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EXPORT POTENTIAL
CCUS & PTX TECHNOLOGY

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CONTENTS

1. EXECUTIVE SUMMARY

The paths towards carbon neutrality are many and most of them involve significant contributions from Power-to-X (PtX) and Carbon Capture Utilization and Storage (CCUS). Both technology groups have received significant international attention from both Governments and international institutions during the past year. The technologies have also received attention in Denmark and during 2021 strategies for PtX and CCUS are being developed by the Danish Energy Agency.

The international focus on PtX and CCUS has created a significant export opportunity for Danish companies, particularly project developers, technology providers, and advisory service providers. These have been investigated and over 70 existing companies active within the value chain have been identified. This is not an exhaustive list but comprises of the main actors within PtX and CCUS in Denmark. We find that Danish companies in general are present in most of the value chain except the EPC part where we have not identified any current actors.

The potential for Danish companies is driven by the internationally chosen technological pathways towards carbon neutrality and the timing of these. The study identifies several pathways from the IEA which will impact the potential for Danish companies differently. In the Sustainable Development Scenario carbon neutrality will be reached in 2070 while in the most recent scenarios on Net Zero Emissions carbon neutrality is reached by 2050. Advancing the carbon neutrality by 20 years obviously will require much more investment in PtX and CCUS technologies. The study also notes that several of the countries that we in Denmark regard as our primary export markets have launched strategies for both PtX and CCUS.

The pathways to net carbon neutrality estimate demand for a total of 110 million tonnes of hydrogen in 2035 in the SDS scenario and 266 million tonnes a year in the NZE scenario where carbon neutrality is advanced to 2050. As for CCUS, 1,352 million tonnes of CO2 are projected to be captured in the SDS by 2035, and 3,059 million tonnes in the NZE scenario.

Globally, on CCUS technologies in 2035, we estimate the IEA SDS and NZE scenarios to correspond to 1,787-4,021[1] facilities (direct air capture, industry and power plants) equipped with carbon capture, 77-177 thousand km of CO2 pipelines, 67-151 ships transporting CO2 and 274-592 underground storages for SDS and NZE scenarios respectively.

On PtX technologies in 2035, we estimate SDS and NZE scenarios to correspond to 174-1,688 GW of electrolysers, 541-661 ammonia and synthetic fuel production units, 57-147 thousand km of hydrogen pipeline networks, 25-242 ships transporting hydrogen, 1,341-2,245 ships running on hydrogen or hydrogen derived fuels, 1.1-2 million hydrogen trucks and 10.6-19.6 million hydrogen cars.

We have estimated the global investment required in these technologies to be 903-1,979 billion EUR in capex spending for CCUS and 375-1,418 billion EUR in capex spending for PtX. When we add operational expenditures and profits achieved in CCUS and PtX projects to complete their total market potential (all value created along their lifetime from planning to decommissioning), we estimate a global market potential of 1,505-3,297 billion EUR for CCUS and 601-2,319 billion EUR for PtX.

[1] X - Y figures refer to SDS - NZE scenarios in 2035. All figures refer to installed units by 2035, i.e. they refer to cumulative investments up to 2035, not annual investments in 2035.

Could Danish companies grasp “just” a share of the market of 1% for CCUS and 3% for PtX, the Danish export potential would be rather significant. We estimate that 35% of the investment costs would be spent within the EPC phase where danish companies are not yet present. Subtracting this 35% of CAPEX yields an adjusted (CAPEX-based) market potential for Danish companies amounting to 6-13 billion EUR in CCUS technologies and 7-28 billion in PtX technologies for SDS and NZE scenarios respectively. When adding operational expenditures and profits to have a view of the total market value of the projects along their lifetime, we estimate a market potential of 12-26 billion EUR in CCUS and 14-55 billion EUR in PtX.

Barriers to the realization of the export potentials are closely correlated with the actual ambitions for net carbon neutrality and the associated advancement in regulation and subsidy schemes determines the attractiveness of export markets. PtX and CCUS strategies and supporting regulation and subsidy schemes are most advanced in USA and Europe. In the short term these will be the most likely markets. Other specific individual geographies are advancing as well. In the estimations and available data material it has not been possible to distinguish between regions.

The preference given to green over blue hydrogen is a central determinant of the market size for Danish companies. For example, many countries may not have the possibility or the finances to pursue green hydrogen in the short term and may turn to blue hydrogen – an area where Denmark may not be the frontrunner. By pushing the agenda for green hydrogen globally, Denmark may increase its share of the addressable market.

2. OVERVIEW

The Danish Government is developing strategies for Carbon Capture Utilization & Storage (CCUS) and Power-to-X (PtX). As an input to this strategy the Danish Energy Agency has commissioned Ramboll to provide analysis on the technology export potential for Danish companies within PtX and CCUS. This report investigates the potentials with the following 4 steps:

1. Mapping of the relevant technologies according to the technology readiness and according to where in the PtX or CCUS value chain they appear. The aim of this is to understand the candidates for export in the short to medium term.
2. Following the mapping of the technologies the main Danish companies producing and delivering services directly and indirectly related to PtX or CCUS are mapped according to the value chain and their products.
3. In task 3 we estimate the investment needs required to reach carbon neutrality by 2050 or 2070. This is done with the outset from the IEA scenarios Sustainable Development Scenario and the Net Zero Emission Scenario.
4. Having established the global market and the potential investments required, the market share and potential for Danish companies is judged based on the company mapping and the distribution of capex for the investments.

3. TECHNOLOGY MAPPING

In this section of the report the most relevant CCUS and PtX technologies have been mapped and described. We have also evaluated each technology according to their estimated **technology readiness level (TRL) on a global level**. All sources consulted are indicated in **References** and cited in **Table 19** and **Table 20**.

3.1 CCUS Technologies

Carbon capture utilisation and storage involves three major steps: capturing CO_2 at the source, compressing and transporting it, and finally using it in an industrial process or injecting it deep into a rock formation at a carefully selected and safe site, where it is permanently stored. **Table 1** lists all relevant CCUS technologies identified and their global technology readiness level along the industry value chain from production to demand. Technology descriptions can be found in **Appendix - Detailed technology mapping.**

Table 1 - List of CCUS Technologies

Technology	Technology Readiness Level (Global)	Value Chain Step
Pre-combustion IGCC-CCUS	7	Production
Post-combustion chemical absorption	9	Production
Post-combustion physical adsorption	7	Production
Post-combustion membrane CO_2 capture	6-7	Production
Post-combustion cryogenic-based CO_2 capture	9	Production
Oxyfuel combustion	7	Production
Chemical looping combustion	4	Production
Direct air capture (DAC)	4-6	Production
Pyrogenic carbon capture	9	Production
CO_2 compression	9	Infrastructure
CO_2 injection pump	9	Infrastructure
CO_2 dehydration	9	Infrastructure
CO_2 liquefaction	9	Infrastructure
New CO_2 pipelines	9	Infrastructure
Retrofitting of natural gas pipelines to CO_2	9	Infrastructure
CO_2 shipping	8	Infrastructure
CO_2 transport by road	9	Infrastructure
Aquifer CO_2 storage	9	Infrastructure
Salt cavern CO_2 storage	9	Infrastructure
Carbon capture and storage enhanced oil recovery (CCUS-EOR)	7	Infrastructure /Demand
PtX technologies using CO_2	5-9	Demand

3.2 PtX Technologies

Power-to-X technologies are those technologies allowing to produce synthetic fuels from renewable sourced electricity. First, hydrogen is produced in electrolysers and this can be subsequently processed with other feedstock (e.g. nitrogen to produce ammonia or CO_2 from carbon capture to produce carbon-based fuels) to produce synthetic electro-fuels. Table 2 lists relevant PtX technologies and their global technology readiness level along the industry value chain from production to demand. Technology descriptions can be found in **Appendix - Detailed technology mapping.**

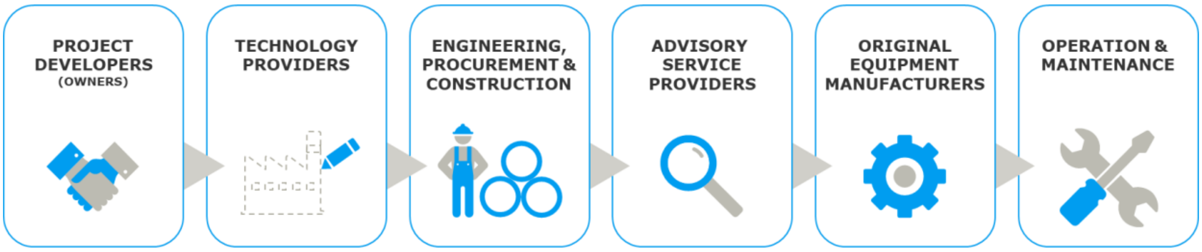
Table 2 – List of PtX technologies

Technology	Technology Readiness Level (Global)	Value Chain Step
Alkaline Electrolysis Cells (AEC)	9	Production
Proton Exchange Membrane (PEM)	8	Production
Solid Oxide Electrolysis Cell (SOEC)	7	Production
Methane synthesis	8-9	Production
Methanol synthesis	8	Production
DME (dimethyl ether) synthesis	3-9	Production
Fisher-Tropsch synthesis (FTS)	5-9	Production
Ammonia synthesis through Haber-Bosch process	9	Production
Ammonia synthesis through electrocatalytic nitrogen reduction reaction	4	Production
Hydrogen compression	9	Infrastructure
New hydrogen pipelines	9	Infrastructure
Retrofitting of natural gas pipelines to hydrogen	9	Infrastructure
Road and rail transportation of gaseous and liquid hydrogen	9	Infrastructure
Hydrogen shipping	8	Infrastructure
Hydrogen geological storage	9	Infrastructure
Hydrogen storage tanks	9	Infrastructure
Liquid electro-fuels shipping	8-9	Infrastructure
Solid Oxide Fuel Cell (SOFC)	8-9	Demand
Proton Exchange Membrane (PEM) Fuel Cell	9	Demand
Molten Carbonate Fuel Cell (MCFC)	7	Demand
Phosphoric Acid Fuel Cell (PAFC)	7	Demand
Direct Ammonia Fuel Cell (DAFC)	7	Demand
Direct Methanol Fuel Cell (DMFC)	9	Demand
2-stroke methanol dual fuel engine for marine transportation	9	Demand
Retrofitting of 2-stroke engines for marine transportation to methanol	9	Demand
2-stroke ammonia dual fuel engine for marine transportation	5	Demand
4-stroke ammonia dual fuel engine for marine transportation	5	Demand
Retrofitting of 2 and 4-stroke engines for marine transportation to ammonia	5	Demand

4. MAPPING OF DANISH COMPANIES AND COMPETENCES

Ramboll has performed a mapping of the Danish PtX and CCUS ecosystem. The mapping was focused on companies that, through their activities in the PtX and CCUS market and value chain, are contributing to the creation of a knowledge and competence pool within the Danish society. This means companies which are owned by a non-danish mother company, but have employees in Denmark who are working in the field, are counted in. The analysis groups the identified companies into 6 categories as illustrated in
Figure 1 below.

Figure 1 – Simplified CAPEX Value Chain of Energy Plants



Source: Ramboll

In summary, the company mapping has resulted in an identification of 70 companies. The companies can be categorised as follows:

Table 3 – Company Mapping Summary Statistics

Number of companies	Project Developers	Technology Providers	EPCs	Advisory Providers	OEMS	O&M
Danish mother companies	**12**	**11**	**-**	**4**	**22**	**25**
PtX	7	5	-	-	9	9
CCUS	3	2	-	-	9	10
Active within both categories	2	4	-	4	4	6
Foreign mother companies	**6**	**9**	**-**	**1**	**12**	**8**
PtX	4	6	-	-	6	3
CCUS	1	2	-	-	5	3
Active within both categories	1	1	-	1	1	2
Total	**18**	**20**	**-**	**5**	**34**	**33**

The six categories are defined as the following:

- Project developers: This category groups companies that build, own and operate PtX plants and CCUS processes. It includes companies that invest in the plants themselves.
- Technology providers: Companies that operate in the field of research, development and basic engineering of CCUS and PtX. These companies typically hold various technology patents and are able to design a plant with a guarantee to create a desired output, if constructed according to specifications.
- Engineering, Procurement and Construction (EPC): Companies that specialise in the detailed engineering, procurement execution and construction execution. Due to the limited market for

CCUS and PtX plants we do not believe such companies exist in Denmark today. It may arise if the market for Danish CCUS and PtX plants grows.

- Advisory service providers: Companies that advice project developers and owners on both the high-level project feasibility, market engagement approach in relation to EPCs and finally evaluate the offered plant designs from technology providers.
- Original Equipment Manufacturers (OEM): Companies that manufacture and supply physical equipment (hardware) to EPCs for the construction of PtX and CCUS plants.
- Operation & Maintenance and general service providers (e.g. logistics): Companies that perform a physical service in relation to the PtX and CCUS market, e.g. logistics and other infrastructure related services. It is uncertain whether these companies will contribute a lot to the technology export, but they do contribute to the Danish PtX and CCUS knowledge pool.

4.1 CCUS Companies, Competences and Maturity of Technologies

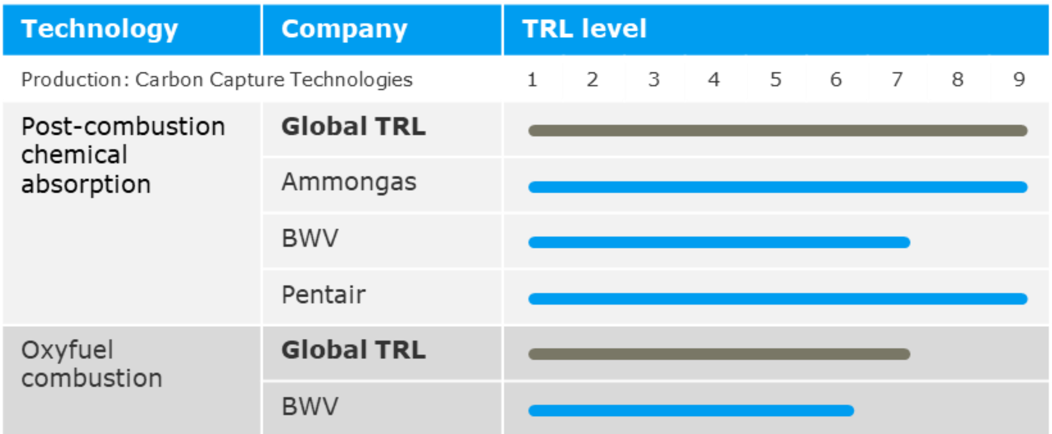
Table 4 – Carbon Capture Competences

Project Developers	Technology Providers	Advisory Providers	OEMS	O&M
Ørsted	FLSmidth	COWI	Ammongas	A.P. Moller Maersk
Justsen Energiteknik	Strandmøllen	FORCE Technology	BWSC	Ammongas
Nature Energy	Ørsted	NIRAS	FLSmidth	Bigadan
Gas Storage Denmark	Danfoss	Rambøll	Justsen Energiteknik	BWSC
Aalborg Portland	Grundfos	SWECO	Verdo	Gas Storage Denmark
BWV (Babcock & Wilcox Vølund)	Welltec		Aalborg Energie Technik	Justsen Energiteknik
Ineos Oil & Gas Denmark	Air Liquide		Danfoss	Process Engineering
	Busch Vacuum Pumps and Systems		Grundfos	Strandmøllen
	Ineos Oil & Gas Denmark		Novozymes	Verdo
			Tunetanken	Ørsted
			Svanehøj	Aalborg Energie Technik
			SEG	DSV Panalpina
			Welltec	Evergas
			Air Liquide	Lauritzen Kosan (BW Epic Kosan)
			BWV (Babcock & Wilcox Vølund)	SEG
			Malmberg	Welltec
			Pentair	Air Liquide
			Busch Vacuum Pumps and Systems	Malmberg
			Geopal Systems	Pentair
				Ineos Oil & Gas Denmark
				Ultragas (Ultranav)

Note: Companies with foreign ownership Companies with Danish ownership

Danish companies are primarily active within 2 of the 9 identified carbon capturing technologies. Instead what most Danish OEMs deliver is equipment that supports the process, such as vacuum pumps, compressors and monitoring equipment.

Figure 2 – CCUS Technology Maturity of companies in Denmark



Source: Ramboll high-level assessment

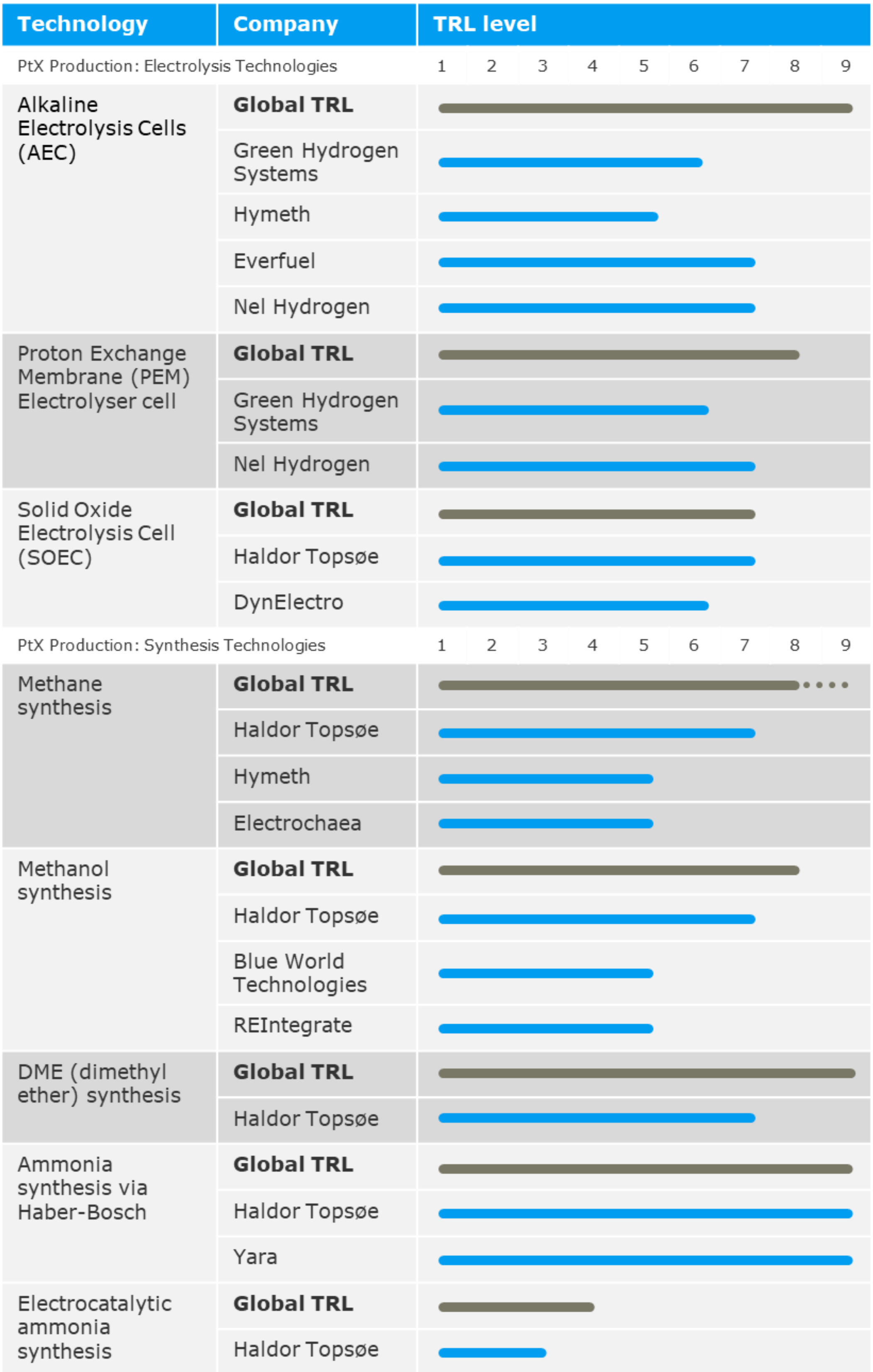
4.2 PtX Companies, Competences and Maturity of Technologies

Table 5 – PtX Competences

Project Developers	Technology Providers	Advisory Providers	OEMS	O&M
CIP (Copenhagen Infrastructure Partners)	Everfuel	COWI	Ballard Europe	A.P. Moller Maersk
Energinet	FLSmidth	FORCE Technology	Blue World Technologies	Ancotrans
Everfuel	Haldor Topsøe	NIRAS	DynElectro	DFDS
Gas Storage Denmark	IRD fuel cells	Rambøll	Everfuel	DGC (Dansk Gasteknisk Center)
Haldor Topsøe	REIntegrate	SWECO	FLSmidth	Energinet
Vestas Wind Systems	Vestas Wind Systems		Green Hydrogen Systems	Everfuel
Ørsted	Ørsted		Haldor Topsøe	Gas Storage Denmark
European Energy	Danfoss		IRD fuel cells	Ørsted
Eurowind Energy	Grundfos		Serenergy	DSV Panalpina
Siemens Gamesa	Electrochaea		Vestas Wind Systems	Andel
Shell Danmark	Hitachi		Danfoss	Norlys
Yara	MAN Energy solutions		Grundfos	Evergas
Ineos Oil & Gas Denmark	NEL Hydrogen		Svanehøj	Lauritzen Kosan (BW Epic Kosan)
	Siemens Gamesa		Alfa Laval Aalborg	Dangødning
	Wärstilä Danmark		Hitachi	Copenhagen Airport
	Ineos Oil & Gas Denmark		MAN Energy solutions	Alfa Laval Aalborg
			NEL Hydrogen	Shell Danmark
			Siemens Gamesa	Vattenfall
			Wärstilä Danmark	Ineos Oil & Gas Denmark
			Geopal Systems	Ultragas (Ultranav)

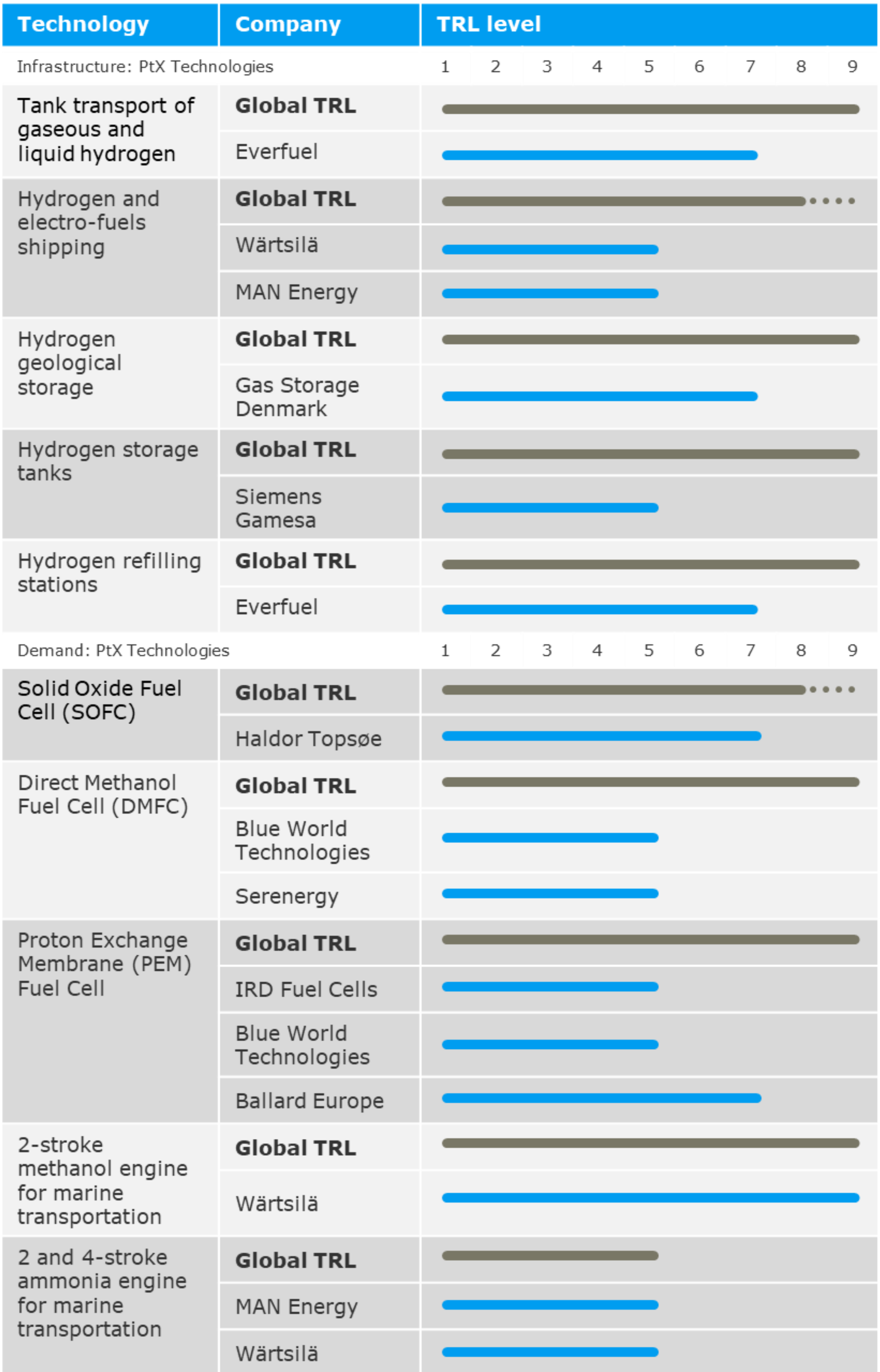
Note: Companies with foreign ownership Companies with Danish ownership

Figure 3 - PtX Production Technology Maturity of companies in Denmark



Source: Ramboll high-level assessment

Figure 4 – PtX Infrastructure Technology Maturity of companies in Denmark



Source: Ramboll high-level assessment

4.3 Danish Strongholds

Danish strongholds (in Danish: "danske styrkepositioner") is in this report interpreted as areas where Danish companies have a high likelihood of developing attractive PtX and CCUS products and solutions together with existing danish industries, so the offering will also benefit the Danish decarbonization. The assessment of the Danish Strongholds is done by reviewing the list of identified companies and their size (turnover, number of employees) in Denmark. It is based on a qualitative judgement as it relies on a high-level, rather than detailed, analysis of the global competitive landscape.

Carbon Capture

Table 6 – Carbon Capture Competences

Value chain step	Project Developers	Tech. Providers	EPC	OEM	Advisors	O&M + Other
Production	◕	◕	○	◕	◕	◕
Infrastructure	◔	◕	○	◕	◕	◕
Demand	◕	◕	○	◕	◕	◔

Legend: ◕ several companies/advanced competences; ◔ few companies/limited competences

On a per capita level, Denmark is a leading country in the transition from coal-fired to biomass-fired combined heat and power plants as well as from natural gas to biogas. In a similar way, Denmark is a leading country on solid waste incineration. Finally, Denmark has a significant cement production per capita, partly due to its important natural resources of limestone and chalk relative to the size of the country. Denmark's advanced position on these four carbon sources means Danish companies have good local opportunities for testing and commercializing carbon capturing solutions on these carbon sources and create the foundation for subsequent technology exports to other countries.

On the other hand, Denmark has limited steel and chemicals production compared to European peers. Denmark also does not currently have any particularly advanced companies with regards to Direct Air Capture technology.

Power-to-X

Table 7 – Power-to-X Competences

Value chain step	Project Developers	Tech. Providers	EPC	OEM	Advisors	O&M + Other
Production	◕	●	○	◕	◕	◕
Infrastructure	◔	◑	○	◕	◑	◕
Demand	◔	◑	○	◕	◑	◔

Legend: ◕ several companies/advanced competences; ◔ few companies/limited competences

Denmark has vast wind resources available for renewable energy relative to its population size, particularly within offshore wind. This creates the potential for significantly more intermittent renewable electricity produced than consumed by the domestic market. Water electrolysis is a key lever to leverage the Danish wind resources to produce hydrogen. If Denmark were to leverage this asset, it would at first create a large demand for renewable energy production solutions from the Danish offshore wind industry. Secondly, a large demand for electrolysis hardware would arise, with it a potential for large scale manufacturing of electrolysis equipment. Large scale electrolysis manufacturing could enable competitive hardware prices, which in turn could enable significant exports of both manufactured goods (hardware) and solutions for production optimization.

As will be covered in Chapter 5, Denmark and North Europe will struggle to compete on the price of blue hydrogen production with countries that have large natural gas and coal reserves as well as on green hydrogen with countries closer to equator that can leverage more low cost solar power. However, one of Denmark's strengths is to have an energy system that can integrate electricity and district heating. The Danish PtX value chain might be able to develop a strong value proposition with energy system solutions that optimize the cost of the overall system with sector coupling.

Denmark has leading technology providers for plants producing ammonia and hydrocarbon-based derivative chemical products, However, Denmark does not have a large ammonia or refinery production, so there will be limited existing plants to convert and leverage for large scale hydrogen off-take.

5. ASSESSMENT OF BARRIERS AND POTENTIALS IN THE INTERNATIONAL MARKET

There are three key factors affecting the Danish export potential of CCUS and PtX-technologies in the coming 15 years:

1. The global commitment to reduce global warming– essentially, the question to ask is which maximum global temperature increase will nations of the world pursue? And how ambitious are the different countries?
2. The expected role of hydrogen in the final energy demand. How much decarbonization is expected to be achieved with hydrogen as opposed to alternative solutions incl. fossil fuels with carbon capture technology?
3. Which preference will authorities give to green over blue hydrogen[2]? The decision will among other things depend on the expected price/kg of green hydrogen. The load-factor and technological learning rates are central determinants for the price of green hydrogen.

These factors eventually lead to a political decision making on how nations will balance the adverse effects of global warming with the demand for energy consumption.

KEY FINDINGS

Based on the above listed factors and various reports from the IEA, Ramboll will work with the following LOW and HIGH scenarios for the global market potential. The following sections elaborate the assumptions for the above-mentioned factors in the two scenarios. The actual quantification is described in **Chapter 6**.

Table 8 – Ramboll's LOW scenario based on the IEA's global SDS scenario

Ramboll LOW scenario (based on SDS)	2030	2050	2070
TFC (TWh/yr)	116,261	111,644	110,322
Net CO2 emissions (Mt/yr)	26,710	9,870	-
CCUS (Mt/yr)	840	5,635	10,409
Hydrogen demand (Mt/yr)	88	287	519
Hydrogen share of TFC	1.7%	4.8%	12.6%
Share of green hydrogen	16%	44%	54%
Share of blue hydrogen	21%	42%	40%

Source: Ramboll. Note: TFC = Total Final Energy Consumption/Demand; SDS = Sustainable Development Scenario.

Table 9 - Ramboll's HIGH scenario based on the IEA's global NZE/FIC scenario

Ramboll HIGH scenario (based on NZE)	2030	2050	2070
TFC (TWh/yr)	109,444	95,556	94,424
Net CO2 emissions (Mt/yr)	20,147	-	-
CCUS (Mt/yr)	1,665	7,602	n.a.
Hydrogen demand (Mt/yr)	212	528	n.a.
Hydrogen share of TFC	6%	18%	n.a.
Share of green hydrogen	38%	61%	n.a.
Share of blue hydrogen	33%	37%	n.a.

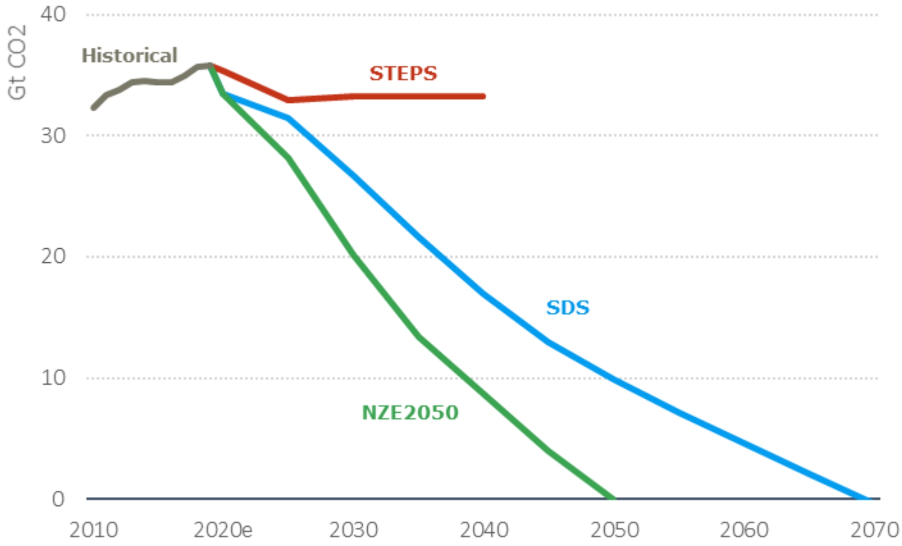
Source: Ramboll. Note: TFC = Total Final Energy Consumption/Demand; NZE/FIC = Net Zero Emissions 2050/Fast Innovation Case.

[2] Green = hydrogen produced with water electrolysis based on renewable energy; Blue = hydrogen produced with steam reforming of natural gas and carbon capture and storage.

5.1 Scenarios for overall CO2 reduction pathways

The International Energy Agency (IEA) models global CO_2 emissions based on macroeconomic and demographic factors and a large variety of energy price projections and Government pledges to reduce global warming. It should be noted that the modelling focuses on CO_2 emissions and not GHG emissions (CO2-eq). All projections are based on long-term goals and commitments, which are then interpolated back to short-term demands.

Figure 5 – Annual CO_2 Emission Trajectories by the IEA



Source: Ramboll adaptation of IEA (October 2020), *World Energy Outlook 2020*

The IEA presents 3 primary scenarios in the 2020 edition of the World Energy Outlook [1]:

- The Stated Policies Scenario (STEPS): Freezes current global emissions targets and regulation incl. a fast recovery from the Covid-19 pandemic. CO_2 emissions rebound and exceed 2019 levels by 2027, a trajectory that would lead to a long-term temperature rise of around 2.7°C in 2100 compared to pre-industrial levels. The STEPS scenario is thus not compatible with the Paris Agreement nor the United Nations Sustainable Development Goals (UN SDGs) related to energy and climate.
- The Sustainable Development Scenario (SDS): Aims to simultaneously achieve the energy related goals of the UN SDGs, and limiting global warming to 1.65°C without relying on global net negative emissions after reaching net zero. The scenario is thus in line with the Paris Agreement's pledge to "limit global warming to well below 2°C, preferably to 1.5°C, compared to pre-industrial levels". The energy related SDGs are universal access to affordable and modern energy (SDG 7); reducing impacts of air pollution (part of SDG 3 and SDG 11); and tackling climate change (SDG 13).
- The Pathway for Net-Zero Emissions by 2050 (NZE)/Faster Innovation Case: As 2°C global warming compared to pre-industrial levels will have dire consequences like severe ecosystem damage and extreme weather events [2], the IEA has also created a scenario that aims to achieve the Paris Agreement's goal of limiting global warming to 1.5°C compared to pre-industrial levels, without relying on global net negative emissions after reaching net zero. The goal of net zero emissions will be achieved by a mix of behavioural changes and increased funding for innovation. As such, the IEA also refers to the NZE scenario as the Faster Innovation Case (FIC).

When estimating the international potential, this report will consider two scenarios: a LOW and a HIGH case. The scenarios will be based upon the SDS (low case) and NZE (high case). As such, we make the assumptions that climate action will not be postponed and rely on negative emission technologies.

5.2 Share of hydrogen and CCUS in Final Energy Demand

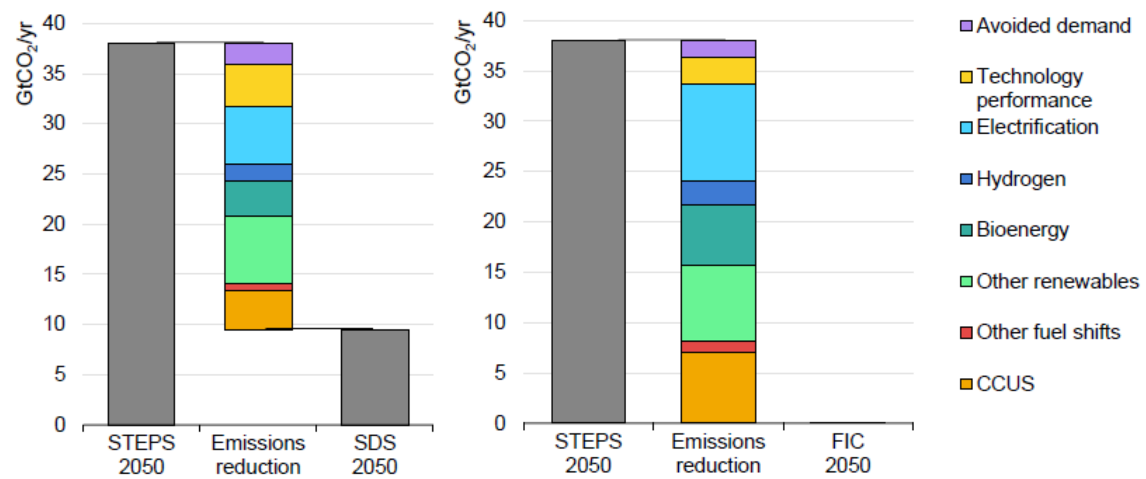
Final Energy Demand predictions

The different pathways to achieve the expected CO_2-reductions are among other things dependent on the expected development of the global final energy demand (TFC). On top of increased investments into low-carbon energy solutions (incl. PtX and CCUS), the IEA describes that the NZE scenario might require behavioural changes that could reduce the overall energy demand. One reason for this is that many countries may simply not afford continuing current behaviours in the transition to a low-carbon future.

Concrete examples from the IEA's WEO2020 include *"replacing flights under one hour with low-carbon alternatives, walking or cycling instead of driving by car for trips under 3 km, and reducing road traffic speeds by 7 km/h"*. Whether these behavioural changes could be achieved, whether the cost of technologies develop as expected, uptake of electric vehicles and numerous other factors, add to the complexity and uncertainty of the scenarios.

Predictions and data should thus be seen as highly uncertain, even on a 15-year time horizon. At the time of writing, detailed scenario data is not made available publicly. The IEA recently announced it will publish a more detailed NZE2050 scenario on May 18th 2021 where both the 17 UN SDGs and the 1.5°C ambition are achieved. **Ramboll therefore assumes the final energy demand to be at a similar level in both the SDS and NZE2050 scenarios.**

Figure 6 – IEA's forecast for global energy sector annual CO2 emissions reductions in 2050



Source: IEA (September 2020), *Energy Technology Perspectives 2020*
Note: Hydrogen includes hydrogen and hydrogen-derived fuels such as ammonia and synthetic hydrocarbon fuels. Nuclear is included in other fuel shifts. STEPS = Stated Policies Scenario; SDS = Sustainable Development Scenario; FIC = Faster Innovation Case.

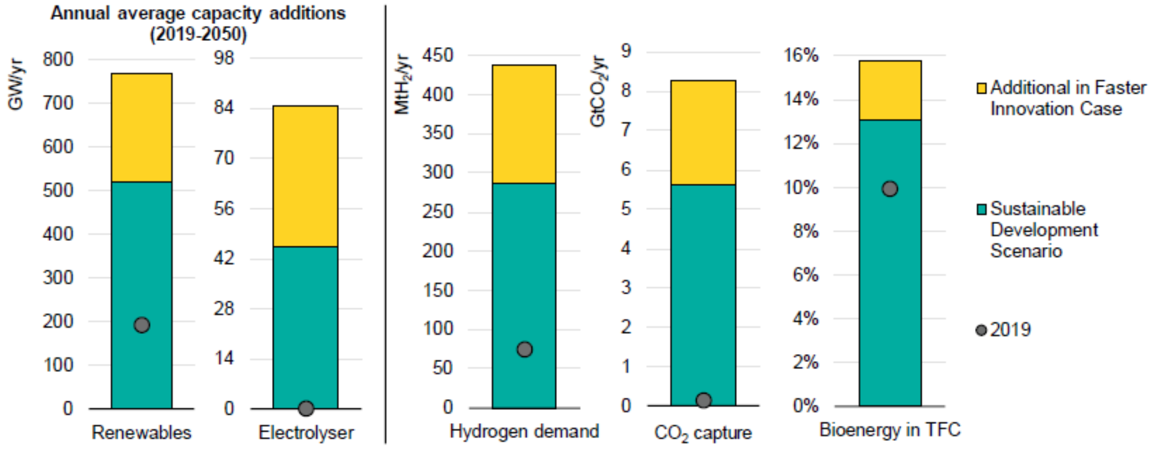
Decarbonization with hydrogen and CCUS

According to the IEAs 2020 predictions, CCUS will contribute a larger share of the way to achieve net zero CO_2 emissions in 2050 than hydrogen in both the SDS and NZE2050 as depicted in Figure 6. The key factors at play are how much of the emissions from final energy demand will be removed with the use of hydrogen and CCUS as opposed to relevant alternatives in each sector. In heavy transport, hydrogen and hydrogen-carriers can be alternatives to biofuels. Hydrogen and electric heat pumps are alternatives to natural gas and bioenergy in industrial and residential heating.

The cost of stranded assets is a factor that also plays a role for the future energy system. Current power and heat generating assets can be kept in use by leveraging carbon capture technology or replacing fossil fuels like coal and natural gas with bioenergy such as biomass and biogas. In both cases however, hydrogen could also be an alternative solution, either as a carbon free fuel at the point of use or as part of balancing intermittent renewable energies in the power grid to supply small- or large-scale electric boilers and heat pumps.

Figure 7 summarises the key indicators from the IEAs two scenarios in the year 2050, which we will use to quantify the global market potential.

Figure 7 – Decarbonization indicators towards 2050 in SDS and NZE/FIC cases



Source: IEA (September 2020), *Energy Technology Perspectives 2020*
Note: Renewables exclude bioenergy-based power generation equipped with carbon capture. CO_2 capture includes captured emissions for storage and use. Sustainable Development Scenario = net zero emissions achieved in 2070; Faster Innovation Case = net zero emissions achieved in 2050.

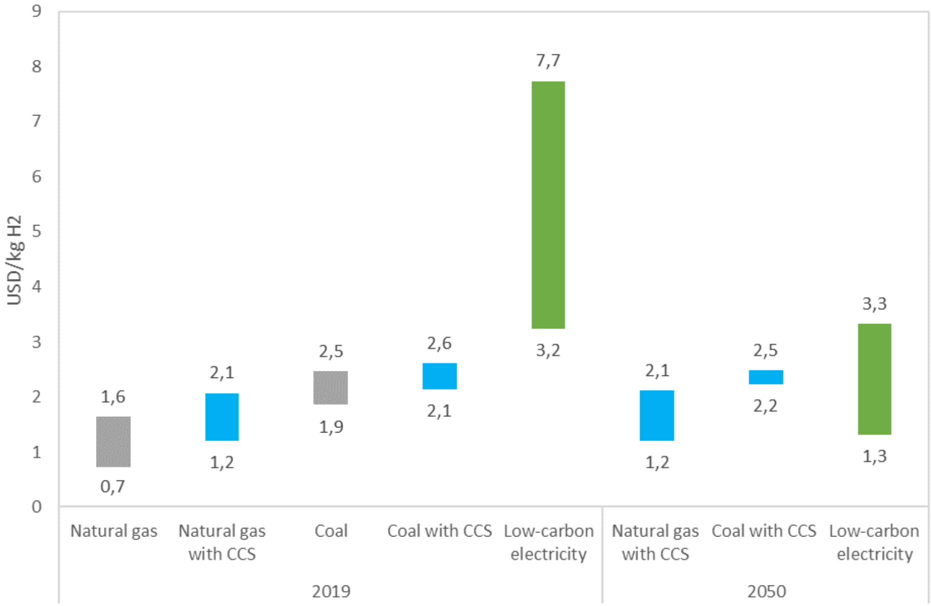
5.3 Green versus blue hydrogen

Hydrogen can either be grey, blue or green. Grey hydrogen is made from fossil sources, such as steam reforming natural gas or coal gasification. Blue hydrogen is made from fossil sources with carbon capture and storage – importantly not CCU, as it would otherwise contribute to continued emissions of carbon dioxide from fossil fuels. Finally, green hydrogen is made with water electrolysis supplied with electricity from renewable energy sources.

The choice of preference between green and blue hydrogen relies on both price and geopolitical factors [3]. As shown in

Figure 8, the price of producing each type varies a lot. Due to high uncertainty of the gains from innovation, it remains uncertain whether green hydrogen will be competitive with blue hydrogen by 2050.

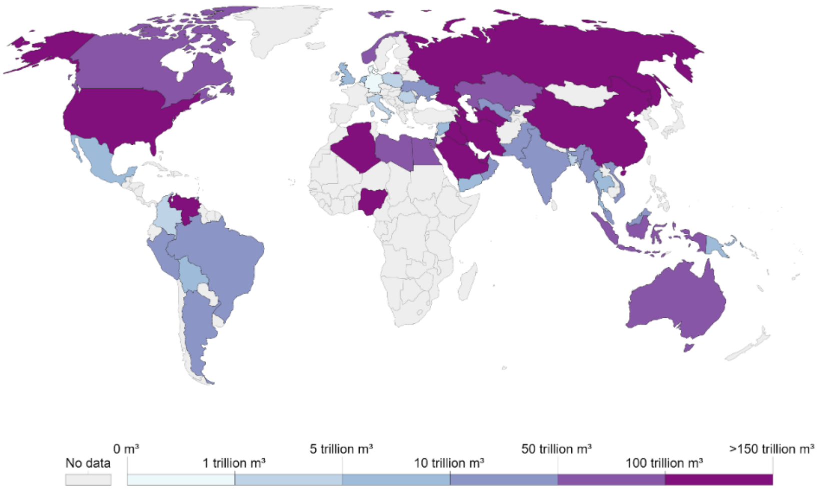
Figure 8 - Global average levelized cost of hydrogen production by energy source and technology



Source: Ramboll adaptation of IEA (2020), *Energy Technology Perspectives*

As Figure 9 and Figure 10 show, the access to proven[3] natural gas and coal reserves which can be used to produce low-cost blue hydrogen is unequally distributed in the world. Ensuring secure and cost-efficient energy supplies at all times to all EU citizens is one of the overarching goals of the European Climate Law [4, p. 15]. A high dependency on foreign supply of blue hydrogen increases the risk of price instability.

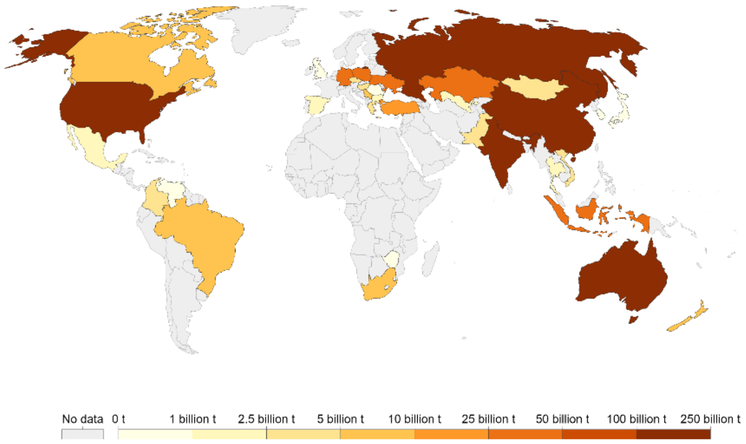
Figure 9 – Proven gas reserves 2019



Source: Our World in Data, BP Statistical Review of World Energy (2019)

[3] "Proven reserves" refers to quantities that geological and engineering information indicates with reasonable certainty can be recovered in the future from known reservoirs under existing economic and operating procedures. As such, this does not account for carbon taxation or additional costs of limiting flue gases.

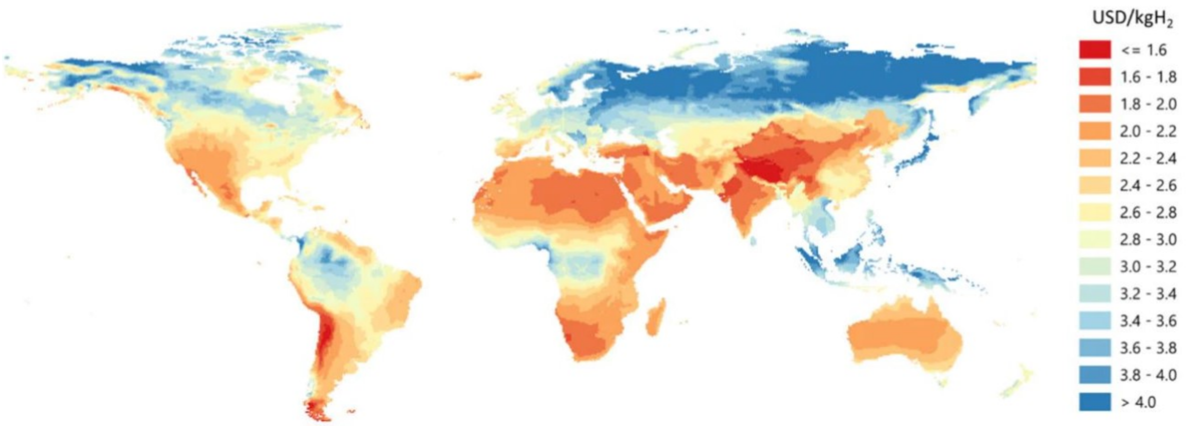
Figure 10 – Proven coal reserves 2019



Source: Our World in Data, BP Statistical Review of World Energy (2019)

Green hydrogen production based on intermittent renewable energies, like wind and solar, is the alternative solution that enables nations with limited access to natural gas reserves to produce their own hydrogen. However, as shown by Figure 11 the price at which countries are able to produce green hydrogen still differs significantly due a range of factors.

Figure 11 – IEA green hydrogen costs from hybrid solar PV and onshore wind systems in 2050



Source: IEA (2019), *The Future of Hydrogen*

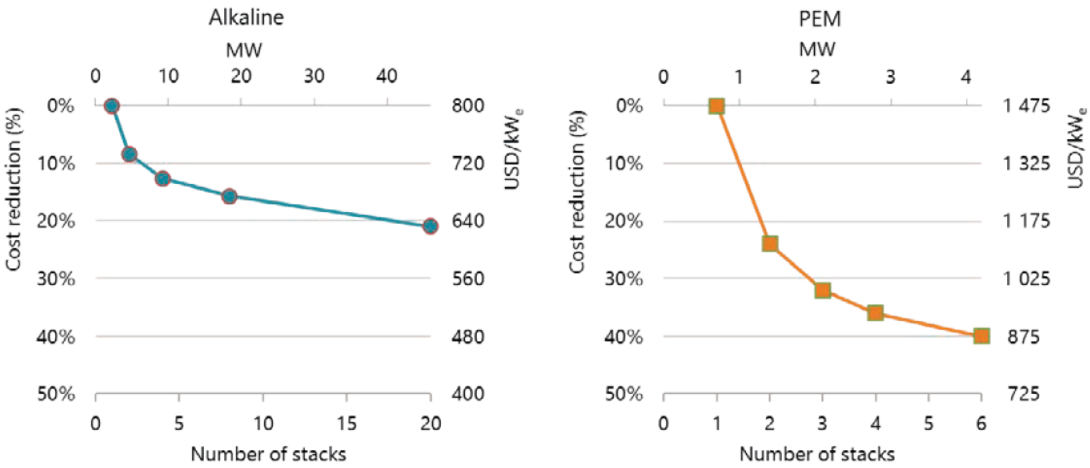
The cost of the green hydrogen primarily depends on three factors:

- Technological learning rate of electrolysis
- Cost of renewable energy
- Load-factor assumptions

Learning rate

The price of electrolyser equipment is expected to decline thanks to economies of scale. As the demand for annual installed capacity grows, it will become economically feasible to invest in large scale manufacturing plants, which will reduce the costs of components significantly. The IEA projects a cost decline for electrolysers CAPEX from USD 872/Kw in 2019 to USD 269/kW in 2050, a cost reduction of 66% in a period of 30 years, which corresponds to an annual cost reduction of 4% from 2019 to 2050 [5].

Figure 12 – Scaled-up electrolysers and automated production processes leading to significant CAPEX reductions



Source: IEA (2019), *Future of Hydrogen*. Note: based on a single stack size of 2 MW for alkaline and 0.7 MW for PEM.

Cost of renewable energy

The Levelized Cost of Energy (LCOE) of utility-scale renewable power generation technologies has fallen substantially over the past decade. According to the International Renewable Energy Agency (IRENA), *"solar photovoltaics (PV) shows the sharpest cost decline over 2010-2019 at 82%, followed by concentrating solar power (CSP) at 47%, onshore wind at 40% and offshore wind at 29%."* [6]. IRENA expects the cost decrease to continue in the future, particularly regarding solar photovoltaics [7].

Load-factor assumptions

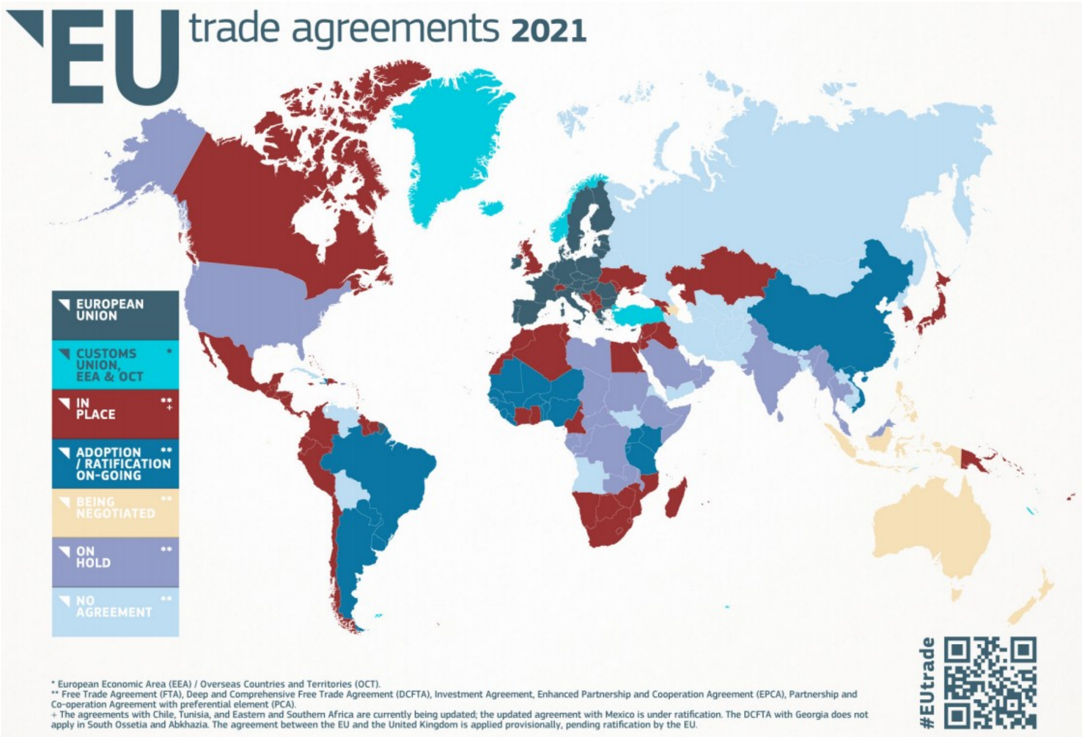
For hydrogen to be certified as green, the electrolysis must be supplied with electricity from renewable energy sources during all hours of operation. This means that countries with access to renewable energy for many hours of the day are able to achieve a high utilization of the electrolysis assets, and thus the CAPEX of the asset can be depreciated over a larger amount of hydrogen produced.

5.4 Regional markets with highest likelihood for Danish exports

In the long run, towards 2050, it is expected that the regions with the largest natural resources for hydrogen production will be the largest markets for exporting technology and equipment. Export of CCS-technology for blue hydrogen will be in North America, China, India, Australia, and the Middle East. Export of technology for green hydrogen is expected to go primarily to North Africa (Maghreb), the Middle East, South Africa, India, Chile, China, and Australia.

As hydrogen and energy carriers are traded on commodity markets there is a high price sensitivity. The markets that Danish companies are most likely to export technology and services to are therefore markets where Danish products can achieve the most competitive prices. Factors that influence competitiveness include transaction costs such as trade tariffs and duties. Therefore, it is expected that markets where Danish companies will have the most competitive prices are markets where the transaction costs are minimized by trade agreements. According to the Ministry of Foreign affairs, Denmark predominantly has Free Trade Agreements through its membership of the EU [8].

Figure 13 - Map of EU trade agreements 2021



Source: EU Commission, 2021

In the short-medium run, towards 2030, we believe the largest markets for CCUS- and PtX-technology export will be the ones that are furthest ahead on developing concise national hydrogen, CCUS- or PtX-strategies. On a regional level, it is particularly the EU that has the highest ambitions on the short term, with a goal of 40 GW of electrolysis by 2030 and an annual production of up to 10 Mt of green hydrogen [9]. Within the EU, the countries which have developed a roadmap include Germany, France, Italy, Spain, Netherlands, Portugal and Finland.

Looking outside the EU, it is the European Economic Area and Overseas Territories (EEA/OCT) where Danish companies are expected to have the second-best conditions for technology export.
In the EEA/OCT group it is Norway and Iceland, whereas Turkey has not developed roadmaps with targets for hydrogen, PtX or CCUS.

The group of countries with third-best conditions is countries with whom the EU has bilateral free trade agreements. These include the United Kingdom, Central Balkans and East Europe, Canada, countries in Central and Western South America, certain Maghreb countries (Marocco, Algeria, Tunesia), certain Middle Eastern countries (such as Egypt, Israel, Jordan, Iraq), Central Asia (Kazakhstan, Georgia, Armenia), Southern Africa, Japan, South Korea and Papua New Guinea. In this diverse group it is the United Kingdom, Canada, Chile, Japan, and South Korea that have developed roadmaps with concrete targets for hydrogen, PtX and/or CCUS.

Going forward, the outcome of the EU's trade deal negotiations may be pivotal for Denmark's export potential. This includes particularly the EU's negotiations with Australia, China, Mercosur, Western Africa, New Zealand, and Vietnam. In this group, particularly Australia, New Zealand have recent hydrogen strategies, while Brazil has a less ambitious strategy dating from 2010. In contrast, particularly the United States, Saudi Arabia, India and Iran will be large markets in which Danish companies will likely not be as competitive due to trade tariffs.

6. QUANTIFICATION OF EXPORT POTENTIAL

In this chapter we estimate the global market potential of PtX and CCUS technologies according to IEA's projections on hydrogen demand and production, and carbon capture and storage towards 2035, in their scenarios "Sustainable Development Scenario (SDS)" and "Net Zero Emissions by 2050 (NZE)", taken as low and high cases.

First, from technology assumptions on efficiencies and sizes and specific investments per capacity, we estimate the global investment required in these technologies. We also add a market potential for project developers and operation and maintenance companies related to the profits and O&M costs realised along the lifetime of the projects.

The total global market potential is then quantified as the total investment in CCUS and PtX technologies, O&M costs, and profits related to these projects. Estimating the potential for Danish companies in this market would require a detailed analysis of the international competition, which is outside the scope of this study. Instead we present two potential scenarios for low and high global market captured by danish companies. Hereafter, we elaborate the applied method and results of the market potential quantification.

KEY FINDINGS

The export potential for danish companies has been quantified within the range of 1 to 3% of the global market for CCUS technologies and 3 to 5% for PtX technologies since Danish companies are considered to have a stronger position in the PtX market than in CCUS technologies. Table 10 presents the export potential figures that we estimate can be realised by Danish companies in PtX and CCUS technologies under low and high global market captured scenarios and the two IEA scenarios, SDS and NZE.

Note that in line with the chapter **Mapping of Danish Companies and competences**, where no EPC Danish companies were identified, the EPC market share has been removed, thus adjusted export potentials are shown below for the share kept by project developers, technology providers, advisory service providers, equipment manufacturers, and O&M companies, where Danish companies are present. The values in **Table 10** must be regarded with care as a mere orientation exercise in the quantification of Danish market potential in CCUS and PtX technologies.

Table 10 - Estimated export potential for Danish companies in PtX and CCUS markets by 2035.

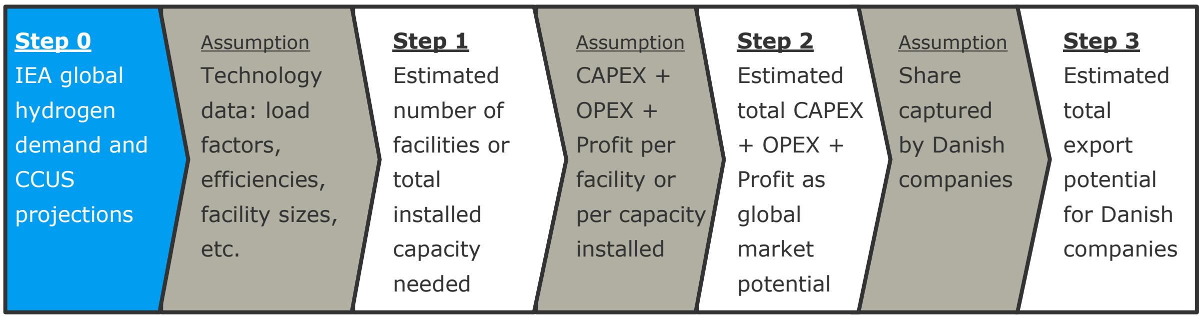
Technology type	Scenario	Low share of global market towards 2035 (1% CCUS, 3% PtX)	High share of global market towards 2035 (3% CCUS, 5% PtX)
CCUS	LOW (SDS)	EUR 12 billion (EUR 6 billion*)	EUR 36 billion (EUR 18 billion*)
	HIGH (NZE)	EUR 26 billion (EUR 13 billion*)	EUR 78 billion (EUR 39 billion*)
PtX	LOW (SDS)	EUR 14 billion (EUR 7 billion*)	EUR 23 billion (EUR 12 billion*)
	HIGH (NZE)	EUR 52 billion (EUR 27 billion*)	EUR 87 billion (EUR 44 billion*)

Source: Ramboll. Note: all values in 2021 fixed prices. * CAPEX-based market potential without OPEX and profit accounted.

6.1 Methodology

As a starting point to estimate the export potential of PtX and CCUS markets for Danish companies, we have assumed hydrogen demand and carbon capture and storage projections from the International Energy Agency. IEA's sustainable development scenario (SDS) and net zero emissions in 2050 (NZE) have been used as low and high cases to estimate the global market potential of PtX and CCUS. From these scenarios, we have done successive calculations under different technology and economic assumptions to reach the final global market potential and the share kept by danish companies. To the extent possible, we have taken all input data from the IEA to maintain consistency between all data assumptions. A scheme of the general methodology followed is presented in Figure 14 and explained below.

Figure 14 - Methodology used to estimate export potential for Danish companies in PtX and CCUS markets. In blue, IEA projections (SDS and ENZ scenarios); in grey, assumptions; in white, estimations calculated.



The methodology used begins with IEA projections on hydrogen demand and CCUS under their two scenarios SDS and ENZ (Step 0). These projections, detailed by sector or technology to a certain extent, have been translated into PtX and CCUS technology markets. Assuming technology characteristics, such as efficiencies, average load factors or facility sizes, we estimate the number of facilities or capacity needed for each technology corresponding to IEA projections. That is, how much capacity is needed to use the amount of hydrogen projected by the IEA, in the case of PtX technologies, or how much capacity must be installed to capture the amount of carbon projected by the IEA, in the case of CCUS technologies (Step 1). Then, assuming an average CAPEX per capacity installed by the year projected, following technology's cost decline due to learning rates and scale-up economies, we estimate the global investment needed for all facilities installed. We also add an OPEX estimation based on a 3% of CAPEX spent annually in O&M services, as well as a profit estimation to be realised by project developers based on a fixed profit margin of 10% of the total costs of the projects. The global market potential corresponds to the sum of total CAPEX, OPEX and profits (Step 2). Last, assuming a rational share of the different technology markets that Danish companies can capture according to their current presence in those markets, we were able to quantify the export potential of Danish companies for each technology (Step 3).

It must be highlighted that our estimations rely on IEA SDS and NZE projections. When these have been compared to other global institutions' projections, such as Bloomberg, Bain & Company, or Hydrogen Council with McKinsey & Co., IEA projections may fall short in particular for the hydrogen share in final energy demand. While the IEA projects hydrogen to represent 5% of the final energy demand in 2050, in their SDS scenario, and 18% in their NZE2050 scenario[4], Bloomberg projects hydrogen to be 7% in their "weak policy" scenario and 25% in their "strong policy" scenario by 2050. An overview of hydrogen share on final energy demand in 2050 is shown in Table 11 for different institutions.

[4] With the assumption that the final energy demand in the NZE scenario is equal to the SDS scenario.

Table 11 - Share of hydrogen in 2050 final energy demand according to different institutions' recent projections

	IEA	Bloomberg	Hydrogen Europe	Hydrogen Council	Bain&Co.
Source	[5]	[10]	[11]	[10]	[12]
Low case Scenario	5%	7%	8%	18%	n.a.
High case Scenario	18%	25%	24%	18%	24%

Although hydrogen final demand may be lower in the IEA scenarios compared to other institutions, we have chosen to follow IEA projections as they offered the more complete and consistent data along the different reports they have recently published on global energy outlook and technology perspectives and, in particular, about hydrogen and carbon capture and storage, as well as the data available. Since estimations in this chapter correspond to "high-level" calculations that follow a large number of assumptions and averaged values for technologies and their economies, we find it important to avoid too many different data sources, as they will all rely on inaccessible underlying assumptions that can lead to inconsistencies among sources. Relating IEA's projections to those of other institutions, the figures presented for the PtX global market potential can be regarded as conservative in both scenarios.

6.2 Export potential for CCUS

The main results of our study for the market potential per technology along the value chain of CCUS - production and infrastructure - are presented in **Table 12** and Table 13.We present results for the year 2035. All monetary figures are fixed 2021 prices.

As for carbon capture technology, **Table 12**, we detail carbon capture by type of plant. We include direct air capture facilities, carbon capture units in different industrial sectors, carbon capture in power plants split by fuel and finally, carbon capture projects applied in bioenergy plants that would count as carbon removal units. In general, we estimate load factors of 90% for industrial plants, except for power plants, where we count on capacity and production projections from the IEA scenarios, and calculate specific FLH by power plant type. The latter range from 30 to 60%. Production plants with the highest market potential for carbon capture are coal power plants, fuel transformation facilities (refining, biofuels, merchant hydrogen and ammonia production), and cement plants, following IEA projections on the amount of CO_2 that will be captured in these three sectors.

Table 12 - Estimated global market potential for CCUS production technologies in 2035.

CCUS Technology	CCUS Volume (MtCO2)		CCUS average facility size		CCUS Volume (number of facilities, * km for pipelines)		Market Potential (MEUR)		Market Potential per facility (MEUR / facility, * EUR/km for pipeline)	
	SDS	NZE	Unit	Value	SDS	NZE	SDS	NZE	SDS	NZE
Direct air capture	19	39	tCO_2/year	80,000	236	488	23,634	48,940	100	100
CC in Iron & Steel	34	57	tCO_2/year	1.2 million	27	45	19,372	32,276	712	712
CC in Chemicals	219	641	tCO_2/year	1.2 million	175	514	124,858	365,807	712	712

CCUS Technology	CCUS Volume (MtCO2)		CCUS average facility size		CCUS Volume (number of facilities, * km for pipelines)		Market Potential (MEUR)		Market Potential per facility (MEUR / facility, * EUR/km for pipeline)	
	SDS	NZE	Unit	Value	SDS	NZE	SDS	NZE	SDS	NZE
CC in Cement	377	939	tCO_2/year	1.2 million	302	753	214,976	535,965	712	712
CC in Pulp & Paper	0	0	tCO_2/year	1.2 million	0	0	171	208	712	712
CC in other fuel transformation[5]	205	487	tCO_2/h	156	222	444	435,408	793,835	1,963	1,832
CC in Power generation from coal	240	480	tCO_2/h	555	184	535	77,965	226,706	424	424
CC in Power generation from natural gas	49	141	tCO_2/h	101	1	59	1,581	107,175	1,812	1,812
CC in Power generation from biomass	2	150	tCO_2/h	513	531	1,074	377,697	764,435	712	712
Bioenergy with CO_2 capture and storage (BECCUS)	133	133	tCO_2/h	156	109	109	67,291	67,291	619	619

On the infrastructure of CCUS, **Table 13**, the highest market potential lies within carbon geological storage, with 274 storages with an annual injection capacity of 4 $MtCO_2$ are necessary to cover IEA carbon storage projections. We assume that 95% of carbon captured will be transported through pipelines from carbon sources to carbon sinks (storages, industrial plants consuming CO_2 or export terminals). We estimate 77-177 thousand km of CO2 pipelines needed in the SDS and NZE scenarios respectively by 2035. For the remaining 55% of carbon captured to be transported by ship, we estimate that 67 (SDS) - 151 (NZE) ships transporting CO_2 are needed.

Table 13 - Estimated global market potential for CCUS infrastructure technologies in 2035.

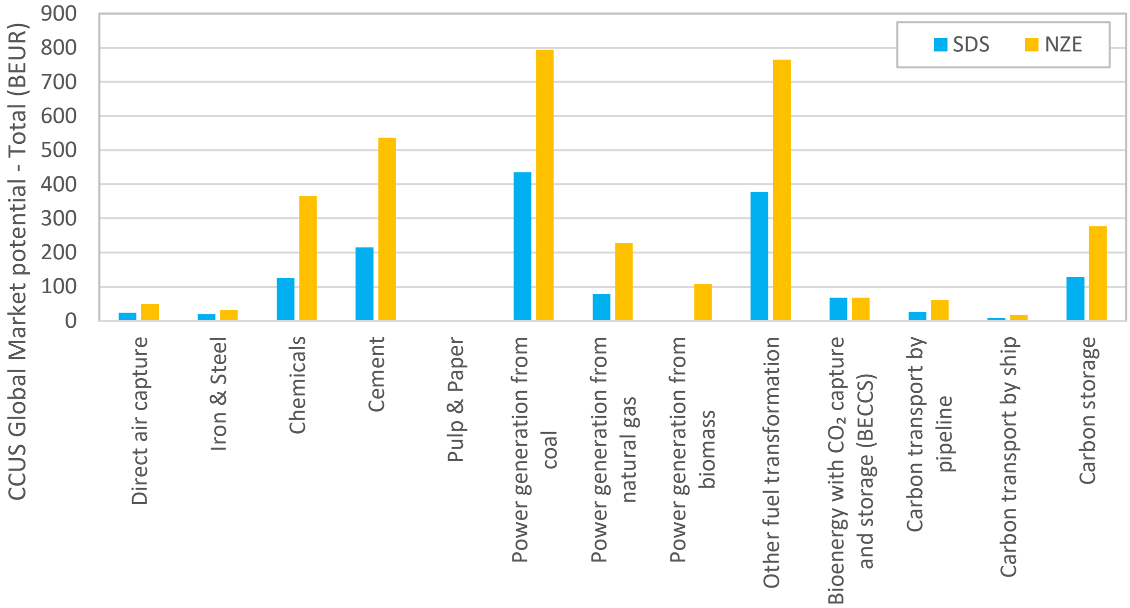
CCUS Technology	CCUS Volume (MtCO2)		CCUS average facility size		CCUS Volume (number of facilities, * km for pipelines)		Market Potential (MEUR)		Market Potential per facility (MEUR / facility, * EUR/km for pipeline)	
	SDS	NZE	Unit	Value	SDS	NZE	SDS	NZE	SDS	NZE
Carbon transport by pipeline	1,251	2,953	km	1	76,507	176,958	26,100	60,369	341,148	341,148
Carbon transport by ship	71	160	tCO2/ship	10,000	67	151	7,377	16,732	111	111
Carbon storage	966	2,236	Mt CO2/year	4	274	592	128,262	276,830	468	468

In **Figure 15**, the final global market potential for all CCUS technologies is presented. As it can be appreciated, the market for CCUS in coal power plants shows the highest potential, with 435 billion EUR in the "Sustainable Development Scenario" (SDS) and 649 billion EUR in the "Net Zero Emissions in 2050" (NZE) scenario. The next CCUS technologies with the highest potential are "Other fuel transformation", which covers fuel synthesis processes, like SMR of natural gas to

[5] Other fuel transformation covers refining, biofuels, merchant hydrogen and ammonia production.

hydrogen and others, with 378-563 billion EUR, followed by carbon capture facilities in cement plants, 215-320 billion EUR. On the infrastructure technologies, underground carbon storage shows a potential market of 128 to 191 billion EUR.

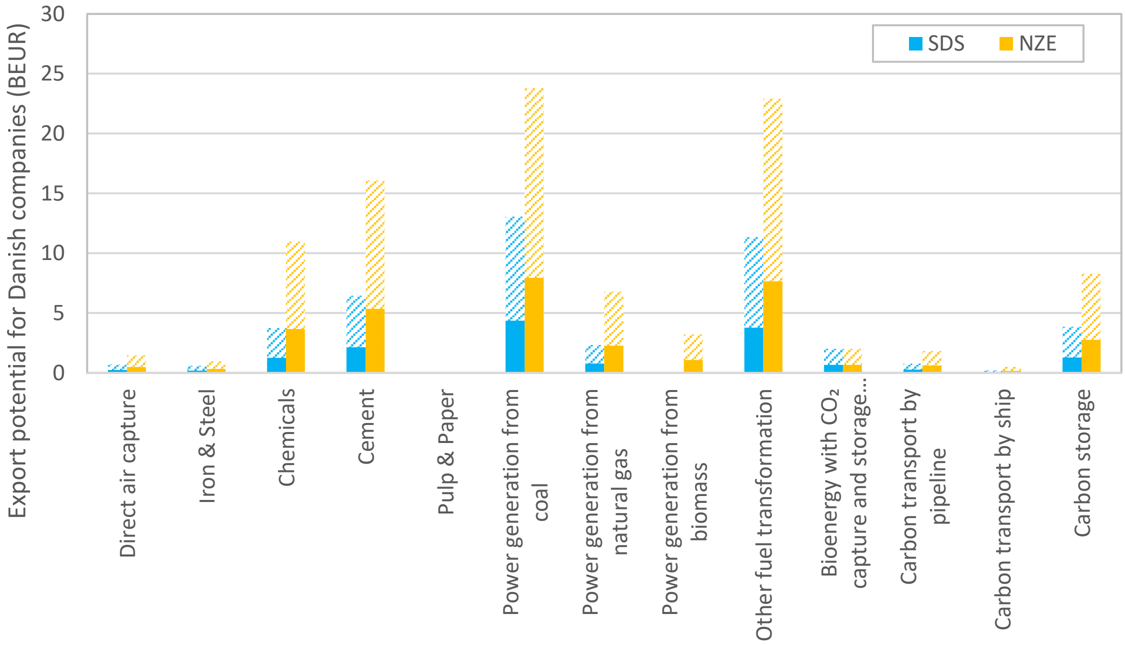
Figure 15 - Estimated global market potential for CCUS technologies in 2035



Source: Ramboll. Market potential is quantified based on CAPEX, OPEX and Profit.

Assuming that Danish companies can capture shares between 1 to 3% of the global CCUS market, we have estimated the export potential levels displayed on **Figure 16**. The difference between 3% and 1% market share is shown as dashed bars.

Figure 16 - Estimated export potential for Danish companies in CCUS markets per technology in 2035. Difference from 1% to 3% market share dashed.



Source: Ramboll

6.3 Export potential for PtX

The main results of our study for the market potential per technology along the value chain of PtX - production, infrastructure, demand - are presented in **Table 14** to **Table 16**. All monetary figures are fixed 2021 prices.

As for the hydrogen production technologies, **Table 14**, electrolysis is of course the technology that accounts for the highest market potential, since it is used as an energy carrier in the energy and transport sectors and as a feedstock for ammonia and fuel synthesis technologies. Ammonia synthesis here covers ammonia produced for shipping and fertilisers. Synfuel production considers methane, diesel, kerosene and methanol, with the latter accounting for the highest hydrogen consumption.

Table 14 - Estimated global market potential for PtX production technologies in 2035.

	PtX Volume (Mt H_2)		PtX average facility size		PtX Volume (number of facilities)		Market Potential (MEUR)		Market Potential per facility (MEUR / facility)	
	SDS	NZE	Unit	SDS	SDS	NZE	SDS	NZE	SDS	NZE
Electrolysis	27.51	266.28	GW	1.0	174	1,688	145,803	1,411,179	836	836
Ammonia	5.51	10.13	MtH_2/ year	0.2	28	51	34,281	63,099	1245	1245
Synfuel production	10.31	12.25	MW synfuel	102	514	610	50,187	59,632	98	98

In hydrogen infrastructure technologies, **Table 15**, hydrogen transport is dominated by hydrogen pipelines. Shipping of hydrogen only becomes competitive for very large distances connecting hydrogen points of large production to hydrogen points of large demand, as it is the case for the hydrogen shipping project connecting hydrogen production in Australia to hydrogen demand in Japan [13]. In the case of hydrogen transport, we estimate market projections based on the European Hydrogen Backbone project [14]. Market potential is based on new hydrogen pipelines, but also retrofitting natural gas pipelines to hydrogen. The share of new and retrofitted pipelines in 2035 is 50% of each following projection in [14].

Table 15 - Estimated global market potential for PtX infrastructure technologies in 2035.

	PtX Volume (Mt H_2)		PtX average facility size		PtX Volume (number of facilities[6])		Market Potential (MEUR)		Market Potential per facility (MEUR / facility[7])	
	SDS	NZE	Unit	SDS	SDS	NZE	SDS	NZE	SDS	NZE
H2 transport by pipeline	-	-	km	1	57,530	146,680	61,945	157,938	1.1	1.1
H2 transport by ship	0.28	2.66	tH2	11,000	25	242	13,073	105,706	522	437

[6] Km for pipelines

[7] MEUR/Km for pipelines

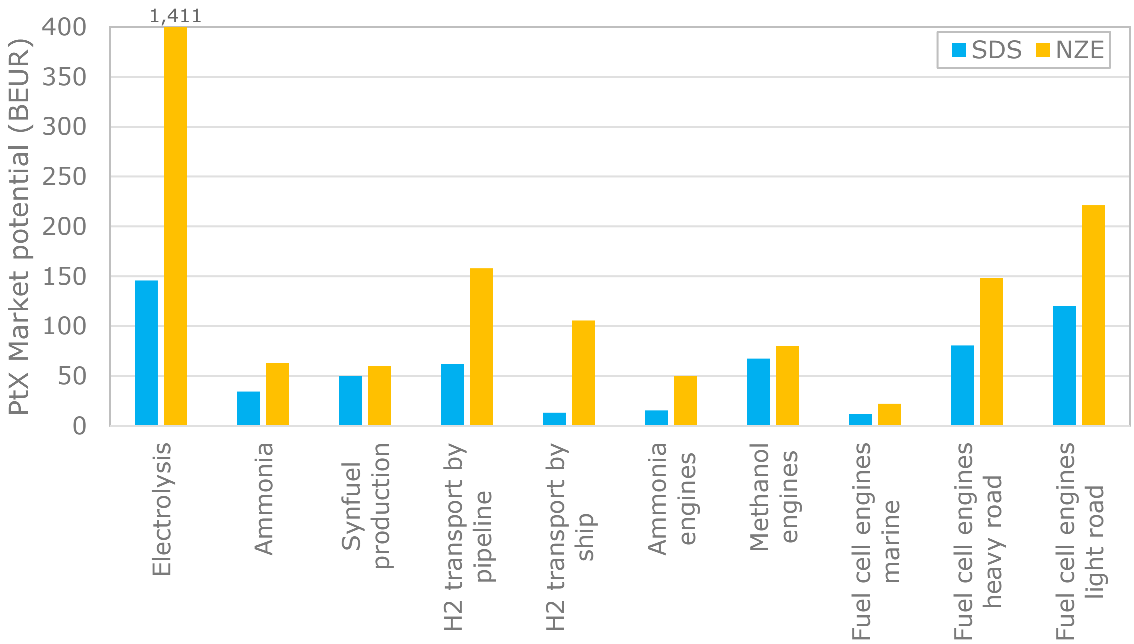
Finally, on hydrogen demand technologies, **Table 16**, the largest market potentials are observed in fuel cell engines for road transport, both heavy road and light road (i.e. hydrogen trucks and cars). We estimate that 80% of hydrogen demand in road transport (projected by IEA) would correspond to trucks, given that light road vehicles will be more dominated by electric vehicles. On marine transport, methanol engines have the largest market potential over ammonia engines and direct hydrogen fuel cell ships.

Table 16 - Estimated global market potential for PtX demand technologies in 2035.

	PtX Volume (Mt H_2)		PtX average facility size		PtX Volume (number of facilities)		Market Potential (MEUR)		Market Potential per facility (MEUR / facility)	
	SDS	NZE	Unit	SDS	SDS	NZE	SDS	NZE	SDS	NZE
Ammonia engines for marine transport	2.84	9.15	t synfuel/ year	102,200	156	502	15,591	50,198	100	100
Methanol engines for marine transport	8.25	9.80	t synfuel/ year	87,600	673	799	67,287	79,952	100	100
Fuel cell engines for marine transport	0.76	1.39	kW	10,989	513	944	12,065	22,208	24	24
Fuel cell engines for heavy road transport	7.24	13.33	kW	350	1.1 million	2 million	80,579	148,316	0.07	0.07
Fuel cell engines for light road transport	1.81	3.33	kW	95	10.65 million	19.6 million	120,149	221,148	0.01	0.01

Figure 17 displays the final global market potential per technology for all three sectors of hydrogen value chain (production, infrastructure, and demand). As it can be appreciated, the market for electrolysers shows the highest potential with 146 billion EUR in the "Sustainable Development Scenario" (SDS) and 1,411 billion EUR in the "Net Zero Emissions in 2050" (NZE) scenario. The high difference for electrolysers between the two scenarios stems from the larger share of green hydrogen in the NZE scenario (48% in NZE, 25% in SDS) and the higher demand of hydrogen (335 Mt H2 in NZE, 110 Mt H2 in SDS). The next PtX technologies with the highest potential are on the demand side, where fuel cell engines for road vehicles represent 120-221 billion EUR for hydrogen cars and 81-148 billion EUR for hydrogen trucks. Methanol marine engines is the technology that shows the highest potential for hydrogen-based fuel in maritime transportation, 67-80 billion EUR.

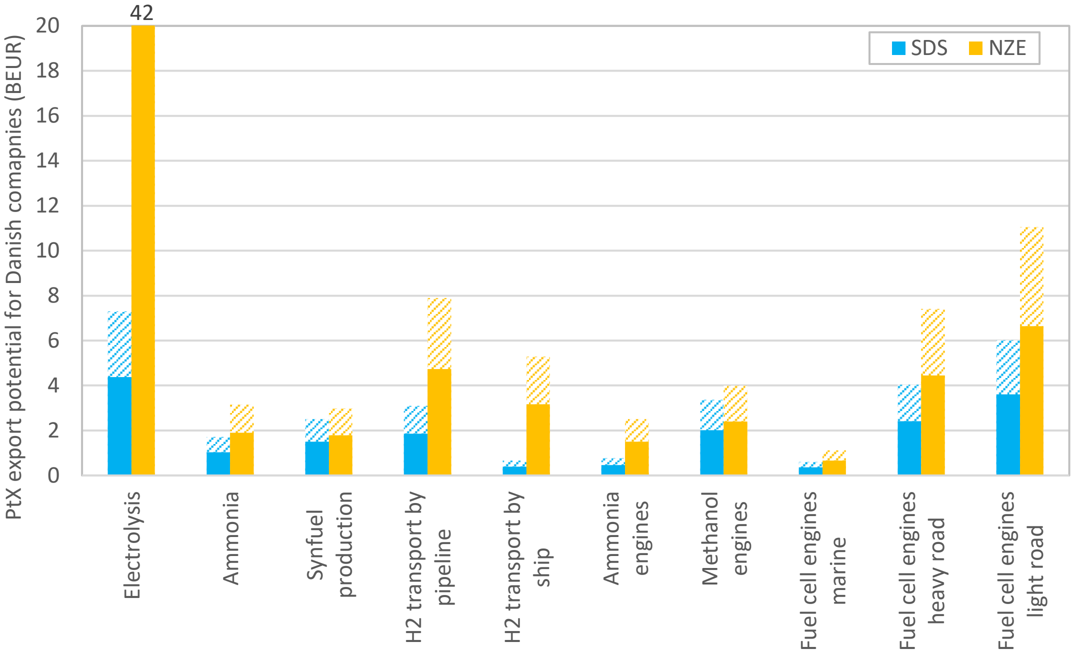
Figure 17 - Estimated global market potential for PtX markets in 2035



Source: Ramboll

From the global market potential, we assume that Danish companies can capture shares between 3 to 5% of the global market. The resulting export potential is displayed in **Figure 18**, where the market values corresponding to this share range (3-5%) are shown.

Figure 18 - Estimated export potential of Danish companies in PtX markets per technology in 2035. Difference from 3% to 5% market share dashed.



Source: Ramboll

6.4 Estimation of market share

The estimated market potentials in the previous sections represent the total market for PtX and CCUS globally. It may be necessary to consider the international competitive landscape to give a precise estimate of the share that Danish companies might obtain. As it is outside the scope of this project to analyse the international competition, we can only quantify the market potential based on market share assumptions.

There are Danish companies operating in large parts of both the PtX and CCUS value chains today. This may enable Danish companies to develop and provide efficient technologies and solutions to the sector, which are competitive at the global scale. PtX and CCUS-markets will have a high price sensitivity as energy products are traded in commodity markets. The successful development of competitive solutions therefore highly depends on the amount of capital invested into research and demonstration of large-scale plants, which can operate at a low cost.

In contrast to previous successes, such as the onshore and offshore wind sectors which Danish companies have pioneered without much competition, many other countries are also investing significant amounts of capital into scaling local PtX and CCUS technology. It is thus likely that Danish companies will meet strong competition abroad. PtX and CCUS are not singular technologies, and a large part of the equipment can be sourced locally.

If it is assumed that Danish companies will on average be among the top 10 to 20 companies competing in these markets, while also acknowledging that Danish companies have currently a stronger position in the PtX sector than in CCS, we estimate that Danish companies may be able to capture between **1 and 3% of the global CCUS market** and **3 to 5% of the global PtX market**.

The likelihood for Danish companies to achieve the higher end of this interval increases with the following variables:

- International preference for green over blue hydrogen.
- Investment into research and development of large-scale demonstration plants with suppliers from the Danish value chains.
- Promotion of cross-industry partnering for achieving cost reductions via system synergies (sector-coupling).
- National strategy for PtX and CCUS that sets national targets.

6.5 Market potential division by type of company

As seen in section **Mapping of Danish Companies and competences**, the value chain for technology investments can be divided in the following sectors or services: project developers, technology providers, engineering, procurement & construction (EPC), advisory service providers, original equipment manufacturers, and operation & maintenance. As a last step in our market potential estimation exercise, we divide the final export potential for Danish companies into the previously mentioned services, so a more detailed picture can be obtained of the export potential per type of company.

These company types provide services and create value in different moments of the market value chain with different shares. To estimate the market potential for each of them, we have assumed the following:

1. Project developers: their market potential is estimated through the achievable profit from projects. This has been roughly estimated with a fixed profit margin of 10% over CAPEX and OPEX.
2. Technology providers: we assume they can represent 10% of the CAPEX-based market potential.
3. Engineering, Procurement and Construction (EPC) companies: we assume they can represent 35% of the CAPEX-based market potential.
4. Advisory service providers: we assume they can represent 5% of the CAPEX-based market potential.
5. Original equipment manufacturers: we assume they can represent 50% of the CAPEX-based market potential.
6. Operation and maintenance companies: we assume their market potential based on OPEX of projects, roughly estimated to be 3% of the CAPEX per year.

In **Table 17**, we present the division of the total Danish export potential for CCUS technologies among the different company types according to the assumptions stated earlier. Since there are no Danish companies providing EPC services, EPC share of the market (35% of the CAPEX-based market) is subtracted to obtain the Danish export potential.

Table 17 - Estimated export potential by type of company for CCUS markets in 2035. Values presented for low and high case scenarios (SDS and NZE2050) and by total Danish global market share captured (1 and 3%). Values in MEUR.

Company Type	Share of the market	LOW (SDS)		HIGH (NZE2050)	
		1% share	3% share	1% share	3% share
Unit	%	MEUR	MEUR	MEUR	MEUR
1. Project developers	Project profit	1,368	4,104	2,997	8,991
2. Technology providers	10% CAPEX	903	2,710	1,979	5,936
3. Engineering, procurement & construction (EPC)	35% CAPEX	3,161	9,483	6,925	20,776
4. Advisory service providers	5% CAPEX	452	1,355	989	2,968
5. Original equipment manufacturers	50% CAPEX	4,516	13,548	9,894	29,681
6. O&M service providers	OPEX	4,647	13,942	10,182	30,545
Total Danish export potential (CAPEX-based excluding EPC companies)	65% CAPEX	5,871	17,612	12,862	38,585
Total Danish export potential (excluding EPC companies)	-	11,886	35,657	26,040	78,121

In **Table 18**, we present the division of the total Danish export potential for PtX technologies among the different company types according to the assumptions stated earlier.

Table 18 - Estimated export potential by type of company for PtX markets in 2035. Values presented for low and high case scenarios (SDS and NZE2050) and by total Danish global market share captured (3 and 5%). Values in MEUR.

Company Type	Share of the market	LOW (SDS)		HIGH (NZE2050)	
		5% share	10% share	5% share	10% share
Unit	%	MEUR	MEUR	MEUR	MEUR
1. Project developers	Project profit	1,804	3,006	7,921	13,202
2. Technology providers	10% CAPEX	1,125	1,875	4,254	7,090
3. Engineering, procurement & construction (EPC)	35% CAPEX	3,938	6,563	14,889	24,814
4. Advisory service providers	5% CAPEX	563	938	2,127	3,545
5. Original equipment manufacturers	50% CAPEX	5,625	9,375	21,270	35,449
6. O&M service providers	OPEX	4,975	8,292	19,121	31,869
Total Danish export potential (CAPEX-based excluding EPC companies)	65% CAPEX	7,313	12,188	27,650	46,084
Total Danish export potential (excluding EPC companies)	-	14,091	23,486	54,693	91,154

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APPENDIX - DETAILED TECHNOLOGY MAPPING

Table 19 – Detailed mapping of CCUS Technologies

Value Chain Step	Technology	Description	Technology Readiness Level
Production	Pre-combustion IGCC-CCUS	In pre-combustion carbon capture, CO_2 is removed from the fuel before its combustion. IGCC (integrated gasification combined cycle) is a power generating technology in which the solid feedstock is partially oxidized with low levels of oxygen (obtained from an air separation unit) to produce a syngas ($CO + H_2$), which is then converted with steam into CO_2 and H_2 through a water gas shift reaction (WGSR). The CO_2 is separated, compressed, and stored, and the H_2 is used as the fuel for the combined cycle (gas + steam turbine cycle) to produce electricity. The carbon capture technology must be applied in the design of new plants, as retrofitting involve major changes in the plant configuration. The efficiency loss of IGCC against a usual coal power plant is estimated to be from 7 to 8% [15].	TRL of 7 since this technology has been developed in demonstration projects under the clean coal power concept [16].
Production	Post-combustion chemical absorption	Amine scrubbing is a mature and commercial technology which is widely used for post-combustion treatment of flue gas. Liquid amino-based sorbents react with CO_2 from the flue gas and CO_2 is then separated in a desorption process, and then compressed and stored or used. The technology has been utilised at commercial-scale post-combustion capture facilities in coal-fired power plants [17]. The process is energy intensive and reduces the overall efficiency of the power plant about 10-30% yet this energy penalty can be offset by an increase in heating production for CHP units [18] and [6]. Despite the commercial status there is potential for optimisation of particularly the absorbent efficiency and the adaptation of the energy cycle for the specific plant. Hot Potassium Carbonate (HPC) is a process that uses an aqueous potassium carbonate solution to absorb CO2 under elevated pressure. The CO2 is released with limited heat input when the pressure of the solution is lowered. The process is in wide commercial use in the process industry. For use as post combustion process, the power consumption is relatively large due to compression of the entire flue gas stream.	TRL of 9 since this technology is mature and has been used for decades to remove CO_2 from natural gas [17]. It is also in commercial use for CO2-capture from flue gases. [6] HPC has TRL 9 for use in the process industry, and TRL 7-8 for use as post combustion technology.
Production	Post-combustion physical adsorption	Physical adsorption process is like chemical absorption but occurs at the surface of a solid sorbent material (activated carbon, zeolites, metal organic frameworks, etc.). It requires that the flue gas is cooled down to 40 to 70°C and that sulfur	TRL of 7 since post-combustion adsorption is only

		dioxide (SO_2) is removed. CO_2 is separated in a desorption process and then compressed and stored or used. Different adsorption technologies exist: pressure, vacuum, electro swing adsorption (PSA, VSA, ESA); none of which is at a commercial stage yet.	at the demonstration level [19].
Production	Post-combustion membrane CO_2 capture	CO_2 capture with membranes is a promising technology as it has proven to be highly efficient for CO_2 concentrations in flue gas above 10%, while optimal economic competitive requirements are achieved for CO_2 concentrations above 20%[8]. Membranes are made of polymer materials, which can degrade in the process in the presence of too low pressure or too high pressures and temperatures (membranes rapidly degraded over 100°C). Membranes made of composite materials under investigation can behave better at high pressures and temperatures. The presence of acid gases (NOx and SO_2) in the flue gas also degrade membranes, thus this is another limitation for the application of membranes for CO_2 capture from combustion processes.	TRL of 6 for polymeric membranes for flue gas carbon capture in power plants since they are at demonstration stage. TRL of 7 for membrane CO_2 capture from natural gas as the technology is more ready for natural gas processing [19].
Production	Post-combustion cryogenic-based CO_2 capture	Cryogenic-based CO_2 capture processes consist in the separation at very low temperature and/or high pressure of the different gaseous components in the flue gas due to their different dew and sublimation points. The available cryogenic technologies are dynamic packed bed, cryogenic distillation, mechanical coolers using Stirling cycle and hybrid membrane/cryogenic process [19]. In these methods, the flue gas is cooled to -100 to −135°C and the CO_2 is separated from other light gases. The CO_2 recovery can reach 90–95% of the flue gas. It is an energy intensive process (600–660 kWh/tCO_2), thus it is ideal to have access to an already available source of excess cooling and not use electricity only purposed for this process. This can be the case in LNG regasification plants.	TRL of 9 since cryogenic technologies are applied commercially for natural gas processing [15].
Production	Oxyfuel combustion	Oxyfuel combustion was developed in the beginning of the 1980's. The process was intended to produce CO_2 for enhanced oil recovery. In the 1990's, the technology gained interest for its potential use as a carbon capture technology. In oxyfuel combustion, oxygen, instead of air, is used for combustion, which makes the composition of flue gases to be mainly CO_2, water, particulates and SO_2. Particulates and SO_2 can be removed by conventional electrostatic precipitator and flue gas desulphurization methods, respectively. The remaining gases contain a high concentration of CO_2 (80–98% depending on the fuel), which can be compressed and stored. This process is technically feasible but consumes large	TRL of 7 as it has been applied in sub-scale commercial demonstration coal power plants [19].

[8] CO_2 level in combustion flue gas is normally quite low, i.e. 7–14% for coal-fired and as low as 4% for gas-fired.

		amounts of oxygen coming from an energy intensive air separation unit (ASU). This results in high cost and the energy penalty may reach over 7% compared with a plant without CC [15]. The oxygen may be delivered as a by-product from electrolyses of water, in the case of power-2-X application of the CO2, where CO2 and hydrogen are used for production of liquid or gaseous fuels such as methanol or DME. The hydrogen, and hence the oxygen, are produced from electrolysis by use, preferably of low cost electricity sources such as excess wind turbine energy	
Production	Chemical looping combustion	Chemical looping combustion is a novel combustion concept with integrated carbon capture. Oxygen is carried to the combustion process in the form of a solid carrier e.g. metal oxide. The oxygen carrier will be reduced through reaction with the fuel and is hereafter regenerated in a separate oxidizing reactor with air. In principle, the technology is a kind of oxy-fuel process as nitrogen is eliminated from the combustion atmosphere. The concept will eliminate the costly air separation unit of oxy-fuel processes, hence offers a cost saving potential. The technology is not relevant for retrofit to existing emission sources [20].	TRL of 4 since the technology working principle has only been demonstrated on a pilot-plant scale with low commercial attention [20].
Production	Direct air capture (DAC)	Direct air capture (DAC) is an emerging technology which can potentially allow for the development of widely distributed CO_2 capture infrastructure. It involves removing CO_2 from air (with around 0.04% content of CO_2) through chemical separation processes. The earliest and most widely studied DAC technique involves the use of aqueous solutions of sodium or calcium hydroxide as sorbents. This reaction forms carbonates and hydroxides. Carbonates are calcined to release a concentrated CO_2 stream, and the hydroxide stream is recirculated in the system.	TRL of 4-6 as it there are only pilot demonstration units using DAC [21].
Production	Pyrogenic carbon capture (PYCC)	If biomass is pyrolyzed (chemically decomposed at high temperatures, 350 to 900°C, in an oxygen-deficient atmosphere), the organic carbon is converted into solid (biochar), liquid (bio-oil), and gaseous (permanent pyrogas) carbonaceous products. This biochar can be used both as a fertiliser and a carbon sequestration method since the original biomass would have captured CO_2 from the atmosphere during its growth (negative emission). The carbon efficiency of the thermal conversion of biomass into biochar is normally considered to be in the range of 30%–50%, but efficiencies of up to 70% can be achieved when the liquid and gaseous pyrolysis products (commonly considered for combustion) are reprocessed into recalcitrant forms suitable for carbon sequestration. Pyrolysis technology is already well established, biochar sequestration and bio-oil	TRL of 9 since the pyrolysis technology is industrially ready and widely used although not for carbon capture.

		sequestration in soils do not present ecological hazards and global scale-up appears feasible within a time frame of 10 – 30 years. This negative-emission technology needs biomass plantation, which can entail potential side effects on other sustainability goals including food security, respecting planetary boundaries and ecosystem protection.	
Infrastructure	CO_2 compression	The efficient transportation of large volumes of CO_2 generally requires pipelines that will operate above the critical pressure of CO_2. Since most capture processes release CO_2 at low pressure, compression of CO_2 from the point of capture to pipeline will generally be required. The compression duty can be achieved using conventional multi-stage compressors or using newer shockwave type compressors. Pumping could also be used if CO_2 is condensed below its critical point [22].	TRL of 9 since compression technologies are industrially available.
Infrastructure	CO2 injection pump	High pressure pump is required at the final stage of the CO_2 compression process for CCUS when CO_2 must be injected into reservoir in supercritical phase. In order to handle super critical CO_2, pump is considered to be more suitable than compressors. Pumps are normally used in liquid phase of the fluid and compressibility is not taken in design. Therefore, there are some points to be considered for design of supercritical CO_2 injection pump. Special care shall be taken for corrosion, low viscosity and density variation [23].	TRL of 9 since the technology is industrially available.
Infrastructure	CO_2 dehydration	CO2 pipeline transportation and storage allows only extremely low amounts of water in the CO2 fluid due to hydrate and free water formation, which can plug valves and fittings along the pipeline or react with CO2 to form formic acid, which causes electrochemical corrosion. Therefore, the CO2 gas fluid from the capture process must be dehydrated to a water content below 50 mg/l before it is transported. There are several commonly used dehydration methods for acid gas stream: compression and cooling, solid adsorption and absorption. Compression and cooling is one of the most widely used methods since it can compress and cool the gases at the same time, but it is not suitable for deep dehydration. Solid adsorption dehydration using an adsorbent (e.g. silica gel, molecular sieve, activated alumina, activated carbon) can be applied to remove water vapor under various temperature, pressure and flow rate conditions, and it is also a mature process. The absorption via solvent is the most adopted method in reason of economic and technical benefits [24].	TRL of 9 since dehydration technologies are industrially available.

Infrastructure	CO_2 liquefaction	CO_2 may be liquefied at various temperature and pressure conditions (-56 to 31°C and pressure of 5.2 to 74 bar). Typical conditions for transport, interim storage and trading of industrial CO_2 is in the order of -28°C and 15 bar. In a standard industrial CO_2 liquefaction solution, concentrated CO_2 is compressed to 15-20 bar and liquefied by chilling at -25 to -30°C. The CO_2 is dehydrated prior to chilling. The requirements for CO_2 dryness for liquid CO_2 will be even more stringent due to greater risk of ice or hydrate formation at the lower temperatures (<30 ppm). Non-condensable gases will also have to be removed to low level as these will change the physical properties of the liquid CO_2. A standard liquefaction plant will include a stripping unit to remove non-condensable gasses, CO_2 dryer and activated carbon (or similar) filter to remove traces of organic compounds from the carbon capture plant. A small loss of CO_2 in the liquefaction process through purging about 1% should be expected [20].	TRL of 9 since liquefaction of CO_2 is a mature industrial process.
Infrastructure	New CO_2 pipelines	Typically, CO_2 is transported in pipelines as fluid in the dense liquid phase or supercritical phase. The operation is typically of 100-150 bar pressure and a temperature between 5-30°C. Booster pump stations may be needed for long distances. CO_2 pipelines can suffer from corrosion with influencing factors being pressure, temperature, flow rate, presence of SO_2 or water.	TRL of 9 since there are commercial CO_2 pipelines (both onshore and offshore) in operation today (most in the US used for enhanced oil recovery) [25].
Infrastructure	Retrofitting of natural gas pipelines to CO_2	When CO_2 is to be stored in depleted oil and gas fields, existing oil and gas pipelines can be retrofitted to transport CO_2, which has a cost of 1 to 10% of the capital cost of a new CO_2 pipeline.	TRL of 9 since retrofitting of oil and gas pipelines has been implemented [25].
Infrastructure	CO_2 shipping	Ship transport of liquified CO_2 is more cost-efficient for long distances (estimated above 1,500 km in [26]), since the transportation costs increase very slightly with distances but present a high initial investment cost, as opposed to pipelines, whose costs are proportional to the distance covered. Liquified CO_2 can be transported under different pressure levels: low (5.2 bar, -56°C), medium (15 to 18bar, -25 to -30°C) and high (40-50 bar, 5 to 15°C), with different designs on the cargo tanks. A liquefaction facility is needed in the point of origin and a CO_2 terminal with insulated storage tanks in the point of destination. Only limited volumes of CO_2 are transported by ship today and in relatively small ships (1000 – 2000 m^3) [27]. There is a possibility to refurbish old gas carriers to transport CO_2.	TRL of 8 as liquified CO_2 transportation by ship is a commercial technology but only available for small ships [25].

Infrastructure	CO_2 transport by road	Transport of CO_2 on road tankers is widely applied today. The conditions used for road transport of liquid CO_2 is 15-18 bar and -25 to -30°C. A truck of 30 t CO_2 capacity can be loaded/unloaded with liquid CO_2 in around 45 min. As an example, transporting 30 t CO_2 25 km will result in emission of less than 1% of the CO_2 for a round trip. Road truck transport of CO_2 will mainly be relevant for small to medium volumes of CO_2 over limited distances. This may for instances by from a CO_2 capture plant at a relatively small emission source and to a nearby export terminal or CO_2 utilisation facility [27].	TRL of 9 since CO_2 transport by road is widely applied today.
Infrastructure	Aquifer CO_2 storage	CO_2 can be stored in underground aquifers just as these have been used to store natural gas (and earlier town gas) since 1953. One or two injection wells as well as a compression facility/injection pump are needed. Once the CO_2 is pumped into the underground aquifer, it is trapped under the impermeable cap rock above the aquifer geological formation. To maintain the pressure of the aquifer, water needs to be released as CO_2 is injected. This water can be used as geothermal energy. Storage in aquifers does only allow to recover between 33 to 50% of the CO_2 injected [28].	TRL of 9 since the technology needed is similar to that of geological natural gas storage, fully commercially available.
Infrastructure	Salt cavern CO_2 storage	Salt caverns are a more expensive geological storage option than aquifers or depleted oil and gas fields since the cavity needs to be created first. This is done by injecting water and dissolving the salt within the geological formation and extracting the resulting brine. Salt caverns, however, allow the highest recovery of CO_2. A common salt cavern is 1,000 m below surface operating at pressures of 65 to 180 bar. It is recommended to store CO_2 in the dense liquid or supercritical phase.	TRL of 9 since the technology needed is similar to that of geological natural gas storage, fully commercially available.
Infrastructure/ Demand	Carbon capture and storage enhanced oil recovery (CCUS-EOR)	Carbon capture and storage enhanced oil recovery, CCUS-EOR, Has the dual objective of recovering additional quantities of oil from reservoirs and storing some of the injected CO_2 permanently in the depleted reservoir. The motivation is to generate as much income as possible from incremental oil to offset the high costs of the CCUS process. Whereas in CO_2-EOR the objective is to produce as much incremental oil as possible using as little CO2 as possible (and recover CO_2 to be reused), with CCUS-EOR there is a balance between recovered oil (to generate income) and the amount of CO_2 stored. This balance is critical in determining the viability of CCUS-EOR processes [25].	TRL of 7 since EOR it has been practiced for several decades in the oil and gas industry but full CCUS-EOR applications have been limited.

Demand	PtX technologies using CO_2	Related to power-to-x technologies, CO_2 is the carbon source for the synthesis of carbon-based green fuels from hydrogen obtained from electrolysis powered by renewables. PtX green fuel technologies using CO_2 are synthesis processes of methane, methanol, DME, and Fischer-Tropsch (where in the latter two, CO_2 is used to produce syngas, CO+H2, as an intermediate feedstock in the process). All these technologies are described in Table 20.	TRL of 5-9 depending on the PtX technology. See details in Table 20.

Table 20 – Detailed mapping of Power-to-X technologies

Value Chain Step	Technology	Description	Technology Readiness Level
Production	Alkaline Electrolysis Cells (AEC)	Alkaline electrolysis is a mature technology that has been commercially available for decades (reaction discovered in 1800 and industrial electrolysers in operation already in early 1900's) [29] [30] [31]. It is widely applied for large-scale hydrogen production in the chemical and metallurgic industry in MW scale [32] [33]. Alkaline electrolysis uses electricity and water as input for the reaction and operates at a temperature in the range of 60-80°C under either atmospheric or pressurised conditions. Hydrogen and oxygen are the outputs of the reaction as well as excess heat, which can be utilised for district heating. Process conversion efficiency range from 43 to 74%. AEC uses a liquid electrolyte for charge transfer as a core part of the process. The electrolyte is an alkaline base solution (KOH or NaOH) which is rather corrosive, and which needs to be handled with caution.	TRL of 9 due to installed capacities of up to 100 MW [34].
Production	Proton Exchange Membrane (PEM)	Proton exchange technology uses a solid polymer membrane. It was first introduced in 1966 and it was commercially available in 1978 [29] [30]. Electrodes typically consist of noble scarce materials such as iridium and platinum [32] [35], [36] [33]. It operates between 50-80°C and can operate at higher pressure than alkaline (80 bar or more). It has a higher regulation ability than AEC with fast response to load changes and an operational load range from 5 to 100%. Estimated conversion efficiencies range from 40 to 69%.	TRL of 7 due to PEM electrolysers available today only in single-digit MW range [34].
Production	Solid Oxide Electrolysis Cell (SOEC)	High temperature SOEC electrolysis is one of the most recently developed electrolysis technologies and was first introduced in the 1980´s [36]. The technology has since been demonstrated on laboratory scale. Unlike AEC and PEM, operating at temperatures between 50 to 80°C and using water, SOEC operates at temperatures between 600 to 1000°C and uses steam. Its potential application thus increases where high temperature heat source is available. It can reach a conversion efficiency above 80% [29]. It can operate in reverse mode as a fuel cell (producing electricity) or in co-electrolysis mode producing syngas ($CO+H_2$) [37] [38] [34] [33].	TRL of 5 as only kW size plants are available [34], but larger sizes may enter the market soon [32] [33].
Production	Methane synthesis	The methanation reaction, also called the Sabatier reaction, was discovered in 1897. It is the reaction of CO_2 and CO with H_2 to form CH_4 (SNG, synthetic natural	TRL of 8-9 due to existing examples of operational

		gas) and H_2O. It has been mostly used to eliminate trace carbon oxides (CO_2 and CO) from feed gas for ammonia synthesis as they damage the catalysts. Methanation has however recently gained renewed interest as a power-to-x technology. Methanation reaction can occur using a Nickel, Rhodium or Ruthenium-based catalyst (catalytic methanation) or using microbes (biological methanation). While the first has reached a pre-industrial scale [39] [32] [40], the latter has only reached demonstration level [41].	facilities producing synthetic natural gas from renewable hydrogen produced by electrolysis [42].
Production	Methanol synthesis	Methanol is commonly obtained from syngas (from steam reforming of natural gas). The alternative power-to-x option consists of a catalytic hydrogenation (+H_2 from electrolysis) of CO_2, a process that is known and technology-ready for industrial scale and whose only limitation is the production of CO_2 and H_2. The largest commercial production plant is located in Iceland (4,000 tons of methanol per year). The conversion efficiency in the direct hydrogenation of CO_2 is reported to be around 79% [32] [43].	TRL of 8 since the technology is industrially ready but limited by the availability of CO_2 and green H_2 and there are limited existing commercial facilities [44] [44].
Production	DME (dimethyl ether) synthesis	DME has been mainly used as aerosol propellant and reagent to produce other organic compounds such as dimethyl sulfate and acetic acid, but it can be a potential substitute synthetic fuel for liquified petroleum gas (LPG) and diesel [45]. Two main routes can be chosen to produce DME: 1) indirect route by dehydration of green methanol [46]. 2) direct catalytic synthesis from syngas (CO+H_2), normally obtained from natural gas reforming, but it can also be obtained from SOEC co-electrolysis of CO_2 with water [47]. While the direct method is more efficient (80% conversion efficiency vs. 67%) [32], it is still not at commercial stage as the indirect method. It is also possible to produce DME from direct hydrogenation (+H_2) of CO_2 with the use of a hybrid catalyst ($CuO/ZnO_2/Al_2O_3$ with ZrO_2). This option is under investigation at laboratory scale [48].	TRL of 9 for indirect production route since it is based on the common process to obtain DME and would be only limited by the green methanol production capability (TRL=8). TRL of 4 for the direct production route due to complexity in the separation process of DME, which deters its commercial feasibility [44]. TRL of 3 for DME from direct hydrogenation of CO_2 as it is currently under investigation at laboratory scale [48].
Production	Fisher-Tropsch synthesis (FTS)	The Fischer-Tropsch synthesis (FTS) process was initially developed in the 1920's to produce hydrocarbons from coal gasification products [49] [50]. It converts a syngas (CO+H_2) into a mixture of hydrocarbons in the presence of a catalyst. It is used to produce a variety of synthetic liquid hydrocarbon fuels. FTS is fully	TRL of 5 to 9 for FTS technologies integrating renewable CO_2 routes for syngas production, such as dry

		commercial, but most facilities use non-renewable feedstocks with CO_2 emitting processes. FTS integrating renewable CO_2 routes for syngas production has a lower technological maturity. The product of the FTS is a syncrude that is then refined (hydrocracked and upgraded in refinery processes) to diesel, kerosene, jet fuel, other hydrocarbons and heat as a by-product.	reforming and reverse-water gas shift (RWGS), with lower technological maturity than FTS [42] [51].
Production	Ammonia synthesis through Haber-Bosch process	Ammonia (NH_3) from power is obtained through the Haber-Bosch process in which Nitrogen (N_2), obtained in an air separation unit (ASU), is combined with Hydrogen (H_2). Their reaction is favoured at temperatures from 300 to 500°C, pressures from 200 to 350 bar, and with the presence of a catalyst (iron or ruthenium based). Ammonia is extracted from this reaction by condensation. This process was discovered in 1913 and has been widely used since then [52]. However, most of the ammonia produced worldwide is currently derived from H_2 obtained through natural gas steam reforming, a process that emits CO_2 and produces CO as a by-product but that is less costly than H_2 obtained from electrolysis. The Haber-Bosch process can achieve a conversion efficiency of 67%. High value heat in the form of steam is an output of the process.	TRL of 9 as the Haber-Bosch process has been used since 1913 and is at global industrial scale [28].
Production	Ammonia synthesis through electrocatalytic nitrogen reduction reaction	Ammonia from electrocatalytic reduction of nitrogen (N_2) is a less energy-consuming alternative to the Haber-Bosch as it can operate at ambient conditions thus not requiring high temperatures and pressures. Electrocatalysts are the paramount components of this process and they are still under investigation. This process is still at research and development stage with NH_3 production rates still below the requirement for practical industry applications [53].	TRL of 4 since the process is still at a research stage in laboratory with production rates below practical industrial applications [53].
Infrastructure	Hydrogen compression	To be fed into the transmission system, the hydrogen must be compressed to the operating pressure of the network. Compressor stations at certain intervals along the line ensure that the pressure is maintained despite loss of flow in the pipeline. To enable optimal utilization with high transport energy density in hydrogen operation, more and higher-power compressors are required than in natural gas operation. In the pure hydrogen operation of a pipeline, an energy flow of 80-90% of the natural gas capacity can be achieved by roughly tripling the amount of gas extracted. This increase can also be achieved in the existing pipeline network due to the higher flow rate of the hydrogen. However, this requires a higher drive power than is reserved for the transportation of natural	TRL of 8-9 since there are still developments to be made in the turbo-compressor technology to adequate this to hydrogen transportation.

		gas. To maximize the hydrogen capacity of the gas network, approximately three times the drive power and therefore a correspondingly higher number of turbines and compressors are required than in natural gas operation. Piston compressors For transport capacities of up to 750,000 Nm³/h, current state-of-the-art piston compressors are the most economical solution. This seems to be the case for planned pipeline projects with the short and medium-term expected amounts of hydrogen. Turbo compressors For transport capacities above 750,000 Nm³/h, turbo-compressors are required. This technology is already available, but its efficiency is currently lower than that of piston compressors and many impellers are required to achieve an acceptable compression ratio. Studies recommend increasing the peripheral speeds of the impellers to over 700 m/s due to the low molar weight of hydrogen to achieve a compression ratio of approximately 1.3-to-1 per impeller. This requires new hydrogen-resistant impeller materials that can withstand high centrifugal forces. The necessary developments have already been initiated so that appropriate wheels should become available in the coming years. Turbo-compressors are likely to be needed in the long-term, where a generalised switch to hydrogen with a transport requirement in the gigawatt range is needed. Retrofitting of existing compressors Current compressors can be kept up to 40% of hydrogen content blended in the natural gas network (with some adjustments to impellers, feedback stages and gears). From 40% of hydrogen content, the existing compressors must be replaced by new ones adequate for hydrogen. [54]	
Infrastructure	New hydrogen pipelines	Pipelines for gaseous hydrogen are likely to be the cheapest delivery option for transport along distances below 1,500 km (most except trans-oceanic) and for local distribution if there is sufficiently large localised demand. Otherwise, transport of liquid or gas hydrogen by trucks may remain the preferred distribution option. Above 1,500 km, shipping hydrogen as liquid hydrogen, ammonia, or a liquid organic hydrogen carrier (LOHC) may be more cost-effective [55]. Typical operating conditions for hydrogen pipelines tend to be between 10 and 30 bar [56]	TRL of 9 since there are already existing commercial hydrogen pipelines.

		and up to 100 °C [57]. Materials of construction can vary with those of natural gas pipelines due to hydrogen embrittlement (penetration of hydrogen into the pipe metal structure). Stainless steel is the preferred material of construction, and lining materials for corrosion and embrittlement prevention are common. Compressor energy demand to transport hydrogen is estimated to be 4.5 times that of natural gas per unit of energy delivered [58].	
Infrastructure	Retrofitting of natural gas pipelines to hydrogen	Relevant studies and previous practical knowledge indicate that it is possible to convert the existing steel pipelines from natural gas to hydrogen operation to fully deploy a hydrogen network. Nevertheless, further examination is needed on whether the operating parameters must be adjusted for certain types of steel and operating conditions. In the case of fittings and control valves, the suitability for hydrogen of the membranes and seals used must also be determined. In the case of safety shut-off valves and pressure regulators, it must be clarified if the control and regulating functions must be adapted for the flow properties of hydrogen. Specific conditions of the existing infrastructure would need to be inspected and assessed and the relevant codes and regulations consulted prior to determining if the pipelines are suitable. The physical H_2 readiness of the natural gas system essentially depends on the possible influence of hydrogen on the materials used. Especially for pipeline pipes and fittings made of steel, a reduction in material toughness can be measured under the influence of hydrogen (‘hydrogen embrittlement’). Depending on the steel grade and the operating conditions of the pipeline, this reduction in toughness can lead to the growth of existing crack-like defects. In these cases, the service life of the line is therefore reduced.	TRL of 7-9 since the equipment technologies are ready but further examination is needed in demonstration hydrogen network projects like the GETH2 Nukleus project in Germany [59].
Infrastructure	Road and rail transportation of gaseous and liquid hydrogen	Hydrogen has so far predominantly used in the petrochemical (refining) industry and when this gas is not produced and used onsite, the preferred industrial transport method remains pipelines with some intermediate storage stations. Yet hydrogen can also be transported by road or rail. For short distances (<200 km), hydrogen can be transported in proofed seamless vessels (usually at pressures of 180 to 250 bar, although there are new cylinders that can stand pressure from 400 to 700 bar). The vessels are usually grouped in bundles and are filled at the premises of the centralized production plant and delivered to the final consumer where the empty set of bottles is replaced. For medium and long distances,	TRL of 9, commercial technology.

		hydrogen is liquified and transported in cryogenic liquid hydrogen tankers by trucks or rail [60].	
Infrastructure	Hydrogen shipping	The transport of hydrogen across the sea was studied intensively during the late 1980s to the late 1990s, although liquified hydrogen transport was not deployed due to its lower density than its most proximate competitor, LNG. However, in December 2019, the world's first liquefied hydrogen carrier has been manufactured. Liquefied hydrogen is transported at 1/800 of its original gas-state volume, and cooled to −253°C. The liquified hydrogen storage tank that the carrier will transport has been manufactured in March 2020.	TRL of 8, since the technology is industrially ready, but only one commercial carrier has been manufactured [61].
Infrastructure	Hydrogen geological storage	Hydrogen can be stored in geological formations just as natural gas or CO_2. The more favourable geological formations for gas storage are aquifers, salt caverns and depleted oil and gas fields [62]. A more detailed description of the different geological formation options for storage is given in Table 19 for CO_2 geological storage.	TRL of 9 since the technology needed is similar to that of geological natural gas storage, fully commercially available.
Infrastructure	Hydrogen storage tanks	Hydrogen in gas from in compressed tanks (pressures above 200 bar) is the most common method for hydrogen storage. These thick-walled tanks (mainly cylindrical) are made of high-strength materials to ensure durability. Gas hydrogen is mostly used for storage of limited hydrogen quantities, for long term storage, or when the cost of liquefaction is prohibitive. Hydrogen in liquid form has a considerably higher energy density than in gaseous form, making it an attractive storage medium. The volumetric capacity of hydrogen increases from 24 or 40g/l (for compressed H_2 at 350 or 700bar at 26°C) to 70g/l (for liquid H_2 at 1atm and -253°C). Effective thermal insulation is essential to maximize the efficiency of the liquid hydrogen (LH2) tank. Typical LH2 tanks consist of metallic double-walled containers, in which the inner and outer walls are separated by vacuum for thermal insulation purposes. The energy requirements of liquefaction are high, typically 30% of the hydrogen's heating value, leading to relatively high hydrogen cost as compared to gaseous hydrogen. The loss of hydrogen by evaporation effects during storage periods are further disadvantages of liquid hydrogen (LH2) storage systems.	TRL of 9 since the technology is fully commercially available [63].
Infrastructure	Liquid electro-fuels shipping	For large distances, shipping is usually the most cost-efficient solution to transport liquid electro-fuels such as liquified ammonia (under insulated tanks at temperatures between -52 to -33°C and atmospheric pressure [64] or pressurised	TRL of 8-9 since commercial carriers transporting these chemical products/fuels have

		at 17atm and ambient temperature), methane (in liquified form cooled at -162°C in cryogenic tanks), DME (liquified in tanks refrigerated at -50°C, pressurized or both) and methanol (in liquid form at atmospheric and ambient temperatures [65]). Methanol bunkering is less developed (although there are existing commercial tanker fleets for marine transport of methanol [66]) and recent guidelines have been developed for its safe handling [67, 65].	been operating for decades but, in the case of methanol, its bunkering is less developed.
Demand	Solid Oxide Fuel Cell (SOFC)	A solid oxide fuel cell (SOFC) allows the direct conversion of chemical energy into electrical energy at high temperatures (above 800°C) using an all solid-state cell equipped with ceramic materials. These systems can in principle achieve efficiency levels significantly higher than conventional technologies used to produce electricity, but they have not reached the maturity level of direct combustion systems due to the high operating temperatures needed and limitations of materials used (stability, reactivity, durability, cost). Research in materials and components is taking place to overcome this reach a commercial stage. SOFCs consist of three elements assembled together: a dense electrolyte between two porous electrodes, the anode and the cathode. A fuel (hydrogen from power-to-x application, but natural gas, biogas and others can also be used) is fed to the anode, where an oxidation reaction takes place, which releases electrons to the cathode through an external circuit (electricity generated) causing the reduction reaction at the cathode (fed with air). High value heat is also produced for potential applications as CHP units.	TRL of 7 since only demonstration models (<1000 kW) have been commissioned and research is taking place to reach a full commercial stage.
Demand	Proton Exchange Membrane (PEM) Fuel Cell	The proton exchange membrane (PEM) fuel cell consists of a cathode and an anode made of graphite and a proton-conducting polymer as the electrolyte. The PEM fuel cell resembles the PEM electrolyser, in which the opposite reaction occurs. The fuel in this case must be hydrogen and together with the electricity produced, water and heat are also an output of the process. Low temperature PEM fuel cells operate at temperatures below 100°C (typically around 80°C) since the membrane must be saturated by water. The fuel cell technology still needs to be matured on issues like lifetime and cost reduction [68].	TRL of 7 since only demonstration plants (<1000 kW) have been commissioned.
Demand	Molten Carbonate Fuel Cell (MCFC)	The molten carbonate fuel cell (MCFC) is a high temperature fuel cell system which is being used commercially for stationary power generation. The name of the system refers to the electrolyte in the fuel cells, which consists of a mix of Alkali carbonate materials that is ionically conductive at the cell operating temperature,	TRL of 7 since there are multiple demonstration plants with a total cumulative capacity of 60 MW [69]

		typically 600 to 650°C. The fuel cell stacks are mostly made of stainless-steel materials, and the electrode structures are porous nickel alloys. Nobel metal catalysts are not needed because of the high operating temperature of the fuel cell. The operating temperature of the fuel cell also promotes the use of internal reforming, in which hydrocarbon fuels are converted to hydrogen inside the cell stack, instead of in an external processor. Research and development on the system has been conducted since the 1950s, and demonstration powerplants based on the technology have been available since 2003 [69].	
Demand	Phosphoric Acid Fuel Cell (PAFC)	Phosphoric acid fuel cells (PAFCs) use liquid phosphoric acid as an electrolyte and porous carbon electrodes containing a platinum catalyst. The PAFC is considered the "first generation" of modern fuel cells. It was developed in the 1960s it has produced the most working units of all fuel cell types. These were all produced in the 1970s. This type of fuel cell was typically used for stationary power generation, but some PAFCs have been used to power large vehicles such as city buses. PAFCs are more tolerant to CO (possible impurity in H_2 obtained from fossil fuels) than PEM cells as they operate at higher temperatures (180 to 210°C). PAFCs can achieve efficiencies of 85% efficient as CHP units but only 37%–42% as electricity-only units [70]. The highest disadvantages of PAFC are their comparatively low current density and the potential hazard of the strong acid used, why they have been nearly abandoned. Yet there are some recent designs that use phosphoric acid electrolyte embedded in solid polymer membrane films [71].	TRL of 7 since the technology has demonstrated to be ready for electricity generation units in the past.
Demand	Direct Ammonia Fuel Cell (DAFC)	The working principles of ammonia fuel cells are similar to hydrogen fuel cells entailing electrode reactions as well as membrane electrolytes. The fuel input feed in a DAFC comprises a direct inlet of ammonia (NH_3). Up to date, the best choice for DAFC is the solid oxide fuel cell (SOFC) technology, although others are also possible [72]. Albeit the working principles of DAFC are well established, their performance is considerably low as compared to hydrogen fuel cells due to the insufficient electrooxidation of ammonia molecules. The type of catalyst activity observed in the case of hydrogen oxidation for fuel cells has not been achieved yet for the case of ammonia oxidation. This remains one of the key factors that prohibit the development of high-performance DAFC [73].	TRL of 4 since the technology is under investigation in laboratory.

Demand	Direct Methanol Fuel Cell (DMFC)	DMFC is a subcategory of polymer electrolyte membrane fuel cell (PEMFC) where liquid methanol is used as a fuel instead of hydrogen gas. Hydrogen is the most used fuel for fuel cells due to its high gravimetric energy density and weak hydrogen–hydrogen bond, but it has some drawbacks such as bulk storage requirements, transport issues, and high flammability. Hence, for portable applications (vehicles) where system compactness is more important than efficiency and cost, hydrogen fueled fuel cells may not be well suited. Liquid fuels, such as methanol, are denser, have higher energy density and require smaller storage space compared to hydrogen gas. Different types of liquid fuels can be used in the PEMFC such as methanol, ethanol, formic acid, hydrazine, ethylene glycol, and dimethyl ether. Methanol has a simple chemical structure, weakly bonded hydrogen atoms, and shows better electrochemical activity in the fuel cell compared to other liquid fuels. Therefore, DMFC is the most advanced type among the liquid fuel cells. Methanol electro-oxidation process was first introduced in the 1920s on alkaline electrolytes, but it was not until the early 1990s when proton exchange membranes where used as a DMFC electrolyte, which currently remains the state of the art. High-Temperature PEM fuel cells operate at 160-180°C and CO_2 and heat are produced in the reaction of methanol with water inside the fuel cell [74].	TRL of 9 since commercial DMFC products are today available [75].
Demand	2 stroke methanol dual fuel engine for marine transportation	<u>The two-stroke engine</u> The 2-stroke engine is the technology that most large vessels have as propulsion system since they offer more power per working volume than 4-stroke cycle engines. These engines are often low-speed marine diesel engines (LSMDE) with rated speeds from 80 to 300 rpm. They attain lower speeds but can work with cheaper low-grade fuel oils, have a higher efficiency, offer more power to weight ratio (more cargo), and have also advantages in O&M since they are simpler in components (no reduction gear) than a 4-stroke engine [76]. Three main manufacturers and their licensees produce these engines: MAN Diesel & Turbo SE, Wärtsilä NSD and J-Eng [77]. <u>Methanol dual-fueled engines</u> Methanol shows very low levels of NOx, SOx and particulate matter compared to conventional marine fuels. Its CO_2 emissions can be considered net zero when the carbon to produce methanol comes from carbon capture. Due to the low cetane	TRL of 9 since there are already commercial vessels with methanol fueled engines.

		number of methanol (related to the self-ignition capacity), a pilot fuel (diesel) is added in the injection to allow its ignition by compression without the presence of an ignition source (i.e. spark). Methanol has some potential issues related to corrosion and lubricity, but these are overcome with lubricating oil and an adequate selection of materials. Another issue of methanol is its lower heating value and lower density than traditional fuels used in marine transport, thus it requires twice as much space. The low flashpoint of methanol (T at which its vapour ignites in the presence of an ignition source) makes it necessary to have double-walled pipes in the fuel supply system. Water can be added to methanol at the injection to reduce the levels of NOx in the exhaust gases. [78]. MAN has commissioned 8 dual fuel engines for vessels in 2019 running on diesel/fueloil/marine gasoil and methanol (engine model LGIM) [78].	
Demand	Retrofitting of 2-stroke engines for marine transportation to methanol	2 stroke engine models for marine transportation have been adapted by manufacturers for dual-fuel operation. Methanol properties imply no major modifications to the existing diesel engines. These are related to the fuel supply system, fuel injection and auxiliary systems. The first ship to convert to methanol was the Stena Germanic ferry (Wärtsilä was the engine manufacturer). It has been operating since 2015.	TRL of 9 since engine manufacturers offer retrofitting solutions for existing engines [78].
Demand	2 stroke ammonia dual fuel engine for marine transportation	There are different projects investigating and designing 2-stroke engines fueled by ammonia [79], with the first commissioned vessels planned for 2024. Although ammonia has advantages over other fuels (carbon and sulphur-free, higher volumetric density than H_2, non-explosive, easier to transport and store than H_2 in need of cryogenic temperatures), it is a toxic substance and corrosive to copper that has not yet been released for use as a marine fuel. [80].	TRL of 5 since the adaptation of compression engines to ammonia is under research by engine builders.
Demand	4-stroke ammonia dual fuel engine for marine transportation	<u>The two-stroke engine</u> Four-stroke engines have smaller weight and dimensions than 2-stroke low-speed engines. They are generally used in smaller marine vessels than larger vessels using 2-stroke cycle engines. The specific cost of the unit power during the construction of 4-stroke engines is lower. Gearboxes and elastic joints are needed to coordinate their rotational speed with the propeller rotational speed, which reduces the efficiency of the propulsion unit. Working cylinders of smaller diameter is compensated by an increase in their number, which leads to an increase in the complexity of servicing such engines. The latter circumstance is partly	TRL of 5 since the adaptation of compression engines to ammonia is under research by engine builders.

		compensated by the smaller dimensions of the parts and, consequently, by their smaller mass [77]. Four-stroke engines are often medium (300 to 1,000 rpm) and high (>1,000 rpm) speed engines and are easier to maneuver than 2-stroke engines [80]. <u>4-stroke engine fueled by ammonia</u> MAN Energy Solutions has begun the 'AmmoniaMot' (Ammonia Engine in German) project. Initiated by MAN with partners from industry and research institutes, it aims to define the steps necessary to produce a dual-fuel, medium-speed engine capable of running on diesel-fuel and ammonia [76].	
Demand	Retrofitting of 2 and 4-stroke engines for marine transportation to ammonia	Today, many of the vessels delivered are ready for later dual-fuel adaption to ammonia (or other low flash-point liquid efuels) [76].	TRL of 5 since the adaptation of compression engines to ammonia is under research by engine builders.