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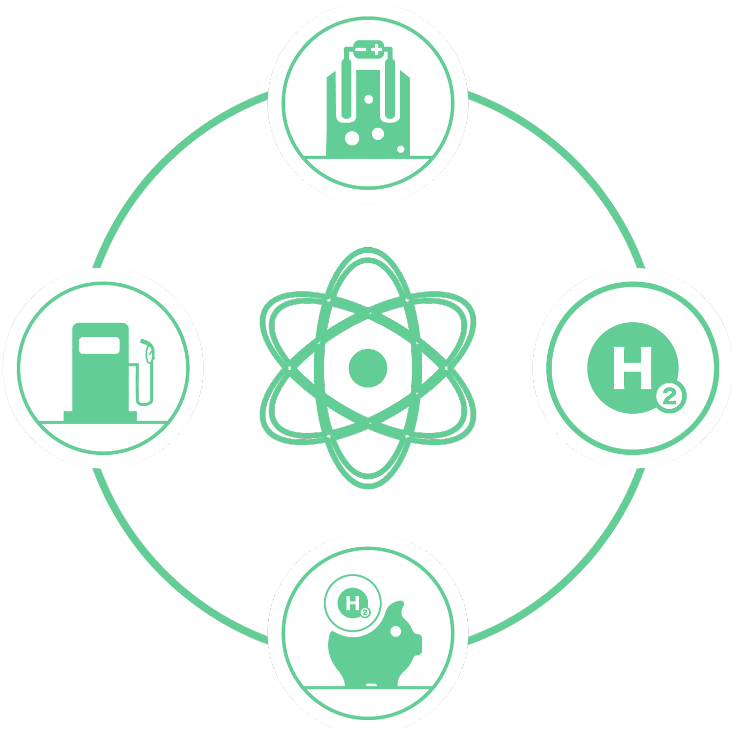

Low-Carbon Hydrogen Production Using Small Modular Reactors

Is energy from small modular nuclear reactors a competitive way of producing hydrogen in the future hydrogen economy?

Master's thesis in Product development and Production engineering

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CHALMERS UNIVERSITY OF TECHNOLOGY
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Master's thesis 2021

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Abstract

Hydrogen has been proposed as a way to achieve decarbonisation within many sectors from transportation to industry. In order to achieve this reduction in emissions the hydrogen itself must be produced with low carbon emissions. The study has investigated what applications hydrogen will most likely have a prominent role in, and what requirements different demands put on the supply. The development of small modular nuclear reactors (SMR) has been investigated as well as their potential as an energy source in low-carbon hydrogen production. The research approach of the study consisted of a literature study, followed by an interview study. The interview study consisted of interviews with 12 experts in the areas of hydrogen applications and nuclear power. The study also included calculations deciding not only production cost but also the final delivered cost of hydrogen. The study found that there are some applications where the demand for hydrogen is certain, including in the production of ammonia and methanol. Other possible hydrogen uses include steel production and transportation are also found as probable areas with growing demands for hydrogen in the future. The study found that SMRs have many synergies with hydrogen production, including process heat, continuous production, modularity and SMRs being less location-specific compared to other alternatives. Finally, the results of the study include calculations of the delivered cost of hydrogen, proving that, under certain assumptions and when accounting for cost of the whole supply chain, small modular reactors provide a competitive source of energy. To summarise, the study has found that there is a need for low-carbon hydrogen in the future and that it is important to consider the delivered cost of hydrogen, which includes production, transportation, and storage cost. It was found that it is important to be technology-neutral when considering energy sources for producing hydrogen and that nuclear and SMRs should be included as an option.

Keywords: Hydrogen, Electrolysis, Levelised Cost of Hydrogen, LCOH, Small Modular Reactors, SMR

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Balder Hagert & Ludvig Blomgren, Gothenburg, May 2021

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List of Abbreviations

GHG - Greenhouse Gas
RES - Renewable Energy System
SMR - Small Modular Reactor

IEA - International Energy Agency
CCS - Carbon Capture and Storage
FCEV - Fuel Cell Electric Vehicles
ICE - Internal Combustion Engine
BEV - Battery-powered Electric Vehicle
TCO - Total Cost of Ownership

LCOH - Levelised Cost of Hydrogen
LCOE - Levelised Cost of Electricity
AEC - Alkaline Electrolyser
PEM - Proton Exchange Membrane
SOEC - Solid Oxide Electrolyser
OPEX - Operational Expenditure
CAPEX - Capital Expenditure
CRF - Capital Recovery Factor

LWR - Light-Water Reactor
PWR - Pressurised Water Reactor
BWR - Boiling Water Reactor
MSR - Molten Salt Reactor
HTGR - High-temperature Gas Reactor
LNP - Large Nuclear Power Plant
FOAK - First-of-a-kind
NOAK - Nth-of-a-kind
WNA - World Nuclear Association
NRC - US Nuclear Regulatory Commission
CNSC - Canadian Nuclear Safety Commission
DOE - U.S. Department of Energy

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Introduction

In this chapter, first, a background to the work will be given together with a problem statement. Next, the collaboration with the company with which the study was conducted together with, *AFRY*, is outlined. The purpose and goals of the work are explained as well as the research questions. Demarcations set for the work are presented and finally, an outline of the thesis is given.

1.1 Background

Climate change is one of mankind's biggest challenges and poses a great threat to the planet and its inhabitants. In order to overcome the challenge, both the emissions of greenhouse gases (GHG) and the concentration of GHGs in the atmosphere must drop sharply. However, despite this, both emissions and the concentration of GHGs are currently increasing. This results in rising global average temperatures which in turn creates more desert landscapes and causes rising sea levels. If something is not done, this will eventually create great disharmony in the way we live and operate as of today. To reverse the effects, the situation requires a change towards more sustainable means of consumption, the way we produce energy, and what types of energy sources we use in transportation, to name a few.

The European Union's latest effort in its strive towards becoming the first climate-neutral continent is "The European Green Deal". The initiative aims to reach an efficient use of resources and a circular economy by, for example, decarbonising the energy sector [1]. More than 75% of GHG emissions are related to the production and use of energy in the EU. In total, the EU plans to invest at least 1 trillion euros to reach its targets [1]. One key part of the EU:s strategy aims at the increased use of hydrogen in the energy sector. The use of pure hydrogen, for combustion or electrification, does not emit GHG. This makes it a necessary alternative to help decarbonise hard-to-abate sectors such as parts of the transport sector and certain carbon-intensive industrial processes [2]. However, hydrogen does not occur naturally in its pure form and requires considerable amounts of energy to produce by separating it from other elements. Today, this is mainly done by using fossil fuels [3]. For hydrogen to be an alternative, and be considered low-carbon hydrogen, the production methods and the supplied energy need to be low-carbon as well. Because of inefficiencies in the production, the amount of energy required to produce low-carbon hydrogen is significantly higher than the amount of low-carbon that is produced, in terms of energy. This means that it is not only the use of hydrogen that needs to increase but also the low-carbon energy it takes to produce it sustainably.

As an example, the German hydrogen strategy estimates that around 90 to 110 TWh of hydrogen will be needed in 2030. At the same time, it is estimated that only around 14 TWh can be supplied domestically with current initiatives [4]. This would in turn require 20 TWh of low-carbon energy. Assuming it would take the same energy consumption to produce the remaining 76 to 90 TWh of hydrogen, the total low-carbon energy demand for hydrogen production would roughly be 140 TWh.

The question that arises is where all of this energy is supposed to come from. The consensus within the EU is to solely rely on renewable energy sources (RES) long-term. In Sweden, a project called Hybrit is currently investigating the possibility of building the first-ever fossil-free steel production site using hydrogen [5]. If successful, the factory would require 15 TWh of renewable energy. This is about 75% of the energy produced from solar and wind in Sweden today [6]. So, even though the expansion of RES is necessary in several ways, it is questionable if it can meet the increased energy demand in the required time frame. Furthermore, it introduces risk regarding what will happen with decarbonisation using hydrogen, if the deployment of renewables cannot keep up.

Another energy source, classified as low-carbon, that is not mentioned as frequently for this application is nuclear power. The energy produced from a nuclear reactor releases very small amounts of GHG emissions and could, from a theoretical standpoint, stand as an addition to RES. Recent advances within the nuclear industry have also been made to combat some of the downsides associated with the technology. One of these is the concept of the small modular reactor (SMR). A small reactor is defined as having a capacity of 300 MW electric (MWe), or less [7]. This means that instead of building one large reactor of 1000 MWe or above, you could build several smaller ones. SMRs are also meant to have a simpler and more standardised design. This opens the possibility for them to be largely factory-built and assembled on-site [8]. Additionally, building several, allowing a steeper learning curve, leads to a decrease in construction delays and capital cost per reactor. These traits are supposed to increase the flexibility and ease mainly some of the financial concerns that surround nuclear today. The reactors also aim to increase the safety of producing nuclear energy by implementing passive safety features, as well as reducing the risk of proliferation of nuclear weapons [9]. The first serial-produced SMRs for civil use are already operational on icebreakers in Russia [10]. In addition, the interest in SMR has grown over the last few years and many other designs are on their way to being realised in the US, UK, Canada, and China [11].

1.2 Problem Statement

The EU is putting a lot of effort and faith in the coming age of hydrogen. Following this, the production of hydrogen also needs to shift from using traditional fossil fuels as the primary source of energy, to a more sustainable source. The current consensus is seemingly centred on the expansion of RES for this application. But as mentioned, there is a gap between the large amounts needed and the strategy for supplying this demand. On the other hand, is the recent progress of SMR development in the nuclear industry that aims to mitigate some of the major downsides and concerns with the technology. Is it feasible, as well as competitive, to include nuclear into the mix of low-carbon energy sources that can be used to produce sustainable hydrogen? Especially in dire times where more solutions are needed rather than fewer.

1.3 Collaboration with AFRY

The study was conducted together with and at the request of, *AFRY - Energy & Power Division.* The company has over 60 years of experience working with nuclear energy and the surrounding areas. The company has experience executing nuclear energy projects in over 35 countries together with energy companies, contractors, constructors, and authorities. They have expertise within all areas of the life cycle of conventional nuclear plants and within construction, upgrades, safety, and maintenance.

Relating to this, small modular reactors is one of the latest areas in the field of nuclear power where AFRY has a dedicated effort on SMR deployment and finding new applications for nuclear beyond electricity. AFRY is actively working with clients, cooperating with other companies and innovations and other developments within SMR and nuclear beyond electricity are followed closely.

The other main theme, hydrogen, is not a new industry, and an area in which AFRY has long experience working within. Hydrogen has been used for a long time but primarily produced with and from fossil fuels. A growing business within this field is to instead use electrolysis, supplied with low-carbon energy. The primary interest for AFRY was to understand different applications for hydrogen in the future, potential methods for more sustainable production, and finally the possible connection to SMRs. Building further knowledge in these areas will be of interest to the company, to better understand where competence might be lacking and have to be developed. In addition, to better meet the future needs of their clients.

1.4 Purpose & Research Questions

In collaboration with *Chalmers University of Technology* and *AFRY - Energy & Power Division*, the study aimed to learn what use areas there are for hydrogen in a more sustainable future. Further more, what is required in terms of its production, and what methods exist to make it a competitive product compared with the alternatives?

Also, since much low-carbon hydrogen is needed in the near future; it investigated under which conditions nuclear, and more specifically small modular reactors, can be a competitive way of generating the energy needed in its production.

The synergy between hydrogen production and nuclear energy generation was in the end analysed and discussed. The work also addressed what foundations there are to realise this in a foreseeable future. The purpose of the thesis has been summarised in the following four research questions and will be answered throughout the report:

1. *What does the hydrogen value chain look like?*
2. *What is an SMR and how does it differ from conventional nuclear power?*
3. *Under what conditions can an SMR be a viable alternative for hydrogen production?*
4. *What are the major barriers for hydrogen produced by SMRs to become a reality?*

1.5 Demarcations

The demarcations of this study are presented below. They are categorised based on the three main topics examined in this report.

Hydrogen Demand

- The study is not meant as an exhaustive compilation of all future and potential applications of hydrogen. Some of the more prominent ones not analysed in this study include hydrogen for producing cement and hydrogen for heating residential and commercial buildings.

Hydrogen Supply

- The study only briefly examined the two most prominent ways of producing carbon-rich hydrogen. These are steam methane reforming and coal gasification. Only steam methane reforming was further analysed throughout the study. Other carbon-rich methods, such as producing hydrogen as a by-product from various industries, fell outside the scope of this study.

- In terms of low-carbon hydrogen production, the main focus was on electrolysis. This means that new and/or innovative production methods such as photoelectrolysis, the usage of biological processes, or other, fell outside the scope.

- The study focused on the usage of the most prominent electrolysis techniques. These are alkaline electrolyser, proton exchange membrane and solid oxide electrolyser. This means that new and innovative techniques, such as the anion exchange membrane, fell outside the scope.

- The study analysed the current and future development of the mentioned electrolysis techniques. This means that the study did not investigate the possibility of technically optimising these techniques.

- In terms of hydrogen storage, the study focused on physical storage methods. This means that chemical storage, such as storing hydrogen in ammonia or various metal hybrids, fell outside the scope. It also means that the transport of chemically stored hydrogen fell outside the scope.

Nuclear Energy

- In terms of nuclear energy, the main topic of the study was SMRs. This means that hydrogen production utilising energy from large and conventional nuclear power plants fell outside the scope of the study.

- The study analysed the current and future development of different SMR designs. This means that the study did not investigate optimising these designs or the nuclear technology used.

- As there are several other studies on the subject, the study did not focus on barriers relating to the handling of radioactive waste. This means that the supply chain surrounding the final storage of radioactive waste fell outside the scope of this study.

- The study focused on utilising SMRs for the sole purpose of hydrogen production. This means that other areas of application for SMRs fell outside the scope of this study.

1.6 Outline of thesis

This section aims to describe the content of each chapter in this report. The general outline of the study will be based on a 3S approach introduced by Canan Acar and Ibrahim Dincer [12]. The 3S stands for service, system, and source. In this report, it will instead be renamed to demand, supply and energy source. The demand is in this case defined as different hydrogen applications. The supply is defined as the hydrogen supply chain, including production, storage, and transport of hydrogen. Lastly, the energy source is defined as the source of energy needed to produce hydrogen. Because the scope of the study is hydrogen production combined with the use of an SMR, the focus of the energy source will be on nuclear energy and SMRs. How the approach has been utilised can be read further in chapter 2.

Chapter 2 describes the research method. The general research approach has been to source literature and to interview experts on the subjects of hydrogen and SMR. The 3S approach has been used to find synergies of the utilisation of SMRs for hydrogen production.

Chapter 3 describes the applications creating a hydrogen demand. This includes existing hydrogen applications and potential future demands. The applications have mainly been divided into industrial applications and transportation applications.

Chapter 4 describes the key components included in the hydrogen supply chain. This includes the main production methods of hydrogen, both those used today but also the main low-carbon method proposed for the future. It also includes other important factors, such as storage and transport of hydrogen, which are important to consider when evaluating the competitiveness of the complete system, or the complete supply architecture.

Chapter 5 describes source of energy needed for hydrogen production. Because of the scope of the study, the source described in this chapter is nuclear energy and more specifically SMRs. The general concept of SMR is explained as well as the economics, current development and key barriers that need to be overcome. Other energy sources have been analysed to some extent, to compare the complete SMR and hydrogen production system with alternative systems. These alternative sources will however be described in chapter 6.

Chapter 6 identifies synergies of SMRs that can have a positive effect on the hydrogen demand and/or the supply. This means the identification of some major factors that can make an SMR competitive in terms of hydrogen production. The main alternatives to produce low-carbon hydrogen are also analysed using SWOT analysis. This has been done to compare what an SMR does well in comparison with other sources and their respective hydrogen supply architectures.

Chapter 7 evaluates the competitiveness of the SMR and hydrogen alternative in comparison to other low-carbon production methods under a set of assumptions. The assumptions do not mirror every individual case but rather reflect under what general conditions an SMR can become a competitive alternative.

Chapter 8 is a discussion on hydrogen, SMR, and the combination of the two. It discusses the general development of hydrogen demand for industrial and transportation applications, as well as identifying some key needs and requirements for them. Next, the general development of SMRs and the main existing barriers needed to be solved for the concept to become fully realised is discussed. Lastly, the combination of the two topics is discussed. It outlines in which way the supply, as well as how this can bring positive effects towards the hydrogen demand. It also discusses in which way the hydrogen market can help the concept of SMRs overcoming its individual barriers. Finally, a discussion on the overall results and the research approach is presented, as well as a general discussion on ethical considerations regarding the study and its topics.

Chapter 9 concludes the study as well as highlights areas that could be of interest for future studies.

In the appendix, an electrolyser benchmark and an SMR benchmark can be viewed.

2

Research Approach

This chapter outlines the research approach used to answer the research questions. First, an overview of the research approach is given, followed by more detailed descriptions of the stages and how they were used to answer the research questions.

2.1 Overall Research Approach

The overall research design for this thesis is visualized in an overview below. It is divided into method stages as well as what the methods are intended to be used for. The research method is inspired by the book *The Good Research Guide* (2014) by Martyn Denscombe [13], which served as practical guidance in the execution of the different stages.

A literature study and an interview study were chosen to be the primary tools for gathering information. The literature study answered the two first overall questions posed in the study, while the interview study served to confirm these findings, as well as to provide more nuanced information in form of future predictions and opinions. In the synthesis the third and fourth question was answered.

1. Literature study
   (a) Find hydrogen applications with needs and requirements for competitiveness.
   (b) Find and research main components in the hydrogen supply chain. Current status and future trends.
   (c) Define and clarify the concept of SMRs, functionality, current development, barriers to deployment, and how they differ from conventional nuclear power.
2. Interview study
   (a) Confirm and clarify findings from the literature study.
   (b) Gather additional information in the form of challenges, opportunities, projections, and opinions.
3. Data synthesis and analysis
   (a) Identify synergies between hydrogen supply and SMRs.
   (b) Consider under what conditions hydrogen production with the help of an SMR is competitive.
   (c) Compare competitiveness with the most recognised low-carbon hydrogen supply architectures.
   (d) Use the result and findings from interviews to discuss the future of SMR and hydrogen production.

2.2 Literature Study

The literature study was focused on three main areas; hydrogen demand, hydrogen supply and SMRs. Regarding the topic of hydrogen demand, the intention was to find current and future applications for the energy-carrier and how it can benefit different sectors such as industry and transportation. Similarly, information on current supply, including production methods and distribution networks was pursued, both current and future supply scenarios. Finally, information on SMRs and the maturity of the technology was a part of the literature study. The focus was on the characteristics and commercialization of SMRs as well as the technical features relating to the production of hydrogen.

To perform the literature search in a systematic way a methodology adopted from Denscombe was followed [13]. First, the scope of the study was decided. Then, the search itself was conducted. To gain the necessary information several sources of documentary data were used, including scientific journals, articles, and books. The databases which was used were *Chalmers Library*, *Scopus*, and *Google Scholar*. The search were divided in the three main categories (demand, supply, and SMR). Examples of keywords that were used in the search can be seen in table 2.1.

Table 2.1: A selection of keywords used in the initial literature search

Hydrogen Demand	Hydrogen Supply	Small Modular Reactor
Hydrogen Application	Hydrogen Production	
Hydrogen Use	Electrolysis	Small Modular Reactor
Hybrit	Alkaline	SMR Concept
Steel Processing	PEM	SMR Designs
Ammonia	SOEC	SMR Economics
Aviation Hydrogen	Hydrogen Storage	Nuclear LCOE
Hydrogen Fuel	Hydrogen Transport	Nuclear Hydrogen Production
Fuel Cell Cars	LCOH	

To find further information, sources that are within the scope and referenced in texts found was also pursued. An example of this is the *"International Journal of hydrogen energy"*, where several hydrogen articles were found. On the topic of SMR, AFRY also aided by providing several sources containing relevant information. Other sources of information were also required, including governmental data, official statistics and company websites. The sources found were continuously categorized and saved.

Secondly, the quality of the information was evaluated and sources were screened for relevance [13]. Certain criteria were used to limit the possible sources and to ensure their quality and relevance. A checklist adopted from Denscombe was used to ensure the credibility of the sourced documents [13]. The basic screening questions were for example; has the credibility of the source/author/sponsorship been considered, have website sources been evaluated in terms of their accuracy and how recently they have been updated, and is possible bias taken into account. An example is information regarding current and future status. Here a search filter has been used to exclude sources not published within the period of 2015 to 2021.

Primarily, the literature study answered the first and second research questions. The goal was to provide an output that details hydrogen applications, key components in the hydrogen supply chain and outlines the basic principles of SMRs. The information found was used as input to the interview study, and was also confirmed by the interview study which will be detailed next. Finally, the information acted as an input to answer the third and fourth research questions in the synthesis of the study.

After the interview study, new information and areas discovered meant the literature study had to be revisited. For example, several experts provided different types of literature which had to be further investigated. This was done using the same method as described in this section.

2.3 Interview Study

The subject of SMR and hydrogen can be considered a capital-intensive and niche market and is therefore quite narrow. There are several key and complex variables across different areas that all play an important role when investigating the area. It was therefore determined that a interview study was suitable for the thesis. The interview study was used for three purposes with an emphasis on the final two, these are:

- First, certain information was confirmed. In the study, this was mainly in terms of requirements for the hydrogen applications and production methods.
- Second, the interview study clarified certain information that was touched upon in the literature study. As an example, certain functionality regarding hydrogen production methods or SMRs were explained further. Also, clarifications were given on how hydrogen is used in different processes. In other words, topics that were unclear or hard to explain by only sourcing it from literature.
- Third, the interview study provided additional information that is hard to come by when only sourcing literature. This was meant to enable developing thoughts around subjects such as challenges, opportunities, projections, and opinions.

To achieve these points, the main method was to perform semi-structured interviews. This means that certain questions were asked to confirm already known information, and to some extent clarify or expand on it. The main purpose of performing interviews in this study however, was to better grasp the complexity of the topics, and the potential connection between them. For this, the interview had to be unstructured to allow the interviewee to speak their mind [13].

The information gathered in the literature study served as a basis for structuring the interviews to confirm rather clear and brief information statements. In addition, it was used to understand the explanatory thoughts of the interviewee.

In addition to helping structure the interviews, the input from the literature study was utilised in sampling interviewees. A non-probability sample of participants was necessary for the study. The objective of the study was to explore two complex topics, meaning individuals who have key information regarding them were necessary to achieve that. Theoretical sampling was also utilised, meaning that as more primary and secondary data was revealed, additional participants were identified. This further lead to a form of snowball sampling where participants recommend or recruit further participants that they feel are relevant to the investigated topic. This was performed to some degree, but mainly the participants recommended additional literature to source, instead of actual people. This continued until a data saturation point was reached. Another source for sampling was webinars and online conferences. Although the information provided during webinars were rather general, the participants were individuals with deep knowledge and connection to the relevant industries.

The interview subjects has been categorised under two main areas, one with a focus on nuclear energy and one on hydrogen, and can be viewed in table 2.2. However, some crossover between the areas exists in the interviews. The interviewees will be referenced by their assigned letter for the continuation of the report.

Table 2.2: Interview subjects

Area	Interviewee	Subject	Role	Sector and Country
Nuclear Energy	A	Policy, Licensing, Financing	Lawyer, Advisor in the area of energy	Energy, US
	B	Licensing, Financing, Hydrogen	Researcher	Nuclear, UK
	C	SMR, Economics, Licensing	Researcher, Professor in Reactor Physics	Nuclear, Sweden
	D	SMR, Safety, Licensing	Safety Consultant, MSc Nuclear Engineering	Nuclear, Sweden
	E	Licensing, Policy, Hydrogen	Political Advisor, PhD Reactor Physics	Energy, Sweden
Hydrogen	F	Steel industry, Storage, Hydrogen market	Head of R&D at energy company	Energy, Sweden
	G	Steel industry	Senior Process Engineer	Metals and mining, Sweden
	H	Process industry, Refining	Consultant/Manager	Process Industry, Refining, Sweden
	I	Electrolysis, Fuel cells	Associate Professor	Fuel Cells, Electrolysis, Sweden
	J	Economics, Policy	Consultant/Manager	Hydrogen, UK
	K	Carbon capture & storage	Research Engineer	Carbon capture & storage, Sweden/Norway
	L	Biorefining	Senior Process Engineer	Biorefinery, Sweden

The interviews were recorded and transcribed. The analysis of the data was done through organising it under main topics. Each transcription was analysed and important parts were highlighted. The findings helped connect different hydrogen production methods and their dependencies, and was utilised in the data synthesis part. This, in turn, helped to answer research questions three and four, as well as confirming and clarifying research questions one and two.

2.4 Synthesis and analysis

The main objective in the synthesis and analysis was to connect the information from the literature study and the interview study. This was done for each of the topics of this study, hydrogen, and SMR. As mentioned in section 1.6, the approach was inspired and adapted from the 3S approach introduced by Canan Acar and Ibrahim Dincer [12]. In their article *"Review and evaluation of hydrogen production options for better environment"*, the 3S stands for service, system and source. In this report, this has been translated into demand, supply and energy source. The approach is illustrated in figure 2.1.

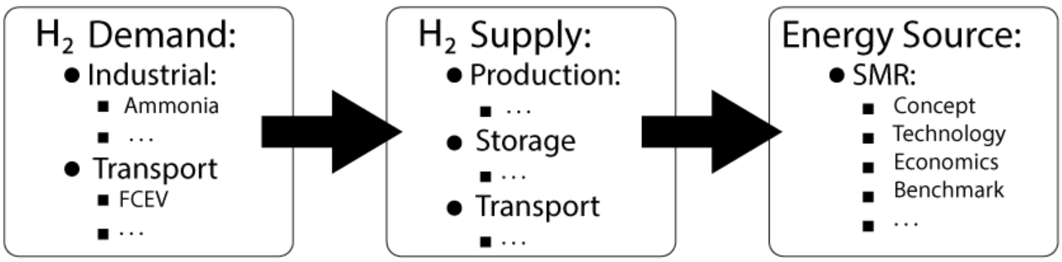

Figure 2.1: The research approach illustrated in this study.

The demand was analysed first to find what general needs and requirements the hydrogen demand put on production. This entails what is demanded by the production of hydrogen for it to become competitive in various applications. As stated, these are general needs and requirements such as amount, price, production rate, and location. These could be uniformly illustrated for all the applications researched in this study. For individual and more comprehensive requirement specifications, every application would have to be analysed in detail. The applications were also analysed to discuss their future potential.

The supply contains analyses of the current and future supply chain surrounding hydrogen. The areas touched upon are not a generic supply chain that works in every case but rather supply chain parameters that can build a particular supply architecture. Depending on which source of energy is being proposed, different supply architectures were created to fulfil the requirements expressed from the demand. All the different options in regards to supply have not been covered. Instead, the study has focused on those most discussed in the literature and during interviews. The hydrogen supply was analysed to find uncertainties and/or synergies where the strengths of an SMR could contribute towards, or make a case for, a competitive hydrogen supply chain. The demand part and supply part together answers research question one.

The energy source can contain a number of different energy source alternatives such as renewables, natural gas, and nuclear energy. Since this study focused on finding opportunities for the utilisation of an SMR, this is what has been analysed. It has focused on researching the general concept of an SMR and what strengths nuclear energy has in comparison to other sources. This was done to find opportunities for creating a competitive supply architecture. It was also analysed at what stage the concept is in development and what barriers might exist. This was used to discuss the future of utilising an SMR for the purpose of hydrogen production. The energy source part answers research question two.

As mentioned, the choice of energy source affects the final supply architecture. This can in turn play a part in whether the needs expressed by the applications can be fulfilled. Therefore, the final part of the study included how the strengths of utilising an SMR as a source can have beneficial synergies for the demand and supply of hydrogen. Together, the energy source and the supply create a supply architecture. Except for a supply architecture utilising an SMR, two main alternative low-carbon supply architectures were also analysed using SWOT analysis. This was done to compare a potential SMR and hydrogen supply architecture with the two most recognised low-carbon hydrogen supply architectures. They were compared in terms of production cost and the final delivered cost (accounting for the total cost of the supply). Finally, the two topics were discussed with the help of the result of the analysis and information gathered from interviews. The analysis of the complete overview (demand, supply and source) and the discussion regarding the two main topics answers research questions three and four.

3
Hydrogen Demand

Hydrogen is already used in many applications with the current demand being dominated by use in oil refining and production of ammonia. About 33% of hydrogen produced globally is used in refineries, over 27% is used for synthesizing ammonia, methanol production is using 10%, and some 6% is used by other industries [14].

The use of hydrogen in all sectors is predicted to increase. One report, initiated by the EU commission, envisioned that hydrogen could provide up to 24%, or up to 2250 TWh, of the total energy demand in the EU by 2050 [15]. This chapter describe the demand part from the overall structure, as illustrated in figure 3.1. This includes some of the many current, as well as future, applications of hydrogen. By describing these, the potentially massive demand for hydrogen in the future is illustrated, as well as what is required for hydrogen to become competitive with other substitutes.

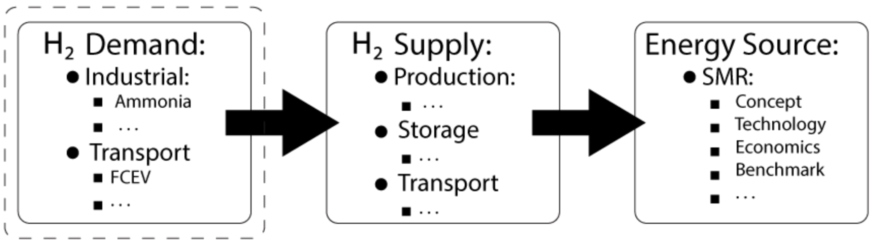

Figure 3.1: The chapter describes the demand part of the overall structure.

3.1 Industrial Applications

Global hydrogen use today is dominated by industrial applications, over 90% of hydrogen consumed today is used as an industrial feedstock. It is utilised in oil refining, ammonia (NH_3) production, and methanol (CH_3OH) production. Except for the applications mentioned above, many future applications could also become large consumers of hydrogen. These applications include using hydrogen in energy-intensive industries where high-grade heat is required, such as in the steel industry. This could prove to be a more efficient route to decarbonization than electrification [16].

Much of the current demand for hydrogen relies on fossil energy sources and will most likely have to reduce their emissions. Experts, including interviewee A, D, E, and J, therefore predict that the largest demand for low-carbon hydrogen will be in industrial applications in the forthcoming years. In these applications, the demand is certain and predictable. Interviewee F, G, and J further predict that demand from the steel industry will increase with the many investments and projects currently planned and in progress. In the following sections, hydrogen demand from industrial applications will be outlined. Oil-refining was not a part of the study due to its connection to fossil fuels and the focus being on future applications.

3.1.1 Ammonia Production

Today, the second-largest demand for hydrogen arises from the production of ammonia at 31 MtH_2/yr [17]. Ammonia is produced by combining H_2 and N_2 through the Haber-Bosch process at about 250 - 350 bar and at a temperature of 450-550 °C [14]. Out of the total demand for ammonia, over 80% of the ammonia produced is used in fertilisers such as urea and ammonium nitrate [14, 17]. The remainder is used for explosives, synthetic materials, and other speciality materials. Again, most of the hydrogen today is produced using fossil sources of energy, with the production of ammonia emitting about 2.5 tonnes of CO_2 per tonne ammonia [18]. The production of ammonia stands for 1-2% of global energy consumption [19] and to decarbonize this sector could provide large environmental benefits. Ammonia could also be used in many other applications than the ones mentioned above. For example, it could help to decarbonize sectors like aviation and shipping in the future, something that was stated by interviewees B and J.

Combining hydrogen and nitrogen to create ammonia solves some of the challenges hydrogen faces as an energy carrier and fuel in the applications mentioned above. Interviewee J explained how converting it implies a cost in energy, but opens up for easier storage and more applications. Ammonia is in liquid form much closer to atmospheric pressure, and stores almost twice as much energy compared to hydrogen, easing storage and transportation issues [3]. Ammonia can also be burned in ship engines with little modifications, and be used to power long-distance transport such as heavy trucks and trains [3].

Demand for ammonia in existing applications is predicted to increase by 1.7% per year up to 2030, and then continue to rise. If ammonia is established as an energy carrier and used as a fuel in its own right, the increase in demand could be much larger and the industry could have a role similar to oil refineries today [17]. One initiative to improve the sustainability of the production process comes from the world's largest ammonia producer, YARA. The company is assessing the feasibility of using hydrogen produced by electrolysis in their operations [20].

The main challenges with producing ammonia, and doing it sustainably, is the extreme pressure and temperature required for the Haber-Bosch process. Extensive research in the sustainable synthesis of ammonia has been performed without successfully finding a low pressure and low-temperature process [19].

In 2030 it is estimated that the demand for hydrogen to produce ammonia will be 37 MtH_2/yr [17]. The price of hydrogen at which ammonia could be competitive as an end fuel product, is calculated to be between 0.90-1.50 $/$kgH_2$ [3, 18].

3.1.2 Methanol Production

Methanol is another chemical, made from hydrogen, which is used for a diverse range of industrial applications and predicted by experts, including interviewees B, J, and L, to play a large part in future demand. End products include adhesives, plastics, and as a component in fuels [18]. Similar to ammonia, low-carbon methanol is also predicted to play a large part in the decarbonization efforts of hard-to-abate sectors such as transport and industry, and as an energy carrier as it is easy to store and transport [21]. Methanol can be used directly in internal combustion engines with only small modifications or could be blended with diesel or gasoline to reduce emissions [14]. Methanol production is the third-largest consumer of hydrogen, using more than 12 MtH_2/yr [17]. The production of methanol mainly relies on the hydrogenation of carbon dioxide (CO_2) at a pressure of 50-100 bar and at a temperature of 250°C [21].

To produce methanol from hydrogen, a source of CO_2 must be added. The CO_2 can come from direct air capture, or carbon-capturing from industrial plants [18]. Depending on the way the CO_2 feedstock is acquired and on the use of the methanol, carbon sequestration varies [18]. The release of carbon when methanol is used as a fuel for combustion is a challenge. Another challenge lies in using a hydrogenation reaction to produce methanol, which require a lot of energy [21].

One initiative in using hydrogen as feedstock to produce methanol is in Iceland at Carbon Recycling International´s George Olah plant. Hydrogen produced from electrolysis and CO_2 captured from a power plant is used to produce 4000 tonnes of methanol per year and recycle 5500 tonnes of CO_2 in the process [16].

The demand for methanol from existing applications is predicted to increase by 3.6 % per year up to 2030, up to a demand of 19 MtH_2/yr. A larger increase in demand is to be expected if methanol is established as an energy carrier or as a fuel [17]. The price at which low-carbon hydrogen for methanol production can compete with fossil sources is 0.80-1.50 $/$kgH_2$ [18]. This estimation is dependant on many factors, region and carbon price being two.

3.1.3 Metallurgical Industry

In the metallurgical industry, hydrogen can be used as a reducing agent, for metal alloying, and the production of carbon steels. The method to produce steel from iron ore using hydrogen is called DRI and is the fourth-largest source of hydrogen demand today [17]. Low-carbon hydrogen is expected to replace fossil feedstock in steel manufacturing, where coke is the traditional feedstock [14]. Interviewee G explains how most large steel manufacturers in Europe include DRI in their future roadmaps aiming to reach the Paris agreement. Reducing iron ore with low-carbon hydrogen instead offers a huge potential to reduce GHG emissions in the carbon-intensive steel production [14]. Today, steel production is one of the largest emitters of CO_2 accounting for about 7-9 % of global emissions [18]. Producing one tonne of steel results in direct emissions of 1.4 tonnes CO_2.

Interviewees F and G outlined the process of using DRI with hydrogen and what requirements are implied on the supply of hydrogen in the process. About 600-700 cubic meters of hydrogen is needed per metric tonne of DRI. The gas circulates in the reactor and system but is continuously consumed in the process of reducing oxygen from the iron ore. The gas will also have to be heated to a temperature of around 900-1000°C, depending on the design parameters. The requirements of the hydrogen supply is further that it can be supplied continuously, since a steel plant operates at least 8000 hours per year and has low flexibility in varying the production. Interviewee G further explained that the large volumes, high energy demand of around 3.5 MWh/tonne, and price-competitive market imply a certain sensitivity to price.

There are many initiatives around the world to reduce emissions from steelmaking and implement a more sustainable alternative utilizing hydrogen. One example is HYBRIT, a collaborative effort between SSAB, LKAB, and Vattenfall [22]. In 2030, LKAB expects to be able to produce 2.7 million tonnes of DRI per year [23]. HYBRIT estimates that the energy demand of the process will be 3.5 MWh/tonne crude steel [22]. The cost of the finished steel is estimated to be 20-30% higher compared to conventional methods [24, 25]. Interviewee F confirmed that this number was from the beginning of the project in 2018, and primarily depended on three factors. The factors highlighted were the price of coking coal, the price of emitting carbon, and the price of electricity. One additional important factor emphasised by interviewee G, is that the concept and end-product are estimated to be more attractive in the future due to the higher cost of emitting CO_2, and an increase in demand for more sustainable products [25]. Finally, with insight into the project of HYBRIT, interviewee F talks about the challenges in the project. One of these challenges, or uncertainties, is the large-scale transport of hydrogen where the final cost is still not known. The transport of hydrogen, as well as the storage solution, is due to be tested in different pilot-project during the coming years. Other than HYBRIT, European steel making companies such as Voestalpine, Liberty steel, and Salzgitter, are all investing in hydrogen direct reduction as a future alternative [24, 26].

One of the challenges to driving a sustainable transition in the steel industry has been that heavy industry sectors (such as steel) often work in a business-to-business market [24]. End-customer preferences for sustainability have thus been left out in favour of cost and availability as key business-drivers.

The Hydrogen Council, a consortium of over 100 leading companies with an interest in hydrogen, calculates that to reach a lower cost than conventional blast furnaces coupled with carbon capture and storage technology (CCS), a hydrogen cost of 1.20-2.30 $/kgH_2$ is required, depending on region. Further more, according to the International Energy Agency (IEA), to compete with natural gas coupled with CCS a hydrogen cost of 0.7-2.0 $/kgH_2$ is required [17]. The demand for hydrogen used in steel production is estimated to 8 MtH_2/yr in 2030 [17].

3.2 Transportation Applications

Regarding the area of transportation there are many prospects of the use of hydrogen in the future, but already today there are hydrogen vehicles in operation and have been for some time. Applications range from cars, busses, and trains driven by electricity generated from hydrogen in fuel cells to applications in aviation and shipping. The consensus among experts in the area, is that hydrogen will be the most beneficial alternative for longer ranges and applications, such as long-haul trucks, busses, and trains. As previously stated interviewees B, D, I, and J predict that current industrial applications will be the first adopters of low-carbon hydrogen. With cars, trucks, busses, trains, ships, and aviation following in the years and decades after. Important to remember is that the applications within transport will play an important role, especially in hard-to-abate sectors such as aviation and shipping, discussed below.

3.2.1 Fuel Cell Electric Vehicles (FCEV)

Cars driven by electric motors have seen a growing popularity in the latest years. The energy for the electric motors can be supplied from different sources, either from batteries or from fuel cells utilising hydrogen to generate electricity. Many large car manufacturers are currently developing and even selling hydrogen vehicles including Hyundai, Honda, and Toyota [27].

Electric hydrogen vehicles utilise a fuel cell stack as their energy source. A hydrogen fuel cell is an electro-chemical device that transforms the chemical energy in hydrogen to electricity driving the electric motor [28]. Fuel cells are categorised after the electrolyte they use, with the most common one being the proton exchange membrane (PEM) fuel cell. It utilises a solid polymer as the electrolyte and porous carbon electrodes containing platinum as the catalyst [28]. The reason PEM fuel cells are preferred in transportation applications is their short start-up time, low operating temperatures (60-80 °C), system robustness, and high power density [29]. Except for the energy in the form of electricity, only water and heat are generated in the fuel cell [28].

The Hydrogen Council, sees great potential in FCEVs. In a report, the council predicts that by 2030, 1 in 12 cars in prominent regions such as Germany, South Korea, and California will be powered by hydrogen. In 2050, they predict an increase to 25% globally or about 400 million passenger vehicles to be powered by hydrogen

[16]. As mentioned, many car manufacturers believe in the future of the fuel cell electric vehicle. Today, several models are available such as the Toyota Mirai, the Hyundai NEXO, and the Honda Clarity [14].

The benefits of no tailpipe emissions for FCEVs is obvious, but FCEVs can also benefit from a higher efficiency than the conventional internal combustion engine (ICE) [28]. This, the lower running cost, together with a lower maintenance cost because of fewer moving parts makes FCEVs competitive with conventional ICE vehicles [14]. FCEVs have also proven to have some unique benefits relative to their closest competitor, the battery-powered electric vehicle (BEV). The high energy density of hydrogen provides FCEVs to drive for a long range [28]. To give a competitive range of 500 kilometers, around 5 kg of hydrogen needs to be stored under high pressure (around 700 bar) in the tank of a car [30]. The tank to store hydrogen could also be manufactured at a lower cost than if compared to a battery [28]. Finally, a vehicle with a hydrogen tank allows for fast refueling, comparable to filling a gasoline or diesel vehicle [14].

Two of the main challenges FCEVs faces are regarding the refuelling infrastructure and the competition against other technologies, such as BEVs. Regarding the refuelling infrastructure, there will be little incentive for customers to buy a FCEV until a refuelling station network has been established. On the other hand, it will not be commercially viable to construct a network until enough FCEVs exist on the road [14]. This is one of the reasons interviewee I believes that the industrial applications will have to lead the way, to then allow more decentralized demands to benefit from the already built infrastructure. Further challenges exist in that hydrogen cannot use existing distribution networks for liquid fuels, meaning large investments at high risk will be required [14]. This is driven by the requirement for refuelling stations to be placed close to main roads and in a decentralized structure to reach a large share of consumers.

Regarding BEVs, the rather high cost of the fuel cell as well as the higher efficiency of the BEV are the main challenges. The efficiency of a BEV can be around 60% "well-to-wheel", while FCEV reach around 30% [16]. This leads to the BEV being a more competitive option for short to medium range applications [18].

In a report by the Hydrogen Council [18], in collaboration with the consultancy company McKinsey & Company, the cost that different hydrogen applications need to reach to be competitive was analysed. It was concluded that the hydrogen option, when compared to BEVs and ICE vehicles, is predicted to first become competitive in applications where long range is needed (500km+) [18]. This could be large family SUVs or larger vehicles for commercial use such as taxi fleets. This view was shared by interviewees I and J, who believes that FCEVs will be competitive only in certain demand patterns. The report suggests these applications could be competitive as soon as between 2025-2030 [18].

In conclusion, FCEVs have benefits in allowing for long range, quick refueling times and being price competitive with conventional ICE vehicles. The main challenges exist in establishing a refuelling network, and in competing with BEVs, which benefits from higher efficiency. The potential demand could be significant, but is also highly uncertain and depends heavily on the development of competing alternatives.

3.2.2 Internal Combustion Engines (ICE)

In addition to utilizing fuel cells to generate power, hydrogen can also be burned directly in a combustion engine. This was how some of the first ICE were powered over 200 years ago [17]. The development has come a long way since then, and today's H_2 internal combustion engines (H_2ICE) can reach increasingly high efficiencies, keep emissions well below regulations, and reach satisfactory power outputs [14].

Using hydrogen in ICEs opens up many advantages. The vast production infrastructure and the mature industry surrounding ICEs are examples. Also, ICEs provide fuel flexibility, provided the engine control is suitably adapted [31]. "Flex-fuel" vehicles could ease the transition from fossil fuels to hydrogen and allow the refuelling network to be built over this period of transition [31]. Further advantages of utilizing H_2ICEs in vehicles is their tolerance to lower hydrogen purity, leading to cheaper fuel [31]. Finally, they could be introduced relatively easily, with a possibility of retrofitting engines, and the technology does not rely on any rare materials [31]. Both FCEVs and BEVs require a ramp-up of production of scarce materials, which has proven difficult. Which gives H_2ICEs an advantage [31].

Between the years 2000-2010, several concept cars were developed by various automotive manufacturers. Many were adopted from previous models to run on hydrogen, with the BMW H_2 7 being the most well-known, produced in 100 units between 2005-2007 [14]. Due to some major challenges of H_2ICEs, further commercialisation has not been pursued. Research has continued, with a focus on advancing the maturity of hydrogen engines.

The challenges include the difficulty to make ICEs running on hydrogen both efficient, adequately powerful, and durable at the same time [31]. Also, the engine characteristics put demands on the onboard storage of hydrogen. The infrastructure required is, as in the case of FCEVs, a principal challenge. Instead, many researchers believe that using hydrogen to chemically create a liquid fuel. That is both easier to store and distribute is the way forward, and is what should be researched [31].

Another way hydrogen ends up as a part of the supply chain of fuels is when producing renewable fuels, such as bio-diesel. Interviewee H explained that in refining, hydrogen is used in the hydrogenation of renewable fuels to bind to, and get rid of oxygen. An increased amount of hydrogen is required when refining renewable fuels in comparison to refining conventional fuels. Interviewee H gave an example of a large project on the west coast of Sweden where Preem will produce 700 000 tonnes of renewable fuels per year.

3.2.3 Buses, Trucks, and Trains

As explained earlier, utilising hydrogen in fuel cells for powering vehicles can come with several benefits. It allows for a simple system with relatively low weight, allows for long range, and also for fast refuelling. These characteristics prove to be even more advantageous when applied to means of transportation that operate over longer distances and more continuously [16]. With FCEVs facing increased competition from BEVs, the focus in FCEV development has shifted towards heavy-duty applications. Where a central refuelling structure infrastructure can be utilised, and where the high energy density introduces less weight than BEVs [14]. These characteristics highlight the promising potential of fuel cell-powered buses, trucks, and trains in the future [32][33]. This view is shared by experts in the field, including interviewees B, I, and J.

In a cost analysis by the Hydrogen Council, it was concluded that hydrogen buses and trucks are the most cost-efficient way to decarbonize the respective segments in the short to medium term [18]. This view seems to be shared when also looking at the automotive industry. Where several manufacturers are developing fuel cell trucks, including Toyota, Daimler, Volvo, Hyundai, and Nikola Motor Company [34, 35, 36, 37]. Fuel cell buses have been in use for some time and have a great advantage in that they reduce emissions locally in city centres. This advantage creates and even bigger opportunity for both buses and trucks when diesel engines are planned to be banned in many city centres for several countries [14].

Regarding trains, there are examples of companies already operating hydrogen-powered trains. One example is Alstom in Germany, whom has developed hydrogen running trains that can reach speeds of around 140 km/h and ranges of up to 1000 km, sufficient for an entire day [14]. Further, many countries and companies are investing in a future with hydrogen trains, including Vivarail in UK, Inlandsbanan in Sweden, Pesa Bydgoszcz SA in Poland, and Stadler Rail Group (Switzerland) supplying California with hydrogen trains [14]. According to present plans in France and the UK, diesel trains will be replaced by fuel cell trains by 2035 and 2040 respectively [38]. Trains powered by hydrogen fuel cells are best suited for longer routes, not already electrified, and with short downtimes allowing little time for charging. Interviewee I highlights examples of train routes in northern Norway where hydrogen trains are the best potentially fossil-free option. Routes that have a relatively low frequency of operation is also especially well suited for hydrogen trains [18].

Fuel cell trucks, busses, and trains face some of the same problems as fuel cell cars. For example, the challenge of infrastructure for refuelling. But these applications have an advantage in allowing for a more centralized infrastructure, with long ranges and defined routes [39]. As an example, some estimates that only 350 refuelling stations could cover the whole United States [39]. Nikola Motors (together with Shell, Air Liquide, Hyundai, NEL, and Toyota) further plan to build their infrastructure with 700 stations, which they will allow rivals to use, by 2028 [38]. The cost of fuel cells and hydrogen storage system is also a challenge. But prices are predicted to drop in the coming years [14, 38].

Regarding the cost perspective, reports show that hydrogen buses can out-compete battery-powered buses when the range exceeds 400km [18]. In these applications, a long range decrease down-time and thereby reducing cost. When it comes to total cost of ownership (TCO), fuel contributes up to 25% and will be the largest opportunity to reduce the total cost [18]. It was calculated that a price of 4-5 $/kgH_2$ was required to reach cost parity [18]. Similarly, regarding trucks, fuel costs are a significant part of the TCO of up to 60% [18]. In 2030, at 4-5 $/kgH_2$, medium and long-range fuel cell trucks could become a more competitive alternative to BEVs and ICEs [18]. Finally, fuel cell trains are already today more competitive than electric trains over longer distances and for low-frequency routes [18].

3.2.4 Aviation

In a report by Fuel Cells and Hydrogen Joint Undertaking (FCHJU), backed by the European Commission, the potential of hydrogen propulsion in aviation was assessed [40]. The conclusion of the report states that *"hydrogen propulsion has the potential to be a major part of the future propulsion technology mix"*, but that *"it will require significant research and development, investments, and accompanying regulation"* [40]. There are several options to power an airplane with hydrogen. It could either be used directly for combustion, in fuel cells, or in the production of synthetic or bio-fuels [18, 41]. With regards to climate impact, using hydrogen for combustion could reduce the impact by 50-75%. For the usage of fuel cells or in the production of fuels these numbers stand at 75-90% and 30-60% respectively [40].

Aircraft utilising hydrogen for propulsion are most competitive for short-range and medium-range routes, including regional and commuter aircraft [18, 40]. Long-range aircraft would require new designs, such as increasing the airframe length to accommodate fuel tanks, if they are to run on hydrogen [40]. For larger aircrafts the most realistic option is to replace the fossil fuels used to produce jet-fuel kerosene with synthetic alternatives that have been produced using hydrogen [18]. One manufacturer aiming to develop hydrogen aircraft is Airbus, with concepts for short-, medium- and long-range [42].

Hydrogen in aviation faces much of the same problems as other applications, such as lack of infrastructure and storage issues [41]. Another challenge lies in the development of the design and layout of the aircraft itself. Increasing power density, reducing cost, and extending the lifetime of fuel cells are pointed out as important factors for the future [41].

Regarding cost competitiveness of the fuel, the Hydrogen Council estimates synfuel could become cost-competitive with bio-kerosene in 2030 [18]. Given a bio-fuel cost of 1.50 \$/liter, hydrogen must reach a cost of 2.70 $/kgH_2$ [18]. FCHJU estimates that in 2050, aviation's demand for liquid hydrogen could grow to 40 million tonnes a year [40].

3.2.5 Maritime Applications

As a whole, the international shipping and maritime sector stands for 2.5% of global carbon emissions [18, 17]. According to current trends, international shipping is further expected to more than triple by 2050 [17]. The sector is reliant on heavy oil fuels and affects the air quality around ports. Hydrogen is seen as the leading option for tackling these issues and decarbonizing this sector [17]. Ships powered by fuel cells are most relevant for passenger ships. Bringing positive benefits such as decreasing local emissions, and reduces both water pollution and noise [16]. In larger-scale operations, such as international shipping, hydrogen-based fuels such as ammonia, are believed to be the best option, with many research projects and demonstration projects ongoing [17, 43]. Ammonia has a higher energy density than for example liquid hydrogen and current engines could be modified for the usage of this fuel. Availability and cost of bio-fuels are also uncertain, since the demand for biomass is expecting to grow in other sectors as well and there is a limited supply [17].

Several companies and countries see the potential of utilising hydrogen as a fuel for shipping in the future. Projects are underway in Sweden, Norway, and France [14]. ABB is collaborating with Hydrogène de France to develop large-scale fuel cell-powered ships [14]. The CEO of Maersk, the largest container shipping line and vessel operator in the world, said that they will have small-scale ships running on fuels such as ammonia and methanol before 2025 [44].

Utilising hydrogen as a fuel for ships comes with some challenges. Although some of the infrastructures for ammonia already exist, a huge scale-up of both distribution and production would be required. To satisfy shipping demand in the long term, it is estimated that 500 Mt/year of ammonia is required, three times today's global production [17]. Another challenge is the storage volume required, with ammonia requiring three times the volume of conventional oil-based fuels. This would either require a redesign of the ships, shorter distance trips, or reduced cargo capacity [45].

The application does however benefit from some infrastructure already existing. Synergy effects with material handling in ports (forklifts, trucks, etc), and the demand being more centralised to fewer locations are also added benefits [17]. For smaller applications, such as ferries, it is estimated that they could become competitive with fuel cells in 2030-2035 [18]. For larger-scale operations, a CO_2 price of up to 326 $/t$CO_2$ would be required to make ammonia a cost-competitive fuel [17]. For further data on the price-point of where hydrogen is used to produce ammonia, see section 3.1.1.

3.3 Hydrogen for Power Generation and Grid Balancing

A final application of hydrogen that will be outlined in this report, is the use of hydrogen generation and storage to use for power and balance an electricity system. Hydrogen's potential for storing large amounts of chemical energy, which can easily be transformed to electricity, makes it interesting in the context of balancing grids [46, 47]. Hydrogen can be stored in different ways and can thereby also balance seasonal variations or a larger share of RES in the overall energy system [17, 46]. In the context of nuclear power generation, benefits from producing and storing hydrogen have been investigated [46]. Operating a nuclear plant at a constant level is simpler and cheaper in terms of fuel and maintenance, and producing hydrogen to compensate for variations in demand could increase the operating life [46].

Hydrogen generated by electrolysis can be stored in a number of ways, further described in section 4.3. To reconvert hydrogen to electricity internal combustion engines, gas turbine power plants, or fuel cells are all possible options [47]. The hydrogen could also be used directly in industry or as fuel for vehicles [47]. One challenge, highlighted by interviewee B, is induced by the low round-trip efficiency of converting electricity to chemical energy and then back to electricity again.

Producing hydrogen in order to balance the power system could have an important role in the future. But is heavily dependent on developments in electrolysers and large-scale storage [46]. Experts, including interviewee J, see a challenge in this solution relating to the problem of optimising hydrogen production of RES to hours of low energy cost, and the storage thereby needed to be able to supply a steady demand of hydrogen.

3.4 Summary of Hydrogen Demand

The chapter has provided an overview of the many different applications hydrogen is used in and where it could be used in the future. There are some applications where the demand is more certain, such as ammonia and methanol production. Other sectors, such as the transport sector, have a potentially larger demand for hydrogen but is more difficult to predict. Regarding cars for shorter distances the FCEV faces competition from BEVs. For longer distances and larger-in-size applications the hydrogen alternative seems to be more competitive. No expert can say for sure which applications will have the largest demand but some estimations has been given through the chapter. The demand from different sectors is summarised in table 3.1 below. The estimations is gathered from the previous sections, from interviews with experts, and from reference [17] and [18]. It is aimed at giving an overview of the current status. The total demand from the selected applications is summarised in the table and is estimated to be up to 450 MtH_2/yr in 2050. If not including FCEVs, which by many experts is deemed the most uncertain, the demand is still 150 MtH_2/yr. The next chapter contains different ways meeting this huge demand.

Table 3.1: Summary of hydrogen demand

Hydrogen Demand	**When?**	**Potential size of demand**	**Price of competitiveness $\$/kgH_2$**	**Location of demand**	**Opportunities**	**Challenges**
Ammonia Production	Now	37 MtH_2/yr (2030)	0.90 - 1.50	Centralised	Important role in hard-to-abate sectors No emissions when used as a fuel Easier to store than hydrogen	High pressure and temperature needed in production
Methanol Production	Now	19 MtH_2/yr (2030)	0.80 - 1.50	Centralised	Important role in hard-to-abate sectors Easy to store and transport Can be used in internal combustion engines	Need a source of carbon Releases CO2 when used Energy-intensive production
Metallurgical Industry	2025	8 MtH_2/yr (2030)	0.7 - 2.30	Centralised	Decarbonise carbon-intensive industry	Need continuous and large supply Price-sensitive
Fuel Cell EVs	2030	Up to 300 MtH_2/yr if hydrogen were to cover today's total fossil fuel demand	Depends on range, could be competitive at $ 5/KGH2	Decentralised	Short refuelling time Zero tailpipe emissions Low material footprint Low weight/stored energy	High cost of fuel cells Low efficiency Refuelling infrastructure lacking Competition from BEVs
Busses, Trucks, and Trains	2025			Centralised	Long range possible Short refuelling time Centralised refuelling Reduces emissions in city-centres	High cost of fuel cells Refuelling infrastructure lacking
Combustion of Hydrogen	-	-	-	Decentralised	Utilise existing infrastructure Could allow "flex-fuel" Avoids expensive fuel cells	Difficulty to make hydrogen ICEs efficient, powerful, and durable
Aviation	2040	40 MtH_2/yr (2050)	2.70	Centralised	Could reduce emissions substantially from carbon-intensive sector	Need significant research, development, and investments
Maritime Application	2030	50 MtH_2/yr (2050)	0.90 - 1.50	Centralised	Reduce emissions and water pollution Possible to modify current engines	High storage cost Lost cargo volume
Balance of Power System	2030	-	-	Centralised	Balance electricity system Easy to restore to electricity	Low efficiency Optimising issues
Total demand		**Up to 450 MtH_2/yr**				

4

Hydrogen Supply

As illustrated in the previous chapter, today hydrogen is mainly used for ammonia production, oil refining and the production of various other chemicals. In 2018, around 74 million tonnes of hydrogen were produced for this purpose [17]. Out of this 74 million tonnes, only five percent was produced using a low-carbon production method. The rest was produced using fossil fuels [48]. If the hydrogen use is to grow as projected, then the supply also needs to shift towards low-carbon production.

This chapter aims to describe the supply part of the overall structure, as illustrated in figure 4.1. This includes an overview of the main ways of producing, transporting, and storing hydrogen. A description of the most prominent ways of production will be presented with the main focus on the most discussed low-carbon method, electrolysis. Different ways of storing and transporting hydrogen will be also described. After storage and transport, hydrogen techno-economics in the form of levelised cost of hydrogen (LCOH) will be presented. The focus will be on the production of hydrogen using electrolysis. The LCOH for other production methods and also cost for storage and transport have been gathered directly from literature. Finally, a summary of the chapter is presented.

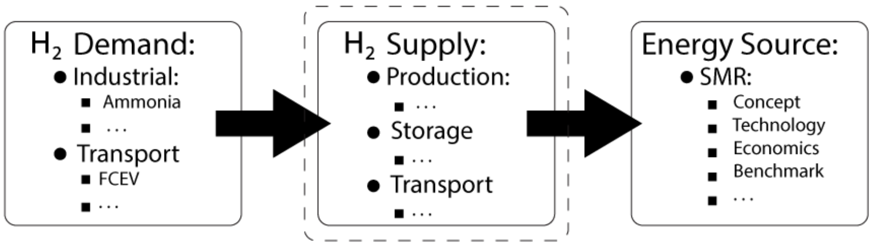

Figure 4.1: The chapter explains the supply part of the overall structure.

4.1 Hydrogen Production - Fossil Fuel

This section describes the two most prominent ways of producing hydrogen using fossil fuels. These are steam reforming and gasification. Although gasification stands for a significant share in producing hydrogen, it is not as widely used outside of China, whereas steam reforming is used on a more global scale. Therefore, both methods will be described in short but only steam reforming will be further analysed throughout the report. Producing hydrogen as a by-product from various industries using fossil fuels has also fallen outside of the scope of this study.

4.1.1 Steam Reforming

Today, steam reforming is the most widely used method for producing hydrogen, accounting for almost 50% of the total hydrogen production [48, 49, 50]. Steam reforming is an endothermic process (requiring heat) that reforms a hydrocarbon and steam into syngas (a mix of carbon monoxide and hydrogen) [49, 51]. The most widely used hydrocarbon for this purpose is methane, the primary building block of natural gas. Natural gas is thus used as a feedstock and as a source of heat.

The biggest advantage of using steam methane reforming is that it is one of the cheapest ways of producing hydrogen, typically producing hydrogen at a cost between \$0.9-3.2/kgH_2 [17]. Therefore, the production cost of using steam methane reforming is often used as a benchmark to compare the competitiveness of other methods. The primary factor determining the cost is the availability of natural gas. Large and centralised production is also needed to reach this cost range. This is why several industrial consumers of hydrogen (ammonia, refineries, etc), uses this method to produce hydrogen on-site.

Table 4.1: Levelised cost of hydrogen based on steam methane reforming production. All numbers are shown \$/kgH_2

Region:	Capital Cost	Operation Cost	Natural Gas	Prod Cost	Capital Cost (w/ CCS)	Operation Cost (w/ CCS)	Natural Gas	Prod Cost (w/ CCS)
USA	0.40	0.10	0.50	1.00	0.60	0.40	0.50	1.50
EU	0.30	0.20	1.25	1.75	0.60	0.40	1.35	2.35
RUS	0.30	0.20	0.50	1.00	0.60	0.40	0.60	1.60
CHN	0.60	0.40	0.75	1.75	0.60	0.40	1.40	2.40
ME	0.30	0.20	0.40	0.90	0.60	0.40	0.45	1.45

The biggest drawback of using steam reforming is that it releases large quantities of carbon dioxide [51]. Estimates suggest that the method releases about 10 tonnes of CO_2 for every tonne of hydrogen produced [52]. To counter this, the future for this method includes a high degree of installed carbon capture, and storage (CCS) technology [52, 53]. CCS can reduce emissions by up to 90% [52, 54] but will in turn also raise the cost of production, illustrated by table 4.1 [17, 52, 53]. The table compares production cost estimates for steam methane reforming with or without CCS. The levelised cost of hydrogen (LCOH) is here indicated as the cost of production. For a more detailed description of the LCOH, see section 4.5. The data is taken from reference [52].

There is also a further cost increase in transporting and finally storing the captured CO_2 [54]. According to a study made for the US region, they found that transporting CO_2 with pipeline would range between 2-38 US dollars per tonne CO_2 depending on the distance [54]. While, on average, the long-term and large-scale CO_2 storage would cost \$8/tCO_2. In Europe, interviewee K explained that the Norwegian Northern Lights project is currently the most viable way of storing CO_2. Their ambition is to reach a cost of between \$36-65/tCO_2, which includes shipping to, and storing, the CO_2 in their North Sea storage facility. Future cost increase for this method could also be dependent on carbon prices and taxes [53]. However, with a capture rate of 90%, carbon taxes on the remaining 10% will have a limited effect on final cost.

4.1.2 Gasification

Gasification is similar to steam reforming except that it also uses oxygen in the process. The feedstock, oxygen and steam, react to form hydrogen, carbon monoxide- and dioxide [49]. The CO_2 can further be reacted with steam to form additional hydrogen, in a so-called "water-gas-shift". Typically the feedstock that is used is coal. Today, around 19% of worldwide hydrogen production is done using coal gasification [48]. 80% of these facilities are located in China [52].

Similar to steam methane reforming, gasification has a low production cost [49], estimated at \$1.2-2.2/kgH_2 [17]. The drawback is similar as well, in that it releases large quantities of GHG emissions. The future for this method also includes the instalment of CCS.

Another option is to use biomass (such as industrial, agricultural, and forestry residues and waste) instead of coal as a feedstock. Although the process is somewhat more complicated, it can be considered more environmentally friendly since it uses biomass and not coal [55]. However, according to interviewee L, biomass is also being proposed as a feedstock for a wide range of other applications. For example, different kinds of synthetic fuels. When discussing this subject further with interviewee L, they believed that biomass can have a higher value than only using it for pure energy purposes.

4.2 Hydrogen Production - Electrolysis

Although the technology for electrolysis has been around for several hundred years the method still only takes up 4% of global production [48, 56]. The reason being that it is a more expensive method than those using fossil fuels. But because of the increased concerns in regards to climate change, the method has seen new life recently. Electrolysis of water only requires energy in the form of electricity and/or heat and the process does not release emissions. Any low-carbon energy source, such as nuclear or renewables, can thereby potentially reduce the emissions of producing hydrogen. With cost increases for fossil-fuel-based production methods and cost decreases of using electrolysers, this method may potentially also compete economically in the future [51]. In may 2021, the IEA published a comprehensive study on how the world can reach a net-zero energy system (removing the same amount of GHG emissions from the atmosphere as is released) by 2050 [57]. According to the study, 54% of all hydrogen should be produced using low-carbon electrolysis in 2030 to reach this goal. By 2050, this number is increased to 62%.

This section will first describe the basic concept of electrolysis. Then give an overview of the three most prominent electrolysis technologies. These are alkaline electrolyser (AEC), proton exchange membrane (PEM), and solid oxide electrolysers (SOEC). The overview will contain general functionality, strengths and weaknesses, and current and future status for each technology.

Several other low-carbon hydrogen production methods exist. Some of which include microbial electrolysis, photosynthesis, radiolysis, and others. However, all these have a relatively low technology readiness level and have thus been excluded from this study [58]. Electrolysis of water has also been deemed the main method to produce low-carbon hydrogen during interviews and several studies.

4.2.1 Basic Concept

Electrolysis is an oxidation-reduction reaction (redox reaction for short). A reaction where electricity is used to make a chemical change happen, that would not happen otherwise. Electrolysis of water is one such reaction, where hydrogen and oxygen together form a water molecule. This water molecule is not going to separate into its core elements again without applying electricity and/or thermal energy. The process is performed in an electrolytic cell and the full reaction can be seen in formula 4.1 below [56]:

$$2H_2O + Energy \rightarrow 2H_2 + O_2 \tag{4.1}$$

Although there are different configurations of an electrolytic cell, it basically consists of two electrodes (an anode and a cathode), and an electrolyte. From formula 4.1, the hydrogen is formed at the cathode and oxygen is formed at the anode. See figure 4.3-4.5 for a visual representation of the process. To separate the elements, the required energy demand can be determined using the change in enthalpy, illustrated in formula 4.2 below [56]:

$$\Delta H = \Delta G + T * \Delta S \tag{4.2}$$

ΔH represents the change in enthalpy, or the required energy needed for separating the elements. ΔG is Gibbs free energy which represents the necessary electrical energy. T represents temperature, ΔS represents the entropy for each molecule and together these correspond to the necessary energy in the form of thermal energy. Holding ΔH constant means that if thermal energy, $T * \Delta S$, is increased, the necessary electrical energy can be decreased, and vice versa. This relation, between the total energy demand and electric and thermal energy for separating water is visualised in figure 4.2. The figure have been taken from reference [59].

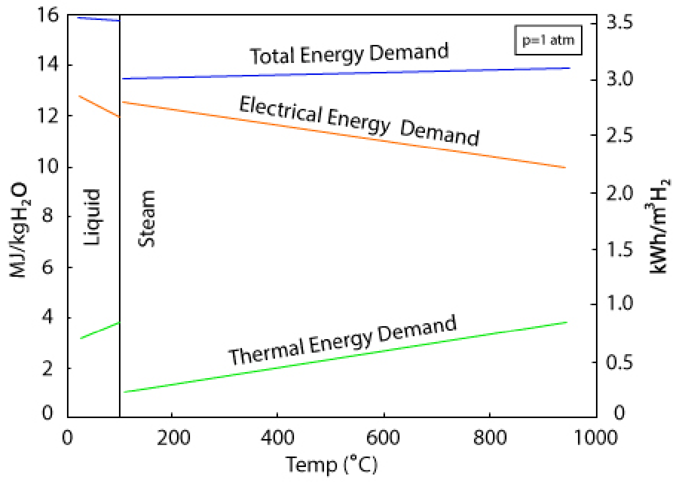

Figure 4.2: Graph illustrates the relation between electrical and thermal energy, based on equation 4.2.

It is also worth mentioning that an electrolyser is often referred to as a stack. A stack is built out of several electrolytic cells and its production capacity is often measured in MW, the maximum electrical power that can be applied. When buying commercial units, stacks are multiplied to reach the desired production capacity of an entire facility [56]. For example, a stack made up of several electrolytic cells has a maximum production capacity of 1 MW. To reach the desired production capacity of 10 MW for the entire facility, you would need to install ten stacks. The amount of oxygen or hydrogen that can be produced (in cubic meters) from 1 MW of electrical power is determined by the type and performance of the electrolyser.

4.2.2 Alkaline Electrolyser (AEC)

Figure 4.3 illustrates the basic functionality of an AEC. It has been made looking at a similar image published in reference [56]. The cell typically consists of two electrodes (the anode and the cathode), a separator, and an electrolyte. The electrolyte consist of an aqueous caustic solution, typically containing potassium hydroxide (KOH) [60]. When power is applied the water reacts at the cathode forming hydrogen and OH^- ions. The OH^- ions travel through the separator and react at the anode. The electrons are separated from the OH^- ions forming oxygen and water. The electrodes travel through the anode closing the circuit. The formed hydrogen at the cathode, and the oxygen at the anode, travels up through the electrolytic solution as gas bubbles where it is collected. The separator separates the oxygen and hydrogen from reacting with each other [61], partly for the sake of efficiency, but also for safety reasons. The AEC typically operates at temperature between 40-90 °C [56, 60, 61].

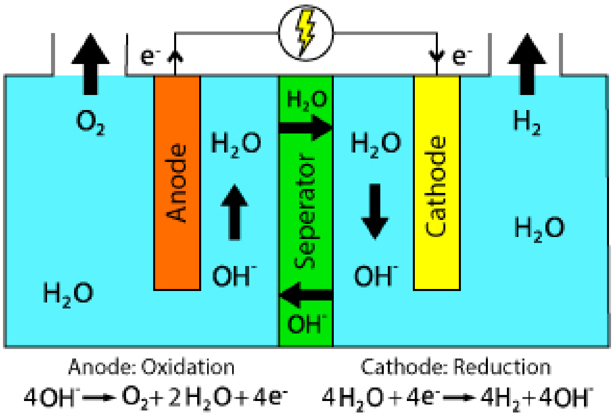

Figure 4.3: Schematic of the AEC functionality.

Strengths & Weaknesses

The major strength of the AEC is that it has the lowest capital cost out of the three mentioned in this study electrolysis technologies [62]. The reason being its relatively simple design and technical maturity [56]. Today, some commercial stacks can produce up to around 1000 m^3 hydrogen per hour [60, 61, 63, 62]. In addition it also has a longer lifetime compared to other electrolysers, ranging from 60,000-100,000 hours [60, 61, 63, 62]. These numbers have been based on previously published articles and a small benchmark that can be seen in appendix A.1.

The main weaknesses can also be explained by the simple design. Firstly, the separator does not completely separate the two gases from remixing, meaning they could react and turn back into water. As a consequence, this lowers the overall efficiency. It can also cause a potential safety hazard, where mixing of highly flammable gases such as H_2 and O_2 can cause an explosion [56, 61]. The risk of this occurring increases at lower power loads [61]. Not being able to handle dynamic power loads makes it less suitable for coupling with renewable energy sources (RES), because of the intermittent power supply. The AEC also operates under lower pressures, meaning that the hydrogen needs to be further compressed when transported and/or stored [60, 61]. This in turn raises the overall delivered cost of hydrogen.

Lastly, since it needs a separator and uses a liquid electrolyte. It receives larger losses compared to other electrolysers, reducing the efficiency further [61]. The operating efficiency is usually between 50-75% for large-scale commercial units [51, 56, 58, 60]. Small-scale, best-practice units can reach an efficiency of 80-85% [56, 58]. The specific energy consumption for the entire system is 4.5-7.5 kWh/m^3 [60, 61, 62].

Current & Future Status

Compared with other electrolysers, the AEC has a high degree of technological maturity and commercial success. It currently has the lowest capital cost that ranges between 1200-1400 $\$/kW$ (depending on scale of plant) [62]. It is also more available and more durable. This makes it currently the most viable option for large-scale hydrogen production using electrolysis. As of 2020, the Japanese company Asahi Kasei started the operation of the world's largest single-stack AEC demonstration project, named the Aqualizer [64]. The Aqualizer has a capacity of 10 MW and is able to produce 1,200 m^3 hydrogen per hour.

Current R&D is focusing on increasing the operating pressure, increasing the current density, and making it more suitable to handle dynamic power loads [62]. From 2030 it is projected that the capital cost of AEC will be around $900-1000/kW [65]. Other sources found it to be able to go as low as $500/kW, depending on the level of scale-up and further R&D [62]. According to interviewee I, although unsure of specific cost numbers, it is unlikely that the technology will receive large cost reductions. Mainly because it is already a highly mature technology. The same goes for the lifetime, which in 2030 is projected to be around 90,000-100,000 hours [66].

4.2.3 Proton Exchange Membrane (PEM)

Figure 4.4 illustrates the basic functionality of a PEM. The figure has been made looking at a similar figure in reference [67]. It consists of a cathode, an anode, and a solid, thin, and acidic membrane which are all pressed together. The membrane is multi-functional, serving both as an electrolyte and as a separator between the two gases [60]. Water reacts at the anode where it is oxidised into oxygen and protons (H^+). The protons travel through the membrane where they are reduced with electrons at the cathode, forming hydrogen gas. The oxygen remains at the anode side as it can not travel through the membrane. It typically operates at a temperature of 50-80 °C [60, 61, 62, 63].

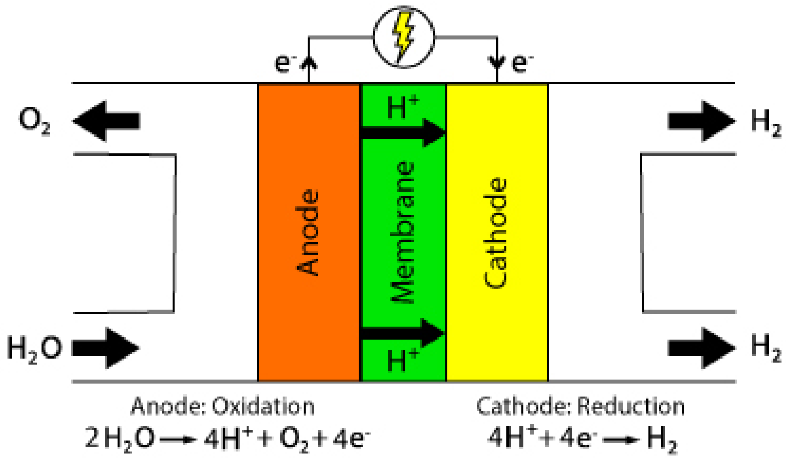

Figure 4.4: Schematic of the PEM functionality

Strengths & Weaknesses

Because of the solid and compact structure, it has three main advantages. First, it gives stronger structural properties which makes it possible to produce hydrogen under higher operating pressures [61]. Commercial units can produce hydrogen up to 85 bar [60, 68]. As stated previously, this reduces the need for extra compression and thus reduces the overall cost of hydrogen. It is also capable of operating under higher current densities. This is because the electrolytic membrane is thin, solid, and also functions as a separator which reduces the experienced losses [61]. The protons travelling through the membrane also respond quicker to fluctuating power loads, and there is a minimal likelihood of hydrogen and oxygen re-mixing. Combining these two makes PEM more suitable to handle dynamic power loads. The operating range is between 5-100% of its total production capacity and has a cold start-up time below twenty minutes [60, 62]. Overall, it has an efficiency ranging between 50-84% [51, 58, 60, 61, 63]. The specific energy consumption for the entire system is 4.2-7.5 kWh/m^3 [60, 62].

The main weakness of PEM is that it is more expensive than the AEC. The PEM operates under high pressures and voltages in an acidic and corrosive environment [61]. Materials that can withstand this environment are few and expensive [60, 61]. It thus relies on scarce materials such as platinum, gold, iridium, titanium, and ruthenium which is the main reason for the PEM having a higher capital cost. The harsh environment also lowers the lifetime compared to the AEC, around 30,000-60,000 hours [60, 61, 62]. Lastly, it is not as mature as the AEC and has not seen large-scale deployment. From a small benchmark, currently, some commercial stacks have proven to produce up to 200 m^3 hydrogen per hour, see appendix A.1. This corresponds to a electric power consumption of around 1 MW.

Current & Future Status

In the EU, there are several electrolyser construction projects planned. Of the ones that have declared which technology they will be using, the majority have said they will be using PEM [69]. One example is the German gas and engineering company Linde whom in January 2021 issued a press release, stating that they will build and operate the world's largest PEM plant [70]. It will have a total production capacity (several stacks) of 24 MW and be operational in the second half of 2022. However, although most projects are using PEM, the total production capacity of the planned European projects will be dominated by AEC (76%) [69]. Even though the AEC will most likely see a larger expansion in terms of hydrogen production capacity in 2020, some experts project that PEM will be a more suitable option in 2030 [62]. The main reason being the expansion of RES, where PEM is a more suitable option for hydrogen production. For this to happen, according to interviewee I, the issue with using scarce and expensive materials must be solved. As it can not be scaled up in a high enough capacity using the current materials.

Currently, the capital cost of PEM is around $1500-1800/kWe [65]. Depending on if the material issue can be solved, this is expected to drop to between $480-1200/kWe in 2030 [65]. Because of the PEM being much less mature than AEC the potential for larger cost reductions is more likely for this technology than the AEC. Further, the lifetime is expected to increase to 60,000-90,000 hours in 2030 [66].

4.2.4 Solid Oxide electrolyser (SOEC)

The AEC and PEM, while different, still operate similarly. The SOEC can be described as quite different than the two first mentioned. The SOEC can operate at temperatures of up to 1000 °C, but typically it is in the range of 600-850 °C [60, 62, 68, 71]. This means that water steam is provided as a feedstock and not liquid water. It thus takes advantage of equation 4.2, where supplying thermal energy drastically reduces the need for electrical energy. The SOEC operates at at ambient atmospheric pressure [66].

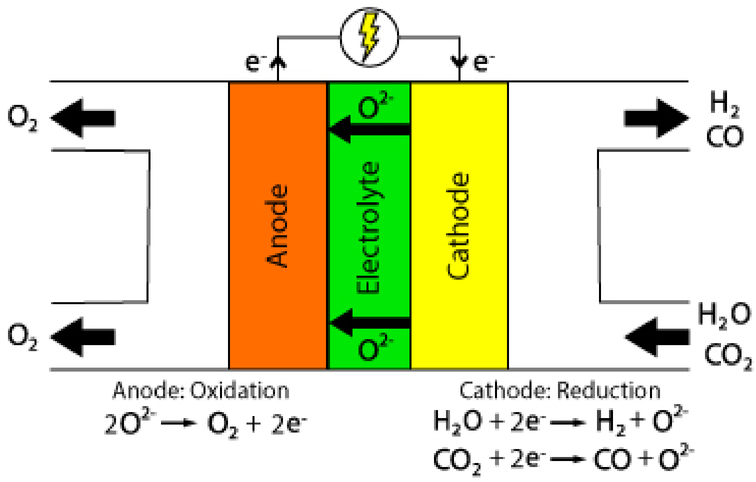

Figure 4.5: Schematic of the SOEC functionality

From figure 4.5, it can be seen that the SOEC consists of an anode, a cathode, and a solid electrolyte. Water steam reduces at the cathode forming hydrogen and oxygen ions (O^{-2}) [60]. The hydrogen is collected and the oxygen ions are transported through the electrolyte. At the anode, the oxygen ions oxidise forming oxygen. In addition to water steam, the cathode can also be fed with CO_2, either in combination or as a stand-alone feedstock [71]. In the end, this produces hydrogen and carbon monoxide (syngas) at the cathode and oxygen at the anode. Figure 4.5 have been made looking at a similar figure in reference [72].

Strengths & Weaknesses

The main advantage of the SOEC is that it can reach a considerably higher electrical efficiency compared to the AEC and the PEM. The electrical efficiency can even go beyond 100%, since it utilise thermal energy in a high enough capacity [62, 61]. Because electrical energy is more expensive to produce than thermal, this is seen as a major advantage [59]. Another advantage, when compared with the PEM, is that it uses abundant earth materials [71]. This reduces cost and the risk of a potential bottleneck emerging when scaling up production. Lastly, the SOEC can operate as a fuel cell, switching between hydrogen and electricity production. In co-electrolysis mode, it can produce syngas from water and/or recycled CO_2 [62]. This has further advantages if implemented in industries such as refineries or chemical process industries.

The downside of the technology is that it is the least developed technology out of the three mentioned in the study. Technically, it has proven to work in laboratory and demonstration-scale with current stacks being able to produce from 1-3 m^3 hydrogen per hour [71]. However, it has seen limited commercial deployment [62, 63, 71]. The main problem for the SOEC stems from the high operating temperatures. The high temperatures lead to fast degradation of the cell components, and low long-term durability of system components such as sealings and interconnects [71, 61]. Currently, SOEC stacks have demonstrated a lifetime of 10,000-30,000 hours [66]. According to interviewee I, because of the high temperatures, there is also a need to produce hydrogen at a steady rate. If the production rate is constantly varying, the materials will be under significant thermal stresses. It will also require a lot of energy in order to reach the desired temperature again.

Current & Future Status
In the US, two commercial plants exist which uses SOEC to turn CO_2 into carbon monoxide [71]. The German electrolyser company Sunfire also has a commercial SOEC producing hydrogen at 200 °C, see appendix A.1. No commercial units exist to produce hydrogen in the 600-850 °C temperature range. This is said to be on the brink of being realised, however. The largest current demonstration project has a total production capacity of 40 m^3 hydrogen per hour and is located in Germany [71]. Other planned demonstration projects, in Germany but also the Netherlands, have decided to increase this to a production capacity up to 300-740 m^3 hydrogen per hour [71]. Of the previously mentioned European electrolyser projects, three percent of the total production capacity is said to be implemented with SOEC [69]. In March 2021, the Danish company Haldor Topsoe announced they will build a large-scale SOEC electrolyser manufacturing facility [73]. The facility will be able to produce 500 MW of SOEC capacity each year. This can also be expanded to 5 GW in future endeavours. The manufacturing facility is expected to be operational in 2023.

Since the SOEC has the lowest level of maturity out of the three it also has the highest capital cost. Currently, this is estimated to be $2400/kWe or above [62, 71]. In 2030 and 2050 this is projected to drop to $1200/kWe and $640/kWe respectively, mainly through economiy of scale [71]. The lifetime is also projected to increase to between 40,000-60,000 hours [66].

4.3 Hydrogen Storage

Hydrogen storage can be divided into physical and chemical storage. Physical storage includes methods for storing hydrogen in its pure form, while chemical storage binds hydrogen to either various types of metal hybrids or by forming substances such as methanol or ammonia, as mentioned in the previous chapter. Physical storage methods can be viewed as technically and commercially more mature and are described below [74]. Methods for chemical storage have fallen outside the scope of this study.

4.3.1 Compressed Hydrogen Vessels

Since hydrogen has a very low density, one way of effectively storing it is to compress it and store it in high-pressure tanks. For the most part, in cylindrical steel tanks, with a volume of 0.05 m^3 but also in larger storage vessels with a volume above thousand cubic meters [74]. At ambient temperature (20 °C) and normal pressure (1 bar), hydrogen has a volumetric density of 0.089 kg/m^3 [75]. If instead compressed to 100 bar, the density increase to 7.797 kg/m^3 [76]. In practical terms, this means you need less volume of storage for the same content of hydrogen. A high compression rate also means you can achieve a higher gravimetric density, the percentage of hydrogen weight relative to the weight of the whole system (hydrogen and storage medium) [75]. A high gravimetric density is better for transport, as you can transport a larger quantity of hydrogen for the same distance. However, a higher compression rate raises the performance, and thus the cost of the storage medium [77]. This means there is a trade-off between the cost of storage and the cost of transport. For storage applications, the hydrogen is typically compressed to around 200-250 bar [48].

Compressing and storing hydrogen is one of the most mature and widely used methods [77]. It is simple and has the advantage of fast charging and discharging of the medium, or fast injection and withdrawal of hydrogen [74]. The main drawback, which is not only evident for this method, is that it needs further energy for compression [75]. This means you will have an energy penalty on the overall energy content of hydrogen. Depending on the level of compression and scale of storage, the energy required to do so can reach between 1-4 kWh/kgH_3 [76, 78]. Another drawback is that, even with compression, the volumetric density is rather low in comparison with other storage methods, such as liquefied hydrogen vessels. This means that this method is less suitable for large-scale hydrogen storage.

4.3.2 Underground Storage

As mentioned, compressed hydrogen stored in various tanks and vessels above ground is not suitable for large-scale storage, both because of cost and geographical footprint reasons. Instead, storing large quantities of compressed hydrogen can be achieved in underground geological structures where the hydrogen is compressed to around 200 bar before injecting it [74]. The three main prospects are aquifers, depleted hydrocarbon deposits, and salt caverns. According to interviewees B and K, these prospects are also what is being proposed for CO_2 storage. Although all three have been proven to work for storing natural gas and CO_2, only salt caverns have experience of storing hydrogen [79]. Since they all use some sort of natural and geological foundation, they are also all very location-specific. Lastly, the fourth method, not mentioned as frequently, is lined rock cavern storage which to a large degree artificially made and is much less location-specific compared to the others mentioned. Table 4.2 summarises some of the characteristics for each method as well as the associated cost. The cost does not account for the benefit of being able to inject and withdraw hydrogen gas several times a year [80]. This benefit, if included, could reduce the cost for the salt and lined rock cavern storage's.

Table 4.2: Underground storage comparison

Type:	Injection & Withdraw Cycle/Year:	Hydrogen Experience:	Location Specific:	Cost: ($/kg$H_2$)
Aquifer	1-2	No	Yes	1.29 [80]
Depleted Hydrocarbon Reserve	1-2	No	Yes	1.23 [80]
Salt Rock Cavern	10-12	Yes	Yes	1.61 [80]
Lined Rock Cavern	10-12	No	Less	2.77 [80]

Aquifers are underground porous rock formations containing water. This type of rock is also called permeable rock [79]. This means it can let fluids travel through the porous spaces of the rock. To be suitable for gas injection it needs to fulfill several storage characteristics. These include depth, tightness, pressure, permeability, and porosity [79]. It also needs an impermeable roof covering the stored gas and a dome-shaped structure to keep the gas in the defined space [78]. It has been deemed a suitable option since hydrocarbon reserves have in most cases been formed via an aquifer [78].

During injection of gas, the water is displaced to create the storage space. The water is also what confines the gas from percolating through the permeable rock formations while the impermeable rock is what keeps it from percolating upwards.

The main upside of using an aquifer compared to a depleted hydrocarbon reserve is that there is less risk of the hydrogen being contaminated by other hydrocarbons [79]. Meaning reacting with other substances forming methane or hydrogen sulfide. There are also more aquifers in the world, as suitable depleted hydrocarbon reserves are only limited to certain regions [81]. The downside is that, whereas a depleted hydrocarbon reserve has already proven to work for storing gas, as it has done for millions of years, an aquifer has not [79]. This means that more testing has to be performed (rock tightness, leakage paths, reactivity between rock and hydrogen) to check its suitability, increasing cost. Lastly, since the gas is stored within the porous rock formations, the gas experiences large flow resistance while being injected or withdrawn from the storage [81]. This means that the injecting and withdrawing cycle can only be performed a maximum of two times a year [79].

Depleted hydrocarbon deposits are, as mentioned, usually, an aquifer where natural gas and/or oil have accumulated over millions of years [79]. In contrast to an aquifer, there is less need for testing one of these sites since it has proven to contain gas already. Although some testing needs to be done to test the suitability of hydrogen instead of natural gas. It also has the benefit of already having certain necessary equipment on-site, which reduces capital cost further [79].

The drawbacks can be seen as the opposite of those mentioned for aquifers. They are more regional specific and there is a higher chance of hydrogen being contaminated during storage. Hydrogen contamination is also more evident if a depleted oil reserve is used rather than a natural gas reserve [79]. Lastly, since it functions similar to an aquifer, the maximum injecting and withdrawing cycle can only be performed two times a year [79].

Salt caverns are, as opposed to the previously mentioned, made artificially. A salt cavern is typically made from drilling a well in a salt formation or a salt dome. A natural structure that occurs when different kinds of minerals (mainly salt) are pushed upwards, expanding sedimentary rock that may lie on top of the salt. After the well is drilled, water is pumped in to dissolve the salt which in the end creates a cavity [81]. The salt dome is considered impermeable meaning it is tight enough to store gas in. It can be viewed as similar to a cylindrical steel tank only it uses rock and salt instead of steel for sealing and mechanical support. In addition, the salt dome is significantly larger than a steel tank.

Since the storage is artificially made, it comes at a higher expense compared to the aquifer or depleted hydrocarbon reserve [79]. But since all hydrogen is stored in a single space, not in porous rock formations, it can repeat the injection and withdraw cycle several times a year [79, 81]. Also, as previously mentioned, it is currently the only underground storage method that has experience in storing hydrogen. With successful hydrogen storage facilities in Teeside, UK and Texas, US [78].

Lined rock cavern is similar to salt cavern storage where a well is drilled deep underground. However, since the foundation is made out of rock and not salt, the necessary tightness for storing gas is questionable [79]. To solve this, the well needs to be lined with steel to make the whole storage impermeable [78]. The space between the rock and the steel is further filled with concrete. The advantages are similar to salt cavern storage but that it also significantly reduces the downside of having location-specific storage [79]. The downside is that it increases the cost of the storage significantly [79]. A facility like this exists in Skallen, Sweden for storage of natural gas [78]. A lined rock cavern is also currently the hydrogen storage method proposed for the HYBRIT project in Sweden [82].

4.3.3 Liquefied Hydrogen Vessels

Another way of storing hydrogen is in liquid form. This can be done by cooling hydrogen down to its boiling point of around minus 253 $°C$ at one bar [78]. The liquid hydrogen is then stored in cryogenic tanks further keeping the hydrogen at this temperature [75]. Depending on the size and performance of the cryogenic tank, between 0.06-3%/day of the stored hydrogen will evaporate due to boil-off [48]. Larger storage will have a lower boil-off rate.

The positive aspect is that liquid hydrogen has a considerably higher volumetric density. At one bar, or atmospheric pressure, the volumetric density for liquid hydrogen is 70.8 kg/m^3, compared to 0.089 kg/m^3 in gaseous state [75]. This decreases the size of the storage tanks and makes them much more suitable to transport over longer distances. The drawback is that the process of liquification is more energy-intensive compared to compression, meaning it has a higher energy penalty [78]. State of the art liquefaction plants currently requires an electrical demand of 10 kWh/kgH$_2$ [78]. However, through scale-up and various process improvements, this is expected to decrease to around 6 kWh/kgH$_2$. Another drawback, if stored for a long period of time, could be the evaporation of hydrogen due to boil-off.

4.4 Hydrogen Transport

This section describes the most discussed or promising ways to distribute hydrogen. Road transport is suitable for short or medium range distances where demand might be lower. Pipelines and shipping will be more suitable over longer distances and/or where demand is high. Figure 4.6 illustrates the efficiency of using pipelines or road transport from a cost perspective, as projected for 2030. The figure is taken from reference [74] and has been modified to exclude distribution options not included in this study. The three methods of distribution included in the study are further described in detail.

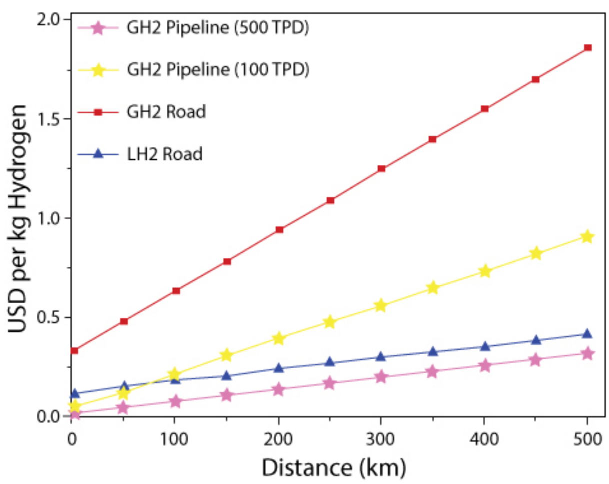

Figure 4.6: A cost comparison of hydrogen distribution methods. TPD stands for tonnes per day.

4.4.1 Road

Both liquid and compressed gaseous hydrogen can be transported by truck, either in a liquid truck or a tube trailer. The tube trailer carries several cylindrical steel tanks that contain hydrogen at a pressure of 200-300 bar [74]. Depending on weight regulations on the truck, the weight of a storage tank, and the number of tanks, the amount of hydrogen a truck can carry ranges from 180-540 kg [74]. The weight of the tanks is typically the determining factor. If composite tanks are used instead, the carried amount can reach 560–720 kg [75]. Nonetheless, this is considered highly inefficient and is only recommended at shorter distances and in lower amounts [74].

The liquid truck can carry more hydrogen per distance due to the increase in volumetric density [75]. The larger amounts make it a more suitable option for long-distance transport. Even though the liquification process in itself is more costly than compression, the most economical solution is to use cryogenic tankers which can carry about 2.5-4 tonnes of hydrogen [75, 74].

Figure 4.6 illustrates the cost for using this method for both gaseous and liquid hydrogen. Other sources estimates the cost for road transport of either gaseous or liquid hydrogen to be in \$1-2/kgH_2, over a 100-500 km distance [83]. However, these costs also include cost of processing (liquefaction or compression).

4.4.2 Pipeline

Pipelines are the most cost-effective method for transporting large amounts of hydrogen over long distances continuously [74]. Several thousands of kg hydrogen can be transported every hour. The initial cost of construction is high with a capital investment that can range from 2.2-4.5 million \$/km [83]. Today, the global hydrogen pipeline system is estimated to reach 16,000 km [74]. This is small in comparison to natural gas which exceeds 2,000,000 km. Instead of new pipeline development, one proposal is to re-purpose the natural gas grid for it to function with hydrogen. This is estimated to be able to reduce the cost by 60% [74, 83]. Plans like this are currently underway within the EU hydrogen strategy [2, 69]. The plan includes retrofitting 6,800 km of the natural gas grid to hydrogen until 2030 and 22,900 km by 2040 [69]. However, the technical suitability needs to be assessed [2]. Since it is unsure if several of the natural gas grid components can function with hydrogen [74]. A new regulatory framework also needs to be put in place [2].

Figure 4.6 illustrates the cost for using this method depending on amount of hydrogen. Other sources estimates these cost to be in \$0.1-1/kgH_2 over a the same distance [83].

4.4.3 Shipping

For transport across the ocean, newly constructed or retrofitted pipelines can prove to be difficult [83]. Instead, shipping is being proposed with liquid hydrogen tankers. This is the case for Japan which will have limited resources to produce their own hydrogen and will instead rely on imports, mainly from Australia [84]. In 2019, Japan developed the first liquid hydrogen tanker which has a volume capacity of around 9000 m^3 [74]. With a volumetric density of 70.8 kg/m^3 this amounts to close to 640 tonnes. Once the demand for hydrogen grows, it is also expected that ports, ships, and liquid hydrogen process facilities will improve to meet this demand [74]. The cost can range from 1-2 $\$/kg$ for distances up to 1000 km [83]. Using the same source, for distance up to 5000 km the cost goes above $\$2/kgH_2$.

Another promising option for shipping hydrogen is to do it by storing it as an energy carrier in ammonia. However, as mentioned in section 4.3, methods of chemical storage (e.g ammonia) has not been covered in this study so neither has the shipping of it.

4.5 Cost of Hydrogen Production

The cost of hydrogen production can be determined by the levelised cost of hydrogen. The total cost of installing and operating a hydrogen production facility, divided by the total hydrogen output each year. It is typically measured in $\$/kgH_2$. The LCOH by using electrolysis is illustrated by the following equation:

$$LCOH = CAPEX + OPEX \tag{4.3}$$

The operational expenditure (OPEX) for electrolysis is dominated by the total cost of electricity [85]. This is the cost of electricity (c_{el} in \$/kWh) multiplied with the systems electricity consumption ($q_{el,system}$ in kWh/m^3). Density (ρ_{H_2}) inverted is applied to receive the result in $\$/kg$. The cost of electricity will in this case be determined by an energy source and its levelised cost of energy (LCOE). The LCOE is similar as the LCOH but in regards to cost of energy generation instead of hydrogen production. Other cost in OPEX are the operation and maintenance cost ($O\&M$ in $\$/kg$). For electrolysis, this typically stands for 2% of the initial CAPEX/year [66]. The OPEX is illustrated in equation 4.4.

$$OPEX = \frac{c_{el} * q_{el,system}}{\rho_{H_2}} + O\&M \tag{4.4}$$

In the case of the SOEC, thermal energy is also used in the operational expenditure. This decreases the amount of electricity used, but still needs to be accounted for in terms of cost. This is illustrated in equation 4.5:

$$OPEX = \frac{c_{el} * (q_{el,EC} + q_{el,BoP}) + c_{th} * q_{th}}{\rho_{H_2}} + O\&M \tag{4.5}$$

Where the amount of electrical energy ($q_{el,EC}$) in relation to thermal energy (q_{th}) can be determined from figure 4.2. $q_{el,BoP}$ is the electrical energy necessary to operate the rest of the system (excluding the electrolyser). The sum of $q_{el,EC}$ and $q_{el,BoP}$ is equal to $q_{el,system}$.

The capital expenditure (CAPEX) is the total cost for installing a electrolyser facility. Illustrated by equation 4.6. The investment cost (C_{inv}) is the upfront cost for the system (in $\$/kW$). The CRF is the capital recovery factor, a ratio used to determine the annual cash payments in order to pay back the initial investment. The CRF is illustrated with equation 4.7. The CRF, investment cost, and electricity consumption is divided by hours in a year and the capacity factor (C_f). This factor describes how much the facility is utilised each year. If it is utilised less, payments are being done without using the equipment. Lastly, the density inverted is used to give the result in $\$/kg$.

$$CAPEX = \frac{C_{inv} * q_{el} * CRF}{8760 * C_f * \rho_{H_2}} \tag{4.6}$$

$$CRF = \frac{i * (1+i)^N}{(1+i)^N - 1} \tag{4.7}$$

From equation 4.7, the CRF is determined by the interest rate (i) and the payback period (N in years) in years. In this case, the payback period is determined by the lifetime of the system, seen in equation 4.8.

$$N = \frac{t_{electrolyser} * (1 + (1 - C_f))}{8760} \tag{4.8}$$

The total operational lifetime of the electrolyser ($t_{electrolyser}$ in hours) determines the maximum lifetime. But since the capacity factor determines the utilisation each year. If utilised less, the electrolyser will have a longer lifetime. This is thus accounted for in the equation. It is divided by hours in a year to have the result in years instead of hours.

4.6 Summary of Hydrogen Supply

The chapter has provided an overview of the important factors in the hydrogen supply chain. Starting with production, 95% of all hydrogen is produced using fossil fuels. Out of this 95%, steam methane reforming is the most prominent method globally. This has the benefit of producing hydrogen at a low cost and is often located close to demand. For reforming to become a viable option in the future, these facilities will need to be installed with CCS. The technology itself and captured CO_2, which will further need to be transported and stored, increases the overall cost of utilising this method.

The most prominent way of producing hydrogen without fossil fuels is electrolysis. The electrolysis method uses low-carbon energy sources to separate hydrogen from water molecules. The three most promising technologies using electrolysis are alkaline- (AEC), proton exchange membrane- (PEM), and solid oxide (SOEC) electrolysers. The specific data for these three methods as well as steam methane reforming are summarised in table 4.3. In general, it can be stated that the AEC and PEM use electricity to separate hydrogen from water. The SOEC uses high-temperature heat in addition to electricity to achieve the same purpose, reducing the need for electricity. Although some more than others, all three are expected to receive cost reductions through scale-up.

The nature of hydrogen also make it a a difficult substance to handle. Meaning that not only the production of hydrogen needs to be consider in the supply chain, but also the storage and transport of it. In terms of storage, although more new and innovative solutions exist, this study has focused on the most mature methods, including compression and liquefaction of hydrogen. Compression is less costly and requires less energy to process. However, the volumetric density is low in proportion to liquid hydrogen. In turn, this makes it more costly to transport. For compressed gas, it can either be stored in steel tanks above ground or underground in geological caverns. For larger amounts, the latter mentioned is preferred. Various underground storage methods exist, such as aquifers, depleted hydrocarbon reserves, salt and lined rock caverns. For liquefied hydrogen, it is often stored above ground in cryogenic tanks. In regards to transport, three alternatives exist, namely road, pipeline or shipping. Transporting by road can be competitive if it is done with liquefied hydrogen. For compressed gas, it is only recommended for shorter distances and in smaller amounts. Pipelines are the most preferred option for transporting large amounts of hydrogen continuously. They can be difficult to construct across oceans however, making shipping a more competitive option for this purpose. Shipping is done with liquefied hydrogen. Another future and promising method is to ship ammonia, however, this method has not been analysed in this report.

Lastly, equations have been given on how to calculate the levelised cost of hydrogen. In this study, this is used to calculate the cost competitiveness of hydrogen production using different means of electrolysis. This is done in chapter 7. In the following chapter, the main energy source analysed in this study will be presented.

Table 4.3: Summary of hydrogen production methods.

Production Method:	**Electricity Cons: (kWh/m^3)**	**Lifetime: (hours) (2030)**	**Inv Cost: (\$/kW) (2030)**	**LCOH: (\$/kgH)$_2$**	**Strength:**	**Weakness:**
Steam Methane Reforming	None	-	-	0.9-3.2	Cheap and mostly co-located with demand.	Uses fossil fuels and needs to be installed with CCS.
AEC	4.5-7.5	90,000-100,000	900-1000	Depends	Most mature and currently most suitable for large scale deployment.	Lower efficiency and bad at handling flexible power loads
PEM	4.2-7-5	60,000-90,000	480-1200	Depends	More efficient and good at handling flexible power loads.	Less mature and uses scarce and expensive materials
SOEC	Depends	40,000-90,000	1200	Depends	Utilizes less electricity and compensate with thermal energy	Least mature and fast degradation because of high temperatures

5

Small Modular Reactors

In this chapter, the energy source of the overall structure is presented, as seen in figure 5.1. A number of energy sources are possible to support hydrogen production. The scope of the study is on nuclear energy and hydrogen production and the chapter will therefore describe the concept of Small Modular Reactors (SMR). First a general description is given, followed by common nuclear reactor technologies utilised in SMRs. Next, different economic aspects of SMRs is described. This is followed by a reactor benchmark, comparing different SMR designs. Finally, some barriers to the concept are described, as well as a potential timeline for the deployment of SMRs.

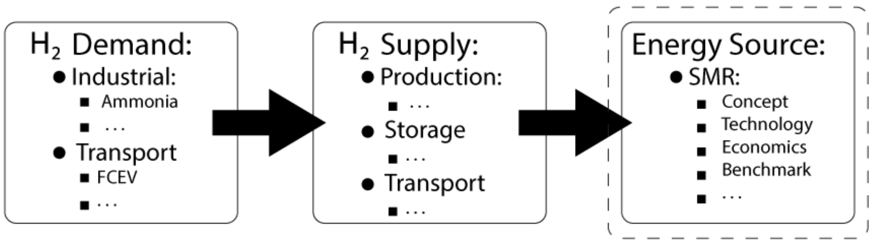

Figure 5.1: The chapter is in regards to the energy source part of the overall structure.

5.1 Basic Concept

A SMR is loosely defined as a nuclear reactor having a power output capacity of less than 300 MWe, even though designs with higher output exist [11]. With "Small" referring to capacity and "Modular" referring to the modularisation of the plant manufacturing and deployment. New builds of conventional nuclear power plants, with high costs and potentially overrunning schedules, are two of the reasons a need for change has been highlighted. The smaller scale and modular design of SMRs aim to solve some of these challenges [86, 87, 88]. The economics of scale originates from the number of units instead of the size of the units. Several units can then be built together to add capacity incrementally and form a larger complex [87]. SMRs can be said to differ from conventional large designs in 5 areas: Safety, Scalability, Flexibility, Deployability, and Economics [86].

Safety inherently comes from the smaller design allowing for increasingly passive safety systems and simpler designs. Passive safety means that the reactor does not need the intervention of an operator or electronic feedback to shut down the reactor safely. For example, safety features could rely on natural foces such as gravity or differences in density [87, 89]. This fact also opens up for smaller planning zones and increases siting possibilities [86].

Scalability comes from the reactors modularity and their ability to be incrementally built to adapt to the required scale. The plant can be built over time adapting to demand and provide economic benefits [86, 90].

Flexibility refers both to SMRs ability to be employed for different applications and also to the role in the power system [86]. Most SMRs are designed with some load-following capabilities for sharing grids with more intermittent sources [91]. Applications considered, in addition to electricity generation, include heating for industry and district heating, desalination, and hydrogen production [89].

Deployablity refers to the ability of constructing and inspecting the reactors almost entirely in factories. The possibility to do site works parallel to manufacturing in factories reduces the timetable, with vendors estimating a build time of 3-5 years [86] as compared to up to 10 years for traditional large nuclear power plants [92].

Economic benefits is a factor of many elements that have been mentioned. A possibility of shorter construction times, a higher level of modularisation, and standardisation are some. Instead of economy of scale, economics of multiples originates from many similar units being built over time and an increased learning rate can be achieved [93]. Finally, being factory-built to a higher degree allows for better control of the manufacturing process and could reduce delays [93]. This is described further in section 5.3.

5.2 Nuclear Reactor Technologies

To provide a better understanding of current and future nuclear technology, this section will describe the technologies relevant for the study. This includes light-water reactors, high-temperature gas reactors and molten salt reactors. But others not mentioned here exist as well. The technologies researched in this study have been chosen since they are used in many SMR designs. There are however SMRs utilising other technologies not mentioned here. Some examples of designs utilising the technologies described here will be given in section 5.4.

5.2.1 Light-Water Reactor (LWR)

Light-water reactors (LWR) are by far the most common type of reactor design in use today. Water is used as both coolant and moderator and design can either use an indirect or direct steam cycle. The pressurised water reactor (PWR) utilises an indirect steam cycle and accounts for about 63% of all reactors in use today [94].

The boiling water reactor (BWR) instead utilises a direct steam cycle and stands for about 18% of the current fleet [94]. The feedstock typically used is low enriched uranium in the form of pellets [95].

They work similarly, since they both uses nuclear fission to heat water. However, in the PWR, the coolant is under a pressure of about 15.5 MPa to prevent it from boiling when heated to around 325°C. The coolant is routed through a steam generator where heat is transferred to a secondary cycle at a lower pressure generating steam. The steam drives a turbine which in turn drives a generator producing electricity. The coolant in the primary system is then circled back to the core to be heated again [95]. Many SMRs utilise an integral PWR (iPWR) design, meaning the steam generator is integrated with the pressure vessel. In the BWR the coolant is boiled at a pressure of around 7.2 MPa and a temperature of 286°C at the core exit. The steam generated is routed to a turbine to generate electricity [95].

The fact that the technology is commercial today means it offers a ready means of producing hydrogen through electrolysis of water and fits together with low-temperature electrolysis such as the AEC and PEM technologies.

5.2.2 Molten Salt Reactor (MSR)

In contrast to the LWR, a molten salt reactor utilises, as the name indicates, molten salt as the coolant. In addition, to act as a coolant, when a mixture of sodium, zirconium, and uranium fluorides is used, the coolant also acts as the fuel. More recent designs, called advanced high-temperature reactors (AHTR) instead uses coated fuel particles with low-enriched uranium [95].

The reactor operates at a lower pressure of around 0.5 MPa and the core outlet temperatures can reach as high as 700-1000°C. The heat is transferred to a secondary compact molten salt cycle to then be transferred to a third energy conversion loop [95]. The potential for high reactor outlet coolant temperatures of the molten salt reactor enables the opportunity to utilise high-temperature electrolysis such as SOEC cells to produce hydrogen [95]. It can also only generate electricity and thus be coupled with low-temperature electrolysis as well.

5.2.3 High-temperature Gas Reactor (HTGR)

The high-temperature gas reactor (HTGR), also known as very high-temperature reactor, is cooled by helium and moderated by graphite. The fuel is in the form of ceramic-coated particles to withstand high temperatures. The coolant can be up to 950°C at the core outlet. Reactors using this technology have been designed in different scales, from 200 MWt (thermal) to 2400 MWt [95].

High-temperature electrolysis is an option that allows the electrolysers to operate at high efficiencies [95]. Similarly to an MSR, this can also be coupled to a high-temperature electrolysis technique as well as a low-temperature technique.

5.3 Economics

SMR loses the "economy of scale" benefit that a conventional large nuclear power plant (LNP) has. This means that construction of an initial, or first-of-a-kind (FOAK), unit may very well be more expensive in terms of overnight capital cost ($/kW) [96]. The capital cost being the total cost it would take to construct it, excluding interest. Instead, an SMR competes based on an "economy of multiples". Even though the FOAK unit is expected to be more costly than an LNP, the average cost of all units together can equal the cost of an LNP.

This is achieved through an improved learning curve. By allowing for a smaller and modular design, it can largely be factory-built and assembled on site. This in turn means a higher degree of standardisation, best practices, and advanced manufacturing and construction methods being implemented throughout the SMR value-chain [97, 98]. This leads to higher rates of cost reductions and reduced construction lead times. The more times a single task is performed, the better it is executed. Something that has been proven to work in other relatively complex industries such as aviation, ship, and offshore wind building [97]. As well as for standardised nuclear reactors constructed in Japan and South Korea [97]. However, these factors are not only dependent on the number of units being built, but also on the number of units being built on the same site [90]. How the concept of "economy of multiples" compensate for the "economy of scale" concept is illustrated in figure 5.2. The y-axis illustrates the overnight capital cost ratio between an SMR and an LNP. The loss of "economy of scale" factor increases this ratio. Meaning an initially higher cost for the SMR. But through various other economic factors, this initial cost increase is decreased. Depending on the number of units, or total capacity on the x-axis, is being built. The figure is taken from reference [90].

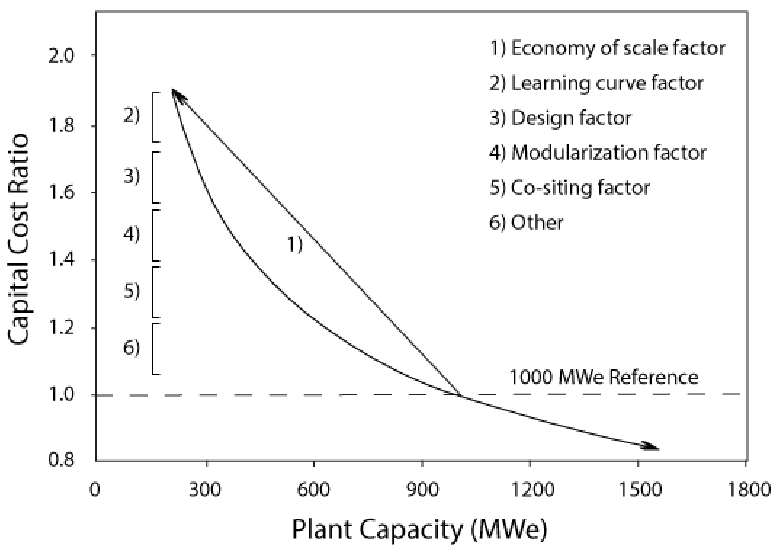

Figure 5.2: Illustrating how "economy of multiples" can compensate for loss of "economy of scale" factor.

These factors may compensate for the loss of the "economy of scale" benefit. But the main economic advantage of SMRs is decreasing the financial risk that comes with the construction of nuclear power. A risk that can be considered the highest financial risk of any energy generation related project [90]. Some discouraging examples exist in the ongoing EPR (European Pressurised Reactor) projects in France, Finland, and the UK. An LNP project requires high up-front capital and takes considerable time to construct. The global average is six years [99]. This in turn entails a long pay-back time for the project. Combining this with the fact that projects like these sometimes lead to large cost-overruns and possible construction delays. But also that liberalised markets in general often deals with a high degree of uncertainty, leads to a high risk that needs to be paid for [96, 90]. Often as a premium that is transferred to, and is in relation to, the capital investment [90]. An SMR can counter this in the following ways:

- First, the lower up-front capital and reduced lead-times for each SMR unit (because smaller in size), leads to a risk reduction in itself. The longer the construction period, the higher the percentage of the capital cost is transferred in interest [90]. This means that if less investment is tied in, combined with shorter construction periods, the amount of interest paid is reduced.
- Second, because of the learning curve effect, even if there is a construction delay on the first SMR unit, the likelihood of this occurring, or the negative outcome from it, is decreased while constructing the second unit [98]. Another point in relation to this, for an LNP, the consequence of a delay is also transferred to the entire project. Meaning the consequence is directly tied to the total investment cost. While for an SMR, it is only transferred to that particular unit, and thus, the consequence is only tied to the investment cost of a single unit and not the entire project. This minimises the consequence in itself.
- Third, when one unit is built, it can start generating energy and thus a potential profit. This means that an SMR project can help in self-financing the construction of additional units. An LNP can only start paying back once the entire plant is built [8, 98].

In conclusion, the modular design also provides a more modular economic model. It responds better to market opportunity or uncertainty since an investor can either expand, halt, or abandon a project in a more timely manner. The less "putting all eggs in one basket" advantage can attract more merchant financing and increase the suitability of nuclear in more liberalised markets, such as the European and North American power markets. It also opens up an introduction to the hydrogen market.

In terms of actual cost, different sources projects that the LCOE could be in the range from $48-120/MWh [96, 98, 100, 101, 102]. With a median value at $71.5/MWh.

5.4 Reactor Benchmark

There are many designs of SMRs existing today. This is thus only a small collection of many. The sample is based on interviews with experts as well as literature. The selected sample have been deemed far along in development, but also utilising any of the technologies described in section 5.2. Table 5.1 illustrates the sample of SMRs, as well as some specifications for each. Each are described further in this section. Other SMR designs far advanced in development can be seen in appendix B.1. In the appendix, all the information is taken from reference [87].

Table 5.1: Benchmark over some of the most developed SMRs

Reactor:	Size:	Lifetime: (years)	Outlet Temp: (°C)	Projected Capital Cost:	Projected Operation:
NPM	250 MWt/ 77 MWe	60	321	$2850/kWe	2029
BWRX-300	870 MWt/ 290 MWe	60	287	$2250/kWe	2027
Xe-100	200 MWt/ 82.5 MWe	60	750	$3030/kWe	2030
Integral MSR	400 MWt/ 192 MWe	56	700	-	-
RITM-200	165 MWt/ 50 MWe	60	313	-	Operational
HTR-PM	2x250 MWt/ 210 MWe	40	750	$1500/kWe	2021

5.4.1 NPM, NuScale, US

NuScale is an American reactor developer currently working on an iPWR, named the NuScale Power Module (NPM). Each reactor, or module, has a capacity of 77 MWe and each plant can have up to twelve reactors. Depending on the energy demands of the customer, a four or six-module design is also possible [87]. When going commercial, the capital cost for this twelve-module design is estimated to be around $2850/kWe with an LCOE target at $55/MWh.

According to the World Nuclear Association (WNA), in 2017 NuScale submitted a design certification application to the US Nuclear Regulatory Commission (NRC) for an earlier 50 MWe version [87], this was further approved in 2020 making it the first SMR to be approved by the NRC. This means that the 50 MWe version can be referenced for a construction and operating license under NRC regulations. However, site-specific licenses must also be approved before construction can begin. NuScale has also stated that they will apply for the same license but for the updated 77 MWe version in 2022. This version has also been applied to the Canadian Nuclear Safety Commission (CNSC) for a pre-licensing vendor design review, an optional service that lets the CNSC provide feedback early in the design process. A demonstration of a twelve-module NPM is projected to be operational in 2029 at the DOE's (American Department of Energy) Idaho National Laboratory [87].

5.4.2 BWRX-300, GE-Hitachi, US & Japan

GE-Hitachi is a joint venture between the American company General Electrics and the Japanese company Hitachi. They have developed a 290 MWe BWR named the BWRX-300 [103]. This is a full passive safety reactor, which they have described as *"the simplest, yet most innovative BWR design since GE began developing nuclear reactors in 1955"*. The BWRX-300 strongly focuses on optimising the cost of constructing and operating a nuclear reactor [103]. This is done by further simplifying an earlier NRC-licensed reactor. After initial reactors have been built, they expect that the capital cost could be around $2250/kWe, provided that serial production is taking place.

According to the WNA, in 2019 the reactor design was submitted to the CNSC for a pre-licensing vendor design review [87]. In 2020 they also submitted the first licensing report to the NRC. They are targeting being operational in the US by 2027 and 2028 in Canada. They are also currently evaluating the economic feasibility of constructing a single BWRX-300 in Estonia and Poland.

5.4.3 Xe-100, X-energy, US

X-energy is an American reactor developer currently working on a HTGR called Xe-100. The design consist of four modules with an 82.5 MWe and 200 MWth capacity per module. The outlet coolant temperature can reach 750 °C [103]. Although the design is not yet complete, X-Energy hopes their design will be finalised by the year 2022 or 2023 [87]. They have also submitted a pre-licensing vendor design review to the CNSC. At the moment it is estimated that the four-module design would cost around $1 billion. Dividing this with the total capacity of a four-module design, the average capital cost becomes $3030/kWe.

According to the WNA, in 2020 X-energy was awarded $80 million in funding to build a commercial-scale reactor that can be ready in 2027. The funding was provided by the DOE within their Advanced Reactor Demonstration Program. Within the same year, the US Department of Defence also awarded a contract to develop their design as a microreactor (below 10 MWe). Lastly, Jordan has signed a letter of intent (2019), which could let X-energy build a 75 MWe four-module design by the year 2030 [104]. Jordan has also been in discussion with other SMR vendors such as Rolls Royce, the CNNC (China National Nuclear Corporation), NuScale, and Rosatom.

5.4.4 Integral MSR, Terrestrial Energy, Canada

Terrestrial Energy is a Canadian nuclear developer. They are developing an integral molten salt reactor with a thermal capacity of 440 MW and an electric capacity of 195 MW [103]. The outlet temperature can reach 700 °C. The plan is to utilise two modules per nuclear plant, however this could be scaled [87]. They expect the LCOE to be competitive to natural gas [87]. Assuming this means the LCOE from natural gas in Canada, the average LCOE from natural gas ranges from $60-70/MWh [105]. Terrestrial Energy is aiming to commission a commercial reactor sometime during the 2020s [103].

5.4.5 RITM-200, Rosatom, Russia

In Russia, the RITM-200 reactor is already in use for marine purposes [87]. More specifically it is used on three icebreakers [103]. Construction of the RITM-200 on land is further planned to begin in 2024 and finished in 2027. The RITM-200 is a iPWR with a capacity of 175 MWt and 50 MWe [87]. It is envisioned that the land-based plant can be designed with two or more modules [103].

5.4.6 HTR-PM, China

One reactor, based out of China, is the HTR-PM, a HTGR reactor with an outlet temperature of 750 °C. A demonstration of a plant that uses two modules is expected to be operational in the second half of 2021 [103]. Each module has a 250 MWt capacity and together drives a 210 MWe steam turbine [87].

The demonstration project will lay the foundation for the eventual six module (250 MWt/module) design [87]. Factory and series produced units is projected to reach a capital cost of $1500/kW with an LCOE of $50/MWh [87].

5.5 Barriers to the Concept of SMR

With any new technology, there will be barriers hindering the development or deployment of it. In the case of SMRs, a concept building on previous technology and experience from nuclear technologies that has existed commercially for many years. The development is not the primary problem. Instead, barriers foremost relating to the deployment are highlighted by experts to be the most critical. In this section, the barriers relating to licensing and promotion of the technology will be described, as well as more general barriers relating to the deployment.

5.5.1 Licensing

Before a reactor design can be implemented commercially, it needs to be certified by a relevant regulatory body [90, 94]. For example, in Europe, the design must be certified in accordance with the European Utilities Requirements (EUR) but also in accordance with national standards. In the UK, there is a four-step process taking around four years, in the US it is the NRC, and in Canada it is the CNSC [94].

Proven and mature technology, such as the LWR implemented in an SMR design, should be more effective in licensing. In contrast to newer non-LWR advanced nuclear technologies such as the MSR or the HTGR. The designs being licensed in the near term will be dominated on proven LWR-technology [90]. The main responsibility of the regulatory authority and the licensing process is to assure all safety, environmental, regulatory, and policy issues have been addressed and resolved [90]. The enhanced safety designs might also open up for the licensing authority to license SMRs with greater emphasis on probabilistic risk assessment (PRA) techniques [90].

Taking the US and the NRC as an example, near-term designs of SMRs utilising PWR technology will be held to the same standards as conventional LNP. Some of the matters in licensing that are specific to SMRs are for example; smaller facilities with less security needed, greater redundancy, more passive features, smaller fuel inventory meaning a smaller amount of radioactivity released in an accident, and a potentially reduced emergency planning zone. Meaning a SMR and a LNP is not directly comparable. The modular nature of the SMR designs also requires licensing authorities to deal with multi-module licensing and the issue of separate licenses for each module, manufacturing licensing for the factories producing the modules, and control-room staffing when using multiple modules [90].

The potential issue of licensing was brought up by many of the experts interviewed. Interviewees A, B, C, D, and E all brought up potential barriers originating from licensing issues. One of these, mentioned by interviewees A, C, D, and E, is the matter of licensing a design in many countries. As mentioned, the design needs to be licensed in the country of origin, but also the country of deployment. This is highlighted as a matter that could lead to large costs and time-consuming processes of having to re-license a design in many countries. No country is willing to lower its standards, or for that matter admit that its standards are too low and increase them. In a newcomer country, this issue becomes even more pronounced with human resources and experience missing. Another issue is brought up by interviewees B and D in that not only the designs need licensing, but also the manufacturing process. The issue of licensing is seen as a huge barrier if SMR are to reach its full potential.

5.5.2 Deployment

Although licensing is the key barrier that needs to be overcome to fully realise the potential of SMRs. Some other issues regarding the deployment were discussed during the interviews. One, highlighted by interviewees A and B, is that many of the new developers are small in size. They do not have experience in large construction projects. The risk is thus more concentrated on the actual production and deployment, after the technical or engineering design have been developed.

As mentioned in the section on licensing, new markets without previous experience in nuclear energy could prove to have larger issues in deploying SMRs. This originates not only from the lack of a relevant regulatory body but also from a lack of experience and competence in the workforce.

One final barrier, brought up by experts in interviews, relates to the small vendors often behind new SMR designs. To reach favourable economics, as explained in the section on economics, manufacturers need to be able to scale up production. Small vendors, as highlighted in the interviews, could have difficulties reaching the Nth-of-a-kind (NOAK) because of lacking experience.

5.5.3 Promotion of the Technology

One final barrier identified during the interviews can be found in the way nuclear power is promoted, or rather, not promoted. Interviewees A and E talk about how the nuclear industry is rather isolated in their communication. They point out how people in the industry only communicate to others in the industry, and how the communication in general, is often saturated with a high-degree of technical terms. For those outside the industry, this might be difficult to understand. This also ties into the public view on the dangers of radiation, and how the nuclear industry has not been able to communicate the actual level, and the measures taken to reduce this. Simply because the public have a difficult time in understanding what is actually being said.

5.6 Timeline

During interviews with experts, including interviewees A, B, C, and D, a potential timeline for the deployment of SMRs was discussed. The timeline can be seen in figure 5.3. It is based on the experts' opinions and the information that has been given in section 5.4, regarding the reactor benchmark.

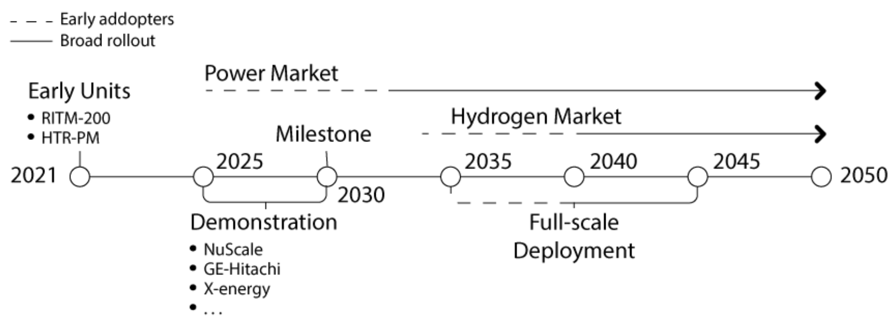

Figure 5.3: Illustrating a projected timeline of SMR deployment and introduction to the hydrogen market.

Interviewees A, C, and D stated that demonstration of SMRs can take place in the mid to late 2020s. This is also the projected timeline for many of the SMR developers. In order for this to happen, interviewee A mentioned that some governmental funding is going to be needed in the early stages. If proven successful, commercial units can start deploying in the early or mid-2030s, as stated by interviewees A, B, C, and D.

After this, the timeline becomes harder to predict. Interviewee A and B mention that for large-scale deployment, or series production, you are probably looking at 2040 or beyond. Interviewee B further expands on this by stating that it is not only regulations around reactors that are going to be an issue, it is also regulations in regards to the factories and supply chain that needs to be accounted for. Interviewee C instead believes that 2035 is a more accurate date for large-scale deployment. This is further expanded on by stating that the RITM-200 reactor in Russia has already started series production in some regard. The question is rather where the next SMR will be deployed outside of Russia. The US, Canada, and China are all potential candidates.

Either way, all interviewees agree that the initial commercial units will most likely be targeted towards the power market. This is a well-known and regulated market with standard procedures. It thus involves less risk than for the hydrogen market. When the concept of SMR is proven in a high enough degree, and the hydrogen market have stabilised, an SMR introduction towards hydrogen will be more likely.

5.7 Summary of Small Modular Reactors

Small modular reactors (SMR), their functionality, and the economics of them have been described. SMRs differ from conventional large nuclear power plants in five areas; Safety, Scalability, Flexibility, Deployability, and Economics. Different reactor technologies exist in SMR designs and provide different opportunities. Light-water reactors are the most common and fit together with low-temperature electrolysis. Molten salt reactors and high-temperature reactors can produce higher temperatures, enabling high-temperature electrolysis. Regarding the economics, SMRs can compete on an "economy of multiples" with many smaller units and being factory-built, driving down the cost.

There are many vendors and designs of SMRs, with some having reached a more advanced stage in development than others. Nuscale, GE-Hitachi, and X-energy are highlighted as examples of designs utilising different reactor technologies. Barriers to the concept of SMRs include licensing, with long processes that are individual to each country and regulatory body. Further barriers are concerns regarding the deployment and the promotion of the technology. Finally, the timeline of the concept of SMRs indicates that demonstration could take place in the mid to late 2020s, with commercial units in the mid-2030s.

6

Hydrogen and Small Modular Reactors

In this chapter, the concept of utilizing SMRs to produce the large amounts of hydrogen needed in the future is described. This is done by first describing the large opportunity that exists in the large amounts of energy needed to produce hydrogen. Further, the synergies between small modular reactors and hydrogen production are highlighted. Finally, the alternative ways of supplying energy and their respective hydrogen supply architecture are discussed as well as how the total cost of delivered hydrogen can be calculated.

6.1 Market Opportunity

As stated in chapter 3, regarding hydrogen demand, there are many applications in which hydrogen is used today. There are also many potential applications where it can be used in the future. Current sources of demand include industrial applications such as ammonia and methanol production, and also the steel industry. Regarding the area of transportation, there are already today vehicles utilising hydrogen as fuel and experts see a large potential within the sectors of long haul trucks, busses, and trains. As stated in chapter 4, today over 95% of the hydrogen is produced using fossil fuels. Following the increased cost of emitting carbon, and increased demand for climate-neutral products. The demand for low-carbon hydrogen is expected to increase. The first large demand for low-carbon hydrogen is predicted by experts to come from the industrial processes which already today have an established demand that is only expected to increase.

An effort will be made to illustrate the potential demand for hydrogen in the future. Table 6.1 illustrates the future hydrogen demand for a couple of applications, these have previously been presented in chapter 3. It also illustrates the amount of electricity it would take to produce these amounts of hydrogen, assuming 54% would be produced using electrolysis in 2030 and 62% in 2050, as recommended by the IEA [57]. Further more, electrolysers electricity consumption is assumed to be 5 kWh/m^3 and a hydrogen density of 0.082 kg/m^3 is used. Finally, it translates how many SMRs with a 100 MWe capacity would be needed to satisfy this electricity demand. This is done under the assumption that 20% of the total demand would utilise nuclear electrolysis, twice of what nuclear energy currently satisfy in terms of global electricity generation [106]. Further more, 8760 hours in a year is used and a nuclear capacity factor of 90%.

There is also a varying degree of uncertainty in regards to these estimations. For reference, in a report by IEA, it was calculated that switching 5% of the global and current ammonia production (31 MtH_2) to electrolysis, would require 110 TWh of additional electricity [107]. If this is increased to 54%, this totals 1188 TWh. Similar to the numbers presented in table 6.1.

Table 6.1: Future demand in amount of hydrogen, electricity and finally number of SMRs

Demand:	**Amount (MtH_2)**	**Electricity (TWh)**	**Nuclear Electrolysis (TWh)**	**100 MWe SMRs (No.)**
Ammonia (2030)	37	1218	244	309
Methanol (2030)	19	626	125	159
Steel (2030)	8	263	53	67
Shipping/ Aviation (2050)	90	3402	680	863

From the three presented industrial applications alone this translates into over five hundred SMR units. According to a study commissioned by the British Department of Energy and Climate Change, to reach a steep learning curve, it would require ten or more SMR units to be delivered each year [97]. This is under the assumption that they are largely factory-built. From these applications alone, it can thus be determined that the potential for SMRs in the hydrogen market is sizeable. Even with a rather low share of around eleven percent of the total hydrogen produced (using electrolysis, reforming with CCS, or other). These applications are also those that can be determined as most of a "sure thing" and all have further potential demand for hydrogen beyond 2030. Further, other sectors where the demand for hydrogen is expected to increase, such as aviation and shipping can be analysed. The potential size of demand from the aviation and shipping sector could be as large as 90 MtH_2/yr combined in 2050. That alone translates into a need for above 850 SMR units under the same assumptions. To further add on to these already huge numbers, the expected demand from the transport sector such as long haul trucks, busses, and trains could be even larger.

The IEA states that in order to reach a net zero GHG emission society, the total low-carbon hydrogen production need to be 150 MtH_2 in 2030 and 520 MtH_2 in 2050 [57]. Using 5 kWh/m^3 electricity consumption and the same hydrogen density as previously. This translates into an electricity demand close to 5000 TWh in 2030, and close to 20,000 TWh in 2050. For reference, in 2018, the total global electricity consumption was close to 22,000 TWh [108].

Needless to say, there exists a huge demand for hydrogen today and an even larger potential for increasing demand in the future. Thereby, the opportunity for low-carbon hydrogen utilising all methods of production is proportionally huge. In order to supply the required energy for hydrogen production via electrolysis, it will require all low-carbon energy sources.

6.2 Nuclear Electrolysis

Depending on the type of reactor (LWR, MSR, HTGR, or other), an SMR can function with both low-temperature electrolysis (AEC and PEM) and high-temperature electrolysis (SOEC). Figure 6.1 illustrates two generic and simplified schematics of the different nuclear electrolysis options.

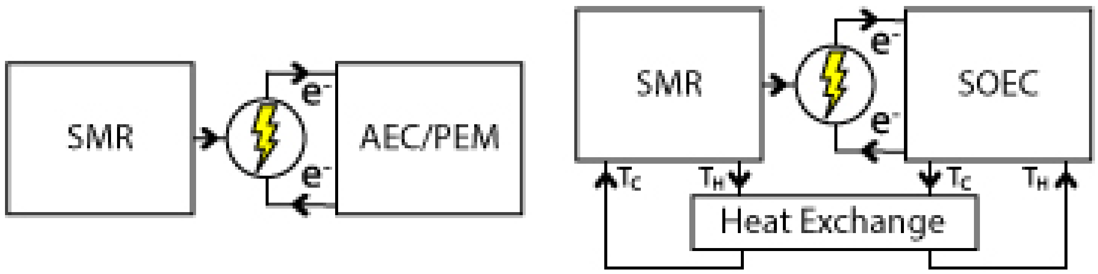

Figure 6.1: The figure on left illustrates low-temperature electrolysis while the figure on the right illustrates high-temperature electrolysis. Both with a nuclear energy source.

To calculate the LCOH, the low-temperature alternative uses the LCOE from the SMR as input to equation 4.4 from section 4.5. This option can use any number of reactors as long as it is fitted to produce electricity. Because of the higher temperature differences, the MSR and the HTGR have higher efficiency in generating electricity. At the same time, the LWR (iPWR or BWR) is a mature technology with reduced complexity.

The high-temperature electrolysis uses both electrical and thermal energy as input, meaning that a part of the SMRs thermal capacity is used directly and the remaining is used to generate electricity. Thus it uses equation 4.5 instead of equation 4.4 when determining the LCOH. The cost of thermal energy (c_{th}), can be assumed to be equal to the cost of electrical energy (c_{el}) times the electrical generation efficiency [59]. For a HTGR the efficiency can reach 50%, meaning that the c_{th} is equal to 0.5*c_{el} [95]. The levelised cost of electricity (LCOE) is used as c_{el}.

In terms of scale, several electrolysers and SMRs can be used in order to reach the desired capacity. For a large- and central demand, this means an economic benefit of co-siting several SMR units. For a smaller- and decentralised demand, less SMR units would be needed. Meaning that the economic benefit of co-siting could be reduced. This will likely result in a higher LCOE and thus a higher LCOH. However, each demand needs an economic analysis on its own.

6.3 Analysis of the Synergies Between Hydrogen and Small Modular Reactors

Utilising energy from an SMR to produce hydrogen proves to provide many synergies. In this section the synergies of heat from the reactor and heat demand in processes will be analysed. Further, high availability and a continuous supply of the reactor is another beneficial quality. Finally, the synergies in locating the energy source, and the modular nature of both electrolysers and SMRs are highlighted as the primary synergies.

6.3.1 Process Heat

One synergy between hydrogen production and small modular reactors is the heat supplied by a reactor and the heat demand from industries. Processes with a demand for hydrogen such as ammonia production, methanol production, and steel production all require process heat, as explained in chapter 3. As an example, when H_2 and N_2 are combined using the Haber-Bosch process to create ammonia. The process temperature is 450-550°C. Process conditions when producing methanol are around 250°C. Heat is needed in steel production as well, where before the DRI the gas needs to be heated to around 900°C.

Further, the hydrogen production itself can benefit from adding heat to increase the efficiency, as outlined previously in section 4.2.1. High-temperature electrolysis has a large potential to increase the electrical efficiency in hydrogen production when paired to a heat source such as a reactor.

In chapter 5, different designs of SMRs and the underlying technologies were described. Light water reactors can supply primary heat at up to around 300°C. Heat at this temperature could increase the efficiency of the processes mentioned above. Waste heat from the reactor could also increase efficiency in some applications. Molten salt reactors and high-temperature gas reactors could supply heat at even higher temperatures, up to 1000°C. The efficiency of processes could be increased, in addition to enabling high-temperature electrolysis.

6.3.2 Availability and Continuous Production

Many of the processes discussed in this report, such as steel production and production of ammonia and methanol, rely on a continuous supply of energy and hydrogen. One clear example of this need for continuity in supply is in the production of steel, explained in section 3.1.3. Steel plants are cited to operate for more than 8000 hours per year and have low flexibility in varying their production rate. Similar conditions apply to other process industries.

Nuclear power is known to have the highest capacity factor of any other energy source. This enables nuclear plants, and SMRs in particular, to supply energy continuously at the demanded rate. Hydrogen can thereby be produced at the required rate, supplying industries, and keeping production at high utilisation. If energy can not be supplied at the demanded rate, facilities will require storage facilities to store hydrogen when they are able to produce. Increased size in variation will require an increased size of storage and increased cost.

A fact is that electrolysers, used to produce hydrogen, have a high capital cost. To have a high level of utilisation of the electrolysers will therefore prove to be important to decrease cost. Nuclear production ensures a reliable energy source, regardless of weather patterns, and thereby ensures high utilisation of expensive electrolysis capacity.

6.3.3 Location

Another synergy between hydrogen production and SMRs is the flexibility in locating. Industries requiring large amounts of hydrogen (ammonia, methanol, etc) are often located in centralised industrial areas. An SMR could thereby operate at full capacity and supply many points of hydrogen demand. An SMR can also be located closer to other industries having a smaller size and capacity, requiring a smaller planning zone.

Being able to locate the energy source closer to demand will also decrease the need for transporting and storing hydrogen. First, supply will be more certain, reducing the need for storage. Second, lesser distances mean shorter distances for transporting energy or hydrogen. As explained, transporting hydrogen can be done in different ways, but all of them induce a cost. The cost of transport, together with storage, is what is most uncertain today. By utilizing an SMR, this cost could in large part be avoided.

One final point relating to locating the energy source to produce hydrogen is the small footprint of SMRs. In relation to renewable sources, such as wind and solar PV, the geographical footprint of SMR per energy unit supplied is very small.

6.3.4 Modularity

One final point of synergy between hydrogen production and SMRs is in the modularity of the techniques. Both electrolysers and SMRs are modular, meaning that a larger facility is built by many smaller units. In the case of SMRs, smaller reactor modules can be added to allow for adopting capacity to demand. The same applies for electrolysers, where stacks can be added to reach the desired production capacity.

As presented in section 5.3, the modular design also allows for a more flexible economic model. The fact that both technologies are modular, allows for a closer match of capacity between the energy source and the production. This in turn induces less cost invested in overcapacity. It also enables increasing capacity as required at the same rate as demand increases. By increasing capacity, incrementally large one-time investments and long periods without income during construction are avoided.

6.4 Alternative Production Methods

The study has introduced mainly two different ways of producing hydrogen. Although there are others, the ones discussed in this study are steam reforming and electrolysis. Steam reforming uses natural gas as an energy source while electrolysis can use any number of energy generation sources. For the hydrogen to be produced in a low-carbon way, the steam reforming can further be installed with carbon capture and storage (CCS). In the case of electrolysis, the energy can be generated from either nuclear power or RES (mainly wind and solar). Other low-carbon ways, for example, the usage of biomass, have been mentioned but been further excluded from analysis in this study.

The choice of energy source and production method leads to different paths throughout the supply chain. With the help of SWOT analysis, this section describes the combined energy and production method of reforming with CCS and RES with electrolysis, and how these affect further choices throughout the supply chain. The analysis presented in this section relies on information from chapter 4 and information gathered during the interviews. More specifically from interviewees A, B, D, E, J, K, and L.

6.4.1 Reforming with CCS

The SWOT analysis of reforming with CCS can be seen in table 6.2 and is explained in the following section. Although the use of CCS is expensive, the total production cost of hydrogen is still relatively cheap compared with the alternatives. It is also dispatchable, meaning it has the advantage to produce on demand. Thus, the main opportunity of using steam methane reforming with CCS is that there is not much that needs to change. Companies using this method of production will not require to make substantial changes to their main process. Interviewee B explains this by stating:

"There is an argument that natural gas companies or the industry might sort of present itself as; Okay, we can't capture 100% of the carbon. But in the interim, which we won't define how long that is, we can deliver partially decarbonized hydrogen, so contributing towards decarbonization in a partial sense. But without requiring all the financial policy mechanisms that renewables would require."

Table 6.2: SWOT analysis for Reforming with CCS architecture

Reforming with CCS	
Strengths	**Weaknesses**
- Relatively low production cost - Use of existing process - Dispatchable energy supply	- CCS increases complexity - CCS controversy - Still emits GHG emissions
Opportunities	**Threats**
- "Business as usual"	- CO_2 storage availability - CO_2 infrastructure cost - Decline in public acceptance

The inclusion of CCS means an increased need for waste management in the form of carbon dioxide. Something that increases the overall complexity. It increases the need for infrastructure and a solid supply chain around the handling of the waste. It also accentuates the downside of being location-specific. For cost to not spiral, the production needs to be located at sites that have near and/or easy access to carbon dioxide storage.

Lastly, a decision regarding the usage of this method is not solely based on financial decisions. The method has seen some public critique in terms of storing the carbon dioxide but also regarding the usage of the method in itself. Public opinion can sometimes dislike the fact of having stored carbon dioxide in their "backyard", while others see it as extending a societal behaviour that needs to be changed for us to decarbonize. Because of this controversy regarding CCS, a region might think twice before adaptation. Interviewee J mentions one example of this by stating the following:

"The German strategy is quite interesting, because they'll quite happily import blue hydrogen (hydrogen produced from reforming with the inclusion of CCS), but they don't want to produce it themselves. This makes absolutely no sense at all to me... but that's a political decision they've made. I think the result of that will be that hydrogen costs in Germany will be higher than they otherwise would have been.".

6.4.2 Renewable Electrolysis

The SWOT analysis for renewable electrolysis can be seen in table 6.3 and is explained in the following section. The RES includes a variety of energy sources such as wind, solar, geothermal, and wave power. In this study, what is mainly meant by RES are solar, offshore, and onshore wind. The main strength of these sources is that they are very cheap to produce and construct. They also recieve the "fuel" (the radiation from the sun or the wind) to generate the energy for free. Lastly, the RES needs limited staff on-site which reduces the overall cost further. Combining these means that RES can generate electricity at an exceptionally low cost. Since the operational cost of an electrolyser is dominated by the cost of electricity, the renewable electrolysis combination has a potentially big advantage in this regard.

Additional benefits are that it is, publicly, one of the most mentioned future methods of producing hydrogen. The most prominent example being the EU hydrogen strategy which has stated that the objective is to have installed 40 GW of electrolyser capacity by 2030 [2]. This will require 80-120 GW of renewable electricity for the sole purpose of producing hydrogen. Combined, the EU is willing to invest 24-42 billion euros for expanding the electrolysis capacity and an additional 220-340 billion euros for the expansion of the renewable capacity.

Table 6.3: SWOT analysis for Renewable Electrolysis architecture

Renewable Electrolysis	
Strengths	**Weaknesses**
- Cheap energy supply - High growth - High public acceptance	- Intermittent energy supply - Location specific energy supply - Large geological footprint
Opportunities	**Threats**
- Low electrolysis OPEX - "Easy" financing	- High electrolysis CAPEX - Increased infrastructure needs - Land availability

The main weakness with RES is that they are intermittent, meaning they only generate energy when there is wind or when the sun is shining. On the hydrogen production side, this can cause a low electrolysis capacity factor, the actual hydrogen production compared with the theoretical maximum. To cover the shortage in production, you would either need to get the remaining energy from somewhere else. Or over-dimension your production and energy facility and possibly the surrounding infrastructure. In the first option, the extra energy needed would most likely be covered by a nation's electrical transmission grid. The potential issue with this is best summed up by Interviewee B, who stated the following:

"If you want to use renewable electricity, to produce affordable clean hydrogen, you are going to have to back up your production from the grid. So, unless you decarbonize the grid, you are not producing entirely decarbonized hydrogen. The percentage of the time that you're using renewable electricity, you are producing renewable hydrogen, but the rest of your hydrogen is as carbon-intensive as your grid"

The other option, to over-dimension, means increasing the size of the energy and production facility, and possibly the surrounding infrastructure as well. Although the overall system operates less frequently, the sheer size of the system may still be able to produce the correct amount of hydrogen. However, the larger system increases capital expenditure. Another issue with this is that although the produced hydrogen amount may be correct, it may not be produced exactly at the time it is needed. This means that the hydrogen also needs to be stored for when it is needed, for days when there is no sun or wind. The overall system thus contains storage as well. Interviewee J sums it up by stating the following:

“The big issue with hydrogen becomes if you’ve got variable renewables, you need a big electrolyser and you need lots of storage...

Lastly, sun and wind availability differ from region to region and the solar or wind installations require a large geographical footprint. These energy sources are thus largely location-specific, meaning that the hydrogen production needs to be co-located at the energy site. In this case, the hydrogen then needs to be transported to the demand site. An alternative is that the energy needs to be transported to the production site, which is optimally located close to demand. This is summed up by continuing the quote from interviewee J:

"... and then you either need to transport the power from the renewables to the end-user, where you then convert it to hydrogen, or you need to transport the hydrogen from the production to the end-user. Either way, that’s going to be expensive. So you know, when we look at production costs, post-2030, we can see green (hydrogen produced from renewable electrolysis) in some locations being almost competitive with blue. But when you look at the delivered cost, that’s a different story.”

6.5 Delivered Cost

The total system cost includes more than just the production cost. The delivered cost is something many experts have talked about, including interviewee J. Today, many of the companies with a demand for hydrogen produce it at their own site co-located with the demand. This is possible since most hydrogen is produced from natural gas. As mentioned, to decrease the environmental impact, one alternative is to install CCS on the reforming of natural gas. This adds cost in equipment but also costs associated with transporting and storing the carbon dioxide which has been captured.

If other energy sources, such as renewable energy sources, are to be used the energy production and location of demand are less likely to coincide. For one, there are locations where there is better or worse availability of RES. To supply sufficient amounts of energy also require large resources in terms of land, another reason RES might not be able to be co-located with the demand for hydrogen. Therefore, to the production cost of hydrogen from RES, a cost of transporting the hydrogen needs to be added. In addition, since RES is an intermittent energy source, storage will be needed to store hydrogen in large amounts when unable to produce. The cost of storage will therefore also have to be added to the production cost to get the delivered cost.

To further illustrate where these types of situations could arise, a European and a US example is given. Figure 6.2 illustrates potential European ammonia, steel, refining, and other chemical process demands for hydrogen in 2040. This data has been gathered from an online workbook [109], used as input in reference [110]. It also illustrates the potential for storing hydrogen using underground salt caverns. The salt cavern storage potential has been drawn by looking at similar maps from reference [111]. As the figure illustrates, although there is a large potential for this kind of storage and some demands are well situated for utilising it, others are not. Other methods for large underground storage (presented in section 4.3) not included in the figure also exist. Some of these may be well situated to the remaining demands but these types of storage's have several complexities of their own. For example not being able to inject and withdraw hydrogen on a regular basis, competing with storage of CO_2 or just being more expensive. Further more, demands situated close to the North Sea may be able to choose reforming with CCS. But this becomes increasingly more difficult the further inland the demand is located.

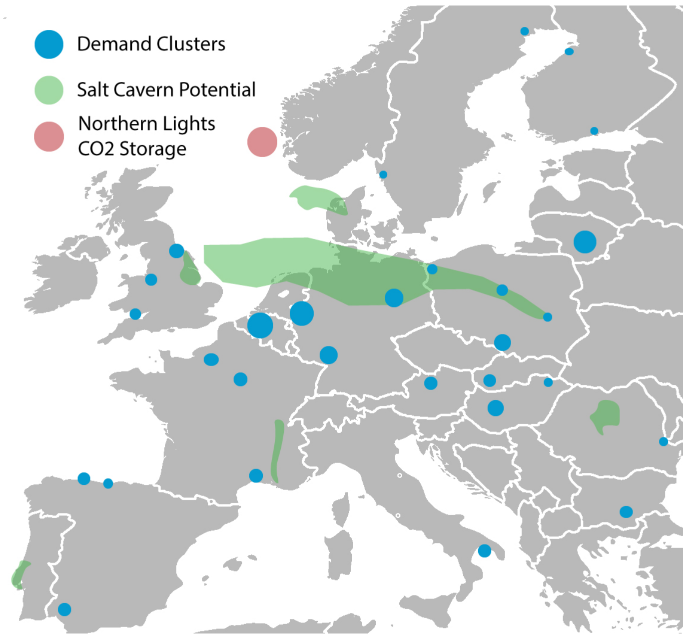

Figure 6.2: A map of Europe illustrating demand clusters and potential storage sites in salt caverns.

The US is another example, illustrating the complexities of having an energy source located far away from demand. The DOE has developed internal strategies on how they are currently working with the topic of hydrogen [112]. Figure 6.3 illustrates potential hydrogen demand clusters under an ambitious hydrogen scale-up scenario (up to 2050). Including applications such as various ways of transportation, steel, ammonia and methanol production and refineries. It also illustrates current operating nuclear facilities (conventional) and the best potential for wind energy. The figure is a collection of several figures presented in DOE's Hydrogen Program Plan [112]. It is worth mentioning that the US also have good solar potential.

But this is mostly located in South West regions [112]. It could thus be able to supply mainly the Californian demands but also some of the Texas demands.

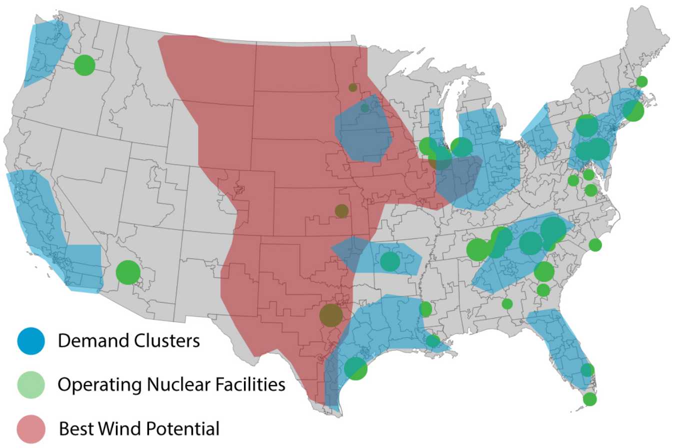

Figure 6.3: A map of the US illustrating demand clusters and the areas with the largest potential for wind power as well as existing LNP.

It is evident that the infrastructure surrounding the hydrogen demand, thus the delivered cost, can come to play a vital role in choosing the production method. Being less location specific and being able to produce continuously are thus two important variables to consider when choosing a production alternative.

6.6 Summary of Hydrogen and Small Modular Reactors

Much of the hydrogen demand today is satisfied with energy from fossil sources and there is a need for a conversion to low-carbon hydrogen. It has been shown that there is a large market opportunity for SMRs in the field of hydrogen. Hydrogen can also be produced through electrolysis with energy, both electricity and heat, from an SMR. There are several synergies between hydrogen production and SMRs. One synergy is the ability to receive process heat from the reactor. Further, SMRs can meet the continuous demand for energy that is required by many of the hydrogen-intensive processes. SMRs have increased flexibility in locating them reducing the need for hydrogen transport. Finally, both SMRs and electrolysers used to produce hydrogen are modular, reducing the risk of cost from unused capacity.

Alternative energy sources for low-carbon hydrogen production include reforming with carbon capture and storage (CCS) and renewable energy sources. Reforming using natural gas and utilising CCS has the advantage of being dispatchable and have a low cost. The cost of transporting and storing the CO_2 need to be added to the total cost. Using renewable energy sources could imply a smaller cost of electricity, but the intermittent nature of the energy source induces other costs. The cost of storage of hydrogen and transporting hydrogen need to be added to the total cost.

To calculate the delivered cost of hydrogen, the cost of storing and transporting hydrogen needs to be taken into account. In the case of reforming with CCS, the cost of transporting and storing CO_2 need to be added to the production cost. Comparing sites of demand with sites of storage and production it becomes clear that the delivered cost of hydrogen needs to be considered.

7

Cost Comparison of Hydrogen from Different Supply Architectures

The chapter illustrates the complete system, or architecture, shown in figure 7.1, by comparing the different alternatives under a set of assumptions. This includes results from calculation determining the levelised cost of hydrogen (LCOH) using different energy sources. First, the data used, which has been illustrated in previous chapters, will be gathered and presented together with the assumptions for the calculations. The calculated production cost is then presented, followed by the calculated delivered cost.

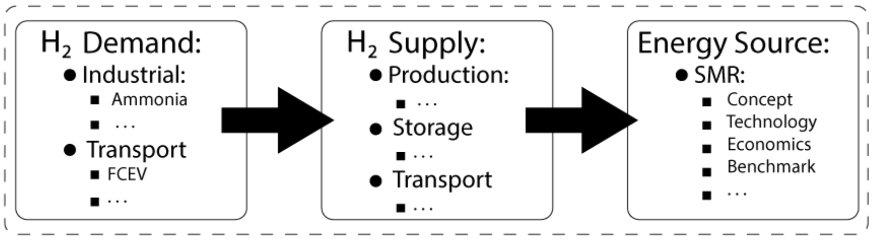

Figure 7.1: The chapter describes the system part of the overall structure.

7.1 Analysing Levelised Cost of Hydrogen

The LCOH utilising different energy sources will be determined. To give a comparable number between different supply architectures, the total delivered cost is calculated. As mentioned previously, the delivered cost includes additional costs such as storage and transport for supply architectures that require it.

The analysis compares nuclear electrolysis to alternative methods mentioned previously, namely renewable electrolysis. These two methods of producing hydrogen utilising electrolysis are the main focus, while steam methane reforming is used as a baseline since it is the most used method today. The addition is that carbon capture is added as a cost in the case of reforming, together with the cost for transporting and storing the carbon dioxide.

Nuclear and renewable electrolysis have each been divided into two scenarios. For nuclear, the first scenario, called the 'standard', is based on a summary of different models and predictions for what levelised cost of electricity (LCOE) SMRs are predicted to reach. The second scenario, dubbed 'best case' is based on what vendors of SMRs project to deliver in terms of LCOE. Information on this has been provided previously in chapter 5 and will be seen as somewhat of an optimal case. Using two cases for SMR is motivated by the difference between what has been predicted and modeled independently and what vendors hope to deliver. For renewable electrolysis, in the best case, both LCOE and the capacity factor is improved from the standard case. The different cases thereby cover a larger span and enables comparing the different assumptions.

The four scenarios compared will thereby be:

- Small Modular Reactor with electrolysis, standard (SMR standard)
- Small Modular Reactors with electrolysis, best case (SMR best case)
- Renewable Energy Source with electrolysis, standard (RES standard)
- Renewable Energy Source with electrolysis, best case (RES best case)
- Reforming Natural Gas with Carbon Capture and Storage (Reforming CCS)

7.2 Assumptions

In this section, the data and assumptions are presented. First, the calculations are based on numbers from 2030 and beyond. Second, a large central demand (industry applications) has been assumed, making transport by road and above ground storage unfeasible. Third, the different alternatives operate under different circumstances meaning that they all have their own supply architecture. The data and assumptions for each alternative will thus be presented for each stage in the supply architecture; energy source, production method, and transport and storage.

For reforming with CCS, LCOH calculations in regards to production have not been performed. This means that there are no assumptions for this alternative regarding energy and production. Instead, a reference value for this method is taken from table 4.1. The reference value taken is aimed at Europe, with an LCOH of \$2.35/kg. However, the supply architecture for this alternative also includes the transport and storage of carbon dioxide. The additional cost for this will be presented in the transport and storage section.

7.2.1 Energy Source

The presented data is for the nuclear and renewable alternative (can be seen in table 7.1). Both energy sources can produce electricity meaning they can both use low-temperature electrolysis (LTE). The energy parameters for low-temperature electrolysis include the cost of electricity (C_{el}) and the capacity factor (C_f). The nuclear alternative also has the added benefit of using heat for high-temperature electrolysis (HTE), meaning this alternative also includes cost of thermal energy (C_{th}).

Table 7.1: The cost of heat and electricity and capacity factor from different energy sources.

Energy Source:	RES Standard:	RES Best:	SMR Standard:	SMR Best:
C_{el} (\$/kWh)	0.4	0.3	0.7	0.5
C_f	0.3	0.4	0.9	0.9
C_{th} (\$/kWh)	-	-	0.35	0.25

As mentioned in section 7.1, for the nuclear alternative, in the standard scenario, the cost of electricity is based on the LCOE projections presented in section 5.3, regarding the economics of SMRs. In the best case scenario, the cost is based on LCOE targets set by NuScale ($55/MWh) and the Chinese HTR-PM reactors ($50/MWh), which can be seen in section 5.4. The cost of thermal energy has been based on the assumption from section 6.2. That is for an HTGR, the cost of thermal energy is equal to half of that of electricity. Lastly, as nuclear has the added benefit of supplying energy continuously, the capacity factor is high and similar in both cases.

For the renewable alternative, the cost of electricity and the capacity factor has been based on wind energy. The numbers are based on numbers from *"IEA: Net Zero by 2050"* [57]. For the best case, both numbers are improved from the standard case. Meaning a lower cost of electricity and a higher capacity factor.

7.2.2 Production Method

Table 7.2 includes cost parameters for either low-temperature electrolysis (using PEM) or high-temperature electrolysis (using SOEC). How these numbers are justified can be seen in section 4.2, regarding different electrolyser technologies. For the year 2030 and beyond, the projected capital cost (C_{inv}) for the PEM technology is assumed to be in the lower quartile. The same assumption is made for the electricity consumption (q_{el}).

Table 7.2: The costs associated to different electrolysers.

Electrolysis:	Low-temperature:	High-temperature:
Type:	PEM	SOEC
C_{inv} (\$/kW)	500	900
O&M (\$/kg)	2% of CAPEX	
q_{el} (kWh/m^3)	4.5	2.7
q_{th} (kWh/m^3)	-	0.7
Lifetime (t_{system}) (h)	90000	60000
Interest rate (i) (%)	7	7

For the SOEC, the capital cost has been assumed to be somewhere in between the projected cost for 2030 and 2050. The energy consumption is determined by using figure 4.2, in section 4.2. Because of the high outlet temperature of certain reactors, it has been assumed that the electrolyser can be fed with thermal energy at a temperature of 700 °C which gives the electrical and thermal consumption ($q_{el,EC}$ and q_{th}). In regards to electrical consumption, this only accounts for the electrical consumption of the actual electrolyser. Therefore, 0.3 kWh/m^3 has been added to this number to compensate for the rest of the facility ($q_{el,BoP}$) and to give the electrical consumption of the entire system (q_{el}). The number is based on parameters presented by the German company Sunfire on their SOEC product [113]. The parameters for both electrolysers do not differ between the type of energy sources used and a hydrogen density of 0.082 kg/m^3 is assumed.

7.2.3 Transport & Storage

As has been shown in section 6.4.2, renewable electrolysis biggest weakness is its low capacity factor. This means that the storage of hydrogen needs to be included in the supply architecture. To store hydrogen, an underground salt cavern has been assumed to be utilised. This method of storage is a bit more expensive than depleted hydrocarbon reserves and aquifers. But it is deemed most appropriate since the withdraw/inject cycle can be done several times a year. It is also proven to work for the storage of hydrogen [79]. The cost of storage is taken from reference [80]. The calculated cost was based on a salt cavern that could store 1912 tonnes of useful hydrogen. For reference, assuming LKAB will produce 2.7 million tonnes DRI over 360 days, and 700 m^3/tonne hydrogen is necessary for its production, as presented in 3.1.3. This equals a hydrogen amount of around 430 tonne/day, using a hydrogen density of 0.082 kg/m^3. The storage could thus cover a demand of up to 4-5 days. Storage is included in both the best case and standard case for renewable electrolysis.

Another weakness of renewable electrolysis is the location-specific energy supply. It is therefore assumed that production and energy supply is co-located away from the demand site. Meaning that transport of hydrogen needs to be introduced in the supply architecture. A new 300 km pipeline has been assumed between production, demand, and storage in the standard case. In the best case, it is assumed that the energy source is located within close range to demand and thus not need transport. Another alternative would be to have production close to demand and transport the electricity needed, by constructing transmission lines. But according to the hydrogen council, this way would prove to be a more costly option [83]. Although this needs to be analysed further on each specific case.

Because of nuclear having the added benefit of availability and being less location-specific, the supply architecture does not include the storage and transport of hydrogen. It is thus assumed that SMRs can be co-located close to demand. Other costs, such as smaller buffer storage and shorter transports, are deemed necessary in all supply architectures and are therefore excluded.

Steam methane reforming also has the added benefit of a high capacity factor, meaning no storage and transport of hydrogen is needed. It is thus assumed that this alternative is co-located close to demand. However, the transport and storage of carbon dioxide need to be included in the supply architecture. For this purpose, a mean value between \$36-65/tCO_2 has been used from the Norwegian Northern Lights cost presented in section 4.1. It is also estimated that the production method produces ten tonnes of CO_2 for each tonne of hydrogen. With a 90% capturing rate, this results in a total of nine tonnes of CO_2 needed to be stored for each tonne of hydrogen. Thus, the cost is multiplied by a factor of nine and converted into \$/kgH_2. All numbers are presented in table 7.3 below.

Table 7.3: The cost of transporting and storing hydrogen and corbon dioxide.

Alternative	RES	SMR	Reforming
Transport (H_2) (\$/kgH_2)	0.48 (Std case)	-	-
Storage (H_2) (\$/kgH_2)	1.61 (Both cases)	-	-
Storage and Transport (CO_2) (\$/kgH_2)	-	-	0.5

7.3 Hydrogen Production Cost

Using equation 4.3, 4.4, 4.6, 4.7 and 4.8 for the PEM, equation 4.3, 4.5, 4.6, 4.7 and 4.8 for the SOEC, with data from table 7.1-7.2 produces the following result which are seen in figure 7.2. It illustrates the production cost for each electrolysis alternative. The values for the reforming alternative are used as a reference value for competitiveness. The result has also been compared with other sources who have shown similar numbers [2, 3, 18].

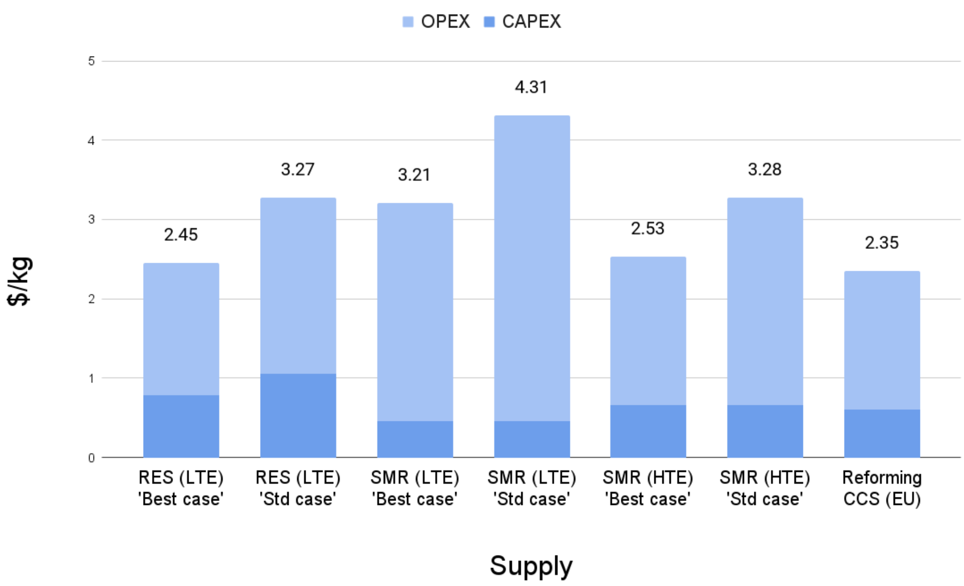

Figure 7.2: The production cost of hydrogen for different supply sources.

Analysing figure 7.2, none of the electrolysis alternatives (the renewable and nuclear scenarios) are as competitive as the reforming with CCS alternative. When comparing the low-temperature electrolysis alternatives against each other, the nuclear alternatives receive lower CAPEX numbers while the renewables receive lower OPEX numbers. This is because renewable energy can produce cheaper electricity while nuclear energy can utilise the electrolysis facility to a higher degree. The OPEX is still the dominating factor though meaning that in terms of low-temperature electrolysis, the renewable alternative is probably a more competitive option when analysing cost of production.

For nuclear high-temperature electrolysis, it shows a competitive production cost against the renewable alternative even when analyzing the standard cases. By utilising heat it decreases the OPEX, which is the main issue with nuclear electrolysis. In the best case scenario, it is even closer to being competitive with the reforming alternative.

7.4 Delivered Cost

As described in 6.5, one can not only rely on the production cost when comparing different supplies of energy in order to produce hydrogen. To receive the delivered cost, the cost of transport and storage of hydrogen is added to the cost of production, as in the case of renewable electrolysis. For the nuclear alternative as well as the reforming alternative it has been assumed that hydrogen supply is co-located with the demand. Therefore, these alternatives are not in need of hydrogen transport. Both are also assumed to be able to deliver energy continuously and is thus in no need of storage. In the case of reforming with CCS, the cost of transporting and storing CO_2 is added. The results of the calculations are presented in figure 7.3.

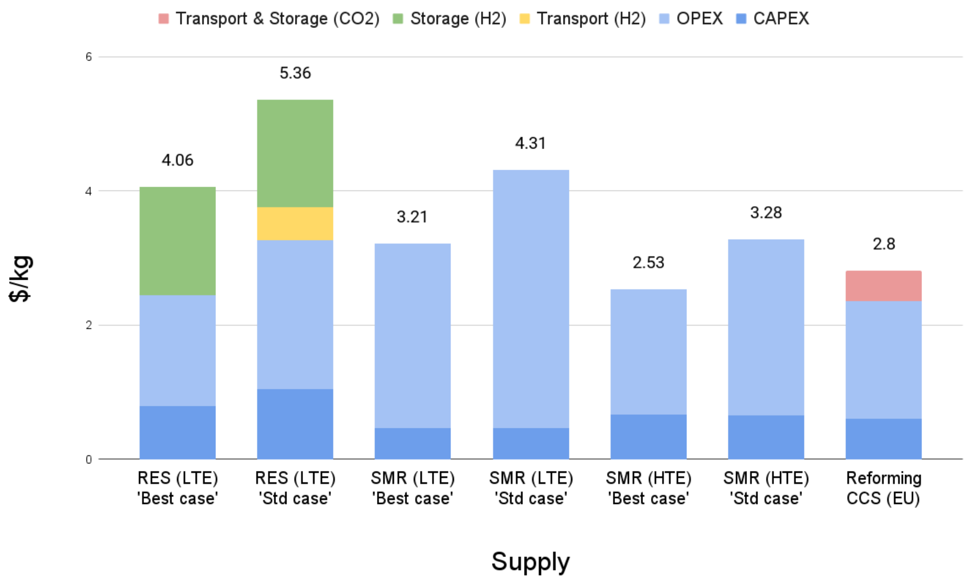

Figure 7.3: The delivered cost of hydrogen for different supply architectures.

From figure 7.3, it can be seen that the renewable electrolysis supply architecture receive an increase in cost from transport and storage of hydrogen. Thus, when accounting for the delivered cost, nuclear electrolysis will be a competitive, and even the less costly electrolysis alternative. Looking at the SMR 'best case', it can be seen that high-temperature electrolysis is not only competitive with the RES alternative but also with reforming with CCS. To the reforming alternative, a cost for transporting and storing the carbon dioxide is added, giving the total cost of \$2.80/kgH_2, compared to \$2.53/kgH_2 for the SMR alternative.

To validate the result, a comparison to data from the Hydrogen Council can be made [83]. For the renewable alternative, the Hydrogen Council found that the delivered cost could reach up to \$5/kgH_2 in 2030 [83], corresponding well to the presented result. In their scenario, using other assumptions, transport cost had an increased percentage of the total cost however. The cost of production and the cost of storage were also lower in that case, compared to the result shown in section 7.3.

7.5 Conclusion of Cost Comparison

Four scenarios where compared in terms of production cost and delivered cost of hydrogen. First, comparing these different types of technology options is complex, since it is difficult to set a precise system boundary in a generic case. Therefore, the presented numbers should not be taken as an absolute value of cost. In order to achieve a more precise result, each individual case needs to be studied in detail. One of the research questions stated *"Under what conditions can an SMR be a viable alternative for hydrogen production?"*. With this in mind, these calculations are instead aimed at illustrating an answer to this question, and not defining a precise number in terms of cost. With this said, it is argued that the result of the calculations, including the assumptions made, can be compared in relation to each other.

Under the assumptions made, the result illustrate that when only considering production cost, reforming is the cheapest option, followed by the best case RES and then SMR utilising high-temperature electrolysis. The improved result using high-temperature electrolysis emphasises the strengths and efficiency-gains of utilising heat from the reactor in the process of producing hydrogen. Even with the SOEC initially being a more costly option. In terms of low-temperature electrolysis, although the best case scenario for SMRs could compete in some regard, renewables are likely looking to be a more competitive option. Under the assumption that production can be co-located with demand, and storage can be managed cost-effectively. Considering all electrolysis options, being competitive with reforming could prove to be difficult if production stand to be the only determining factor.

Further more, the result should be related to that in section 6.5. Two examples was shown of where future large demands are likely to be located in Europe and the US, assuming a large-scale deployment of hydrogen. In relation to the demand, it also illustrate that the supply architecture is not always optimally built for certain alternatives. Meaning, production should in some cases not only be the determining factor. Nuclear electrolysis have an advantage over renewable electrolysis in regions with low renewable capacity and semi-optimal storage locations. It could further benefit in places far away from CO_2 storage.

8

Discussion

This chapter contains a discussion of the research conducted in this study. Figure 8.1 illustrates the structure of the discussion. First, a discussion on the topic will be presented. This includes discussion on hydrogen, SMR and the combination between them. This is presented in section 8.1 to 8.6 and is based on the general result of this study and interviews of experts. Second, a discussion is held on the actual study. Section 8.7 to 8.9 discuss the validity of the result and approach in general. Lastly, a discussion is held on the ethical considerations of the topic.

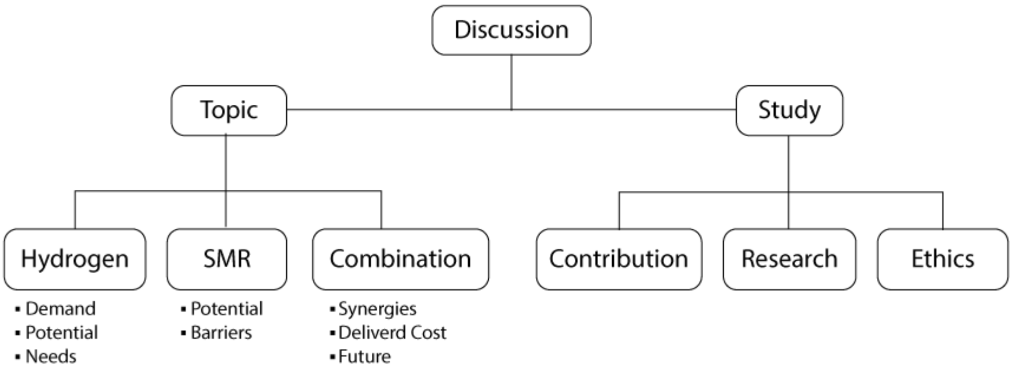

Figure 8.1: Illustrating the structure of the chapter, including a discussion on the topic and discussion on the study in general.

8.1 Hydrogen - The Fuel of the Future?

The hydrogen economy is in very early development and is, at the current stage, surrounded by uncertainties. On the demand side, it is almost presented as if it would replace the entire energy system including power applications, heating, several energy-intensive industries, and transport. This is unlikely to happen since there are other and probably better alternatives for some of these applications. Interviewee I said the following: *"It is not for all applications and we must look at when it is a good idea to use and when it is not. As the debate looks now nobody knows. Many are guessing, hoping, believing, and betting but there will certainly be a lot of applications where hydrogen will play an important factor"*. In regards to interviewee I's last sentence, this study has highlighted some of these. It has also accounted for which ones might have a suitable connection with SMRs. The ones analysed have been divided into industrial and transportation applications and are further discussed. In general, it can be stated that the industrial demands are more certain to predict, while transportation has a potentially larger demand but with a higher degree of uncertainty.

8.1.1 Industrial Applications

Hydrogen is being proposed as a energy carrier and fuel for a wide range of applications, as outlined in chapter 3. The major industrial ones were described in section 3.1 and included in the study are ammonia, chemical processes industries, refineries, and steel production. For ammonia, refineries, and chemical process industries such as methanol, there is a direct need for hydrogen. Therefore, these consumers of hydrogen can be seen as a "sure thing" in terms of demand, at least in the short- and medium-term. Ammonia and methanol have further been proposed as synthetic fuels for various transportation sectors, meaning they have an additional potential to grow. Refineries producing various transportation fuels are a bit more unsure. Since there are substitutes to petrol and diesel in the transportation sector, some have predicted that the demand for these fuels will decrease [110]. This translates to a decrease in the sector and thus a decrease in hydrogen demand. Others, for example, interviewees B and H, think it will rather be a shift in their product inventory. If there is a decrease in demand for petrol and diesel, there might be an increase in demand for biofuels. The process of producing biofuels also requires more hydrogen than for example diesel, described by interviewee H. This means that although this industry will likely decrease as a whole, their future need for hydrogen might still be on similar levels as today. This is all very speculative, and largely dependent on what future fuels will be used in the transportation sector.

The steel industry, described in 3.1.3, also uses hydrogen today and is estimated to be one of the sectors with the most potential growth. The DRI process for producing steel is not a new technology and is used in many places to produce steel. Today, the process is mainly fed with natural gas. Hydrogen can function as a direct substitute for natural gas, with only minor changes to the overall process. Although, the quality of the product is weakened and will need to be improved upon somehow. The major obstacle is that low-carbon hydrogen is looking to replace natural gas, not carbon-rich hydrogen as for the previously mentioned industries. Regarding this, interviewee J said that *"When we look at the cost gap between carbon-rich hydrogen and low-carbon hydrogen, we can see how that might be bridged. But when we look at the cost gap between natural gas and hydrogen, it's much bigger... We think you probably need a carbon price around 200-250 euros per tonne of carbon emissions to bridge that gap, which is, you know, a long way off from where we are now, and probably where we see it naturally developing in the next 20 years"*. This could be a potential issue in regions with a large share of natural gas, such as the Middle East or North America. Nevertheless, in Europe, most major steel manufacturers include DRI fed with hydrogen in their future roadmaps. Regions with a high share of natural gas are probably looking more towards the instalment of carbon capture and storage (CCS).

All these industrial applications have similar needs in that they have a large- and centralised demand, require continuous production, and uses process heat to a varying degree. To fulfil the demand with the help of electrolysis, two barriers can be identified. The first is the sheer size of the demand. Currently, even with the benefit of modularity, the electrolysers are too small to produce the significant amount of hydrogen that these industries will need. Thus, electrolysers will need to scale up if they are to compete with reforming with CCS. The other is price-competitiveness. Chapter 7 illustrated that even if including the cost of storage and transport of CO_2, this could prove to be difficult. On the other hand, CCS is by no means a sure thing, the technology is not yet fully mature and has several issues on its own. There is also a varying degree of stigma surrounding it and the availability of natural gas plays a key factor. Still, for electrolysis to become more competitive, either the consumption or cost of electricity needs to decrease. The last option is for the investment cost of electrolysers to decrease. A generic "one is always better than the other" conclusion cannot be drawn here. Each region and case is different and will need an analysis on its own. The prerequisites of each case will determine the strongest alternative in terms of competitiveness. Important and general parameters to analyse are continuous production, production cost, and co-location with demand.

8.1.2 Transportation

After the industrial demands for hydrogen, the study has discussed the vast opportunities in transportation applications in section 3.2. Utilising hydrogen in transportation can prove to be one part of the puzzle in decarbonising a sector often described as hard to abate. Vehicles including passenger cars, busses, trucks, and trains have already been proven to be able to run on hydrogen. Applications such as aviation and shipping also have potential demand for hydrogen in the future, one which could prove to be significant.

As the study shows in chapter 3.2, in the shorter ranges and smaller-in-size applications, there is an uncertainty on whether battery-powered or fuel cell-powered electric vehicles will have the largest share. Battery-powered vehicles (BEVs) have established themselves on the market with many vehicles in operation as well as a growing infrastructure for charging. Fuel-cell electric vehicles (FCEVs) exist but it has been shown that the demand has to reach a certain range and use pattern for them to have a competitive cost. The infrastructure for FCEVs is also lacking and could prove to be challenging to expand. There is a contradiction between low demand for FCEVs because of a lacking infrastructure and the demand for building a refuelling network lacking because there are few users. One potential effect of hydrogen being used to a larger extent in society, pointed out by experts interviewed in the study, is that an expansion of a refuelling network could follow the hydrogen expansion as a whole. Interviewee I summarise this point with the following example: *"It has gone slow, and would probably continue to do so if it were a single system. But if you connect everything, then that is a different story. When you construct HYBRIT, then you could also install a fuel station. If you are doing one you might as well do the other. It is those types of synergies that makes it easier to bring about a complete system"*

When discussing larger-in-size applications such as trains, trucks, and ships, the study points to a large potential for hydrogen to be competitive. Here, the alternatives are fewer and provide hydrogen with an advantage in these particularly hard-to-abate sectors. The more centralised refuelling infrastructure and the need for long ranges are in favour of the hydrogen alternative. One threat is from biofuels but there are also many applications where bio-fuels could be needed and a limited supply.

In conclusion, it can be said that in which transport applications and to what extent hydrogen will be utilised is by no means certain. However, if either the pure hydrogen path, synthetic fuels such as ammonia, or bio-fuels are chosen, there will be a demand for low-carbon hydrogen. The difference between them is that the pure hydrogen path will be more of a decentralised and smaller demand per location, while bio- or synthetic fuels are produced on a large and centralised level.

8.1.3 Conclusion of Discussion of Hydrogen

As far as the study has established, there will most likely be a gap between the supply of, and demand for, hydrogen. As of now, most of the hydrogen is produced using fossil sources, which will have to be switched eventually. In addition, the demand is certain to stay at the same high levels, or by most predictions, increase with new applications. Many potential applications have been presented in this study, some more certain than others. Whichever application becomes the most prominent, the need for low-carbon hydrogen is a fact. The cost of this hydrogen is subject to many factors, some of which have been described and accounted for in this study. The result shows that there are different options for supplying this low-carbon hydrogen and that the cost varies from case to case. Even if the cost of low-carbon hydrogen ends up higher than the carbon-intensive counterpart, this option should probably not even be considered in times where emissions need to be reduced. One should also consider the power of the end consumer and their increased interest in sustainability and low-carbon solutions.

8.2 Small Modular Reactors

In regards to the concept of SMR, described in chapter 5 the first thing that needs to be addressed is whether the concept will fully be deployed in the manner in which it is intended. There are already designs in use today, such as the Russian RITM-200 reactor and soon the Chinese HTR-PM reactor, described in 5.4. Many other developers have also come far in their development, with planned demonstrations and commercial projects. But a full-scale production and supply deployment has yet to be realised. In regards to gaining a more cost-efficient economic model by standardising and producing smaller and more modular units, interviewees B and E mentioned that there is no reason on paper to dispute some of the claims that are made.

Although it is natural to be suspicious over these types of promises, interviewee B said that *"... the economic theory tells you that this is what should happen, and it has been shown to happen in other industries"*. But interviewee B further explains that some uncertainties exist.

Although more established companies also have their reactor designs, much of the SMR development is being led by smaller companies. One uncertainty mentioned is whether these smaller companies can deliver on their promises. Interviewee B argued that it is one thing to design reactors on paper, and another to physically construct and deploy the supply chain around them. It is less a factor of technology readiness and more a factor of manufacturing readiness. Interviewee A mentioned that this is something that these smaller companies understand. Further interviewee A stated that they are taking efforts to reduce this risk by venturing up with well-known construction companies. Interviewee A also mentioned that the smaller size of the company can be seen as an opportunity. These companies do not have the funds to continuously research and update their designs. Meaning they have an increased urgency in actually bringing them to market. This could help to push the deployment of SMRs forward. Whether or not this is the case is too early to say. Both Interviewee A and B conclude this topic by stating that everything will be a question of demonstration. First in line are NuScale and X-Energy (among others) that will have to deliver on their respective demonstration units. This will be a big statement regarding the future of SMRs. As Interviewee B said it, *"The proof is in the pudding"*.

Nonetheless, the main obstacle to overcome is licensing, described in section 5.5.1. To fully realise the potential of SMRs and the "economy of multiples", export markets would need to be established. This is not possible if there is no harmonised licensing procedure across nations. By having to constantly re-design, an SMR will lose many of the economic advantages that come with standardisation. Not only in terms of the actual re-design in itself but also the cost of the various documentation and classifications that come with it. Interviewee D highlights this fact with an example and said *"... to buy sixty-four nuclear-grade classified bolts, it would cost €20000. In a regular hardware store, the 'same' bolts would cost €160. Standardisation is key. If everyone is to 'do' SMR in their way, there will be no SMR"*. Interviewee A further mentioned that perhaps this will be possible in one or two new markets but certainly not fifteen.

There is optimism regarding some potential new nuclear markets, for example, Estonia and Poland. Since these nations lack a licensing and regulation process of their own. It can generate the opportunity for them to accept license and regulation processes of already established markets. This ensures that no re-design has to take place. But interviewees A, C, and D said that these markets are probably too small in themselves to make any significant impact. If this is true, similar approaches need to be made between the established markets as well. Interviewee C said that attempts like this have been made but that nothing has happened for the last thirty years or so.

Still, this is probably the number one issue hindering the full-scale potential of SMRs. It should also be the number one issue to be solved. If unsolvable, however, interviewees A, C, and E state that the US, Chinese, and perhaps some other markets as well, would most likely be big enough to be self-sustainable. But the full potential would then not be reached.

Lastly, Interviewee A and E approached the subject of SMR with some caution. They explained that similar attempts to re-invent the nuclear industry have been made before. But with little success. In the early, to mid-2000s there was a lot of hype surrounding the concept of Generation IV nuclear energy. Although a different concept, this quickly fell out of favour due to circumstances such as Fukushima, and the price of oil dropping. Concerns have been raised about whether the same thing will happen to the concept of SMR. But this could also be a question of timing. The issues surrounding the climate, the need for electrification and sustainable heat generation, as well as desalination of water and decarbonization by the means of hydrogen are more prominent now than ever. All of these factors create opportunities to open a door rather than closing it.

8.3 Hydrogen and Small Modular Reactors

Chapter 6 describe the connection between hydrogen and small modular reactors. The result shows that the versatility of an SMR opens up for several other market applications than just the power market alone and that hydrogen production is one of them. In addition, the result shows that SMRs also bring additional benefits to this new and potentially extensive market. The first benefit described in section 6.3.1 is the use of process heat, especially for high-temperature reactors. Several industries, such as refineries and steel producers, also use this directly in their respective processes. An SMR could thus bring multiple benefits in producing the hydrogen needed as well as the heat that is used for other purposes in these industries. Although not covered completely in this study, further research and development could look at the possibility of utilising this versatility of an SMR to a larger extent. Even though the initial cost of hydrogen could fall out of the price-competitive range, by using an SMR and heat on a system level, the cost of the final product (e.g low-carbon steel) might reach the desired value. As illustrated by this study, a high-temperature reactor is also a competitive way of producing hydrogen if combined with a SOEC. In a best-case scenario, it could even become directly competitive with alternatives methods using fossil fuels and carbon capture. Some critique could be directed towards the combination of the two technologies of SOEC and SMRs. As of now, both of them have not been developed to a high enough degree. The combination of these two "immature" technologies could thereby be deemed uncertain. But since the scope of this study is set to 2030 and onward, it was chosen to look at the current potential of the two technologies. The case for competitiveness is strong enough for it to not be excluded at this early stage in the hydrogen economy.

The result show, in section 6.3.2, another benefit of SMRs connected to hydrogen production in the availability and continuous production. This is not only a need, but often a requirement for several industries such as ammonia, steel, and refineries, looking at using hydrogen in their respective processes. Using alternatives means of supply means that storage has to be introduced and interviewees B, E, and J all had concerns about whether this can be managed cost-effectively. Interviewee E further expressed concerns that even though the cost of production using electrolysis is likely to go down, it does not automatically mean that the cost of storage should follow the same pattern. Interviewee E state this by saying *"... maybe the technology for drilling large underground caverns won't develop that much, or reducing the energy losses when compressing gas. This is sometimes the mistake I think economists and politicians do. They assume that all parameters will have a learning factor, even the ones that are physically constrained."*. The conclusion is that since some of the technologies used in the storage of gas are quite mature, they are unlikely to see significantly increased performance or reduced cost. This is not necessarily the case for all methods of storage. There are other and more innovative ways of storing hydrogen not covered in this study. But it is wrong to believe that all variables in the hydrogen value chain are suddenly going to receive large cost reductions only through scale-up.

The third benefit shown is the fact that SMRs are less location-specific, described in section 6.3.3. Today, the most sizeable hydrogen users keep their costs down by having supply co-located with demand, which reduces the need for transportation costs. Several national and regional initiatives (including the EU hydrogen strategy) also recognise the importance of this [2, 114, 115, 116]. This means that, if utilised correctly, hydrogen production using SMRs can have a strong case in certain regions and industrial clusters. For example, it could have an advantage in those where RES has a high degree of geographical limitations, or where the storage of CO_2 is limited. For future and decentralised applications, such as various means of transportation, the location of production could play an even greater role in regards to competitiveness. Again, this provides an opportunity for the use of SMRs. The argument against this would be that the demand for each location is likely to be smaller. The economic benefit of having co-located modules could thereby be lost, resulting in a higher LCOE and thus a higher cost of hydrogen production. But since the reforming with CCS alternative needs to be large. It favours either the renewable or the nuclear electrolysis alternative. Thus, here lies a trade-off between cheaper electricity or a more suitable supply architecture.

The last benefit (or synergy), presented in section 6.3.4, is modularity. The previous benefits are not exclusive to SMRs alone. For example, an LNP operates similarly and can very well bring the same benefits as an SMR. But the benefit of modularity is not only directed to the design itself but the economics as well. Since electrolysers have the same benefit, it reduces the risk of investing in overcapacity of the entire energy and hydrogen system. Something that could very well be seen as a necessity in a market like the hydrogen market. Since it is likely to still be in an early stage of development over the next decade, with several of the key variables being covered in uncertainties.

8.4 Delivered Cost

To test some of these benefits it is important to not only look at the production cost, but also the delivered cost of hydrogen. The results from the study have made it clear that the delivered cost needs to be considered in many cases of hydrogen demand. In chapter 7, the cost comparison shows that production cost can differ significantly from the delivered cost. This will, in the end, affect the different hydrogen applications.

As mentioned previously, if only considering production cost, the SMR combined with the SOEC gave better results than expected, shown in section 7.3. This emphasises the efficiency gains of utilising the added benefit of heat from the reactor. Even without utilising high-temperature electrolysis, the nuclear option could become competitive with renewables in a best-case scenario. This result was particularly interesting because of the large emphasis put on renewables in different national and regional hydrogen strategies, and the oversight of nuclear energy in these. Both the nuclear and renewable alternative probably also have a large potential of decreasing the cost of hydrogen production further. But as has been illustrated in this study, and mentioned by several experts, this is not the whole story.

When comparing delivered cost, hydrogen production utilising an SMR as the energy source could be a significant competitive low-carbon option. The delivered cost is presented in section 7.4. This result clearly illustrates under what conditions an SMRs could become competitive. By further illustrating in section 6.5 that the assumptions are not a single specific case. It makes the technology a real option to produce hydrogen in the future, and an option that should be considered. It could be argued that the additional cost of storage and transport, mainly experienced by the renewable alternative, can decrease as well as the production cost. This reduction is however not as obvious as to happen, which was mentioned by interviewee E and discussed in section 8.3.

This will also not change much in the future, storage sites will remain where they are, and demand is not likely to change locations either. Again, emphasising the need to consider the delivered cost of hydrogen, as well as including all potential technologies in hydrogen strategies moving forwards.

8.5 First Step

What is seen in these early stages of hydrogen deployment is alliances and partnerships forming. One example discussed in this study is the Swedish HYBRIT project between SSAB, LKAB, and Vattenfall. Another example is a German alliance between the steel company Salzgitter AG, the power company E.ON, and the hydrogen developer company Linde [117]. Or the example between the fertiliser company YARA and the French power company ENGIE [118]. There are even national alliances forming, where for example Germany has made agreements to import hydrogen produced in Morocco [119, 120]. What they all have in common is that they are looking at using renewable electrolysis.

With the previous discussion in mind, the nuclear industry also has a responsibility in this. The third barrier presented in the results of this study is the isolated communication within the industry itself. The nuclear industry has predominantly operated in the power market, a well-known and organised market. Expanding the versatility of nuclear power to other markets also means an expansion of consumers with different needs. Therefore, the nuclear industry needs to take an increased interest in these various new consumers. This study has recognised some of the major benefits of SMR and how this relates to a couple of consumer needs in relation to hydrogen. In the future, more thorough research needs to be done on each and every one of the potential markets. An increased interest could also lead to knowledge exchange between the two parties. Meaning that just as the nuclear industry learns about new market needs, the potential consumer can also form a better understanding and view of the benefits of nuclear power.

Furthermore, an increased understanding between the nuclear industry and others could lead to potential partnerships. By including other major parties of the economy of a nation it could in turn bring a positive effect on other issues, such as the issue of licensing. Although this is a highly complex issue and deserves several studies and collaborations on its own, the nuclear industry would benefit from an outside voice aiding them in this matter. A European example is an alliance created in 2020 between nine organisations mainly dealing in the area of energy [121]. In February 2021, they signed the Tallinn Declaration, targeting nine principles for a more harmonised SMR licensing process. This would also benefit greatly by the aid of stakeholders outside the nuclear and energy industry. Another example is a letter urging the European Commission to stop the hampering of nuclear power, signed by France, Czech Republic, Hungary, Poland, Romania, Slovakia, and Slovenia [122]. Interviewee E said that more Western European countries also need to be a part of this, like Sweden or Finland, to strengthen the message across Europe. Again, by coupling different sectors of society, the chance of this happening is increased.

Lastly, when analysing the timeline of SMR, utilising them for hydrogen production purposes can be viewed as far away in time. By having a forward approach regarding licensing surrounding the fabrication and supply chain of SMRs, this could be reduced. In the meantime, it is recommended that owners of existing LNPs examine ways of utilising leftover capacity, if any, towards the production of hydrogen. This can also strengthen the idea that nuclear power has potential in this market, even in its early stages of development.

8.6 Final Remarks

The study on this area has not been whether which alternative is, in general, a more competitive option. There may very well be regions where nuclear electrolysis, renewable electrolysis, or reforming with CCS, have a considerable advantage over one or the other. The study has merely highlighted certain areas of uncertainties, where the strengths of an SMR can make a considerable case for nuclear electrolysis. Spoken from an industry perspective, interviewee F stated that, *"It is almost impossible to objectively compare the different technological options. It all depends on how far the system boundaries are stretched. Of course, if you are to build a lot of wind farms, then you will end up in worse and worse wind locations. Then maybe you have to build longer and longer transmission or pipelines. Then maybe you end up in unsuitable storage locations. Somewhere along the chain, a breaking point is reached."*. Similar things can be stated for all the alternatives. Meaning that what is deemed most competitive, is dependent on each case's prerequisites. In the end, it is about utilising the strengths of each alternative and minimising their weaknesses. The Canadian hydrogen strategy has done this well. It highlights which regions have strong cases for electrolysis and which have strong cases using other methods, depending on each region's distribution of energy sources [114]. The idea of having a "one-solution-fits-all" (such as in the EU strategy) can actually hinder the hydrogen value chain more than it helps. Interviewee J explained this by saying *"One thing that we're concerned about is that if we can't achieve the amount of renewable deployment that is required, then that's going to stall the roll-out of hydrogen deployment"*. The complexity is further increased if also accounting for other highly complex topics, such as energy security and geopolitics, something that this study has not even touched upon. Thus, not remaining technologically neutral introduces unnecessary risk to an already difficult and uncertain endeavour. If spoken in organisational terms, the organisation is too big to control every entity's day-to-day business. Policy needs to aid and set targets on what to achieve and when. Not explicitly state how it should be achieved in every individual case, since they all come with different prerequisites. Three major alternatives can bring about change and help decarbonise several applications using hydrogen. Not utilising them all, wherever possible, is not only a threat to the hydrogen economy. But a threat to the environment as we know it. To conclude with a quote from interviewee D:

"If you want an entire economy to be based on hydrogen, then you will need each and every method available to you, in order to produce it"

8.7 Contributions of Work

In large, an overview has been given of hydrogen; where the demand stems from, and how it is supplied both today as well as what is predicted for the future. In addition, a similar overview has been given of SMRs and their future as energy sources. The combination of these two is the unique aspect of the study. In the literature study, this became evident. For the combination of nuclear hydrogen production, there where some literature written, while the combination of SMRs and hydrogen was much more limited. From this, one conclusion is that this study is rather unique in its approach. Not much research has been conducted on hydrogen production using SMRs, emphasising the value of the study. The same proved to be true in the interview study. Not many experts had knowledge on the combination of the areas, confirming the conclusion that the area is new and unique. The notion that the area would not be relevant at all can also be disregarded since many of the experts displayed an interest in it.

It is clear that there is value in gathering information on the two areas in one place. It opens the door to new markets for SMRs and for new sources of energy to produce hydrogen. The result of the study indicates that there is a rather convincing case for the combination of the two areas and that it under certain conditions provides competitive features.

The result of the study has also provided a system-oriented approach to calculating the cost of hydrogen from different supply architectures. In interviews and literature, it became evident that the delivered cost of hydrogen is not always accounted for when making comparisons between different energy sources. Instead, only production cost is accounted for and compared. In many cases, this gives an advantage to some technologies, while others are easily overlooked. The results show that the continuous demand for hydrogen will require storage of hydrogen and that in many cases transport is also needed, both associated with a cost. By expanding the system boundary, including factors such as delivering and storing hydrogen, the number of options to include in terms of energy supply increase. Increasing the number of options for supplying energy will be instrumental in the future. The need for energy will increase, while traditional ways of supplying it, such as from fossil sources, will not be an option. In the study, it also became clear that the cost of hydrogen many times was compared to fossil options such as steam reforming. In the future, this will not be a relevant measure, as fossil sources should not even be considered an option in the combat against climate change.

8.8 Research Approach and Validity of Result

The research approach described in chapter 2, consisting of a literature study and an interview study, provided the intended result. The literature study aimed at finding information on hydrogen demand, supply, and production. In addition, it aimed at finding information on small modular reactors, and their functionality in relation to hydrogen. Many sources of information were found and after screening many relevant sources could be utilised. When it came to hydrogen, there was an indication of more articles being written either in the earlier 2000s or in the last few years. This indicated that there was hype around the area about fifteen years ago, and then again today. As a main rule, the most updated sources were used. Also for SMRs, there was a lot of literature written on the subject.

Next, the interview study aimed to deepen the knowledge on the areas mentioned, as well as widen the scope and include matters such as future predictions, barriers, and opportunities. Twelve interviews were conducted in total, with experts from the areas of nuclear energy and hydrogen. The number of interviews covered the sought information well, and saturation of information was reached in the two areas separately.

Calculations were performed to exemplify the relation between hydrogen production and the associated costs. In comparison to deeper techno-economical studies, the calculations performed in the study were less complex. Still, although the individual numbers differed some, the relation between the results reached corresponded well to that in literature. The results of the calculations should be seen as approximations of the delivered cost of hydrogen under certain assumptions, not precise values of cost in every case. The result provides an overview as well as illustrating the relationship between factors affecting the final delivered cost of hydrogen. A further elaborated approach could be taken but is left for future studies. For example, something that was not included in this scope was the consideration of the different lifetimes and construction times between RES and SMRs. This could be detailed further using an LCOH/LCOE discounting method instead of an LCOH/LCOE annualising method, as was used in this study.

The study aimed to research and portray a future scenario, from 2030 and forwards in most cases. This adds uncertainty to the information and assumptions made from that information. In the calculations of delivered cost, the standard case for nuclear energy is based on predictions from independent modelling. Using these numbers should ensure that the result is not overly optimistic. The best-case scenario is instead based on SMR vendors' calculations, which could be more optimistic but also numbers that will have to be defended by the vendors. One conclusion could be that that the truth may be somewhere in between these cases in the early phases of SMRs. After the early phases, it should be mentioned that SMR has large potential in reducing cost in the future as well, something that has been shown by the results of the study.

The assumptions relating to storage and transport are using either averages or, in the case of storage, the option which seems most feasible. The storage solutions not chosen have complexities such as very low rates of cycles per year, or higher cost. These variables could thereby vary somewhat but are deemed precise enough to compare the different supply architectures. It should further be mentioned that the cost of storage does not account for certain benefits, such as having several injection/withdraw cycles a year. If these are included, the chosen storage solution could potentially receive a cost reduction. The quality of the assumptions is deemed sufficient to provide an overview.

8.9 Sustainability and Ethical Considerations

In this section, the two main areas of the study, hydrogen and SMR, will be discussed relating to sustainability and ethical considerations. Through the entirety of the study, the focus has been on sustainability and finding alternative means of producing hydrogen. It has been established that today, hydrogen is almost exclusively produced from fossil sources. Highlighting alternative production pathways with the goal of producing low-carbon hydrogen is thereby motivated by decreased environmental impact.

With the result showing that nuclear should be considered as an alternative energy source when producing hydrogen, one should again consider what environmental impact this could have. Nuclear power is considered a low-carbon means of producing energy. Studies shows that the life-cycle greenhouse gas emissions of nuclear power is 15 tonnes CO_2-equivalent/GW_eh, lower than that of solar PV (39 tonnes CO_2/GW_eh), and comparable to wind (14 tonnes CO2/GWeh) [123]. The emissions from a natural gas is 469 tonnes CO_2/GW_eh and from a coal-burning plant 974 tonnes CO_2/GW_eh [123]. Land use, another important aspect, is also less in the case of nuclear power compared to that of wind power [123]. It can be concluded that the emissions of nuclear energy are significantly less than those of fossil sources and comparable to renewable sources while having less land use.

Another concern of nuclear energy, regarding the ecological aspect, is nuclear waste. Increased use of nuclear energy will also mean an increase in nuclear waste. The amount of waste is small compared to that of for example of a coal plant, but not insignificant. To illustrate the scale; a coal-burning plant produces millions of tonnes of waste, while a nuclear plant of the same size produces less than 30 tonnes of waste [123]. The waste of a nuclear power plant is radioactive, and the long-term storage of the waste is an important problem not yet demonstrated on a large scale.

The most prominent ethical aspect when discussing nuclear power is nuclear proliferation, or in other words, the spread of nuclear weapons. A global expansion of nuclear energy to mitigate climate change could imply an increased risk of nuclear proliferation. There are several initiatives to counteract nuclear proliferation, one being the UN "Non-Proliferation of Nuclear Weapons" treaty [124]. Through the study, information has only been gathered from nations that are signatories of the treaty.

Regarding hydrogen and its increased production and use, there are further factors to consider. The main hydrogen production method that has been studied is electrolysis. Some electrolysers require rare metals such as platinum. Platinum is also used in hydrogen fuel cells, converting hydrogen to electricity in many applications. The rarity of the metal can be seen as a problem from an ecological as well as ethical aspect. Concerns are being raised about the sustainability of its mining and also of the long-term supply of the metal. The world's platinum resources are extensive but concentrated in certain regions, primarily in South Africa [125].

9
Conclusions and Future Work

In this chapter, conclusions of the study will be stated together with suggestions for future work.

9.1 Conclusions

Low-carbon hydrogen is considered as one of the solutions to decrease emissions of greenhouse gases and to be used as a fuel in an increasing number of applications. It has been found that the demand for low-carbon hydrogen will increase in the production of ammonia, methanol, and steel. Most likely, larger-in-size applications over longer distances such as trains, busses, and ships will also stand for an increased demand for low-carbon hydrogen. The production of low-carbon hydrogen can be done through different types of electrolysis methods, which have been outlined in the study. To supply the large energy-demand small modular reactors (SMR) have been studied and compared to renewable and fossil energy sources.

The results of the study show that there are several synergies between hydrogen production through electrolysis and SMRs. First, the heat from the reactor can increase the efficiency of the electrolysis process, requiring less electricity. Many of the processes requiring hydrogen also benefit from the ability to receive process heat from the reactor. Second, these processes often also require a continuous supply of hydrogen, well-matched to the high availability of a nuclear reactor, resulting in requiring less storage of hydrogen. Third, SMRs are less location-specific, reducing the need for transporting hydrogen to the demand. Finally, both SMRs and electrolysers are built up by modules, potentially reducing the cost of overcapacity. Utilising renewable sources instead induces the need for storage and distribution of hydrogen, adding to the delivered cost of hydrogen.

Barriers to the concept of SMR include intricate licensing processes, specific to each country and regulatory body. Further barriers include risks connected to the deployment of reactors and smaller vendors. A lacking promotion of the technology and communication regarding the benefits and safety was also identified as a barrier.

The importance of accounting for more than the production cost when calculating the cost of hydrogen is illuminated by the calculations made. When including the cost of storage and distribution of hydrogen under set assumption it is shown that SMR is a competitive energy source for hydrogen production. The delivered cost of hydrogen from an SMR could be \$2.53/kgH_2. The lowest delivered cost for hydrogen utilising renewables was \$4.06/kgH_2 when only assuming the need for storage. For comparison, reforming with CCS was calculated to a delivered cost of \$2.8/kgH_2.

Gathering the two topics of hydrogen and SMR in the same study has not been done similarly before. The results of the study showing that SMR is competitive against other low-carbon sources of energy are unique and could lay the groundwork for further studies. It can be concluded that nuclear power should indeed be included when considering low-carbon hydrogen production. At a stage where we need as many potential solutions as possible nuclear power and small modular reactors stand out as a relevant and competitive alternative. For hydrogen produced by SMRs to become a reality, barriers such as licensing need to be prioritised to overcome, and national hydrogen strategies should strive to be technology-neutral.

9.2 Future Work

The study does not cover the entirety of the span between hydrogen and small modular reactors, and many areas could be researched further. Some suggestions for future work are given here.

- The calculations performed in this study aimed to give an overview of the cost components and magnitude of these. More thorough calculations, focusing on the cost of delivered hydrogen, could be an area of a future study
- It has been stated that many of the processes with a demand for hydrogen also have a demand for process heat. A closer study of optimising the heat generated from SMRs and the heat demand from these industries could be subject to further studies.
- The study introduced the application of balancing renewable and nuclear energy with hydrogen as an intermediate. However, this was not further analysed to a full degree. Future studies could look at this important topic.
- The study has focused on producing hydrogen using SMRs as the energy source. The production of hydrogen is just one of the many potential utilisations of SMRs. Of course, producing electricity to the grid is one of them, but there can be many others.
- The study has in part discussed the issue of licensing. However, how to harmonise licensing processes needs to be done in greater detail and should therefore be subject to further studies.

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A

Electrolyser Benchmark

Table A.1: Some commercial electrolysers currently on the market.

Company:	Country:	Name:	Type:	Prod Cap: m^3/h	Prod Cap: kW	Energy Cons: kWh/m^3	Ref:
Asahi Kasei	Japan	Aqualizer	AEC	1200	10000	-	[64]
NelHydrogen	Norway	A3880	AEC	-	2200	4,4 (stack)	[126]
Sunfire	Germany	Sunfire-Hylink Alkaline	AEC	1090	5000	4.7 (system)	[113]
Water2H2	Sweden	CDQ1000	AEC	1000	-	5.0 (system)	[127]
H-Tec Systems	Germany	S 30/50	PEM	1,57	5	-	[128]
H2B2	US	EL200N	PEM	207	1056	5,1 (system)	[129]
NelHydrogen	Norway	H6	PEM	30	-	5.8 (system)	[130]
Water2H2	Sweden	SDQ200	PEM	50	-	5.0 (system)	[131]
Sunfire	Germany	Sunfire-Hylink SOEC	SOEC	750	2680	3.6 (system)	[113]

B

SMR Benchmark

Table B.1: Benchmark over other SMR designs far ahead in development.

Name	Type	Size	Status	Country
CNP-300	PWR	300 MWe	Operational	Pakistan, China
PHWR-220	PHWR	220 MWe	Operational	India
KLT-40S	PWR	35 MWe	Operational	Russia
CAREM25	iPWR	27 MWe	Under Construction	Argentina
VBER-300	PWR	300 MWe	Near-term deployment	Russia, Kazakhstan
SMR-160	PWR	160 MWe	Near-term deployment	Canada
ACP100	iPWR	125 MWe	Near-term deployment	China
SMART	iPWR	100 MWe	Near-term deployment	South Korea
PRISM	SFNR	311 MWe	Near-term deployment	USA
Natrium	SFNR	345 MWe	Near-term deployment	USA
ARC-100	SFNR	100 MWe	Near-term deployment	USA
Seaborg CMSR	MSR	100 MWe	Near-term deployment	Denmark
BREST	Lead FNR	300 MWe	Near-term deployment	Russia
BANDI-60S	PWR	60 MWe	Near-term deployment	South Korea
ACPR50S	PWR	60 MWe	Near-term deployment	China

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