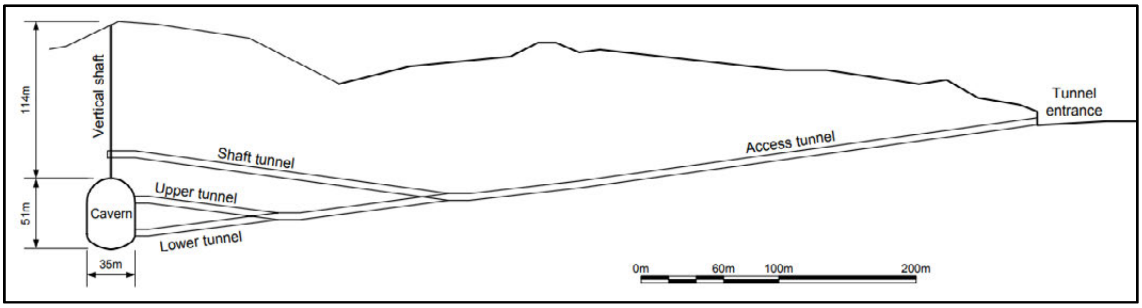

Figure 18 Layout of storage cavern and access tunnels at the LRC Demo Plant (Mansson, Marion et al. 2003)

Aside from the economic barrier the pilot was considered a success from a technical perspective with high pressure (20-50 MPa) low temperature (10-20 °C ambient) storage proving feasible. The main conclusions drawn from the study were:

1. Great freedom of localisation with respect to geology
2. High deliverability and turnover rates
3. Low impact on landscape and environment
4. No need for gas treatment
5. Possibility to expand a storage plant in steps by adding storage cavern modules.

2.2.3. Floating Storage and Injection unit (FSI)

For CO_2 transported by ship, alongside the option of quayside facilities for offloading ships, there is also the option to do this offshore, at the injection site. There is the potential to transfer liquid CO_2 from the tanker to a floating storage injection unit (FSI). Compared to onshore facilities this system remains unproven and is in general more costly and less well understood (IEAGHG 2020). The potential deployment of FSIs is discussed in great detail in IEAGHG's 2020 Report regarding shipping infrastructures, the summary of which is presented in Table 7. A schematic diagram of an FSI design is also provided in Figure 19.

As with quayside facilities, these floating storage units could be designed to provide an overcapacity and be able to either store extra CO_2 that could be utilised to prevent shut-ins or provide extra capacity should the injection need to be temporarily suspended. The type of offshore system to be deployed will to a large extent be determined by the surrounding conditions and water depth the storage site is located at (Choi, Chang 2011).

Table 7 Summary of key features of floating storage and injection unit (FSI) concepts (IEAGHG 2020)

Concept	Key features	Water depth	Storage size
Ship-shape	• Well-known and often used • Space efficient • Turret is preferred in harsh weather, can be spread moored in benign weathers • Higher motions than other concepts • Weather-vaning unit, if turret is used • Can be a conversion rather than new-build	All	All
Spar	• Platform with cylindrical hull • May have cylindrical hull and truss or cell of multiple cylinders. • Low motion design • Current designs used for production and do not have storage – requires re-design	Deep	Small
Circular form stable units (SEVAN)	• Large diameter cylinder • Low motions • No weather-vaning (shape same for all weather directions) • Spread moored (see next section)	All	Large
Semi-submersible unit	• Well-known for production without storage • Low motions • No weather-vaning • Spread moored	All	Small
Tension Leg Platform (TLP)	• Mooring consists of tension legs between the platform and seabed • Low vertical motions allowing for (low cost) steel risers	Up to Medium	Small
Jack-up Platform	• Buoyant hull • Can be moved between locations • No vertical motions when jacked-up	Shallow/ Medium	Small
Fixed platform	• Legs connect to the seabed (e.g. concrete or steel) • Not possible/Very difficult to move • No vertical motions allowing for (low cost) steel risers • Good in harsh weather	Up to Medium	All

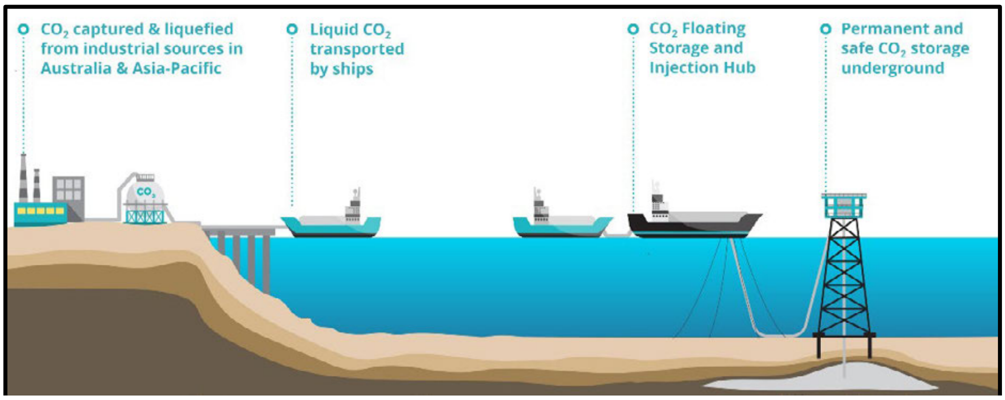

Figure 19 Schematic of potential FSI set-up. Source: (Deep C Store Project website, 2022)

Case Study 5: CO2LOS II

Floating injection offshore has also been investigated in the CLIMIT funded R&D project CO2LOS II. The scope of the CO2LOS II (CO_2 Logistics by Ship Phase II) project is to reduce the cost of CO_2 ship transportation by utilizing new technology and investigate optimization possibilities in the logistic chain. In their study a screening of wave data from 1958 to the present found that the longest period where a connection would not have been possible was 19 days, the FSI was sized with this taken into account (CO2LOS 2020) .

The concept in CO2LOSII consists of a shuttle tanker with CO_2 unloading to a ship-shaped floating storage and injection unit. The shuttle tanker is equipped with bow loading system and dynamic positioning but no pre-treatment equipment. In the CO2LOS report the FSI tank arrangement as shown in Figure 20 was planned:

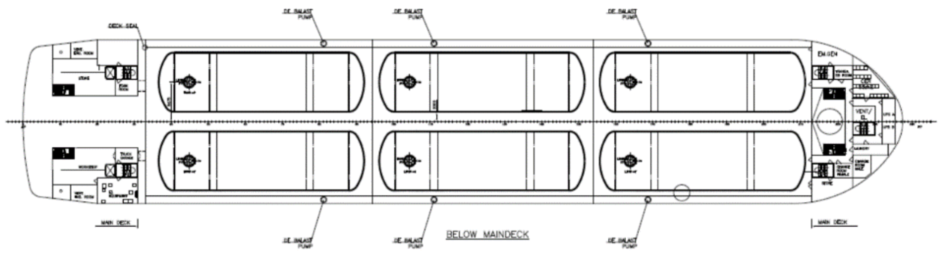

Figure 20 Tank arrange for floating storage and injection unit (FSI) in CO2LOSII Project (CO2LOS 2020).

The ship's main dimensions allowed for 6 tanks, 44.2 m long with a total combined volume of 35994 m^3. This is a larger capacity than the shuttle tanker which can transport 30,802 m^3 of CO_2 in one trip. Compared to batch-wise injection, or continuous injection by utilising two ships at once, an FSI was the most expensive option modelled in CO2LOSII.

Case Study 6: Carbon Collectors

In the Netherlands, a company called Carbon Collectors are offering a CO_2 shipping service that also allows for continuous injection. Carbon Collectors aim to place a compression and conditioning unit near the capture plant to bring the CO_2 to the right conditions for transportation in liquid phase at 40 bar and 5°C. The CO_2 is then directly loaded in an empty barge that is moored near the customer's site. This can take several hours to several days, depending on the rate of CO_2 production. When the barge is full it is connected to a pusher-tug and transported to the offshore storage location. In the meantime, CO_2 from the compression/conditioning unit continues to flow into a new, empty barge. As such, this is a continuous process at the customer's location.

The tug-barge combination arrives at the storage location and is moored at a tower offloading unit (TOU), also known as a Single Point Mooring System. The tug-barge combination stays at the TOU while the CO_2 is discharged via a flexible hose, to the injection pump located on the tower. The injection pump (powered from the barge) brings the CO_2 to the required pressure and delivers it to the wellhead on the platform via a short subsea pipeline. This approach could be a cost-effective solution for storage sites for which a pipeline connection would not be considered.

Case Study 7: Stella Maris CCS

Altera and Höegh LNG's "Stella Maris CCS" project will provide a chain of large-scale floating infrastructure for collection, transport, and injection of CO_2 into subsea reservoirs/aquifers, as shown in Figure 21. Their aim is to provide cost efficient floating CCS infrastructure solutions for a global market, not limited by size or geographical location. Altera will be providing the FPSO (Floating Production, Storage and Offloading) infrastructure and Dynamically Positioned Shuttle Tankers, and Höegh will be providing the Floating Storage Regasification Units (FSRU's).

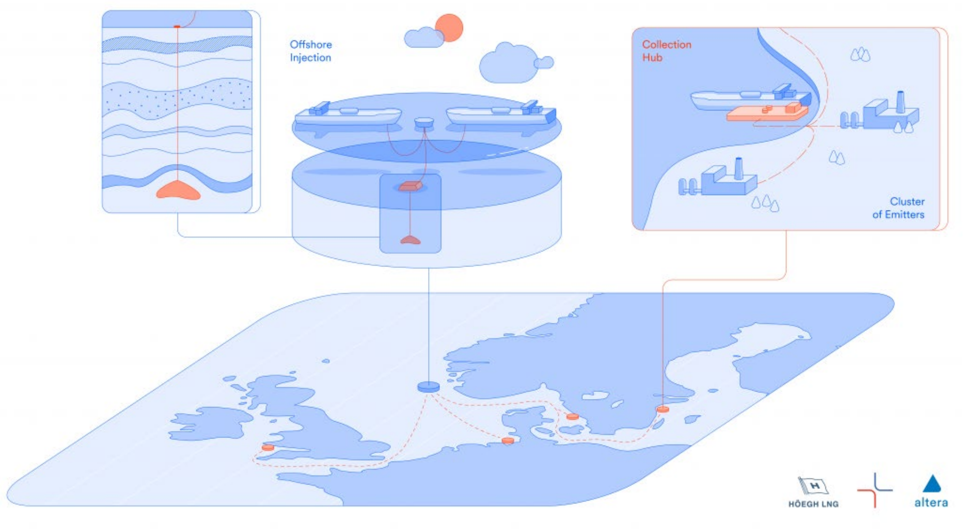

Figure 21 Schematic of the Stella Maris CCS Project initiated in 2019 (Source: Altera Website - Stella Maris CCS Project, 2022)

The main elements of the planned logistic chain are: (Altera Website - Stella Maris CCS Project, 2022)

- Floating CO_2 Collection, Storage and Offloading hub (CCSO) located in the proximity of a central cluster of industry, which will allow for the reception and further conditioning of various grades and states of CO_2.
- Shuttle tankers with a capacity of 50,000 m^3 of liquid CO_2 under low pressure, making the total amount of CO_2 injected up to 10 million tonnes per year.
- Offshore offloading system with dual buoys ensuring continuous injection.
- Floating pumping station receiving CO_2 from the shuttle tankers, conditioning the CO_2 for injection through a flexible riser.
- Dedicated subsea systems, wells, and suitable saline aquifer for safe and permanent storage of CO_2.

In 2020-2021 the CLIMIT Board granted partial funding of the progressed development of the Stella Maris CCS project.

3. Modelled Scenarios

Simulations have been conducted in this study to demonstrate the temporary storage required for given flow-rate scenarios. Injection wells have both a minimum and maximum injection rate. In particular, the minimum flow rate is critical in the discussion on the requirements for temporary storage or buffering. To avoid shutting in wells for short periods, the total flow rates to the injection site must be maintained above the sum of the minimum rates of the open wells. Some background is therefore provided here before the scenarios are discussed in more detail. There are three important well behaviour aspects to understand when discussing these simulations, these are described below.

Well bottomhole pressure: This is dictated by the required injection rate and the reservoir pressure drop. When flow is occurring, the bottomhole pressure is determined by the pressure drop in the reservoir.

Wellhead pressure: This is dictated by the bottomhole pressure, the gravitational head in the well and the frictional pressure drop. For non-flowing conditions, it is caused by the reservoir pressure and the hydrostatic pressure of the wellbore fluid. Typically, unless high flow rates or smaller tubings are used, the hydrostatic head in a well is not enough to ensure that CO_2 is in the dense phase in the well. The frictional pressure drop can be steered a little by completion design (i.e. increasing the frictional pressure drop by using smaller tubing) but this is at the cost of flexibility in the mass flow rate as the design is made to almost fixed mass flow rate. Only at high reservoir pressures will the bottomhole pressure be high enough to maintain the well CO_2 in dense phase. This means that in flowing conditions, the conditions at the wellhead are often in two-phase conditions.

Choking: Pipeline and ship offloading conditions are often required to be in single phase. In the pipelines, the CO_2 is often transported at pressures above the critical pressure, to ensure transport occurs in the dense phase. The wellhead choke (see Figure 22) controls the flow rate of CO_2 into the well (and also indirectly the pressure in the pipeline).

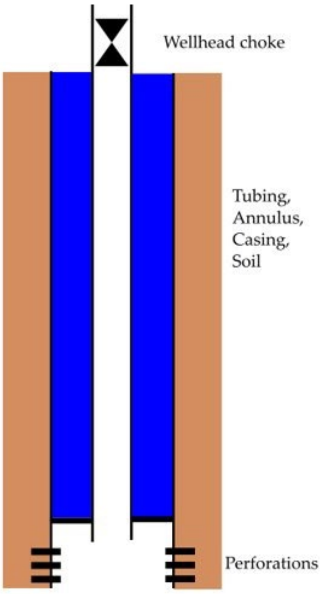

Figure 22 Schematic well diagram to show terminology used.

With the upstream conditions in the liquid/dense phase, the control choke must limit the flow into the well. Often, a fully open choke would lead to very high rates. A pressure reduction across the choke is therefore required. In the well, the required wellhead pressure to inject at the required rates is often low enough that the conditions will be in two-phase conditions. This directly means lower temperatures. At lower rates, the required pressure is less and as the conditions are at the phase line, the temperature will be lower. With lower rates, the temperature downstream of the choke is lower. As this temperature is often limited to avoid for instance freezing of annulus fluids or a higher set subsurface safety valve (SSSV), there will be a minimum flow rate associated to this minimum temperature.

3.1. Flowrates Required to Prevent Well Shut-ins

One of the critical operational limits in the CO_2 injection is a limit on the wellhead temperature. Most well designs have a temperature constraint of -10 to 0 °C to avoid freezing of fluids. At pressures less than 35 bar, the fluid wellhead temperature drops below 0 °C which means that **wellhead pressures need to be higher than 25-35 bar or single phase conditions need to be ensured.**

A secondary requirement is the avoidance of hydrate formation. This can occur at temperatures below approximately 12 °C. A small temperature margin to the actual hydrate formation line is often used. This means that a bottomhole injection temperature limit of 15 °C is often used. This can be guaranteed by operating the well in single phase conditions with high enough wellhead temperatures or to **ensure that the bottomhole pressure is higher than 50 bar** as this relates to a phase-line pressure of 15 °C. Both conditions lead to a minimum flowrate requirement.

A maximum flow rate is also defined due to a range of restrictions such as:
- to avoid exceeding the maximum injection rate possible for a given pipeline pressure;
- to minimise vibrations and erosion;
- to avoid exceeding the maximum pressure gradients (and therefore temperature gradients) in the near well zone and to avoid damage to the storage reservoir formation; or
- to avoid exceeding the maximum bottomhole pressure given allowed reservoir pressures.

To demonstrate these minimum and maximum flow rates a set of example systems were modelled consisting of a single well with a mass flow control choke, Figure 23.

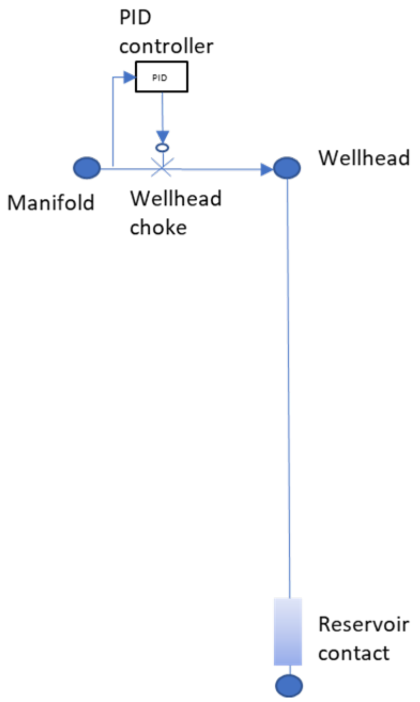

Figure 23 Diagram of an example system (one CO_2 source and a single well) modelled to demonstrate potential flow rates.

For this example, upstream of the choke, the pressure is kept at 85 bar and the upstream temperature is set to 4 °C (the lower end of seawater temperature*****).

***Note:** This temperature is important in the limitations of the flow rate. If a temperature limit of 0 °C is set, the 'space' between the upstream and wellhead temperature is very small and allows for hardly any pressure drop across the choke.

The well was modelled as a straight vertical well with total vertical depth of 3000 m calculated with a reservoir pressure between 10 and 200 bar. The injectivity was based on reservoir permeabilities (k) for a given formation thickness (h) given in millidarcy-meters (mDm) of 100 mDm, 500 mDm, 1000 mDm and 5000 mDm.

No constraints regarding bottomhole temperatures were set for these simulations as these are highly project specific but in reality this would also have to be taken into account.

The results from two of these models are presented below (in Figure 24 and Figure 25) but more simulations including 2 km reservoir depth and the temporary reservoir pressures (between 10 and 200 bar) are included in Appendix A. These also include models for varying well diameter.

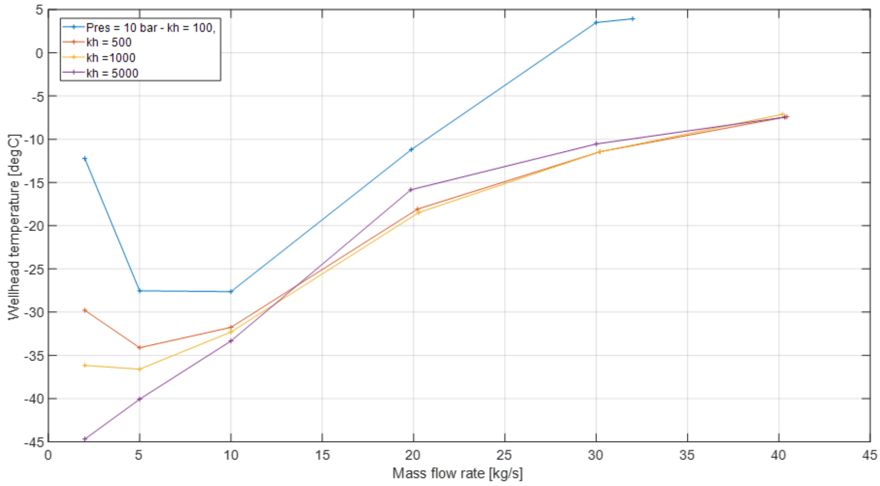

Figure 24 Wellhead temperatures for a given CO_2 flow rate for a 3 km reservoir at **10 bar** pressure and injectivities (kh) of 100 – 5000 mDm. Temperatures above T=0 °C are allowed for operation.

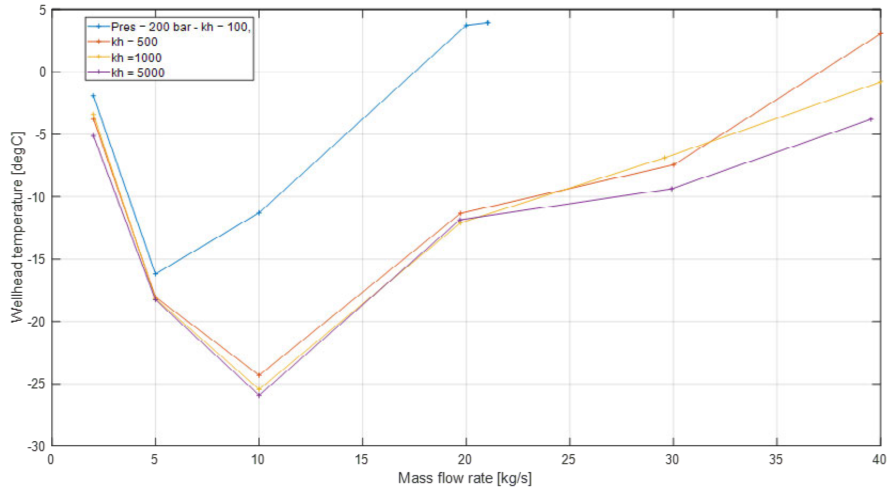

Figure 25 Wellhead temperatures for a given CO_2 flow rate for a 3km reservoir at **200 bar** pressure and injectivities (kh) of 100 – 5000 mDm. Temperatures above T=0 °C are allowed for operation.

Assuming a maximum flow rate of 40 kg/s and a minimum allowed wellhead temperature of -5 °C, Figure 24 demonstrates that at a reservoir pressure of 10 bar only the 100 mDm injectivity provided suitable conditions for flowrates higher than 24 kg/s. For a higher pressure reservoir the mass flow required decreases, Figure 25 shows the 100 mDm injectivity provides suitable conditions for flowrates of 14 kg/s and the others at approximately 35 kg/s (35 kg/s corresponds to 3000 t/day or 1.1 Mtpa) .

3.2. Pipeline Simulations

Using these flowrate requirements, simulations have been run to see at what point well shut-ins would be required in different scenarios. The model (shown in Figure 26) consists of two pipelines feeding into a collection hub, with injection occurring at a platform with two wells. One pipeline is from the planned CO_2 source, and the other is from a storage buffer such as a ship terminal. The input to the model included:

Pipeline Network:

- One onshore pipeline from a compressor to the collection hub, 1 km long with a 12" diameter. Non-insulated.
- A second onshore pipeline from the temporary storage location to the collection hub, also 1 km long with a 12" diameter. Non-insulated.
- A high pressure pipeline from the collection hub to the injection platform, with a 16" diameter made from 100 mm thick concrete with a 50 km length. This pipeline is insulated.

Wells & Storage:

- Reservoir pressure of 50 bar.
- Vertical well with a TVD of 3000 m.
- Well internal diameter of 100 mm.
- Injectivity (PI) of 1x10-5 (kg/s)/Pa.
- Well A has a pressure control. This keeps the pipeline operating pressure at 85 bar.
- Well B has a mass flow control of 35.5 kg/s (and a 1/2 combined flow).

Heat Transfer:

- An air temperature of 4 °C is assumed.
- Water temperature of 10 °C is assumed.

CO_2 Sources:

- The main CO_2 source has a flowrate of 29.1 kg/s at 40 °C.
- The back-up CO_2 source has a flowrate of 41.9 kg/s at 0 °C.

All scenarios begin with steady state for 2 days. This is then followed by 3 separate case scenarios:

Case 1: The source of CO_2 from the original source stops for 2 days, nothing is done. (This scenario provides the baseline study to assess the impact of the following two scenarios.)
Case 2: The source of CO_2 from the original source stops for 2 days. The control of the well is adjusted to try to accommodate that stop by changing the mass rate setpoint for well B.
Case 3: The source of CO_2 from the original source stops for 2 days. After 30 minutes an additional flow of CO_2 is brought in from the reserve storage location.

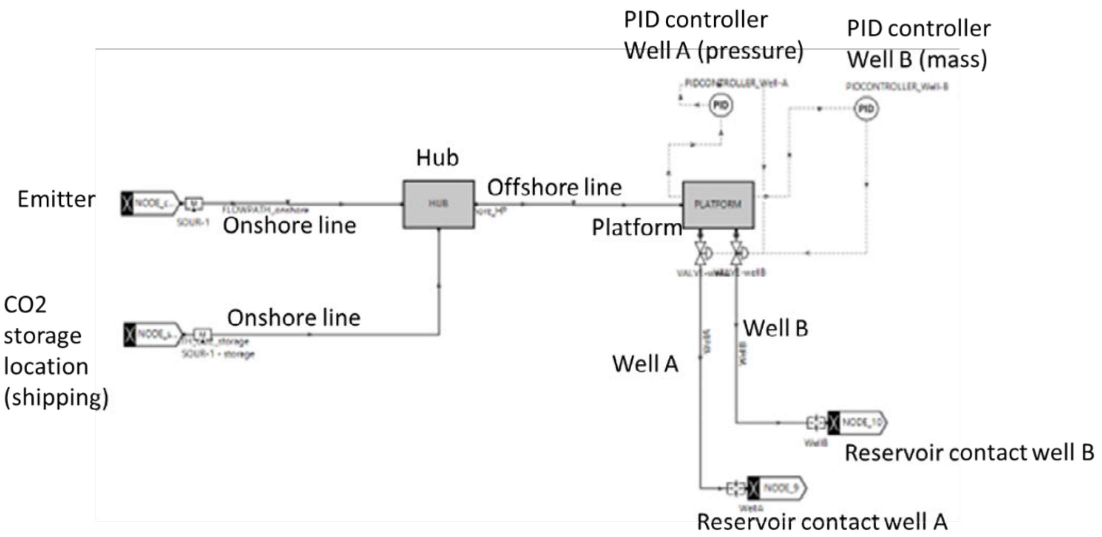

Figure 26 Diagram of the pipeline and well system used in the simulations. It comprises 2 CO_2 sources (one buffer site) to a single collection hub with a high pressure pipeline to the platform. Two wells are available from the platform.

Results from Case 1

In all scenarios the system response to changes in the inlet flow rates is fast. The whole pipeline is in liquid/dense conditions and therefore there is an almost immediate response when the inlet conditions change. The temperatures (both at the wellhead and downhole) react slower due to the heat capacity within the system but the reduction in flow rate to one of the wells directly leads to too low temperatures. This is due to the fact that the system is already operating at the edge. That is, the flow rate is close to the critical flow rate before the wellhead temperatures drop below T = 0 °C. The results are shown in Figure 27.

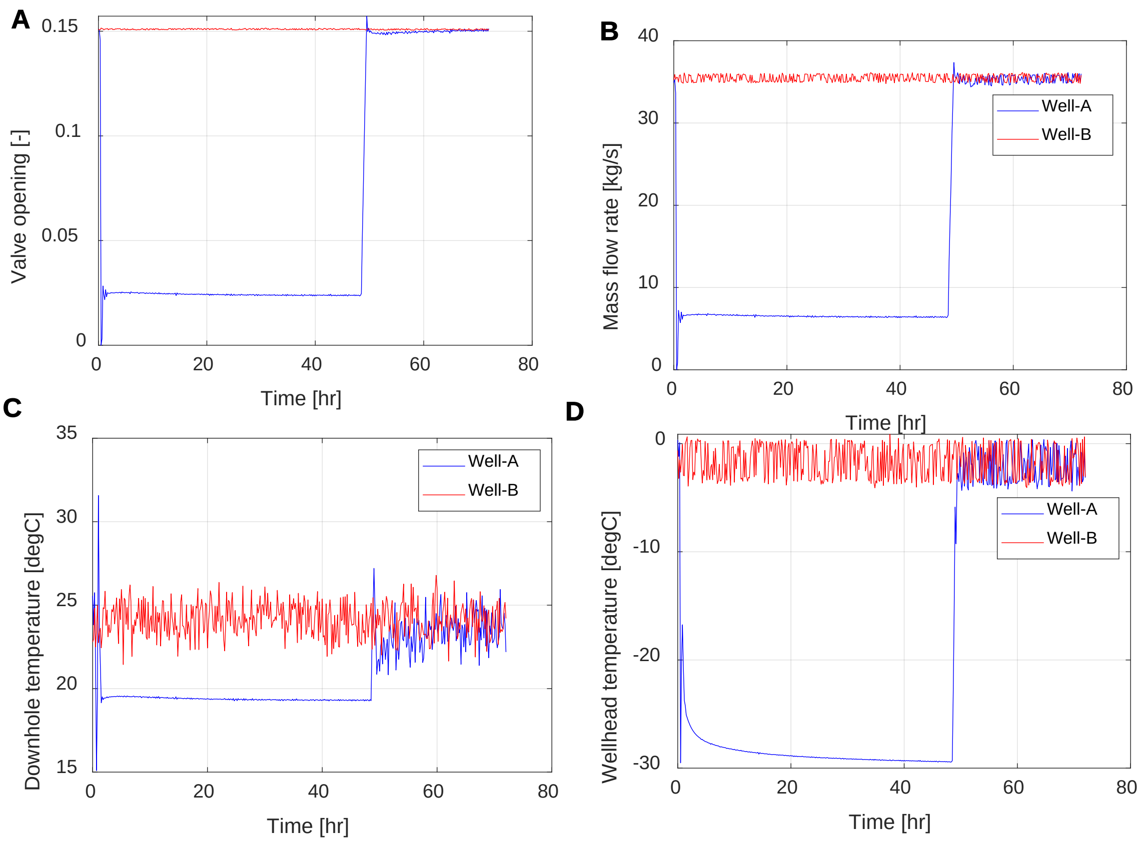

Figure 27 Results of simulations from Case 1 **A** Shows valve opening for both wells **B** Shows flowrate for both wells **C** Shows downhole temperature variations for both wells **D** Shows wellhead temperatures at both wells.

Results from Case 2

In Scenario 2 where the setpoint of Well B is adjusted to try and accommodate the reduced CO_2 flow, the balancing of the flow does help in reducing the very deep temperatures. As both wells are operating on the edge the balancing of the rates now results in both wells essentially operating at excessively low temperatures.

Operating at the reduced temperatures for these longer time frames can lead to freezing of annulus fluids. Typically around only 1 to 6 hours of heat capacity is available in the fluids and surrounding formation to accommodate these temperatures. This means a period of 2 days is too long to safely operate under these conditions.

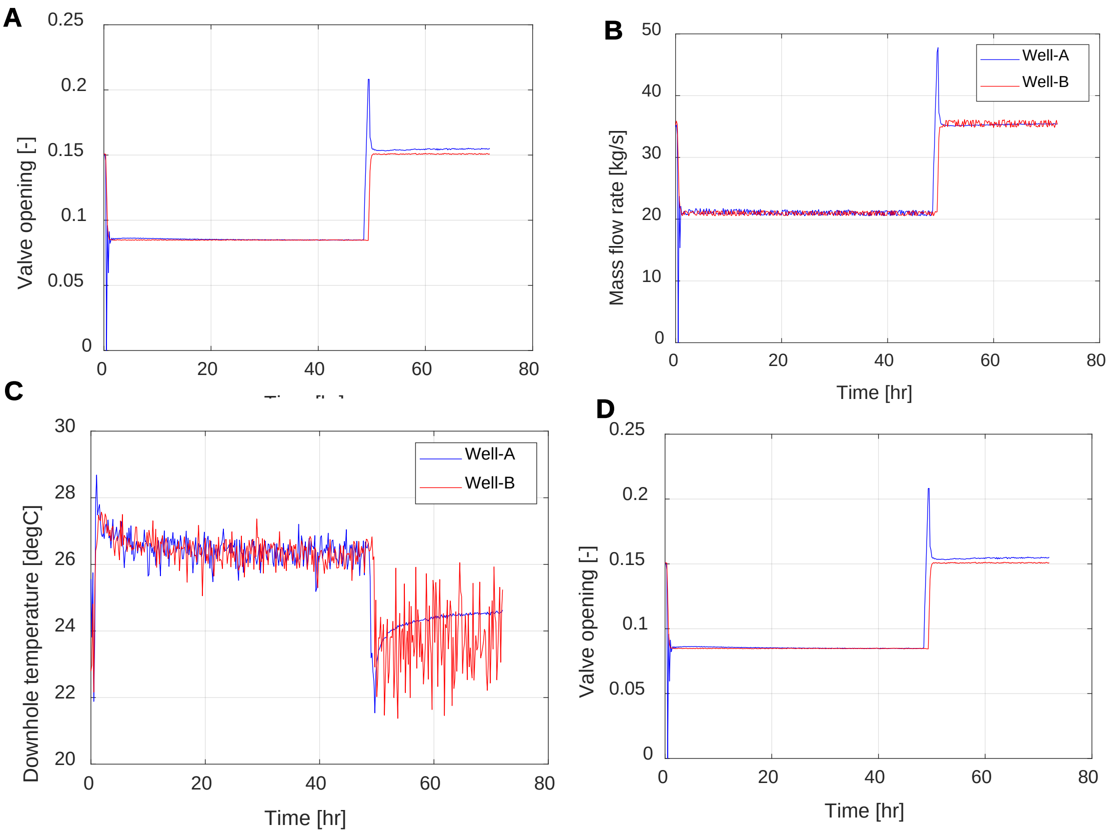

Figure 28 Results of simulations from Case 2 **A** Shows valve opening for both wells **B** Shows flowrate for both wells **C** Shows downhole temperature variations for both wells **D** Shows wellhead temperatures at both wells.

Results from Case 3

In Scenario 3 the following was simulated:

- At t=1000 s (15 minutes) the flow from onshore is reduced (this is completed over a period of 600 s).
- 30 minutes later the flow from the reserve CO_2 storage is increased (over a ½ hr period).
- After approximately 2 days the flow from onshore is increased back to its original rate over an hour period.
- At the end of this hour (t = 177998 s) the flow from the storage location is reduced (over a 30 minute period).

In Case 3 the mass flow setpoint of Well-B is not changed. As expected, and shown in Figure 29, by adding additional flow the well temperature could be kept safely within the operating window.

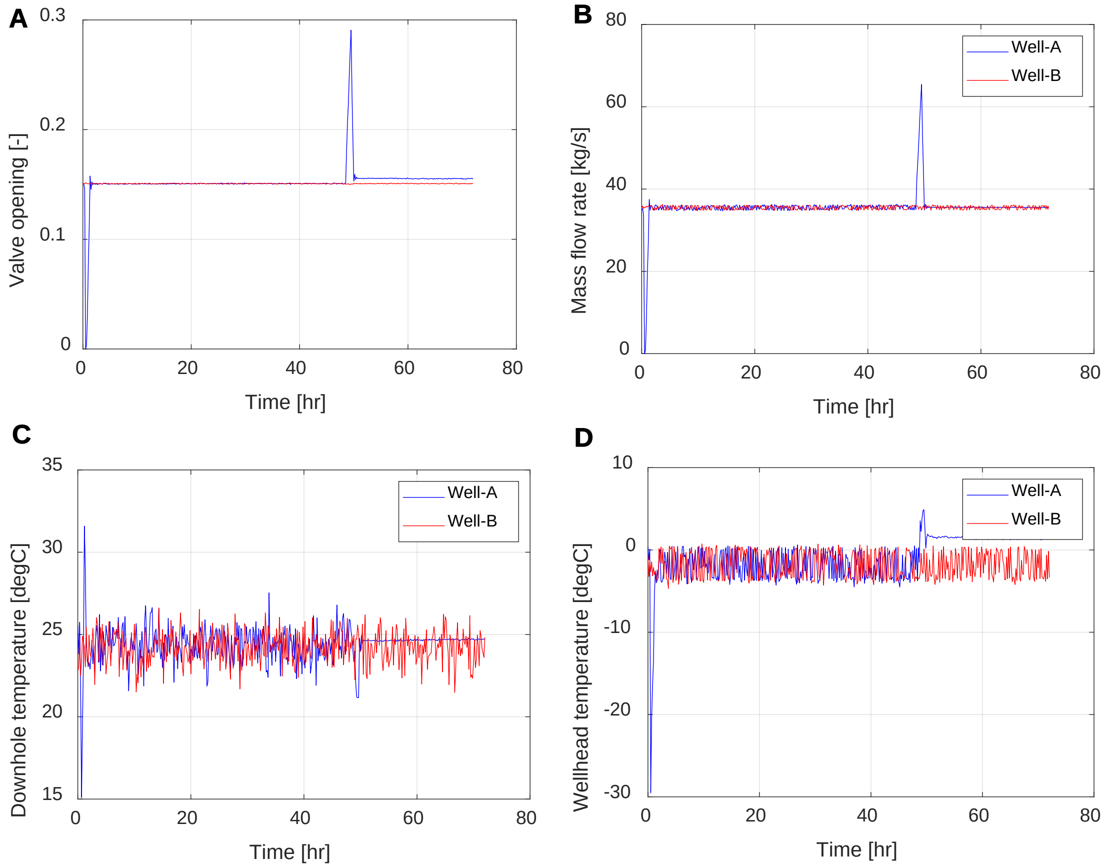

Figure 29 Results of simulations from Case 3 **A** Shows valve opening for both wells **B** Shows flowrate for both wells **C** Shows downhole temperature variations for both wells **D** Shows wellhead temperatures at both wells.

Summary of findings regarding linepacking and buffering requirements:

1. Typical minimum CO_2 flowrates at the well are in the order of 10-15 kg/s (40-60 tonnes/hr). This is the flowrate which buffer capacity needs to be designed to maintain.

2. If a drop in total flow rate occurs, to keep the wellhead and bottomhole temperature within a safe operational window, a buffer or well shut-in will be required relatively quickly (in a matter of hours) to prevent temperatures becoming too low to operate the well safely.

3. Linepacking cannot provide enough buffering beyond this short timeframe: the buffer capacity in the pipelines is limited. In high-pressure networks the capacity is often less than a few hours. The capacity in low pressure networks is often higher due to the often large-diameter pipes. However, even in these networks the capacity is limited by the operational window which is defined by the requirement to operate with CO_2 in gas phase.

4. Cost Assessment

Cost estimates in the literature regarding temporary or buffer storage technologies are often difficult to obtain, as they are often site-specific and also dependent on available infrastructure and the available geological structures. The temporary storage cost and compression work is also included in the capture cost in some studies and included in the transportation cost in others. As described in Section 2, several possibilities for temporary /buffer storage of CO_2 are available, including vessels, underground/ geological storage and pipeline storage. The most common way to store liquefied CO_2 is in insulated steel vessels. These vessels are also used for other pressurized gases and can be in different shapes; spherical, bilobe/trilobe or cylindrical. The cost for these vessels are defined based on parameters as pressure, material, temperature, size and wall thickness. The installed cost may vary quite a lot based on the ground characteristics and location factors, and if the vessel is horizontally or vertically oriented or if the vessel is welded/built at site. The cost for these tanks may be found in databases like Aspentech or from suppliers. In this work, cost data for the buffer vessels are estimated in Aspentech and a total installation cost factor is estimated by means of SINTEF's much-used proprietary estimation tool. The installation factor[2] gives an indication of the cost level for the installation of vessels and should be used with care.

The cost for buffer storage should be considered as an alternative to pay CO_2 quotas for the CO_2 that is realised if there are no place to store the captured CO_2. Some industries also have strict restrictions for emitting the CO_2 that they have said they would capture and need a buffer storage to keep the CO_2 that is produced in the T&S cannot receive CO_2. An empty buffer storage should be located close to the capture plant, as it should be able to receive CO_2 if the T&S cannot receive CO_2. The full buffer storage for the purpose to keep the flow in the well if there is stop in the production/capture of CO_2should be located close to a compression unit. With the amount that is required for the buffer storage in the scenarios, it is not consider to have CO_2 storage at high pressure close to the injection well. Therefore, the full buffer storage is located before the pipeline transport. If several sources is combined in a network, a buffer storage may be located at the connection point if there is a compression unit at that site.

In this following section, the impact of buffer capacity on the transport costs is shown in three different scenarios. It is assumed that the CO_2 is transported at 15 bar and -28 °C for the ship transport, and at low pressure (approx. 35 bar) in onshore pipelines and high pressure (approx. 130 bar) in offshore pipelines.

Both the source/capture plant and the transport/storage network may be out of production for several weeks. It is not feasible, due to the high costs, to have buffer capacity for such a long time. Therefore, in this study the buffer capacity is assumed to allow for 2 days production/injection. That means that if the T&S network fails, the CO_2 produced for 2 days is kept in the buffer storage. If the T&S network is not available after 2 days, the CO_2 should be transported to other networks or released. If the capture plant does not capture CO_2, the buffer capacity is 2 days of injection at minimum flow. If the T&S network does not receive CO_2 after these 2 days, the injection well will be shut down.

The vessels estimated are horizontal, low temperature steel tanks. The buffer storage only accommodates for the "extra capacity need" if the chain meets unexpected issues and normal operation is disturbed. The temporary storage needed under normal operations is not investigated. The injection well can handle the flows that are indicated from the sources during normal operation, but the lower limit of flow before shutting down is 54 tonnes per hour. If the

[2] Installation factor includes subcontracted costs, associated direct labour costs and materials needed for installation of equipment.

flow becomes lower, the injection well will shut down due to risk of temperature-related issues as described in Section 3.

The required buffer capacity is estimated based on these possible failures in the chain:

- The capture plant cannot deliver CO_2.
- The injection well cannot receive CO_2.
- The ship cannot receive CO_2.
- The ship cannot deliver CO_2.
- The pipeline cannot receive CO_2.

Buffer storage which is empty at normal operation is needed to be able to collect the CO_2 produced from the industrial plant if the injection well or transport network cannot receive CO_2. A full buffer store is needed before the injection well to secure continuous injection if the emitters, capture plant or transport network cannot deliver CO_2.

In the following section three different scenarios are presented and the CAPEX for extra buffer capacity is estimated.

4.1. Scenario 1

Scenario 1 is a simple source to well system, starting with a cement plant with CO_2 capture that produces 1000 kt CO_2 per year. The capture rate is 85% and thereby the yearly CO_2 amount to be transported and permanently stored is 850 kt. The transport pipeline is a high-pressure pipeline (130 bar), and the well can handle the assumed yearly flow, but as a minimum it should have a flow of 54 t/h to avoid temperature issues.

As the pipeline transport is a continuous process as opposed to ship transport, no temporary storage capacity is needed during normal operation. If there is a failure in either the injection well, pipelines, the cement plant or the capture plant, buffer storage capacity may be required. To be able to keep a continuous injection rate of 54 tonnes/h, a buffer storage of approximately 2 days injection at minimum injection rate of CO_2 is suggested. (That equals the product of the injection rate and the 2 day stoppage time, 54 t/h * 48 h = 2.6 kt of CO_2). That will ensure delivery of CO_2 to the injection well if the flow of CO_2 from the capture plant is disrupted. The buffer storage is loaded with CO_2 during normal operation and is only used if the delivery of CO_2 from the plant fails.

If the pipeline or injection well cannot receive CO_2, two days' production of CO_2 equal to 5.1kt (106 t/h * 48 h) from the capture plant, should be stored in a buffer storage. This buffer storage is empty during normal operation and is only in use if the source or capture plant cannot deliver CO_2 to the transport chain.

The volumes of the cement plant, capture plant, and the two buffer storage options are shown in Table 8:

Table 8 Volumes of the cement plant and storage capacity in Scenario 1.

	Cement Plant Emissions	**Captured CO_2 (85% of total)**	**Buffer storage ***	**Buffer storage ****
CO_2 per year (kt)	1000	850		
Size (kt)			5.1	2.6
Max flow (t/h)	123	106		

*** if pipe/ well cannot receive CO_2 , normally empty and located close to the capture plant.**

** **if CO_2 source cannot deliver CO_2 , normally full and located close to the compression unit**

Figure **30** shows the scenario including buffer storage (marked as green vessels).

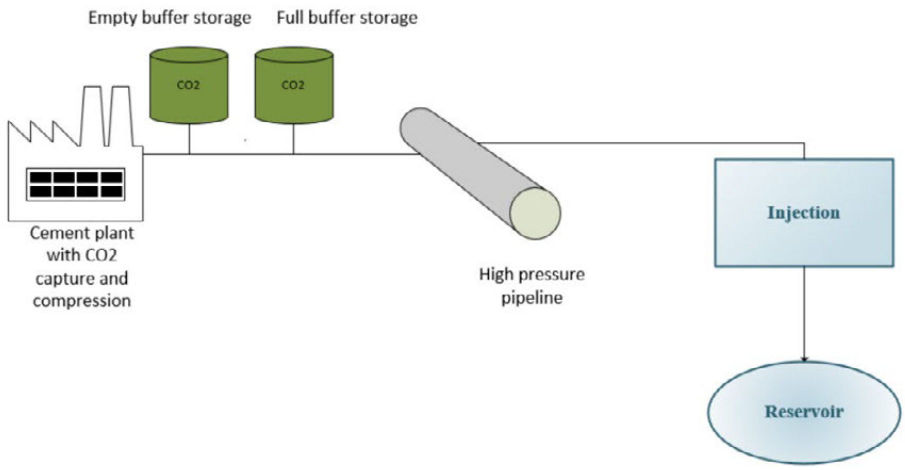

Figure 30 Schematic overview of Scenario 1.

Table 9 gives an overview of the estimated cost for the extra buffer capacity.

Table 9 Cost estimation for buffer tanks in Scenario 1

Tank size (t)	Material	Design pressure	Horizontal tank	Equipment cost k€	Suggested Installation factor	Total installed cost k€
2 600	A353	20 bar	1	1801	4.80	8 645
5 100	A353	20 bar	1	2999	4.79	14 365

If no buffer capacity is included, there is no need for the two buffer vessels. The extra cost for the two vessels is approx. 23,000 K€. The buffer tanks estimated are cylindrical, horizontal tanks, but vertical tanks may be of interest if there is limited available area close to the capture plant or the injection site.

If no buffer storage is included, and the cement plant cannot deliver CO_2 to the pipeline / well, the well must be shut down as the potential for line packing is limited for high pressure pipelines. It will take some hours with reduced capacity to go back to normal production after a shut down. If the pipeline/well cannot receive the CO_2 that is produced, the CO_2 must be vented to air if not stored in the buffer tanks. For stops of more than a couple of days, it does not seem relevant to have empty storage with large capacity available due to the high cost.

A rough calculation of the Capital Expenditure (CAPEX) including both buffer storages over a project lifetime of 20 years, and with 7.5% discount rate, shows that the cost for the buffer storage is 2.7 €/t. The operational cost is difficult to estimate, but it would include at maintenance, staff and some energy to keep the temperature low. No extra staffing is properly included for these tanks, as it would be part of the normal operation staffing.

In the “Road project in the Netherlands”, the total transport cost for a similar chain with a source, a pipeline and storage, totalling 65 M€ (GCCSI, 2019). As shown by these numbers, the suggested buffer capacity has a high cost compared to the total investment of the chain, and it should be discussed if the cost of the buffer storage justifies the risk avoided.

4.2. Scenario 2

Scenario 2 is a more complex transport system with several sources and ship transport to a shared terminal, where the CO_2 is compressed and further transported in a high pressure pipeline to the injection well. In this scenario, it has been decided that the sources have exclusive dedicated ships going back and forth from the source to the shared terminal and it is a shared storage before the pipeline transport to the injection site. As the ship transport is a batchwise system and the sources/ capture plant produce CO_2 continuously, there is a need for temporary storage during normal operation both before and after the ship transport. Please note that the storage requested in the chain for normal operation are presented as " temporary storage" (grey vessels in figures) and storage to give buffer capacity is presented as " buffer storage" and is marked as green vessels in the figures in this report. The scenario is presented in Figure 31.

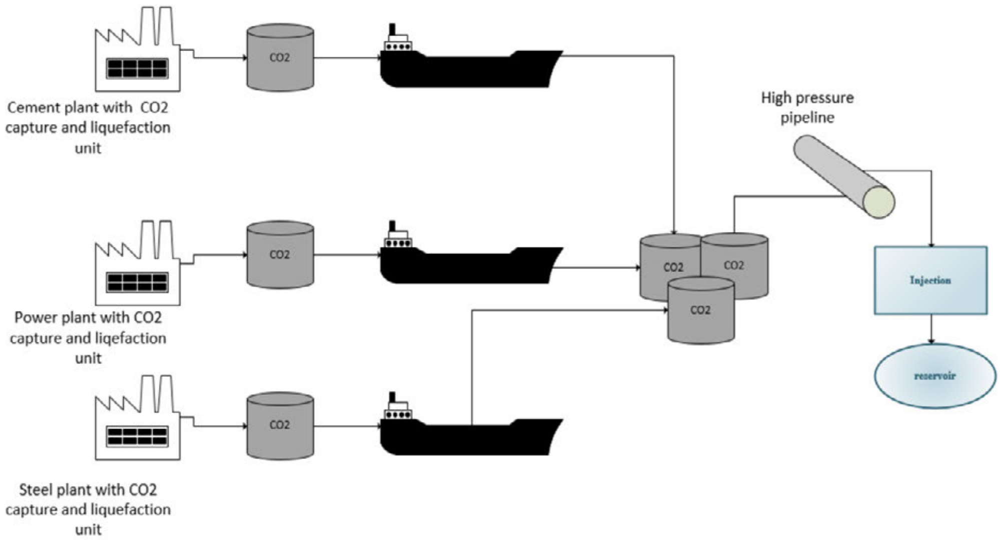

Figure 31 Schematic overview of Scenario 2

The sources in this scenario are a cement plant, a power plant and a steel plant with variable amount of CO_2 produced. As in Scenario 1, buffer storage capacity covering 2 days of operation is included. It is assumed that the three sources do not fail at the same time. If one source cannot deliver CO_2, it is assumed that the other two can deliver CO_2 to the shared storage and thereby continue the injection, and no buffer storage at the injection site is needed. Three buffer storages close to the capture plants with a capacity of 2 days production is included. These buffer storages are empty during normal operation and will only be loaded if the ship cannot receive the CO_2 or the rest of the transport chain cannot receive the CO_2 produced. The scenario is showed in Figure 32. The buffer capacity is shown as green vessels, and the temporary storage needed in normal operation is shown as grey vessels.

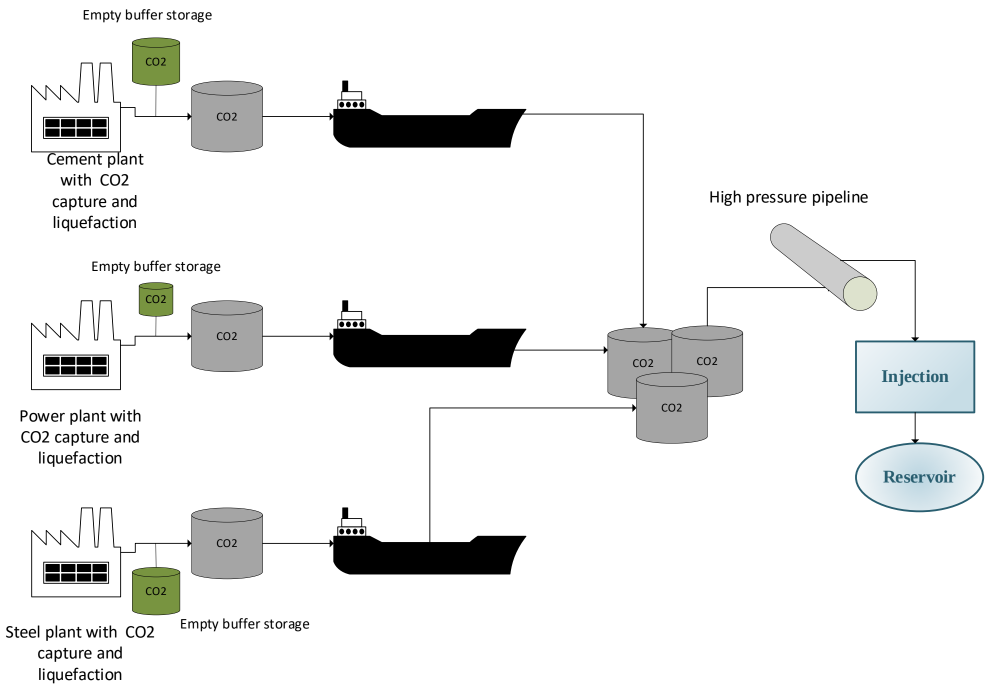

Figure 32 Schematic overview of Scenario 2 including buffer storage.

The buffer capacity varies with flows from the emitters. Even if the power plant has a lower yearly amount of CO_2 produced, the buffer capacity and the transport chain are designed for maximum flow. The operation hours are assumed and will vary from plant to plant. The chosen operation time is to show that the operation hours may vary. An overview of the volumes of CO_2 produced and captured, size of buffer storage and ship capacity are presented in Table 10:

Table 10 Volumes for the cement plant including extra buffer storage in Scenario 2.

	Cement plant (hours in operation per year: 8112)	**Captured CO_2 (85%)**	**Buffer storage ***
Amount CO_2 pr year (kt)	1000	850	
Capacity (kt)			2.6
Max flow (t/h)	123	105	

*** if pipe/ well cannot receive CO_2 , normally empty and located close to the capture plant.**

Table 11 Volumes for the power plant including buffer storage in Scenario 2.

	Power plant (hours in operation per year: 4380)	**Captured CO_2 (85%)**	**Buffer storage ***
Amount CO_2 pr year (kt)	500	425	
Capacity (kt)			4.7
Max load (t/h)	114	97	

*** if pipe/ well cannot receive CO_2 , normally empty and located close to the capture plant.**

Table 12 Volumes for the steel plant including buffer storage in Scenario 2.

	Steel plant (hours in operation per year: 8500)	**Captured CO_2 (85%)**	**Buffer storage ***
Amount CO_2 pr year (kt)	2500	2125	
Capacity (kt)			12.2
Max load (t/h)	296	252	

*** if pipe/ well cannot receive CO_2 , normally empty and located close to the capture plant.**

A cost overview of the buffer storage tanks is presented below (not including the temporary storage needed in normal operation):

Table 13 Cost estimation for the buffer tanks in Scenario 2.

Site	Tank size (t)	Material	Design pressure	Horizontal tank	Equipment cost k€	Suggested Installation factor	Total installed cost k€
Cement plant	5 100	A353	20 bar	1	2999	4.79	14 350
Power plant	4 700	A 353	20 bar	1	2764	4.79	13 225
Steel plant	12 200	A353	20 bar	2	7376	4.10	30 817
Total							57 817

The extra buffer capacity (not including the temporary storage need in normal operation) in the chain has an estimated cost of approx. 58,000 k€. That includes all the three buffer storages located close to the capture plant, The cost for the extra buffer capacity is estimated to be (20 year lifetime and 7.5% discount rent) 1.5 €/t. That would only include CAPEX. Operational Expenditure (OPEX) is not included.

4.3. Scenario 3

This scenario is a combination of a ship transport network and a pipeline network. A cement plant with CO_2 capture transports the captured CO_2 in a low pressure pipeline to a shared terminal where the CO_2 is compressed and transported further in a high pressure pipeline to an injection well for permanent storage. Another source, a steel plant with capture facilities, transport the captured CO_2 by ship to the terminal and then the CO_2 is transported in the same high pressure pipeline as the CO_2 from the cement plant. In normal operation, there is no buffer storage in the transport chain from the cement plant. As the steel plant uses ship transport, temporary storage before and after the ship transport is required. In Figure 33 the temporary storage is presented as grey vessels. The buffer storage, marked as green vessels, is required to contain the CO_2 from the sources if the T&S system cannot receive the produced CO_2. There is no need for buffer capacity if one source fails, as it is not assumed that both of the sources will be out at the same time and both sources has enough CO_2 to keep the wells open by itself.

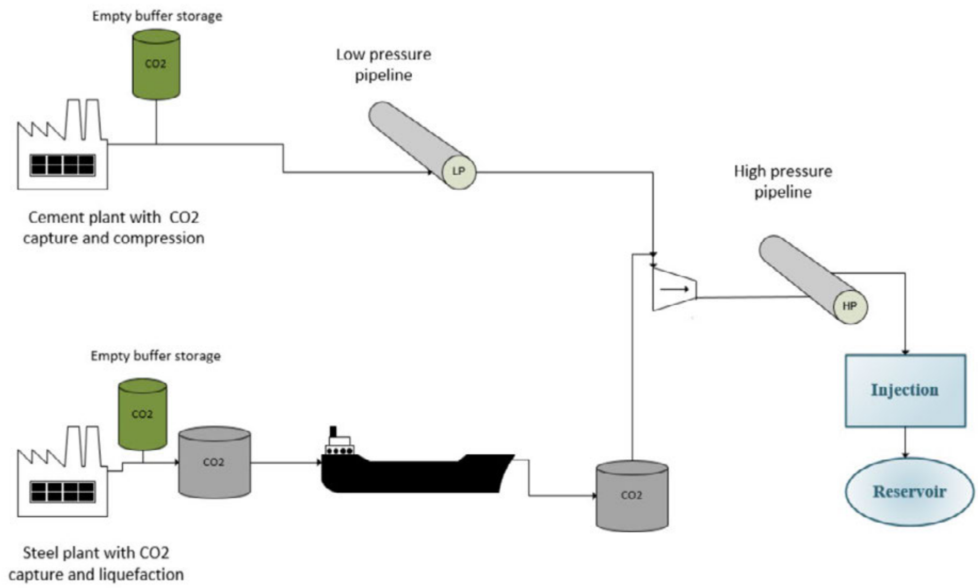

Figure 33 Schematic overview of Scenario 3.

The cement plant has a production of 1000 kt CO_2 per year, and with a capture rate of 85%, that equals 850 kt CO_2 captured each year. The buffer storage needed after the capture plant to keep the CO_2 produced in two days is estimated to be 5.1 kt. As there are two sources connected to the same well and it is assumed that the two sources do not fail at the same time, there is no need for a buffer storage to maintain the flow in the well.

The steel plant produces 2500 kt CO_2 per year, and with a capture rate of 85 % the capacity of the capture plant is 2125 kt per year. The transport is by ship and temporary storage before and after transport is required during normal operation. In addition, a buffer storage of 2 days production is needed in case the T&S system cannot receive the CO_2. The size of this buffer storage is estimated to be 12.1 kt. (252 t/h * 48hr = 12096 t)

Table 14 Volumes for the cement plant including buffer storage in Scenario 3.

	Cement plant (hours in operation per year: 8112)	**Captured CO_2 (85%)**	**Buffer storage ***
Amount CO_2 per year (kt)	1 000	850	
Capacity (kt)			5.1
Max flow (t/h)	123	105	

*** if pipes or injection well cannot receive CO_2 for up to 2 days**

Table 15 Volumes for the steel plant including buffer storage in Scenario 3.

	Steel plant (hours in operation per year: 8500)	**Captured CO_2 (85%)**	**Buffer storage ***
Amount CO_2 per year (kt)	2500	2125	
Capacity (kt)			12.1
Max flow (t/h)	296	252	

*** if ship cannot receive CO_2 for up to 2 days**

Table 16 Cost estimation for the buffer tanks in Scenario 3.

Tank size (t)	Material	Design pressure	Horizontal tank	Equipment cost (k€)	Suggested Installation factor	Total installed cost (k€)
5100	A353	20 bar	1	2999	4.79	14,350
12,100	A353	20 bar	1	4566	4.79	21,848
						Total: 36,199

As can be seen in table 16 the total buffer capacity increases the cost by approx. 36,000 k€. That includes the two empty storage vessels before the transport. As the assumption is that the sources does not fail at the same time, there is no need for extra buffering to avoid shut down of the well if one source fails.

The cost for the extra buffer capacity is estimated to be (20 year lifetime and 7,5% discount rent) 1,0 €/t. That would only include CAPEX for the buffer vessel. Operational Expenditure (OPEX) is not included.

4.4. Geological gas storage

Geological gas storage is common for natural gas as presented in Section 2, and would be an option for storing large amounts of CO_2. The cost of geological storage is very site specific, and the cost will vary with parameters like volume, depth, type of storage option, well drilling, cost of injectivity, infrastructure needed, platform operation and maintenance costs.

The different storage cost opportunities were investigated by the EU Zero Emission Platform in 2010 (ZEP 2010). They found out that in general (on a per tonne of CO_2 basis), onshore storage is cheaper than offshore; depleted oil and gas fields are cheaper than deep saline aquifers; larger reservoirs are cheaper than smaller ones and the cost of wells is increasing along with their depth.

As for buffering storage in a CO_2 chain, the volumes of CO_2 needed to maintain the chain for a couple of days is not large compared to the cost of a geological storage. These storage options should be used if there is a need for buffering large amounts of CO_2, for instance if a steady supply is required for operational reasons such as when CO_2 is utilized as a feedstock. For smaller volumes, as for the buffer storage in the scenarios examined here, buffering with steel tanks is usually more cost-effective.

The Q16-Maas field is a small offshore depleted gas field, with a capacity for CO_2 in the range of 1.5 - 2 Mt. Connected to the nearby Porthos CO_2 transport system, it could play a role in evening out seasonal variations in the demand for CO_2 from greenhouses, ensuring a more stable supply of CO_2 to the offshore depleted gas fields for permanent storage. A high-level estimate of the cost of buffering showed that the buffering process adds about €10 /tonne of CO_2 (unit technical cost) to the cost of capturing, transporting and storing the CO_2 (Koenen, Neele et al. 2018). This is of the same order of magnitude as the cost of permanent storage, for similar fields in the same region (EBN & Gasunie 2018).

4.5. Floating buffer storage

The buffer tanks may be located at the industry site or on a barge close to shore. These barges are defined as floating storage and will be possible to reuse at other sites if needed. This possibility for reuse may reduce the risk of investing in buffer storage capacity, but it should be taken into account that the storage size and temperature/pressure and thereby the material requirements may be different in a new location. In addition, tie-ins and size of the buffer storage would be site specific. Floating buffer storage is an option if there are limitations in space at the quay, but as tanks that could be moved around and fit several different projects, it does not seem optimal.

4.6. Summary of cost for buffer storage

It can be seen from the work presented here that the cost of buffer storage is generally high. The risk of not including buffers in a CCS chain is that CO_2 will be emitted to air the T&S goes out of operation or undesired well shut-ins may be required. Design and consideration of the inclusion of buffer storage should reflect the risks of emitting CO_2 to atmosphere and the associated impact on social acceptance. The cost for both having CO_2 available in part of the chain and have extra capacity with empty buffer available for such cases must be weighed against the risk aspects.

If the sources are connected in a T&S network, the need for buffer capacity to prevent shutdowns in the injection site is likely to be reduced. Therefore, it is cost beneficial to group the CO_2 sources together, at least when it comes to buffer storage costs. The buffer storage that should prevent CO_2 losses of the captured CO_2 if the T&S storage cannot receive CO_2 is not affected if the sources are connected and should be included close to the capture plant.

The size of the buffer storage is difficult to estimate, as it depends on the assumptions and the operation philosophy for the plant and the T&S network. In this report, 2 days production has been used to estimate the buffer capacity needed. The buffer storage is costly, and it should be taken into consideration when deciding the size of the buffers.

5. Future Projections & Considerations

5.1. Future Network Developments

Many future CCS projects are likely to follow a hubs and cluster approach with numerous emitters utilising a single collection network joined and to a hub with one or more storage locations. Although more emitters increase the likelihood of unplanned changes in CO_2 supply, the chances of two or more emitters stopping supply at the same time is still relatively low. Hence the requirement for buffering is not likely to increase as a CCS project becomes larger with more complex networks. On the contrary, more emitters may add more flexibility in the network when one of the suppliers temporarily goes offline this will represent a smaller proportion of the CO_2 flow as more emitters share the network. The same also applies to the storage hub, with more wells and storage sites online it may increase the system's capacity to compensate for additional flow should one well experience temporary shut-in.

Regarding the high costs of additional buffer storage, as CCS chains become larger with more emitters, the costs of buffering can be shared between more partners. However, if the plant is small, the buffer storage may become a more significant part of the overall T&S costs. Given that approximately the same volume of buffer storage will be required, larger projects are more likely to be able to add this in the CCS chain. Large-scale plants such as those required for cement, steel, ferroalloys, etc, will need larger buffering capacities. As discussed this is likely to be incorporated as part of onshore tank facilities. As buffering capacity is likely to become less and less required as clusters mature, a weighted approach to buffering could be adopted. More buffering could be incorporated at the start of a project and scaled back as networks and systems develop. However, given the high costs it is probably prohibitive for fewer emitters to accommodate larger buffering capacity needs at the early stages of a network's development.

Up to 2050, CCS is going to be increasingly applied to abate CO_2 sources such as the cement and steel industries. Currently the majority of projects are based on power generation sources and natural gas processing (Global CCS Institute 2021). This is likely to move towards capture from sources such as blue hydrogen production as countries accelerate towards net zero targets and use of renewable energy sources increases. Different industries may have different requirements/needs with regard to the configuration of a buffer storage.

5.2. Management of Multi-actor Projects

As CCS projects become larger, with more emitters coming online, these projects will also need to address the issue of cross-sector or intra-cluster management of CO_2 supply. For example, to minimize the potential impact on supply rates, routine maintenance and planned downtime could be organized between the various capture facilities or industry sites. This could dramatically reduce the need for well shut-ins which would occur if all planned maintenance occurs within the same periods. To improve the flexibility of the system and to share the costs, buffer storage should be shared and be at a collection point which all the emitters feed into. How this capacity is shared, between different suppliers and across the full CCS-chain would also need to be planned. However, given the commercial needs of the capture site downtime may be difficult to plan to incorporate the needs of other sites, especially if there is no financial incentive for the capture site undergoing the maintenance to plan this around the CCS network as a whole.

5.3. Buffering & EHR Projects

Throughout this study the need for buffering capacity in full-chain capture and storage projects has been investigated. One specific scenario not yet considered is the temporary storage of CO_2 during enhanced hydrocarbon recovery projects (EHR). EHR systems operate differently to CCS projects, e.g. due to different financial drivers, back production of CO_2, etc., but through these projects there is already extensive experience with handling the temporary storage of CO_2. Most experience to date is in the United States where the majority of CO_2 injected in CO_2-EOR projects (70%) is produced from naturally occurring underground CO_2 deposits (International Energy Agency Website, 2022). These CO_2 resources are in high-demand, which has led to the development of a CO_2 pipeline network (over 6000 km) in the Permian Basin area of the US. This CO_2 supply appears to be relatively reliable, although struggling to meet the current CO_2 demand, and no literature was found which relates to the intermittency of supply or how buffering is integrated into these systems.

5.4. Low TRL Technology

As discussed in Section 2 onshore storage tanks and quayside facilities are already being deployed for temporary CO_2 storage and are ready for further commercial deployment. The main technology yet to be deployed that may play a role in future CCS projects for buffering are offshore injection units from ships which can deliver injection ready CO_2 to the offshore platforms. Research and development is still ongoing in this area regarding the need for continuous versus batch-wise injection for CO_2. If permanent injection from ships is deployed in future CCS projects there is the potential to oversize the capacity offshore to allow for some buffering. As offshore CO_2 injection units from ships are yet to be deployed these are currently at a low technology readiness.

5.5. Regulatory and Public Perception Implications

Onshore storage tanks, the size of those discussed in this report for temporary CO_2 storage, are already in commercial deployment. Although regulatory requirements will be in place these are already well developed and unlikely to provide barriers to buffer storage development. Many future CCS developments are likely to be in industrially developed areas, especially if the buffer storage is located at the CO_2 capture site. These are unlikely to have footprints larger than ongoing gas-storage activities in industrial areas, for example the Northern Lights onshore storage tanks (12 tanks storing 8250 m^3) will have a footprint on the order of approximately 2500 m^2. Therefore no concerns are foreseen regarding public perceptions associated with buffer storage that would vary from a CCS project with no buffering. As with all infrastructure projects it is important to actively communicate with all relevant stakeholders. This will include both direct and indirect communication with governmental parties, regulators, communities and NGOs.

6. Conclusions and Recommendations

Designing extra CO_2 storage capacity into a full-chain CCS system beyond that needed for daily operations is going to incur significant costs. As a rough estimate, the cost for buffer storage would be in line with 5-10% of the transport cost. The question therefore arises as to what the benefits are in doing so, and whether these benefits warrant the extra costs. For a stop in CO_2 supply, the main benefit of having excess CO_2 to buffer the system is that a well shut-in could be prevented. This is highly beneficial if such a stop occurs regularly, but a well shut-in can be managed and is unlikely to be highly problematic if undertaken infrequently. In the case of an unexpected shut-down of the transport and storage system, resulting in surplus CO_2 supply, the benefits of having spare temporary storage is that it prevents CO_2 being emitted to atmosphere. This is beneficial as firstly it would prevent any financial incentives (such as ETS allowances) having to be paid back, but it is also beneficial for public perception of the project, where emissions from a CCS project could be highly controversial.

The volumes of CO_2 to be produced on a daily basis are likely to be large, on the order of 1000s of tonnes a day, i.e. a ship load a day. Therefore long periods of downtime would require extensive storage reserves to accommodate these changes. These extra costs are likely to be economically unfeasible. Therefore, any buffer capacity is likely to be designed for short-term unplanned changes in the CCS chain, on the order of a couple of days maximum. Beyond this, well shut-ins or CO_2 being emitted to atmosphere are likely to be the only viable options from a cost perspective.

After reviewing each technology available to provide this buffer capacity, the most likely solution is that onshore facilities being designed for shipping, e.g. onshore tanks, could be built slightly over capacity, to accommodate these unplanned short-term changes. It is unlikely that geological storage will be developed purely for temporary storage purposes given the longer timescales for storage and injection cycles (months rather than days). There is the potential for permanent storage sites to extract CO_2 to provide a buffer, but this will be complicated given these are likely to be permitted for permanent storage only. Smaller scale constructed underground storage tanks are likely to become more common in the run-up to 2050 as energy storage, e.g. hydrogen and compressed air, become more popular due to the increase in renewable energy deployment. This may provide opportunity to also store CO_2 in such designs. At the moment this remains a low TRL technology, untested for CO_2 deployment.

By providing an overcapacity of onshore CO_2 storage quayside facilities (e.g. from 10-50% extra storage capacity) an unplanned downtime of either the T&S network or a stop in CO_2 supply could be compensated. This would also require the storage to be full or empty depending on the circumstances. As a project becomes larger with more emitters or injection wells coming online, this buffer capacity is unlikely to be increased. Unplanned stoppages are likely to be rare and hence the likelihood of two occurrences happening at once is unlikely. Therefore the buffering capacity needs are likely to be the same for smaller and larger projects. More emitters, all interconnected by the same collection network, will also make it easier to keep the minimum flowrate required in place and therefore this increased flexibility may reduce the need for buffering.

Utilizing the pipelines for buffering capacity, through a process known as linepacking, is unlikely to provide storage beyond a few hours. The higher the pressure that the pipeline is operated at, the greater the potential is to accommodate a sudden drop in CO_2 supply. As shown in this study through simulations, this can only prevent a well shut-in for approximately half a day and the extra compression required to operate a higher pressure pipeline also incurs extra costs.

Shipping is being increasingly incorporated into new CCS projects, for example Porthos and Snøhvit are currently focusing on pipeline transport but projects such as Northern Lights and Teesside are planning to incorporate shipping. For these projects there is a great potential to oversize the inherently needed shipping loading/unloading terminals, as the temporary storage is essential in shipping projects. For pipeline based projects, e.g. Porthos, the extra costs of incorporating onshore storage which is otherwise not needed will create much higher additional costs.

The costs associated with buffer storage are unlikely to change dramatically in the near future. Most of the facilities such as shipping tanks, quayside facilities and onshore storage tanks are already commercially mature technologies. There may be some changes, such as changes in materials, but in general costs are unlikely to change through further deployment. There is the potential to further cool or compress the CO_2, to minimise the spatial volume, and thus materials and costs, needed to store the CO_2. Compression and/ or cooling are expensive processes, and higher-pressure tanks or materials that can withstand colder temperatures will also add additional costs. This option is likely to be costlier than accommodating for extra space.

As more emitters come online in a project more ship capacity may be required. It is not yet known how multiple emitters, or collection hubs, will be structured in terms of collection cycles. Larger ships are going to be preferred from an economics perspective as ship building is usually the main cost driver. It is unlikely that more smaller ships would be preferred. For future buffering scenarios it will be key to consider whether buffering will be required to accommodate longer trips between collection.

It is important to emphasise that economics and the costs of buffering capacity in comparison to paying back subsidies are not the only factors to consider. Emitting CO_2 from what will be early-mover CCS projects could have much greater implications for the public perception of the project and CCS in general. Projects may want to prevent any emissions, and be willing to take on these extra costs, as the implications of emitting CO_2 when a CCS project's reason for existing (and the subsidies that incentivise) is climate mitigation.

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8. Appendix A

In Section 3.1, the results from the 3 km True Vertical Depth (TVD) well were presented, to show the mass flow rate requirements given the changes in well head temperature for different injectivities. More results for the 3 km TVD well, as well as for a 2 km TVD well, are presented here. This appendix also includes models for different well diameters.

8.1. 2 km reservoir depth, 85 bar pipeline pressure

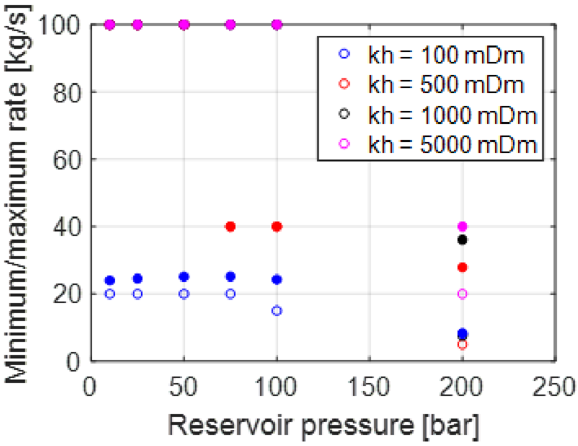

Figure 34

Minimum flow rates (open circles) and maximum flow rates (closed circles) for a 2km TVD well, at 85 bar and **4.5 inch diameter.**

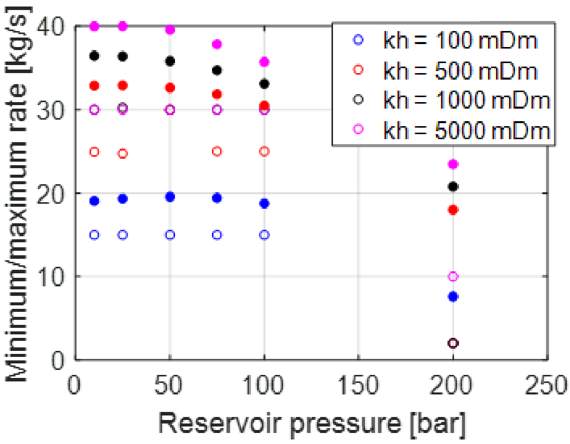

Figure 35

Minimum flow rates (open circles) and maximum flow rates (closed circles) for a 2km TVD well, at 85 bar and **3.5 inch diameter.**

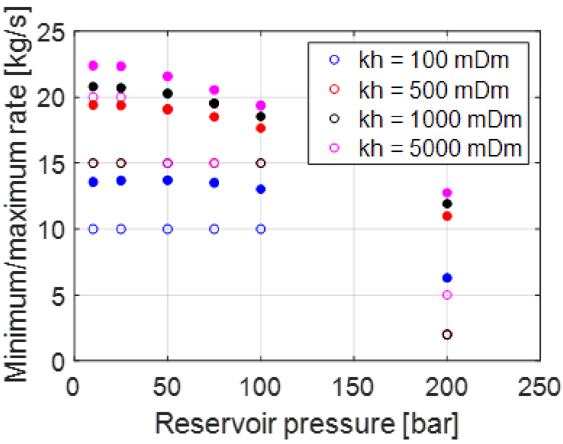

Figure 36

Minimum flow rates (open circles) and maximum flow rates (closed circles) for a 2 km TVD well, at 85 bar and **2.875 inch diameter.**

8.2. 2 km reservoir depth, 120 bar pipeline pressure

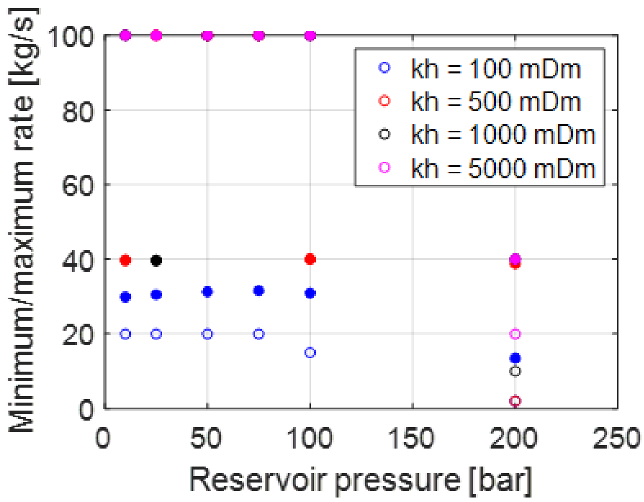

Figure 37

Minimum flow rates (open circles) and maximum flow rates (closed circles) for a 2 km TVD well, at 120 bar and **4.5 inch diameter.**

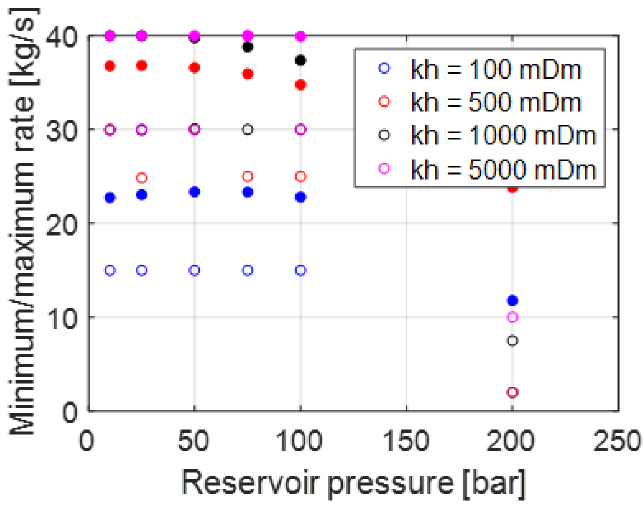

Figure 38

Minimum flow rates (open circles) and maximum flow rates (closed circles) for a 2 km TVD well, at 120 bar and **3.5 inch diameter.**

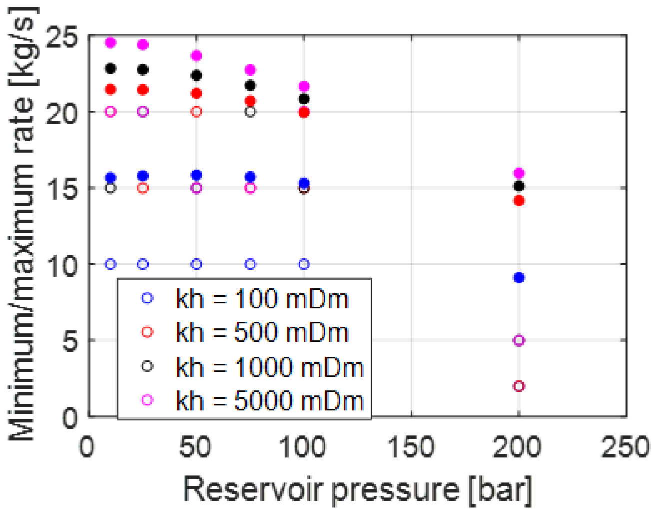

Figure 39

Minimum flow rates (open circles) and maximum flow rates (closed circles) for a 2 km TVD well, at 120 bar and **2.875 inch diameter.**

8.3. 3 km reservoir depth, 85 bar pipeline pressure

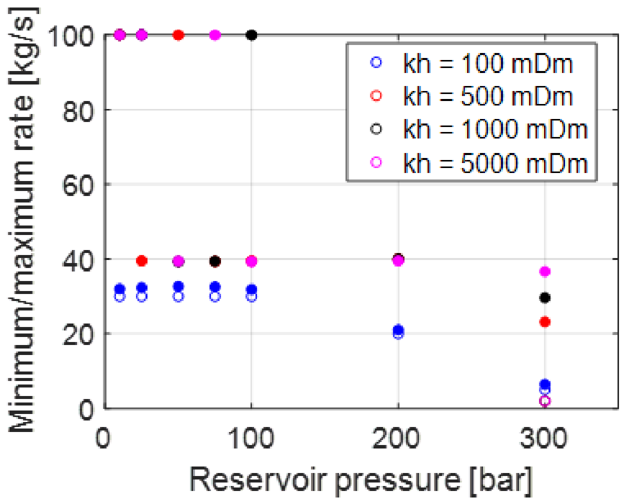

Figure 41

Minimum flow rates (open circles) and maximum flow rates (closed circles) for 3 km TVD well, at 85 bar and **4.5 inch diameter.**

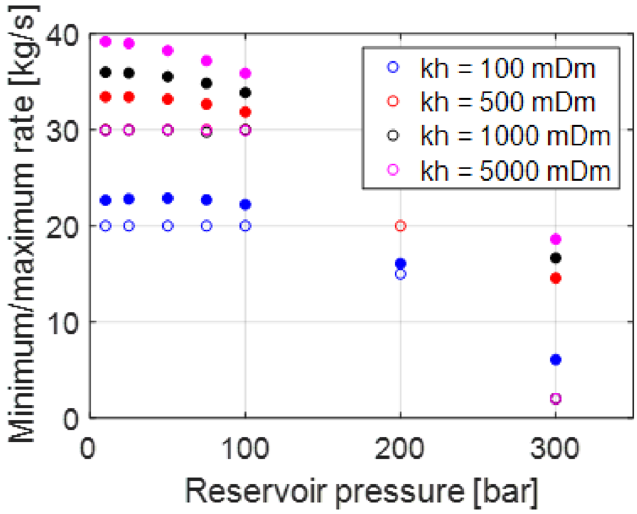

Figure 40

Minimum flow rates (open circles) and maximum flow rates (closed circles) for 3 km TVD well, at 85 bar and **3.5 inch diameter.**

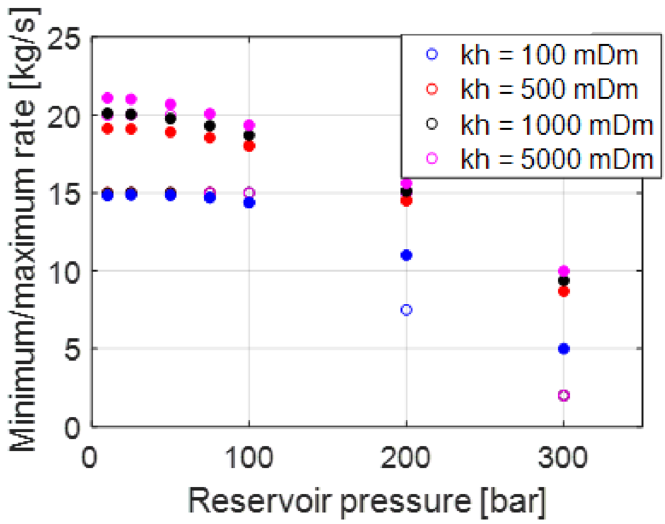

Figure 42

Minimum flow rates (open circles) and maximum flow rates (closed circles) for 3 km TVD well, at 85 bar and **2.875 inch diameter.**

8.4. 3 km reservoir depth, 120 bar pipeline pressure

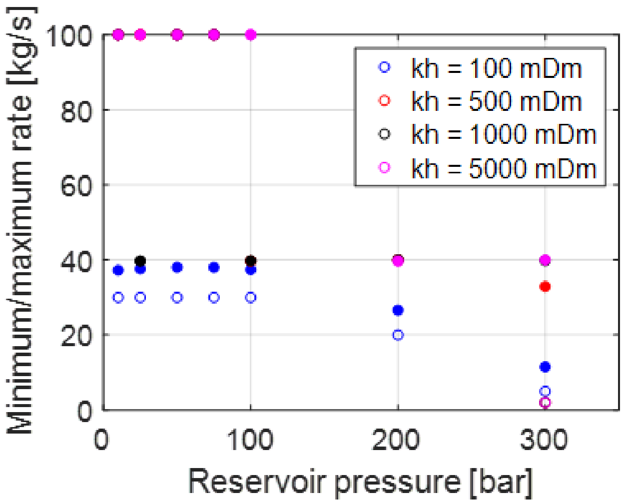

Figure 43

Minimum flow rates (open circles) and maximum flow rates (closed circles) for 3 km TVD well, at 120 bar and **4.5 inch diameter.**

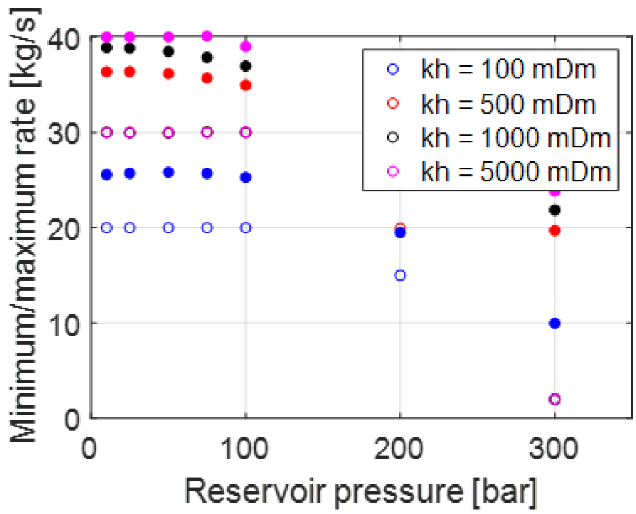

Figure 44

Minimum flow rates (open circles) and maximum flow rates (closed circles) for 3 km TVD well, at 120 bar and **3.5 inch diameter.**

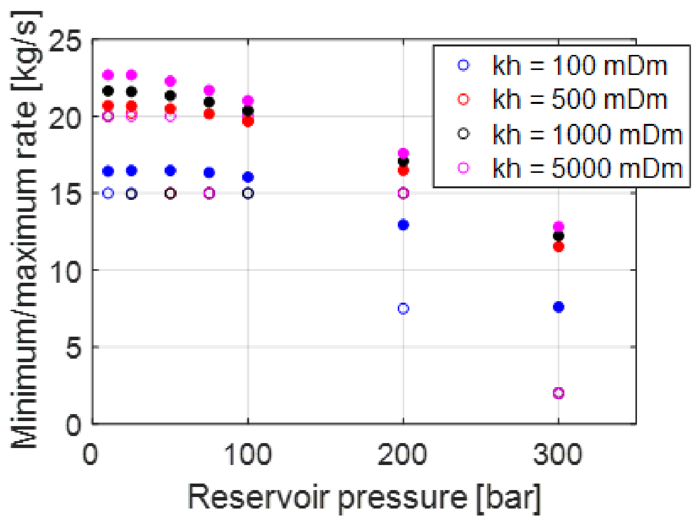

Figure 45

Minimum flow rates (open circles) and maximum flow rates (closed circles) for 3 km TVD well, at 120 bar and **2.875 inch diameter.**

Evaluating technology options to mitigate greenhouse gas emissions

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