Preem CCS
Synthesis of main project findings and insights

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Summary

The *Preem-CCS* project was a Swedish-Norwegian collaboration that investigated CO_2 capture from the Preem refineries in Sweden, and subsequent ship transport of captured CO_2 for permanent storage on the Norwegian Continental Shelf. The project was conducted from early 2019 to beginning of 2022 and funding was provided by the Norwegian CLIMIT-Demo program via Gassnova, by the Swedish Energy Agency and by the participating industry and research partners (Preem, Aker Carbon Capture, SINTEF Energy Research, Chalmers University of Technology, and Equinor).

The key findings of the main project activities are summarized below:

- **Pilot-scale testing of CO_2 capture at the hydrogen production unit (HPU) at the Lysekil refinery using the Aker Carbon Capture (ACC) mobile test unit (MTU)**

  The on-site pilot-scale tests of amine-based CO_2 capture from the flue gases (~18-20 vol%_$CO_{2,wet}$) of the refinery's HPU were conducted successfully, thereby demonstrating the technical feasibility of the capture process. Test campaigns were conducted with both a 30wt.% MEA solvent and ACC's proprietary solvent S26. For 90% capture rate, the specific reboiler duty (SRD) with S26 was 15-18% below the SRD of MEA. Furthermore, MEA experienced significantly more degradation, as evidenced by solvent miscolouring and high levels of ammonia emissions in the absorber. The S26 solvent showed little degradation and the amine losses were thus one order of magnitude lower than those associated with MEA solvent, despite the significantly longer duration of the pilot test campaign.

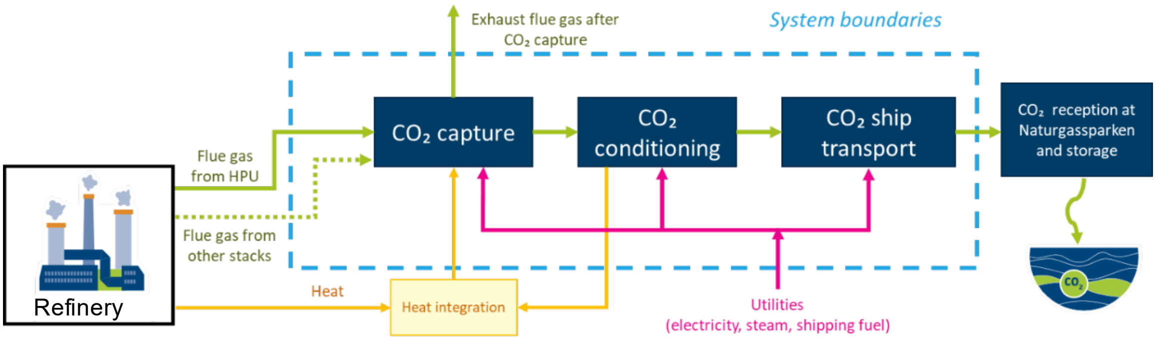
- **In-depth investigation of energy efficiency opportunities along the CCS chain, including the use of residual heat at the Lysekil refinery site to satisfy the energy requirements for solvent regeneration**

  A detailed analysis of the Lysekil refinery site energy system was conducted and three sources of heat supply were identified: 1) extractable residual heat; 2) existing unused steam generating capacities; and 3) new boiler capacities. A multi-period optimization was conducted using mixed-integer-linear programming to find the mix of heat sources that minimizes external energy demand. The results indicate that residual heat alone could supply ~40% of the heat required to capture most of the site's CO_2 emissions. Furthermore, the use of residual heat reduces the annual cost of capturing CO_2 from the four main stacks in Lysekil (80% avoided site emissions) by 29-36%, compared to using external energy exclusively.

- **Evaluation of the technical feasibility and cost evaluation of the CCS chain including CO_2 capture and transportation by ship to storage facilities off the Norwegian west coast**

  A CCS chain analysis was conducted adopting the system boundary shown in the figure below. The value chain includes CO_2 capture from the Lysekil and Gothenburg refineries, CO_2 conditioning (compression and liquefaction), and ship transport to the Northern Lights on-shore terminal in Øygarden, Norway, with subsequent pipeline transport to the injection well for permanent storage under the seabed in the North Sea (Johansen formation). The CCS chain cases are summarized in the table below and consider capture from the four major stacks in Lysekil (HPU, FCC, combined stacks 1 and 2) as well as the HPU in Gothenburg. For these cases, a capture target of 90% implies 0.6–1.6 Mt/a of captured CO_2. The calculated avoidance costs were in the range 94–128 €/t CO_2-avoided. Capturing larger volumes of CO_2 does not lead to lower specific avoidance costs because (1) stacks with lower CO_2 concentration (~8%, combined stacks) have higher specific capture cost; (2) the cost of external energy for heat supply and associated emissions

dominates and outweighs any economies of scale for on-site piping and ship transport to storage. It was also shown that a reduced transport pressure of 7 barg (instead of 15 barg, cf. Case 1A in table below) leads to 44% lower costs for on-site storage, loading and shipping (corresponding to ~4 €/t CO_2 avoided for the full chain in Case 1). The project also assessed Preem's potential CO_2 supply compared to the CO_2 suppliers to the first phase of the Northern Lights project (Fortum Oslo Värme and Norcem Brevik). Case 4 could potentially trigger implementation of the second phase of the Northern Lights project, which requires a CO_2 supply of 1.5-5 Mt CO_2/a.



System boundaries of the CCS chain analysis.

Overview of CO_2 sources considered in the CCS chain analyses, including: flue gas from the hydrogen production unit (HPU) via steam methane reforming (SMR), flue gas from the fluid catalytic cracker (FCC) regenerator; flue gas from two combined stack. Assumed CO_2 emissions baselines 1.855 Mt CO_2/a (Lysekil); 0.570 Mt CO_2/a (Gothenburg)

Case	CO_2 source at the Preem refineries	Approx. capture (90% of yearly emissions of corresponding stacks) [Mt CO_2/a]	Transport pressure [barg]
Case 1	Lysekil: HPU flue gas (SMR)	~0.616	15
Case 1A	Lysekil: HPU flue gas (SMR)	~0.616	7
Case 2	Lysekil: HPU+ combined stack 2 (low sulphur)	~0.940	15
Case 3	Lysekil: HPU + FCC	~0.799	15
Case 4	Lysekil: HPU + FCC + combined stack 1 + 2	~1.581	15
Case 5	HPU flue gas in Lysekil and Gothenburg	~0.916	15

- **Investigation of relevant legal and regulatory aspects related to trans-border CO_2 transport and storage and national emissions reduction commitments in Norway and Sweden**

In October 2019, the International Maritime Organization approved provisional application of the amended Article 6 of the London Protocol, thereby allowing transboundary ship transport of CO_2 for the purpose of geological storage. Such provisional application of amended Article 6 requires Sweden and Norway to deposit a Unilateral Declaration and enter a bilateral agreement about export and import of CO_2.

A recent proposal for revision of the EU Emission Trading System (ETS) allows other transport modes than pipeline and clarifies the operator of the transport/injection system is responsible for CO_2 leakage during transport/injection. With this suggested change, Preem will not be able to subtract emissions until the CO_2 reaches the Northern Lights terminal, and, furthermore, any CO_2 leakage during the transport from Preem to Øygarden cannot be subtracted from Preem's emissions even though it has been captured by Preem. A contractual agreement between Preem and Northern Lights will need to account for this.

Next steps towards implementation of CCS at Preem refineries

Preem has announced their goal of net-zero CO_2 emissions over their complete value chain by the Year 2035, including scope 3 emissions. This implies, inter alia, a vast ramp-up of biogenic feedstock, thus paving the way for bio-CCS and negative emissions. The results of the Preem-CCS project have led to initial planning of full-scale CCS implementation at Preem refineries HPU units by Year 2026-2027. Implementation of CCS for other sources can potentially be of interest thereafter. The next steps for implementation at the Lysekil HPU unit are to conduct a Feasibility study and initiate the BED/FEED phase starting sequentially from 2022.

Nomenclature

AMP	Amino-Methyl-Propanol
CCS	Carbon Capture and Storage
CDU	Crude oil Distillation Unit
CLC	Chemical Looping Combustion
CO_2	Carbon dioxide
CRU	Catalytic Reforming Unit produces high-octane liquid products from naphtha distilled from crude oil
DCC	Direct Contact Cooler (cools incoming flue gases in direct contact with water).
EEM	External Energy Minimization (minimized); relates to heat integration solution
EPC	Engineering, Procurement, and Construction costs
FCC	Fluid Catalytic Cracking unit (cracks heavy portion of crude oil into lighter products)
FGD	Flue Gas Desulfurization
HCN	Heat Collection Network
HPU	Hydrogen Production Unit
HRSG	Heat Recovery Steam Generator
HSCM	Heat Supply Cost Model
ICR	Iso-CRacker unit (producing low-sulphur diesel).
ISO	ISOmerization (chemically transforms straight hydrocarbons into branched hydrocarbons)
LCO_2	Liquid CO_2
MDEA	Methyl DiEthanolamine
MEA	Monoethanolamine; refers to an aqueous solution with 30 wt.% MEA
MHC	Mild HydroCracker unit, (desulfurizes vacuum gasoil and converts it into lighter products and feedstock for the hydrocracker)
MHSCC	Marginal Heat Supply Cost Curve
MVR	Mechanical Vapor Recompression
NHTU	Naphtha HydroTreating Unit
NL	Northern Lights (project).
PZ	Piperazine
SMR	Steam Methane Reforming
SRD	Specific Reboiler Duty; refers to heat demand for solvent regeneration per captured CO_2
SRU	Sulphur Recovery Unit
SSU	Sulphur Solidification Unit
TCR	Total Capital Requirement
TDC'	Total Direct Costs without process contingencies
TPC	Total Plant Cost
TRL	Technology Readiness Level
VDU	Vacuum Distillation Unit (separates heavier oils coming from atmospheric distillation).

1 Introduction

This report summarizes the main findings and insights of the project "Preem CCS" that was conducted during the period February 2019 through March 2022. The project was initiated by Preem AB and funded by the Norwegian Climit program (Climit project 618157 "Techno-Economic Feasibility Study of the Implementation of Carbon Capture from Major Emission Sources at Preemraff Lysekil") and the Swedish Energy Agency's Industriklivet program (project P47607-1 "Preem CCS – Carbon Capture and Storage)"). The purpose of the project was to investigate the feasibility of implementing full-scale CO_2 capture from Preem's hydrogen production unit (HPU) at Preemraff Lysekil in Sweden, producing liquid CO_2 for permanent storage off the Norwegian west coast, in agreement with the specifications and requirements set out in the Norwegian Northern Lights/Longship transport and storage initiative.

The main project activities were as follows:

- demonstration of carbon capture at the hydrogen production unit (HPU), which is based on steam methane reforming (SMR), at Preemraff Lysekil using Aker Carbon Capture's mobile test unit (MTU) for pilot-scale testing of CO_2 absorption
- extrapolation of the results of the demonstration into the context of a pathway towards full-scale implementation of CO_2 capture from the HPU, and other major emission sources at the Lysekil refinery as well as at Preem's refinery in Gothenburg
- in-depth investigation of energy efficiency opportunities along the CCS chain, including recovery and use of residual heat at the refinery site to drive the solvent regeneration process as well as use of alternative carbon capture solvents
- evaluation of the technical feasibility and cost of the CCS chain including CO_2 capture and transportation by ship to storage facilities off the Norwegian west coast
- investigation of relevant legal and regulatory aspects related to trans-border CO_2 transport and storage and national emissions reduction commitments in Norway and Sweden.

This report summarizes the main findings of the project and outlines possible directions for future work.

2 The role of CCS for reaching climate targets in the transportation fuel sector

Preem's climate goal is to become the world's first climate neutral petroleum and biofuel company. This entails achieving net zero emissions along the entire value chain by 2035 at the latest, from upstream feedstock extraction, through pre-treatment and refining, to downstream end-use including product combustion. Since 2020, Preem has adopted several important priorities linked to this transition. The company's focus is now entirely on projects and initiatives that actively contribute to the climate target, and climate neutrality will be achieved by focusing on the following four priority areas, whereof one includes implementation of CCS:

1. **Adapt the refineries so that fossil crude oil can be replaced by renewable raw materials**. The combustion of fossil products is the main cause of carbon dioxide emissions along the value chain. To achieve the climate goal, Preem needs to drastically reduce the use of fossil crude oil and replace it with renewable alternatives, such as bio-oils sourced from sustainable waste streams from forestry, agriculture and the food industry.

2. **Switch to fossil-free hydrogen production**. Hydrogen is an important ingredient in fuel production, especially renewable fuel production. Today, natural gas is the main feedstock used to produce hydrogen and hydrogen production is one of the main sources of CO_2 emissions from refineries. One option for reducing fossil CO_2 emissions is to replace fossil natural gas with renewable alternatives such as biogas and bio-methane as well as renewable residual streams from production. In the long term, it is also possible to install new hydrogen plants that can produce fossil-free hydrogen through the electrolysis of water using fossil-free electricity.

3. **Establish CO_2 capture facilities at both refineries**. Preem's refineries in Lysekil and Gothenburg are among Sweden's largest point sources of CO_2 emissions. Fossil emissions will decrease as fossil feedstock is replaced with fossil-free alternatives. By installing carbon capture technology, CO_2 released from refinery sources during the production of fuels can be captured instead of being released, thereby reducing the CO_2 footprint of the refinery products. Capture and storage of biogenic CO_2 emissions (often referred to as Bio-CCS) will result in carbon dioxide removal from the atmosphere, also referred to as negative emissions. Preliminary calculations indicate that full-scale application of CCS for the HPU units at both refineries could reduce CO_2 emissions by approximately 900 kt/a, corresponding to approximately 40% of total on-site emissions.

4. **Adapt production capacity to develop a product portfolio that is aligned with the needs of a sustainable society**. To achieve their climate target, Preem will gradually reduce today's large-scale production and sales of fossil fuel products. Preem also sees significant opportunities to broaden the scope of their business area and include more types of product offerings that are aligned with the needs of a sustainable society. One example is the increased production and sale of renewable platform chemicals for further downstream processing in chemical industries.

3 Overview of state-of-the-art CO_2 Capture technologies

3.1 Pre-combustion, oxy-fuel combustion, and post-combustion capture technologies

There are three main capture options for separating CO_2 from other bulk flue gas components (mainly nitrogen and oxygen): 1) *post-combustion*, 2) *pre-combustion*, or 3) *oxyfuel combustion*. Post-combustion capture involves the separation of CO_2 from flue gases downstream of the combustion unit. Pre-combustion capture involves partial oxidation/gasification of hydrocarbon feedstock with oxygen/steam to produce a syngas, which is thereafter converted to a mixture of CO_2 and H_2 from which CO_2 is separated, leaving hydrogen for combustion. Oxyfuel combustion involves combustion with oxygen instead of with air, resulting in a flue gas containing CO_2 and H_2O from which the water vapour can easily be condensed. Chemical Looping Combustion (CLC) is a special form of oxyfuel combustion, in which an oxygen carrier (metal oxide) is used to transport heat and oxygen between a fuel reactor (in which the fuel is oxidized to CO_2 and H_2O in the flue gas by reacting with the metal oxide) and an air reactor (in which the metal oxide oxygen carrier is re-oxidized using air).

Figure 1 provides an overview of the technology readiness level (TRL) of a variety of CO_2 capture technologies currently being developed (with TRL ranging from 3-9). **Post-combustion capture** using chemical absorption with traditional aqueous amine solutions (TRL 9) has been used since the 1930s for natural gas sweetening (Global CCS Institute, 2021). The technology is widely applied in fertilizer production and was demonstrated for dedicated CO_2 capture and storage at full scale in coal-power plants at Boundary Dam (Saskatchewan, Canada) in 2014 and Petra Nova (Texas, USA) in 2017. Other liquid solvents, e.g. Benfield (hot potassium carbonate) or physical solvents such as Rectisol/Selexol have also been widely applied in natural gas processing and fertilizer production, and are commercially established (TRL 9). Polymeric membranes developed at the Norwegian University of Science and Technology (NTNU) have been tested at pilot scale (TRL 6) in coal-fired power plants and other combustion processes (Bui et al., 2018). **Pre-combustion capture** was demonstrated (TRL 7) in a coal-fired integrated gasification combined cycle power plant in Kemper County (Alabama, USA) in 2015-2016. However, the gasification section was shut down in 2017 and demolished in 2021. Lack of flexibility, complexity, technical issues, as well as abundant availability of low-price gas fuel were reported as the main reasons for discontinuing the project (Wagman, 2017). Pre-combustion capture using solid adsorbents has reached TRL 5-9 (Global CCS Institute, 2021), with pressure swing adsorption/vacuum swing adsorption having been implemented successfully at full scale (TRL 9) at Air Products and Chemicals' SMR facility at Port Arthur, Texas. The facility demonstrated full-scale CO_2 capture in May 2013. The technology is now commonly applied to separate hydrogen from CO_2 in SMR plants. The commercially available membrane Polaris^{TM} has also been successfully used for separating CO_2 from syngas. **Oxyfuel combustion** was successfully demonstrated at Vattenfall's Schwarze Pumpe site in Germany in 2014 in a 30 MW demonstration unit (TRL7). Chemical looping combustion has been tested successfully at pilot scale (e.g. 1 MW_{th} unit in Darmstadt, Germany) at TRL 6.

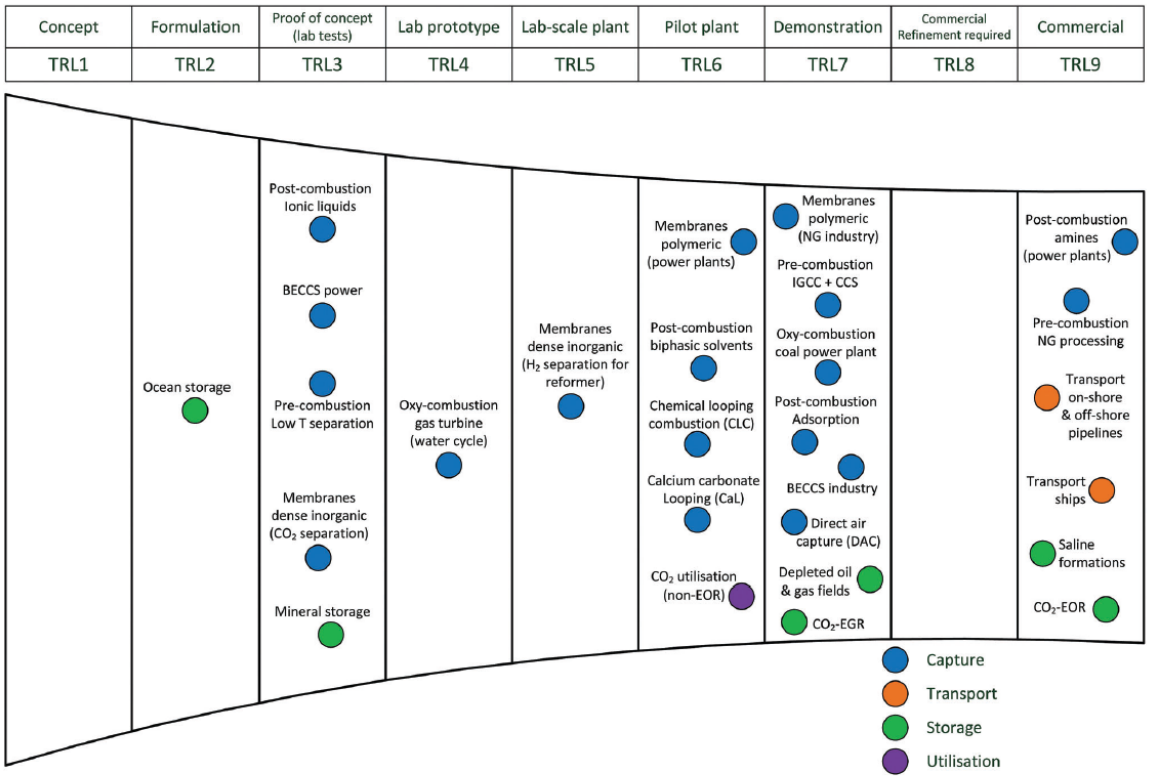


Figure 1 Technology readiness level of carbon capture and storage technologies. From (Bui et al., 2018)

3.2 CO_2 capture at refineries

For refinery plants, post-combustion capture is applicable to all the major emission sources and is particularly suitable for retrofitting existing plants. The ReCAP project performed a detail techno-economic study on retrofitting of refineries to capture CO_2 from various emission sources (IEAGHG, 2017b). The application of oxyfuel combustion in the fluid catalytic cracking (FCC) unit was investigated in the CO_2 Capture Project-Phase 3 (CCP3) (De Mello *et al.*, 2013). The pilot test results indicated that it is technically feasible to operate an oxyfuel fired FCC unit and the CO_2 can be concentrated to 95 vol%. The ongoing CHEERS project focuses on the development of chemical looping combustion of petroleum coke, heavy gas oil or refinery fuel gases as fuel for power and heat generation. The technology is expected to be developed from TRL 4 to TRL 7 (CORDIS, 2021). Oxyfuel combustion in utilities boilers was investigated in (Escudero *et al.*, 2016) using fuel gas consisting of a mixture of refinery fuel gas and natural gas. It was concluded that the high capital expenditure of the oxyfuel combustion power plant is a key barrier for the development of this technology. The pre-combustion technology is mainly applicable to the steam methane reformer (SMR) unit for hydrogen production. A study by IEAGHG (2017a) evaluated several cases for capturing CO_2 from the SMR unit including (1) capture of CO_2 from shifted syngas using MDEA (Methyl diethanolamine), (2) capture of CO_2 from PSA tail gas using MDEA, (3) capture of CO_2 from PSA tail gas using low temperature and membrane separation and (4) capture of CO_2 from SMR flue gases using MEA (monoethanolamine). Cases (1-3) involve pre-combustion capture whereas Case (4) involves post-combustion. The capture rates reported for pre-combustion are 53.2-66.9% whereas the reported capture rate for post-combustion is as high as 90%. Thus, from the perspective of CO_2 emissions reduction, post-combustion capture of SMR flue gases is preferable to pre-combustion capture from shifted syngas. However, the levelized cost of hydrogen and cost per tonne of CO_2 avoided are higher for post-combustion.

Concerning refinery operations, post-combustion capture is considered an add-on technology, whereas pre-combustion and oxyfuel are retrofit technologies which require major adjustments/modifications of existing processes for their implementation (Berghout *et al.*, 2019), leading to significant down-time for the refinery. Pre-combustion could be used to supply hydrogen as fuel to process heaters, however this would imply significant modifications to the entire refinery site and upscaled hydrogen production. Post-combustion capture requires more space and more energy and is estimated to have higher costs than oxyfuel and pre-combustion (Kuramochi *et al.*, 2012; Berghout *et al.*, 2013, 2019). Note that retrofitting costs were not included in these academic comparisons.

3.3 Inventory of CO_2 emission sources at the Lysekil refinery

Table 1 shows the main CO_2 sources at Preemraff Lysekil and the contribution of each stack to the emissions baseline of 1.855 Mt/a CO_2 which represents the expected future emissions. Only major emission sources were considered for CO_2 capture. These are: Combined Stacks 1 and 2, which are mainly flue gases from process heaters and steam boilers; Stack 3, which is the flue gas from the regenerator of the fluid catalytic cracker (FCC); and Stack 5, which is the flue gas from the hydrogen production unit (HPU) based on steam methane reforming (SMR). Stacks 4 and 6 were not considered for CO_2 capture in the Preem CCS project due to their relatively low flowrates.

Table 1: Overview of characteristics of all CO_2 sources (stacks) at the Preemraff Lysekil site. Abbreviations referring to process unit names are defined in the Nomenclature section.

	STACK 1	STACK 2	STACK 3	STACK 4	STACK 5	STACK 6
Sources of flue gas	Combined stack from: SRU, CDU, VDU, steam boilers, incineration.	Combined stack from: CRU, MHC, SSU, ISO, NHTU	FCC	ICR	HPU (SMR)	VDU2
Flue gas flow (dry) [Nm^3/h] (1)	379 000	268 000	87 100	44 000	152000	30 000
CO_2 [vol% dry]	8	8	14	8	25	8
Operating hours per year	8585	8585	8500	8500	8500	8500
Contribution to emissions baseline [kt/a CO_2]	508	359	202	58	685	40

(1) at normal conditions (0°C and 101.325 kPa)

3.4 Suitability of available capture technologies for CO_2 emission sources at Lysekil

Based on the results of the literature review, a number of candidate capture technologies were assessed with respect to their applicability to the CO_2 sources at Lysekil. Table 2 provides an overview of this assessment together with indicative TRL levels. Note that the list of included technologies is not exhaustive. Post-combustion capture is the only technology that can capture CO_2 from all existing CO_2 sources and has the necessary technological maturity. Stacks 1 and 2 already combine flue gases from various units, resulting in large flue gas flows, which is favourable for post-combustion. The application of oxyfuel (TRL 7) in the underlying individual process units was not assessed in detail but would likely imply a substantial retrofit effort. Pre-combustion capture at the existing HPU is likely to be more cost-effective and energy-efficient than post-combustion. However, this capture technology would imply a lower overall CO_2 capture rate. Scaling up pre-combustion to include hydrogen production as fuel for process heaters for the entire site is possible, however, this would involve a site-wide retrofit. Given the project's focus on near term implementation, post-combustion as a mature add-on technology that is applicable to all CO_2 sources was chosen as the most suitable technology for Preem CCS.

A final comment on hydrogen production with CCS: Table 2 adopts the perspective of an existing HPU based on the common SMR process (as is the case at Lysekil). However, if new hydrogen units were to be built at Preem refineries, other options more suitable for CO_2 capture, such as autothermal reforming (ATR) or partial oxidation (POX) should be considered. These are currently less widely used than SMR, however they are also available at large scale and are considered to be proven technology (TRL 9). In the ATR process, all CO_2 is concentrated in the PSA tail gas stream at high CO_2 concentrations (~70%) leading to lower capture cost than SMR (SINTEF and IPFEN, 2019), despite the need for an air separation unit to provide oxygen.

Table 2: CO_2 capture options for CO_2 sources at Preemraff Lysekil and their technology readiness level (TRL) considering the current refinery configuration. Colour code is indicative: TRL1-4: red; TRL 5-7: yellow; TRL 8-9: green. Technologies not assessed (n.a.) are coloured in grey.

CO_2 source	**HPU (Stack 5)** (steam methane reforming)	**FCC (Stack 3)**	**Stack 1**	**Stack 2**
Post-combustion (Amine absorption)	Separate CO_2 from flue gas TRL 9	TRL 9	TRL 9	TRL 9
Oxyfuel	n.a.	Pilot scale tests; TRL6; (De Mello et al., 2013)	Some of the boilers/process heaters may be feasible to retrofit with oxyfuel (Escudero et al., 2016); TRL7	
Pre-combustion	Separate CO_2 from shifted syngas/PSA tail gas; TRL 9	n.a.	n.a.	n.a.
Chemical looping combustion (CLC)	Technically possible; also, chemical looping reforming.	Technically possible; at R&D level, lab tests, TRL3 (Güleç et al., 2020)	Some of the process heat may be provided by CLC of petcoke, heavy gas oil or refinery fuel gas; TRL 4-7	

3.5 Assessment of Aker Carbon Capture ACC™ process for CO_2 capture at the Lysekil refinery

Aker Carbon Capture's Advanced Carbon Capture (ACC™) technology was investigated in detail for the CO_2 capture plant at Preem's Lysekil refinery. The ACC™ process is an energy and cost-efficient process with low environmental impact, based on the ACC™ S26 proprietary solvent. The ACC™ process is described briefly below.

3.5.1 Overall description of ACC^{TM} process

The main process equipment units are shown in the overview flowsheet diagram in Figure 2 and include: the direct contact cooler (DCC), absorber, and desorber columns, the reboiler, reclaimer, the flue gas booster fan, and a liquefaction unit.

Flue gas is extracted downstream of any existing flue gas emission control units and upstream from the booster fan. Depending on the plant's existing emission control system, the flue gas may require additional pre-treatment in the Direct Contact Cooler (DCC). The purpose of the DCC is to cool the flue gas and to remove any acid gases remaining, such as SO_2, HCl and HF. Condensed water from the flue gas will exit the DCC as a bleed stream. Flue gas from the DCC is routed to the CO_2 absorber downstream of the booster fan. The CO_2 absorber consists of a CO_2 absorption section in the lower part of the column and a water wash section with emission control units in the upper part of the column. In the absorption section, flue gas contacts with the lean amine solvent in a counter-current flow regime, absorbing CO_2 from the flue gas mixture. Continuing to the water wash part of the column, water is used to cool and clean the CO_2-lean flue gas of traces of amines and amine degradation products. The subsequent ACC^{TM} Anti-Mist Design effectively prevents emissions of amine and amine degradation products in the form of aerosols. CO_2-lean flue gas is either emitted from the absorber stack or returned to the existing flue gas stack downstream the flue gas extraction point.

CO_2-rich amine is drained from the absorber sump. The rich amine solvent is regenerated using steam in the desorber, where the steam is condensed in a reboiler and returned to the battery limits as hot condensate. The increase in temperature when indirectly heating the rich solvent with steam strips the CO_2 out of the solvent. The resulting lean amine is returned to the absorber, while low-pressure CO_2 exits the top of the desorber. The low-pressure CO_2 is washed and cooled, condensing most of the water. The CO_2 is then compressed to 20 bara and dried in a molecular sieve unit. The compressed and dried CO_2 is further cooled and liquefied, before stripped of non-condensable inert components to the specified CO_2 quality. Liquid CO_2 is then sub-cooled and sent to onsite liquid storage vessels.

A reclaimer is included to intermittently (batch process) remove impurities and degradation products from the amine solvent in order to maintain high solvent performance. A small amount of concentrated liquid waste is generated in the reclaimer. This reclaimer waste needs to be batch-wise disposed as chemical waste. Due to the low degradation rate of the solvent, along with a properly designed DCC, the amount of reclaimer waste from the ACC^{TM} process is very low compared to standard plants operating with generic solvents such as MEA. More information on solvent degradation based on Aker Carbon Capture's Mobile Test Unit measurement campaign at Preem's Lysekil plant is provided in Section 6.1 of this report.

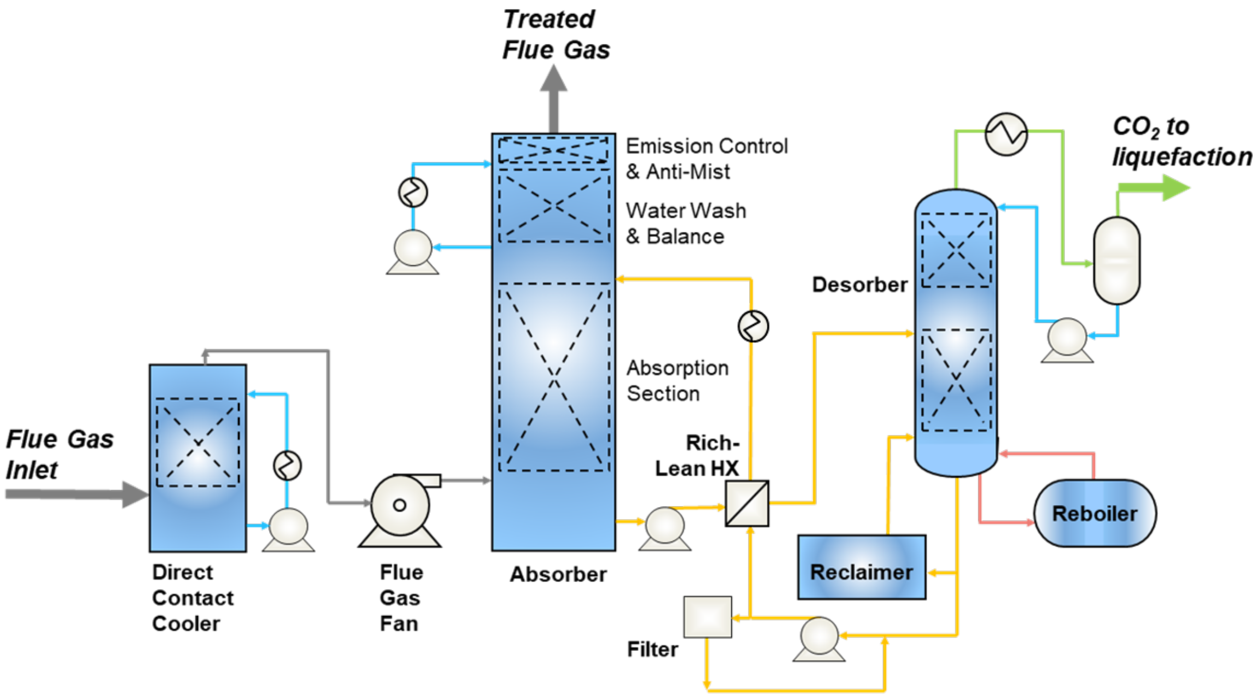


Figure 2: Simplified Generic Flowsheet of the ACC™ capture process

3.5.2 Key features of the ACC™ process

- The capture process has been demonstrated in industrial conditions through two years of operation at the 80 kt CO_2 per year plant at the Technology Centre Mongstad (TCM), Norway, by testing on flue gases from a Combined Heat and Power plant and a Residual Catalytic Cracker, as described in Gorset *et al.* (2014) and Bade *et al.* (2014).
- The capture process, including CO_2 conditioning, intermediate storage and CO_2 export has been certified by a third-party technical auditor (DNV-GL) as ISO 9001 and ISO 14001 during the Norcem's cement plant FEED project in Brevik, Norway. These two certificates are the international standards for quality and environmental management, respectively.
- Verified for operation on flue gas from cement kilns, waste-to-energy plants, coal-fired power stations, gas boilers, gas power plants and refinery applications, through campaigns with an in-house Mobile Test Unit
- Highly energy-efficient process with innovative heat integration solutions
- Highly robust S26 solvent for environmentally benign operation. The S26 solvent is a second-generation solvent characterized by low solvent degradation (one order of magnitude less than conventional solvents, see Section 6.2), which results in significantly reduced corrosion rate in the plant; low amine make-up requirement; low emissions of amine degradation products; low demand for amine reclamation, and thereby low production of reclaimer waste
- The process includes a proprietary advanced emission control system to prevent amine mist formation, which further reduces emissions of amine and amine degradation products
- No consumption of water in the CO_2 capture processes, only cooling water is needed
- No generation of wastewater contaminated with amine traces during normal operation, except during solvent reclaiming operations (batch process)

4 Overview of ongoing projects for conditioning, transportation and long-term storage of CO_2

4.1 Overview of CCS chains investigated within Preem-CCS

The CCS chains evaluated within the Preem CCS project include CO_2 capture from the Preem refinery in Lysekil, Sweden, CO_2 conditioning (compression and liquefaction), and ship transport to the Northern Lights facilities at Naturgassparken (Øygarden, Norway) for permanent storage beneath the seabed off the West coast of Norway. The project also considered additional capture at Preem's refinery in Gothenburg for the purpose of assessing the performance of a CCS chain in which ship transportation of CO_2 is shared between the two refineries. Technical integration of the CO_2 capture process at the Gothenburg refinery was not investigated in detail. Figure 3 depicts the main building blocks and the system boundaries for the CCS chains considered within the project. An overview of the CO_2 sources and building blocks of the CCS chain is included below. Note that the planned scope of the services provided by Northern Lights includes the CO_2 transport from the source of emissions to an intermediate storage terminal in western Norway, before being transported by pipeline for permanent storage in a reservoir 2,600 metres under the seabed (see Section 4.2). Thus, the cost of the ship transportation will be included in the fee charged by Northern Lights. Northern Lights has indicated that by 2030 they aim to achieve cost levels for transport and permanent storage of around 30-55 €/t of CO_2 (Aasen and Sandberg, 2020). Nevertheless, it was considered to be of interest to estimate this cost and relate it to other cost components of other operations along the CCS chain shown in Figure 3.

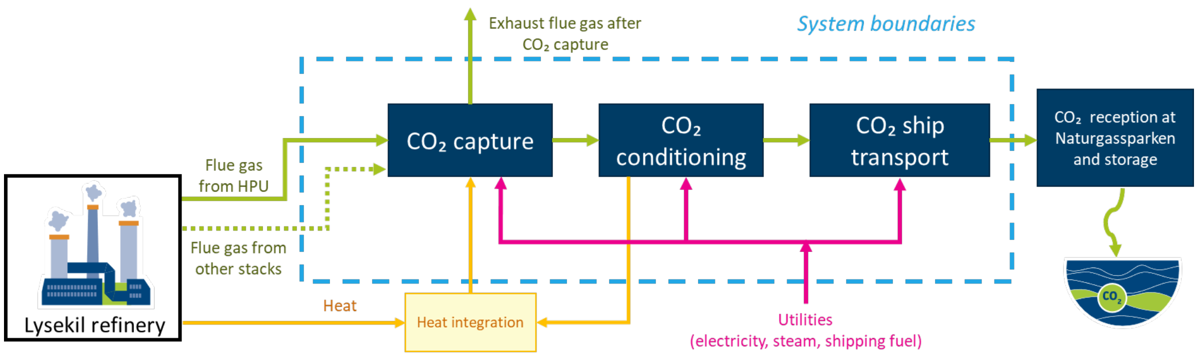


Figure 3 Generic block structure and system boundaries (blue dashed line) of the proposed CCS chains for the Lysekil refinery. Note that the CO_2 reception and storage are not included.

Figure 4 shows the shipping routes from Preem's two refineries on the West coast of Sweden to Naturgassparken in Norway. As discussed above, in one of the CCS chain cases investigated, CO_2 captured from the Gothenburg refinery was assumed to be shipped to Lysekil for joint transportation to the permanent storage facilities.

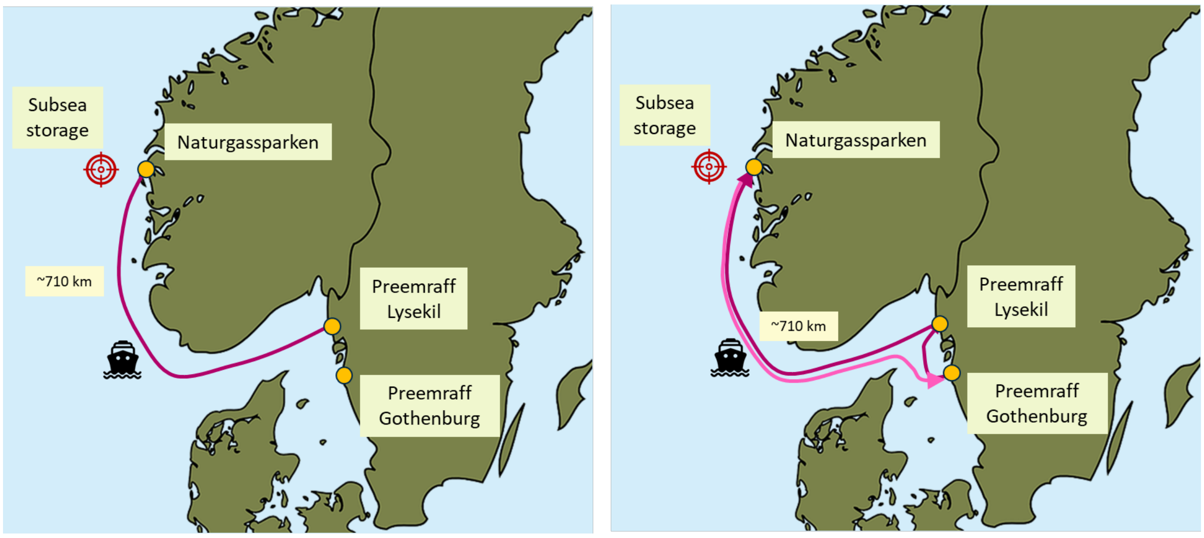


Figure 4 Shipping from the Preem refineries to the Northern Lights Project (onshore terminal at Naturgassparken in Øygarden and final storage). Left: from the Preemraff Lysekil to Øygarden. Right: additional transport from Gothenburg to Lysekil.

4.2 Overview of planned CO_2 storage projects in the North Sea area

The Longship/Northern Lights project was selected for assessing storage of the CO_2 captured at Preem's refineries. Longship is the Norwegian Government's full-scale CCS project and it will be the first ever cross-border, open-source CO_2 transport and storage infrastructure network offering companies across Europe the opportunity to store their CO_2 safely and permanently underground. Phase one of the project will be completed in mid-2024 with a capacity of up to 1.5 Mt/a of CO_2. There are also plans to implement a Phase 2 with a storage capacity of up to 5 Mt/a of CO_2.

Longship includes capturing CO_2 from industrial sources in the Oslo-fjord region (cement and waste-to-energy) and shipping liquid CO_2 from these industrial capture sites to an onshore terminal on the Norwegian west coast. From there, the liquefied CO_2 will be transported by pipeline to an offshore storage location subsea in the North Sea, for permanent storage. Northern Lights (www.northernlightsccs.com) is responsible for the transport and storage components of the project.

Other planned and emerging permanent CO_2 storage projects in the North Sea area include the following (see Figure 5):

- **Porthos (www.porthosco2.nl/en/project/)**: the Port of Rotterdam CO_2 Transport Hub and Offshore Storage (Porthos) project aims to store 2.5 Mt/a of CO_2 from industry in the Port of Rotterdam as of 2024. Specifically, the project will transport the CO_2 to a depleted gas field 20 km off the Dutch coast. It will then store it at a depth of three to four km under the North Sea seabed. Porthos is a joint venture of EBN, Gasunie, and the Port of Rotterdam Authority. Porthos has been recognised by the European Union as a Project of Common Interest. The planned CO_2 storage capacity of the initial phase of Porthos is fully booked by industrial companies in the Port of Rotterdam. However, there might be plans to open up for import of CO_2 via ship in the future.
- **Project Greensand** (www.projectgreensand.com) aims to validate technical and commercial feasibility of permanent CO_2 storage in depleted oil and gas reservoirs in the Danish part of the North Sea, starting with the Nini West Field. The initial injection volume capacity is ½-1 Mt/a of CO_2 from 2025, increasing to 4-8 Mt/a of CO_2 by 2030. In 2020, the project cleared a major

hurdle when DNV GL independently certified that the Nini West field is conceptually suitable for injecting 0.45 Mt/a of CO_2 per well for a 10-year period, and that the subsea reservoir can safely contain the CO_2. The project has three phases: Appraisal, Pilot (Proof of concept) and Full project execution. The first phase has been completed and planning for the Pilot phase is now underway. The project is led by INEOS Energy and has two other commercial partners, Wintershall Dea and Maersk Drilling. GEUS (Geological Survey of Denmark and Greenland) is included as a research partner.

- **Project Bifrost** will evaluate the potential for CO_2 transport and storage at the Harald field in the Danish North Sea with an expected start-up storage capacity of 3 Mt/a of CO_2. The newly formed CCS partnership (including TotalEnergies, Noreco, Norsöfonden, Ørsted and DTU) has applied for funding under the 'Energy Technology Development and Demonstration Programme' (EUDP), a Danish public subsidy scheme, to develop and select the transport and storage concept for Project Bifrost. The project aims to reuse existing North Sea infrastructure while demonstrating CO_2 storage in a depleted offshore gas field. This will be matured towards a final investment decision (FID) if the application for funding and the following development and demonstration program proves successful. The scope of the EUDP application includes a study to qualify the significant potential of utilizing partner North Sea reservoirs as they become available, as well as the possibility to use the existing pipeline infrastructure connecting the partner fields to Denmark. Reusing the pipeline infrastructure to the Danish shore could be a first step to connect to a future European cost and climate efficient CO_2 transportation system.
- **Acorn CCS** is one of the leading UK CCS and hydrogen projects. The project plans to capitalize on existing offshore pipelines and well understood CO_2 storage resources to provide fast and cost-efficient build-up of CO_2 storage capacity in the vicinity of the offshore pipeline corridors at St Fergus off the Northeast coast of Scotland. Acorn has been designated a European Project of Common Interest (PCI).
- **Zero Carbon Humber** brings together international energy producers, major regional industries, leading infrastructure and logistics operators, global engineering firms and academic institutions in a plan to decarbonise the UK's largest industrial region. This will be enabled by shared trans-regional pipelines, for low-carbon hydrogen and captured carbon emissions, creating the world's first net zero industrial cluster by 2040. The Northern Endurance Partnership (NEP) will deliver the onshore and offshore CO_2 infrastructure and store CO_2 from emitters across Teesside and Humber in the Endurance store.
- **New licenses for CO_2 storage on NCS to be awarded spring 2022:** The Norwegian Department of Oil and Energy announced in December 2021 that they have received applications from five companies related to injection and storage on the Norwegian Continental Shelf. The applications relate to areas in the North Sea and in the Barents Sea and the applicants are A/S Norske Shell, Equinor ASA, Horisont Energi AS, Northern Lights JV DA, Vår Energi AS. The decision will be announced during the first half of 2022 (https://www.regjeringen.no/no/aktuelt/fem-soknader-for-lagring-av-co2-pa-sokkelen/id2892304/).

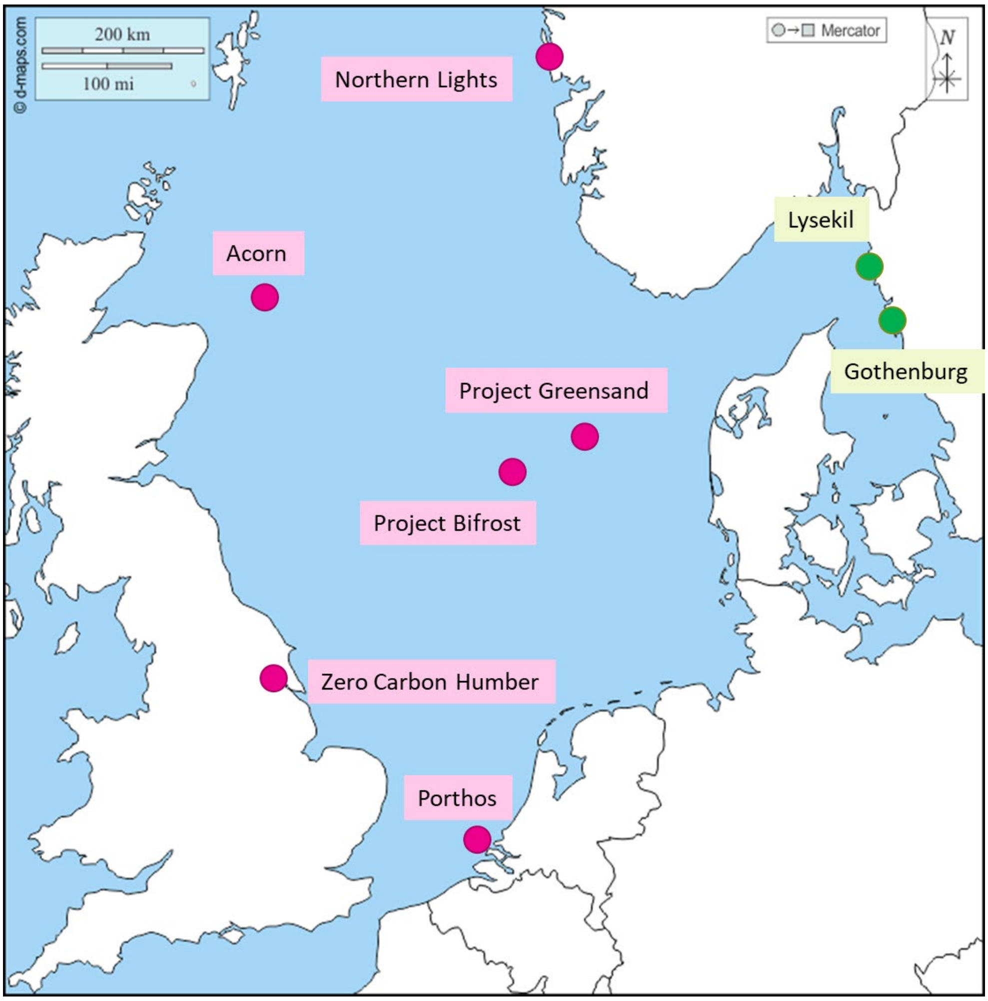


Figure 5 Location of potential permanent CO_2 storage site projects in the North Sea

4.3 Development of common CO_2 infrastructure in Gothenburg

Implementation of economically viable CO_2 capture and storage projects can be facilitated by pooling resources for collecting and storing CO_2 from multiple plants prior to shipping to a permanent storage location. This was the purpose of the CinfraCap project (Carbon Infrastructure Capture), a joint venture involving private and public parties in Gothenburg, namely Preem, St1, Nordion Energi, Renova, the Port of Gothenburg and Göteborg Energi. The project aimed at identifying the conditions required to achieve efficient transport and storage of captured CO_2 in the Gothenburg area and thereby enhance the incentives to realize industrial implementation of CCS.

The Swedish government Inquiry report SOU 2020:4 (Swedish Government, 2020) highlighted CCS as an important part of the pathway towards a climate-positive future for Sweden. The industrial and transportation sectors account for a significant part of Sweden's total fossil CO_2 emissions. A functioning and efficient value chain is required to enable widespread implementation of CCS. The CCS chain considered within CinfraCap involves land transport systems, liquefaction and intermediate storage, as well as a terminal for loading liquid CO_2 onto ships.

A feasibility study was conducted within the CinfraCap project with partial funding provided by the Swedish Energy Agency. The overall goal was to investigate a cost-effective infrastructure for transporting captured CO_2 to a common intermediate storage location in the Port of Gothenburg prior to ship transportation to the final storage infrastructure. The intended infrastructure will also be open and thus available for third-party connection.

The parties, if the right business conditions prevail, intend to start capturing CO_2 in 2025, with a gradual ramp-up to reach a level of 1.856 Mt/a of CO_2 by 2040. This anticipated capture rate ramp-up as well as assumptions about shipping logistics and location of the final storage infrastructure were used as input data for dimensioning the part of the CCS chain that was covered by the feasibility study. The scope of the CinfraCap feasibility study was defined from the battery limit of each party's current facility (where CO_2 capture is intended to take place) to the loading arm in the Port of Gothenburg for the export of CO_2 by ship.

The Energy docks (Energihamnen) located at Skarvik 4 in the Port of Gothenburg was selected as a suitable location for the CO_2-terminal (intermediate storage and possible liquefaction). Transport of CO_2 from the parties' various facilities in Gothenburg to the CO_2 terminal was evaluated in the feasibility study. Based on physical conditions, technical feasibility and capital investment (CAPEX), it was concluded that the most suitable options for such transport are via a pipeline (in either gaseous or liquid state) from Preem, St1 and Göteborg Energi's facilities and by means of a tanker truck (in liquid state only) from Renova's facility.

The CAPEX cost for the given scope was estimated in the feasibility study, and the liquefaction process was identified as a significant cost driver. To evaluate possible synergy gains, two liquefaction concepts were investigated. In Concept A, it was assumed that liquefaction takes place at each individual site whereas. For Concept B, partly joint liquefaction was assumed whereby a common liquefaction plant is located at the CO_2 terminal for liquefaction of CO_2 from the parties Preem, St1 and Göteborg Energi. For Renova, joint pre-liquefaction was not considered to be a feasible alternative due to high technical complexity and CAPEX costs linked to establishment of a piping route through densely populated areas, thus it was assumed that liquefaction of the CO_2 captured at Renova’s facility occurs on-site for both concepts.

The CAPEX was estimated to be approximately SEK 2.8 billion for separate liquefaction (Concept A) and approximately SEK 2.5 billion for partial joint liquefaction (Concept B). The CAPEX estimate applies to fully expanded terminals in 2040 with an accuracy of ± 40%. The results indicate that the total CAPEX investment is lower for partial joint liquefaction. According to the pre-study report (COWI, 2021), the liquefaction plants and the intermediate storage tanks together account for about 30–35% of the total CAPEX for the given scope.

Liquefaction of CO_2 is an energy-intensive process that requires a lot of cooling. The electricity requirement of the system was estimated at 10-16 MW with separate liquefaction requiring 14-38% less electricity than partially common liquefaction. The system is estimated to have a cooling demand of 30-40 MW. Low cooling water temperature, integration with existing cooling water systems and heat recovery are factors that have the potential to reduce operating costs.

Discussions with suppliers also indicated that there is a potential for reducing energy use for the case of separate liquefaction through integration upstream in the value chain. Furthermore, separate liquefaction also has advantages related to operation and maintenance since the parties' ordinary plant staff can to a large extent also be used for the liquefaction plant. In the case of partial joint liquefaction, a completely new operation & maintenance organization needs to be established.

It was concluded that both liquefaction concepts should be retained for more in-depth investigations since the uncertainties are significant and do not allow clear conclusions to be drawn regarding the most cost-effective configuration.

In order to evaluate additional factors that contribute to cost-effectiveness, it was recommended that an extended study evaluates the integration of liquefaction with upstream steps in the CCS value chain. This will enable a holistic perspective on the CCS value chain and thus also reduce sub-optimization effects that can arise with too narrow boundaries.

An implementation plan based on the partly joint liquefaction configuration proposed conducting an extended feasibility study phase starting in Q2 2021 followed by a pre-design phase and detailed design phase targeting start-up of the CO_2-terminal in 2025. Decision hold-points for continued financing of the project are to be taken between phases. One important issue for the project's implementation is the permitting process which can be time-consuming. Furthermore, the development of an appropriate business model is a key factor to ensure cooperation between the parties, operation of the CO_2-terminal final storage of the captured CO_2, and secure financing.

After completion of the feasibility study in Q1 2021, the parties continued their cooperation and committed to engage in a more extended study, CinfraCap Phase 2. This extended study has been granted funding by the Swedish Energy Agency and will take place in 2022.

5 CCS and Bio-CCS – Status of current and planned regulations and incentives with a focus on regulatory challenges

5.1 The London Protocol – the main legal hurdle for trans-boundary CO_2 transport has in principle been resolved

The purpose of the London Protocol (in force since 1975[1]) is to preserve the marine environment from dumping of waste. Article 6 of the London Protocol prohibits a Contracting Party to export waste or other matter to other countries for dumping or incineration at sea. The unintended consequence of this was that export of CO_2 for offshore geological storage became illegal. An amendment of Article 6, allowing transboundary movement of CO_2 for the purposes of geological storage, was adopted in 2009. Both Norway and Sweden have ratified this amendment, but it needs to be ratified by 2/3 of the contracting parties to enter in force.

Since October 2019, the IMO allows for a provisional application of the amended Article 6 until the amendment enters in force. In order to be able to apply this provisional application for export of captured CO_2 from Sweden to Norway, for the purpose of geological storage, both Sweden and Norway must deposit a Unilateral Declaration of their intention to export/import CO_2 in accordance with the amended Article 6. Thereafter, Sweden and Norway must enter a bilateral agreement about export and import of CO_2, which must also be notified to IMO. Thereafter, it will be legal to transport CO_2 from Swedish sites such as the Preem refinery in Lysekil to a provider of sequestration services in Norway, for example the Northern Lights terminal at Øygarden in Norway.

5.2 The EU ETS and ship transport of captured CO_2

Each year, industrial installations that are included in the EU Emission Trading System (EU ETS) must surrender emission allowances equal to the total amount of *fossil* CO_2 emissions from that installation during the preceding calendar year. The EU ETS allows subtracting emissions captured and transported for storage, so that they can be traded and generate an income, and therewith be part of a viable business model for CCS. However, in the EU ETS, CO_2 transport is defined as transport by *pipeline* and it has previously not been clear if CO_2 transported by ship for permanent storage could be covered. A formal request for clarification was submitted by Norway to DG CLIMA in 2019, with the argumentation that "When transfer of CO_2 from a ship or truck to a pipeline network or storage site is completed, the capture installation can subtract the CO_2 from its emissions." The answer from DG CLIMA to Norway was sent in July 2020: "*The capture installation should be allowed to deduct from its emissions any CO_2 intended for the offshore storage facility*". This means that CO_2 emissions from e.g. Preem can be subtracted and traded, once the CO_2 transported by ship reaches e.g. the Northern Lights terminal in Øygarden, Norway. Under the current ETS, Preem would be responsible for CO_2 emissions during the ship transport. In a proposed revision of the ETS, published on 14 July 2021, this is changed: emissions of CO_2 during ship or truck transport will be the responsibility of the ship or truck owner/operator.

With this suggested change, Preem will still not be able to subtract emissions until the CO_2 reaches the Northern Lights terminal, and, furthermore, any CO_2 leakage from a Northern Lights ship during the transport from Preem to Øygarden cannot be subtracted even though it has been captured by Preem. A contractual agreement between Preem and Northern Lights will need to take this into account. It is also observed that accurate fiscal metering along the CCS chain will be very important.

[1] Convention on the Prevention of Marine Pollution by Dumping of Wastes and Other Matter (imo.org)

5.3 Incentives for Bio-CCS

The Swedish Inquiry on a “Strategy for negative greenhouse gas emissions” (SOU 2020:4) concluded that supplementary measures including Bio-CCS will be required to reach the Swedish climate goal of net zero emissions in 2045 and even more so to reach the target of net negative emissions thereafter.

In order to support Swedish Industry in their transformation towards zero GHG emissions, the Swedish Government has set up the program “Industriklivet”. After several extensions, the program had a total budget of SEK 750 million in 2021 of which SEK 100 million were dedicated to investing in technologies leading to negative emissions (Ministry of the Environment 2020, Ministry of Finance 2021).

The Swedish Government has also set up a program for green investment credit guarantees through which the state will promote large industrial investments that contribute to achieving the environmental goals and the climate policy framework. For 2022, the Government proposes to raise the program framework from SEK 15 billion to SEK 50 billion and thereafter to SEK 65 billion in 2023 and SEK 80 billion in 2024 (Ministry of Finance 2021).

In December 2020, the Swedish Energy Agency was commissioned by the government to draft a proposal for an agreement that enables the export of CO_2 from Sweden for long-term geological storage and which ensures that transport and storage takes place in a safe and responsible manner. The assignment includes that the Swedish Energy Agency should draft a proposal for an agreement with Norway that meets the requirements set by the London Protocol (see Section 5.1) and examine conditions for similar agreements with other countries, such as the United Kingdom and the Netherlands. The Swedish Energy Agency was at the same time also appointed National Centre for CCS.

The Swedish Energy Agency was also tasked by the Government to propose a system for the financing of bio-CCS either through reverse auctioning or so-called fixed price storage remuneration. The Energy Agency published its final proposal in November 2021 suggesting reverse auctioning with the first auction taking place in 2022-2023 with actual first storage in 2026, pending on the proposed aid scheme being approved by the EU Commission.

In November 2021, the Swedish Parliament approved the state budget for 2022 put forward by the opposing parties in the Parliament. The state budget for 2022 includes introducing a system for operating support for bio-CCS in the form of reverse auctioning whereby the players who can deliver the service of capturing and storing CO_2 at the lowest cost win the tender. The budget proposes that the Swedish Energy Agency should be provided with funds so that up to 2 Mt/a of CO_2 can be captured and stored. It is also proposed that the Energy Agency should receive an additional funding of SEK 30 billion between the years 2026 and 2046 to support bio-CCS (yielding a total of SEK 36 billion). Also, the budget allocates SEK 5 million per year to the Energy Agency to prepare for an increased use of bio-CCS and to review how CCS in general can be implemented in Sweden (The Swedish Parliament 2021).

As of December 2021, there are no incentives in place for bio-CCS at the EU level. However, the Commission is investigating ways to create such incentives and possible instruments will be investigated in the Commission’s further work on the European Green Deal.

In that regard, the European Commission has announced that they will publish a Communication entitled "Restoring sustainable carbon cycles" during the fourth quarter of 2021[2]. A roadmap for this initiative was published in September 2021 (EC 2021a) in which it is mentioned that "The initiative aims to

[2] The Communication was published December 15th, 2021 after the completion of this report, see EC COM (2021) 800 Final. "Sustainable carbon cycles"

develop a long-term vision for sustainable carbon cycles (including capture, storage, and use of CO_2) in a climate-neutral EU economy and to kick-start the development of technological and nature-based solutions. The Communication will present the long-term role of nature- and technology-based solutions for the capture, storage or use of CO_2 towards an EU economy that first becomes climate neutral and subsequently removes more greenhouse gases than it emits." The roadmap provides a link to another initiative, the "Certification of carbon removals – EU rules" (EC 2021b), in which it is announced that a public consultation is planned for the first quarter of 2022 and the adoption by the Commission by the fourth quarter of 2022. This initiative will propose EU rules for certifying carbon removals, and develop the necessary rules to monitor, report and verify the authenticity of these removals. The aim is to expand sustainable carbon removals and encourage the use of innovative solutions to capture, recycle and store CO_2 by farmers, foresters, and industries.

6 CCS opportunities for oil refineries with state-of-the-art post-combustion carbon capture technology

6.1 Pilot tests at Lysekil with Aker Carbon Capture's Mobile Test Unit

The Mobile Test Unit (MTU) pilot test campaign was conducted by Aker Carbon Capture at the Lysekil refinery between February and December 2020. The equipment arrived on site on February 12, 2020. Unpacking, assemblage, and commissioning was completed by late March but due to the COVID-19 pandemic, operations were not started until May. On May 8, the MTU was charged with 30 %wt. MEA solvent, and on May 14 the MTU started CO_2 removal from the flue gas Preemraff Lysekil's HPU plant. The pilot test campaign included two stages:

- MEA campaign: May 14 – June 17, 2020
- S26 campaign: June 19 – November 2020

The MEA campaign lasted for 508 operating hours and captured 57 tonnes of CO_2. Thereafter the unit was charged with Aker's proprietary S26 advanced amine solvent. The S26 campaign lasted for 3,047 hours during which 363 tonnes of CO_2 were captured.

The MEA campaign operated steadily with flue gas containing two distinct levels of CO_2 content, 18 %vol. and 20 %vol., and obtained a scatter of SRD values. Optimization of the performance was achieved by varying the absorber packing height, stripper pressure, liquid-to-gas ratio, etc. Operations targeted CO_2 capture rates of 90%. Larger capture rates were achieved, at the expense of a higher energy demand for solvent regeneration.

6.1.1 Operating issues

No operating issues occurred during the MTU campaign with MEA. Meanwhile, the only issues experienced during the S26 campaign were:

- One event of carbonate precipitation in the solvent, leading to a pump failure, whilst operating under extreme conditions (very low capture rates and very high amine strength), on July 9, 2020.
- One event of leakage of the stripper overhead condenser water into the dedicated spillage area, the bund, on January 13, 2021. This leakage was fully contained in the bund.

6.1.2 Solvent Performance

6.1.2.1 MEA

During the short MEA campaign, a visible shift in colour from transparent to dark brown was observed in the MEA solvent, indicating solvent degradation. Furthermore, alkalinity measurements showed that MEA losses were 1.1 kg per tonne of CO_2 captured during the 508 hours of operation. A series of amine samples were sent to SINTEF for chemical analyses. Degradation of MEA generated 0.02 mol/kg of heat stable salts, plus non-negligible amounts of 4-(2-hydroxyethyl)piperazin-2-one (HEPO) and N-(2-hydroxyethyl)glycine (HEGly) (1.5 %wt. of these two products). Emissions of ammonia over the absorber stack were overall high, ranging from 20 to 100 ppm as measured by FTIR. The production of ammonia is yet another indication of solvent degradation, as discussed by Kolstad Morken et al (2019). The degradation profile of MEA during the MTU campaign is illustrated in Figure 6 where past emission campaigns using MEA and S26 at TCM's CHP are also presented as reference. Conversely, emissions of MEA were often below detection limits. Since MEA is less volatile than ammonia, MEA emissions are associated with aerosol formation. The low level of MEA emissions indicates the good performance of the Anti-mist™ design.

Finally, the amounts of iron (19.3 mg/l) and chromium (3.29 mg/l) measured at the end of the campaign in the MEA solvent are indicative of corrosive behaviour. It is well known in literature that MEA degradation renders the solvent more corrosive, and that the accumulation of metals in the solvent catalyse solvent degradation, in a snowball effect. The extent of the degradation during the MEA campaign can be seen in Figure 7.

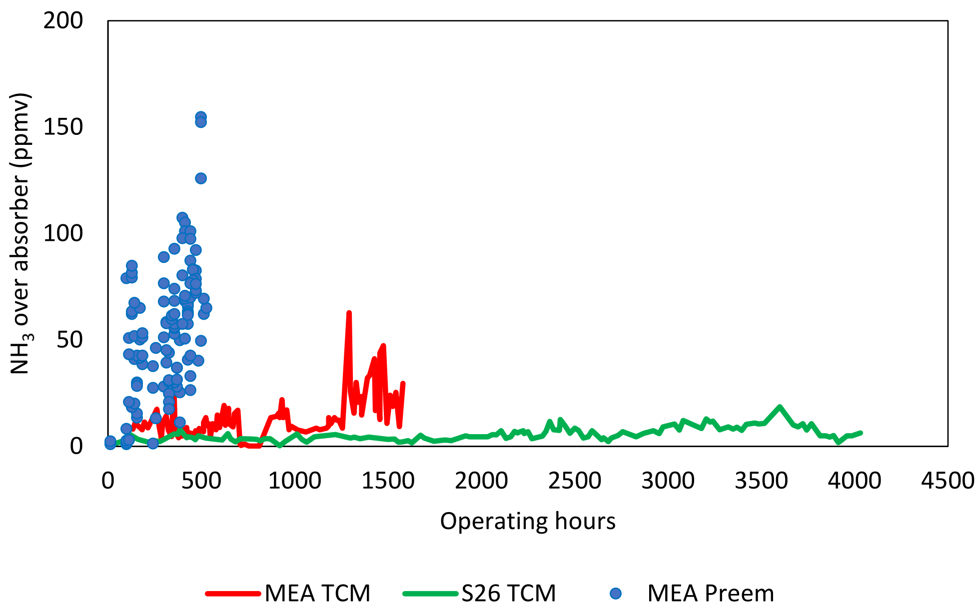


Figure 6: Ammonia emissions during the MEA campaign at Lysekil (dotted point). As a reference, the full lines are extracted from previous campaigns at TCM (see Gorset *et al,* 2014)

Figure 7: MEA solvent colour as a function of operating hours in the Preem CCS MTU campaign. Text in Norwegian ('drift' = 'operation')

6.1.2.2 Aker Carbon Capture S26

The S26 campaigns were subject to a similar performance optimization targeting a series of process variables. Optimal SRD values were identified to be 15–18% below those obtained during the 30 %wt. MEA campaign, indicating a good performance of the S26 solvent. Once again, this campaign mainly focused on 90% capture rates. However, extension of the S26 campaign (not within the scope of this project) veered into higher capture rates, achieving up to 98% CO2 capture. Naturally, these higher capture rates come at the price of higher SRDs.

Solvent losses during the S26 campaign were evaluated both by alkalinity and by direct LC-MS measurements carried out by SINTEF. Amine losses amounted to 0.11 kg/tonne CO_2, one order of magnitude below the losses observed for 30 %wt. MEA. Heat stable salts in the solvent amounted to 0.04 mol/kg – more than the concentration observed in MEA, though it must be kept in mind that the S26 campaign lasted six times longer than the MEA campaign. Ammonia emissions during the S26 campaign were measured by the FTIR as being between 1–2 ppm throughout the campaign, which is more than one order of magnitude below those experienced in the MEA campaign and indicative of low levels of degradation. Furthermore, the solvent did not present any visible discoloration as it aged (see Figure 8).

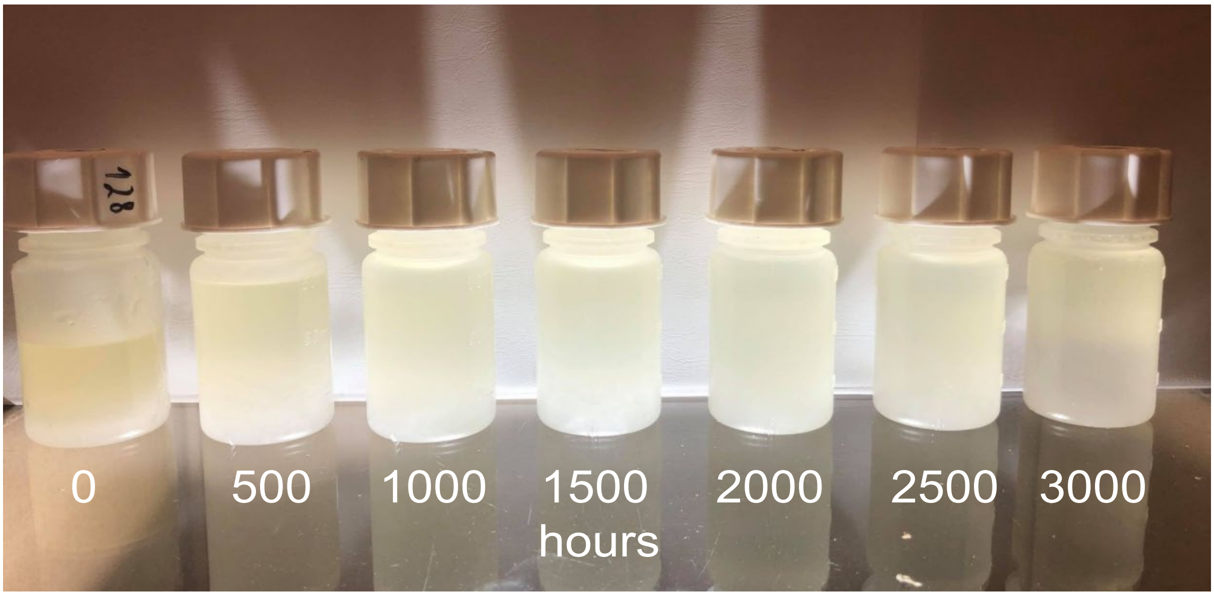


Figure 8: Preem CCS MTU S26 colour development

Other emissions: emissions of amines were below 1 ppm (FTIR measurements) and ranged from 0.1–0.6 mg/Nm^3 via isokinetic sampling. Emissions of nitrosamines and nitramines were below detection limits via isokinetic sampling (0.01 µg/Nm^3). Emissions of aldehydes and ketones measured through dinitrophenylhydrazine (DNPH) cartridges were around 0.7 and 0.4 mg/Nm^3, respectively.

Concentrations of metals in the solvent never exceeded 0.4 mg/l of iron and 0.4 mg/l of chromium during the S26 campaign, whereas concentrations of molybdenum were identified at 0.5 mg/l. These are very low concentrations when compared to those obtained during the MEA campaign, which indicates that the S26 solvent has very little corrosivity.

Measurements were also performed in the CO_2 product stream leaving the desorber overhead condenser. This stream contains mostly CO_2, saturated with water, and encompassing very small concentrations of contaminants. For the S26 campaign, these contaminants were 0.04 mg/Nm^3 of solvent amines, 0.01 mg/Nm^3 of ammonia, 3.3 mg/Nm^3 of aldehydes and 0.25 mg/Nm^3 of ketones. These contaminants will have to be removed downstream of the carbon capture plant for most CO_2 capture applications.

6.2 Techno-economic analysis of CO_2 capture for main emission sources at Lysekil and Gothenburg refineries

6.2.1 CCS chains analysis investigated within the Preem-CCS project

Table 3 summarizes the main characteristics of the six CCS chains evaluated in the Preem-CCS project. For an overview of the main characteristics of all CO_2 emission sources at the Lysekil refinery, see Table 1 in Section 3.3. The flue gas from the hydrogen production unit (HPU) has the highest CO_2 concentration among all stacks and the highest contribution to refinery CO_2 emissions. Capture from the HPU was therefore selected as the base case (Case 1). Cases 2, 3 and 4 consider capturing CO_2 emissions from other existing stacks, in addition to the HPU. Case 5 is an extension of Case 1 and considers a possible integrated CCS value chain, capturing CO_2 emissions from the HPU at Lysekil as well as additional 300 kt/a from the Gothenburg refinery. The transport pressure is 15 barg for all cases, in accordance with the pressure specifications for the Northern Lights project. The effect on CO_2 transport costs of a reduced transport pressure of 7 barg was investigated in Case 1A.

Table 3 CCS chain cases considered in Preem CCS

Case	CO_2 source	Approx. capture (90% of yearly emissions of corresponding stacks) [Mt/a CO_2]	Transport pressure [barg]
Case 1	HPU flue gas (Stack 5)	~0.616	15
Case 1A	HPU flue gas (Stack 5)	~0.616	7
Case 2	HPU+ low sulphur stack (Stacks 5 & 2)	~0.940	15
Case 3	HPU + FCC (Stacks 5 & 3)	~0.799	15
Case 4	HPU + FCC + other major stacks (Stacks 1, 2, 3 & 5)	~1.581	15
Case 5	HPU flue gas in Lysekil and Gothenburg	~0.916	15

6.2.2 Key findings from technical assessment of heat integration opportunities

One of the main aims of the technical assessment in this project was to investigate heat integration opportunities between the refinery and the CO_2 capture and conditioning processes. For this purpose, a detailed analysis of the site energy system was conducted. A total of seven heat sources were identified and categorized into three classes:

1. *residual heat*: using vented steam, heat recovery steam generators, or install a heat collection network to raise steam from process coolers;
2. *existing steam generating capacity*: increasing the load of existing gas-fired steam boilers, switch pump/compressor drives from steam to electric mode;
3. *new boilers*: installing electric or natural gas boilers.

A multi-period optimization was conducted using mixed-integer-linear programming to identify the mix of these heat sources that minimizes heat supply cost or external energy demand (external energy minimization, EEM). Characteristic temporal variations (hour scale) were included into the analysis. More detailed information on the methodology and findings can be found in (Biermann et al., 2021, 2022).

Figures 9a and b show how the mix of heat sources and the resulting heat supply cost vary when minimizing the demand for external energy as a function of increasing steam demand/capture rate. Figure 9c shows the impact of the heat supply on the capture cost (excl. CO_2 conditioning, site buffer storage, loading, and shipping) for varying capture rates. Note that this analysis considers partial capture for all 4 major stacks.

The following was concluded from the heat integration study:

- Heat supply for solvent regeneration is a major cost contributor
- The cost of heat supply increases with site capture rate as the dependence on external energy increases
- The use of residual heat at site could supply ~40% of heat required to capture most of the CO_2 emitted today at the Lysekil refinery.
- The import of external energy leads to higher capture cost, outweighing the economies of scale associated with capturing more CO_2 from other stacks
- The intermittency of residual heat needs to be managed by flexible load-following heat sources, such as gas or electric boilers or sufficiently large heat collection networks. The inclusion of temporal variations instead of using annually averaged values in the analysis led to cost and emission increases of 7-26% and 9-66%, respectively, depending on the share of the intermittent heat sources in the mix.
- The use of residual heat in combination with heat pumps and electric boilers would allow CCS at the Lysekil refinery to operate at minimum external energy and without using additional fossil fuels, thus maximizing CO_2 abatement.
- The use of residual heat minimizes the import of external energy and, thus, saves 29-36% of annual CO_2 capture cost (amine scrubbing; €/t CO_2 avoided) compared to relying on external energy alone when capturing 90% of the emissions from all four major stacks.

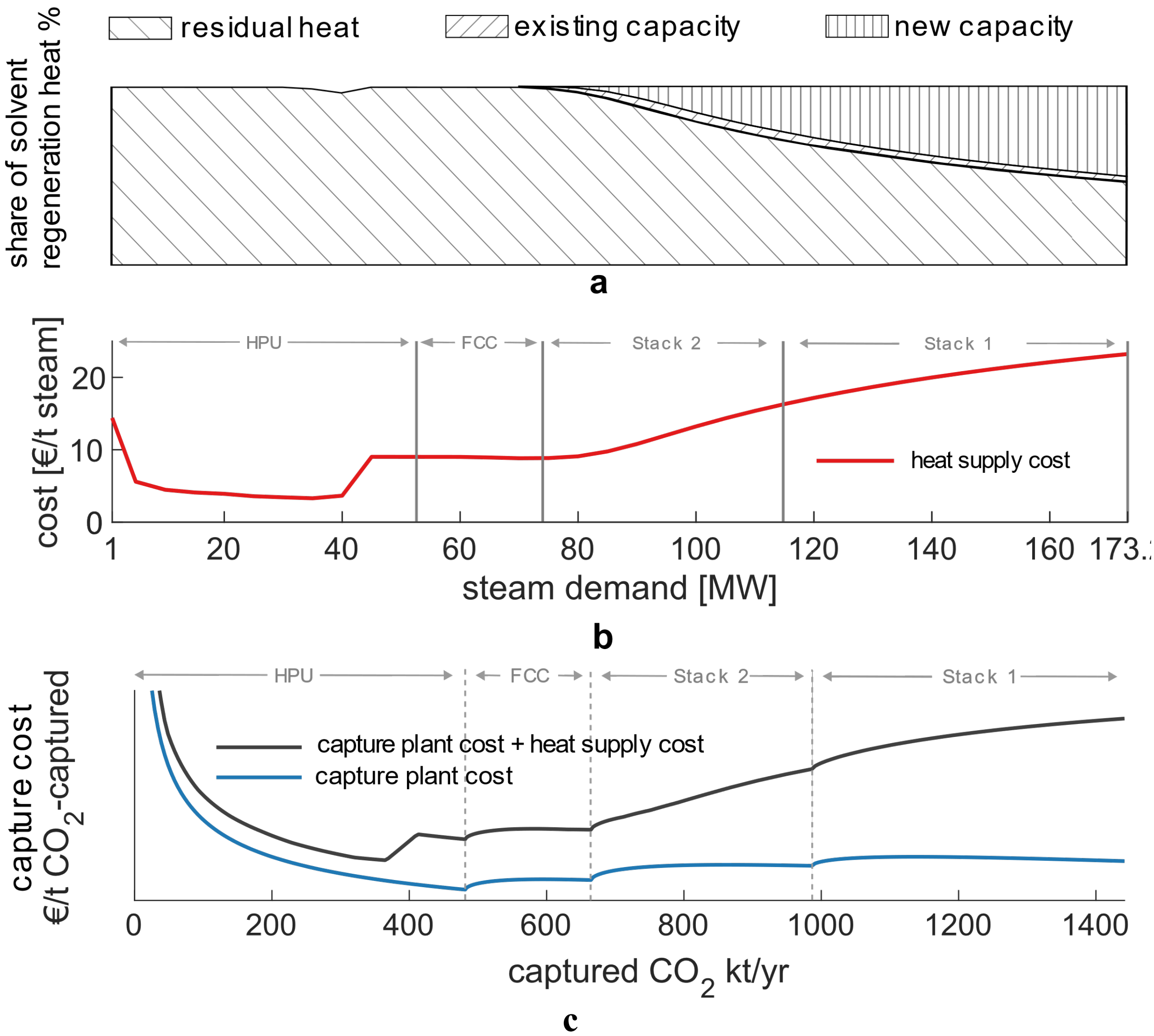


Figure 9: Source of heat for amine solvent regeneration (a), the resulting heat supply cost when minimizing external energy demand (b), and the impact of heat supply cost on the capture cost, i.e., CAPEX & OPEX of the amine capture plant (excluding CO_2 conditioning, site CO_2 buffer and loading, ship transport). The capture plant costs represent one separate capture unit for each stack and follow a rough CAPEX estimate. Adapted from *(Biermann et al., 2022)*.

6.2.3 Modelling and evaluation of AMP-PZ as new benchmark solvent

Another key goal of the technical assessment was to model and evaluate both MEA (monoethanolamine, a widely used benchmark solvent) as well as a recently proposed new benchmark solvent - a blend of AMP (amino-methyl-propanol) and PZ (piperazine) - as solvent for CO_2 absorption (IEAGHG, 2019; Feron *et al.*, 2020). The assessment was conducted for the HPU only (Case 1). Compared to the MEA capture technology, the energy consumption related to CO_2 capture is reported to be reduced by 27% and 16% for a coal-fired ultra-supercritical power plant and a natural-gas-fired combined-cycle, respectively. Correspondingly, the cost of CO_2-avoided is estimated to decrease by 22% and 15%. In addition, the solvent is known to present fewer degradation issues compared to MEA. In this project, process models for both MEA and AMP-PZ were developed and applied using the same design bases and a standard flowsheet without modifications. Table 4 compares the results and key design data for both solvents for the capture from the HPU flue gas (~22 vol.$_{\%wet}$ CO_2 concentration). The innovative solvent PZ+AMP (33 wt% AMP and 12 wt% PZ) shows a ~7% lower SRD of 2.95 MJ/kg CO_2 at slightly lower reboiler temperature (118 °C) compared to MEA. The solvent demonstrates lower liquid-to-gas ratios, which reduces the column diameters. Compared to the reviewed literature, the energy savings identified in the project were not as high. Possible reasons are that modified flowsheets including, e.g., rich-solvent splitting and absorber intercooling, were not considered and that the CO_2 content in the feed stream is different. Also, the level of detail in the reviewed literature was insufficient to enable a detailed validation of the calculated performance.

Table 4 Simulated CO_2 capture performance indicators and design parameters for AMP-PZ (33 wt% AMP + 12 wt% PZ) and 30wt.% MEA. Case 1 conditions (HPU flue gases).

	MEA	AMP-PZ
CO_2 capture rate [%]	90	90
Specific reboiler duty, [MJ/kg_CO_2]	3.16	2.95
Stripper bottom temperature, [°C]	120.4	118.2
Specific power requirement, [MJ/kg_CO_2]	0.18	0.16
Specific solvent makeup, [kg/tonne_CO_2]	2.38	3.74
Specific water makeup, [kg/tonne_CO_2]	311	397
Lean loading, [molCO_2/mol_Solvent]	0.24	0.18
L/G ratio of absorber (Mass basis)	6.95	3.82
Stripper overhead pressure, [bara]	1.9	1.9
Absorber packing height, [m]	18	18
Absorber diameter, [m]	6.3	5.5
Stripper packing height, [m]	9	9
Stripper diameter, [m]	4.3	4

6.2.4 Key findings from the CCS chain analysis

6.2.4.1 CO_2 avoided and cost of CO_2 captured

Figure 10 compares the CO_2 captured and the CO_2 avoided for the cases evaluated for the Lysekil refinery, considering the CCS chain boundaries described in Section 4.1 (Figure 3) and the CCS chain cases described in detail in Section 6.2.1. Steam costs were calculated using the method described in Section 6.2.2, minimizing either costs or external energy demand. It was noted that in most cases, the cost only increases marginally if steam is produced with external energy minimization (using residual heat, heat pumps, and electric boilers), which increases the avoidance of CO_2 emissions. Therefore, the following results consider steam costs when minimizing external energy demand.

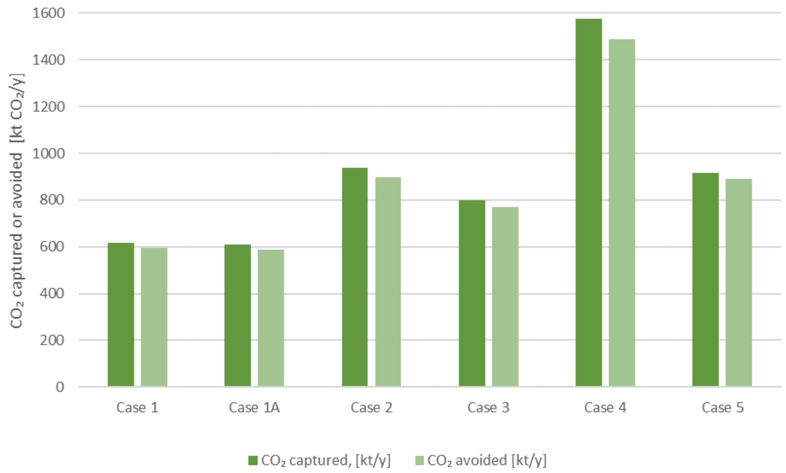


Figure 10 CO_2 captured and CO_2 avoided for all capture cases at the Lysekil refinery, with the value chain boundaries in Figure 3. The steam supply mix minimizes external energy demand.

The CO_2 avoidance cost was used to compare the different cases. This key performance indicator (KPI) captures the average discounted CO_2 emissions charge (tax or other) over the duration of the project that would be required as income (avoided operating costs) to match the net present value of additional capital and operating costs due to investment and operation of the CCS infrastructure (Jakobsen et al., 2017; Roussanaly, 2019). The CO_2 avoidance cost was calculated as follows:

$$CO_2\ avoidance\ cost\ [€2018\ per\ t\ CO_2\ avoided] = \frac{Annualized\ investment + Annual\ OPEX}{Annual\ amount\ of\ CO_2\ avoided}$$

Figure 11 summarizes the cost of CO_2 avoidance for each of the cases at the Lysekil refinery. As expected, the lowest cost is achieved in Case 1A, which benefits from the lower cost of buffer storage and shipping due to the reduced transport pressure. Cases 1 and 1A also benefit from the high CO_2 concentration in the HPU flue gas.

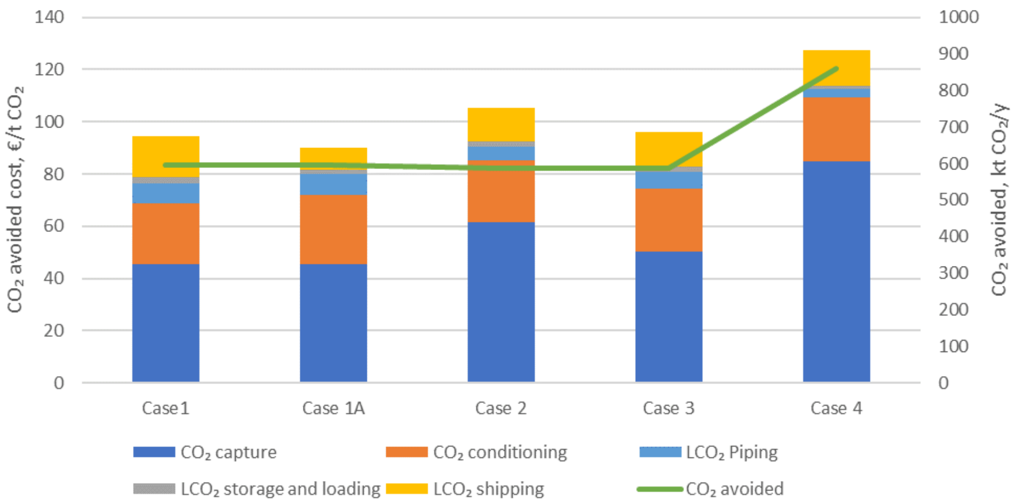


Figure 11 CO_2 avoided and cost of CO_2 avoidance for the value chain boundaries described in Figure 3, which do not include final storage costs.

There are several factors that increase the cost of CO_2 avoidance for Case 4, which has the largest cost of CO_2 avoided, especially in the capture section. The larger investment and operating costs compared to other cases are not compensated by having the largest amount of CO_2 avoided. This is because Case 4 has the highest level of emissions associated with meeting the increased steam demand. Case 4 is the only case which includes the stack with the largest flue gas flow rate, but a relatively low CO_2 concentration, which increases capture costs. Both Cases 2 and 3 capture CO_2 from the HPU and one additional stack. However, the CO_2 avoidance cost of Case 3 is lower than for Case 2, due to the higher CO_2 concentration of the flue gas stream in Case 2, which reduces costs. In addition, costs for the deSO$_x$ unit required in Case 3 are not included and adding these costs will further increase the CO_2 avoidance cost. Moreover, Case 2 is characterized by higher CO_2 emissions and costs associated with steam generation compared to Case 3.

The results from this work are site-specific in terms of cost of steam and associated emissions. Also, the steam cost includes the investment costs which are dependent on the capacity needed. For the cases with a lower steam demand (e.g. Case 1), the demand can be met by on-site heat recovery, while for the cases with a larger demand (e.g. Case 4), additional investments and energy supply are required, as shown in Figure 12. For Case 4, which has the highest steam demand, highest steam cost, and highest associated emissions, it is clear that the heat supply cost for solvent regeneration represents a higher fraction of the total cost compared to Case1 and it even is the largest cost contributor of all value-chain cost components in Case 4.

To summarize, the CCS chain costs (CO_2 capture, conditioning, liquid CO_2 piping, buffer storage, loading and shipping) were in the range of 94 – 128 €/t CO_2/avoided, depending on the CO_2 sources and, thus, the amount of CO_2 captured. To give an indicative range for the full chain cost including the reception of CO_2 at the Northern Lights terminal in Kollsnes and subsequent permanent storage, the on-site cost determined for Lysekil (as above excl. shipping) are added to the range of shipping and storage cost expected in Year 2030 as communicated by Northern Lights, i.e. 30-55 €/t CO_2 (Aasen and Sandberg, 2020). The indicative full chain cost would be around 109-134 €/t CO_2 avoided and 144-169 €/t CO_2 avoided for combined shipping and storage cost of 30 and 55 €/t CO_2, respectively.

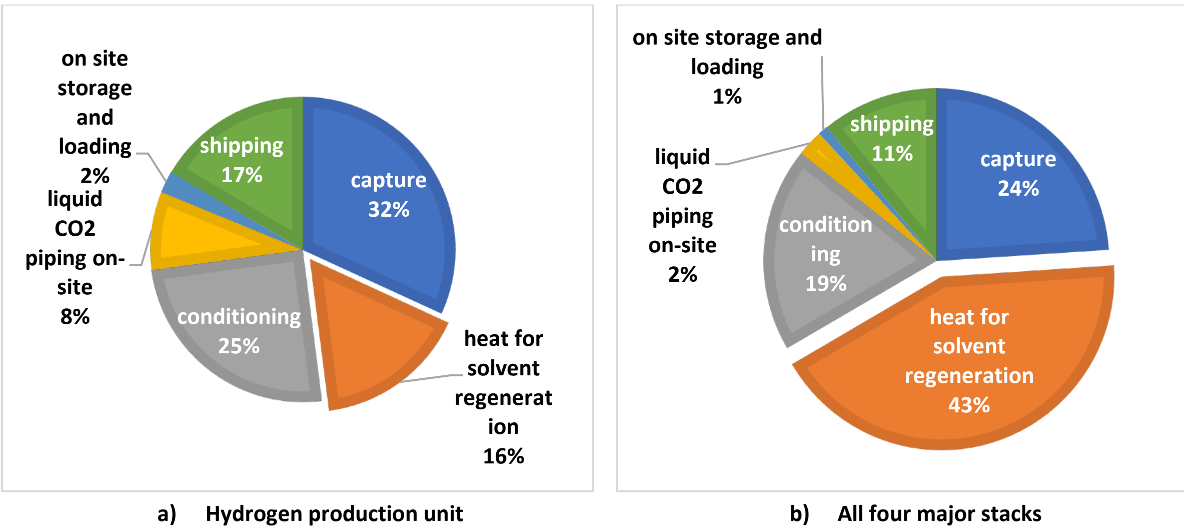


Figure 12: Breakdown of CCS chain costs for Case 1, CO_2 capture from the hydrogen production unit (a), and Case 4, CO_2 capture from all four major stacks (b) with a heat supply that minimizes external energy demand (EEM). Permanent storage costs not included.

6.2.4.2 Effect of CO_2 transport pressure on total capture costs

Case 1A investigated the effect of reducing the CO_2 transport pressure from 15 barg (Northern Lights specification) to 7 barg. Figure 13 compares the CO_2 transport cost for Cases 1 and 1A, for the same amount of liquid CO_2 transported. The reduced pressure enables a transport cost reduction of 44%. The main contributors to the cost reduction are the capital costs and the fixed operating costs of the ships.

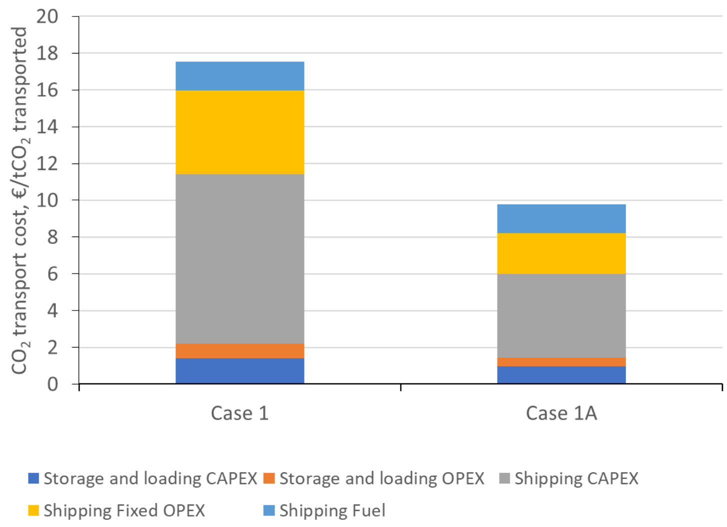


Figure 13 Effect of pressure on CO_2 transport cost. Case 1: CO_2 transport at 15 barg; Case 1A: CO_2 transport at 7 barg.

Potential transport cost synergy gains related to capturing and transporting CO_2 from the Gothenburg refinery can be read from Figure 14 (transport pressure: 15 barg in all cases). Case 5 considers capturing and transporting CO_2 from the HPU in Lysekil (Case 1) plus an additional 300 kt/a CO_2 from the Gothenburg refinery. The specific CO_2 transport cost is reduced by 10% for Case 5, even though the amount of CO_2 transported, the ship size and the transport distance are larger.

However, this specific cost reduction is not observed if larger amounts of CO_2 are transported from Lysekil. The specific transport costs for Case 5 are slightly higher than for the rest of the cases capturing from the Lysekil refinery only, with similar volumes of CO_2 transported for cases 2, 3 and 5. This can be explained by the fact that collecting CO_2 at both refineries increases the shipping distance as well as the idle time at harbours.

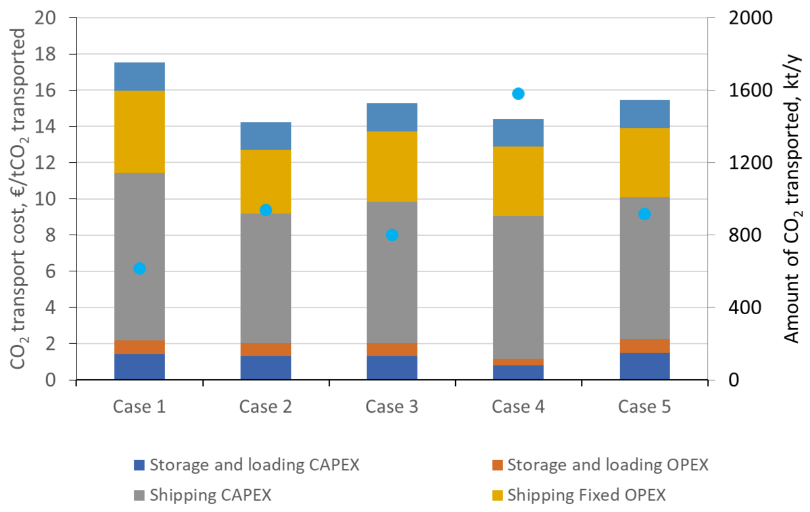


Figure 14 CO_2 transport costs. Cases 1-4: capture from Lysekil refinery only. Case 5: capture from HPU at Lysekil + an additional 300 kt/a CO_2 from the Gothenburg refinery

6.3 Possible pathways for implementation of CCS at the Lysekil refinery.

This section describes possible pathways for CCS implementation at the Lysekil refinery with the target of full capture, i.e. 90% capture from all four major stacks. The aim is both to quantify cost and emissions impacts for selected pathways considering a possible timeline and the context of EU ETS and carbon prices. Furthermore, the potential impact of implementation of CCS at the Lysekil refinery is discussed in the context of Northern Lights and the Swedish national emission targets. Finally, a roadmap for possible implementation of CCS at the Lysekil site is discussed for selected pathways.

6.3.1 Pathways to full capture at Lysekil and their marginal abatement cost

Table 5 proposes a ranking of the CO_2 sources at the Lysekil refinery. CO_2 capture from HPU flue gases (Stack 5) is the most preferable source since it combines a large CO_2 amount, low levels of impurities, a high CO_2 concentration, and thus, a low capture energy demand and resulting low cost. Capture from either the FCC (Stack 3) or Stack 2 are ranked in second position. The FCC outperforms the Stack 2 with respect to SRD, however, it will likely require a deSOx treatment prior to the capture of CO_2 to minimize solvent degradation. Stack 1 contain large amounts of CO_2, however, it has high levels of impurities and is therefore ranked lower than Stack 2 which has a similar SRD and CO_2 concentration.

Based on this CO_2 source ranking, three pathways (PW1-3) to reach full capture were compared to map the implications of: (1) implementing CCS in one or two phases, and (2) forward planning, i.e. planning, dimensioning, and construction of some units for full capture (see Table 6) already in phase 1:

- Pathway 1 (PW1): CCS implementation in two phases *with* forward planning: first HPU, then all other stacks
- Pathway 2 (PW2): CCS implementation in two phases *without* forward planning: first HPU, then all other stacks.
- Pathway 3 (PW3): CCS implementation in a single phase: capture from all four major stacks (Case 4)

Table 5: CO_2 sources at Lysekil refinery ranked individually according to emissions, CO_2 concentration, SOx impurities, modelled heat demand with MEA, and CCS cost.

CO_2 sources ranked		kt/a CO_2 emitted	CO_2 conc. vol.%$_{wet}$	SO_2 average (range) Vol ppm.	SRD - Specific reboiler duty (MEA) MJ/kg CO_2
1.	**HPU flue gas (STK-5)**	685[a]	18-23	1.8 (0-1.9)	3.16
2./3.	**FCC (STK-3)**	203	13	16.1 (11.2-37.4)	3.25
2./3.	**Combined stack 2 (STK-2)**	360	7	3.3 (1.1-15.8)	3.46
4.	**Combined stack 1 (STK-1)**	509	7	25.1 (4.4-218)	3.45

[a] assuming an increase in future hydrogen production; today's levels are ~535 kt/a CO_2

Table 6 summarizes these pathways and the details on the phase-wise implementation of units at the site. The following aspects were considered when defining the pathways:

- The target year for net-zero emissions communicated by Preem is 2035, and a three or four step implementation over a 12 year period is highly unlikely.
- Stacks 3 (FCC) and 2 are relatively small sources of CO_2, thus CO_2 capture for these stacks should preferably be implemented in combination with other stacks
- Stacks 3 (FCC) and 1 will both likely require DeSOx treatment prior to CO_2 capture, thus, a simultaneous implementation is rational to avoid building two DeSOx units.
- CO_2 conditioning units should preferably be designed to match operating scale to avoid compression efficiencies (operation below nominal design flow requires energy inefficient recirculating of CO_2 to avoid surge). Furthermore, the cost of conditioning units scales approximately linearly with respect to capacity
- Common desorber sections should be implemented whenever possible
- Buffer storage tanks should be adopted when needed (including modularization beyond a certain size)
- Full scale loading should be possible to implement from the beginning
- Liquid CO_2 piping can be critical and should not be over-dimensioned, due to the risk of evaporation caused by pressure drop.

Table 6: Overview of CCS implementation pathway scenarios at the Lysekil refinery

Pathway		CO_2 capture units	
		Phase 1	**Phase 2**
PW1	**Two phases with forward planning**	**Dimensioned for phase 1 (STK 5):** - Capture unit 1: 1 absorber/desorber - CO_2 conditioning unit - CO_2 buffer storage - Liquid CO_2 piping (including rack) **Dimensioned for phase 2:** - Ship - Loading facility - Heat supply: heat collection network	**Dimensioned for phase 2 (STK 1, 2 &3):** - Capture unit 2: 2 absorbers (STK1 & STK3) + STK2, 1 common desorber - CO_2 conditioning unit - Liquid CO_2 piping (additional piping – rack already in place) - CO_2 buffer storage - Second ship - Heat supply: electric boilers
PW2	**Two phases without forward planning**	**Dimensioned for phase 1 (STK 5):** - Capture unit 1: 1 absorber/desorber - CO_2 conditioning unit - CO_2 buffer storage - Ship - Loading facility - Liquid CO_2 piping (including rack) - Heat supply: heat collection network	**Dimensioned for phase 2 (STK 1, 2 &3):** - Capture unit: 2 absorbers: (STK1+ STK3) + STK2; 1 common desorber - CO_2 conditioning unit - CO_2 buffer storage - Second large ship - Loading facility - Liquid CO_2 piping (additional piping – rack already in place) - heat supply: additional electric boilers
PW3	**Single phase**	• 3 absorbers: STK5, STK2, (STK1+STK3) • 1 common desorber • 1 CO_2 conditioning unit • CO_2 buffer storage • 2 similar sized ships • Loading facility • Liquid CO_2 piping • Heat supply: heat collection network and electric boilers	

Figure 15 shows the marginal abatement cost curve for the three pathways and for Case 1 (capture from the HPU (Stack 5) only). For pathway PW1, the implementation of phase 1 equipment under consideration of a second phase (forward planning) costs approximately 2 € per tonne CO_2 avoided with that equipment over 25 years, compared to not planning for phase 2. This is due to the installation of a larger heat collection network (heat integration), investment in a larger first ship, and the design of the loading facility in phase 1 (see Table 6). These early investments pay off in phase 2, where forward planning of phase 2 leads to a marginal abatement cost that is ~3 €/t CO_2 avoided lower compared to no forward planning (see PW2). This is because the unforeseen implementation of phase 2 requires a replacement or debottlenecking of the loading facility and a larger second ship due to the larger amount of CO_2 being handled. Also, the invested heat collection network in phase 1 with no forward planning is too small, triggering an investment in electric boilers in phase 2, which both increases the capture cost and decreases the amount of CO_2 avoided. Note that additional liquid CO_2 piping only causes small additional cost since the pipe-racks installed in phase 1 can likely be reused. Averaged over both phases, the two-phase implementation leads to avoidance cost of 128 €/t CO_2-avoided and 129 €/t CO_2-avoided for PW1 and PW3, respectively, compared to 126 €/t-CO_2 avoided for the single-phase implementation.

If a two-phase implementation is desirable, the choice of planning strategy (PW1 or PW2) will further depend on the time span between the implementation of the two phases. This was assessed calculating the net present value (NPV) of both pathways over a 25-year period with an 8% discount rate for a time difference *t* between the implementation of phases of 3-10 years. The difference in NPV between PW1 and PW2 as a function of *t* is shown in Figure 16. For $t < 5$ years, the difference in NPV is negative, i.e. the planning strategy which includes forward planning (PW1) is preferable. The benefit for the CO_2 avoidance cost in phase 2 from the early planning in phase 1 would be small, in the range of 0 - 0.3 €/t CO_2 (for $t = 3$-5 years). To conclude, given the underlying assumptions (see Table 6), forward planning for a time delay between phase 1 and 2 that exceeds 5 years does not pay off from an NPV perspective.

Aside from cost impact, the impact on cumulative emissions over a 25-year period are worthwhile comparing for a two-phase and a single-phase implementation, as shown in Figure 17. Cumulative avoided emissions for a single-phase implementation are ~37 Mt CO_2, whereas two-phase implementation leads to a lower cumulative abatement (28-34 Mt CO_2) assuming a 3-10 year time lag between phases 1 and 2. Note that the avoidance cost shown on the secondary ordinate in the figure are not reduced as much by the two-phase implementation and remain above 120 €/t CO_2 avoided. Not shown are the cumulative emissions of a single-phase implementation of CO_2 capture from the HPU only, which are significantly lower (by 15 Mt CO_2) over a 25-year period although achieved at a lower avoidance cost (94 €/t CO_2 avoided). From a climate mitigation perspective, the single-phase implementation of CO_2 capture from all major stacks is most preferable.

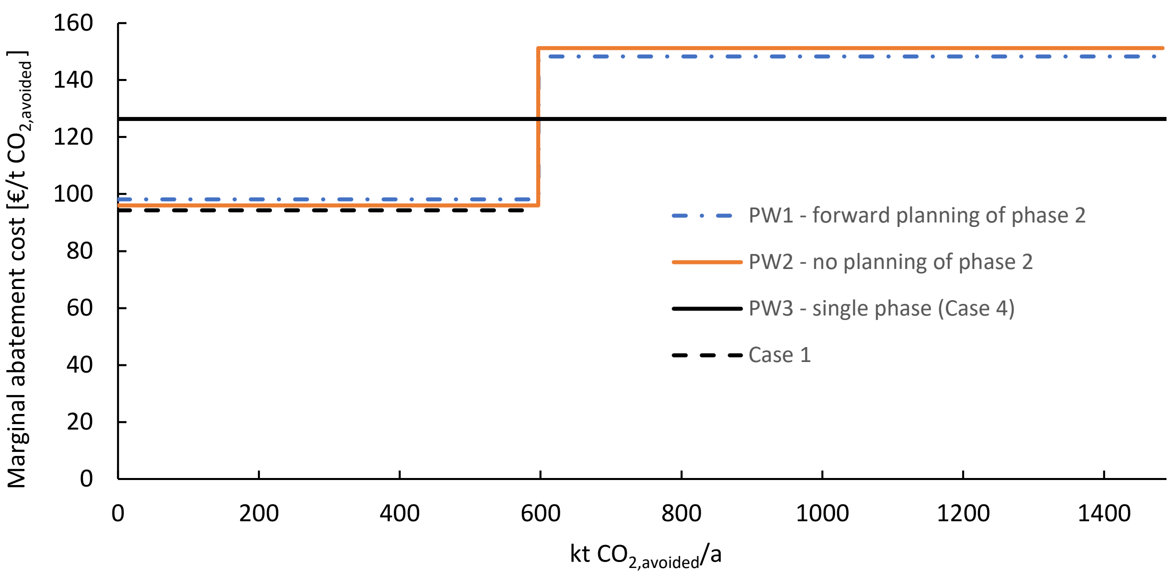


Figure 15: Marginal abatement cost curve for the three pathways (capture from all four major stacks) and Case 1 (capture from the HPU only (Stack 5))

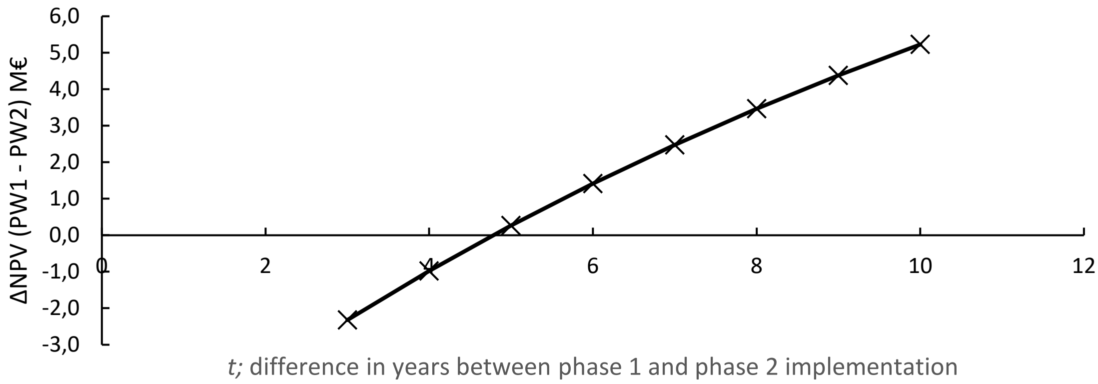


Figure 16: Difference in net present value (NPV) between Pathway 1 (forward planning) and Pathway 2 (no forward planning) depending on the time delay between the implementation of Phases 1 and 2. Assumptions: 25 year period, 8% discount rate, capital expenditures are paid the year before operation.

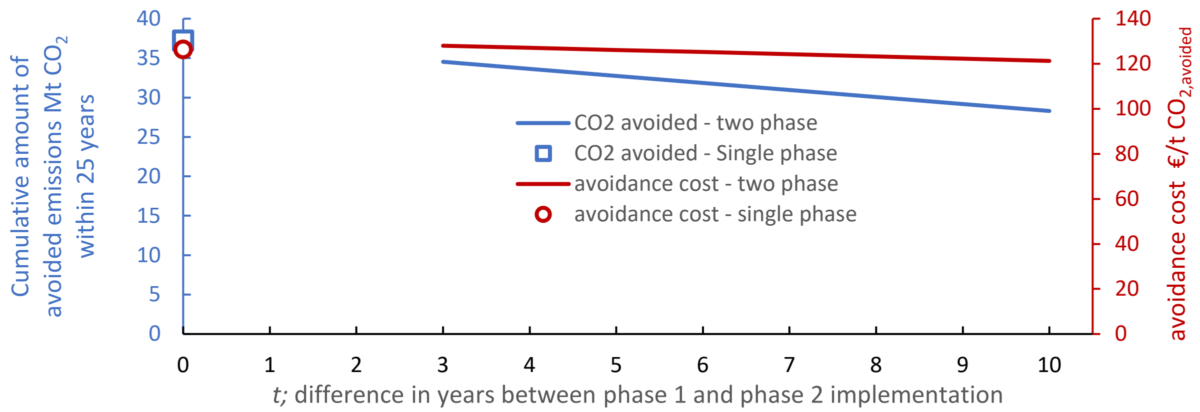


Figure 17: Cumulative emissions (blue ordinate to the left) and avoidance cost (red ordinate to the right) for a two-phase implementation depending on the time difference between the implementation of Phases 1 and 2, as well as for a single-phase implementation.

6.3.2 The potential impact of Preem CCS in the context of Northern Lights

This section presents the potential impact of the implementation of the value chain alternatives proposed within Preem CCS, both within the Northern Lights Project and within Sweden. This section presents updated results based on selected results from Reyes-Lúa *et al.* (2021).

Potential impact of Preem CCS within the Northern Lights Project

Figure 18 compares the CO_2 that could potentially be captured in the different Preem CCS cases with the CO_2 to be captured in the Norcem Brevik and Fortum Oslo Värme (FOV) facilities considered in the Longship project (Norwegian Ministry of Petroleum and Energy, 2020; Regjeringen (Norwegian Government), 2020).

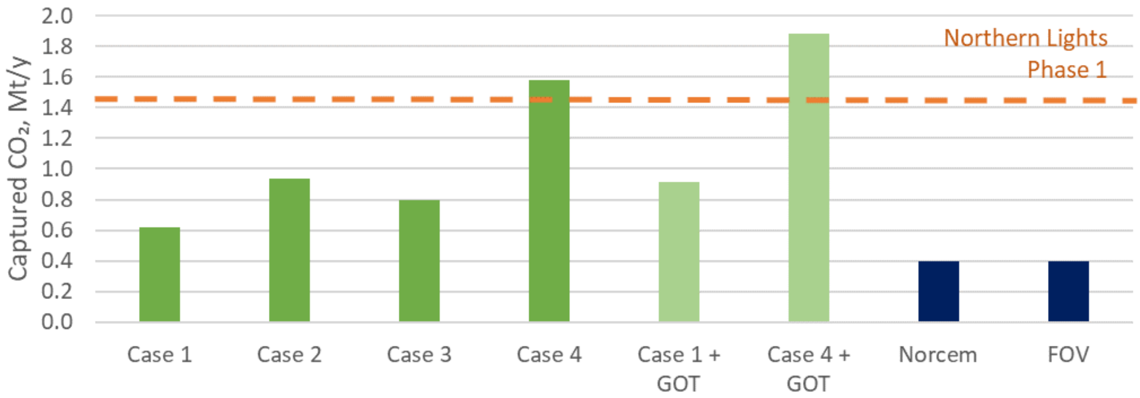


Figure 18 Potential amounts of CO_2 that could be captured in the different Preem CCS project cases compared to amounts to be captured in the Norcem and Fortum Oslo Varme (FOV) plants (Longship Project).

All cases evaluated within the Preem CCS project consider a larger amount of CO_2 captured than the CO_2 captured (individually) at the facilities included in the Longship project. Case 1, capturing ~616 kt/a CO_2, corresponds to ~90% of the CO_2 in the flue gas from the HPU at the Lysekil refinery, and has the lowest CO_2 capture potential among all the possible alternatives considered within the Preem CCS project. This amount of CO_2 is nonetheless higher than the expected 400 kt/a CO_2 to be captured at either the Norcem Brevik or Fortum Oslo Varme (FOV) facilities. The capture potential of Case 2 and Case 1+GOT (i.e. full capture of CO_2 from the Lysekil HPU plus an additional 300 kt/a from the Gothenburg refinery) both correspond approximately to the combined CO_2 capture quantities of the two Longship facilities. Note that if Case 2 or Case1+GOT were realized, the excess capacity of the first phase of the Northern Lights project would be exceeded, assuming that the FOV project is implemented. Case 4, capturing from all major refinery stacks in Lysekil, and Case 4 + GOT (not investigated in detail in the project) both have the potential to capture more than the first phase of the Northern Lights project, which implies that they would need to be implemented in the second phase of the Northern Lights project. Therefore, Preem could potentially be the anchor supplier that could trigger the expansion to 5 Mt/a storage capacity of the Northern Lights project (Equinor ASA, 2019). Figure 18 also shows the cases in which an additional 300 kt CO_2/y are captured from the refinery in Gothenburg. Capture from the HPU in Lysekil (Case 1) and additional capture from Gothenburg corresponds to Case 5 in the Preem CCS project. Capture from all major stacks in Lysekil and additional capture from Gothenburg (Case 4 + GOT) was not analysed within the Preem CCS project. As with Case 4, this alternative would also trigger the expansion to the second phase of the Northern Lights project.

The impact of scale

The specific costs of the Norwegian full-scale project are relatively high compared with estimated costs for other future developed full-scale capture sites and value chains. This is due to the inherent overcapacity of the Norwegian project and cost reductions can be expected in the future for several reasons. The cost per ton of CO_2 is expected to decrease significantly when the value chain capacity is fully utilized, i.e. increased from 0.8 to 5 Mt/a CO_2. Contracting third party volumes is therefore regarded as a key driver for more affordable CCS for all Northern Light partners (Gassnova SF, 2019). As the quantities of CO_2 to be captured from the Preem refineries are higher than the CO_2 captured from the facilities included in the Longship project, the cost per ton for Preem's CO_2 can be expected to be lower than the initial specific cost for the Longship project facilities. This will also reduce the average unitary costs, which might be especially beneficial for small emitters (Roussanaly *et al.*, 2021), which may also use the Northern Lights facilities.

It should also be noted that CO_2 would be captured (at least partly) from flue gas from refinery HPU units and the cost of capture from processes for hydrogen production from fossil methane is expected to be lower than the cost of capture from cement and waste to energy plants (Gassnova SF, 2019), further contributing to reducing the cost per ton for Preem's CO_2 compared to other CCS projects.

Potential impact of Preem CCS for achieving Sweden's climate goals

In 2017, Sweden announced the goal of reaching net zero greenhouse gas emissions by 2045 at the latest and passed a new Climate Act legally binding this commitment (Ministry of the Environment, 2017; United Nations Climate Change, 2017). This target responds directly to the United Nations' sustainable development goal (SDG) 13, which is to "take urgent action to combat climate change and its impacts" (UN, 2017).

In 2018, the total CO_2 emissions in Sweden were ~41.8 Mt (Friedlingstein *et al.*, 2020), of which ~16.4 Mt corresponded to the industrial sector (Statistics Sweden (SCB), 2020). Together, Preem's two refineries in Gothenburg and Lysekil account for approximately 80% of the Swedish refinery capacity, with on-site CO_2 emissions on the order of 2 Mt/a. Figure 19 depicts total fossil CO_2 emissions in Sweden including Preem's contribution to emissions from the industrial sector.

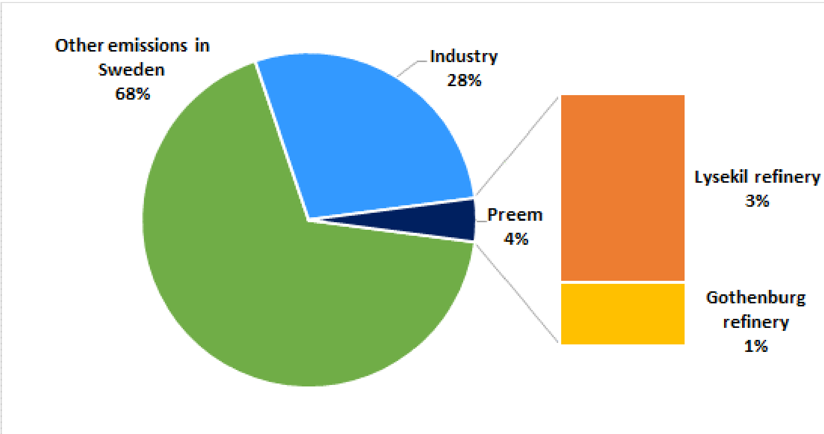


Figure 19: Contribution of Preem's CO_2 emissions to total fossil emissions in Sweden in 2018.

Reducing CO_2 emissions from Preem's two refineries will be a major enabler to reach Sweden's climate goals. It should be noted that the amount of CO_2 captured will depend on the selection of capture case(s) to be implemented. Preem also plans to rapidly ramp up its production of advanced biofuels at their refineries in Lysekil and Gothenburg. This will create a clear opportunity for Bio-CCS with *negative* CO_2 emissions as more renewable feedstock is processed at the two refinery sites, which will enable Preem to reach its climate neutrality goal for 2035 (Preem, 2019, 2021). This will also contribute to reaching Sweden's goal for net zero emissions by 2045.

6.3.3 Roadmap and the window of opportunity

In order to sketch a possible timeline for the implementation of CCS at the Lysekil refinery, and possibly also at the Gothenburg refinery, the following assumptions regarding project time duration from initial planning to operation were made:

- Feasibility study ~12 months (Gassnova SF, 2020)
- Front-end engineering and design (FEED) study ~ 8 months
- EPC including 3 months commissioning ~ 36 months

Assuming initiation of the feasibility study in early 2022, this would imply a start of operation at the end of 2026/beginning of 2027. If the project is implemented in two phases, the second phase is assumed to come into operation in the year 2035 when Preem intends to be climate neutral. Figure 20 shows a timeline for a single-phase implementation (Pathway PW3, i.e. Case 4) and for a two-phase implementation (Pathway PW2) in the context of historic EU ETS prices and a span of carbon price scenarios taken from the World Energy Outlook 2021 (IEA, 2021). Based on an NPV-perspective of 25 years and an 8% discount rate, the avoidance costs of PW3 and PW2 are 126 and 122 €/t CO_2 avoided, respectively, and the cumulative avoided emissions are 37 and 31 Mt CO_2, respectively. Although EU ETS prices have recently experienced a steep price increase to around 80 €/t CO_2, a gap to break-even with CCS cost for the Lysekil site may remain. Funding mechanisms, e.g., in the form of carbon contract for difference, may be needed to cover initial cost. The figure also shows that if the pledges made by governments on net zero targets are fulfilled, carbon prices above the Lysekil PW2 or PW3 cost estimates are not unlikely. Also, carbon taxes may be raised, see for instance plans in Norway to raise taxes to 200 €/tCO_2 (Bellona, 2021). Thus, there is a risk of exposure to increased taxes and/or EU ETS prices for emissions not mitigated by CCS. This risk could be mitigated by choosing a single-phase implementation that maximizes the CO_2 abatement (PW3) early on.

Apart from cost and cumulative emissions, the choice of a two-phase implementation or a single-phase implementation needs to consider the timeline of the prospective storage site Northern Lights which plans to start operation in 2024, i.e. three years earlier than capture at Preem's refineries under the assumptions above. It is possible that no other 3rd party to Northern Lights will fill the remaining 0.7 Mt/a CO_2 capacity before 2027, which would allow Preem to supply the captured emissions from the HPU (~0.6 Mt/a CO_2). However, if phase 1 of Northern Lights is complete by the time Preem wants to implement CCS, large volumes of contracted CO_2 storage will be required to trigger the second phase. This could be accomplished by one or several 3rd Parties to Northern Lights or by Preem alone through a single-phase implementation at the Lysekil refinery that captures from all stacks (PW3). Thus, the window of opportunity for a swift CCS implementation at Preem depends fundamentally on the communication, planning, and agreement with the transport storage partner.

Finally, it is important to stress that CCS can play an important but limited role in achieving Preem's goal of climate neutrality by 2035. In 2018, Preem's value chain greenhouse gas emissions, including upstream and downstream emissions, were ~60 Mt/a $CO_{2,eq}$, of which only about 3.6% were related to direct emissions from refinery operations (Preem 2021,b). Only the latter can be mitigated by CCS or via electrification. Most emissions come from product use (combustion) downstream of the refinery (~83%), which can be mitigated by introducing biogenic feedstock as replacement for crude oil, decreasing the production rate, and verifiable off-setting mechanisms such as geological sequestration. The latter would imply the purchase of fossil feedstock whose emissions have been compensated for by the upstream vendor. For example, Equinor has announced its ambition to become a net-zero company including its scope 3 emissions (Equinor, 2020). These mitigation pathways and their interplay with CCS require further study (e.g. the potential for Bio-CCS and the interaction with the Swedish emission reduction obligation for petrol and diesel fuels which creates a clear requirement for ramp-up of biofuels). Such studies should be coordinated with other research projects related to future development of Preem's operations, such as the ongoing FUTNERC project ("Transformative change towards net negative emissions in Swedish refinery and petrochemical industries", project P49831, with funding provided by the Swedish Energy Agency, Preem and Borealis).

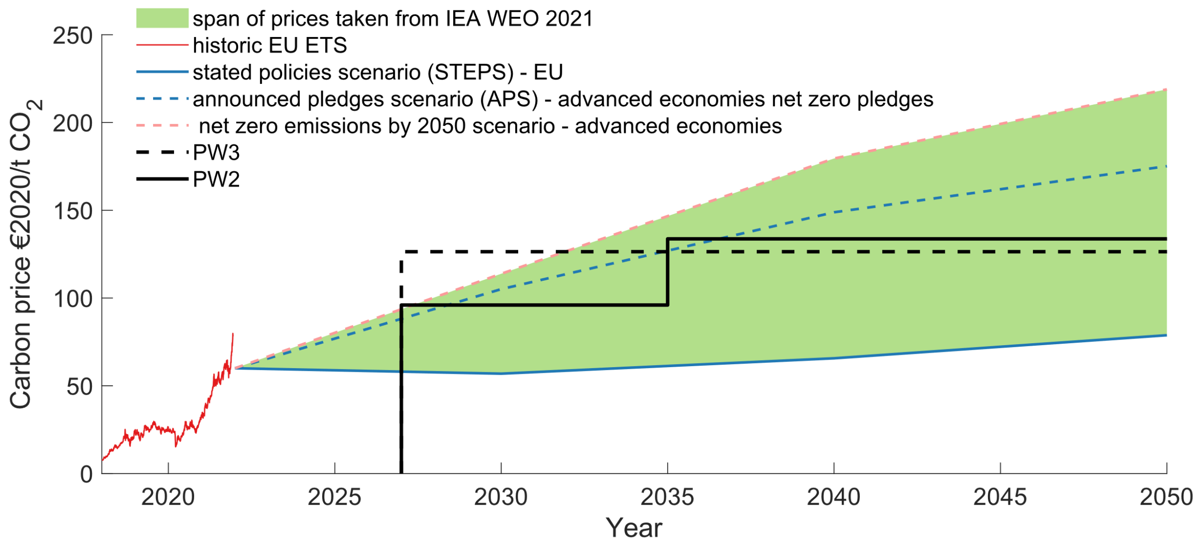


Figure 20: Comparison of a single-phase CCS implementation (PW3) and a two-phase CCS implementation (PW2) starting in Year 2027 with historic EU ETS prices and a span of scenario prices taken from the IEA's World Energy Outlook (WEO) 2021. The Stated Policies Scenario (STEPS) "does not take for granted that governments will reach all announced goals. Instead, the STEPS explores where the energy system might go without additional policy implementation". The Announced Pledges Scenario (APS) "takes account of all of the climate commitments made by governments around the world, including Nationally Determined Contributions as well as longer term net zero targets, and assumes that they will be met in full and on time." The net zero emissions by 2050 scenario "shows a narrow but achievable pathway for the global energy sector to achieve net zero CO2 emissions by 2050, with advanced economies reaching net zero emissions in advance of others". *(IEA, 2021)*

6.4 Inventory of potential risks and operability issues along the CCS chain

This section presents a non-exhaustive list of potential risks and operability issues associated with implementation of CCS at Preem's refineries in Lysekil and Gothenburg. It should be seen as input to a detailed risk assessment.

Strategy/Financing/Business model:

- Competition for storage capacity in the early CCS ramp up period. Northern Lights is a prime example and likely the first mover to start operations in the North Sea in 2024. A start-up of CCS later than 2024 could require triggering the second phase of the Northern Lights project, or an alternative site for permanent storage would be necessary. Therefore, coordination between all parties involved is required.
- Need to formulate contracts between all involved companies covering all possible situations regarding e.g. quality/volumes/economic compensation.

Legal liability/ Regulatory:

- Accurate measurement devices for fiscal metering of CO_2 are necessary. Transport conditions for CCS occur at close to liquid-vapor equilibrium at low temperatures. This poses a challenge for fiscal metering technologies, where no capacities to provide traceable fiscal metering exist worldwide (Moe et al., 2020). The major bottleneck for the verification of the performance of existing measurement principles for CCS is the lack of a primary reference and large-scale test facility for metering technologies (Moe *et al.*, 2020); Hollander *et al.*, 2021). For further information regarding ongoing research regarding measurement devices and their operation under the conditions relevant in the CCS value chain, see (Kocbach et al., 2020; EURAMET, 2021; Løvseth et al., 2021; NCCS Research Center, 2021; Norwegian Research Council, 2021).

- Setting up of a comprehensive and approved Monitoring and Reporting Regulation (MRR) system for keeping track of the CO_2 volumes, covering the whole value chain.
- The EU taxonomy's technical screening criteria for transport of CO_2 (activity 5.11), partly adopted in June 2021, limits CO_2 leakage to max 0.5% by mass between the capture site and the injection point, regardless of distance and complexity of the transport chain. This may pose a challenge and increasingly so as the complexity of the transport chain increases including multiple transport mediums and intermedium storage sites (EC, 2021c).
- As mentioned in Section 5.2, until the EU ETS has been finally revised it is uncertain who will be responsible for emissions during the transport from the capture site to the receiving terminal at Öygarden in Norway.
- As of February 2022, there is still no regulatory acceptance or financial incentives within the EU to allow stored biogenic CO_2 to be counted as negative emissions. However, the EU is working on these issues and is planning to propose rules to certify carbon removals by the end of 2022. As stated in the Directive on Sustainable Carbon Cycles (see EC, 2021a); *"BECCS deployment should be approached in full consideration of the limits and availability of sustainable biomass in order to avoid excessive demand of biomass for energy that would have negative effects on carbon sinks and stocks, biodiversity and air quality"*.
- The moratorium on climate related geo-engineering adopted by the Convention on Biological Diversity which basically sets a moratorium on bio-CCS. In November 2021, the Swedish Energy Agency stated that they would investigate further the implications of the moratorium for Bio-CCS within its role as national centre for CCS (Swedish Energy Agency, 2021)

Technical risks/bottlenecks:

- Utility supply: particularly transfer capacity from the electric power grid.
- Heat recovery: space constraints for placement of equipment for heat recovery. Cost of moving/retrofitting equipment were not assessed in this project.
- Unexpected solvent degradation and subsequent emissions: low risk for Aker Carbon Capture solvent S26 due to extensive testing. Solvents based on fast-reacting amines such as MEA are likely to experience thermal degradation due to high CO_2 concentration if not controlled.
- Risk of rupture/leakage of CO_2 tanks and pipelines on site.
- Risk of off-spec CO_2 due to the relatively strict specifications stated by Northern Lights

Health, Safety and Environment:

- Leakage of CO_2; CO_2 plume; there is an exposure risk for staff at site and staff on ship with requires safety measures (gas leak monitoring; oxygen masks). The exposure to local residential areas and wildlife is most likely low but nevertheless needs a detailed assessment.
- Degradation products and nitrosamine emissions from amine solvents; low risk since technically manageable yet requires monitoring and detailed risk assessment.
- The risk of prolonged time for receiving permits for the operations.

Public relations/reputation:

- Historically it is an important aspect to actively manage and engage the local community to inform and prevent spread of false information on the technology and associated risks.

7 Suggestions for further work

Preem has gained a lot of valuable insights from the project about the implementation of CCS at an existing refinery and about the issues that need to be addressed for such an implementation. A next step could be a more detailed study on how to implement full scale CCS on the HPUs at the Lysekil refinery. Important issues to be addressed in such a study include:

- Heat and operational integration between the refinery HPU and the capture plant including HAZard IDentification (HAZID) and HAZard and Operability (HAZOP) studies
- Detailed investigation of the cooling systems.
- Detailed investigation of the interfaces needed for ship loading.

Furthermore, it is clearly necessary to continue with ongoing efforts to monitor legislation and work with authorities to understand and comply with all necessary legal frameworks. In particular, there is a need for further monitoring of regulations regarding responsibility for CO_s leakage during transportation from the capture site to the permanent storage site. The current provisions in the draft version of the EU taxonomy regulations for transport of CO_2 (Activity 5.11) indicate a maximum allowable leakage of 0.5% (by mass). Furthermore, there is currently no regulatory acceptance for stored biogenic CO_2 to be classified as negative emissions, and no financial incentives at the EU level for storage of such emissions.

In the context of resource efficiency (carbon feedstock) it could also be of interest to evaluate opportunities for producing electro-fuels using captured carbon and renewable hydrogen (CCU) in terms of potential and profitability compared to CCS, which permanently stores a share of the carbon feedstock in form of CO_2. To maximize the climate mitigation benefits of CCU, the captured carbon should be non-fossil, i.e. either biogenic or captured from air and the fuel produced should be targeted at transportation sectors that lack viable alternatives (e.g. via electrification) such as long-range aviation/shipping.

The present study has assumed air cooling systems, consistent with the current situation at the Lysekil refinery. This has an effect on both investment and operational costs. It also determines, and limits, some operational points and thereby plant efficiency. With a more detailed investigation of implementation of full-scale CCS at the Lysekil refinery, it would be of interest to assess the actual cost difference between air cooling and cooling water for both the carbon capture and conditioning sections. Since air cooling requires 0.08-0.19 MJ/kg CO_2 (for capture and conditioning), fluctuations in electricity prices and electricity carbon footprint could be considered. Furthermore, a sensitivity analysis with respect to energy import costs should be performed, since costs for heat supply (solvent regeneration) have a large impact on the operating costs and the full CCS chain (see Section 6.2). Although some sensitivity analysis has been done for heat supply cost and capture cost (Biermann et al., 2022), a full-chain sensitivity analysis was not performed.

This study demonstrated that heat integration with the refinery could lead to significant reduction of operating costs for CO_2 capture. Further analysis should focus on the practical feasibility on-site and a re-evaluation of the heat sources with updated data including the flue gases and potential other heat sources that may be of potential interest for heat pumping. In this work, steam raising with a heat collection network was investigated, however pressurized hot water collection may also be of interest (smaller pipe diameters), in combination with a more detailed analysis of heat pumping configurations including mechanical vapor recompression as well as conventional vapor-compression using e.g., butane (Andersson et al., 2016).

Furthermore, the assumed 90 % CO_2 capture rate is an assumption based on conventional techno-economic considerations. However recent advances suggest that capture rates of up to 95 % could be achieved at similar cost, see e.g (Jones and Brien, 2019). Feron et al. identified increased CO_2-avoidance cost by 3.5% and 10% for ultra-supercritical coal-fired power plants (99.7% capture) and for a natural gas fired combined cycle (99.1% capture), respectively (Feron et al., 2019).

If the number of CO_2 storage projects increases in the North Sea area, it could be possible to develop a joint network for CO_2 ship transport, which may reduce transport costs by sharing assets, optimizing routes and ship capacities, and taking advantage of economies of scale. The assumptions in this study were conservative regarding the CO_2 intensity of the fuel for ship transport. There are emerging alternatives for low carbon seaborne transport, and these should be considered when developing the full-scale project.

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