Economic competitiveness of green hydrogen based on its alternatives for the Dutch industry

A comprehensive overview of green hydrogen alternatives cost development from 2021 to 2050

Simon Johannes Gerard Teluij

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Delft University of Technology

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S.J.G. Teluij (4300610)

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Thesis comittee:
Dr. Rudi Hakvoort, Dr. Aad Correljé, Dr. Linda Kamp

DNV Company supervisor:
Joeri Posma

Preface

This report describes the research project that I have performed in the pursuit of obtaining my Masters degree in Sustainable Energy Technology at the Delft University of Technology. Together with DNV I have looked at the alternatives to green hydrogen for the Dutch process industry, to form a perspective on the competitiveness of green hydrogen based on alternatives from 2021 to 2050.

I would like to express my gratitude towards my daily supervisor from DNV, Joeri Posma, who has helped me out a lot whilst working on my thesis over the past 9 months. He was always willing to help me out and has managed to push and pull me through the deep valley I by lifting my spirit. Furthermore, I would like to thank Rudi Hakvoort for keeping me on track and Aad Correlje for his insights and help where needed. Finally I would like to thank Linda Kamp for joining my graduation committee as well, on behalf of SET so that I could actually graduate.

Simon Teluij

Abstract

As the energy transition is starting to accelerate, the Dutch industrial sector is in danger of falling behind with its decarbonisation efforts. Green hydrogen is often suggested as a key-player to decarbonize the industry, replacing fossil fuels used for process heat generation as well as in hydrogen feedstock production. As there are an increasing number of projects that aim to produce green hydrogen and a Dutch hydrogen backbone is scheduled for completion 2030, the question remains how green hydrogen has to be priced in order to be competitive with its alternatives.

This research project assesses the economic competitiveness of green hydrogen based on its alternatives towards 2050 for the Dutch industry. It compares four different process heat generation fuels and technologies as well as four hydrogen production alternatives to green hydrogen for hydrogen feedstock production, by using an altered levelized cost of energy method. The costs of these alternatives are based on a 25 year lifetime, assessed over investment in 2021, 2025, 2030 and 2035 with a commodity and CO2 price forecast up to 2065.

The results are divided over two scenarios. Scenario I aims to demonstrate the real LCOE for green hydrogen alternatives at the time of investment and Scenario II compares the alternatives from 2021 to 2050 combined with business as usual costs up to the four investment moments. The results show the development of the economic competitiveness of green hydrogen based on the cost development of its alternatives over the coming years. The order of sectors where green hydrogen competitiveness is the highest are high temperature process heat generation, followed by hydrogen feedstock, medium temperature process heat generation and low temperature process heat generation in 2030.

It can be seen that fuel costs are by far the largest part of the LCOE of all the alternatives that are assessed, which implies investment decisions ought to be made based on the expected fuel costs and not so much on overnight capital costs of investment. It can also be seen that for the majority of all investigated investment moments for the two scenarios, that the most economically sound investment options simultaneously is the option that contributes most in terms of pollution through CO2. This is a prudent indication that the current free market forces unfortunately do not aid the transition towards a lower polluting industry without nudging or pushing them into the right direction. This implies that well directed policy measures are vital to free market forces to take the first step towards lower pollution.

With this research a contribution to science is delivered in assessing and implementing suggestions for improving the LCOE method as well as using the LCOE for process heat generation and hydrogen feedstock production, when comparing fossil fuels with sustainable energy sources across various industrial sectors. A comprehensive overview of the research green hydrogen alternatives presents insights in costs corresponding to four different investment moments for the Dutch industry.

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1 Introduction

The ongoing increase of global Greenhouse Gas(GHG) emissions is more and more reason for debate. Since the Paris agreement was signed in 2015, the global GHG emissions have continued to rise. Despite the fact that the worlds' total energy demand will rise towards 2050, the emissions of GHG will have to go down simultaneously. Whilst the electricity production is quite rapidly changing towards a higher share of renewable energy sources, the current global primary energy mix is still heavily reliant on fossil fuels, which can be seen in Figure 1.

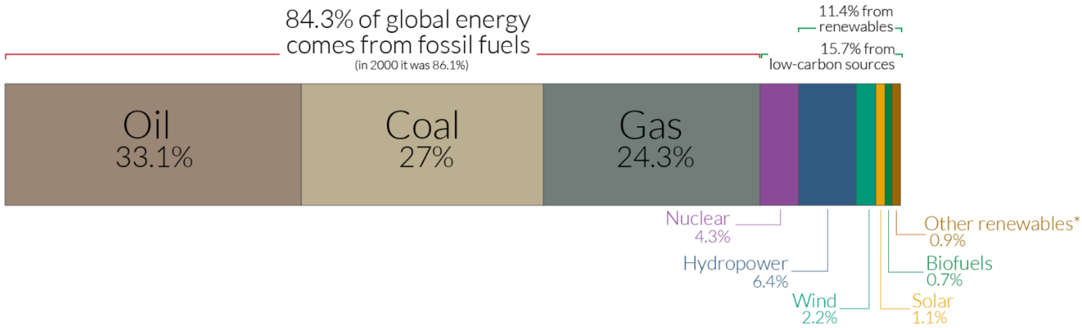


Figure 1: Global energy demand per source (Ritchie & Roser, 2017)

In order to limit these emissions, several sectors have to make significant changes in terms of energy usage, as can be seen in Figure 2. Hydrogen, and especially green hydrogen is often mentioned as a promising means of reducing the GHG emissions in the industry, transport and residential sectors. With the transport sector moving more and more towards electrical vehicles and residential sector transitioning more to electrification of the energy sources, the harder to decarbonize industrial sector is aiming more towards energy efficiency and saving or recycling energy. Replacing oil, gas, coal and non-renewable electricity with green hydrogen is seen as an option, but at what cost?

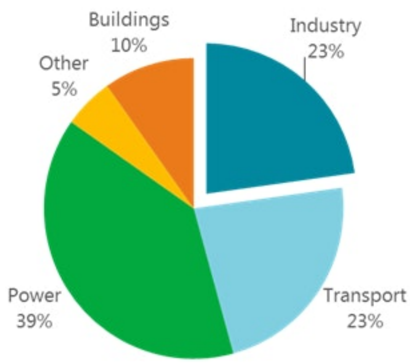


Figure 2: CO2 emissions per sector as a percentage of total global CO2 emissions (IEA, 2019b)

Over the course of the last decades, it can be seen that the industrial demand for hydrogen feedstock is ever increasing as shown in Figure 3. Globally, around 50% of the total industrial heat demand consists of high temperature heat, which is supplied through burning fossil fuels. The allocation of the total process heat demand can be seen in Figure 4. When combining these two and looking at the increase of GHG that follows, it shows that need for something to happen is increasing.

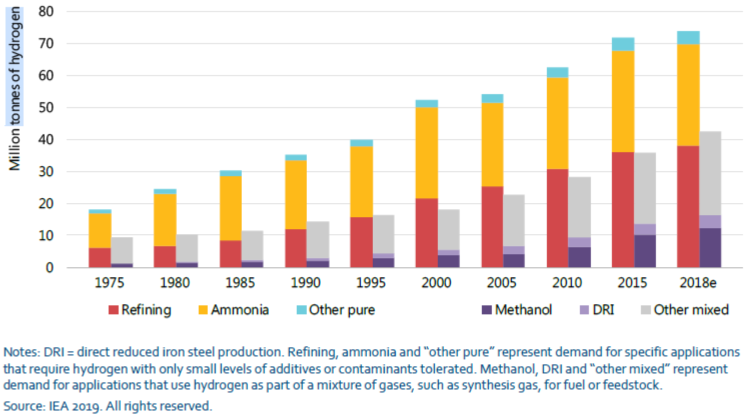


Figure 3: Hydrogen demand growth from 1975 to 2018 (IEA, 2019a)

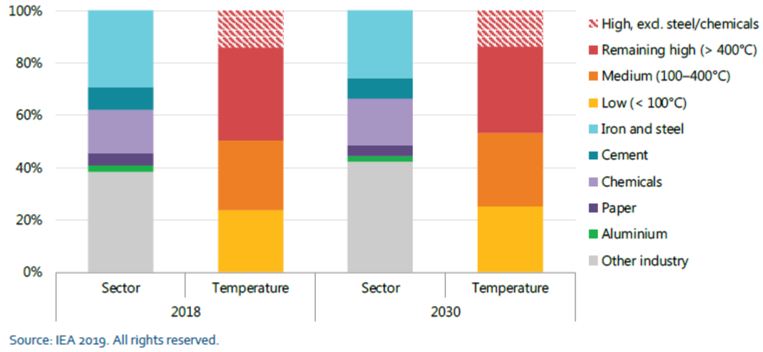


Figure 4: Breakdown of industrial heat demand (IEA, 2019a)

Hydrogen is widely regarded as a solution for industrial decarbonization in processes that are not easily electrified or require high temperature heat. To provide the industry with a clean energy source, green hydrogen is an option if it can be cost competitive with other fuels in the Dutch industry. Over the course of the last years however, the decline in emissions from the Dutch industry has stagnated (Ministerie van Economische Zaken en Klimaat, 2018). Therefore the need to switch to a clean source of energy grows even bigger. The problem however is that green hydrogen is far from competitive and not yet available on a large scale to compete with fossil fuels. To try and accomplish the national and global decarbonisation goals industries will look at the costs of the alternatives for green hydrogen and their development. Based on the cost development of the alternatives, a competitive price for green hydrogen can be established accompanied by the potential demand towards 2050.

1.1 Green hydrogen alternatives for the Dutch industry

This master thesis project will look at the alternative fuels for green hydrogen in the Dutch industrial sector, focusing on the processes and sectors that already have a high hydrogen consumption or have a large potential green hydrogen demand. More specifically, this thesis will look at the costs for green hydrogen alternatives as a feedstock and as a fuel across these processes. As The Netherlands has a relative high emission intensity (Ministerie van Economische Zaken en Klimaat, 2018) compared to European countries, the industry has ample room for improvement. The industrial sector is responsible for 31 percent of the GHG emissions in the Netherlands(Rooijers & Naber, 2019). This is due to the fact that a the majority of Dutch industrial energy use is related to oil refining, steel production and chemicals production. These three sectors make up around 70% of total CO2 emissions in the industry.

As mentioned before, a large role in reducing GHG emissions in the industrial sector is being awarded to hydrogen even though its use is hardly widespread. In the transport sector, the market value of fossil fuel alternatives is set by petroleum and diesel product and in the built environment household gas and electricity prices, but this is not the case for the industry (Ball & Weeda, 2016). The costs of commodities that are used as fuel or feedstock are several times lower than its counterparts in the transport sector and built environment. This affects the green hydrogen business case in a negative way.

As the industrial demand will continue to rise and emissions will peak approximately around 2035 (Gerwen, Eijgelaar, & Bosma, 2019). Electricity prices are pushed lower and lower due to the increased share of renewable power generation. However for some processes in the industry electrification (Power to heat) of process heat is not an economical option. High temperature processes heat generation is almost completely relying on burning fossil fuels and industrial production of hydrogen. The prices of these commodities are expected to rise in the coming decades due to environmental policies and progressive CO2 pricing, until a point at which hydrogen production with renewable energy sources will become cost competitive in terms of operational cost (Gerwen et al., 2019).

Today, the capital investments in electrolysis processes as well as the lack of available renewable electricity render these investments almost un-doable. By analyzing the value chains of green hydrogen alternatives, such as fossil fuels with carbon capture or electrification, a prediction can be made on when green hydrogen is an economic alternative.

In which of the industrial sectors the cost of green hydrogen alternatives is the highest, and when will this maximum price of alternatives be matched by green hydrogen itself? The cost development of the alternatives value chains will determine the price point at which the industry can make a shift towards a green hydrogen. The industry will most likely switch to hydrogen as soon as it is a more economical fuel or feedstock material as its alternatives.

This project focuses on understanding in which processes in the Dutch industry the highest potential green hydrogen demand exists, what its alternatives are and what their corresponding value chain price development will be. Focus on alternatives lies on those that are present currently or in the near future and will exclude technologies that are still in early development stages. Selected industrial processes that currently have the highest hydrogen or energy demand will be taken as the main point of interest.

1.2 Research approach

The research approach for this thesis is chosen to be one of a techno-economic analysis (TEA). This methodology provides itself as a tool to analyse technical developments, their feasibility or likelihood of use and the corresponding cash flows. The cost assessment method in this TEA is going to be based on the concept of levelized costs of energy, which is commonly used in comparing different renewable and fossil energy technologies. The research objective of this master's thesis is to provide an overview to on the economic competitiveness of green hydrogen, reasoned from the perspective of alternatives that are at hand. That is, what are the costs for alternatives for different end uses of hydrogen? This economic competitiveness will be shown by providing an overview of the processes that have a (future) demand for hydrogen, their alternatives and ultimately the alternatives' cost development from 2030 to 2050 in the Dutch industrial sector.

1.2.1 Problem definition & Scientific research gap

The decarbonisation of industrial processes is often researched by means of specific technologies or process alterations, as well as several different ways of expressing costs or the final research results. Amongst the different cost assessment methods, there is discussion on which one is most suitable. The levelized cost of energy is a widespread cost assessment or evaluation method that is used by business investment stakeholders, policy makers and researchers. Decarbonisation is often researched as a single process fuel substitution or process alteration. To the best knowledge of the author, a comprehensive overview of different decarbonisation options specified in values with demand levels for different industrial sectors and processes is not found.

The scientific contribution that is aimed to be created will be of a theoretical as well as a practical nature. There is a current scientific research gap, as to the best knowledge of the author, a comprehensive overview of several different decarbonisation options has not been compiled for industrial process heat generation as well as hydrogen feedstock generation processes. Many works have been published with their focus on the costs of (green) hydrogen production or use costs in a specific industrial process. The cost competitiveness is then addressed by presenting several carbon emissions prices or green hydrogen premiums at which green hydrogen is an economical option yes or no. By turning the viewpoint around, this research aims to present an overview of several green hydrogen alternatives' expected LCOE for four Dutch industrial sectors that form the maximum costs at which green hydrogen is a cost competitive option based on the lowest cost alternatives in several different years of investment. Secondly, the research gap on the several reverting remarks LCOE are implemented and studied. These recommendations in prior works comprise of the background of the levelized cost of energy calculations (Aldersey-Williams & Rubert, 2019), as it is oft criticized for its lack of theoretical foundation (Hansen, 2019), the effects of the assumptions on the outcome(Nissen & Harfst, 2019; Darling, You, Veselka, & Velosa, 2011) and a lack of CO2 costs which creates a bias towards fossil fuels (Loewen, 2019, 2020). Finally, LCOE are most often used for electricity generation, heat generation and hydrogen production project evaluations. The focal points are not on merely the costs of energy use in industrial processes, but often focus on potential revenue streams from selling the generated energy.

Concluding, this thesis aims to fill part of the scientific research gap that exists addressing the cost competitiveness of green hydrogen for the Dutch industry when reasoning from the demand perspective, as well as implementing suggested alterations to LCOE from a scientific background. Both a theoretical and practical research problem are solved by creating an altered levelized cost of energy overview which in turn is used to judge the economic competitiveness of green hydrogen based on alternative decarbonisation options in the Dutch process industry.

1.2.2 Research problem

This research will be of a theory developing nature, by combining scientific literature on potential demand, its alternatives and the the various value chains. Cost modelling theory for modelling the will be investigated and the final model validation can be conducted based on expert opinions from the industry. Scientific literature is the main source of information in this thesis project.

Key concepts are:

- Cost modelling
- Hydrogen alternatives
- Value chains for industry
- Carbon capture and storage

The theoretical basis that will be constructed will make use of:

- Literature review
- Cost modelling theory

1.2.3 Research questions

The previous sections ultimately lead to the formulation of the following main research question:

- What is the economic competitiveness of green hydrogen based on the cost of its alternatives in the Dutch industry and how does this develop towards 2050?

This main question will be answered by solving several sub-questions. By answering these questions the research objectives can be achieved, that is, a model can only be constructed when enough information is at hand to assess the value chains of the various alternatives and come up with a conceptualisation of the various stages. Exploring the answers to the following sub-questions will provide guidance in order to design such a model:

1. In the context of this research, what is the definition of economic competitiveness?
2. Which sectors and processes in the Dutch industry have a potential demand for green hydrogen (incl. volumes) and what are the alternatives in these processes?

3. What are the value chains for these alternatives and what are their associated costs?

4. How can the alternatives' costs development towards 2050 for the Dutch industry be identified?

1.3 Research stages

This section will provide a plan for performing the master thesis research project. The stages that are presented have been structured by using (Verschuren, 2010). A flow diagram for the 5 identified stages can be seen in Figure 5 at the end of this section.

Stage 1: Information gathering

The first step is an in depth literary research on the subject. The literature review will firstly help with formulating a definition on economic competitiveness of green hydrogen in the context of this research. Then sub-question 2 will be addressed. Identifying several processes that are energy intensive and require high-grade heat as well as the current processes that require hydrogen feedstock. It is important to also bear in mind the expected growth of the selected processes. The deliverable for this sub-question will be a short-list of the selected processes and their current and expected demand in terms of energy and feedstock material.

Answering sub-question 3 will require more information on how the selected processes in sub-question 2 will develop. What are their current fuels and feedstocks, are there already transformations taking place in the light of CO2 abatement or increasing fuel or feedstock prices? What does literature say about ongoing developments in these industries, if any? What are industry players looking for in an alternative, what do experts think on the feasibility of utilizing green hydrogen in the near future.

Stage 2: Conceptualisation and constructing of value chain cost models

The conceptualisation of a value chain model will serve as a basis for the cost model of stage three. Important here is identifying the different stages before and behind the meter. How are they built up, what are overlapping parts, if any. The goal is to first identify two conceptual value chain models: before the meter and after the meter costs. After this, what are complications in these chains, and is it possible to find a "standardized" build up in these costs to aid in making simplifications for modelling. Secondly, what are assumptions that need to be made in order for this value chain model to be produce the best results?

In second part of this research stage, the conceptual model is broken down in the defined "standard" segments that are found in the previous step. Perhaps it is also possible that withing the value chain several pathways are found from one source to another end use.

Subsequently, the cost for each of these value chain segments need to be determined, how is the final use cost built, in other words what is the "weight" of these factors? To find these variables, an energy systems analysis will be needed in order to find the (energy) flows, conversion losses.

Then a number of scenarios on which the basis for the cost comparison will be made have to be constructed. How do businesses look at the predicted costs and what are the actual costs of the value chains.

The main methods used will be literature study, cost modeling theory and an energy systems analysis. The deliverable is a conceptual model.

Stage 3: Analyzing model results

At this point in the the model will be completed and ready for analysis. The first inputs in the model will be the scenario of 2021 investment. The model results will then be complemented by the additional scenarios and combinations for comparing costs with for example, levelized cost of energy approach. The main method used here will be cost modeling as well literature research for result validation. The deliverable will be the model results for several years: cost for 2021, 2025, 2030 and 2035.

Stage 4: Concluding and recommendations

In this section the cost of the different chains and scenarios are found. What can be said on the results and how to improve the model? What are key findings in this research? Can we say something about minimal expected revenue or recommend industrial processes a point in time which would be ideal to change fuel or feedstock source?

The main deliverable will be a merit order of alternatives and costs, a discussion of the results and the conclusion which answers the research questions. Additional recommendations for further research are also provided here.

Stage 5: Final thesis writing

After completing the first 4 stages, the researching part of this thesis has come to an end. Now it is key to write everything down and produce a first draft report of this master thesis.

Graphical representation of planning

In this section the a graphical representation in the form of a flowchart through the stages can be found in Figure 5.

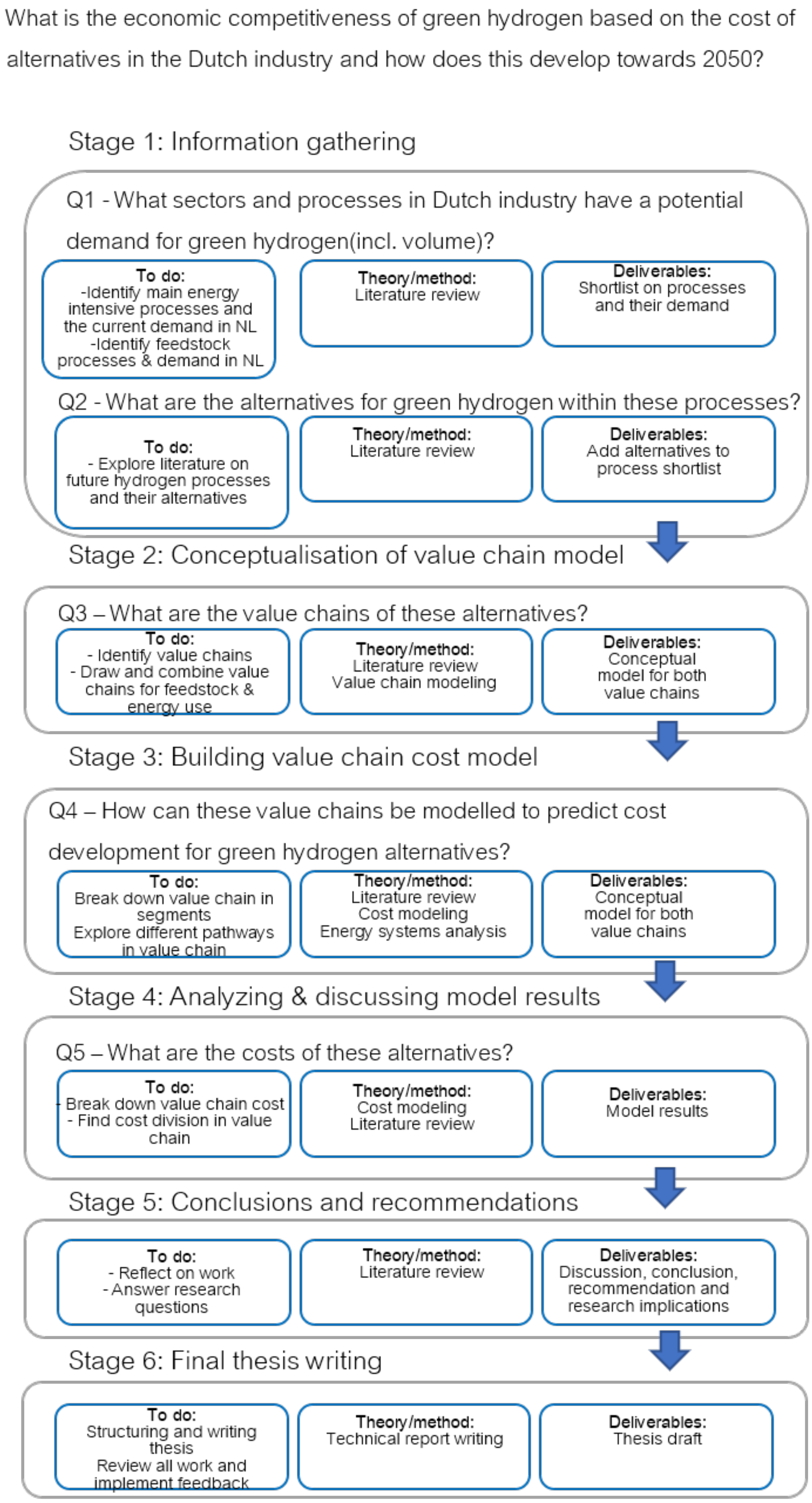


Figure 5: Flow diagram on 6 stages of research with to do's, theory/method and deliverables for each stage

1.4 Thesis outline

This report is split into several chapters. This outline is to guide the reader in the structure of the report and addressed topics per section starting on the next page.

4. *Background*
   This chapter provides information on the background of this research and answers some of the research questions. The state of art about Dutch hydrogen consumption and the lookout in this market is presented. Subsequently, the processes that have a potential demand, their alternatives and what the value chains of these alternatives look like. Finally a background for defining economic competitiveness is presented.

5. *Methodology*
   In this chapter the modelling is explained: approach, system boundaries and design, the build-up of all the elements in the cost model, the used input data and the corresponding assumptions and simplifications that are made are presented.

6. *Results*
   A presentation of the cost modelling results can be found in this chapter. For different sectors the costs are presented, split over two scenarios. After that merit orders are presented followed by a sensitivity analysis.

7. *Discussion*
   This chapter consists of the findings of this research project. The insights that come from the general research as well as the model insights are presented. A discussion on the limitations of this thesis concludes this chapter.

8. *Conclusion & Recommendations*
   The final chapter concludes this thesis project. The answers to the research questions are presented starting with the sub-questions which answers combine into the answer of the main research question. Finally, recommendations for further research are presented.

2 Background

The purpose of this chapter is to provide the necessary background knowledge on the alternatives to green hydrogen, the processes with potential demand and their value chains. First an introduction in the current hydrogen market is given, globally and nationally. Second, the state of the art alternatives are described, followed by processes that have a potential green hydrogen demand. Third, the alternatives value chains are presented with their possible development towards the future. Fourth, an overview on costing methods is corroborated.

2.1 Hydrogen markets today

In this section, an overview will be given on the global and national level of hydrogen demand, production and costs. First global and then Dutch current hydrogen demand and production costs will be shown.

2.1.1 Global hydrogen trends

The global hydrogen demand is expected to continue growing with about, 4-5% per year, due to increased demand for oil refining, methanol and fertilizer production. The hydrogen production market has grown from $115.25 billion in 2017 to an expected $154.74 in 2022 (Abdin et al., 2020). The target costs for green hydrogen in the market has a different value for each market, due to potential alternatives and the end-use, fueling different processes or as a chemical input (Mansilla, Avril, Imbach, & Le Duigou, 2012). Mostly, these hydrogen target costs are compared to contemporary alternatives, being oil, gas or electricity (Mansilla et al., 2012).

There are three distinctive categories of hydrogen production: grey hydrogen, blue hydrogen and green hydrogen (van Renssen, 2020). Grey hydrogen is hydrogen that is being produced by steam methane reforming of natural gas, also known as SMR, and gasification of coal. In terms of GHG emissions, grey hydrogen is on par with directly using fossil resources as fuels of feedstock. Blue hydrogen is hydrogen that is produced from fossil fuel resources while capturing, storing and potentially utilizing the carbon emissions that are created with hydrogen production. Lastly, green hydrogen is hydrogen that is created from renewable energy sources, such as solar or wind electricity, biomass or biogas and hydroelectricity. Zero carbon or even negative carbon emissions can be realised when producing green hydrogen.

Today, utilization of hydrogen is dominated by industrial applications. The top use of hydrogen is feed stock material in the chemical industry, oil refining and, and metal production and its demand has been ever growing over the last years and is expected to continue its rise. Almost the entire hydrogen production is fueled with fossil fuels - 76% from natural gas, around 22% from coal and the remaining 2% through electrolysis (IEA, 2019a).

As stated above, the current market for hydrogen is mainly limited to its use as a feedstock for the chemical and petrochemical industry, with ammonia production being the largest consumer with about 50% of total hydrogen use, followed by 40% of total hydrogen production for oil refineries (Ball & Weeda, 2016). Other applications exist in smaller terms: methanol production, metallurgy, glass industry, and synthetic fuel production making up the rest of the hydrogen demand (Mansilla et al., 2018). The global market for industrial hydrogen is rather significant, with a production of around 700 billion Nm^3 and almost exclusively based on production from natural gas, coal and oil (Ball & Weeda, 2016). A Sankey diagram depicts the various flows of dedicated production and consumption on a global scale, which underlines the statement that hydrogen consumption is dominated by industrial demand, as shown in Figure 6. However, global policies on hydrogen use in various sector least focus on the industry, with only 2 countries having implemented policies to promote clean hydrogen use in the industry, while in other places current regulations hinder industrial adaptation to clean hydrogen (IEA, 2019a).

The benchmark for hydrogen pricing is grey hydrogen, with key drivers in the market being natural gas and CO2 prices (Mansilla et al., 2018). The main competitor of green hydrogen in the future will be natural gas with carbon capture, utilization and storage (CCUS) (Newborough & Cooley, 2020). Several industrial consortia have been established to speed up the cost competitiveness of green hydrogen (Ball & Weeda, 2016). For industrial use of green hydrogen for process energy the same considerations need to be taken into account as for feed stock use. The difference in prices for hydrogen, grey or blue, is significant

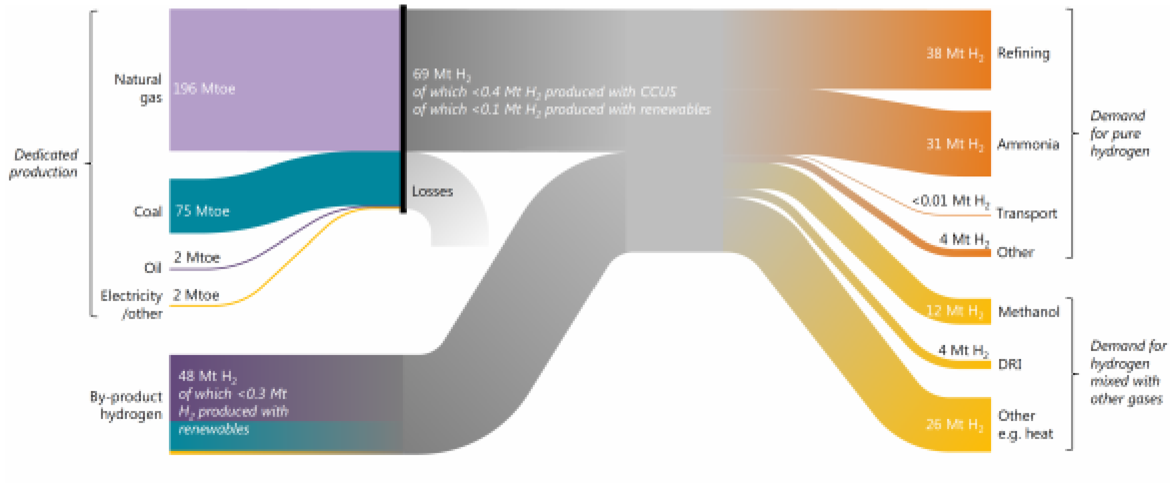


Figure 6: Sankey diagram on the global dedicated production and consumption of hydrogen in 2019 (IEA, 2019a)

around the world, as can be seen in Figure 7. This shows that the largest component of current hydrogen prices are from fossil resource costs, ranging between 45-75 % of the total price (IEA, 2019a)

The global differences of cost of hydrogen production can be found in Figure 7 and are based on assumptions that vary in numbers regionally. The CAPEX for SMR plants without CCUS lies in between \$500 and \$900 per kW of production capacity. The CAPEX for SMR plants with CCUS are between \$900 and \$1600 per kW of capacity. As stated before, the varying prices of natural gas make up the largest part of the cost, ranging between \$3 and \$11 per MMBtu.

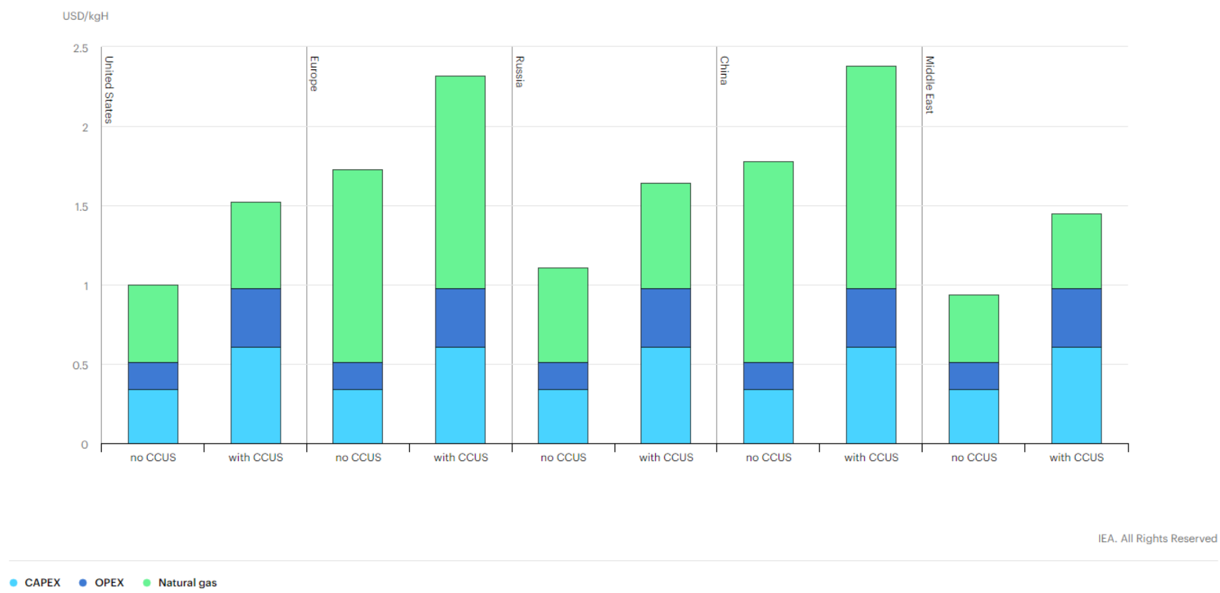


Figure 7: Global differences in grey and blue hydrogen production costs including cost fractions(IEA, 2019a)

2.1.2 Dutch hydrogen trends

For the Netherlands, the production costs of hydrogen - grey, blue green - have been studied to provide an outlook for a Dutch hydrogen market and policy recommendations. The prices show a clear gap between green, blue and and grey (Mulder et al., 2019). These differences can be found in Figure 8.

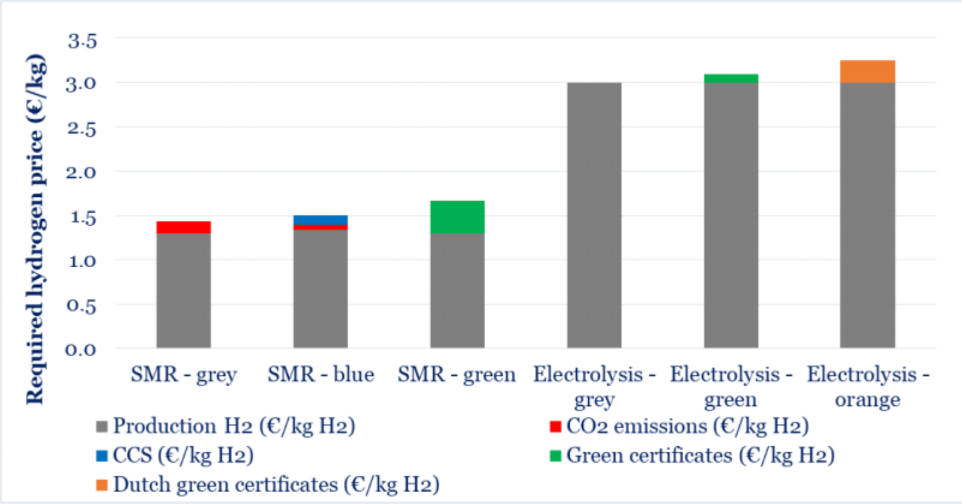


Figure 8: Cost components of hydrogen prices in the Netherlands for various kinds of hydrogen production (Mulder et al., 2019)

The assumptions from (Mulder et al., 2019) are based on Dutch natural gas prices of €20 per MWh and a C02 price of €15 per tonne of emissions with a CCUS efficiency of 55%. SMR plant assumptions in (Mulder et al., 2019) come frome (Collodi, Azzaro, Ferrari, & Santos, 2017), with CAPEX of roughly €1 mln. per MW production capacity and C02 transport and storage costs of €5000 per tonne.

Assumptions on electrolysis are based on an electricity price of €47 per MWh, CAPEX of €750 per kW of production capacity for electrolyser and a grid power and renewable electricity premium of €2 and €5 per MWh, respectively. Lastly, SMR green is based on biogas production and electrolysis grey uses grid electricity. Green and orange are renewable grid electricity and Dutch generated renewable electricity respectively.

The Dutch hydrogen market is evolving as the Dutch government adapted the use of hydrogen in its long term energy strategy in March 2020 (*Focus on Hydrogen: Strategy report*, 2020). A large part to play is set up for hydrogen in Dutch decarbonisation of fossil fuel heavy industry, with key concepts begin upscaling, cost reduction and stimulation of innovation. Within the shift towards using hydrogen, blue hydrogen is set to pave the way first, followed by green hydrogen later in the future (CE Delft, 2018). Hurdles to take are present in upstream, midstream and downstream processes. Production of blue hydrogen with offshore CCS may face opposition, and green and imported hydrogen face mainly cost issues. Storage and transport face risks when importing hydrogen for the Netherlands from Mediterranean areas. Downstream, with distribution and use the potential use for industry is relatively easy, as for other sectors rolling out might prove difficult (CE Delft, 2018). Aim is that by around 2030 market prices for both green and imported hydrogen to become on par with locally produced blue hydrogen and supplant it. Dutch initiatives for production of hydrogen are aplenty, ranging from Gigawatt electrolysis plants to CCUS infrastructures in port of Rotterdam (de Laat, 2020). The Dutch Enterprise Agency (RVO) aims for the Netherlands to become world leader in a global hydrogen economy, calling it the second natural gas revolution (Netherlands Enterprise Agency, Topsector Energie, FME, & TKI Niew Gas, 2021).

It is important to take note that a large amount of government guarantees is needed, due to e.g. high uncertainties in price risk regarding natural gas for H2 production. Government stimulation in the form of regulation and support is necessary. (CE Delft, 2018)

The numbers from the studies mentioned in Figure 7 and Figure 8 are based on merchant produced hydrogen. For the Netherlands however, most hydrogen that is consumed in the industry is created on site, with only one merchant hydrogen producer on an industrial scale present in the Netherlands - AirLiquide (Weeda & Segers, 2020). Due to sheer size advantage for such plants, the result is that local production of hydrogen will most likely be more expensive than represented above.

2.2 Processes with potential demand for green hydrogen,their alternatives and volumes

This subsection will look at which processes have the highest potential demand for green hydrogen and what are their alternatives.

Three main distinctions are being made to classify the processes on their (potential) hydrogen use:

Feedstock :
These processes utilize hydrogen as an ingredient in their production process.

High temperature process heat :
Production processes that require process heat from 600 degrees C and higher.

Medium temperature process heat :
Production processes that require process heat between 200 and 600 degrees C and higher.

Low temperature process heat :
Processes that require heat input of 200 degrees C or lower.

The current hydrogen demand is dominated by feed stock for chemistry, refining oil and steel production. The demand for these products will continue to grow in the coming decade (Ball & Weeda, 2016) and the current alternative to green hydrogen in these processes grey hydrogen or blue hydrogen, which is essentially hydrogen produced through SMR with addition of carbon capture and storage or utilization and storage (CCS, CCUS).

Potential demand for green hydrogen in energy intensive manufacturing industry lies in sectors such as iron and steel manufacturing, cement production, refining industry and ammonia production. Switching from fossil fuels to less energy intensive fuels can consist of switching from coal to natural gas or using waste heat, decarbonised electricity or green hydrogen. Green hydrogen can function as both a fuel or a feedstock. Other options are energy efficiency and heat recovery. The industry needs highly reliable and cost-effective equipment, with investment decisions focused mainly on performance and economic rationale. With investment decisions based primarily on technical performance and economic rationality, long equipment life cycles of for example gas or coal furnaces and investment cycles in conservative sectors will mean a slow transition to cleaner energy. Thus a change towards hydrogen is not expected to appear before 2030 (Staffell et al., 2019).

The amount of hydrogen that is being produced and used in the Dutch industry can be seen in in Figure 9, Figure 10 and Figure 11

Quality type	Estimated amount of hydrogen		
	bcm/y	kton/y	PJ/y (LHV)
Pure [a)]	10.8	968	116
Syngas [b)]	1.1	102	12
Rich residual gas [c)]	3.8	338	41
Other residual gas [d)]	1.0	93	11
Total (hydrogen only)	**16.7**	**1,500**	**180**

[a)] SMR/ATR-natural gas and refinery gas; Shell Gasifier; by-product Chlor-alkali; water-electrolysis

[b)] SMR-natural gas for methanol

[c)] Naphtha and other catalytic reforming processes; naphtha steam cracking

[d)] Coke oven gas and Flexicoker fuel gas.

Figure 9: Estimated annual production in the Dutch industry per quality type of hydrogen (Weeda & Segers, 2020)

Source type	Estimated amount of hydrogen		
	bcm/y	kton/y	PJ/y (LHV)
Natural gas [a)]	9.6	862	104
Oil [b)]	6.4	574	69
Coal [c)]	0.5	45	5
Electricity/water [d)]	0.2	19	2
Total	**16.7**	**1,500**	**180**

[a)] Hydrogen from SMR/ATR; main product; by-product CO/Syngas; part of syngas

[b)] SMR-refinery gas; naphtha and other catalytic reforming; naphtha steam cracking; heavy residue processing

[c)] Hydrogen in coke oven gas

[d)] By-product Chlor-alkali; water-electrolysis.

Figure 10: Estimated annual production of hydrogen per source type (Weeda & Segers, 2020)

Application type	Estimated amount of hydrogen		
	bcm/y	kton/y	PJ/y (LHV)
Ammonia [a)]	5.3	480	58
Refinery [b)]	6.0	544	65
Other pure hydrogen use [c)]	1.6	143	17
Methanol [d)]	1.1	102	12
Fuel gas [e)]	2.6	231	28
Total	**16.7**	**1,500**	**180**

[a)] SMR-natural gas

[b)] SMR-natural gas and refinery gas; Shell Gasifier; Naphtha catalytic reforming

[c)] SMR/ATR-natural gas; by-product chlor-alkali; water-electrolysis

[d)] SMR-natural gas

[e)] Various catalytic reforming; naphtha steam cracking; by-product chlor-alkali; Flexicoker fuel gas (but excluding small fractions of hydrogen that may be present in other residual refinery gas) and coke oven gas.

Figure 11: Estimated annual use of hydrogen in in the Dutch industrial sector. Hydrogen present in fuel gas is used for energy application (Weeda & Segers, 2020)

The next sections will address the processes in the Dutch industry that require hydrogen as a feedstock in a part of their production process. A brief explanation on how the hydrogen is currently used or has potential use is given in each following process description. The current method of hydrogen production in the Dutch industry is done through steam reforming of natural gas (SMR) or other fossil fuel based hydrocarbons, as can be seen in Figure 12.

2.2.1 Ammonia production

Ammonia production is one of highest natural gas consumers for non-energetic use in the Netherlands. Ammonia production is part of the fertilizer industry, in which ammonia is a key ingredient for production. The global ammonia industry growth projection towards 2050 is 1.5-2% annual growth, based on extrapolation of annual growth in the past 20 years, from 180 million tons in 2015 to around 360 million tons per year by 2050 (Alexandratos & Bruinsma, 2012). The Netherlands, being a large ammonia and fertilizer producer, is expected to share in this growth In order to create ammonia, natural gas is converted into ammonia through the Haber-Bosch process, which makes use of steam methane reforming to create hydrogen from natural gas that is needed in this process (Smith, Hill, & Torrente-Murciano, 2020). Afterwards, the ammonia is further processed into fertilizer, as can be seen in Figure 13.

The total annual demand of natural gas amounted to 96 PJ, of which 70 PJ is used non-energetically,

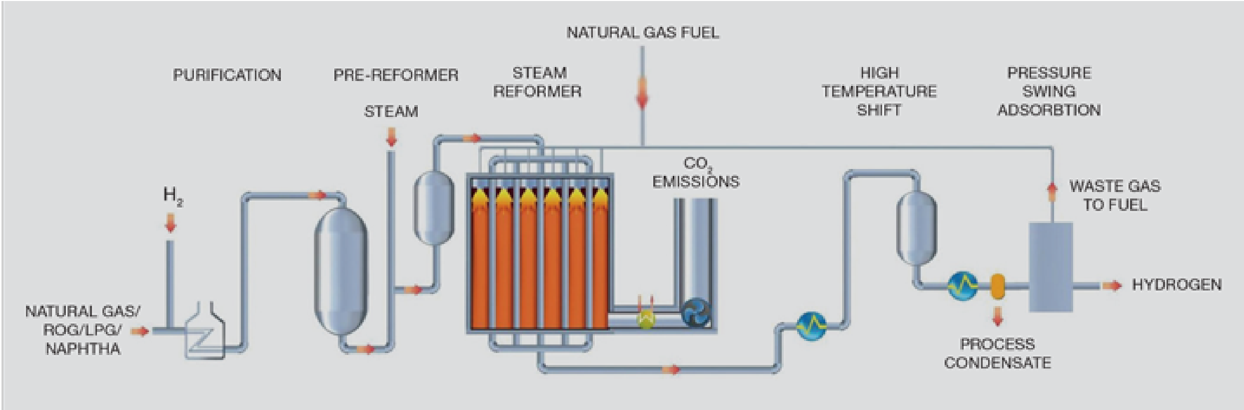


Figure 12: Schematic overview of hydrogen production through steam reforming (Bill Cotton, 2019)

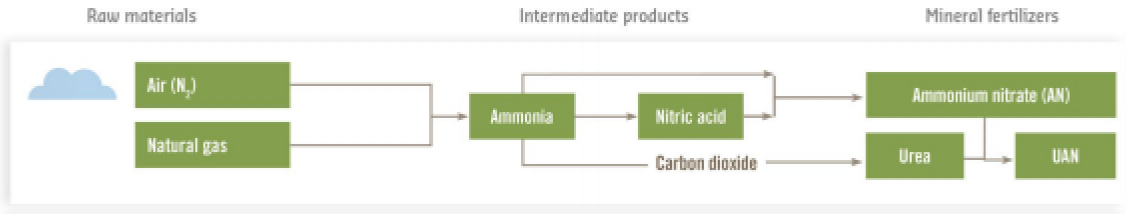


Figure 13: Fertilizer production with Haber Bosch process (Batool & Wetzels, 2019a)

i.e. feedstock for hydrogen production. 23 PJ of natural gas is used for process heat and CHP-plants for steam and electricity production (Batool & Wetzels, 2019a). As can be seen in Figure 11, the amount of hydrogen that is used on an annual basis, amounts to 58 PJ annually.

Alternatives to green hydrogen for ammonia production are found in fuel substitution with grey hydrogen and blue hydrogen use, both fed with natural gas (Batool & Wetzels, 2019a). Note that when there is no C02 present from hydrogen production by SMR, it needs to come from somewhere else as it is needed in the final step of fertilizer production. The 26 PJ of energetically used natural could also be replaced by green or blue hydrogen or by electrifying the process.

2.2.2 Merchant hydrogen production

Next to captive production of hydrogen, there is also merchant hydrogen available. On site production accounts for 64%, by product production 27% and thus 9% is merchant produced hydrogen in Europe. Merchant hydrogen is currently produced by two companies in the Netherlands, Air Liquide, and Air products. The production of hydrogen is by means of SMR and carbon capture and storage or utilisation (Cioli, Schure, & Van Dam, 2021). Total annual production is estimated at 32 PJ with approximately 1.8 - 2 Mton C02 emissions (Cioli et al., 2021). There are four alternatives for merchant green hydrogen, that is natural gas based SMR, with or without CCS, natural gas based ATR and coal gasification.

2.2.3 Oil and gas refining: Hydrocracking& Hydrotreatment

The Dutch refining industry is a large consumer and producer of hydrogen as well. In several processes of producing fossil fuel products, somewhere along the production line either hydrocracking and/or hydrotreatment occurs.

Refinery sector in the Netherlands accounts for roughly 10 Mton C02 emissions in 2017 (Rooijers & Naber, 2019). The companies active in this sector are crude oil refineries and cokes oven product suppliers (Rooijers & Naber, 2019) with four main suppliers, Shell BP and ExxonMobil and Zeeland Refinery with over 1.5 Mton C02 emissions each (Oliveira & Schure, 2020). Combined, this sector has a nominal production capacity of around 67 Mton per year. In terms of production capacity, the largest processes are:

1. Gas oil/diesel production
2. Naphtha production
3. Kerosene
4. Fuel oil production

Hydrotreating and hydrocracking are important techniques in these production processes. These techniques make use of hydrogen feedstock and thus are important in the scope of this thesis. Hydrotreating is a process that reduces the impurities in the feed for further processing in the refining production (Speight, 2011). Hydrocracking, or catalytic hydrocracking is a form of hydrotreating as well, but here the feedstock is converted into more desired products to used in the rest of the production processes (Speight, 2011). These processes require hydrogen, which is mostly produced on site, but smaller amounts are imported from merchant hydrogen producers (Oliveira & Schure, 2020).

In terms of process energy and heat most of the energy comes from natural gas and fuel gas recycling, which is a methane rich byproduct of most refinery processes and mainly used as fuel for furnaces and boilers. The sector total fuel gas production in 2018 was around 87.8 PJ (Oliveira & Schure, 2020; CBS, 2020) and the fuel gas consumption was around 81.8 PJ. This leaves around 6PJ for exporting fuel gas to other parties. The total amount of imported natural gas in 2018 amounted to 50.4PJ. The use in of fuel gas and natural gas for electricity and steam production through CHP plants amounts to 13.7 PJ and 6.8 PJ respectively (Oliveira & Schure, 2020). Natural gas use as a feedstock for hydrogen production amounted to 16.1 PJ annually in 2018. Therefore this is not counted for as energy use. The electricity use is 9.3 PJ. 6.1 PJ is supplied from CHP, from 20.5 PJ fuel gas and natural gas, also producing 8.5 PJ steam annually. The leftover 3.2 PJ electricity demand is grid intake. (Oliveira & Schure, 2020; CBS, 2020) The rest of the energy consumption is shown in Figure 14.

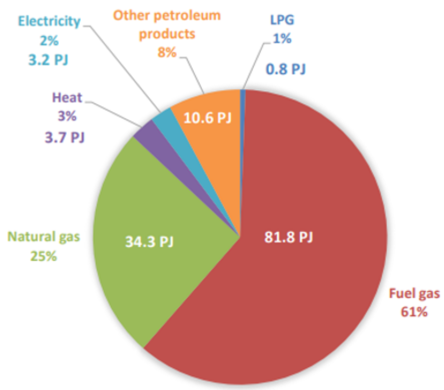


Figure 14: Energy use shares in the refinery sector in 2018 (CBS, 2020)

Hydrogen occurs in several stages in the refining processes, as mentioned above. Besides hydrogen byproducts in fuel gases, some plants use coal gasification and others use natural gas with SMR to produce hydrogen. The amount of SMR hydrogen production amounts to 167 kt annually, from coal gasification 104 kt annually and hydrogen byproducts from naphtha production are 2016 kt per year (Oliveira & Schure, 2020).

The current hydrogen production can be replaced with green hydrogen from renewable sources or blue hydrogen through CCS of natural gas SMR and coal gasification. Another option is thermal decomposition of methane from fuel gas into hydrogen. It should be kept in mind that the largest hydrogen production on site occurs as a byproduct in naphtha production and is essentially free of charge. Therefore the hydrogen that can be substituted amounts to 271 kt/year, which corresponds to 16PJ per year of natural gas(Oliveira & Schure, 2020).

Fuel substitution for process heat are possible through several means, according to (Oliveira & Schure, 2020). Electrification of furnaces, boilers and steam turbines: 127.5 PJ of process heat needs to be substituted. This corresponds to roughly 32 TWh of (renewable) electricity for both boilers and furnaces and CHP replacement. 81.8 PJ of this heat supply is provided with fuel gases and is therefore economically hard to substitute. For hydrogen use as a fuel: Complete fuel gas and natural gas substitution amounts to 1063 kt of hydrogen for the refinery sector. Only natural gas would result in around 286kt of hydrogen demand. The excess of fuel gas would leave a substantial amount of methane that needs to be utilized elsewhere.

2.2.4 Synfuels & Methanol production

Methanol is considered a promising synfuel in a future with less carbon emissions. Over the last years, the production of synfuel in Europe has increased significantly, from 84 PJ in 2005 to 586 PJ in 2018 (Khandelwal & van Dril, 2020), with the Netherlands coming in after Germany and France as the largest producers of methanol with an annual production of 69 PJ. Methanol and synfuels consist mainly of the production of bio-ethanol and bio-diesel (Khandelwal & van Dril, 2020).

The production of methanol in the Netherlands is mainly done at BioMCN and ALCO. The annual estimated amount of non-energetic hydrogen use in methanol production is 12 PJ/yr at BioMCN and 6 PJ at ALCO(Weeda & Segers, 2020; Khandelwal & van Dril, 2020). The methanol production process can be divided into three parts: steam reforming of natural gas, conversion of steam reformed gas to methanol and distillation of the mixture to extract methanol. In the production process, the first step is desulphurization of natural gas. This is the first process that requires hydrogen for purification. The purified natural gas enters a steam reformer to produce a syngas mixture of hydrogen and C02. This is then converted to methanol and a hydrogen surplus (Khandelwal & van Dril, 2020). Additional liquid CO2 with the leftover hydrogen can again form more methanol. This increases the energy efficiency by 5-10% (Khandelwal & van Dril, 2020). Around 32 GJ and 29.5 GJ for respectively traditional and CO2 added production is needed as process energy.

Feedstock alternatives are biogas based methanol or green/blue hydrogen with liquid C02 addition. Currently, part of the C02 emitted in hydrogen production is captured and used to improve methanol production efficiency by 10-15%. The production process of natural gas reforming takes place between 500 to 850 degrees C. Methanol conversion takes place at around 250-260 degrees C. Process energy is fueled with natural gas (2.4PJ), hydrogen from separation (2.1PJ), methane from separation (0.8PJ) and electricity (0.06PJ) can be achieved with electrification of boilers (up to 350 degrees C), burning hydrogen(green/blue) for steam and burning natural gas with CCS/CCUS (Weeda & Segers, 2020).

2.2.5 Steel manufacturing

The steel manufacturing in the Netherlands takes place at Tata Steel in Ijmuiden. The steel industry process heat currently is fueled by fossil fuel sources, and thus has a great potential demand for green hydrogen. The smelting of iron is very energy intensive and is currently performed with coke ovens (Keys, Van Hout, & Daniëls, 2019). There are two main decarbonisation options for Tata Steel Ijmuiden, which are direct reduction processing of iron and iron ore electrolysis technology. Direct reduction processes make use of natural gas blast furnaces, that can be either retrofitted with CCS installations or switching the fuel for these furnaces to green or blue hydrogen at a later stage. This would require 75 PJ of natural gas annually. The iron ore electrolysis technology would require 88 - 106 PJ of electricity on a yearly basis. This magnitude of electricity is still unrealistic in the Netherlands, combined with the required transmission cost. (Keys et al., 2019). A hydrogen production cluster combined located around Amsterdam will test the feasibility. The annual C02 emissions at Tata Steel currently amount to 7 Mton per year (Keys et al., 2019).

2.2.6 Plastics production

The plastics production in the Netherlands mainly produces LDPE and LLDPE polyolefines at DOW, SABIC and Ducor. The majority of the energy demand is connected to creating ethylene and propylene, which is a steam cracking process that requires medium to high temperature heat which requires 12.6 MJ of steam for 1 kg of produce (Negri, Ligthart, Negri, & Ligthart, 2021). Their total production capacity lies at around 2400 kt of plastics annually, with corresponding CO2 emissions total of 220 kton. The total energy demand of plastics production that can be replaced with green hydrogen amounts to 30 PJ annually (Negri et al., 2021).

Options for decarbonisation of these processes are found in fuel substitution. Alternatives here are natural gas with and without CCS, blue hydrogen or electrification (Negri et al., 2021).

2.2.7 Paper and board production

The Dutch paper and board industry has a significant process heating demand, as well as an electricity demand. The main process heating demand is supplied through burning natural gas to produce steam or to directly use it in drying the paper. The required temperatures are between 150 and 180 degrees C. The total heat consumption was 12.5 PJ in 2015, of which 7.8PJ was produced by CHP. Total electricity consumption to power electrical production equipment was 4.7PJ, of which around 2.8 PJ comes from CHP installations.(Rademaker & Marsidi, 2019)

The 2016-2017 natural gas use amounted to a total of 12.8PJ, 7PJ of electricity, around 1.8PJ waste heat. Decarbonisation options are focused on steam supply. This steam can be supplied through the use of electrical boilers, biogas boilers, natural gas boilers with CCS, Hydrogen fueled boilers. (Rademaker & Marsidi, 2019)

2.2.8 Food processing industry

The Dutch food industry has a very large final energy consumption of 85.3 PJ in 2017. However, this process heat consumption is scattered throughout the country and not focused on several of the largest companies (Segers, Keller, & Geertjes, 2017). Manufacturing of food products its process heat demand is all below 500 degrees C. 55 PJ of natural gas is consumed, 24PJ of electricity and around 5 PJ of heat. 45% of the natural gas use for PH is below 200 C, 10% of CHP steam is below 200 C and 55% of natural gas PH is between 200 C and 500 C. The electricity use is for operating machinery and this can be neglected.

Decarbonisation options are focused on steam generation. This steam can be supplied through electrical boilers, natural gas boilers with CCS and green or blue hydrogen boilers.

2.2.9 Building materials

The Dutch building material and ceramics industry has a significant process heat demand of around 25 PJ annually. 17.6PJ from natural gas, around 4.5PJ of electricity and 2.3PJ of coal/oil. This energy consumption is strongly allocated towards glass and brick production, taking 8.6PJ and 7.3PJ respectively (Segers et al., 2017). The high temperature alternatives for process heat are : green gas furnaces, hydrogen furnaces, natural gas furnaces with CCS and electrification of kilns and drying processes.

Glass production

Glass production accounts for around 6.7PJ of natural gas consumption and 1.7PJ of electricity consumption annually. Most of this heat generation is between 800 degrees C to a maximum of 1550 degrees C. All temperatures are above 200 degrees C. (Papadogeorgos & Schure, 2019)

Ceramics, bricks and building materials production

In the ceramics/bricks industry, it is assumed that all natural gas use goes directly into process heat production. Almost all process heat is above 200 degrees C (around 350 degrees C and 1100 degrees C). This is around 6.7 PJ of natural gas on 2016-2017. (Besier & Marsidi, 2020)

2.3 Alternatives to green hydrogen

This section aims to provide insights on the state of art of green hydrogen alternatives for the Dutch industry. First, carbon capture and storage technology is investigated. Second electrification of industrial processes is investigated. Thirdly, hydrogen technologies are explored.

2.3.1 Carbon capture and storage

Carbon capture and storage can be split into different segments, as the name already encompasses. This technology is widely described as the key to the decarbonisation of the industry sector, bridging the gap between fossil fuels and more sustainable fuels. Carbon capture is performed at industrial facilities to mitigate carbon emissions by storing them away. There are three main distinctions in CCS technologies that produce different levels of C02 purity (Oliveira & Schure, 2020; Porter et al., 2017). In pre-combustion carbon capture, a hydrocarbon-rich fuel is pre-treated, led into a gasifier and then converted into a mix of C02 and hydrogen. Then in the shift reactor the concentration of this new syngas is increased. Heat is recovered and then from absorption the hydrogen and C02 are separated which leads to an almost pure hydrogen stream. Hydrogen can be used and C02 is taken away and stored (Durmaz, 2018). An illustration of this process is given in Figure 15. Pre-combustion CCS installations could be connected to any equipment that requires pure hydrogen, for feedstock or combustion (Oliveira & Schure, 2020).

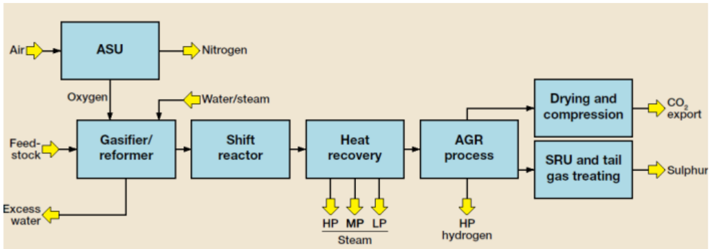


Figure 15: Schematic of carbon capture pre-combustion. ASU and AGR stand for air separation unit and acid gas removal.(Ferguson & Stockle, 2012)

Post combustion carbon capture removes carbon from flue gas in fossil fired installations after combustion. The C02 is removed from the flue gas that results after combustion processes and is cooled, compressed, absorbed and stored separately. The cleaned flue gas is released into the atmosphere. Pre-treatment of the flue gas is sometimes necessary if sulfur content is high (Oliveira & Schure, 2020). A schematic can be seen in Figure 16. This kind of carbon capture unit can be combined with most combustion systems.

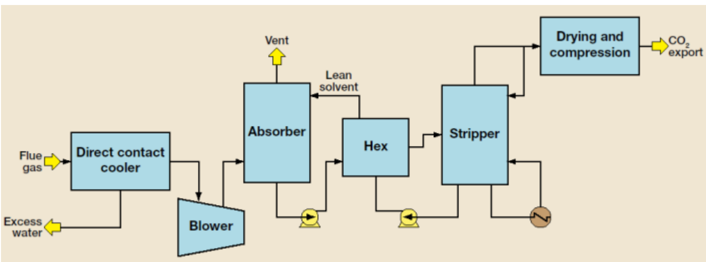


Figure 16: Schematic of post combustion carbon capture (Ferguson & Stockle, 2012)

The third variety is the least conventional of the three, namely oxyfuel combustion carbon capture. In these processes, fuel is burned in pure oxygen instead of air. This results in a flue gas stream of vaporized water combined with C02. Then the C02 can be removed and provides a high level of C02 purity due to absence of nitrogen (Durmaz, 2018). Efficiency of CCS technology also varies with the process that it is being used in and concentrations of C02.

The cost of capturing carbon is often expressed in the levelized cost of captured carbon(Roussanaly et al., 2021). These costs are different per processes and the corresponding volume percentage of C02 that can be found in the gas stream. The CAPEX range from 45 €/t C02 capture for low C02 concentrations (5%), 31-39 €/t C02 captured for medium concentrations (8-10%) and 28-31 €/t for concentrations above 10%. Respectively the fixed O&M are, 19, 15-18 and 14-15 €/t C02 captured (Oliveira & Schure, 2020). The energy use in can be found in Figure 17. Efficiency of carbon capture also differs per production process. Pre-combustion capture is estimated to capture around 90% of the total C02 emissions (Cormos, Cormos, & Agachi, 2013) whilst post combustion is less efficient with capturing around 50-80% (Pérez-Fortes, Moya, Vatopoulos, & Tzimas, 2014).The consumed electricity also emits C02 upon generation.

	Low CO_2 concentration (5 %vol)	Medium CO_2 concentration (8-10 %vol)	High CO_2 concentration (10-18%vol)
CAPEX [EUR 2017/t CO_2 captured]	45[35)]	31[36)]-39[37)]	28[38)]-31[39)]
Fixed OPEX[40)] [EUR 2017/ t CO_2 captured/yr]	19[35)]	15[36)]-18[37)]	14[38)]-15[39)]
Steam consumption [GJ/ t CO_2 captured]	2.5	2.5	2.5
Electricity consumed [kWh/ t CO_2 captured]	183	149-185	162-166
CO_2 avoided/CO_2 captured[41)]	0.65	0.67	0.67

Figure 17: CCS cost for different streams of C02 concentration(Oliveira & Schure, 2020)

The second step is transporting the captured C02 towards the final storage location. This transportation costs vary with range and volumes. Transporting of C02 can either be performed by trucking, shipping or by pipeline (Psarras et al., 2020). The projected cost of C02 transport range from €17-20 per tonne C02 (Skagestad, Onarheim, & Mathisen, 2014).

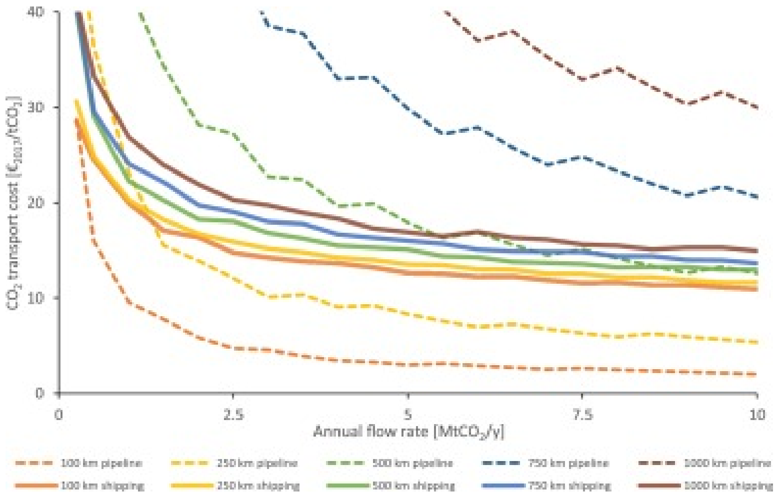


Figure 18: Depiction of cost development of shipping C02 to offshore locations (Roussanaly et al., 2021)

Storage of C02 is the third and final step. Underseas gas fields or empty salt caverns are often used for storage of carbon. In the Netherlands, the use of CCS is restricted to offshore storage and transport of C02 via pipelines and shipping are designated transport technologies (Vendrik, 2020). Costs of CCS offshore storage range from €1-7 per tonne stored C02 (Vendrik, 2020).

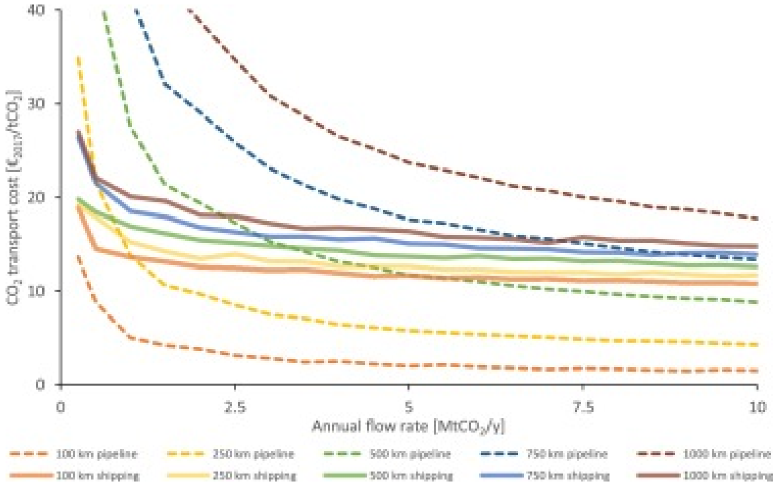


Figure 19: Depiction of cost development of storing C02 at offshore locations (Roussanaly et al., 2021)

2.3.2 Electrification

Electrification in the process industry is seen as a promising option for decarbonisation with an ever increasing share of renewable and C02-free electricity generation in the future. Generating or process heat or upgrading waste heat with electricity, is called power-to-heat (Schüwer & Schneider, 2018) and has a significant potential for both low and higher temperature heat in decarbonising the future industry demand. (Bühler, Müller Holm, Elmegaard, Bühler, & Holm, 2019). Besides the potential of C02 reduction, there are a number of other benefits to electrification as well. Some cases of electrical heating reach higher efficiencies, it is more precise and quicker, resulting in higher production and quality of product (Bühler et al., 2019) Depending on whether high or low temperature heat is required in different processes, the technology also differs. Available technologies are listed: For process heat, industrial heat pumps, electric boilers, induction furnaces, electric arc furnaces and direct resistance heating are promising power-to-heat technologies, for both short and long term (Ouden et al., 2017). An overview of the power-to-heat potential for different processes is given in Figure 20.

Unit operations	Technologies	Category
Process heat – steam and hot water, thermal oil ...	Heat pumps Electric boiler / electrode boiler Hybrid CHP-EB concepts Steam recompression / vapour recompression	Power to heat Power to pressure
Process heat – baking, melting and casting	Induction furnace Microwave heating Electric melting Electric arc furnace Plasma heating /plasma recycling Infrared heating	Power to heat
Drying	Infrared drying Impulse drying Impingement drying Microwave drying / combining with convection. Vapour recompression Heat pumps for low temperature drying	Power to heat
Distilling/separation	Mechanical Vapour Recompression Filtration: MF / UF / NF / RO Electrical field / electrostatic techniques Mechanical techniques e.g. centrifugation	Power to heat Power for separation
Sterilisation and pasteurisation	Infrared sterilisation UV Microwave pasteurization and sterilization Microwave blanching of vegetables Heat pumps HP sterilisation	Power to heat Power for sterilisation

Figure 20: Power to heat technologies and applications in different processes (Ouden et al., 2017)

Industrial heat pumps and electrical boilers are technologies that have potential in the lower temperature process heating range, below 200 degrees. They are direct alternatives for natural gas or hydrogen boilers in processes that require hot water of indirect heating. These technologies are readily available (Wapstra, 2018; Ouden et al., 2017). Costs of electrical boilers or industrial heat pumps amount to 0.07M€/MW and 0.3-0.9 M€/MW respectively. Electrification for steam production is also promising with electrical boilers at low temperatures.

For processes at medium temperatures, ranging from 200 to 600 degrees Celsius - such as drying, distillation and chemical conversion - direct en indirect heating technologies are required. For drying processes, steam production through electrical steam boilers for indirect heat is possible, as well as direct air heating technology. Investment cost here are depending on the capacity that is required. For electrical steam boilers up to 5 MW, it is 0.07-0.08 M€/MW and up to 80 MW the CAPEX are 0.1-0.15 M€/MW. Direct air heating is more expensive and not expected to be economical, with costs of 1 M€/MW installed capacity (Wapstra, 2018). The same technology options goes for distillation processes in the refining industry, with the addition of mechanical vapour recompression, which essentially is the same as an industrial heat pump, but it utilises high temperature waste streams (Ahirrao, 2014). Expected investment cost excluding grid connection is estimated at 0.26-0.6M€/MW for MVC (Wapstra, 2018). Chemical conversion process heat currently fueled by hot flue gas can be replaced by direct air heaters and electrical steam boilers, the same as for distillation.

Last, for high temperature heat processes such as glass, steel and ceramics production direct heating is required. This is already being done in the industry through electrical arc furnaces but these technologies require vasts amounts of electrical power and no retrofitting options are available. High investment costs are needed for installation of electrical smelters or furnaces, around 130€/tonne of produced product. Other high temperature heat applications in the chemical sector can make use of electrical steam boilers, in e.g. steam cracking or naphtha production (TNO, 2018).

For electrification of process heat it is noteworthy that connection to the grid and grid capacity in general require substantial investments. In The Netherlands, grid connection cost for industrial users average at around 0.13M€/MW connection. Using the Dutch electricity transmission network also comes with annual fixed cost of 0.02-0.025 M€/MW of connected capacity (Hers et al., 2018)

2.3.3 Grey/Blue Hydrogen

Another alternative to green hydrogen for the Dutch industrial sector is grey or blue hydrogen. As mentioned in Section 2, grey and blue hydrogen are already used as a feedstock in the Dutch chemical industry. Besides feedstock, hydrogen has a potential for replacing coal, oil or natural gas in providing process heat (Detz, Lenzmann, Sijm, & Weeda, 2019). Natural gas furnaces can be retrofitted with technology for hydrogen combustion, and boilers can be replaced with hydrogen boilers as well (Wapstra, 2018), making hydrogen suitable for low, medium and high temperature process heat. Hydrogen used as a feedstock is most often produced on-site from natural gas reforming or harvested as a by product in refining processes and immediately used in other processes (Oliveira & Schure, 2020).

Grey or blue hydrogen are currently the only readily available alternatives to green hydrogen for the industrial sector in the Netherlands. The production of grey and blue hydrogen is done through steam reforming of natural gas or gasification of coal - with or without carbon capture. Hydrogen from SMR without carbon capture has investment costs of 0.74 M€/MW, with fixed O&M at 5% with 96% energetic efficiency (Janssen, 2018a). Blue hydrogen production has capital costs of 1.33 M€/MW with O&M at 3.5%, 1% fixed and 2.5% variable with a lower energetic efficiency of 90% (Janssen, 2019). For blue hydrogen production from auto thermal reforming with carbon capture and storage, the CAPEX are €1.200.000, with 3.5% fixed OPEX and 84% energetic efficiency. For merchant hydrogen production, prices found by (Mulder et al., 2019) and (Hers et al., 2018) are used from Section 2.

The gasification of coal to produce hydrogen is a more complicated process, which makes use of a shell reactor. Coal is first dried, gasified at high temperature and pressure. This newly formed syngas is moved into a water gas shift reactor and cleaned from impurities(Kaplan, 2020). Here hydrogen and C02 are separated from the mix and the remaining flue gasses are recycled. A schematic of gasification of coal for hydrogen production can be found in Figure 21. The capital and operational costs for coal gasification and CCS with 90% efficiency are found in Poland. CAPEX for a plant without CCS are 2M€/MW and fuel efficiency is 0.58% (Kaplan, 2020). CAPEX with CCS are 2.6 M€/MW and fuel efficiency is 52.5% (Kaplan, 2020).

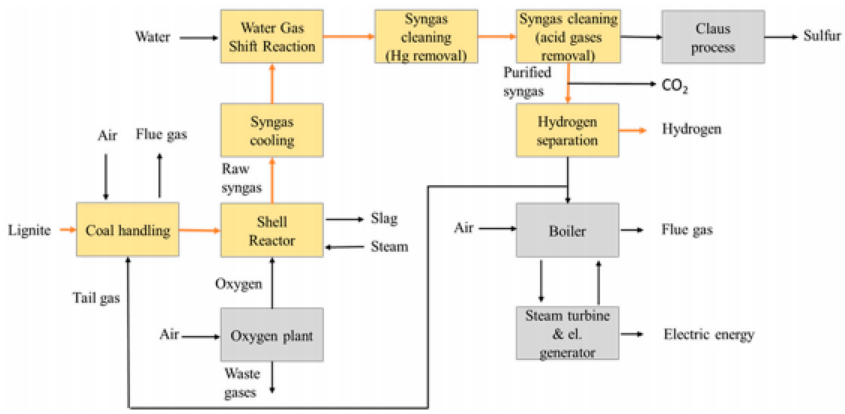


Figure 21: Schematic of hydrogen production from coal gasification with a shell reactor (Kaplan, 2020)

For low temperature process heat, the natural gas boilers that are used can be altered for hydrogen use or hydrogen burners can be installed. However, these burners are not ready off the shelf and possible higher NOx emissions need to be dealt with in order to be effective. Process changes due to changes in heat transfer from different fuel properties still need to be studied in some cases (Wapstra, 2018). Investments for such a system based on the possibility of a retrofit are 0.015-0.020 M€/MW up to 1 MW capacity. For 1 MW to 80 MW the investment cost are 0.01-0.015 M€/MW. In case retrofitting is not possible, the costs are estimated at 0.05-0.06 M€/MW.

Processes that require heat from 200 to 600 degrees Celsius need only slight modifications to be eligible with hydrogen systems. Natural gas burners can either be retrofitted to burn hydrogen, or hydrogen burners or steam generators can be installed. As mentioned before, these processes are distillation, chemical conversion and some drying processes (Wapstra, 2018). The expected CAPEX for retrofit are 0.015-0.020 M€/MW up to 1 MW capacity. For 1 MW to 80 MW the investment cost are 0.01-0.025 M€/MW. In case retrofitting is not possible, the costs are estimated at 0.1-0.15 M€/MW. Interaction between burning hydrogen instead of flue gas, and the produce need to be studied further to make guarantee quality of the final product (Wapstra, 2018).

High temperature heat is where a lot of potential lies for burning hydrogen gas (H-Vision, 2019). Furnaces that are currently used above 600 degrees Celsius for steel, glass and ceramics production run mostly on natural gas. These furnaces can often be altered and retrofitted to (co)fire hydrogen or a natural gas-hydrogen mixture. CAPEX are estimated at 0.4-1.2M€/MW for a 10MW hydrogen furnace (Romgens & Dams, 2018) Research is needed for the effect of burning hydrogen instead of fossil fuels on the quality of the final product as much as for the temperature range from 200 to 600 degrees (Wapstra, 2018).

Finally, hydrogenation of carbon dioxide, or hydrocarbon synthesis could be an alternative production process (Detz et al., 2019). However, due to the low level of technology and specific application in the refining sector, this is left out of scope.

2.3.4 Coal

Hard coal or hard coal products such as cokes are currently used in the Dutch process industry in the refining sector to produce hydrogen through gasification and as process heating fuel in the steel and scarcely in the cement sector (Oliveira & Schure, 2020; Keys et al., 2019; Xavier & Oliveira, 2021). Coal furnaces are highly polluting and CCS retrofit options are expensive, therefore often reductions in C02 emissions from burning coal are fuel substitutions to heavy oil, natural gas or in some cases biomass (Xavier & Oliveira, 2021). Post combustion CCS for coal fueled plants CAPEX are estimated at 1.2 M€/MWe, combined with OPEX for CCS this amounts to 24-62€/ton of C02 for newly constructed plants, whereas retrofitting is expected to be more expensive (Lamboo, 2020).

2.3.5 Natural gas

Natural gas is the main energy driver of the Netherlands, with 301 PJ used in the process industry. Natural gas is an alternative combined with CCS retrofits for decarbonising process heat or producing blue hydrogen. It is currently used as state of art for low through very high temperature process heating and is a fully matured technology (Rutten, 2019). For processes that require heat below 200 degrees Celsius, fire tube boilers are used. These have CAPEX of 18k€/MW for up to 5 MW boilers, and 9.7k€/MW for hot water boilers up to 25MW (Rutten, 2019). For steam generation and process heat up to 600 degrees, water tube steam boilers are used. These have higher CAPEX, of around 55k€/MW for installations of 20MW and up(Rutten, 2019). For high temperatures ranging from 600 degrees C and above, natural gas (blast) furnaces are used. CAPEX with are €1.200.000 per MW without CCS.

2.4 Alternatives value chains and development

This section aims to demonstrate the value chains of mentioned fuel alternatives for decarbonising the Dutch industry demand for hydrogen and process heat. The supply chain will be investigated, as well as future trends and possible policy implications. In Section 2.4.1the natural gas value chain will be looked at. Then in Section 2.4.2 we look at the value chain for electrification. In Section 2.4.4 the use and value chain of coal will be investigated.

2.4.1 Natural gas value chain

Natural gas is widely regarded as the ideal fuel for transitioning from a coal fueled industry/society towards a more sustainable source of energy (Becerra-Fernandez, Cosenz, & Dyner, 2020). In the Netherlands, most of the energy demand is already fulfilled by natural gas instead of other, but more polluting fossil fuels such as coal or crude oil are still present (*The great Dutch gas transition*, 2019). This among other reasons led the Netherlands to become the natural gas hub for Europe, with its trading center (Dutch TTF) being the main price indicator for the rest of the EU (Gasunie, 2019). The total consumption of natural gas in the Netherlands amounts to 1285 PJ, with the industry being responsible for 270 PJ in 2018, around 25% of the total gas consumption.

The value chain of natural gas can be subdivided in three categories, upstream, midstream and downstream. This roughly translates to production, transmission, storage and distribution and final consumption. However, there are two main differences: natural gas and liquefied natural gas. An overview of the supply chain is shown in Figure 22

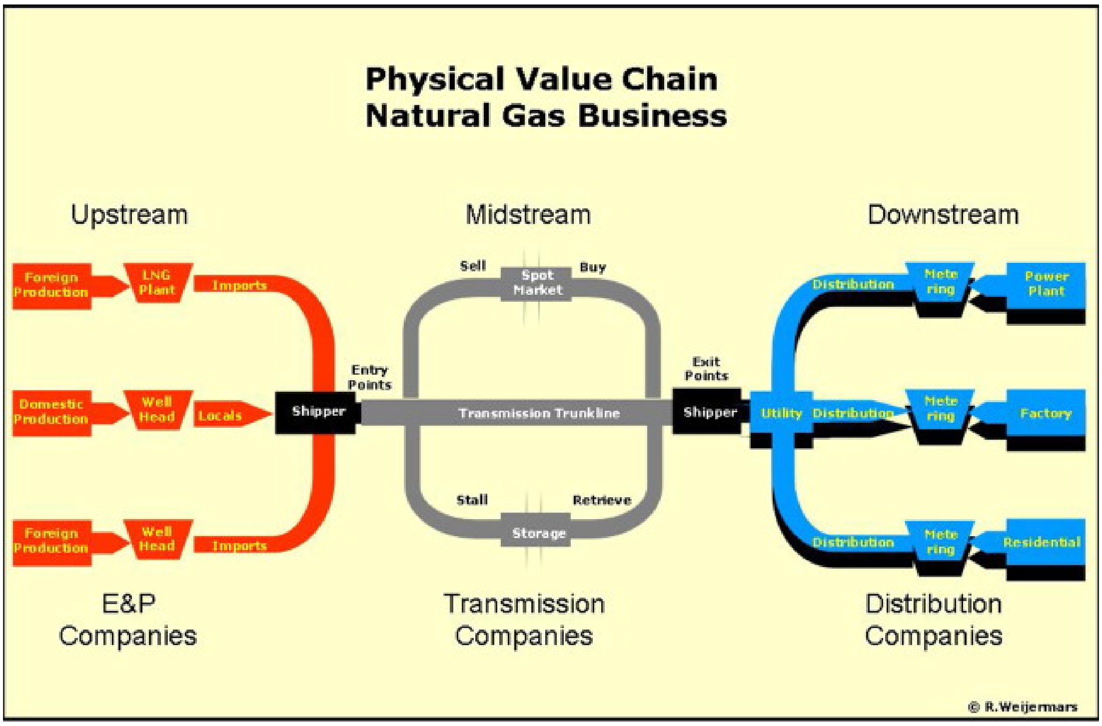


Figure 22: Depiction of natural gas value chain(Weijermars, 2010)

Within this value chain, the cost breakdown for natural gas is more complicated. The production of natural gas and LNG, as well as the final market price are equal. However, depending on where the natural gas is produced, the production costs are different. The expected production price for natural gas at the Henry hub in the US is expected to stay below \$4 per MMBTU towards 2050, due to large low prices of competitors in Russia and the Middle East (Energy Information Administration, n.d.). The prediction for the cost can be seen in 23.

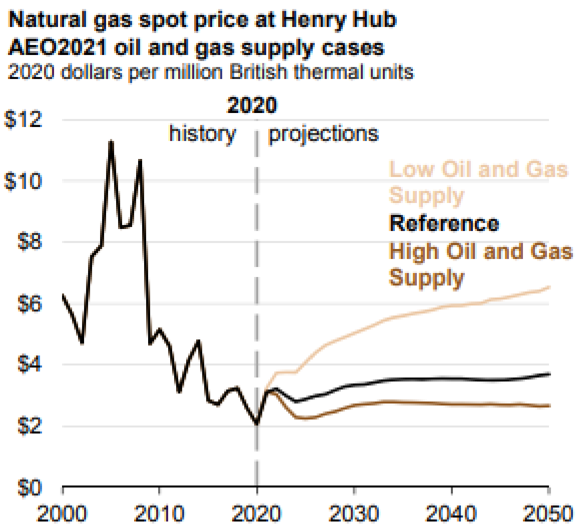


Figure 23: Long term price forecast of NG production at U.S. Henry Hub (Energy Information Administration, n.d.)

The imported natural gas by pipeline in the EU is produced in Russia and Norway (Europeenne, De L' Energie, & Nies, n.d.), whereas nowadays, the LNG that is imported comes from The Middle East and the United States (Rogers, 2018).

Pipelined natural gas is transported from production source to the Dutch gas grading hub and there distributed towards various end consumers in the Netherlands. The transmission tariffs for pipelined gas are based on existing infrastructure, with the newest addition being NordStream 2 from Russia to Germany. The presumptive price of this offshore pipeline transport amounts to 10-12 billion USD (Przybyło, n.d.). This translates to a transmission cost of 0.96 /MMBTU and its development is hard to predict towards the future.

LNG transport costs depend on more parameters. Feed gas price, liquefaction (LNG-production), transport costs (charters rates, boil off rate, canal costs and other costs) and re-gas and grid entry fees (Rogers, 2018). Charter rates are at an all time high for with rates ranging between $ 55,000 - $ 70,000 per day. The boil off rate is estimated at around 15% and the final number is depending on the gas production price (I. Lee, Park, & Moon, 2018). A cost overview is shown in Figure 24

	$/MMBtu				
	Feedgas	Liquefaction	Transport	Regas & Grid Entry	Total
Qatar (high Liquids Yield) to Asia	-2.5	2.5	0.81		0.81
Qatar (Barzan reported yields) to Asia	1.5	2.5	0.81		4.81
US Brownfield to Europe	3.3	2.0	0.67	0.69	6.66
US Greenfield to Europe	3.3	2.5	0.67	0.69	7.16
US Brownfield to Asia	3.3	2.0	1.52		6.82
US Greenfield to Asia	3.3	2.5	1.52		7.32
Russia - Yamal2 to Europe *	2.0	3.5	1.60	0.69	7.79
East Africa - Lowto Asia	3.0	3.5	0.86		7.36
East Africa - High to Asia	3.5	4.0	0.86		8.36
Australia Expansion - Low to Asia	4.5	3.5	0.51		8.51
Australia Expansion - High to Asia	5.0	4.0	0.51		9.51
Canada to Asia	4.5	4.5	0.67		9.67

Figure 24: LNG cost breakdown for 2020 (Rogers, 2018)

In The Netherlands, both distribution and storage costs for natural gas are tariffed by the net operator of natural gas, GasUnie. This is based on an entry-storage-exit system, regulated in NC-TAR by the EU, that started in 2020 (*Tariefinformatie vanaf 2020 Gasunie Transport Services*, n.d.). The costs of distribution, transport and storage in the Netherlands amount to a price of €1.32 per MWh of natural gas (CBS, 2020). These costs are not expected to develop in significant matter, as it is expected that the natural gas demand is starting to decline significantly from 2030 on wards (PWC, 2021). Even though the tariffs in for gas network use are expected to decrease, the number of users of the gas network also decreases, therefore the costs per unit are expected to stay relatively constant, with a slight cost increase of 0.1% annually up to 2050 (PWC, 2021).

2.4.2 Electricity value chain

A means of decarbonizing the industrial sector is by electrification. In the industry that is the case for power to heat or power to gas. In order to sustain the industrial energy demand, large amounts of electrical power are needed in order to fulfill the current fossil industrial energy demand (Bühler et al., 2019). Combined with an increasing share of renewable energy in the electricity mix, this poses some challenges in production, transmission, distribution and perhaps storage of electricity in the future or congestion management. The electricity value chain is split into the aforementioned sections, production, distribution, transmission and storage/balancing. A schematic for the Dutch electricity supply chain can be found in Figure 25.

Electricity production comes in many shapes and ways. Renewable technologies such as wind, solar and geothermal energy or more conventional technologies relying on fossil fuels with optional carbon capture and storage (Tichler, Böhm, Zauner, Goers, & Kroon, 2018). Renewable energy technologies often have a high capital cost compared to marginal costs of operation and therefore they push down the electricity prices, when following the dispatch of merit order curves that are used at the electricity wholesale market. The rapid decline of production cost of renewable wind energy is, averaged over on- and offshore wind, slowly stagnating and amounts to 26-54 USD/MWh levelized cost (Ray & Douglas, 2020). For solar generation, this cost range from 31-42 USD/MWh (Ray & Douglas, 2020). The development of these costs since 2019

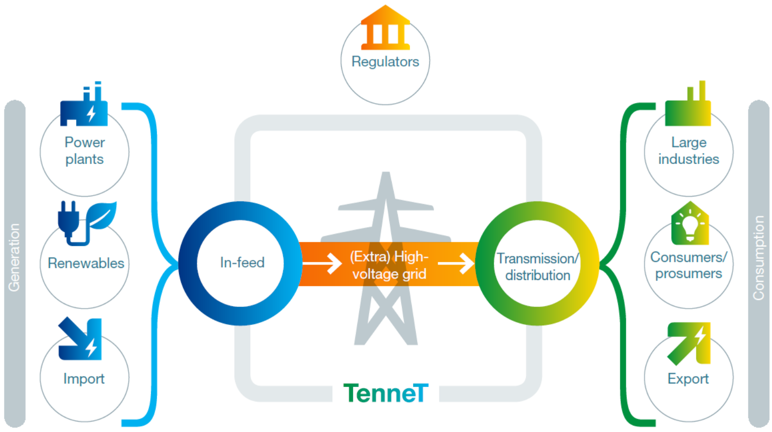


Figure 25: Dutch electricity supply chain schematic (*Investeringsplan*, 2020)

can be seen in Figure 26.

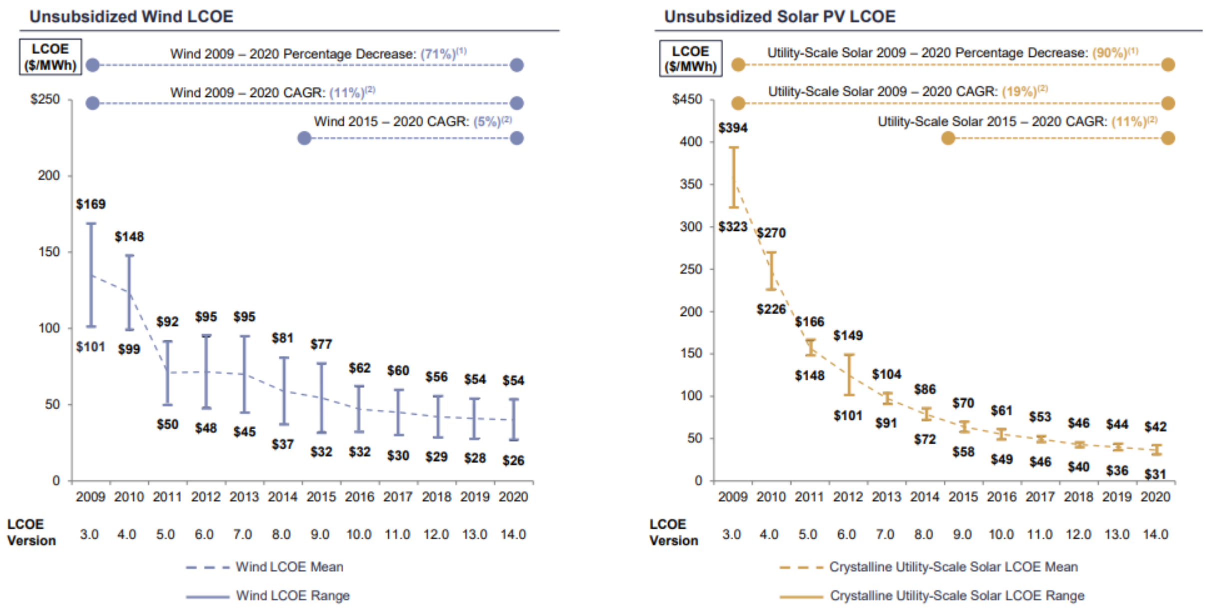


Figure 26: Electricity production costs forecast(Ray & Douglas, 2020)

However, fossil fired technology has a large benefit over renewable energy, and that is being able to meet demand with supply of energy, whilst renewable energy generation is highly intermittent and can hardly be influenced (van Cappellen, Croezen, & Rooijers, 2018). Therefore, contemporary solutions are fossil fired back-up generators. Overall costs for electricity production from fossil fuels are mostly fuel driven. With a fuel efficiency of around 60% for NG fired turbines, it would require around 1.6 MWh natural gas per MWh electricity(Wojcik & Wang, 2018). Peak generation is more expensive, with lower efficiency. Coal plants are being closed in The Netherlands and are not used in future energy scenarios. In the near future, when the share of renewables becomes increasingly larger, it is no longer financially attainable to turn off large power plants - coal/nuclear - and then congestion management is battled by wasting electrical energy from renewable sources. What most probably is required here, is large scale storage of energy to cope with the intermittency of the supply and demand (van Cappellen et al., 2018).

Transmission of electricity in the Netherlands is the responsibility of Tennet, the Transmission System Operator. Transmission trough high voltage grids are prone to congestion with an increasing electricity generation portfolio. Due to high intermittency of renewables, the peak load that the transmission network needs to be able to withstand to avoid congestion are extremely high and require substantial investments towards a renewable fueled future (Fürsch et al., 2013). The construction of new transmission grids or extensions of transmission grids is proceeding rather slowly. For a least-cost optimized approach for an integrated European network, around 76% of HV network, 228,00 km, needs to be built to connect various favourable RES-generation locations (Fürsch et al., 2013). The study performed by (Fürsch et al., 2013) aims for 80% RES in the electricity mix, which aligns with the Dutch goals that have been set for 2050. Optimal development of grid capacity will result in lower amounts of generation and lower curtailment of renewables as well. A sub-optimal scenario, which is currently plays out, will result in roughly half of the transmission development and will require more installed capacity. For the Netherlands, likewise scenarios have been studied by (ECN, 2017). For optimal development of the Dutch electricity networks, and to reach 85% renewable electricity, the optimal least-cost solution is a cross-border European effort. That amounts to an increase of transmission capacity of 62 GW to 121 GW in 2030 and up to 241 in 2040. For the Netherlands, respectively 11 and 33 GW increased interconnected capacity. These methods imply that cross border energy exchange is the main tool for demand response in the future to provide the flexibility needs. However, power curtailment and substantial investment in the grids are unavoidable (ECN, 2017). The required investment in the power system for the Netherlands in the optimal scenario amount to 4.45 billion Euros, and around €6.35 billion in the sub-optimal scenario. Today, around 20% of the total electricity price is allocated to transmission and distribution costs. In 2020 the cost of T&D tariffs were €11/MWh (StatLine, 2020). The required investment of 4.45B euros in the optimal scenario come down to annual investment costs of €153 million for an added interconnection transmission capacity of 1.138 GW. This causes an increase in annual capacity of 11.65 TWh based on 8760 hours of availability.

Distribution of electricity in the Netherlands is the responsibility the DSOs - the distribution system operators that operate regionally in the Netherlands. The DSO's and TSO investments are, on top of the €2billion that is invested yearly (PWC, 2021), an added 2-5% annually up to 2030, and around 5-7% annually from 2030 to 2050 (ECN, 2017). Flexilibity-based measures can reduce that number by 30-50% in the best case for. (PWC, 2021) have calculated that around €100 billion investment is required, that amounts to around a cumulative of €30 billion additional investment by TSO and DSO. This development can be seen in Figure 27. The expected increase in network tariff costs is 3% annually in the short term and a total increase of 54% up to €16.94/MWh in 2050, for with low interest and inflation (PWC, 2021).

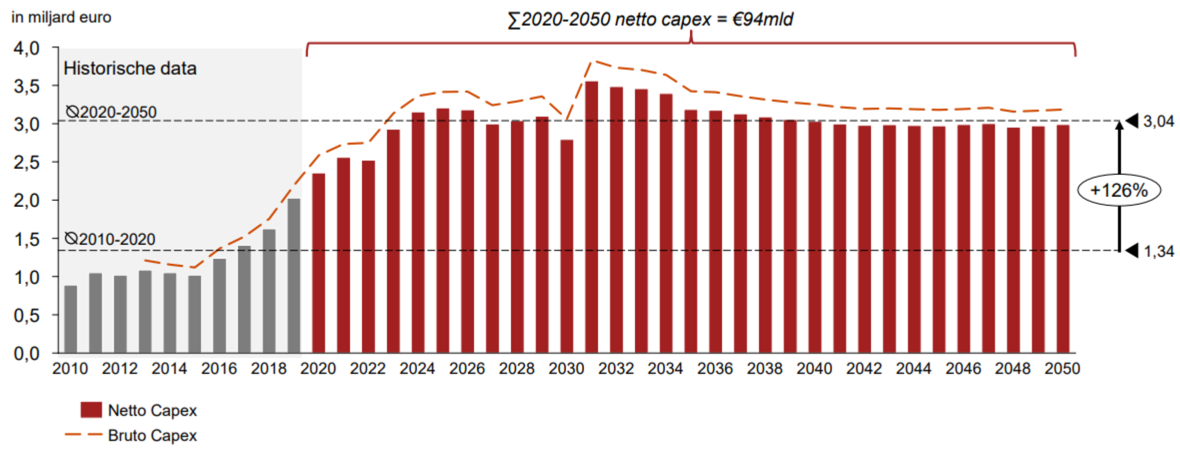


Figure 27: Overview of annual investments by TSO and DSOs in the Netherlands towards 2050 (PWC, 2021)

In the case of optimal interconnection, the demand and supply response mechanisms make large scale electricity storage virtually redundant due to the high costs of energy storage in batteries (ECN, 2017; PWC, 2021). High intermittency is expected to be absorbed by creation of hydrogen and EV-fleet grid interaction.

2.4.3 Hydrogen value chain

This section aims to inform on the hydrogen supply chain for the Netherlands towards 2050. Hydrogen production, storage and distribution from centralized locations and or hydrogen hubs are covered. Decentralized hydrogen production is not considered.

As previously mentioned, around 10% of the total Dutch natural gas use goes to production of hydrogen and this figure is expected to grow towards the future. Hydrogen production for the future energy supply system in the Netherlands can be split threefold: blue hydrogen, green hydrogen and imported hydrogen (Hers et al., 2018). Grey hydrogen is left out as there are no decentralized grey hydrogen production plans for the Netherlands. The already existing hydrogen so called "merchant" production is blue hydrogen. The production of hydrogen is planned with ATR plants with CCS for fossil based and green hydrogen production is based on local electrolysis or imported green hydrogen. The production costs for fossil fueled hydrogen are highly dependent on the natural gas price. Production costs of fossil fueled hydrogen and the correlation between fuel cost and production cost are found in Figure 28. The same correlation between green hydrogen and electricity price can be found in Figure 29.

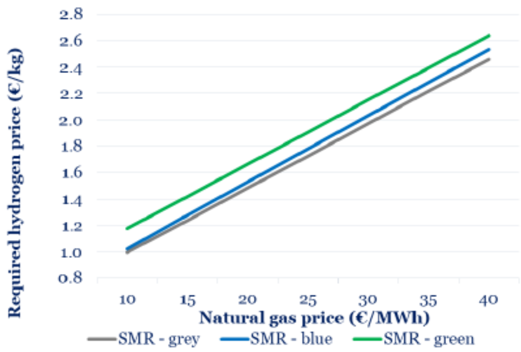


Figure 28: Correlation between natural gas prices and grey or blue hydrogen(Mulder et al., 2019)

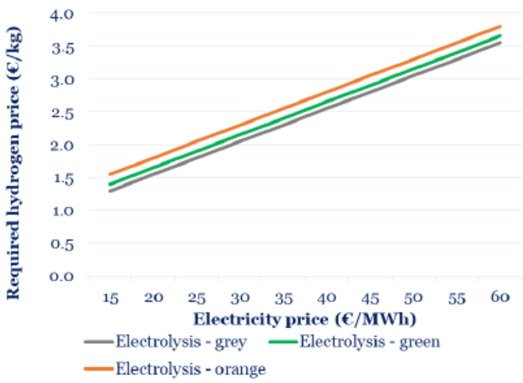


Figure 29: Correlation between electricity prices and grey or blue hydrogen(Mulder et al., 2019)

Transportation of hydrogen can take place in several ways. Through the current natural gas grid with minor additions in pipelining, as proposed by GasUnie and TenneT, creating the "hydrogen backbone" of the Netherlands. This project proposal is known as HyWay 27 and will connect the industrial clusters that are spread across the Netherlands, storage facilities of H2 as well as interconnect with neighbouring countries. Around 85% of the 2030 hydrogen infrastructure will be existing natural gas pipelines. This can be seen in Figure 30. Hydrogen transportation by truck does not benefit from an increased demand as hydrogen transportation by pipelines does and therefore in an attempt to decarbonize industry pipeline transport is the main point of interest (Reuß et al., 2017). The cost of hydrogen transportation is based on the cost of the pipelines and compression, both CAPEX and OPEX. The CAPEX & OPEX of the first are depending on the dimensions of the pipelines yearly maintenance on the pipelines. The latter its costs are based on the compressor stations and equipment as well as the required energy for compressing the hydrogen through the pipelines, much like the current situation with the gas infrastructure(ENTSOG, 2020). The costs of such an infrastructure are found in (ENTSOG, 2020). Based on 100% new infrastructure that needs to be built, the levelised cost of transport are €0.16-€0.23 per kg/1000 km of pipeline. For a 100% retrofit the estimated costs are €0.07-€0.15 per kg/1000 km of pipeline.The Dutch 85% retrofit would amount to €0.08 - €0.16

Figure 30: Schematic depiction of Dutch HyWay 27 project for hydrogen interconnection based on existing natural gas pipelines(Gasunie, 2020)

per kg/1000km, or €2.66-€5.33 per MWh/1000 km(ENTSOG, 2020).

Hydrogen storage in the Netherlands can be performed by storing hydrogen underground in empty salt caverns or in depleted natural gas fields (Mulder et al., 2019). Storage in depleted natural gas feed would require additional investment to prevent sulfur contamination and therefore salt cavern storage is the preferred method (H-Vision, 2019). The amount of storage that is required is based on the need of flexibility in the system. In this case, a 50/50 flexibility between storage and production flexibility is assumed, which leads to the necessity of 3 to 9 storage caverns for hydrogen in 2030 (Soest & Warmenhoven, 2019). The Netherlands aims at storage in salt caverns, and the estimated CAPEX are around 150-160 M€, with an additional 35M€ per cavern. O&M costs are around 7M€ per year, whilst adding a single cavern for more storage capacity would add 2-3% to the fixed O&M costs. These numbers are based on a storage cavern with 600,000 m3 capacity, which equals around 351,000 MWh of hydrogen annually with a maximum withdrawal capacity of 18,000 MWh/day (H-Vision, 2019).

Concluding, the realisation of a hydrogen backbone in the Netherlands, with pipeline transmission based on the current natural gas grid and hydrogen storage in underground natural gas caverns, at least €1.5 billion is needed to ready the backbone and storage for a maximum industry demand of 325 PJ of hydrogen per year in 2050

2.4.4 Coal value chain

The supply chain for hard coal of the Netherlands is less complicated as it is for natural gas, electricity or hydrogen as there is no wholesale market but a more direct business to consumer structure. The coal value chain is split in mining and production, transmission and distribution. The Colombian production and shipping is considered for evaluation of the total chain, due to the agreements made in the coal covenant of Dutch businesses, known as Bettercoal ("Dutch Coal Covenant 2020", 2019).

Coal production and mining are within a tight range in Colombia, ranging from 22-24 US dollars per tonne of coal in 2005 USD. Coal transmission and distribution is often an combination of rail transport of coal and water transport of large quantities of coal. Typically, the coal mining and/or production facility is directly connected by railway to a shipping port. The inland coal transporting via mine is only a small part of the final coal cost per tonne. The cost of railing between 80-3000 km ranges from $2-14 2005(!) in the most expensive case, but averaging 2.5-7.2 US dollar per tonne of coal. The cost goes up if the railing distance approaches the upper limit. Over time, the cost of railing coal does not fluctuate significantly.

Total breakdown can be seen in Table 1.

Table 1: Cost fractions of coal production, transportation and distribution transformed to 2021€ (Baruya, 2007)

Coal price and cost components						
	Production	Transport	Freight	Import tariff	Distribution	Total
Cost fraction	38%	15%	26%	6%	15%	100%
2021 €/t	€ 29.84	€ 11.48	€ 20.66	€ 4.59	€ 11.48	€ 78.03
€/MWh	€ 3.67	€ 1.41	€ 2.54	€ 0.56	€ 1.41	€ 9.59

2.5 Cost modelling theory

Total cost modelling of a value chain can be done in several ways with different outcomes all together. The purpose of this research is development of a model that will determine a competitive market price for green hydrogen. First several modelling options are introduced. Second, the pro's and cons of each of these methods are addressed in the following order: energy systems analysis, Levelized cost of energy and last cost-benefit analysis and supply chain costing.

To determine operational cost through the value chain, the supply chain can be analyzed. An analysis of supply chain costs (SCC) will determine how the cost of the end use of a product is built up throughout various stages of supply (Pettersson & Segerstedt, 2013). The green hydrogen alternatives have comparable supply chains, therefore an approach as chosen by (Wu & Smith, 1995) is preferred. A SCC-model has been constructed that determined 5 general phases in the SC that are equal for various processes. The outcome of a SCC-model can build up the total operational cost (OPEX) for a green hydrogen alternative. However, not just OPEX needs to be considered in order to find a market price in a given scenario. Capital investments (CAPEX) need to be considered too. A popular method for a total cost of electricity or energy is found in the levelized cost of energy (LCOE) method. LCOE is used to asses energy generation cost for various energy technologies (Hansen, 2019). The LCOE often is used as a policy or decision making instrument and can be found in determining for example future hydrogen prices (Hansen, 2019; D. H. Lee, 2016). An improved LCOE method is found in (Hansen, 2019). The use of a cost-benefit analysis with LCOE as seen in (D. H. Lee, 2016).

Another way of determining cost in an energy system is the energy system analysis (ESA). This method applies a complete energy system analysis to cover the direct and indirect energy system dynamics. For example, additional demand in the heating sector also affects the leftover capacity in electricity sector. Also included in ESA are CO2 costs, fuel costs, investments and O&M (Hansen, 2019).

When looking at the abatement of CO2, the marginal abatement cost (MAC) also could play a role in decision making for investing in less carbon intensive technologies and fuels (Baker, Clarke, & Shittu, 2008; Vogt-Schilb & Hallegatte, 2014)

A cost benefit analysis together with LCOE is also an option to consider when finding cost competitiveness for new technologies. When will the investment decision be made and how do we make use of possible return on investment (D. H. Lee, 2016). Establishing a minimum acceptable rate of return (D. H. Lee, 2016) and modelling towards the future may prove that the investment in low carbon options is worth while earlier on than expected.

It is desirable to define a modelling approach in the thesis proposal. Therefore, the most common approaches are judged on their strengths and weaknesses for application in this thesis project.

2.5.1 Modelling options comparison

An energy system is a system with all components and aspects that are related to energy production, energy conversion, energy delivery and energy end use. Energy economics also includes energy markets and thus combines the technical and economical system . The previously mentioned ESA, LCOE, CBA and SCC will be discussed.

Energy Systems Analysis

ESA is a method to analyze an entire energy system, not focusing too much on individual technologies within the system itself. It is a thorough modeling method for complex energy systems, usually based on pre-developed energy systems analysis tools or software. The required data input depends on the chosen software. The output can vary from relative simple electricity focused energy cost and consumption development to spot market predictions where supply and demand are matched (Hansen, 2019).

Several studies for European energy forecasts have been made by using different ESA modeling tools. These take into account a wide range of data sources, from GDP growth, to population growth, emission trading systems and compare the interaction in between various energy technologies within these systems (Höglund-Isaksson et al., 2012; Simoes, Nijs, Ruiz, Sgobbi, & Thiel, 2017). Various input scenarios and models - PRIMES, GAINS, CAPRI - have been made use of to provide insights in possible development future emissions and cost for different sectors, following specific policy outlines.

When summarizing the ESA approach, it can be said that for clear perspective on energy system (cost) development for different technologies this method is highly valuable. The interaction between technologies, daily/hourly price volatility input across several commodities and supply and demand interaction provide a detailed prediction. However, the high amount of data that is needed to model future scenarios in such detail is a slight drawback, as is the variance in output depending on whose pre-developed modeling tool is used. It is a recommendable method when modeling for policy creation for GHG emission reduction on an (inter)national level.

Levelized Cost of Energy

LCOE is considered a cost metric that can compare different parts of energy systems that have unequal characteristics, such as different capital cost, efficiencies, lifetime and capital and operational cost (CAPEX & OPEX) (Berrada & Loudiyi, 2019). It is a widely used metric for investment decisions and policy creation, showing the economic potential of these technologies compared to each other. The LCOE combines all lifetime costs of a specific part of an energy system: operation and maintenance, construction, taxes, insurances and divides this by the lifetime energy generation (Dincer & Abu-Rayash, 2020).

However, the LCOE method has some drawbacks as well. It will tend to understate changes in the energy system that is investigated, for example changes that are made due to transmission capacity (Moore, 2016). When taking a highly critical look on the LCOE, there are some points that stand out. Discount rates are hard to determine in financial analyses, thus also in LCOE calculations (Aldersey-Williams & Rubert, 2019). The discount rates for different technologies may vary, whether or not to include taxes. When being careful in finding discount rates, the most risk abating rate is often chosen, which in turn favours current low-risk technologies that are proven in practice already (Manzhos, 2013). Inflation rates are normally not taken into account in LCOE calculations (Aldersey-Williams & Rubert, 2019). These can be accounted for, combined with a correct choosing of discounting rate and more intensive calculations. However, inflation incorporation can also cause divergent results due to differences in LCOE build up, mostly CAPEX or OPEX (Sklar-Chik, Brent, & de Kock, 2016). There is also an uncertainty in future costs for non-renewable energy sources. Renewable energy generation cost is build up of are mostly CAPEX. The non-renewable - for example CCGT plants - energy sources its cost are dominated by fuel costs, or OPEX. These vary towards the future and this uncertainty can create wrong values of LCOE. When using probabilistic analysis on fuel cost volatility can offers a tool to tackle this problem (Aldersey-Williams & Rubert, 2019). If energy scenarios from for example the Dutch Government IRENA, IEA or DNV are used, these uncertainties are accounted for.

Whens summarizing, the LCOE is considered a highly informative metric for comparative economics of energy generation alternatives. Despite the shortcomings that are previously mentioned, its use is widespread and widely understood and straightforward (Aldersey-Williams & Rubert, 2019).

Cost-Benefit Analysis

A Cost-benefit Analysis (CBA) can be explained as a method to estimate all costs that are involved in business opportunities and the possible profits that can be made on the same project (D. H. Lee, 2016). A CBA takes into account quantitative as well as the qualitative aspects of particular projects or business opportunities. All costs and benefits that can be listed are monetized as far as possible and then are adjusted in time through e.g. NPV to be able to correctly conduct the analysis (D. H. Lee, 2016).

CBA has been used and a framework for renewable technology assessment has been set up by the EU Commission JRC to conduct such a research(Giordano, Onyeji, Fulli, Sánchez Jiménez, & Filiou, 2012). Guidelines on how to monetize benefits, qualitative and quantitative and how to handle with beneficiaries are presented.

Most research focuses on cost effectiveness rather than costs and benefits. When using a CBA for evaluation of economic feasibility of a possible alternative to green hydrogen, detailed cash flows, the costs and benefits, need to be estimated and will be based on assumptions (D. H. Lee, 2016).

In summary, a CBA is a valuable tool to determine investment options and to predict the right moment for investment in new technologies. However, for estimating cost development of green hydrogen alternatives towards 2050, a CBA on its own is not the correct tool for this research. This research will be mostly quantitative whilst a CBA requires qualitative impact analysis as well to come up with an overall assessment (Giordano et al., 2012). Equally important for a CBA are the discounting methods that are mentioned for the LCOE in order to determine a correct NPV of the costs and benefits.

Supply Chain Costing

Supply chain costing (SCC) provides a tool to model how the total costs of an end product are built up through various stages in the product supply chain. When modelling a supply or value chain, the cost from source to end product are accounted for. Use of end product is not considered (Wu & Smith, 1995). When creating an SCC model, the built of of cost throughout the chain can be characterised in several generic steps: material, labor, logistics, inventory holding/storage and overhead cost. (Wu & Smith, 1995). In order to understand and properly analyse a supply chain a foundation needs to be established in understanding (Wu & Smith, 1995):

- Incidence of costs throughout the various supply chains.
- Underlying cost drivers, e.g. what is it that makes the costs fluctuate in different stages.
- The impact of cost trade-offs, if any.

Summarizing, the SCC method is particularly useful when looking at and comparing different supply chains of products that have different sources but have overlapping end-uses. Generalizing different steps in the value chain to "standardize" the different chains can be useful in comparing the cost development. However, on a standalone basis, a SCC method does not prove sufficient in the scope of this research. It only takes into account the development of source material cost towards the end use, the development of the fuel costs. Therefore a complementation on needs to be made to calculate integrated costs of the entire supply chain as well as the use of the commodities.

3 Methodology

This section aims to describe the methodology that has been followed in creating the levelized costs of energy model. As already mentioned in the research approach and outline in Section 1.2, the focus of this thesis project lies in literature findings combined with cost modelling theory. In this chapter, first the system boundaries and scope are presented, secondly the modelling approach is explained and finally the cost model and the implemented assumptions are corroborated.

3.1 System boundaries and system design

After identifying the alternatives for processes with potential green hydrogen demand, the next step in this research is identifying the value chains that make up the total cost of the alternatives and to set constraints on system boundaries to make clear what is in and out of scope when conducting this research project. A graphical representation of the research scope and boundaries can be seen in Figure 31. In order to create such a flow chart, the preliminary literature review results are used to create Figure 31.

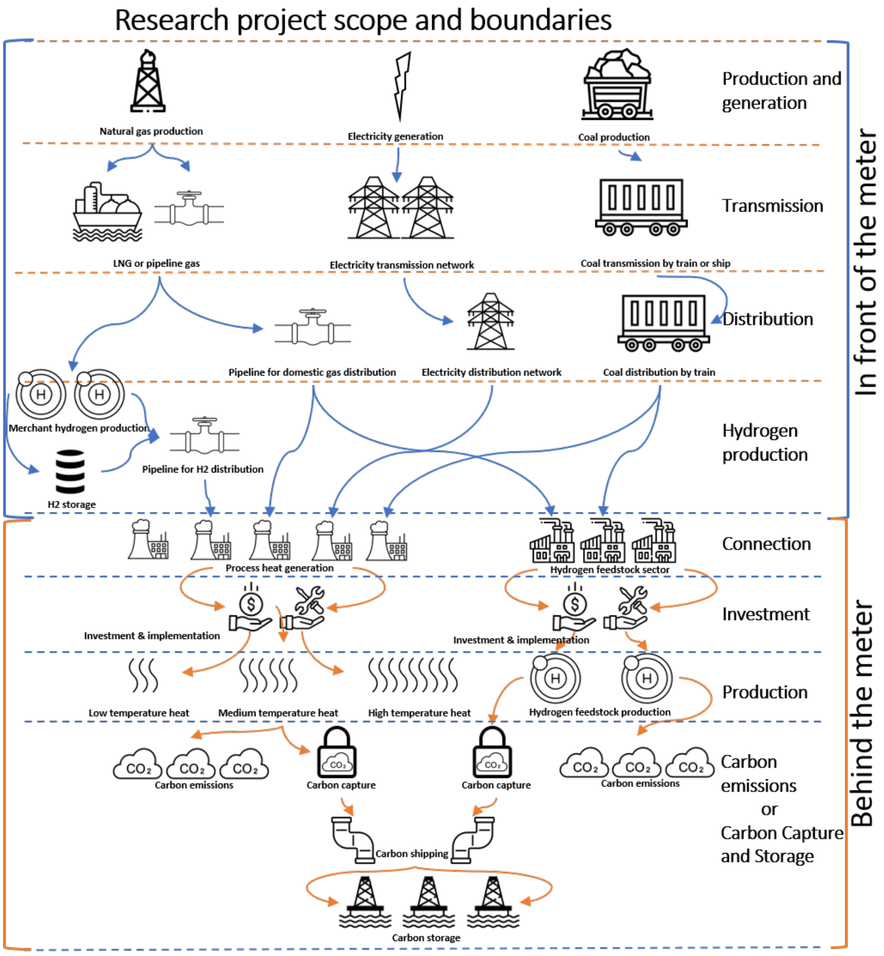


Figure 31: Overview of green hydrogen and its alternatives value chains combined from (Robles et al., 2018; Stockford et al., 2015; Khalilpour, 2018)

3.2 Method and approach

To compare economic competitiveness between different fuels and feedstocks, is is important that a definition of what this economic competitiveness is needs to be provided, followed by how this economic competitiveness is going to be used.

3.2.1 Economic competitiveness

This subsection aims to provide the reader with a definition of economic competitiveness that is used throughout the research paper.

In the context of this research, the economic competitiveness is based mainly on the concept of cost competitiveness. That means, that the lowest priced green hydrogen alternative has the highest competitiveness when used in a comparable way: the conversion of different commodities into process heat or hydrogen feedstocks, both expressed by their energetic content in MWh. The altered levelized cost of energy includes CO2 costs, economic growth, learning effects, economies of scale and carbon capture and storage costs on top of the standard LCOE. More on the costing approach follows in the next sections. This is accounted for within an investment lifetime of 25 years, studied on four different investment moments: 2021, 2025, 2030 and 2035.

To combine the aforementioned paragraphs of Section 3.2, a definition for the economic competitiveness in context of this research project is given:

The economic competitiveness is the competitiveness of demand side altered levelized costs of energy of green hydrogen alternatives' value chains for the Dutch process industry, based on the costs of installation and use of the alternatives as a fuel substitute in process heat generation or as an alternative means of producing hydrogen feedstock across different sectors in the Dutch industry.

3.2.2 Altered levelized costs of energy

This subsection describes the alterations that have been made based on several recommendations from prior research into the standard levelized costs of energy when expressing and/or comparing costs of both fossil and renewable fuels.

Generally, the LCOE is widely used when comparing different electricity or heat generation options to provide an overview of the expected costs and benefits of the different studied options (Dincer & Abu-Rayash, 2020). Based on the standard LCOE, policy decisions or business investments are made (Nissen & Harfst, 2019). However, as briefly mentioned in Section 2.5, there are shortcomings in literature that require slight alterations to the standard LCOE. The shortcomings mentioned as well as other additions are addressed in creating the new LCOE are listed below:

An often named shortcoming of the LCOE is unrealistic discount rates that are used for assessing business investments (Aldersey-Williams & Rubert, 2019). Discount rates that are commonplace in business investment assessments, that include risk premiums and a correction for inflation, have been implemented here.

CO2 costs are not accounted for in standard LCOE, which means that the standard method favours fossil fuels over renewable or cleaner technologies (Loewen, 2019). The inclusion of CO2 costs aims to improve this assessment.

Fluctuating commodity prices over the full lifetime of an investment is often not considered in LCOE (Nissen & Harfst, 2019). By including a commodity price forecast this addition aims to address the issue.

Learning rates and economies of scale can have high impact on the costs of CAPEX or the efficiency of new installed equipment (Sklar-Chik et al., 2016). To implement this recommendation, an attempt to account for this effects is made by including learning rates and economies of scale effects on CAPEX. Maturing of technology on not yet widespread used equipment has been implemented as well.

Strictly demand side costs are

LCOE is often used for generation of electricity or heat and includes potential revenues as well. In this context LCOE has been restricted to demand side costs without revenues, accounting for a more comparable description of the different assessed green hydrogen alternatives.

The above-mentioned changes to the standard levelized cost; learning rates, efficiency improvement, scaling of CAPEX, economies of scale effects and CO2 costs are included in the standardized LCOE, as shown in Equation 2 in Section 3.3 and explained more in detail in Section 2.5 .

$$LCOE_{nergy} = \frac{CAPEX_t + \sum_t (FIXOM_t + VAROM_t + FUEL_t + DECOMM_t + CO2_t) \times (1+r)^{-t}}{\sum_t Energy\ consumed \times (1+r)^{-t}} \tag{1}$$

with

r is discount rate

t is time in years

3.2.3 Approach

The chosen costing approach for this thesis project is a combination of supply chain costing and LCOE. Where the commodity costs development can be covered by the supply chain modeling, the capital investment, payback times, taxes or levies, depreciation incentives and others can be provided by using LCOE as a final evaluation method for cost development of green hydrogen alternatives. The final outcome will be a merit order that will reveal the maximum cost for green hydrogen based on the alternatives that are available.

The method that is used to model the total cost of a value chain to find a competitive price for green hydrogen from 2021 towards 2050 needs a theoretical base to work. The information gathering part on the different value chains and their cost development, combined with the designing of a total cost model, means that this is both an exploratory and design oriented research problem (Verschuren, 2010). A model of the value chain cost development for green hydrogen alternatives will be developed and this model will be tested and validated through information from companies and experts within the industry and comparing it with existing literature. Scenarios for 2021, 2025, 2030 and 2035 as well as a timespan of 2021-2050 will be used as input for the modelling.

The price bandwidth of green hydrogen in the Dutch industry to be competitive is set by its alternatives that have the lowest cost in terms of fuel supply and operation/implementation. A merit order visualisation of the alternatives cost and volumes needed across the different sectors will show what the cost of green hydrogen may be for the industrial sectors. These merit orders are constructed for 2021, 2025, 2030 and 2035 with a lifetime of 25 years each, as well as a scenario that looks at the costs combined with business as usual between 2021 and 2050 for each of these mentioned investment moments. This is to show the development of the prices and create insights in when it is the most economic moment for reducing carbon emissions for the Dutch process industry.

The prices of alternatives are strictly based on the demand side, which implies that hydrogen production or profits from by products are not taken into account. The cost competitiveness of the alternatives is based on the value chain, from commodity production and shipping to final use in the industrial processes. This value chain is split in two sections; "in front of the meter" and "behind the meter" with the merit orders as a final way of comparison.

Costs "In front of the meter"

The costs in front of the meter are found by analyzing the alternatives' supply chains from the initial production of an energy carrier towards the final user. In these supply chains, several stages are distinguished: production, transmission, distribution, storage and conversion. Combined with the predicted commodity market prices towards 2050, the cost fractions of each of these stages is highlighted. It is expected that each of these stages has its own development in terms of cost. By representing these stages as different price fractions, the share of each cost fraction towards 2050 can be displayed.

Costs "Behind the meter"

The costs behind the meter are the total implementation and operational costs in these processes. To switch from current processes to alternatives requires capital investments and comes with additional operational costs, e.g. more expensive fuel or additional electricity/heat consumption for CCS.

The costs behind the meter are expressed as an altered levelized cost of energy, respectively heat and hydrogen. Different alternatives and their costs are considered for the industrial processes, starting with business as usual, CCS combined with business as usual, electrification and the use hydrogen - grey and blue. Capital investments to be considered here range from retrofitting CCS equipment, to placing hydrogen boilers and connection costs to the high voltage electricity grid for large industrial energy demands. The operational cost will be fuel costs, fixed and variable operational cost, C02 prices and CCS costs.

Merit order

A final comparison of the alternatives' cost will identify in which processes in the Dutch industry green hydrogen will be considered as a competitive option in terms of LCOE. The competitiveness follows from the merit order effect, in which the demand combined with alternatives prices is presented as the "supply side" of the merit order and the projected levelized cost of green hydrogen will function as the "demand side" of the merit order. The intersection of these two will define the price, and the area above will show where the cost of the expected costs of alternatives are higher than the expected costs of green hydrogen. The area below the intersection will be the area that is not competitive yet. An example of this is shown in Figure 32

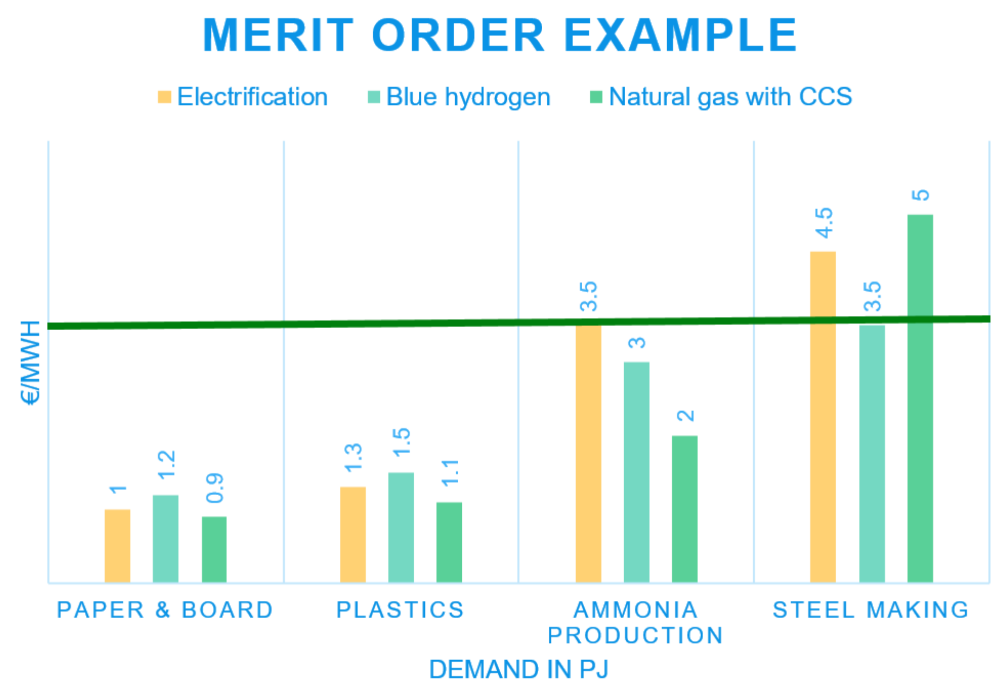


Figure 32: Merit order example with dummy figures, showing different alternatives costs and a green line that represents the green hydrogen price

3.3 Cost model

In this section, the elements that comprise the costs before and behind the meter will be provided. First the models' foundation is explained. Then the process heat generation and its alternatives costs are presented followed by hydrogen feedstock and its alternatives are costs.

3.3.1 Model foundation

The cost model is created with Microsoft Excel. The supply chain cost model is based on supply chain costing principle (Wu & Smith, 1995; Pettersson & Segerstedt, 2013) and a combination of available business data and work on development for the various SC stages in the value chains. The improved levelized cost of heat and hydrogen are based on (Reuß et al., 2017; Nian, Sun, Ma, & Li, 2016b; Kost, Shammugam, Jülch, Nguyen, & Schlegl, 2018; Hallam & Contreras, 2015; Hansen, 2019; Keys et al., 2019) and can be seen in Equation 2

$$LCOE_{nergy} = \frac{CAPEX_t + \sum_t (FIXOM_t + VAROM_t + FUEL_t + DECOMM_t + C02_t) \times (1+r)^{-t}}{\sum_t Energy\ consumed \times (1+r)^{-t}} \quad (2)$$

This LCOE is built from the following components:

- Capital investments for using a specific technology or retrofitting.
- Annual fixed operations and maintenance cost. This is set at a fixed 2-3% of the initial CAPEX, depending on technology used (Nian, Sun, Ma, & Li, 2016a; Kost et al., 2018).
- Variable operating costs are secondary costs that are dependent on the process and used technology, e.g. electricity consumption of carbon capture installations.
- Fuel costs are the costs before the meter of the main fuel that is used in.
- CO2 costs are the prices for emitting one tonne of CO2.
- Decommissioning costs are costs for dismantling the technology and are fixed at 10% of the initial investments (Nian et al., 2016a).
- Discount rate r, consisting of inflation correction, risk premium and opportonity costs of capital.
- Total cumulative of energy consumed over the entire lifetime t.

It is important to note that the final prices are in 2021 € per MWh of energy and the projected demand for the different processes is given in PJ. A list of assumption that were necessary to create this cost model is presented in Section 3.5.

Starting of with the capital investments. The required installed capacity for a process depends on the costs per MW of the used equipment and the development of technology that can improve energetic efficiency. The required installed capacity calculation is found in 3

$$Q_{required} = Demand_t \cdot \eta_{equipment_t} \quad (3)$$

where,

Q is required capacity in MW,

$\eta_{equipment_t} = \eta_{equipment_{t0}} \cdot (1-r)^t$,

η is efficiency,

r is rate of annual technological improvement in %,

$t_0 = 2021$

t_i is year of investment

A combination of economies of scales and reductions on cost from technological improvements - respectively affect capital investments and efficiency improvements - is essential to investigating the development of costs with different investment moments spread throughout time (Festel, Würmseher, Rammer, Boles, & Bellof, 2014). Learning effects are simulating the effect of economies of scale in not yet widespread technologies and are implemented in the initial CAPEX, as seen in Equation 4. As the cumulative use of a certain technology increases over time, this increase in deployed capacity is accompanied by a decrease in capital investments (McDonald & Schrattenholzer, 2001; Mcdonald & Schrattenholzer, 2002). It is to be noted that not only the capital investments benefit from learning rates of technology. The operational cost are subject to efficiency improvements and variability of fuel costs (Laude, 2010)

$$CAPEX_{learn_t} = CAPEX_{t_0} \cdot LR_t \tag{4}$$

where

where $LR_t = (1 - Learning\ rate)^{t_i - t_0}$ with Learning rate = 1% up to 2030

$t = t_i - t_0$

$t_0 = 2021$

t_i is year of investment

Learning curves for (new) energy technologies show average learning curves of 8-9% in the long run towards 2050 (Kost et al., 2018; Tichler et al., 2018; Rubin, Azevedo, Jaramillo, & Yeh, 2015). Expected cost development from (Kost et al., 2018) combined with the average learning rates show an annual decrease in capital investment cost of 1.6%. Note: for mature technologies there is no learning curve effect on capital investments. A more conservative fixed rate of 1% is taken for discrepancy. Annual energy efficiency improvement as a result from learning are thus also important to take into account. In recent years, annual energy intensity - units of energy per unit GDP - have globally declined by 1.4-1.8% (*Energy Efficiency 2020 – Analysis - IEA*, n.d.). To keep a balance between demand growth and increased efficiency, the annual energy efficiency improvement on fuel consumption is set at a fixed 0.75% up to 2050.

The total sum of the capital investments are susceptible to inverse scaling effects, that is, a decrease in specific investment cost when a system scales up and an increase of specific investment cost when a system scales down, compared to the chosen standard investments (Blok, 2020). This is shown in Equation 5

$$Invest_{scaled} = Invest_{base} \cdot (\frac{Q_{scaled}}{Q_{base}})^n \tag{5}$$

where

n represents the investment scale factor,

Q_{scaled} is the capacity required of the investment, seen in Euqation 3 as $Q_{required}$

Q_{base} is base capacity,

$Invest_{base}$ is specific investment cost for an installation in €/MW,

The final CAPEX costs are a combination of Equations 3, 4 and 5 which is shown in Equation 6.

$$CAPEX_{total_t} = Invest_{scaled} \cdot LR_t \cdot \tag{6}$$

The net present value of the investments is calculated by using a discount rate r. This rate is set at a fixed 9% for the entire lifetime of equipment. This 9% rate takes into account a risk premium of 3%, inflation correction of 2% and an opportunity cost percentage of 4%. This discount rate is then used to calculate a discount factor, which is shown in 7, from (Giampietro, Guidolin, & Pedio, 2018).

$$Discount\ Factor = \frac{1}{1 \cdot (1 + r)^t} \tag{7}$$

where

t is time in years,

r discount rate

The electricity mix in 2018 was 28% renewable energy and 72% fossil fired, by either natural gas or coal (European Commission, 2018). Aiming for an 85% renewable energy mix in 2050, a linear growth is assumed for the increase of renewable electricity generation in the total electricity generation mix as can be seen in 8.

$$\%_{RES,t} = \%_{RES,2018} + \frac{\%_{RES,2050}}{t} \tag{8}$$

In order to calculate the carbon dioxide emissions that are generated by using various different fuels, the amount of CO2 that is emitted per unit of energy is considered from direct emissions approach. The potential benefits of selling carbon dioxide are not in scope of this research. For specific emissions of electricity generation and fossil fuel emissions, the Dutch list of emissions for electricity is used(*Lijst emissiefactoren — CO2 emissiefactoren*, n.d.). An overview can be seen in Table 2

Table 2: Emissions per fuel type (*Lijst emissiefactoren — CO2 emissiefactoren*, n.d.)

Input:	CO2 emissions	Unit
Electricity:		
- RES	0	g/kWh
- Grid	404	g/kWh
- 15% RES Mix (2021)	71.4	g/kWh
Natural gas	238	g/kWh
Coal	324	g/kWh

The CO2 emissions per process are calculated from the energy demand and corresponding polluting factors minus potential carbon reductions through CCS and are shown per as emissions per MWh.

The calculation efforts for the different processes are split into two main categories: process heat generation and feedstock. Process heat is split in 3 different sub-groups: low temperature heat below 200 degrees C, medium temperature heat between 200 and 600 degrees C and high temperature heat above 600 degrees C. For all assets a lifetime of 25 years is assumed for comparability of investments. Feedstock hydrogen production is a direct utilization of hydrogen, but for comparability also shown in MWh.

The commodity market price and CO2 price forecasts towards 2050 are provided by DNV energy markets modeling department, who use energy price forecasting software PLEXOS to provide fuel and CO2 prices as shown in Section 3.4.1.

3.3.2 Process heat generation costs

The alternatives' cost in process heating are split into three different subcategories. Low temperature heat, below 200 degrees C, medium temperature heat - between 200 and 600 degrees C - and high temperature heat above 600 degrees C. The processes that are investigated differ in the size of their demand per category of heat. Each production process makes use of the same technologies and due to unknown remaining lifetime for existing equipment, all alternative will always require the use of newly installed technology and thus require capital investments. Retrofitting is a possibility, however, the low cost component of capital investment compared to total fuel costs makes retrofitting often negligible in difference with new installations, as well as the unknown of remaining operational lifetime at the point of retrofitting.

Low temperature process heat

The sector of low temperature heat generation involves two industrial sub-processes. Paper production and the low temperature demand for the food processing industry. The low temperature applications both have a relative high demand for installed capacity that exceeds 25 MW. The used base equipment here is a standard boiler on natural gas of 25MW, the electrical boiler and the hydrogen boiler. Post combustion CCS is applied to the natural gas boiler. The specifics of used base investment are shown Tables 4, 5,6.
The total number of options for low temperature heat generation equipment can be found in Appendix 7.

Medium temperature process heat

The medium temperature process heating subcategories are the food industry, the refining industry and the plastics industry. The used machinery here for medium temperatures are an 80 MW electrical steam boilers, a natural gas water tube boiler with and without CCS installation and 80 MW hydrogen steam boilers. Specifics can be found in Tables 4, 5, 6.
The total number of options for medium temperature heat generation equipment can be found in Appendix 7.

High temperature process heat

The high temperature process heat sector encompasses glass production, ceramics and steel production. The used technologies are different from the previous two categories, with (electrical/hydrogen) furnaces instead of steam generators and an addition of coal generated heat is present as well, for steel production. The higher required temperatures and thus lower heating efficiencies are to be noted. Post combustion CCS is applied to the natural gas furnace with CCS. Specifics can be found in Tables 4, 5, 6.

Note: Even though the steel industry currently runs on coal ovens, this is not calculated as an alternative due to the sheer size of demand, 88PJ annually and newly installed coal ovens with CCS not being an option for decarbonising factories with new equipment.
The total number of options for high temperature heat generation equipment can be found in Appendix 7

A special point of interest goes to the additional costs that are attached to electrification of process heat. The costs of creating a high voltage grid connection as well as annual fixed costs per MW of contracted capacity are highly influencing the CAPEX and fixed O&M costs. The costs are shown in Table 3.

Table 3: Costs of creating a connection to high voltage grid and annual costs per MW of contracted capacity

Grid connection costs		
CAPEX [1]	€ 130,000.00	€/MW
FIX OPEX [1]	€ 20,000.00	€/MW

Table 4: Technology and capital and operational cost for natural gas process heating technologies

Process heat generation from natural gas		
Parameter	Costs	Unit
FIX OPEX [2]	2.00%	% of CAPEX
Low temperature process heat		
Natural gas boiler - 25 MW		
CAPEX [3]	€ 9,700.00	€/MW
FIX OPEX [2]	€ 194.00	€/MW
VAR OPEX	-	€/MWh
Energetic efficiency [3]	95%	%
Medium temperature process heat		
Water tube steam boiler		
CAPEX [3]	€ 55,000.00	€/MW
FIX OPEX [2]	€ 1,100.00	€/MW
VAR OPEX	-	€/MWh
Energetic efficiency [3]	95%	%
High temperature process heat		
NG furnace		
CAPEX[3]	€ 1,200,000.00	€/MW
FIX OPEX [2]	€ 24,000.00	€/MW
VAR OPEX	-	€/MWh
Energetic efficiency [3]	85%	%

[1](Sebastiaan Hers, Afman, Cherif, & Rooijers, 2015)
[2](Nian et al., 2016a; Kost et al., 2018)
[3](Rutten, 2019)

Table 5: Technology and capital and operational cost for electrification of process heat

Process heat by electrification		
Parameter	Costs	Unit
FIX OPEX [4]	2%	% of CAPEX
Low temperature process heat		
Electrical boiler		
CAPEX [5]	€ 30,000.00	€/MW
FIX OPEX [4]	€ 600.00	%
VAR OPEX	-	€/MWh
Energetic efficiency [5]	0.99	%
Medium temperature process heat		
80MW Electrical steam boiler		
CAPEX [5]	€ 100,000.00	€/MW
FIX OPEX [4]	€ 2,000.00	€/MW
VAR OPEX	-	€/MWh
Energetic efficiency [5]	95%	%
High temperature process heat		
Electrical furnace		
CAPEX [5]	€ 2,000,000.00	€/MW
FIX OPEX[4]	€ 40,000.00	€/MW
VAR OPEX	-	€/MWh
Energetic efficiency [5]	80%	%

[4](Nian et al., 2016a; Kost et al., 2018)
[5](Wapstra, 2018)

Table 6: Technology and capital and operational cost for hydrogen fueled process heating technologies

Process heat fueled with hydrogen		
Parameter	Variable	Unit
FIX OPEX [6]	2%	% of CAPEX
Low temperature process heat		
H2 boiler- new		
CAPEX [7]	€ 60,000.00	€/MW
FIX OPEX [6]	€ 1,200.00	€/MW
VAR OPEX	-	€/MWh
Efficiency [7]	0.98	%
Medium temperature process heat		
H2 steam boiler- new		
CAPEX [7]	€ 1,000,000.00	€/MW
FIX OPEX [6]	€ 20,000.00	€/MW
VAR OPEX	-	€/MWh
Efficiency [7]	80%	%
High temperature process heat		
Hydrogen furnace - new		
CAPEX [7]	€ 1,200,000.00	€/MW
FIX OPEX [6]	€ 24,000.00	€/MW
VAR OPEX	-	€/MWh
Efficiency [7]	85%	%

[6] (Nian et al., 2016a; Kost et al., 2018)
[7] (Wapstra, 2018)

3.3.3 Feedstock costs

This section provides insight in how the cost forecast for green hydrogen alternatives in hydrogen feedstock production for the Dutch industry is created. The processes that are part of this sector are the ones found in Section 2. For feedstock costs, there are four options discussed: SMR without CCS, SMR with CCS, ATR with CCS and coal gasification with CCS. For each of these processes, the required capital investments are based in newly installed capacity and not on retrofitting current installations, due to unknown lifetimes remaining in the equipment that will be retrofitted. The size of the potential demand for green hydrogen is What distinguishes these production processes. The equipment with their CAPEX, OPEX and efficiencies can be found in Table 7.

Table 7: CAPEX and OPEX for hydrogen production technologies in feedstock use of hydrogen

Feedstock		
FIX OPEX [89]	1.0%	% of CAPEX
VAR OPEX [89]	2.5%	% of CAPEX
SMR- Grey hydrogen		
CAPEX [8]	€ 740,000.00	€/MW
FIX OPEX [89]	€ 7,400.00	€/MW
VAR OPEX [89]	€ 18,500	€/MW
Energetic efficiency [89]	96%	%
SMR- Blue hydrogen		
CAPEX [8]	€ 1,330,000.00	€/MW
FIX OPEX [89]	€ 13,300	€/MW
VAR OPEX [89]	€ 33,250	€/MW
Energetic efficiency [8]	90%	%
ATR - Blue hydrogen		
CAPEX [9]	€ 1,200,000.00	€/MW
FIX OPEX [89]	€ 12,000	€/MW
VAR OPEX [89]	€ 30,000	€/MW
Energetic efficiency [9]	84%	%
Coal gasification - Blue hydrogen		
CAPEX [10]	€ 2,600,000.00	€/MW
FIX OPEX [89]	€ 26,000	€/MW
VAR OPEX [89]	€ 65,000.	€/MW
Energetic efficiency [10]	52%	%

[8] (Janssen, 2018b)
[9] (Janssen, 2019)
[10] (Kaplan, 2020)

3.3.4 Carbon capture and storage costs

Carbon capture and storage is split into three cost components. Capital investments of CCS installation, operational cost of capturing and operational cost of storing carbon emissions. Since the Netherlands plans on industry clusters storing carbon off shore, the investment costs in pipelines or storage caverns are implemented in the operation cost of shipping and storage.

Pre-combustion carbon capture is applied in creating hydrogen feedstock. Creating hydrogen feedstock leaves a high purity hydrogen and CO2 after processing. The capital costs are found to be at 11.2 €/t CO2 captured with fixed operating cost of 5.6 €/t CO2 captured annually and 65 kWh/t CO2 electricity consumption. Energy losses in capturing CO2 are 12.8% (Oliveira & Schure, 2020). The costs and performance are shown in Table 8.

Post-combustion CCS is applied for reducing process heat emissions. For low and medium high temperatures there CO2 concentrations are around 8-10% of CO2 resulting in capital investments of 39 €/t CO2 captured, 18 €/t fixed OPEX and around 185 kWh/t CO2 electricity use. When generating high temperatures, the CO2 concentrations are lower, resulting higher costs of carbon capturing installations of 45 €/t CAPEX and 19€/t fixed OPEX with 183 kWh/t CO2 captured, with capturing 80-85% of CO2. Energy losses in capturing CO2 are 12.8% as well (Oliveira & Schure, 2020). The costs and performance are shown in Table 9.

Table 8: Pre-combustion CCS costs per tonne of CO2

Pre combustion SMR		
CAPEX [11]	€ 11.20	€/t CO2
Fixed OM [11]	€ 5.60	€/t CO2/yr
Variable Cost [11]	0.07	MWh/t CO2
Energy loss [11]	13%	%
Capturing efficiency [11]	88%	%
Pre combustion ATR		
CAPEX [11]	€ 11.20	€/t CO2
Fixed OM [11]	€ 5.60	€/t CO2/yr
Variable Cost [11]	0.07	MWh/t CO2
Energy loss [11]	13%	%
Capturing efficiency [11]	92%	%
Coal gasification		
CAPEX [11]	€ 11.20	€/t CO2
Fixed OM [11]	€ 5.60	€/t CO2/yr
Variable Cost [11]	0.07	MWh/t CO2
Energy loss [11]	13%	%
Capturing efficiency [11]	75%	%

[11] (Oliveira & Schure, 2020)

Transporting and storage of CCS in the Netherlands are set at 17e/t and 1 /t of CO2. The costs per tonne CO2 captured are shown in Table 10. The costs of carbon transportation and storage are also subject to the learning and efficiency improvements as mentioned in Section 3.3.1 3.3.1. These numbers are based on an annual capture of 3,000 kt CO2 per year (Roussanaly, Anantharaman, Jordal, Giraldi, & Clapis, 2017).

Table 9: Post-combustion CCS costs per tonne of CO2

Post combustion CCS		
Low temperature		
CAPEX [12]	€ 39.00	€/t CO2
Fixed OM [12]	€ 18.00	€/t CO2/yr
Variable Cost [12]	-0.16	€/t CO2
Energy loss [12]	13%	%
Capturing efficiency [12]	85%	%
Med temperature		
CAPEX [12]	€ 39.00	€/t CO2
Fixed OM [12]	€ 18.00	€/t CO2
Variable Cost [12]	0.16	€/t CO2/yr
Energy loss [12]	13%	%
Capturing efficiency [12]	85%	%
High temperature		
CAPEX [12]	€ 45.00	€/t CO2
Fixed [12]OM	€ 19.00	€/t CO2
Variable Cost [12]	0.18	€/t CO2/yr
Energy loss [12]	13%	%
Capturing efficiency [12]	80%	%

Table 10: Carbon shipping and storage cost per tonne of CO2

CCS shipping and storage cost		
CO2 shipping [13][14]	€ 1.00	€/t CO2
CO2 storage [14]	€ 17.00	€/t CO2

[12] (Oliveira & Schure, 2020)
[13] (Skagestad et al., 2014)
[14] (Roussanaly et al., 2021)

3.3.5 Blue hydrogen cost

The cost of blue hydrogen as a fuel is found by deconstructing the predicted price from (). The energetic efficiency of blue hydrogen production from ATR is 84%, which corresponds to 1.19 MWh natural gas use for every 1 MWh yield of blue hydrogen. The constructed H2 price in (Hers et al., 2018) is €1.56 per kg. For 1 MWh hydrogen that is equal to or 25.3 kg for respectively LHV and HHV, the cost are estimated at to be or 39.52€/MWh. The HHV of hydrogen are 141.88 MJ/kg respectively. The assumed natural gas fuel cost from (Hers et al., 2018) was €4.5/GJ, which equals €16/MWh LHV ("Watersto ackbone Gasunie", n.d.). The resulting cost of blue hydrogen excluding natural gas fuel costs are 32.91 and 20.48 per MWh, LHV and HHV. The carbon capture and storage cost are subject to annual improvements of efficiency. This all results in a hydrogen price of 55.61 per MWh for HHV.

3.3.6 Costs before the meter

The costs before the meter are modelled by breaking down the price forecast into several different parts. Generation/production costs, transmission costs, distribution costs and market effects. For each of the scenarios, the generation cost, transmissions costs and distribution costs development are found in literature, provided in Section 2.4. Natural gas, electricity, blue hydrogen and coal supply chains have been investigated and the development of the cost fractions are implemented in the price forecast. Linear correlations are used for cost estimates found directly in literature. Extrapolations are used to try and predict the developments of cost element predictions that could not be found in literature.

3.3.7 Scenario I: Real LCOE of green hydrogen alternatives

The first scenario of the cost modelling shows the real LCOE of the green hydrogen alternatives. This means that the respective investments take place in the years 2021, 2025, 2030 and 2035 and there are no prior costs taken into consideration leading up to the year of investment. The discounting of costs starts at the respective time of investment. The then applicable costs of capital and operational costs are used to construct a levelized cost of energy for the four different sectors. All costs are expressed in 2021 Euros per MWh and are split into cost fractions to accurately show the developments in CAPEX consisting of initial investment and decommissioning costs at the end of the lifetime, fixed and variable operations and maintenance, fuel costs, carbon capturing costs and CO2 prices.

3.3.8 Scenario II: LCOE with business as usual from 2021 - 2050

The second scenario is where the period of 2021 to 2050 is modelled including the current situation, or business as usual. The LCOE are expressed over this entire period, instead of a 25 year lifetime. All process heating sectors are assumed to run on natural gas without CCS and the feedstock sector is assumed to run on SMR without CCS. Investments 2021, 2025, 2030 and 2035 are combined with the current assumed usage. The residual value of the CAPEX is subtracted from the LCOE and there are no decommissioning costs. The costs are modelled starting with discounting in 2021 for all investment options, instead of at the moment of investment in Scenario I.

3.4 Input data

This section aims to show what the input data is for modelling the LCOE. First, the commodity price forecast is shown and secondly the demand overview per sector is presented.

3.4.1 Commodity price data

The input commodity price data that has been delivered by DNV is presented in Figure 33. The blue hydrogen price is constructed based on the natural gas price, CO2 price and CCS costs that have been combined from the input data of DNV and findings of this report. The years 2051 to 2065 have been extrapolated based on running average development of costs. This explains stagnation in electricity costs, as the cost decline halts in the years close to 2050.

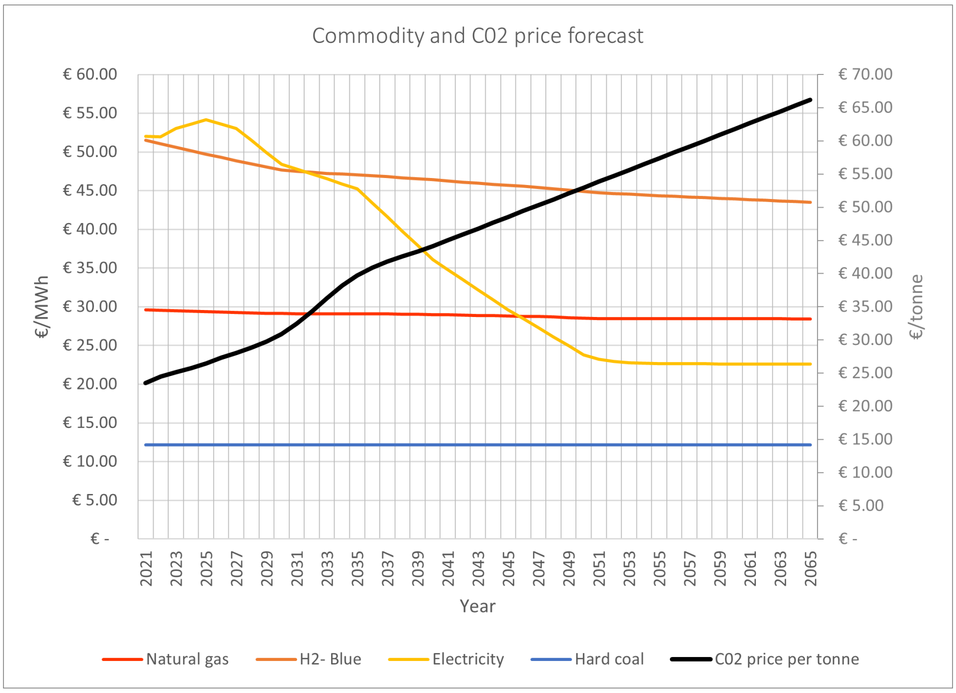


Figure 33: Commodity price and CO2 price forecast from 2021 to 2065

3.4.2 Energy demand input data

The potential green hydrogen demands that have been found across different processes in the Dutch industry are presented as input data in Table 11. Whilst modeling the LCOE it became clear that the simplifications and assumptions that are in the model show no distinction between different processes in the same sector apart from demand and thus scaling effects. The demand data that is used for modeling is shown in Table 12. The results are categorized as sector wide and not per process. As explained in Section 3.5, the annual growth is set at a fixed 1% with efficiency improvements in energy use in the factory of 0.75%.

Table 11: Summary of total demand per process and per sector as found in Section 2.2.1 and the calculated demand from annual growth and efficiency improvements for 2025 and on wards

Demand overview per process & sector							
Demand in PJ per year:	*2021*	*2025*	*2030*	*2035*	*2040*	*2045*	*2050*
Feedstock hydrogen production:							
Ammonia [15]	58	59	59.3	60.0	60.7	61.5	62.2
Methanol [16][17]	15	15	15.3	15.5	15.7	15.9	16.1
Refining [18]	16.1	16	16.5	16.7	16.9	17.1	17.3
High temperature heat >600 C:							
Glass [19]	6.7	7	6.8	6.9	7.0	7.1	7.2
Ceramics [20]	8.6	9	8.8	8.9	9.0	9.1	9.2
Steel [21]	88	89	89.9	91.0	92.1	93.3	94.4
Medium temperature heat: 200-600 C:							
Food industry [22]	30	30	30.7	31.0	31.4	31.8	32.2
Plastics [23]	30	30	30.7	31.0	31.4	31.8	32.2
Oil refining [18]	20	20	20.4	20.7	20.9	21.2	21.5
Low temperature heat: <200 C:							
Paper industry [24]	22.5	23	23.0	23.3	23.6	23.8	24.1
Food industry [22]	20	20	20.4	20.7	20.9	21.2	21.5
Total sum of demand per sector:							
Feedstock	89.1	90.0	91.1	92.2	93.3	94.4	95.6
High temperature	103.3	104.3	105.6	106.9	108.2	109.5	110.8
Medium temperature	80	80.8	81.8	82.8	83.8	84.8	85.8
Low temperature	42.5	42.9	43.4	44.0	44.5	45.0	45.6

Table 12: Homogenized demand data used for modelling LCOE

Modeled demand and demand growth for all sectors							
Year	*2021*	*2025*	*2030*	*2035*	*2040*	*2045*	*2050*
Demand in PJ	10.00	10.10	10.22	10.34	10.47	10.60	10.62

[15] (Batool & Wetzels, 2019a)
[16] (Khandelwal & van Dril, 2020)
[17] (Weeda & Segers, 2020)
[18] (Oliveira & Schure, 2020)
[19] (Papadogeorgos & Schure, 2019)
[20] (Besier & Marsidi, 2020)
[21] (Keys et al., 2019)
[22] (Segers et al., 2017)
[23] (Negri et al., 2021)
[24] (Rademaker & Marsidi, 2019)

3.5 Simplifications and modelling assumptions

This section is dedicated to showing the simplifications and modelling assumptions that are made in this project. First the simplifications are listed, second the assumptions are shown.

3.5.1 Simplifications

Several simplifications have been made throughout the research project that can have a fair amount of influence on the final results. These simplifications are summed up and explained here.

Potential demand for green hydrogen

The potential demand for green hydrogen is based on natural gas use in process heat generation or natural gas or coal use for hydrogen production. Waste heat streams and CHPs as well as hydrogen extraction from flue gasses have been left out of scope. The complexity of design across the different processes for recycling waste heat streams or recovery of hydrogen in flue gas, it is hard to tell how much of waste heat per process is recovered and what the corresponding efficiencies are. This can differ between plants or factories that operate in the same sector. The effect whether plants are operating together in an industry cluster influences the value of waste heat. As this thesis project looks at The Netherlands as a whole and at fuel or feedstock substitution and not so much process alterations, waste heat recovery is left out of scope. CHP plants create heat as well as electricity for either a single factory, or a combined CHP plant is used for an industrial cluster. The Chemelot industrial is developing a biogas plant that will be used to fuel OCI Nitrogen, which will return a large portion of waste heat to produce more biogas (Batool & Wetzels, 2019b). Electricity used for running equipment in for example chemical processes can not be substituted with green hydrogen and therefore the CHPs and their natural gas demand are also left out of scope. Hydrogen fueled CHP are mostly used for storing renewable energy in the form of hydrogen to be converted back to electricity at a later stage for residential use(Maleki, Hafeznia, Rosen, & Pourfayaz, 2017)

Green hydrogen alternatives

The alternatives for green hydrogen have been limited to fuel substitution for the different sectors as a result of the previous necessary simplification. Natural gas, natural gas with CCS, electrification and blue hydrogen are treated as fuel substitute alternative to green hydrogen for process heat generation. SMR, SMR with CCS, ATR with CCS and coal gasification with CCS are considered alternatives that are considered for hydrogen feedstock production. Process alterations such as hydrogenation of carbon for synthetic fuel production have not been taken into account. This is because these technologies are not yet widespread implemented as process alterations are often considered as an alternative option to fuel substitution (Oliveira & Schure, 2020; Khandelwal & van Dril, 2020; Batool & Wetzels, 2019b).

No profits or benefits

Only costs on the demand side are considered. There are no benefits or profits taken into account from selling waste gas stream, excess heat or carbon dioxide or the end product of the different processes. This is because the workings of these markets would be based on assumptions only, as the business interactions between parties at industrial clusters are not specified in literature The effects of the location of the different processes again play a role, as the sold carbon or waste heat is often locallay distributed, as is the case with a ammonia producer Yara in Sluiskil that partially sells their CO2 emissions to local farmers (Batool & Wetzels, 2019b).

Merchant blue hydrogen costs

The prices of blue hydrogen are assumed to be equal to the sum of the total costs. The market for blue hydrogen is not yet fully developed. Therefore, the predicted price fluctuations are fully dependent on the natural gas market as this is the highest cost factor in blue hydrogen.

No inter-dependency on infrastructure developments and use of alternatives

The use of commodities is independent on existing infrastructure. The costs connected to development of the electricity grid or hydrogen backbone are taken into account. However, there is no interaction between network capacity and demand that can be fulfilled. It is possible that for example electrification of process heat can not prevail due to underdeveloped electricity infrastructure, or the use of hydrogen can prohibited by an incomplete hydrogen backbone.

High temperature heat generation

Whilst steel manufacturing is the driver of high temperature heat demand, some options for decarbonisation are not viable for the Netherlands. Electrification of process heat would require electricity use on a scale that is yet unknown to The Netherlands (Keys et al., 2019). The demand of Tata Steel Ijmuiden for green hydrogen would have a lower chance of implementation, as green hydrogen production requires more electricity than electrification of process heat (Keys et al., 2019). Steel production is the only process that still uses coal combustion for process heat and is not likely to switch to another fuel due to the high complexity in process design and the sheer size of the steel production plant in Ijmuiden.

3.5.2 Modelling assumptions

In order to model the alternatives of green hydrogen across various sectors and as a result of the simplification in the previous sections a number of assumptions has been made in developing a LCOE model. The assumptions are presented below.

Fixed rates for input constants

The rate for annual growth, general annual efficiency improvements, learning rates, discount rates, scaling factor and renewable energy generation portfolio growth are set a fixed number.

Commodity price forecasts

The commodity price forecasts until 2050 have been extrapolated from 2051 to 2065 by means of running average. This is assumed because of the low impact of the prices in the last years between 2051 to 2065, due to it being at the end of the assumed lifetime or due to effects of discounting future costs.

Maturing of technology

For learning rates cost and equipment efficiency improvements, the development proceeds until 2030, at which fully matured technologies costs or efficiency have been reached and possible economies of scale have emerged. As the state of the art equipment is already rather efficient and a lot more cost effective, it is unlikely that emerging technologies will supersede the characteristics greatly.
The business as usual equipment does not benefit from maturing of technology or emerging economies of scale, as they are already in use for a long period of time and completely integrated in their respective sectors.

Industry demand

The industry demand, as well as growth and efficiency improvements are homogenized for all four researched sectors and set at respectively 10 PJ, 1% and 0.75% per year. This is to ensure the fairest comparison between different sectors, as a disproportional high demand w.r.t. other sectors also comes with scale advantages leading to a distorted comparison.

CAPEX

All lifetimes of equipment are set at 25 years for a fair comparison and as is customary in LCOE calculations.
There is no residual value on equipment that is being replaced modeled for Scenario II, due to unknown leftover lifetime of the to be replaced equipment at the time of investment.
Residual value is calculated as the percentage of lifetime that is left multiplied by original CAPEX. This can be simplified because at the end of the lifetime, the installed process heating or hydrogen production machinery are not likely to be completely dismantled and sold to third parties, as sometimes happens with old power generation plants to are sold after the end of life to function as a load

balancing generator.
Operations and maintenance costs are set at a fixed percentage of the CAPEX, as commonly used in LCOE calculations.
No retrofitting of equipment is considered due to unknown remaining lifetimes of equipment at the time of investment.

Carbon capture and storage
Energy losses from carbon capturing equipment are equal for different sectors, as the CO2 concentrations in flue gasses are in close proximity of each other, or have been compensated by a higher energetic efficiency loss.
Costs of transporting and storage are of carbon are equal for all sectors.
All CCS related costs are subject to cost decrease from technology maturing.

Costs before the meter
The supply chain cost developments are independent of used commodity input data, because the rate of development of infrastructure might be influenced by the popularity or availability of certain alternatives.

Carbon emissions costs
Blue hydrogen as well as electrification are not subject to carbon emission costs behind the meter as these are already implemented further upstream.

Merit orders
The constructed merit orders make use of the total sector demand combined with the costs that are found for the homogenized demand input. The size of the demand is the average annual demand over the lifetime of 25 years for Scenario I. For Scenario II the demand is the average annual demand between 2021-2050. The average is taken, as the capacity of factories can be up or down scaled slightly with increasing or decreasing full load hours of operations

4 Results

This section aims to present and elaborate on the outcome of the modelling process. The results presentation is split up in two parts: the costs before the meter and the costs behind the meter. First, the results that are described are the costs before the meter up to 2050. The commodity supply chain costs are presented in order of electricity, natural gas, blue hydrogen and coal. Secondly the results behind the meter are presented per investment period across various sectors for Scenario I, then Scenario II. Finally, a the merit orders of the alternatives of Scenario I and Scenario II.

4.1 Costs before the meter

In Figure 34 the development of electricity supply costs has been depicted. The cost is split in power generation, development of the electricity transmission and distribution grid and investments in power curtailment options. The development of the T&D grid is an increasing substantial part of the predicted electricity costs towards 2050, developing from €11.33/MWh in 2021 up to €17.54/MWh. The increase of the T&D costs can be explained due to the fact that major investments have to be made to ready the electricity grid for the projected increase of electrification in both industrial and residential applications. It can also be observed that the generation costs slightly decrease from around €29.58 in 2021 to €22.16 in 2036 and the cost decrease stagnates from there on towards 2050. This can be declared based on the decreasing marginal costs of power generation with an increased market share of renewables. The marginal costs of operation for renewable energy is significantly lower than for natural gas or even coal fired power plants, due to the lack of fuel costs of generation. The market effects on the electricity price can be seen to decline from €22.42 towards a much lower margin in 2050 of €1.63. As the prices decrease, the profit margin for power generators are likely to decrease as well. Due to a stark rise in power demand, it is still economically viable to generate electricity with these lower profit margins.

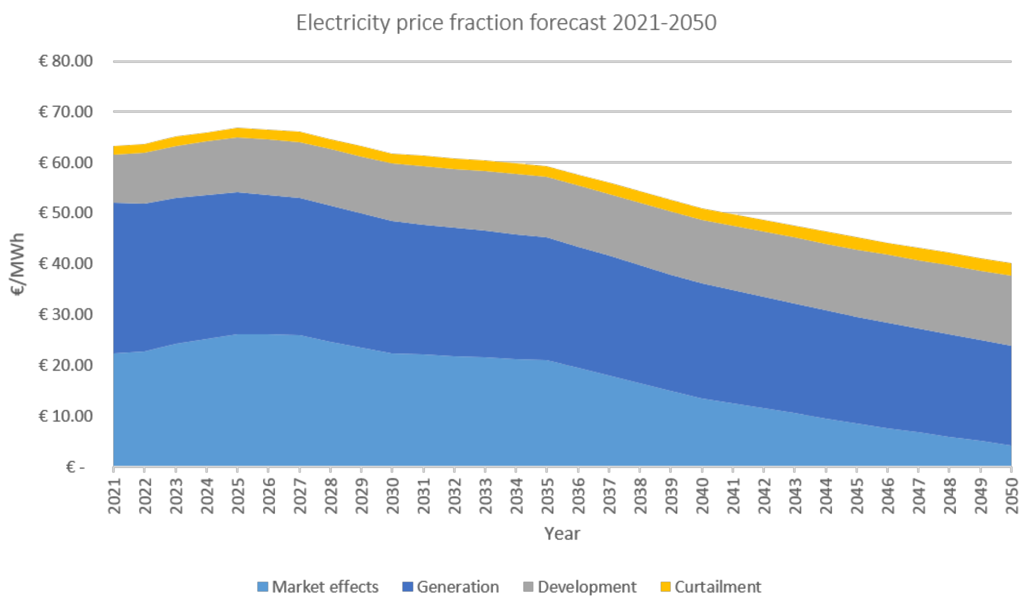


Figure 34: Expected development of various aspects of electricity costs before the meter

The natural gas supply costs are split in two figures, Figure 35 for pipeline distributed natural gas from European and Russian suppliers and Figure 36 for overseas produced LNG from the U.S. It can be seen that the expected price will hardly develop for natural gas consumers between 2021 and 2050. The production costs in 2021 of €9.32/MWh is expected to rise to€15.16 in 2050. This can be explained by the depletion of easier to reach natural gas resources and the more need to tap resources that are located in more remote areas and require costlier equipment to produce. The pipeline distribution costs are expected to increase annually with roughly 1%, from €2.95 to about €3.93. As the NordStream pipeline is considered as the standard, the increased costs come from higher fees that are charged by Russia for using the pipeline. Costs of local natural gas distribution is hardly affected towards 2050, ranging from €1.32 to €1.36 in 2050, an increase of 0.1% annually. This can be explained by a development of the commodity demand in the Netherlands towards a more sustainable portfolio and thus the natural gas network would require less additional investment as for example the electricity grid. The increased pipeline costs as well as the very slight increase in local distribution with a nearly constant wholesale price leaves smaller margins in the market.

LNG cost factors are expected to decrease as well. LNG production costs are on the decline due to maturing of technology and economies of scale emerging more and more. Liquefaction costs are decreasing whilst gaining energetic efficiency up to 2030, making the prices drop from €6.10 to €5.70 per MWh of produced LNG. Transportation costs of LNG are also expected to decrease due to fuel efficiency improvements on the tankers that are fueled on boil off gas. The costs develop from €2.04 /MWh in 2021 to €1.91 in 2030-2050. The regas and grid entry fees are assumed to stay constant at €2.12/MWh, due to combined factors of technological improvements that reduce costs for re-gassing LNG and decarbonising policy measures that heighten grid entry fees cancelling each other out. Local distribution grid costs are the same as for pipelined natural gas and are mentioned in the previous paragraph.

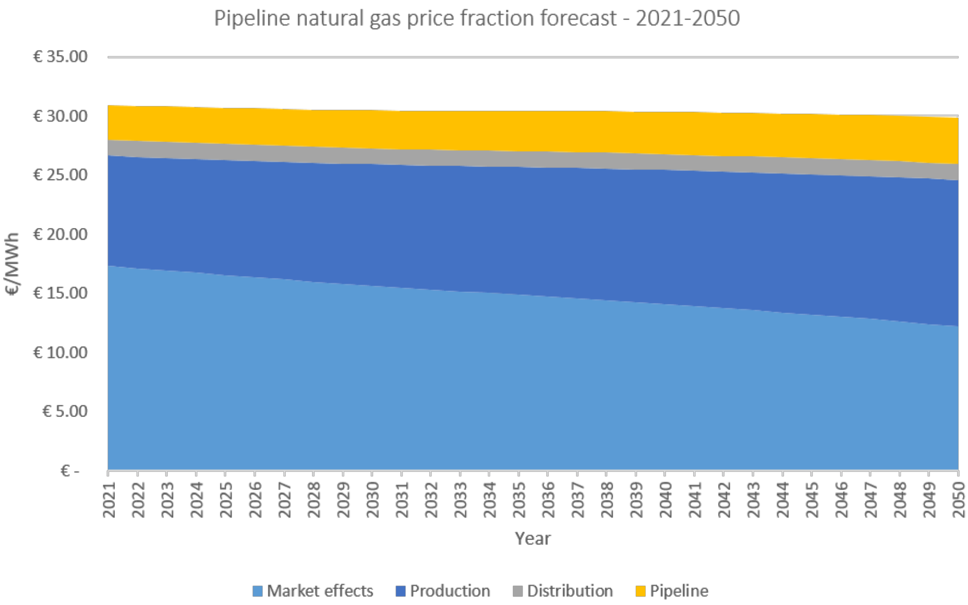


Figure 35: Expected development of aspects of pipelined natural gas costs before the meter

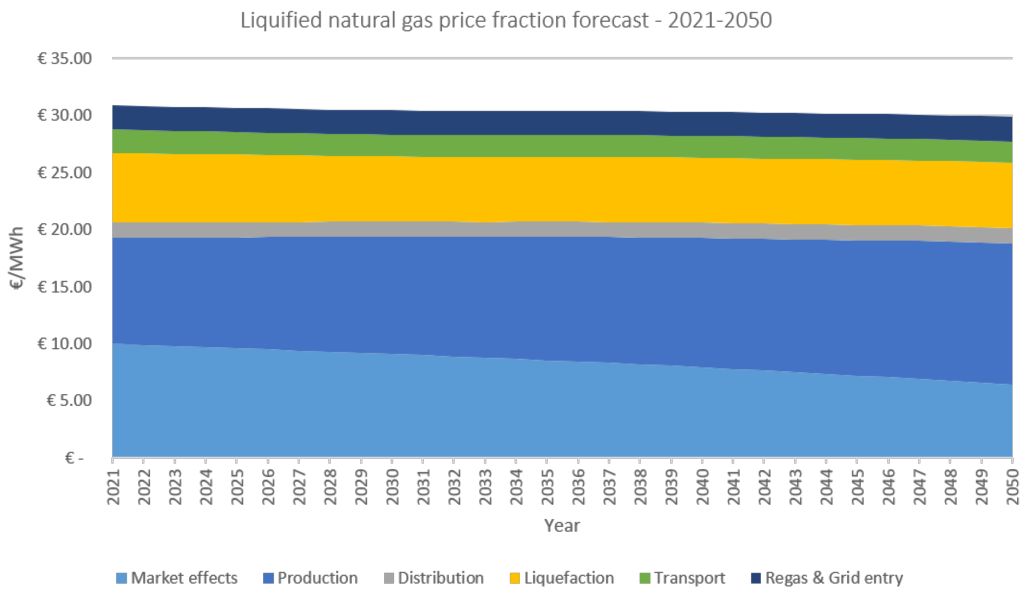


Figure 36: Expected development of various aspects of LNG costs before the meter

The blue hydrogen cost prediction towards 2050 can be seen in Figure 37. The largest part consists of the natural gas fuel costs for production. With blue hydrogen production that has an energetic efficiency of 84% in 2021 to 90% in 2030, the production fuel costs develop from €34.96 to €31.49 in 2050. The production costs excluding fuel and CCS or carbon costs decline from €12.41 to €9.30 due to economies of scale emerging for higher volume blue hydrogen production. This annual decrease is set at 1.5% annually from 2021 to 2030. Carbon emissions costs are relatively low with €0.28 per MWh in 2021 to €0.58 in 2050 and CCS costs slightly increase due to higher efficiency carbon capture rates combined with a decrease in storage and transport costs up to 2030. These costs stabilize up to 2050 from €4.07 to €4.09. Transmission and distribution costs are twice as high as natural gas distribution costs with roughly equal price development, from €2.66 to €2.74. This comes from the necessary investments that are going to transform part of the natural gas grid into a hydrogen backbone for the Netherlands and the multi billion euro investments that are connected to developing this hydrogen grid.

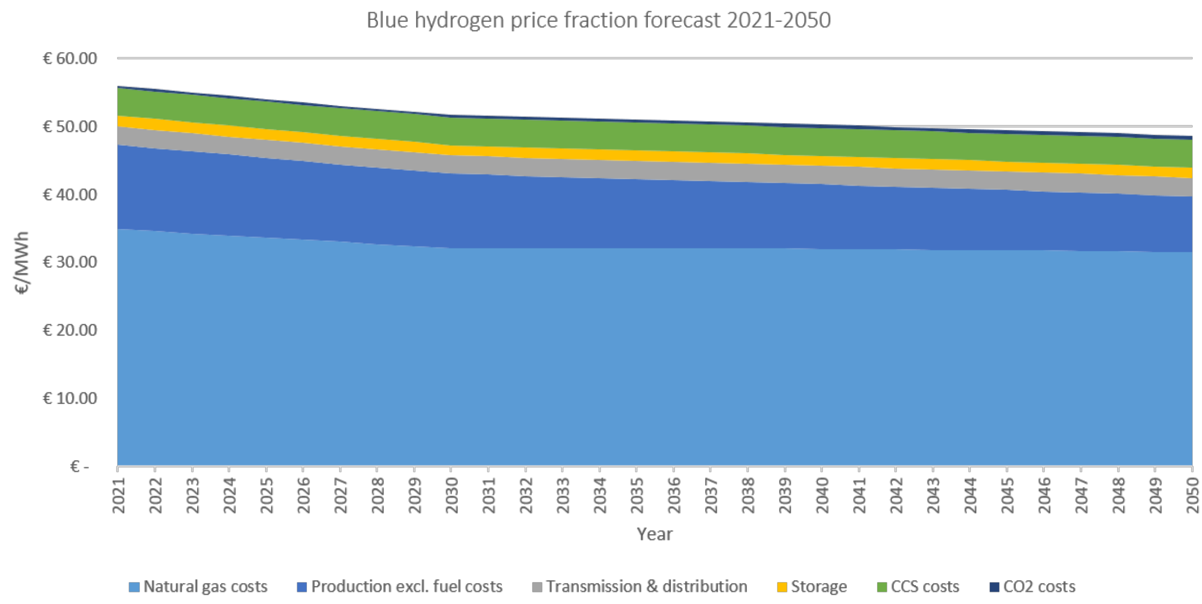


Figure 37: Expected development of blue hydrogen production costs before the meter

4.2 Costs behind the meter

This section aims to illustrate the total costs associated with implementing and using green hydrogen alternatives for process heat or hydrogen feedstock production. First, for the 4 different times of investment each end use of hydrogen alternatives is displayed. This starts with low, medium and then high temperature process heat, and subsequently feedstock use. Then a merit order for the different sectors is presented. Secondly, a comparison for the time span of 2021-2050 for the same times of investment combined with business as usual use are shown. Subsequently the corresponding merit orders for different sectors are presented as well.

4.2.1 Low temperature process heat

The costs of alternatives for supplying process heat of 200 degrees Celsius and lower are seen in Figures 38a,38b,38c and 38d. What can be observed here is that for all alternatives the fuel costs take up a the majority of the costs. CAPEX, variable and fixed operations and maintenance cost are negligible as a total of costs, except for electrification. This is due to high costs of grid connections and annual capacity payments that need to be made when applying power to heat. As the time period moves towards 2035, the share of costs of CO2 emissions for natural gas is increasing due to rising CO2 emission prices. The costs of carbon capture and storage also increase towards the end of the time spectrum. This can be attributed to the improved performance of CCS equipment, which results in higher number of captured CO2 emissions per MWh of energy delivered.

Figure 39 presents an overview of the low temperature alternatives levelized cost of energy with investments taking place in 2021,2025,2030 and 2035 with a lifetime of 25 years. It can be observed that until 2030 investment, natural gas based process heat is the cost effective option, which seems to switch places with CCS installed natural gas process heating equipment. Electrification as well as blue hydrogen are not competitive in terms of cost, mainly due to the much higher fuel costs of electricity and blue hydrogen. However, the stark decline in electricity costs shows that towards the 2035 investment point, electrification is closely competitive with blue hydrogen fuel.

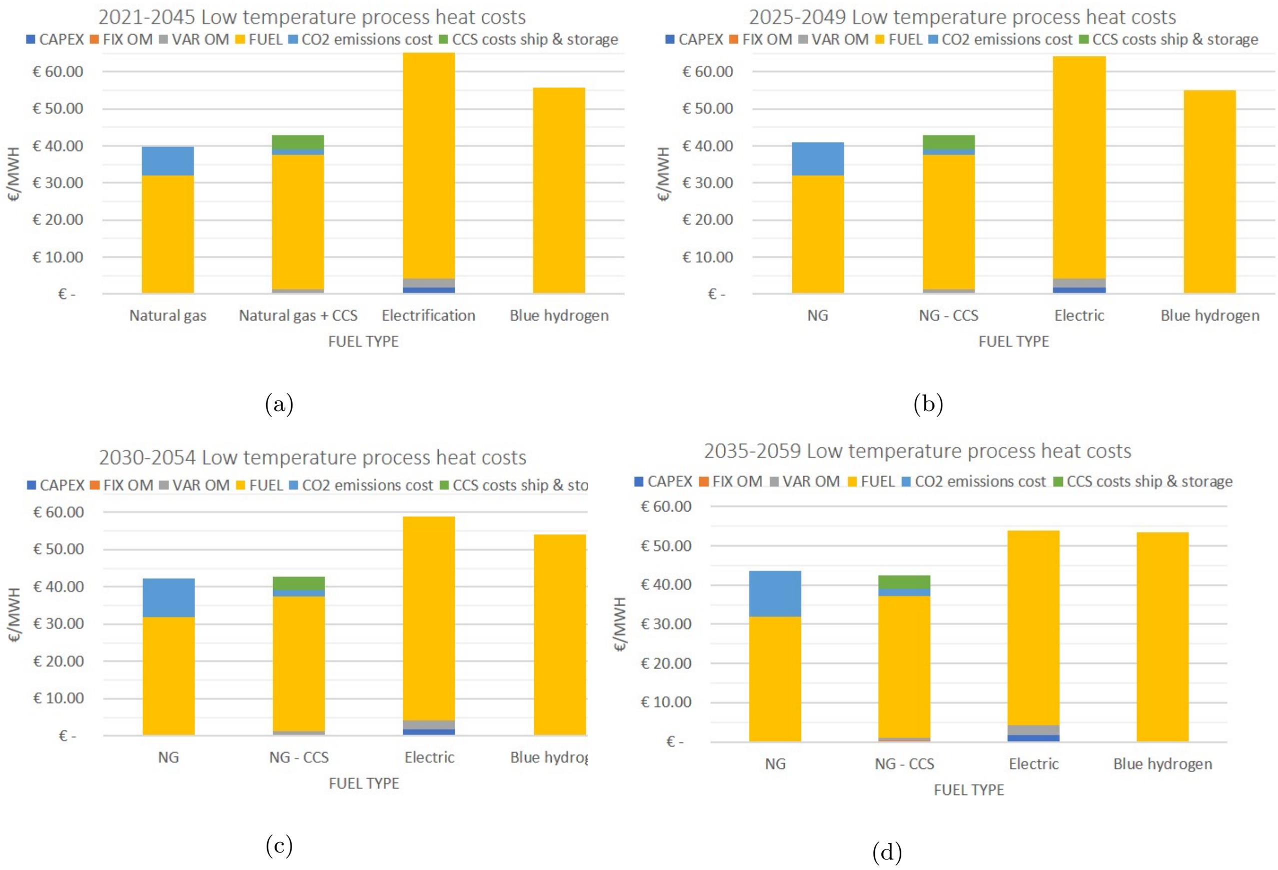
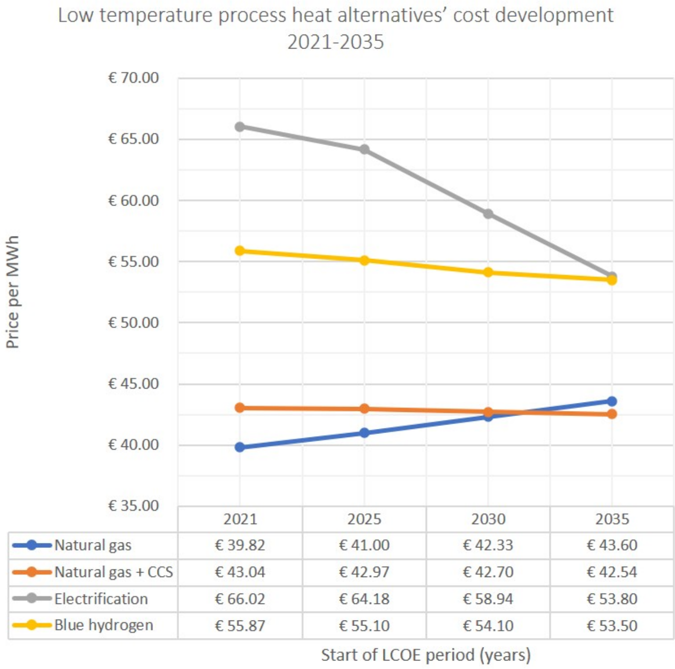


Figure 38: The four different investment moments and the corresponding levelized costs fractions development for LT process heat



	2021	2025	2030	2035
Natural gas	€ 39.82	€ 41.00	€ 42.33	€ 43.60
Natural gas + CCS	€ 43.04	€ 42.97	€ 42.70	€ 42.54
Electrification	€ 66.02	€ 64.18	€ 58.94	€ 53.80
Blue hydrogen	€ 55.87	€ 55.10	€ 54.10	€ 53.50

Figure 39: General overview of LCOE development for low temperature heat generation alternatives

Table 13: CO2 emissions and amount of CO2 emissions captured over total lifetime of 25 years for each alternative in low temperature process heat generation

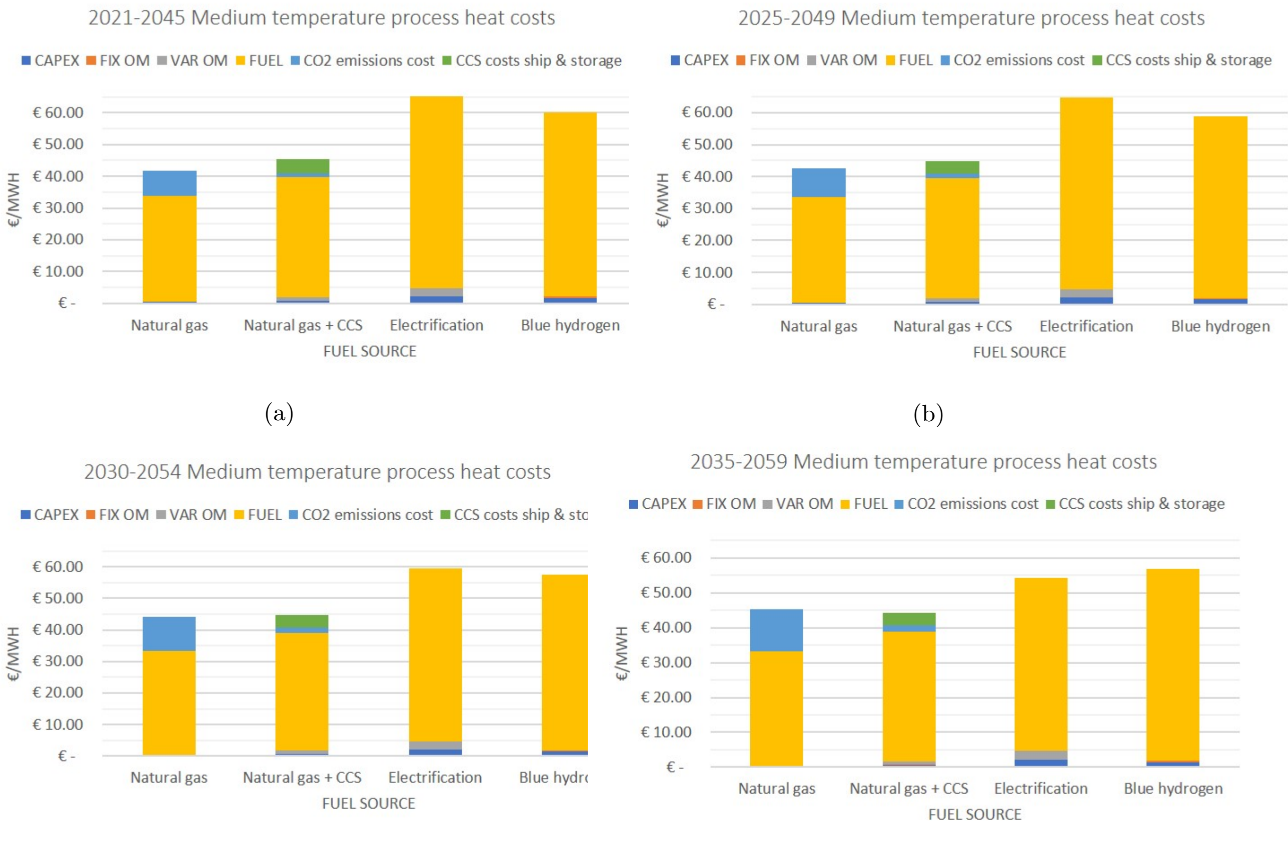
Low temperature process heat CO2 emissions & CO2 captured in million tonnes								
Year	*Natural gas*		*Natural gas + CCS*		*Electrification*		*Blue hydrogen*	
	Emissions	*Captured*	*Emissions*	*Captured*	*Emissions*	*Captured*	*Emissions*	*Captured*
2021-2045	17.913	0	2.880	17.484	16.559	0	1.005	20.320
2025 - 2049	18.088	0	2.875	17.662	14.321	0	1.005	20.528
2030 - 2054	18.308	0	2.891	17.884	11.459	0	1.011	20.784
2035 - 2059	18.531	0	2.925	18.102	8.552	0	1.023	21.038

In Table 13 the amount of CO2 emissions and captured emissions are shown. The natural gas scenario obviously has the highest emissions, as there is no carbon reduction mechanism. The total amount of emitted carbon for natural gas with CCS is higher, due to the reduced energetic efficiency and thus increased fuel consumption that is allocated to CCS installation. It can be seen that the emissions that escape the capturing mechanism only have a small increase compared to the cumulative emissions. This is due to the increased fuel efficiency that comes from technology maturing of the CCS equipment. The total emissions of electrification also steadily decline. This is because the increased share of renewable energy generation reduces the CO2 that is emitted in power production. The blue hydrogen that is imported as a fuel is found have similar total emissions as the natural gas with CCS application, however the rate of capture is significantly higher. This an be attributed to the use of ATR + CCS for the merchant hydrogen production, which has a higher CO2 capture rate than post-combustion CCS. It has to be noted, that for the electrification and blue hydrogen use, there are no costs per emitted tonne of CO2 for the final consumer, because the CO2 is emitted and penalized further upstream the value chain.

4.2.2 Medium temperature process heat

The levelized costs of energy for the green hydrogen alternatives for supplying process heat between 200 and 600 degrees Celsius can be found in Figures 40a, 40b, 40c and 40d. What one can see here is very similar to the results for low temperature process heat alternatives costs. Fuel costs take up a the majority of the total levelized costs. CAPEX, variable and fixed operations and maintenance cost are still negligible as a total of costs even though the capital costs for medium temperature heat equipment is several times higher than it is for low temperature heat. Electrification only has a noteworthy CAPEX, which is direct result of the high costs of grid connections and annual capacity payments that need to be paid when switching to power to heat technology. Slightly lower efficiencies in heat generating equipment make for an increase in the fuel costs as well as the CO2 emissions and CCS costs per MWh. As the time period moves towards 2035, the share of costs of CO2 emissions for natural gas is increasing. The costs of carbon capture and storage also increase towards the end of the time spectrum due to efficiency increase in CCS equipment, larger amounts of carbon need to be stored. This effect is cancelled out by the reduction in CO2 emissions costs that follows suit. Electrification as well as blue hydrogen do not have to compensate for carbon emissions, as this is already paid for at the generation of power as well as blue hydrogen.

Figure 41 presents an overview of the medium temperature alternatives levelized cost of energy with investments taking place in 2021,2025,2030 and 2035 with a lifetime of 25 years. It can be observed that until 2030 investment, natural gas based process heat is the cost effective option, which seems to switch places with CCS installed natural gas process heating equipment. Electrification as well as blue hydrogen are not competitive in terms of cost. However, electrification of process heat rapidly declines in costs towards 2035 and is expected to overtake blue hydrogen in terms of competitiveness around the 2032 mark.



(a) (b) (c) (d)

Figure 40: The four different investment moments and the corresponding levelized costs fractions development for medium temperature process heat

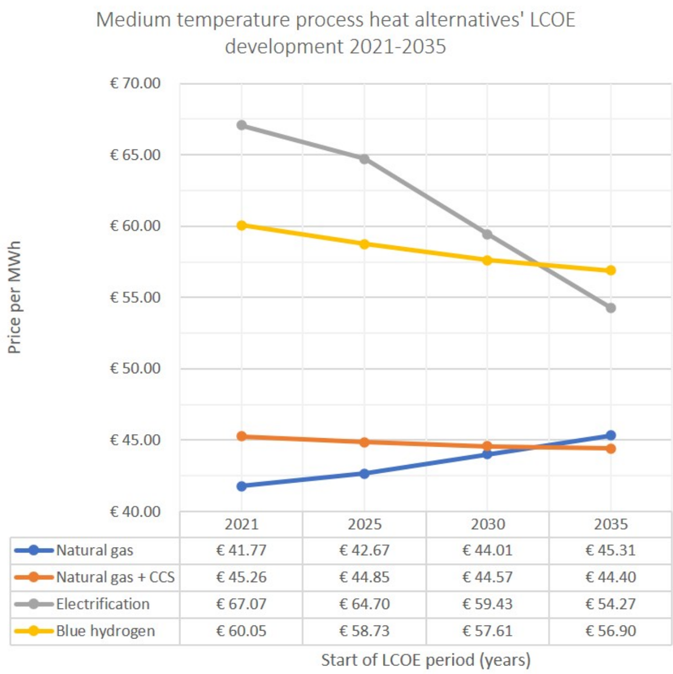


Figure 41: General overview of LCOE development for medium temperature heat generation alternatives

Table 14: CO2 emissions and amount of CO2 emissions captured over total lifetime of 25 years for each alternative in medium temperature process heat generation

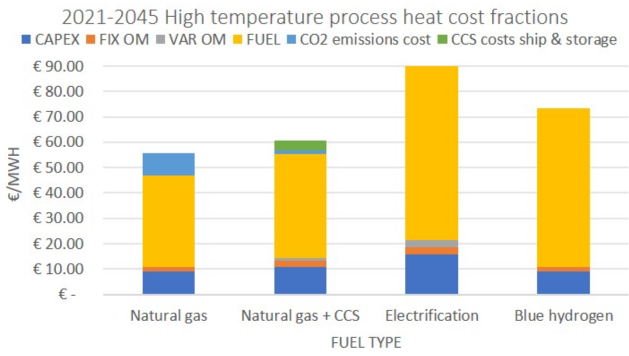
Medium temperature process heat CO2 emissions & CO2 captured in million tonnes								
Year	*Natural gas*		*Natural gas + CCS*		*Electrification*		*Blue hydrogen*	
	Emissions	*Captured*	*Emissions*	*Captured*	*Emissions*	*Captured*	*Emissions*	*Captured*
2021-2045	18.397	0	2.974	18.054	16.559	0	1.038	20.983
2025 - 2049	18.554	0	2.969	18.238	14.321	0	1.038	21.198
2030 - 2054	18.763	0	2.985	18.467	11.459	0	1.044	21.462
2035 - 2059	18.992	0	3.021	18.693	8.552	0	1.056	21.724

In Table 14 the amount of CO2 emissions and captured emissions are shown for medium temperature process heat generation. The emissions total emissions and explanation of these emissions are almost identical to the lower temperature process heat generation emissions. The natural gas scenario still has the highest emissions, as there is no carbon reduction mechanism in place. The cumulative amount of emitted and captured carbon for natural gas with CCS is higher, due to the reduced energetic efficiency and thus increased fuel consumption that is allocated to CCS installation. For medium temperature generation, the energetic efficiency of the installed equipment lies at 92%, compared to 95% for low temperature heat. This results in slightly higher fuel consumption and a mild decrease in total energetic efficiency for these processes. The total emissions of electrification are identical to the ones in low temperature heat, as the equipment has the same energetic efficiency. The blue hydrogen emissions are higher, due to decreased efficiency compared to the low temperature process heat, 95% to 92% efficiency. It has to be noted here as well, that for both electrification and blue hydrogen use, there are no costs per emitted tonne of CO2 for the final consumer, because the CO2 is emitted and penalized further upstream the value chain.

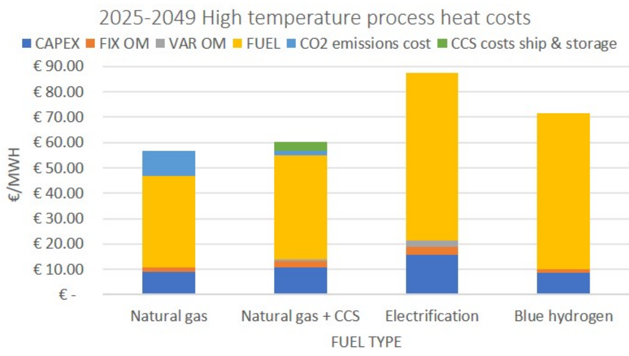
4.2.3 High temperature process heat

The results of the LCOE calculations for high temperature process heat are different from the low and medium temperature process heat results. It can be seen that the CAPEX are a significant part of the total LCOE, unlike the lower temperatures previously explained. This is due to the fact that high temperature equipment has a price per MW that is up to twenty times higher than medium temperature heat generating equipment. The prices per MW of capacity are around 1 million euros. The largest share of the costs are still being contributed by fuel. However, the height of CO2 emission costs and subsequently CCS costs and O&M costs are significantly higher then in the previous processes. This all can be observed in Figures 42a, 42b, 42c and 42d. These differences can be accounted to the equipment used in high temperature heat generation. The fuel efficiencies are lower, which results in higher fuel consumption per generated unit of heat. The higher complexity and size of the installation resulting in higher capital costs as well as higher costs for carbon capture equipment. The effect of scaling capital investment costs subsequently play a larger role in the total costs.

Overall, when looking at the development of LCOE for the high temperature heat processes in Figure 43, the trend that was seen in low and medium temperature is not followed. With natural gas without carbon capturing having the lowest LCOE. Electrification is the most expensive, followed by blue hydrogen. It also has to be noted that with such vast differences in costs, the power to heat option is easily discarded as it is not financially viable to produce process heat with such high costs. The differences in CAPEX magnify the results, with electrification, natural gas with CCS and blue hydrogen equipment having a significantly higher cost per installed MW of capacity than natural gas furnaces have.



(a)



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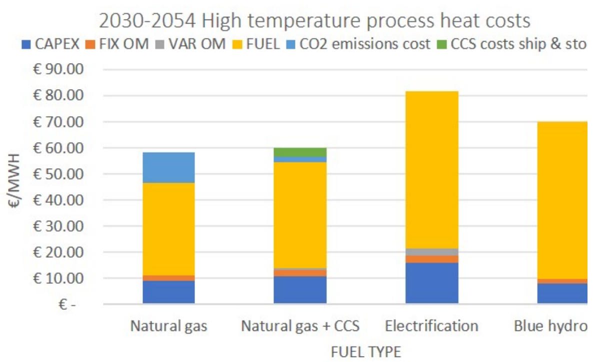

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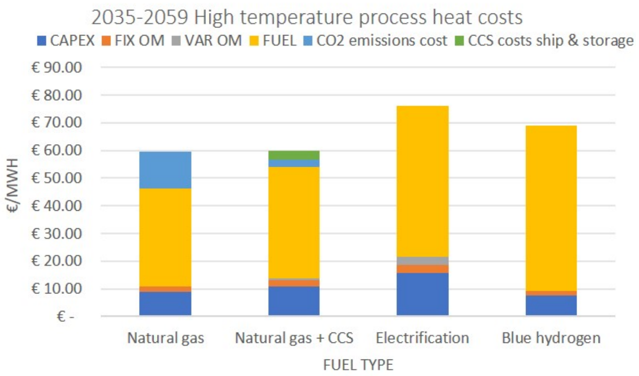
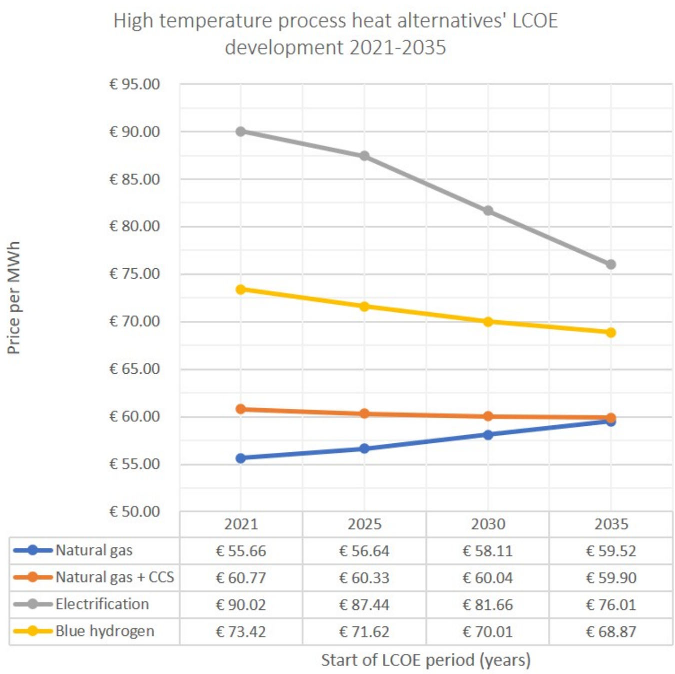


(d)

Figure 42: The four different investment moments and the corresponding levelized costs fractions development for high temperature process heat



	2021	2025	2030	2035
Natural gas	€ 55.66	€ 56.64	€ 58.11	€ 59.52
Natural gas + CCS	€ 60.77	€ 60.33	€ 60.04	€ 59.90
Electrification	€ 90.02	€ 87.44	€ 81.66	€ 76.01
Blue hydrogen	€ 73.42	€ 71.62	€ 70.01	€ 68.87

Figure 43: General overview of LCOE development for high temperature heat generation alternatives

Table 15: O2 emissions and amount of CO2 emissions captured over total lifetime of 25 years for each alternative in high temperature process heat generation

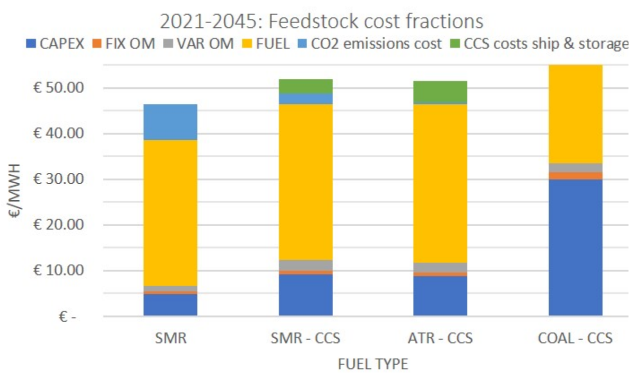
High temperature process heat CO2 emissions & CO2 captured in million tonnes								
Year	*Natural gas*		*Natural gas + CCS*		*Electrification*		*Blue hydrogen*	
	Emissions	*Captured*	*Emissions*	*Captured*	*Emissions*	*Captured*	*Emissions*	*Captured*
2021-2045	20.021	0	3.841	16.523	18.215	0	1.124	22.711
2025 - 2049	20.216	0	3.833	16.703	15.753	0	1.123	22.943
2030 - 2054	20.462	0	3.855	16.920	12.605	0	1.130	23.230
2035 - 2059	20.711	0	3.901	17.127	9.407	0	1.143	23.513

Table 15 shows the carbon emissions and captured carbon emissions. The total amount of fuel that is required to deliver a MWh of energy is higher than in the previous applications, due to lower equipment efficiencies. The amount of carbon that can be captured is also lower, at 80% compared to 85% for LT and MT processes. The higher volumes of captured CO2 also result in higher costs for transporting and storing the carbon as well. This results in the highest emission results. The decline of emissions in electrification is significant, due to a higher share of renewable energy.

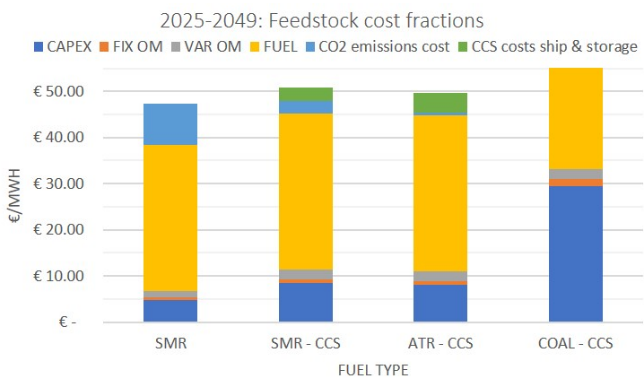
4.2.4 Hydrogen feedstock production

For hydrogen feedstock production alternatives, the levelized cost look different, as the technologies are more similar and three out of four have carbon capture and storage installations. The results can be observed in Figures 44a, 44b, 44c and 44d. The fuel costs are similar for SMR, SMR - CCS and ATR - CCS, since these technologies are all based on natural gas. Coal gasification with CCS has lower fuel costs, but higher emission avoidance costs. The maturity of these technologies is taken into account by applying learning effects and efficiency improvements. ATR technology efficiency is increased from 84 to 90% between 2021 and 2030, with 0.75% annually untill it is on par with the current state of art technology performance. CCS costs are declining as well. Technological improvements decrease energetic losses and the costs of transporting and storing carbon also slightly decrease between 2021 and 2030. The CAPEX make up a significant part of the LCOE for each of the alternatives. SMR without CCS has a significantly lower CAPEX than the other alternatives. However, economics of scale effects and maturing of technology for CCS as well as for ATR, make the CAPEX converge towards the costs of SMR, with an increased fuel efficiency and lower CO2 emissions costs.

In Figure 45 it can be observed that the current state of art for feedstock production, SMR without CCS, will be out-competed by SMR with CCS as well as ATR with CCS. ATR with CCS is likely to become the lowest cost alternative to green hydrogen around 2027, and SMR with CCS LCOE are overtaking SMR around 2032. This is due to an increase in CO2 costs as well as the previously mentioned maturing of technology and the corresponding increase in efficiency and decrease in costs.



(a)



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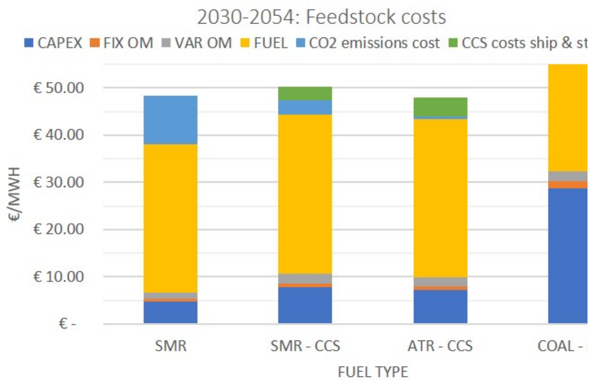

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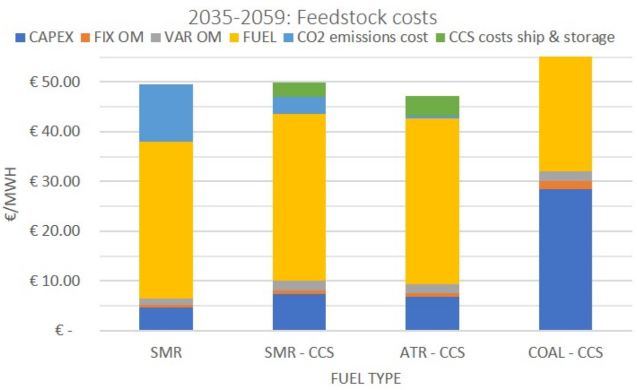


(d)

Figure 44: The four different investment moments and the corresponding levelized costs fractions development for hydrogen feedstock production

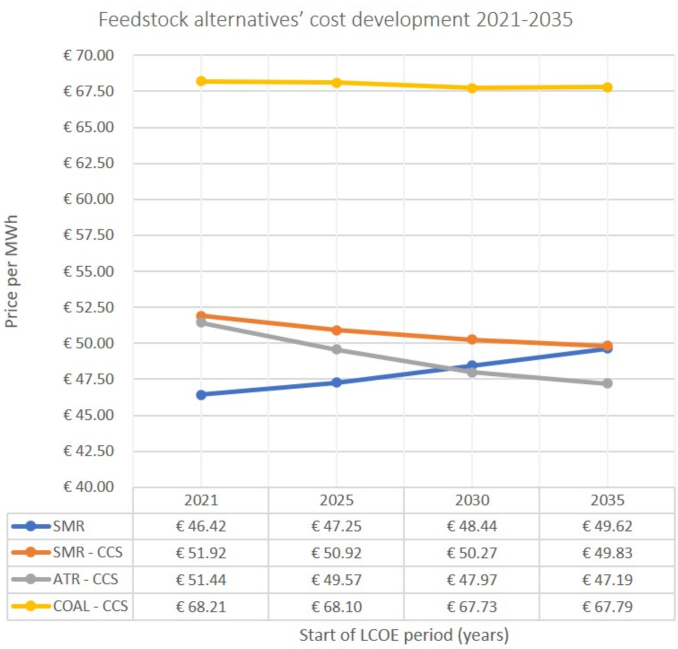


Figure 45: General overview of LCOE development for hydrogen feedstock production alternatives

Table 16: Add caption

Feedstock production CO2 emissions & CO2 captured in million tonnes								
Year	*SMR*		*SMR + CCS*		*ATR + CCS*		*Coal + CCS*	
	Emissions	*Captured*	*Emissions*	*Captured*	*Emissions*	*Captured*	*Emissions*	*Captured*
2021-2045	18.319	0	5.525	14.016	0.987	20	6.715	35.193
2025 - 2049	18.880	0	5.637	14.502	1.007	21	6.852	36.383
2030 - 2054	19.735	0	5.859	15.192	1.046	22	7.121	38.095
2035 - 2059	20.736	0	6.154	15.964	1.099	23	7.480	40.031

Table 16 shows the carbon emissions and captured carbon emissions for feedstock production. The carbon emissions for the same energetic demand as the other sectors yield different results. SMR obviously has the highest emissions. SMR with CCS has higher carbon emissions as the previous sectors, because the capturing efficiency for pre-combustion CCS is lower with SMR. The optimal energetic efficiency and carbon capturing rate is set at 70%, to prevent too high losses in fuel consumption. ATR is more compatible with CCS, and therefore the capturing efficiency is significantly higher, at 95%. The energetic efficiency however is 84%, but increases towards 90% due to improvement in technology, resulting in very low carbon emissions. Coal with CCS has very high emissions with 75% capture CO2 capture rate. The differences in carbon emission and capture rate result a faster shift of lowest LCOE alternatives from SMR to ATR with CCS.

4.3 Combination of business as usual with different investment times

This section shows a different approach to the LCOE than the previous section. For the time span 2021-2050, four investment moments are compared, combined with business as usual scenarios. The results are combined in process heat application and feedstock generation. The scenario where business as usual and investments are combined and compared yields slightly different results from the previous figures. The costs all seem to converge towards the initial costs of the business as usual scenario, with differences in between the alternatives and final LCOE being lower than the results that are presented in the previous section.

4.3.1 Process heat generation

Table 17 shows the most important costs from the business as usual scenarios, not yet combined with the different alternatives. The fuel costs per MWh are all similar for the different sectors, due to no improvements in technology. The CO2 costs per MWh also slightly rise, because the stark incline of CO2 prices only starts after the end of 2035, not showing significant increase in costs for the B.A.U. scenarios. The total emissions over the entire period obviously rise, because of the longer time for each scenario.

Table 17: Overview of the core cost components of business as usual scenarios, showing fuel costs per MWh, CO2 emissions costs per MWh and total Emissions in Mt

Business as usual levelized cost fractions & CO2 emissions costs and quantity in Mt												
	LT - Natural gas			MT - Natural gas			HT - Natural gas			Feedstock - SMR		
Period	*Fuel*	*CO2*	*E.*	*Fuel*	*CO2*	*E*	*Fuel*	*CO2*	*E*	*Fuel*	*CO2*	*E*
2021-2025	€ 31.71	€ 6.03	2.8	€ 33.51	€ 6.37	2.9	€ 36.27	€ 6.90	3.1	€ 32.11	€ 6.11	2.8
2021-2030	€ 31.93	€ 6.47	6.3	€ 33.39	€ 6.76	6.5	€ 36.14	€ 7.33	7.1	€ 32.00	€ 6.49	6.3
2021-2035	€ 31.96	€ 6.95	9.9	€ 33.32	€ 7.23	10.2	€ 36.06	€ 7.84	11.1	€ 31.93	€ 6.95	9.8

As can be seen in Figures 46, 47 and 48 the business as usual case combined with reinvestment in natural gas yields the lowest costs for the first two periods, followed and form 2030 on, reinvestment in natural gas with CCS is the more economical option. It can also be noted that the costs of the alternatives are all converging to the level of B.A.U. + NG costs, which do not seem to change from 2021 to 2050. The longer the investment is postponed, the cheaper the investment becomes over the time span 2021-2050. This is declared due to the discounting of future costs as opposed to present costs as well as the combination of the B.A.U. with other alternatives. The converging of alternatives costs towards the BAU + NG costs is mainly due to declined costs of alternatives as well as the highly discounted costs for CAPEX in 2035 as opposed to the CAPEX in 2021. It is noteworthy, that for low and medium temperature heat, the BAU + NG scenarios the costs are seemingly constant, while the HT costs only decline. This is a result of discounting the higher capital costs, which are negligible at lower and medium temperature, but definitely not at high temperature heat.

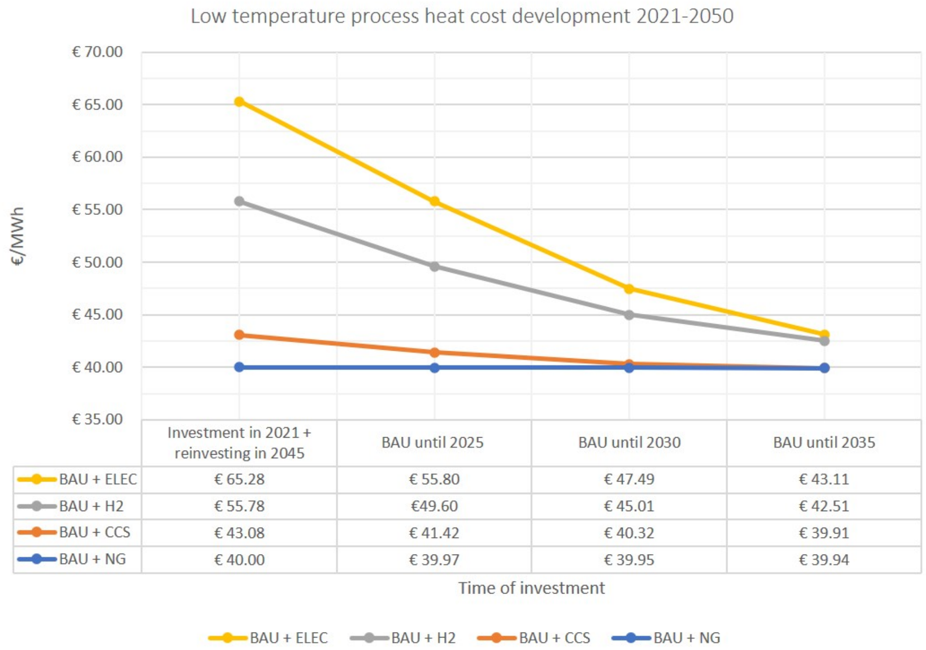


Figure 46: Low temperature process heat generation LCOE development with B.A.U. and investment scenarios combined for all four alternatives

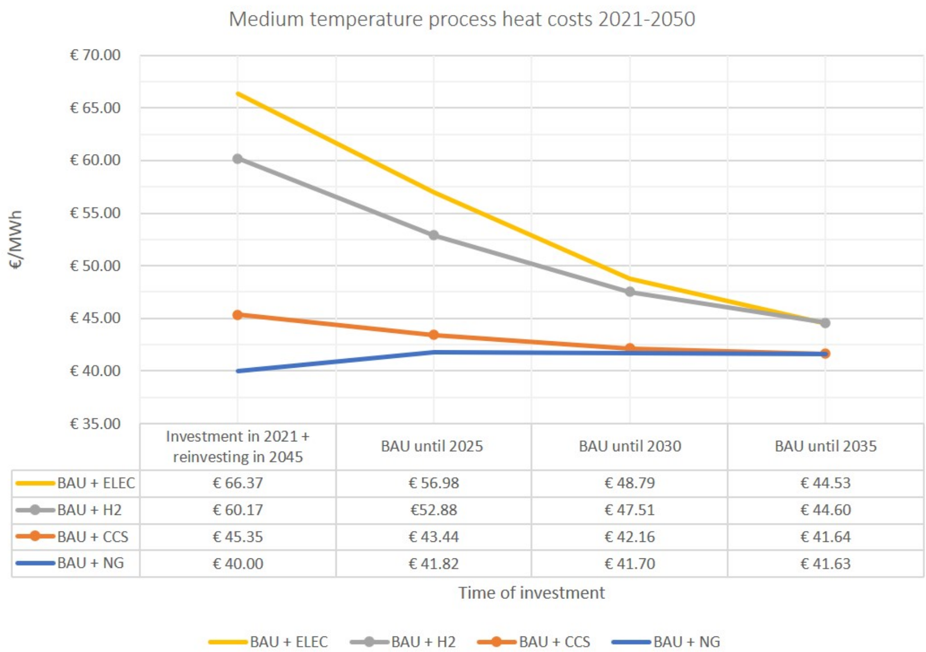


Figure 47: Mediumw temperature process heat generation LCOE development with B.A.U. and investment scenarios combined for all four alternatives

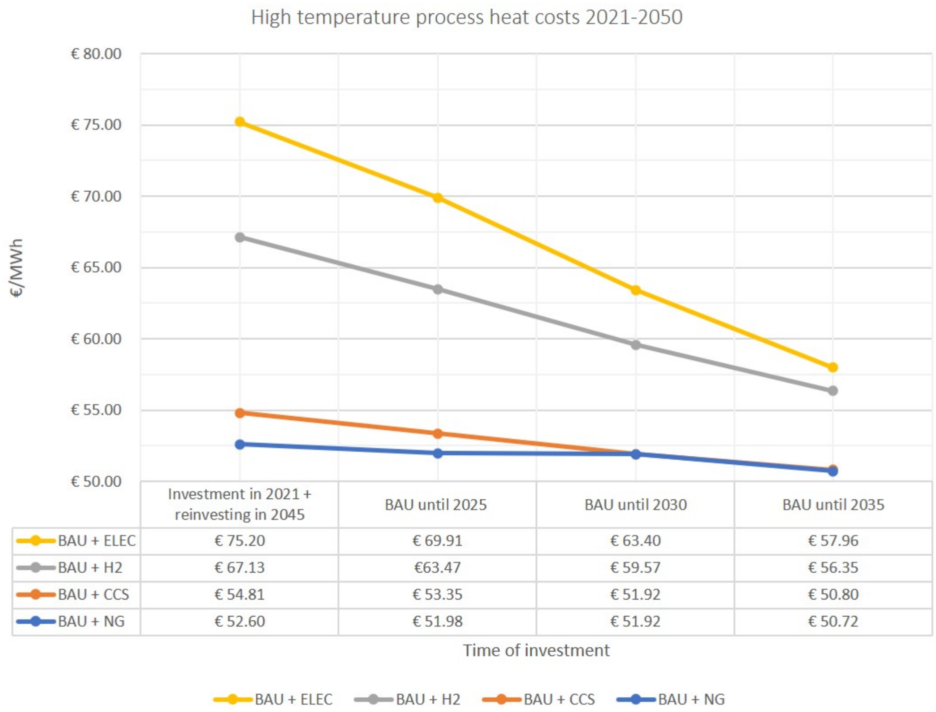


Figure 48: High temperature process heat generation LCOE development with B.A.U. and investment scenarios combined for all four alternatives

The total CO2 emissions for the different scenarios can be observed in Table 18. BAU combined with NG has no emissions reduction and thus yields higher total emissions for all different scenarios. When combined with NG + CCS, it is seen, that the longer the investment is postponed, the higher the total emissions become for each of the sectors. When combined with electrification, one can see that the total CO2 emissions seem to decline when the BAU period is extended. This can be attributed to the fact that in 2021, the generation mix of electricity is still heavily reliant on fossil generation. In 2033, the CO2 emissions from electricity generation per MWh are lower than the emissions of using natural gas for process heat. This can be seen by the increase in emissions from 2030 to 2035, at which electrification is a cleaner solution than natural gas. For blue hydrogen use, the emission results are similar to NG + CCS. An increase in CO2 emissions is seen the longer the BAU holds.

Table 18: CO2 emissions in Mt for B.A.U. combined with the four alternatives for all three process heat sectors

CO2 emissions in Mt for combined scenarios of B.A.U.from 2021 to 2050												
	Investment in 2021			B.A.U. until 2025			B.A.U. until 2030			B.A.U. until 2035		
BAU with:	LT	MT	HT	LT	MT	HT	LT	MT	HT	LT	MT	HT
NG	20.9	21.4	23.3	20.9	21.4	23.3	20.9	21.4	23.3	20.9	21.4	23.3
NG + CCS	3.3	3.5	4.5	5.7	5.9	7.0	8.6	8.9	10.1	11.6	12.0	13.4
Electrification	17.9	17.9	19.7	17.1	17.2	18.9	16.7	16.9	18.4	16.8	17.1	18.7
Blue H2	1.2	1.2	1.3	3.8	3.9	4.2	7.1	7.3	8.0	10.5	10.8	11.7

4.3.2 Feedstock hydrogen production

In Figure 49 the same pattern as described in the previous paragraph can be observed here. The costs converge towards the B.A.U. + SMR scenario. All costs have a steady decline, due to discounting the CAPEX when BAU is extended. The positive effects on the LCOE that result from declining costs of ATR and SMR with CCS are barely visible, due to the discounting effect, that weighs the current costs situation heavier than future costs. Therefore, the prices converge towards the longest extended BAU scenario. The lower costs of alternatives hardly have any effect on the combined LCOE.

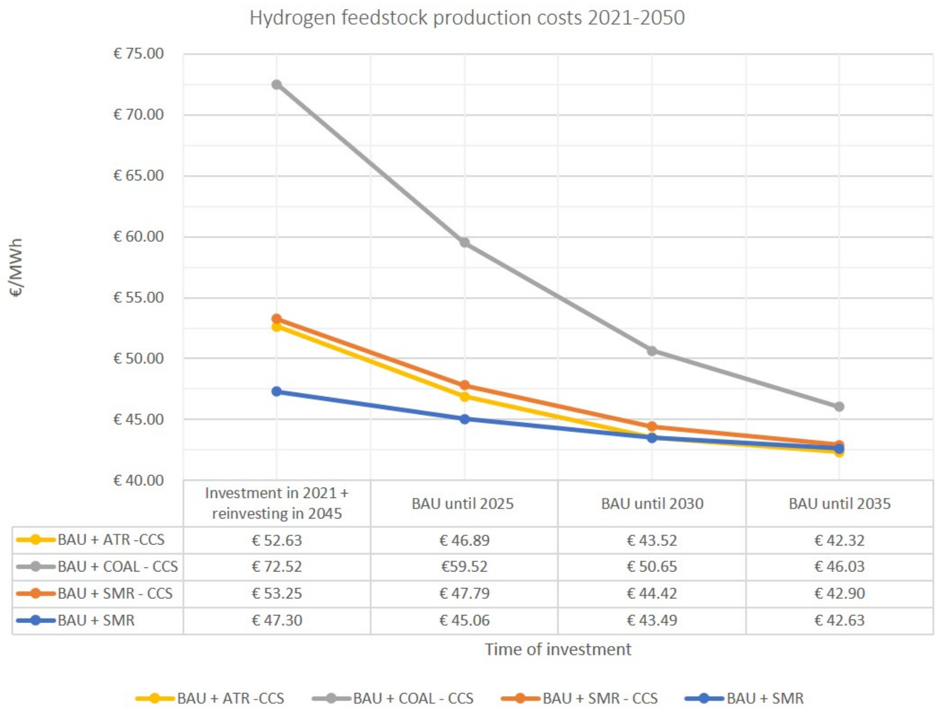


Figure 49: Caption

Table 19: Total CO2 emissions for different feedstock alternatives until the end of B.A.U. period

CO2 emissions for combined scenarios of B.A.U. from 2021 - 2050				
BAU combined with:	Investment in 2021	B.A.U. until 2025	B.A.U. until 2030	B.A.U. until 2035
SMR	22	22	22	22
SMR + CCS	7	8	11	13
ATR + CCS	1	4	7	10
Coal + CCS	8	10	12	14

Table 19 can be interpreted the same as Table 18. BAU with SMR yields no CO2 emissions reduction, whilst extending the BAU period increases the CO2 emissions for every alternative that has CCS in place. The earlier the investment, the lower the total emissions between 2021 and 2050.

Concluding on the combined scenarios for alternatives costs, the business as usual scenario has seemingly low LCOE, whilst not specifically utilizing the lowest cost alternative that is available in all time frames. The effect of discounting future cash flows in the levelized cost method is clearly present in the results. Natural gas without CCS is the lowest cost alternative for the first two investment periods. However it can be seen that while these costs slightly increase, the other alternatives costs all go down and converge to the natural gas scenario. When looking at the period from 2021 to 2050 and comparing all alternatives across sectors, that would imply that postponing investment as long as possible is economically the best option.

This can be explained because the discounting of costs in the LCOE method weighs the costs in the present more than future costs, and therefore the business as usual scenario has an advantage over alternatives. In LCOE, the initial investment is obviously not discounted, which results in a large fraction of costs where the CAPEX is high. Electricity prices rapidly decrease from 2035 on, and in the same time period the CO2 prices per tonne start on an accelerated incline. As previously noted, the levelized cost of energy mostly represent the costs at the start of each investment time span due to the discounting in cost assessment. The real cost per MWh of energy will is expected to be significantly lower or or higher than the LCOE outcome.

4.4 Merit orders for green hydrogen alternatives

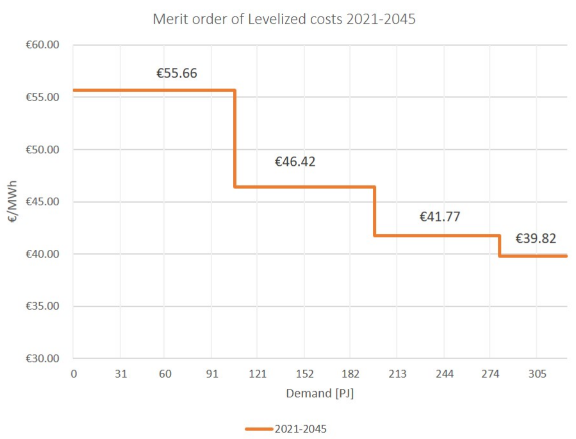
The representation of the levelized costs per time span in a merit order provides us with the maximum costs for green hydrogen for specific demands at the start of each one of the investment periods. In order to be cost competitive, the LCOE for the final use of 1 MWh of green hydrogen is limited for the thresholds per sector that are represented in the merit orders. First, the separate investment scenarios are placed in merit orders for each of their own investment periods. Secondly, the combined cases of B.A.U. with investments are represented in their corresponding merit order for 2021-2050.

4.4.1 Merit order for Scenario II for 2021,2025,2030 or 2035

The lowest costs alternatives are plotted with their corresponding demand, which has been averaged over the total life cycle of the investment. This shows that the green hydrogen use in the Dutch industry when considered at the time of investment would have a demand. The results are visualized in Figures 50a, 50b, 50c and 50d with the exact demands presented in Table 20. Green hydrogen can be most competitive in the high temperature heat sector, followed by feedstock, medium and then low temperature process heat processes. It has to be noted that the indicated costs in the merit order are per unit of energy that is generated. Therefore, the total LCOE for green hydrogen and not just the fuel costs need to be considered when looking at these merit orders.

Table 20: Merit order profiles with demand, and corresponding costs for various times of investment

Different investment periods Scenario I								
Sector	*LCOE*	*Demand*	*LCOE*	*Demand*	*LCOE*	*Demand*	*LCOE*	*Demand*
	2021-2045		2025-2049		2030-2054		2035-2059	
HT heat	€ 55.66	106	€ 56.64	107	€ 60.04	109	€ 59.90	110
Feedstock	€ 46.42	92	€ 47.25	93	€ 47.97	94	€ 47.19	95
MT Heat	€ 41.77	82	€ 42.67	83	€ 44.57	84	€ 44.40	85
LT Heat	€ 39.82	44	€ 41.00	44	€ 42.70	45	€ 42.54	45



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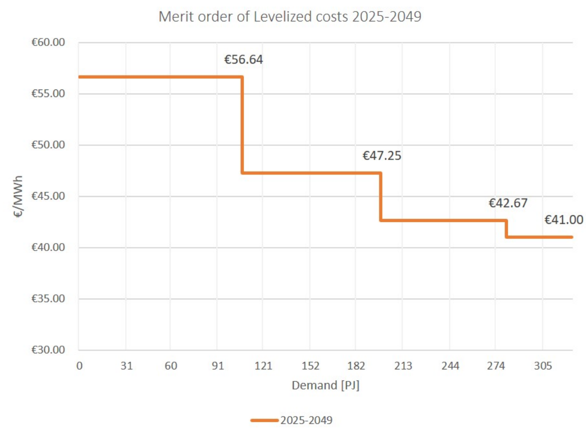

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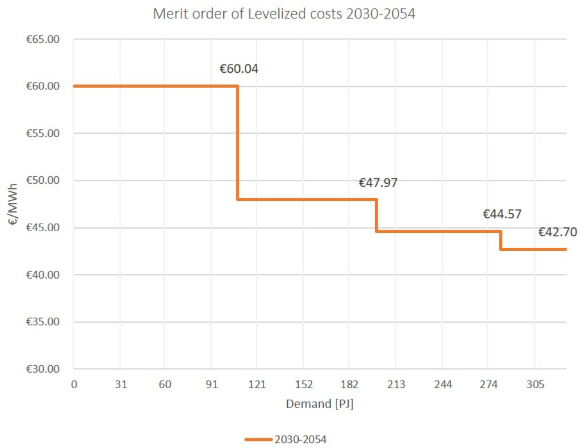

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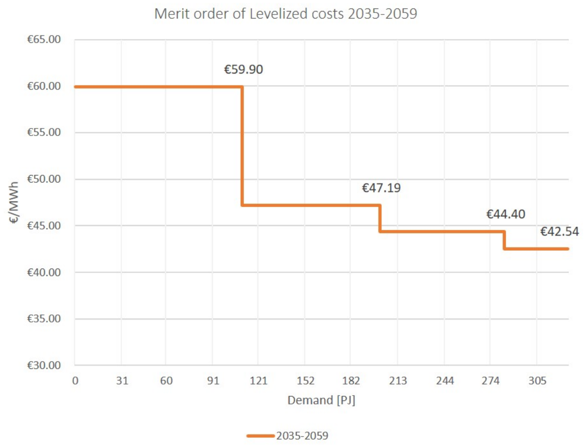


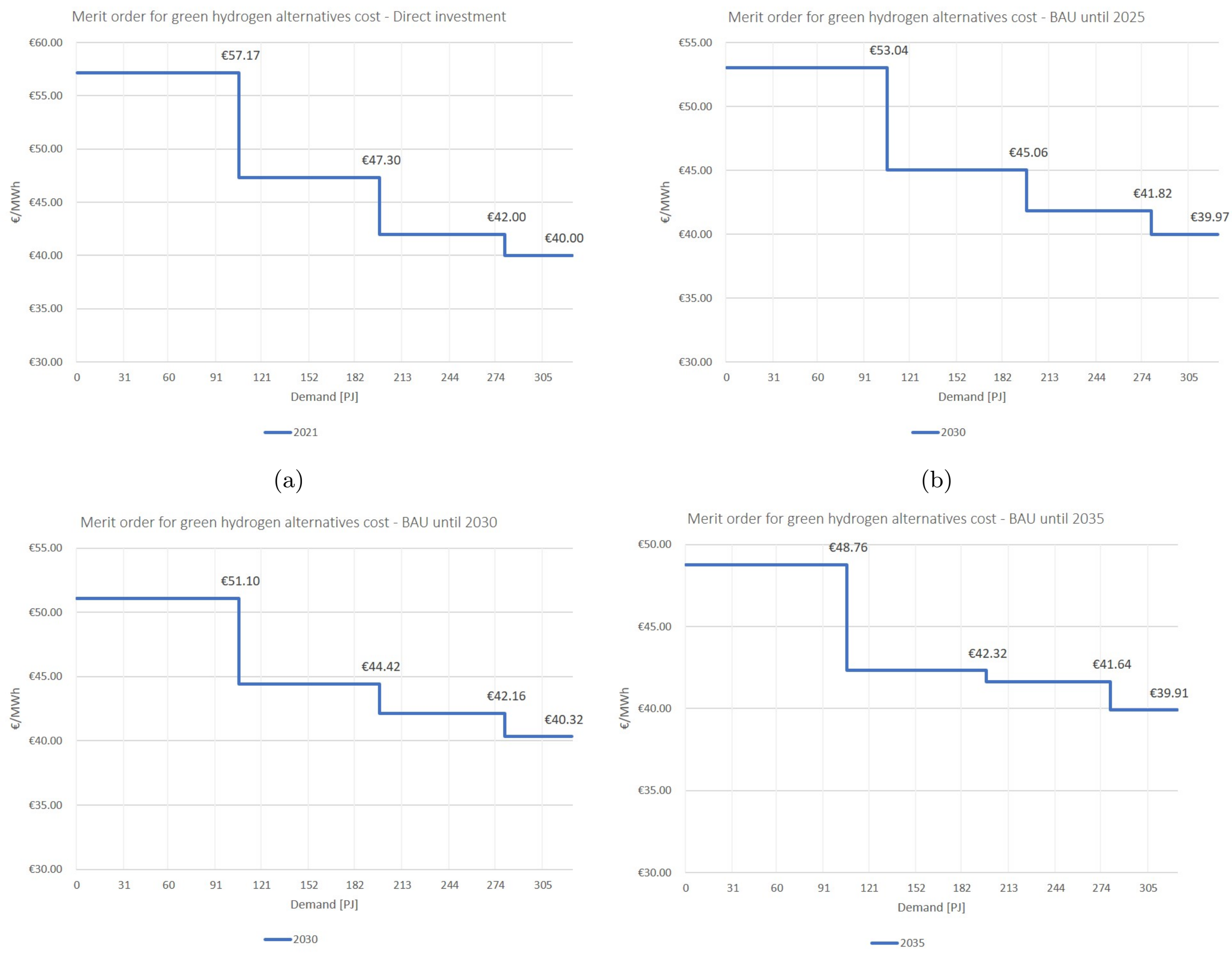
(d)

Figure 50: All four merit orders for the first scenario. In all cost scenarios the orders follow HT heat, Feedstock, MT and finally LT process heat

4.4.2 Merit orders for Scenario II for 2021-2050

The results for the levelized cost of energy for alternatives to green hydrogen when combined with several business as usual scenarios can be found in Figures 51a, 51b, 51c and 51d and Table 21. The competitive cost for green hydrogen in this merit order is based on the last scenario, with business as usual until 2035, at which point the same alternative, natural gas without CCS, is reinstalled. This is an expected result as the result that came from previous section show that the levelized cost of energy method favours the current state of art with respect to new alternatives. As the majority of the costs for all four different sectors comes from fuel costs.

For this entire period, the final merit order in Figure 51d provides the one that is price setting as the competitive price for green hydrogen in the Dutch industry between 2021 and 2050.



(a) (b) (c) (d)

Figure 51: All four merit orders for the first scenario. In all cost scenarios the orders follow HT heat, Feedstock, MT and finally LT process heat

Table 21: Merit order profiles with demand, and corresponding costs for various times of investment

Scenario II with different investment periods 2021-2050					
Sector	*Demand*	*Levelized costs of energy*			
		2021	2025	2030	2035
HT heat	106	€ 57.17	€ 53.04	€ 51.10	€ 48.76
Feedstock	92	€ 47.30	€ 45.06	€ 44.42	€ 42.32
MT Heat	82	€ 42.00	€ 41.82	€ 42.16	€ 41.64
LT Heat	44	€ 40.00	€ 39.97	€ 40.32	€ 39.91

4.5 Sensitivity analyses

This subsection aims to demonstrate the sensitivity of the modelling results by changing several key input parameters for both of the main scenarios to show the differences in calculation method. First the effect of varying discount rates is demonstrated, followed by studying the impact of varying scaling factors. Concluding, an analysis on the effects of varying CO2 prices is demonstrated. In all sensitivities, the case for high temperature heat generation is shown, because the high capital costs, high fuel costs and high CO2 emissions show the sensitivities best of all four sectors.

4.5.1 Sensitivity to discount rates

The sensitivity to discount rates for is rather high for both scenario studies, as can be seen in Figures Figure 52a, 52b, 52c, 52d and 53a, 53b, 53c and 53d. As already briefly mentioned in the previous subsections, the scenarios react differently to the discount rate. Figure 52a, 52b, 52c, 52d shows, that in the case of no comparison with business as usual, when increasing the discount rate from 0% to 12%, the effect on natural gas for process heat is different than for the three alternatives. The LCOE for natural gas increases, the other costs all decrease. The increase in costs of natural gas is smaller than the alternatives costs decrease. The sensitivity is different per alternative. The outliers are electrification and blue hydrogen with respectively €18/MWh and €10/MWh differences in LCOE for 12% change of discount factor, which indicates a sensitivity of €1.5/% and €0.83/%.

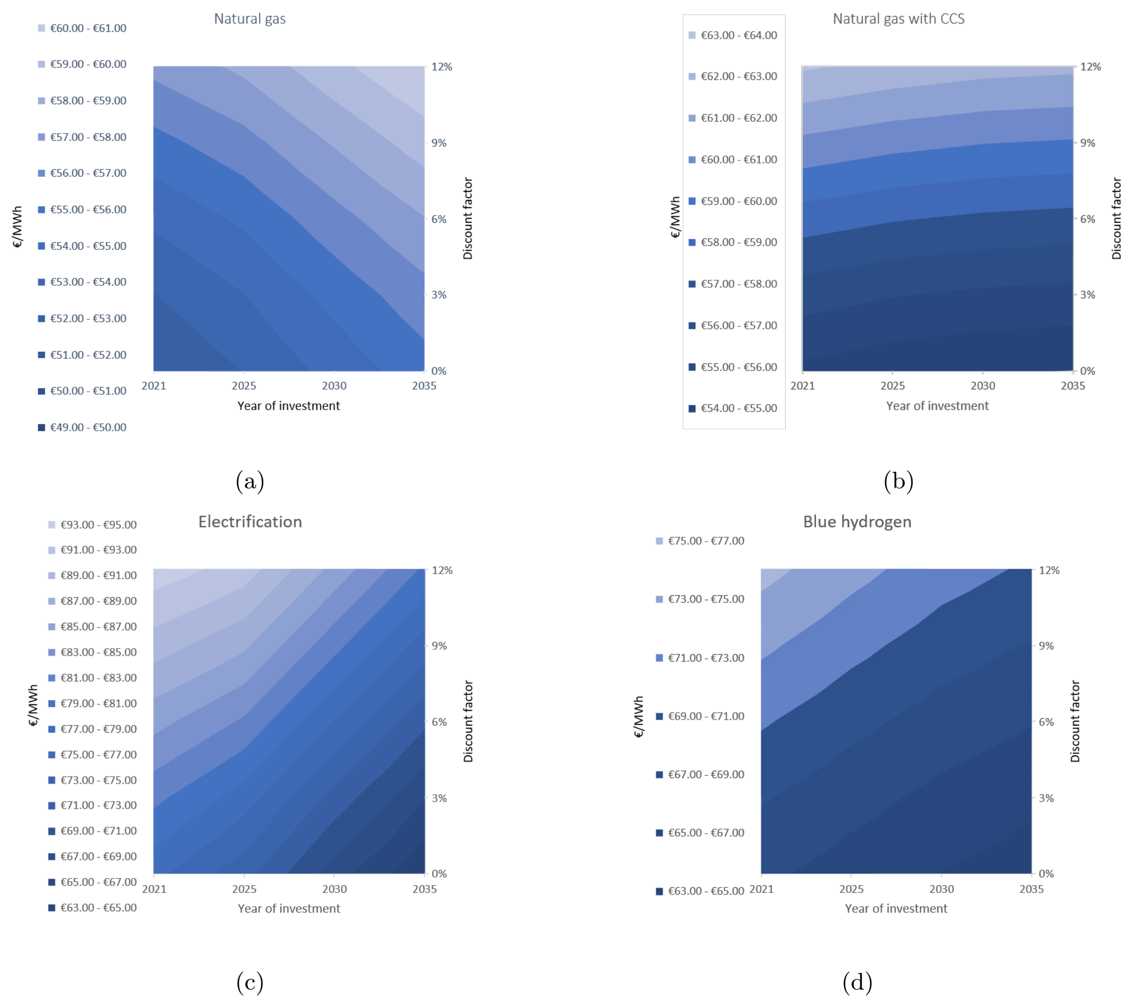
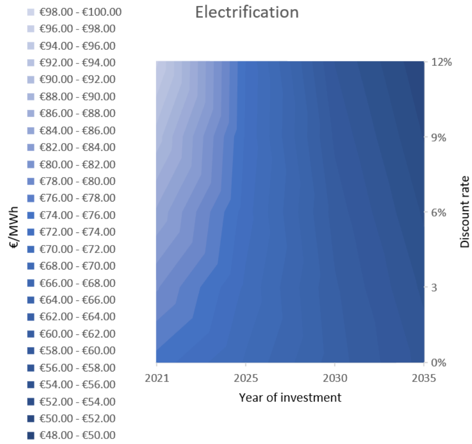


Figure 52: Price sensitivity of LCOE with respect to discount factors for each different process heat alternative of the first scenario

When comparing to the sensitivity of Figure 52a, 52a, 52a, 52a the behaviour that is found in Figures 53a, 53b, 53c, 53d is quite different. For all technologies, it can be seen that the behaviour in cost development is the same from the contour lines, which go more vertical indicating that the influence on of the discount rate is limited when 2030 is approached. The sensitivity decreases when times passes on, showing that the change in LCOE is more affected by year of investment than actual discount rate. The outliers from the previous paragraph, electrification and blue hydrogen have a sensitivity in 2021 of respectively €2/% and €1.17/% and in 2035 these sensitivities are both €0.67/% change in discount rate.

Discounting in this scenario favours the current state of art with respect to alternatives, because the alternatives fuel costs, CO2 price and the difference between CCS costs and the CO2 price are improving with respect to the current situation.



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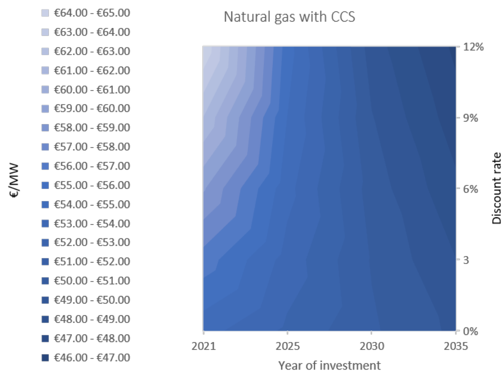

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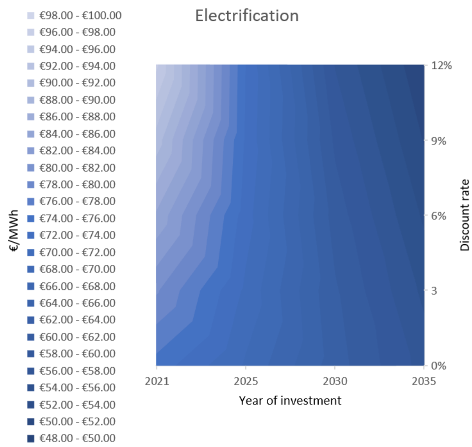

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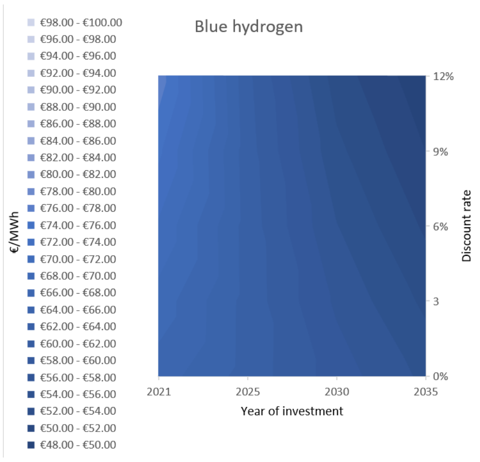
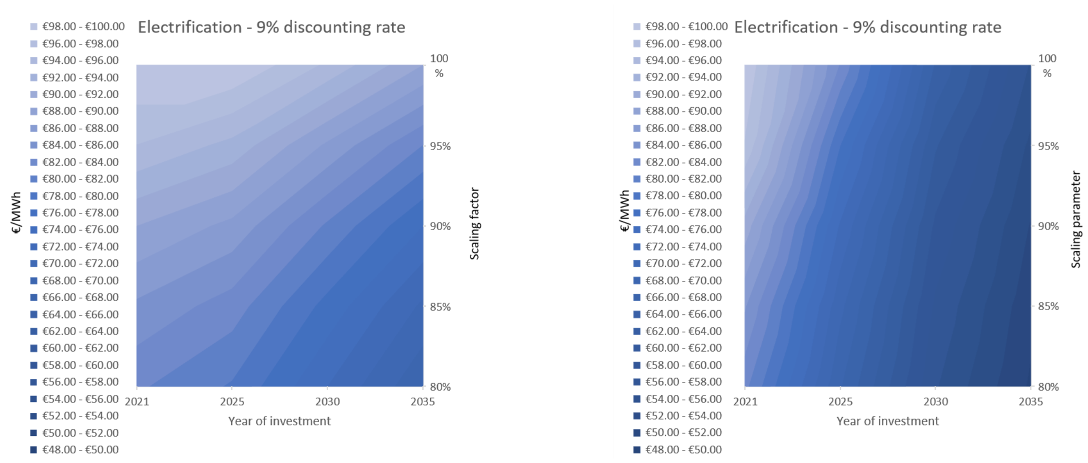


(d)

Figure 53: Price sensitivity of LCOE with respect to discount factors for each different process heat alternative of the second scenario with B.A.U.

4.5.2 Sensitivity to investment scaling factors

The sensitivity to the scaling factor from Equation (reference) is rather high. This is shown in Figure 54a and 54b for respectively the scenario with and without business as usual high temperature electrification. It shows that the LCOE change by €22/MWh for a difference of 20% scaling factor. In the BAU comparison scenario this sensitivity is heavily influenced by the year of investment due and thus the discounting rate.

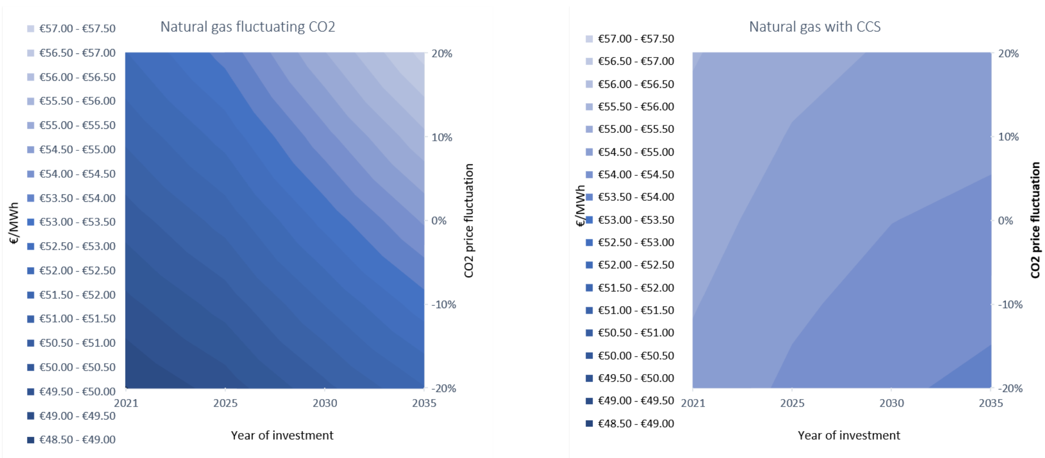


(a) (b)

Figure 54: Sensitivity with respect to scaling factor for the scenarios with and without business as usual in respectively Figure 54a and Figure 54b

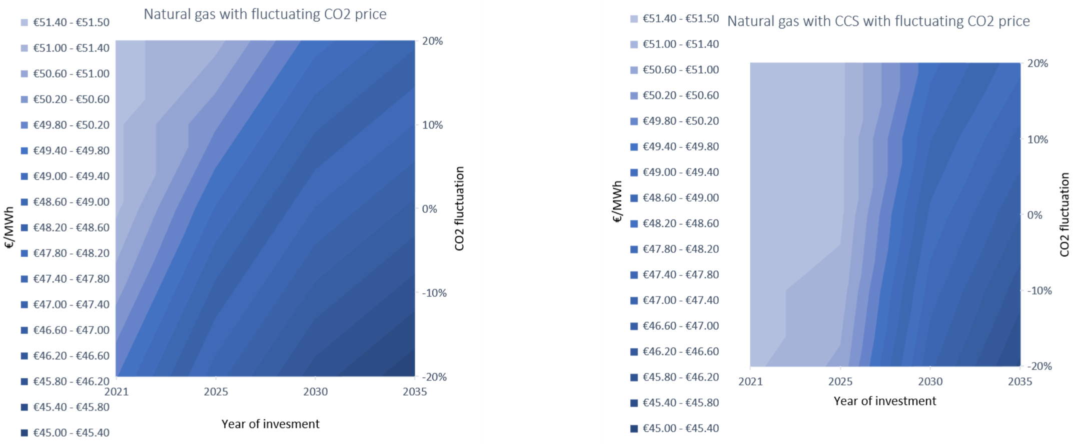
4.5.3 Sensitivity to CO2 prices

The sensitivity to CO2 prices is shown by comparing high temperature process heat from natural gas and from natural gas with carbon capture at the standard discounting rate of 9% for the two main scenarios in Figures 55a, 55b and Figures 56a, 56b. The LCOE and CO2 fluctuation have a stronger effect later towards the future where the CO2 costs are higher. The LCOE of natural gas with CCS is hardly affected by a change in CO2 price, a maximum change of €2/MWh between a 40% CO2 price difference as opposed to a change of €12/MWh for a 40% price fluctuation. Figures 56a, 56b show a different sensitivity. Here, the sensitivity is a lot lower, because the higher CO2 prices are more heavily discounted. For natural gas and natural gas with CCS, the LCOE change by respectively €2/MWh €3.5/MWh for a 40% CO2 price fluctuation.



(a) (b)

Figure 55: Price sensitivities of the LCOE with respect to fluctuating CO2 prices for high temperature heat generation with natural gas with and without CCS for scenario 1 without B.A.U.

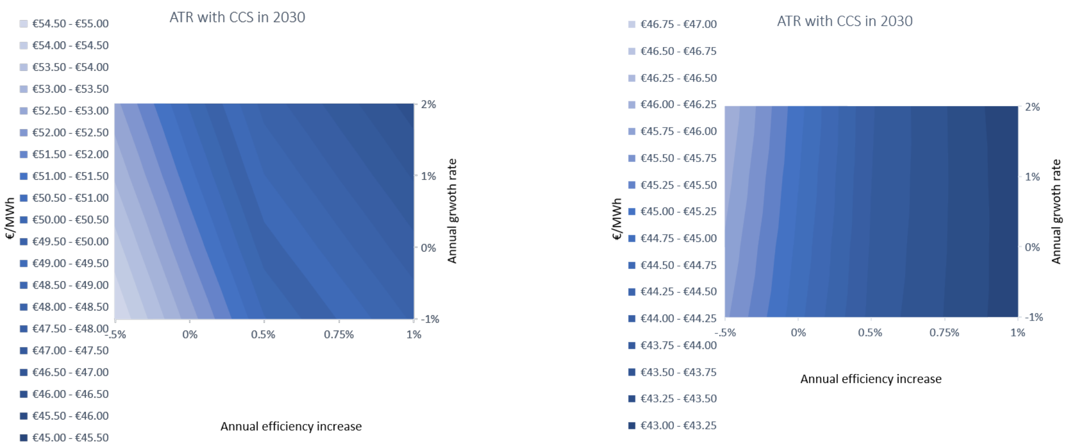


(a) (b)

Figure 56: Price sensitivities of the LCOE with respect to fluctuating CO2 prices for high temperature heat generation with natural gas with and without CCS for scenario 1 without B.A.U.

4.5.4 Sensitivity of annual growth vs efficiency improvements

This section aims to shown the interaction between annual growth rates and annual efficiency improvements. The case of ATR with CCS for hydrogen feedstock production has been chosen, due to its assumed efficiency improvement between 2021 and 2030, in which the technology is fully matured. Figure 57a shows Scenario I, Figure 57b depicts Scenario II. It can be seen that growth and efficiency amplify each others effects negatively and positively, which makes sense. Increase in growth has positive a positive effect on the scaling that occurs in CAPEX whilst efficiency improvements reduce the fuel costs as well as the required installed capacity and thus its CAPEX. The differences between Scenario I and Scenario II are that the effect of efficiency increase is higher for Scenario I. The sensitivity is slightly negative for Scenario II, except for the highest efficiency improvement combined with the highest growth rate.



(a) (b)

Figure 57: Price sensitivities of the LCOE for ATR with CCS in 2030 with respect to fluctuations in annual growth rate with respect to annual efficiency improvements. Scenario I is shown in Figure 57a and Scenario II is shown in Figure 57b

5 Discussion

This chapter presents the findings of this research project. The findings are based on the background research as well as the modelling part. After presenting the main findings, the limitations of this research project are discussed.

5.1 General research findings and insights

This thesis aims to create an insight on the costs of several green hydrogen alternatives for the Dutch industry sector. The ultimate goal for this switch to green hydrogen is the decarbonisation challenge that the Netherlands are facing as a fossil fueled country with a high emission intensity in its industry. Green hydrogen for various industrial applications is often regarded by politicians as a magic energy transition fuel. However, as it can be seen in Section2, the current use for hydrogen, globally and on a national scale, is as a feedstock product industries with high CO2 emissions. Virtually all hydrogen that is currently produced and used is based on reforming of natural gas, comes from coal gasification or from byproducts and rest streams in oil refining processes or the production of chlorine. Some cases involve carbon capturing, most cases do not. The share of green hydrogen production is close to negligible compared to this, resulting in a low competitiveness. The use of hydrogen as a fuel for generating process heat is not yet in practice in the Netherlands, let alone using costly green hydrogen for these processes. Secondly, even though the use of hydrogen is widespread in the chemical and refining industry, these are located in clusters or hubs that have somewhat direct access to merchant hydrogen production or large scale production on site. For other processes, the distribution network for hydrogen is not yet created adding another obstacle to decarbonisation. Large scale electrification of industrial heat also requires investment and expansion of the electricity grid. Natural gas distribution networks is connected to industrial sites and thus natural gas is available in abundance. This adds to the difficulty of achieving decarbonisation goals in the Dutch industry. The chance of polluting and paying the price for it being more economic than using (green or blue) hydrogen, power to heat or carbon capturing fossil fuel combinations, is a realistic obstacle in the goal towards decarbonisation of the Dutch industrial sector.

In general, there is not a lot of development in reducing carbon emissions in the Dutch process industry, with even an incline of greenhouse gases noted in the last years.

The different processes that are found in Section 2.2 have been researched for their decarbonisation potential in the MIDDEN database project. However, there were no implications on costs attached to these various alternatives. The complexity of every single process shows that the task at hand is difficult as many sectors seem to have been locked in current production processes. Refining industries being extremely efficient with their energy and flue gas streams make up for a seamless production process, but a highly polluting one. The same goes for for example steel making, where each step of the process is essential for the following step in production. Feedstock use of hydrogen also is dominated by highly efficient production processes and corresponding flue gas streams in between different companies at industrial clusters. Changing a small element of the process could have major implications for the costs of production. The differences in complexity between refining, plastics production and food production processes however made it hard to differentiate on a detailed scale between processes, resulting in a division of four main sectors instead of being able to zoom in on a process level.

The value chains and their developments are a point of discussion as well. The costs of production of the several green hydrogen alternatives do not reflect the prices at the market. The height of the margins on natural gas and market effects on electricity prices are rather high in the Netherlands. The development of the cost elements for each value chain are relatively constant. Comparing natural gas production and electricity use, electrification is more CO2 intensive per MWh than natural gas. From 2032 and further on, when goals of increasing the share of renewables are met, the CO2 intensity of electricity decreases below the natural gas intensity.

The research into cost modelling had an impact on the methodology and modelling results. Several available cost assessing methods that share high similarities are present, however not all are suitable for such a cost perspective only analysis. Business case analyses - cost-benefit, energy systems analysis, LCA - often include benefits or some other sort of income, which was not the case in this project. For the costs before the meter, supply chain cost modelling is the only option for such an analysis as conducted.

When looking at costs only, LCOE is suited for the task. Widely accepted as a way of expressing costs of (renewable) energy projects, there is a small gap in academic foundation of levelized costs of energy. By addressing the concerns with respect to oversimplifications in cost forming, an adjusted LCOE could be created.

5.2 Modelling findings and insights

The insights of the modelling part of this report are based on the results section presented in Chapter 4. The results are split into two central parts: cost before the meter and cost after the meter. The latter is split into 3 parts, investment in different periods, combinations of business as usual and investment between 2021 and 2050 and a sensitivity analysis on both scenarios.

5.2.1 Costs before the meter

When looking at the results for the electricity price fraction forecast, the decreasing market effects and increase in transmission and distribution costs are noteworthy. The effect of the market on price formation can be partly attributed to the CO2 emissions trading system in Europe. This market is dominated by intermediate traders that only trade in emission rights without using them. The increased scarcity of these rights have a price driving effect. With high shares of fossil fueled power generation, the CO2 costs have an important part in price forming. However, when the share of renewables is increasing towards 2050, that would require less and less emission rights that have to be traded when generating electricity, resulting in a lower cost of electricity per MWh. The increase in T&D costs from €11.33/MWh to €17.54/MWh can also be discussed. The required investments in the electricity grid to cope with the increased share of renewable energy (higher intermittency and higher peak loads). However, it is arguable whether these costs will be transferred to consumers or not.

Natural gas supply chain cost fractions are split in pipelined and LNG transported gas. When looking at the results of both the expected cost development, the curves are fairly stagnant. As mentioned in Section 4, the production costs of natural gas go up due to the depletion of easy-access gas wells and hard to reach wells have to be tapped into. The distribution costs are also expected to be almost constant, as there is mainly annual operations and maintenance costs and no additional investments or grid expansion. The LNG specific costs decrease over the coming years, however the total cost of LNG transport is simply not competitive with pipeline transport. The profit margin needs to decrease if gas prices drop, or else LNG transport would be sold below marginal costs.

Blue hydrogen costs before the meter are dependent on natural gas price, CCS costs and distribution costs. Market effects are taken out of the equation due to the lack of a wholesale hydrogen market for now. The hydrogen backbone in the Netherlands for the distribution and storage of hydrogen is going to be finished in or around 2030. The height of these costs is based on assumptions of the hydrogen demand in 2030. With lower demand, obviously the net costs will increase and vice versa. However, it can be seen that the largest cost fraction is natural gas costs, thus the decrease in costs of natural gas will make blue hydrogen prices drop, but without subsidizing hydrogen or penalizing natural gas, the blue H2 costs will always be higher than the natural gas costs.

5.2.2 Costs behind the meter

To make a fair comparison between sectors, all the demands have been set at 10 PJ annual heat demand, with an annual growth of 1% and annual efficiency improvement of 0.75% until 2030. For the costs behind the meter the almost absence of CAPEX in the results for low and medium temperature heat for all the alternatives. The costs of CAPEX only become a substantial part in electrification, where CAPEX are 5 times higher than natural gas CAPEX. Fuel costs dominate the LCOE, making electrification and blue hydrogen unfit for competition with natural gas due to high commodity costs. The costs of carbon capturing and the corresponding increased fuel consumption are higher than emitting CO2 and polluting. Even though the emissions are roughly six times higher for NG compared to NG + CCS or blue hydrogen, neither one is competitive until 2030. This can be attributed to CO2 prices being too low to push towards more sustainable investments.

High temperature heat has an even more unfavourable outcome when the goal is to reduce CO2 emissions. Natural gas is the most economic option until 2035. Being the highest polluting sector, the potential for emission reduction is high. However, due to natural gas being significantly less expensive when it comes to fuel costs, and CAPEX, the additional CO2 costs do not weigh it down enough. Electrification and blue hydrogen are simply too expensive to compete.

For hydrogen feedstock production, the case of reducing carbon emissions is the most positive, with SMR LCOE being overtaken before the other alternatives by ATR with carbon capturing, around 2027. The produces an enormous carbon reduction, as the efficiency of carbon capturing is close to 100%, which also makes the costs decrease more rapidly as the difference between CCS costs and CO2 emission costs increases towards the future. It is also the only sector in which a carbon reducing alternative becomes lower in costs than the natural gas fired alternative in the scenarios where business as usual is taken into the equation.

A second point of interest are the CAPEX of electrification of process heat. The grid connection costs are found to be €120,000 per MW of required capacity. In the case of low and medium temperature heat, this is respectively 10 or 2 times as high as the equipment costs and raise high temperature costs by an additional 10%. On top of the connection costs and the electricity costs, there is an annual fee of €20,000 per installed MW of capacity. Question is whether it is a viable assumption that companies will have to pay all these costs or that the costs are shared between companies located at industrial clusters, reducing cost. Secondly, if such enormous amounts are to be paid for electricity, there is a possibility that mentioned clusters start generating their own renewable electricity.

In terms of sensitivity, the effect of discounting is more visible in the combined B.A.U. scenario as it is without business as usual. This is due to the discounting of (future) costs. This results in favouring the extension of B.A.U. for as long as possible in the combined scenario, as well as the convergence of the costs towards the B.A.U. scenario. The effect of discounting also weakens the higher CO2 price in the future, as well as the lower electricity and CCS costs, whilst amplifying favourable current natural gas tariffs w.r.t. the alternatives. The effects scaling are also amplified by discounting the future. A lower difference or equal discounting sensitivity allows for a more fair comparison of alternatives and scenarios.

The sensitivity of annual growth versus efficiency improvements shows that the annual growth rate has a direct effect on the LCOE. When demonstrating this with ATR with CCS, the effects of scaling can be seen in the CAPEX resulting in a lower specific investment cost. The increased growth is also discounted, thus the increased fuel consumption costs are relatively speaking lower. The annual efficiency improvement influences the fuel costs as well as the specific investment costs which reduces the positive effect of scaling. However, the lower resulting required capacity leads to lower CAPEX as well. The influence on fuel costs is most significant, as this is the largest part of the LCOE for both Scenarios. The difference in sensitivity between Scenario I and II can be attributed to the fact that for Scenario I, ATR with CCS is already cost competitive around 2027, whereas for Scenario II, the LCOE of ATR slightly overtakes the business as usual scenario with SMR in 2035. This results in a higher benefit from the improved technology.

A direct comparison between these two scenarios can not be made with standard discount rates. This does not mean that there are no take-aways when trying to compare the consequences of the different ways of looking at the scenarios. Depending which way of looking at the investments is taken, the outcome varies between sustainable towards the future or not. Depending on the way of implementing LCOE, it can either be favourable or not for green hydrogen. Higher costs overall for all alternatives create a more competitive position for green hydrogen than when alternatives becomes increasingly less expensive. However, green hydrogen production requires electricity to produce and this might implicate that up to the point that electricity prices are significantly lower than natural gas prices, the cost competitiveness for green hydrogen does not look promising.

Measures to increase the competitiveness of green hydrogen as a fuel or feedstock would quickly resolve to subsidizing natural gas - hydrogen combined process heat installations, that would allow the industries to switch to blue and then green hydrogen with relative ease. As soon as the backbone for hydrogen and heat generation installations are in place, the industry can switch to hydrogen use. However, for it to be competitive, the costs of natural gas would have to go down drastically with increasing CO2 emissions costs and CO2 storage costs, or else natural gas without or with CCS would still be the more favourable option.

However, blue hydrogen as a transfer medium might be unwanted, due to the economies of scale that would start to emerge and drive down costs of blue hydrogen that have to disband quickly after achieving growth to make place for green hydrogen. This is an undesirable situation as it would lock-in the use of blue hydrogen, which would hinder the overall energy transition progress.

Concluding on these different scenarios, one might say that the decarbonizing is not necessarily too expensive, but the price on polluting is too low. This makes it difficult for the companies across the researched sectors to bridge the cost gap from the B.A.U. scenarios towards a more sustainable means of generating process heat or hydrogen as a feedstock. Reasoned from the cost perspective, the competition of green hydrogen alternatives in terms of costs will be either natural gas or natural gas with CCS, which can be seen in the merit orders presented at the end of the Results section. They show natural gas as the lowest cost alternative until 2030 and until 2050 for the combined business as usual scenario. As the hydrogen backbone prospect of completion lies in 2030, this would be the ultimate goal for green hydrogen to reach competitive prices.

5.3 Discussion on simplifications, assumptions and model behaviour

This section the limitations of this research project are discussed. The limitations consist of simplifications that were made in the project as well as the assumptions that are done in the modelling part of this project.

5.3.1 Simplifications

In order to create a model to predict LCOE of green hydrogen alternatives for determining competitiveness of green hydrogen across several processes and sectors, a fair amount of simplifications needed to be made.

To start of with the biggest simplification that is made, which is saying that all the natural gas used for heat generation in the mentioned processes could be replaced with alternatives or green hydrogen. No waste heat, or CHP generated heat are considered. This simplification resulted in there being no distinctions between processes in the same sector, apart from the energy demand differences. This resulted in a necessary change of perspective, to a generalized sector wide approach instead of being able to find the value for each process specifically. Therefore, the calculated results for an entire sector might vary significantly between two processes that are considered to be in the same sector.

Blue hydrogen cost calculations are assumed to be equal to blue hydrogen prices. Obviously, this is not the case, as this is not how markets work. However, no market price information for high volume hydrogen trade is presently available. This however, makes the case of blue hydrogen prone to error as a free market price hardly is just the sum of its costs. When the use of blue hydrogen over natural gas is stimulated by for example energy premiums, the market price can drop below its marginal cost of production and this improves the competitiveness of blue hydrogen. However, when the demand for blue hydrogen rises suddenly, this can result in a price peak on the market due to an imbalance in supply and demand, which has a negative effect on the competitiveness of blue hydrogen.

The alternatives that are presented for green hydrogen are in reality, not limited to the mentioned alternatives of this paper. However, these are the current state of art and focal areas when it comes to research into decarbonising industries. There is ample amounts of research taking place that looks at specific sustainable applications for specific processes. When limiting the industries options to only fuel or feedstock substitution, one can provide a more comprehensive overview without having to go too much in detail for a selection of production processes. However, the alternation of processes is not taken into account in this research project, as this would be close impossible to investigate for all mentioned processes industry wide and this is already performed for specific cases in the research for the MIDDEN database. In some cases it might be possible that none of the modelled alternatives is a favourable option over a more tailored solution such as a process alteration.

Fourth, only costs are considered, and no benefits to any party whatsoever. This means, that the captured CO2 needs to be transported and stored, whilst in current market situations the captured CO2 is often partially sold to third parties, reducing CCS costs per tonne drastically. In a more realistic approach for example, CCU (carbon capturing and utilization) instead of CCS would greatly alter the outcomes, as the avoided CO2 emission costs combine with revenue generated from selling CO2. This is currently in practice at some industrial clusters already as mentioned in the Section 3.5. The inclusion of added revenue would positively affect the cost decrease of carbon capture and storage making it a better competitor in terms of cost with respect to the other alternatives. This would have a negative impact on the competitiveness of green hydrogen, as the costs for CCS processes might drop far below marginal production cost of green hydrogen.

The simplification of no inter dependency between infrastructural developments and the use of green hydrogen alternatives affects the outcome of the model in such a way, that independent of the actual availability of the alternatives technology, the availability of the fuel is guaranteed and vice versa. As mentioned in the previous paragraph, hydrogen as a fuel for process heat generation or feedstock substitution would require the completion of the hydrogen backbone. The lack of infrastructure, or higher costs than assumed for CO2 shipping and storing would also rule out the possible benefits of carbon capturing over CO2 emissions costs. For electrification of process heat the same principle counts as well. The effect on the results could be that even though in theory a proposed alternative is the most economical at a certain moment of investment, it might not be possible to actually make use of this technology. Therefore it is important that required infrastructure is ready at ideal investment moment. For business investors, the consequences of for example economies of scale not emerging and momentum shifting towards another alternative can thus completely change the outcome of the modelling results. For policy makers, it can be difficult to make a correct assessment on the ideal energy strategy for different alternatives because the capital investments required for infrastructural developments are incredibly high compared to stand alone power plants.

The final simplification of leaving out steel production as the standard case for high temperature heat generation seems to have low impact on the outcome of the results. For the generalized demand of 10 PJ, it can already be seen that electrification as well as blue hydrogen use are not on par in terms of cost with natural gas or natural gas with CCS. With steel production having an incredible annual demand, the 10PJ demand results would likely be exaggerated for 88PJ. The consequence of this, is that by default the steels sector can not decarbonize its production process due to the incredible costs connected to investing in new equipment, as well as the high factory energy demand of Tata Steel Ijmuiden. Process alterations would be the only option for decarbonising such a plant, which is more specifically discussed on different research papers.

5.3.2 Discussion of modelling assumptions

There is a high number of assumptions that is made in modelling the economic competitiveness of green hydrogen , of which the most high impacting ones are discussed in the following paragraphs.

Firstly, the used commodity and CO2 price forecasts are based on data delivered by DNV until 2050. After 2050 they are extrapolated towards 2065 using running average method. The intermittency of commodity prices due effects of a free market as well as the length of these forecasts make the results highly susceptible of change. Secondly, the inflation rate as a part of the discounting rate, is fixed from 2021 to 2065 as well as the discounting rate. Different starting and ending times of investment would probably require a different valuation of discounting and inflation rates. For ease of modelling, the growth of all industries is set at a fixed rate of 1% until 2065, with efficiency improvements in the factories energy demand of 0.75% annually. This results in a steady energy demand growth of 0.25% annually from 2021 to 2065. Energy demand growth and efficiency improvements are realistically not going to follow a linear development over time, but are more fluctuating of nature. Finally, a last linear development that has been assumed is the share of renewable energy generation increase in the total electricity generation mix and the according CO2 emissions that are released with electricity generation.

The different costs that are used for CAPEX are based on the most recent cost data, which is subject to change. The O&M costs, fixed and variable, are all represented as a percentage of the CAPEX and thus also subject to scaling of these costs. The real O&M costs are more likely to be process based than they are CAPEX based, however due to the small cost fraction they are modeled in this simple manner. With the actual CAPEX possibly being higher than only a small fixed percentage, this would have negative results on the LCOE for the studies alternatives.

When it comes to used equipment, it is assumed that all lifetimes are 25 years and no retrofitting of machinery takes place. On top of that, in the BAU scenario there is no way to know which industries still have what amounts of lifetime or residual value left. However, this will be taken into account by industries looking for investment. The residual value, elongated use or already fully depreciated investments could have a significant impact on the business case for the proposed alternatives. This is because replacing equipment before the end of lifetime or before it needs to be replaced has a negative effect on the costs. Secondly, when it comes to required installed capacity, there are no limits to the size of each installation. It is assumed that for example a 25 MW installation can scale to a 100 MW installation, without taking into account that it would require a multiple of installed machinery. Even though the effect of scaling factors for CAPEX is taken into account, economies of scale are only considered in non-mature technologies up to 2030, with a cost decrease of 1% annually. It is highly likely, that when an industry sector switches from one commodity to the other, the effects of the cost reduction through emerging of economies of scale is noticeable in more than just the CAPEX. The effects of learning that influence the energetic performance of technologies are also applied linearly, up to 2030 until the technology performance is on par with state of the art equipment. This results in a faster decline of costs, and may have a "snowball effect" in the first couple of years leading to even faster cost decline which in turn yields a competitive price that is less far away for new technologies.

Due to simplifications made for the potential demand of green hydrogen across the sectors, there is no distinction between processes in the same sector apart from the demand. However, the combined sector demand is way too large to give a reasonable estimate of the costs for the "average" factory in the corresponding sectors. This is partly due to the large differences in the effects of scaling, as well as the results of incredibly high CAPEX that are not realistic. Therefore, setting the demand per sector at 10 PJ for all sectors leads to a generalized result, on which different processes or factories can base estimates of their own cost on.

The scale of hydrogen production that is needed to fulfil the predicted demand is, as of now still unknown on a national or even global scale. The installations that currently are in use on such a large scale are in industries that already produce and use large amounts of hydrogen as a feedstock product, such as refining industries or ammonia production. Merchant production spread out over the Netherlands amounts to roughly 31 PJ yearly, which is also a combination of grey and blue hydrogen. The sheer size of production increase that is needed to fulfil the industries demand would require an increase of production of a factor 10. As previously mentioned, to fulfil this need would require an even higher use of natural gas for the industrial sector than currently is in place, making it unlikely for blue hydrogen to progress towards such a large scale as would be necessary to meet demand.

Finally, the combination of business as usual with new investments is simplified in a number of ways. The residual values of CAPEX in the combined scenario with business as usual is simplified by omitting decommissioning costs and converting the lifetime that is left of the investment into a percentage that is then subtracted from the CAPEX costs at time of investment. Normally, the residual value is calculated with use of opportunity costs, but as stated that is simplified here. However, as the residual value is paid back at the end of the discounted period of 2021-2050, the impact on the LCOE is negligible, as the CAPEX fraction of the LCOE is already rather low when no discounting is applied.

5.3.3 Model behaviour

The behaviour of the LCOE model is tested and shown in the sensitivity analysis in Section 4.5. Several input constants, such as annual energy demand growth versus efficiency improvements and the influence of varying CO2 prices, discount rates and scaling factors on the LCOE development towards 2050 are varied. This shows, that within reasonable input value fluctuations, the output of the model behaves as it is expected to behave under these varying constants. No outliers in terms of costs are observed. Overall annual decrease in energy demand from high efficiency improvements or low annual growth yields higher costs due to a smaller amount of discounted energy in the denominator of the LCOE equation. Higher CO2 prices raise the costs for all alternatives that emit CO2, higher or lower discounting rates result in a shift of the lowest cost alternative.

Validation of model output with findings in other works that make use of LCOE are rather hard for a number of reasons. First of all, due to using LCOE for process heat generation or feedstock production on site for specific industrial applications instead of the usual electricity generation. Combine that with total sector demands that have been equalized at 10 PJ instead of specific processes integration of the alternatives, the possibility of comparing the results from the altered LCOE with existing work gets increasingly difficult. As the LCOE is altered, there are several cost development that are present in this work that have not been taken into account by other authors. This brings us to the last point of difficulty, the research gap that has been identified and that is aimed be fulfilled with this research, indicates that there is no previously created overview of LCOE development for the four identified industry sectors to compare the results with.

6 Conclusion

This section of the report is written to form a conclusion on the report. First off, the answers on the main research question and sub questions will be presented after which recommendations for future research are presented. Finally, a personal reflection on the project is given.

6.1 Conclusion

At the start of this thesis project, a main research question has been formulated. To help answer this main question four sub-research questions have been derived. This research questions will be repeated and then the sub-questions will be answered followed by the main research question.

– *What is the economic competitiveness of green hydrogen based on the cost of alternatives in the Dutch industry and how does this develop towards 2050?*

The answers of the following sub-questions together form the answer to the main research question. These are presented in the next paragraphs.

1. *In the context of this research, what is the definition of economic competitiveness?*

   To be able to indicate the competitiveness of green hydrogen, the definition for economic competitiveness needs to be clear. This definition has been defined in Section 3.2 and reads as follows:

   – *The economic competitiveness follows from the price range that is set by the demand side altered levelized costs of energy of green hydrogen alternatives' for the Dutch process industry. These costs are based on the costs of installation and use of the alternatives as a fuel substitute in process heat generation or as an alternative means of producing hydrogen feedstock across different sectors in the Dutch industry. For green hydrogen to be economically competitive, the LCOE should fall within or below the price range that is set by the alternatives to green hydrogen for the various investment moments.*

   The costs that form the basis for this economic competitiveness are split in two parts. Costs before and after the meter. Costs before the meter aim to show the development of the fuel costs' supply chains and costs behind the meter incorporate these costs as well as the necessary investments that need to be made and costs that occur when using one of the alternatives. Finally, the combined costs behind the meter are expressed in an altered levelized cost of energy, which is explained in detail in Section 3.5. The final economic competitiveness is pictured in a demand side costs merit order. The different sectors that are addressed have different LCOE for each alternative and variable total sector demands. This merit order shows what the LCOE for green hydrogen needs to be in order to be economically competitive with the alternatives that are presented.

2. *Which sectors and processes in the Dutch industry have a potential demand for green hydrogen (incl. volumes) and what are the alternatives in these processes?*

   The answer to this question is found in dedicated Sections 2.2 and 2.3. Research on decarbonisation of the Dutch process industry is continually worked on and published since the start of the MIDDEN database project of the Dutch government as well as the Dutch hydrogen outlook for potential markets of hydrogen. Large industrial sectors are analyzed in depth, how their processes work as well as the alternatives there are for decarbonising their processes. For this research a number of these processes have been scrutinized, based on their potential of decarbonisation and size of the industry. This project assumes that the hydrogen production from natural gas and coal can be replaced by green hydrogen, whilst hydrogen found in residual gas stream at refining sites can not be replaced as it is economically not viable to import green hydrogen when it is freely available in waste streams. For process heat generation the processes in each sector use the same equipment without installation costs. Due to these assumption, there is little difference between processes and sectors, resulting in combining simplifying the different processes per sector into one.

First off, processes that require hydrogen as a feedstock material have been investigated. These are ammonia production, methanol/synfuel production and refining processes such as hydrotreatment of oil products. Their respective potential demands in 2021 are 58, 15 and 16.1 PJ. The current way of producing hydrogen is either SMR or coal gasification, and the presented alternatives are SMR with carbon capturing and storage and ATR with carbon capture and storage. Secondly, generation of process that is considered and split into three groups, high, medium and low temperatures that have temperature ranges of respectively 600 C and higher, 200 - 600 C and below 200 C. High temperature heat generation involves glass, ceramics and steel production with respective demands of 6.7, 6.8 and 88 PJ. Medium temperature heat generation consists of a partial demand of the food industry, plastics production and oil refining processes, with respective potential green hydrogen demands of 30, 30 and 20 PJ. Finally, low temperature heat production is found in the paper and food industries, with respective demand of 22.5 and 20 PJ. The alternatives for the process heat generation are the same across sectors, being natural gas, natural gas with CCS, electrification and blue hydrogen. The distinction between sectors lies in the difference in required equipment and the performance difference between these sorts of equipment.

3. *What are the value chains for these alternatives and what are their associated costs?*

The answer to this question can be found in Section 2.3 and 2.4. The value chain is split into the supply chain of the commodities and the integration of these commodities in the different sectors. The value chains have been analyzed from "well to industry use" so to speak. The four different commodities have supply chains that are split into production or generation, transmission and local distribution. This are the up and midstream segments that have overlap for each of the sectors. The industry part of the value chain consists of the implementation of using these various commodities for their intended purpose, being process heat generation and hydrogen feedstock production. The total value chain costs are expressed in the LCOE, consisting of the sum of the supply chain costs combined in fuel costs, as well as the integrated costs for CAPEX, O&M, CCS and CO2 costs.

4. *How can the alternatives' costs development towards 2050 for the Dutch industry be identified?*

The results in Section 4 as well as the chosen approach from Section 1.2 are dedicated to providing the answer for this sub-question. By incorporating CO2 costs, learning effects as well as the effects of economies of scale and technology maturing and changing commodity and network prices over the entire timespan of the studied investment into the LCOE calculations. An incorporation of steady annual growth of industry energy demand, combined with an increase in overall process efficiency, the alternatives LCOE development is displayed. All cost developments start in 2021 and end in 2050. The scenarios I and II are comparing the same alternatives for the three process heat generation sectors as well as the feedstock production sector over the four distinct investment periods. The first scenario does not include business as usual and assesses the entire 25 year lifetime for all four periods. Scenario two includes business as usual and looks at the four investment moments in the timespan of 2021-2050.

As seen in the Discussion, the LCOE show a bias towards the state of the art due the discounting of future costs. The longer an investment is postponed, the more economical the investment looks. When looking at commodity prices, the discounting partially neglects the annual increase in costs of CO2 emissions and the decreased costs of electricity and blue hydrogen. Technology maturing and economies of scale effects that are causing a significant decrease in CAPEX as well as the costs of carbon capturing, shipping and storing in between 2021 and 2035 are also overlooked with this method. capital cost decrease and CCS technology. The identification of differences in cost development between scenarios one and two therefore yields different results.

The LCOE development in the first scenario, are identified by taking the investment period and allowing the discounting to start at its respective year of investment. This provides an image of the "real" LCOE at the moment of investment which differs from a standard LCOE approach. The cost identification shows a significant variability of LCOE for the researched alternatives in the four different investment moments. This way of looking at future costs provides insights in the different aspects of the LCOE and how these change over time. This can aid the business cases of the lesser polluting alternatives compared to fossil fueled options without carbon capturing as it can be seen that for all four sectors, the state of art is no longer the lowest cost alternative, and is overtaken by a carbon capturing alternative before or around investment in 2030 due to an increase in CO2 costs as well as an increase in performance in terms of energy efficiency as well as decreased costs of capital.

In the second scenario, combining business as usual with the different times of investments in the timespan of 2021 to 2050 yields contrasting results. This is a more classical approach to identifying future costs, in which the discounting starts today and thus the effect of neglecting future commodity price development and CAPEX fluctuations is strongly present. This becomes clear when looking at the results for Scenario II in Section 4, where the state of the art remains the most cost effective alternative towards 2035 and even decreases in costs per MWh from 2021 to 2035. The other alternatives all converge towards natural gas without carbon capturing and reach parity prices in 2035.

When comparing the results of Scenario I and Scenario II, the outcome is highly different. For Scenario I it pays off to invest in low polluting alternatives as for scenario two, the highest polluting alternatives are the ones with the lowest expected costs between 2021 and 2050. This difference implies that the current way of looking at future costs can not be called a fair comparison for decarbonisation versus business as usual investments. When the world is aiming for a net zero economy by 2050 and the main cost identification method favours the present and downplays the effects of measures that are taken in order to reach those climate goals - increase in CO2 emissions and decrease of electricity prices - a change in identifying costs of polluting and more renewable options for the industry should be taken into account. The method of assessing costs as used in Scenario one is a first step in the right direction for making an honest comparison between alternatives.

To conclude, the main research question is answered combining the answers on the four research questions.

– *What is the economic competitiveness of green hydrogen based on the cost of alternatives in the Dutch industry and how does this develop towards 2050?*

Having answered the four sub research questions, these answers combined form the answer to the main research question. The economic competitiveness of green hydrogen based on alternatives for the Dutch industry is not yet where we would like it to be. First of all, it is important to note that the economic competitiveness stands or falls with the way one looks at the cost assessment of the alternatives of green hydrogen. As described in the Discussion in Section 5, the course of the LCOE development depends heavily on whether Scenario I or Scenario II is taken as a point of reference. Scenario I displays the fairest comparison between alternatives, with a visible development of the LCOE towards 2050 for all the investigated alternatives throughout the sectors. Increasing costs for natural gas fueled operations and decreasing costs for CO2 abating alternatives shows an increase in natural gas costs towards 2050, which raises the bottom level of the price range in which green hydrogen has to be in order to be a competitive alternative. These extra euros can make a large difference in overall costs. For Scenario II, the start of discounting in 2021 towards 2050 creates a poor investment base for carbon abating alternatives. Green hydrogen is regarded as a zero-carbon fuel and is highly influenced by the price of electricity. The stark decrease in future electricity costs as well as the increase of CO2 costs that occur around 2030-2035 are discounted to minimal values in Scenario II, starkly reducing the competitiveness of the CO2 abating alternatives as well as the economic competitiveness of green hydrogen towards 2050.

Across the researched sectors, the most competitive alternative between 2021 and 2025 is natural gas without carbon capturing installations, as it yields the lowest LCOE. This is somewhat expected as the energy transition starts to accelerate very gradually. For green hydrogen, as a new player in the market, to compete with established natural gas heat generation or feedstock production would be unrealistic in the first two investment stages. Apart from the fact that there is no hydrogen distribution network as well as large scale production, the costs of CO2 emissions and natural gas per MWh are simply too low to compete with across all investigated sectors.

Moving towards investment 2030, it can be seen that the increase of LCOE for natural gas is speeding up across all sectors. This can be attributed to the increase in forecasted CO2 costs. The costs of carbon capturing installations decline slightly, allowing for natural gas and natural gas with CCS to reach parity prices around 2030 for all four sectors except for high temperature process heat generation. The expected completion of the hydrogen backbone for the Netherlands in 2030 as well as large scale green hydrogen production plants starts to allow the implementation of green hydrogen and further cost reductions can be made due to economies of scale emerging. The main competitors around 2030 will still be natural gas, complemented with natural gas and CCS for process heat generation and SMR or ATR with CCS for hydrogen feedstock generation. Electrification or blue hydrogen for process heat generation are still not not in a price range that allows for direct competition with natural gas.

Around investment in 2035, the natural gas LCOE parity has been reached or in all the four sectors. In feedstock production both the CCS employing hydrogen production methods from natural gas outcompete standard SMR production. All three process heat generation sectors have a cleaner CO2 emitting alternative as most cost effective option available. Electrification costs are rapidly declining towards the price level of natural gas or natural gas with CCS, apart for high temperature process heat generation, decreasing the price range between the alternatives. The highest costs per MWh generated are found in high temperature process heat generation, followed by feedstock production, medium temperature heat and finally low temperature heat generation. When looking at the development of the alternatives' LCOE, the economic competitiveness is the highest in the high temperature heat sector. This is because natural gas remains the lowest cost alternative until 2035, with all CO2 emissions reducing alternatives not beating natural gas in terms of costs. This implies that the this will be the sector that has the highest need for a more cost effective alternative which creates space for green hydrogen implementation.

The second highest costs are found in feedstock generation. This is the first sector in which price parity is reached between natural gas and other alternatives with lower emissions, resulting in a lower direct need for green hydrogen to decarbonize the sector. That means that the measures that can be taken by governments such as increasing CO2 costs hardly have an effect on the LCOE of the two lowest cost alternatives, SMR and ATR both with CCS.

For medium and low temperature heat generation, the cost development of the alternatives is similar on the lowest cost end, with electrification making a stark decline in LCOE from 2025 onward. Due to the high fuel efficiency of the used equipment as well high rates of carbon capture, the LCOE for these two sectors are relatively low, with almost the entire LCOE consisting of fuel costs. This makes these two sectors more difficult to enter for green hydrogen, resulting in a lower economic competitiveness.

Up to 2030, the economic competitiveness of green hydrogen is not seen as particularly high, because of the correlation that can be seen between the amount of CO2 emissions and the LCOE of energy. The alternatives to green hydrogen with the highest CO2 emissions are also the ones that have the lowest costs. The lower the emissions, the higher the costs are until 2035. This indicates that for green hydrogen, which is a zero-emissions fuel, it is going to be difficult to compete with natural gas or natural gas with CCS. This indicates that for green hydrogen to become competitive, the free market forces are not likely to contribute to implementing green hydrogen, as they reinforce the current strong market position of fossil fuels.

As the LCOE are mostly based on the total lifetime fuel costs. With a total sector demand of 10 PJ, it can be seen in Section 4 that the CAPEX as well as CO2 costs per MWh of energy are omitted when comparing to fuel costs. The discussion on investing for transitioning towards a cleaner industry should therefore be more focused on the commodity costs instead of overnight investment costs. This increases the competitiveness of newer technologies, as their capital costs are often a lot higher than more matured technologies or the best practice cases, showing that these costs are less important over the lifetime of equipment when investing. It can be seen that for process heat generation, electrification does approach the price range set by the lowest cost alternatives of natural gas with and without CCS. For high and low temperature heat generation it even is the least economical option. However, electrification of process heat is considered an important pathway for decarbonising the industry and seems to get a foothold in industrial heat generation, despite the higher costs, due to government action that is taken to nudge industries away from fossil fired installations by the use of premiums or green energy tax discounts. As the ingredients of green hydrogen are water and electricity, it is key that the final fuel costs for electricity need to be on par with natural gas costs per MWh to reach an economically competitive market position for green hydrogen and thus specific action to accelerate the cost decline of electricity needs to be undertaken.

As the costs of green hydrogen alternatives that reduce CO2 emissions drop towards the future, it becomes more and more difficult for green hydrogen as a market entrant to compete with them. The same goes for the total LCOE of natural gas fueled alternatives, if the use of natural gas does not become increasingly more expensive in relation to green hydrogen, the competitiveness of natural gas fired solutions is going to be hard to beat for green hydrogen in the Dutch industry. Policy measures are needed to improve the competitive position of green hydrogen with respect to its alternatives.

With this research, a contribution for academics as well as the industry is created in gaining insights in the feasibility of green hydrogen for the Dutch process industry in terms of economics. A combination of several research papers has been made, combining the different processes and sectors and their proposed fuel substitutions for decarbonisation with their proposed costs. This leads to better insights in possible measures that need to be taken in order to create a more favourable decarbonisation pathway for the Dutch industry on an techno-economic basis.

6.2 Recommendations on future research

There are several recommendations that can be made for future research on the researched subject of this thesis. The first recommendation is to implement green hydrogen itself as one of the alternatives to make a better comparison on the feasibility of the proposed alternatives. However, the predictability of green hydrogen production is low, as the effects of economies of scale emerging can drastically decrease prices, as we have seen in the LCOE for wind and solar generated electricity, making it less valuable as a method for cost evaluation, but an important addition nonetheless.

Another recommendation would be combining qualitative research with this mostly quantitative analysis into a feasibility study for the researched alternatives and processes. More tailor made modeling results for the different processes instead of a sector wide result. Qualitative insights such as different locations, distances to a high voltage electricity grid, distance the proposed hydrogen backbone and whether or not factories are part of industrial clusters could cross out some of the proposed combinations whilst adding other options.

Thirdly, including the potential benefits of certain technologies and not limiting the research to costs of green hydrogen alternatives only. As already mentioned in previous sections, when capturing carbon and utilizing it, it may reduce cost and thus have a business value increasing the competitiveness of alternatives. On top of that, the real cost of carbon emissions is different than the ETS carbon emissions pricing. The side-effects of pollution can be included to offer better insights in different investment moments. For example, whilst investing in 2035 might be the most cost effective for now, the actual costs for ongoing climate change can result in much higher figures than assumed and perhaps could be incorporated in a follow up research.

To finalize the conclusion, a different viewpoint is added to the discussion on decarbonisation of the Dutch industry: It is not that decarbonisation options are too expensive, the price that is put on pollution is merely too low.

Implications on policy measures or incentives that need to be designed and instated to reach the decarbonisation goals for the Dutch industry are further elaborated on in Section 6.3.

6.3 Research implications

This section aims to describe the implications of this research project with respect to academics as well as to society. First the academic implications are described, followed by societal implications, which consist of implications for the energy transition, policy makers and the industry.

6.3.1 Academic implication

As the problem description in this thesis has mentioned, the levelized cost of energy way of assessing projected costs has room for improvement. After implementing suggestions on altering LCOE, the key academic implication found in this project is the high effect of discounting future costs which negatively highlights new, more sustainable technologies with respect to the state of art. This makes the standard LCOE unqualified for assessing renewable energy technologies, especially when comparing with fossil fuel alternatives, which corresponds with the findings of (Loewen, 2019, 2020). An alternative method that still implements net present value, but does not efface the future cost reductions of renewable energy or the increased cost of pollution is likely to produce a more realistic value for decarbonisation projects.

6.3.2 Societal implications

The implications for society, that is policy makers, industry parties and the energy transition as a whole of this research paper are found in the expression of costs by using levelized cost of energy as well as the decoupling of grid infrastructure for natural gas, electricity and hydrogen. Using LCOE for assessing different alternatives when replacement of equipment is needed, this leads to a biased result in favour of the state of art. As industries highly value the net present value and LCOE is assumed to correctly address this issue, the outcome of Scenario II is expected to be used by industry parties. This implies that for the industry to start reducing its carbon emissions drastically, we would have to wait until 2035. When using Scenario I results, the shift towards decarbonisation is expected to begin before or at latest 2030 as this outcome is less biased towards fossil fuels for process heat and hydrogen feedstock production. One might think that the high costs of sustainable alternatives would be favourable for the competitiveness of green hydrogen, however high costs for alternatives would likely hold back investment in equipment that is designed for green hydrogen use, because natural gas with carbon capturing is more economical to implement.

The implications for policy makers can be taken as straightforward as that there is need for policy to urge the industry to move away from fossil fuels without carbon capturing. From the sensitivity analysis of the LCOE with respect to CO2 price fluctuations it shows that an increase of CO2 price has different effects on both scenarios, but both are favourable for an earlier acceleration of industrial decarbonisation. As the current free market clearly does not aid in a transition to a net-zero economy, there are external measures necessary from policy makers to nudge the industry towards a quicker decarbonisation pathway. There are several options to the realisation of the decarbonisation goals. Mostly, these measures involve penalizing the CO2 emissions. However, by making everything more expensive the common complaint from the market is that they lose overall competitiveness to producers that fall outside the borders of the regulations. Another way of nudging the market, is by instead making decarbonisation options less expensive by introducing premiums or tax reductions to make the costs of durable alternatives go down towards the fossil fueled options.

This research also implies that as the majority of the LCOE consists of fuel costs over the entire lifetime, there should be more attention to these fuel costs when considering investment or policy. Even though the overnight capital cost are substantial, they make up to 10% of the total LCOE in the most expensive cases. The discussion on investment and policy design should therefore aim to focus more on lifetime costs than capital costs of investment.

The fourth implication is, that policy makers should not rely on levelized cost of energy calculations as it is used today for designing policy. They could consider changing to a more favourable metric for renewable or sustainable energy evaluation to get a honest comparison of alternatives. It is known that the LCOE is not solely used as a policy designing tool but used as an indicator for further research. However, due to the previously mentioned bias, the importance is stressed of making a fair comparison based on LCOE before discarding possible technologies or pathways based on an LCOE exploration.

The fifth implication for policy makers is the matter of carbon capture and storage as well as the use of blue hydrogen. Carbon capture and storage with natural gas is favourable over all alternatives by 2035, and in most cases around 2030. However, this would still require large amounts of natural gas use, and carbon capture and storage or using blue hydrogen is supposed to be a transitional method to switch to more sustainable green hydrogen or electrification of processes. As CCS and blue hydrogen production require infrastructure to for shipping and storing, the question is if this is a desirable outcome. The electricity price needs to be subsidized with a higher CO2 penalty in order to close the gap between electricity and natural gas prices. Furthermore, as green hydrogen is created with electricity, it is not going to reach a competitive price on par with natural gas without lower electricity prices. If society needs to shift towards net zero carbon in 2050, they are not going to make it without proper policy incentives such as a steeper increase in carbon pricing as well as stimulation of (renewable) electricity use in the industry.

Lastly, the implications for the energy transition are addressed. Scenario I yields slightly positive results, as Scenario II does not look as bright towards a net - or close to - zero economy in 2050. As seen in the results for Scenario II on the CO2 emissions per alternative per sector, it looks as if there is a correlation between high CO2 emissions and low levelized costs of energy. Also, for the energy transition to succeed, every step that is taken earlier than presumed is an extra step in the right direction. As long as the costs for carbon emissions are not significantly higher than the sum of CCS and their residual CO2 penalties, the low carbon alternatives will most likely not prevail. This research has shown that there is a lot of room for improvement in the Netherlands, and when choosing the next process heating or hydrogen production method wisely, big steps towards reaching climate agreements in the Netherlands can be taken. However, it is an interaction between the various stakeholders that needs to be streamlined in order to reach the goals that are in mind.

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7 Appendix I: Machinery options for investment

This appendix aims displays the total number of investigated equipment options that are not being modelled for process heat generation. In Table 22 all options for process heat with natural gas are shown. Table 23 shows all electrification options and Table 24 shows the process heating equipment for blue hydrogen.

Table 22: All equipment options and performance for process heating generation with natural gas

Process heat generation from natural gas		
Parameter	Costs	Unit
FIX OPEX Percentage [25]	2.00%	% of CAPEX
Low temperature process heat		
NG Boiler - 5 MW		
CAPEX [26]	€ 18,000.00	€/MW
FIX OPEX [25]	€ 360.00	
VAR OPEX	-	€/MWh
Efficiency	95%	
NG Boiler - 25 MW		
CAPEX [26]	€ 9,700.00	€/MW
FIX OPEX [25]	€ 194.00	€/MW
VAR OPEX	-	€/MWh
Efficiency [26]	95%	%
Med temperature process heat		
Water tube steam boiler		
CAPEX [26]	€ 55,000.00	€/MW
FIX OPEX [25]	€ 52,250.00	€/MW
VAR OPEX		€/MWh
Efficiency [26]	95%	%
High temperature process heat		
Water tube steam boiler		
CAPEX [26]	€ 55,000.00	€/MW
FIX OPEX [25]	€ 1,100.00	€/MW
VAR OPEX		€/MWh
Efficiency [26]	95%	%
NG furnace without CCS		
CAPEX [26]	€ 1,200,000.00	€/MW
FIX OPEX [25]	€ 24,000.00	€/MW
VAR OPEX		€/MWh
Efficiency [26]	85%	%

[25] (Nian et al., 2016a; Kost et al., 2018)
[26] (Rutten, 2019)

Table 23: All equipment options and performance for process heating generation with electricity

Process heat by electrification		
Parameter	Variable	Unit
FIX OPEX Percentage [27]	0.02	%
Low temperature		
Industrial heat pump		
CAPEX [28]	€ 70,000.00	€/MW
FIX OPEX [27]	€ 1,400.00	
VAR OPEX		€/MWh
Efficiency [28]		100%
Electrical boiler		
CAPEX [28]	€ 30,000.00	€/MW
FIX OPEX [27]	€ 600.00	%
VAR OPEX		€/MWh
Efficiency [28]	0.99	%
Med temperature		
5MW Electrical steam boiler		
CAPEX [28]	€ 70,000.00	€/MW
FIX OPEX [27]	€ 1,400.00	€/MW
VAR OPEX		€/MWh
Efficiency [28]	95%	%
80MW Electrical steam boiler		
CAPEX [28]	€ 100,000.00	€/MW
FIX OPEX [27]	€ 2,000.00	€/MW
VAR OPEX		€/MWh
Efficiency [28]	95%	%
Direct air heating		
CAPEX [28]	€ 1,000,000.00	€/MW
FIX OPEX [27]	€ 20,000.00	€/MW
VAR OPEX		€/MWh
Efficiency [28]	80%	%
High temperature		
80MW Electrical steam boiler		
CAPEX [28]	€ 100,000.00	€/MW
FIX OPEX [27]	€ 2,000.00	€/MW
VAR OPEX		€/MWh
Efficiency [28]	95%	%
Electrical furnace		
CAPEX [28]	2,000,000.00	€/MW
FIX OPEX [27]	€ 40,000.00	€/MW
VAR OPEX		€/MWh
Efficiency [28]	80%	%

[27] (Nian et al., 2016a; Kost et al., 2018)
[28] (Wapstra, 2018)

Table 24: All equipment options and performance for process heating generation with blue hydrogen

Process heat fueled with hydrogen		
Parameter	Variable	Unit
FIX OPEX Percentage[29]	0.02	%
Low temperature		
H2 boiler - 1 MW - retrofit		
CAPEX [30]	€ 20,000.00	€/MW
FIX OPEX [29]	€ 400.00	
VAR OPEX		€/MWh
Efficiency [30]	98%	
H2 boiler 80 MW - retrofit		
CAPEX [30]	€ 15,000.00	€/MW
FIX OPEX [29]	€ 300.00	€/MW
VAR OPEX		€/MWh
Efficiency [30]	98%	%
H2 boiler- new		
CAPEX [30]	€ 60,000.00	€/MW
FIX OPEX [29]	€ 1,200.00	€/MW
VAR OPEX		€/MWh
Efficiency [30]	0.98	%
Med temperature		
H2 steam - 1 MW - retrofit		
CAPEX [30]	€ 70,000.00	€/MW
FIX OPEX [29]	€ 1,400.00	€/MW
VAR OPEX		€/MWh
Efficiency [30]	99%	%
H2 steam - 80MW - retrofit		
CAPEX [30]	€ 100,000.00	€/MW
FIX OPEX [29]	€ 2,000.00	€/MW
VAR OPEX		€/MWh
Efficiency [30]	99%	%
H2 steam - new		
CAPEX [30]	€ 1,000,000.00	€/MW
FIX OPEX [29]	€ 20,000.00	€/MW
VAR OPEX		€/MWh
Efficiency [30]	80%	%
High temperature		
Hydrogen furnace retrofit		
CAPEX [30]	€ 400,000.00	€/MW
FIX OPEX [29]	€ 8,000.00	€/MW
VAR OPEX		€/MWh
Efficiency [30]	95%	%
Hydrogen furnace new		
CAPEX [30]	€ 1,200,000.00	€/MW
FIX OPEX [29]	€ 24,000.00	€/MW
VAR OPEX		€/MWh
Efficiency [30]	85%	%

8 Appendix II: Detailed results tables of cost fractions and development

This section is to show the exact results of cost developments of the results that are presented in Section 4 for the four different sectors.

Table 25: Low temperature process heat generation costs developments

Natural gas boiler							
Year	*Eff.%*	*Cap. (MW)*	*Capex(M€)*	*Capex/MW*	*Fuel (€/MWh)*	*CO2 (€/MWh)*	*CCS (€/MWh)*
2021	95%	365	€ 1.97	€ 5,376	€ 31.95	€ 7.78	€ -
2025	95%	369	€ 1.98	€ 5,371	€ 32.05	€ 8.87	€ -
2030	95%	374	€ 2.00	€ 5,365	€ 31.91	€ 10.34	€ -
2035	95%	378	€ 2.03	€ 5,358	€ 31.80	€ 11.72	€ -
Changes 2021-2035	0%	3%	3%	-0.3%	-0.5%	50.6%	-

Natural gas boiler with carbon capture and storage							
Year	*Eff.%*	*Cap. (MW)*	*Capex(M€)*	*Capex/MW*	*Fuel (€/MWh)*	*CO2 (€/MWh)*	*CCS (€/MWh)*
2021	84%	412	€ 8.39	€ 20,361	€ 36.39	€ 1.26	€ 4.09
2025	85%	415	€ 8.17	€ 19,715	€ 36.41	€ 1.42	€ 3.87
2030	85%	418	€ 7.91	€ 18,938	€ 36.21	€ 1.63	€ 3.69
2035	85%	423	€ 8.02	€ 18,956	€ 36.08	€ 1.85	€ 3.53
Changes 2021-2035	1%	3%	-4%	-6.9%	-0.8%	46.5%	-13.6%

Electrical boiler							
Year	*Eff.%*	*Cap. (MW)*	*Capex(M€)*	*Capex/MW*	*Fuel (€/MWh)*	*CO2 (€/MWh)*	*CCS (€/MWh)*
2021	99%	351	€ 51.39	€ 146,529	€ 61.79	€ -	€ -
2025	99%	354	€ 51.66	€ 145,863	€ 59.93	€ -	€ -
2030	99%	358	€ 52.00	€ 145,067	€ 54.70	€ -	€ -
2035	99%	363	€ 52.63	€ 145,049	€ 49.57	€ -	€ -
Changes 2021-2035	0%	3%	2%	-1.0%	-19.8%	-	-

Hydrogen boiler							
Year	*Eff.%*	*Cap. (MW)*	*Capex(M€)*	*Capex/MW*	*Fuel (€/MWh)*	*CO2 (€/MWh)*	*CCS (€/MWh)*
2021	95%	365	€ 4.00	€ 10,957	€ 55.71	€ -	€ -
2025	95%	369	€ 3.88	€ 10,515	€ 54.95	€ -	€ -
2030	95%	374	€ 3.73	€ 9,987	€ 53.96	€ -	€ -
2035	95%	378	€ 3.77	€ 9,975	€ 53.36	€ -	€ -
Changes 2021-2035	0%	3%	-6%	-9.0%	-4.2%	-	-

[29] (Nian et al., 2016a; Kost et al., 2018)
[30] (Wapstra, 2018)

Table 26: Medium temperature process heat generation costs developments

Natural gas high pressure water tube boiler							
Year	*Eff.%*	*Cap. (MW)*	*Capex(M€)*	*Capex/MW*	*Fuel (€/MWh)*	*CO2 (€/MWh)*	*CCS (€/MWh)*
2021	95%	377	€ 11.47	€ 30,387	€ 33.24	€ 8.06	€ -
2025	95%	381	€ 11.57	€ 30,357	€ 33.09	€ 9.11	€ -
2030	95%	386	€ 11.70	€ 30,320	€ 32.95	€ 10.59	€ -
2035	95%	390	€ 11.82	€ 30,284	€ 32.84	€ 12.01	€ -
Changes 2021-2035	0%	3%	3%	-0.3%	-1.2%	49.0%	-

Natural gas watertube boiler with carbon capture and storage							
Year	*Eff.%*	*Cap. (MW)*	*Capex(M€)*	*Capex/MW*	*Fuel (€/MWh)*	*CO2 (€/MWh)*	*CCS (€/MWh)*
2021	82%	412	€ 20.53	€ 49,838	€ 37.86	€ 1.31	€ 4.25
2025	82%	415	€ 20.38	€ 49,154	€ 37.60	€ 1.46	€ 4.00
2030	82%	418	€ 20.20	€ 48,328	€ 37.39	€ 1.69	€ 3.81
2035	82%	423	€ 20.44	€ 48,311	€ 37.26	€ 1.91	€ 3.64
Changes 2021-2035	1%	3%	0%	-3.1%	-1.6%	45.4%	-14.3%

Electrical steam boiler							
Year	*Eff.%*	*Cap. (MW)*	*Capex(M€)*	*Capex/MW*	*Fuel (€/MWh)*	*CO2 (€/MWh)*	*CCS (€/MWh)*
2021	99%	351	€ 64.92	€ 185,098	€ 62.26	€ -	€ -
2025	99%	354	€ 64.76	€ 182,876	€ 59.93	€ -	€ -
2030	99%	358	€ 64.60	€ 180,224	€ 54.70	€ -	€ -
2035	99%	363	€ 65.37	€ 180,163	€ 49.57	€ -	€ -
Changes 2021-2035	0%	3%	1%	-2.7%	-20.4%	-	-

Hydrogen steam boiler							
Year	*Eff.%*	*Cap. (MW)*	*Capex(M€)*	*Capex/MW*	*Fuel (€/MWh)*	*CO2 (€/MWh)*	*CCS (€/MWh)*
2021	95%	377	€ 51.85	€ 137,389	€ 57.96	€ -	€ -
2025	95%	381	€ 50.25	€ 131,848	€ 56.74	€ -	€ -
2030	95%	386	€ 48.31	€ 125,234	€ 55.72	€ -	€ -
2035	95%	390	€ 48.84	€ 125,083	€ 55.10	€ -	€ -
Changes 2021-2035	0%	3%	-6%	-9.0%	-4.9%	-	-

Table 27: High temperature process heat generation costs developments

Natural gas furnace							
Year	*Eff.%*	*Cap. (MW)*	*Capex(M€)*	*Capex/MW*	*Fuel (€/MWh)*	*CO2 (€/MWh)*	*CCS (€/MWh)*
2021	85%	408	€ 268.69	€ 657,752	€ 35.98	€ 8.77	€ -
2025	85%	412	€ 271.04	€ 657,115	€ 35.82	€ 9.92	€ -
2030	85%	417	€ 274.01	€ 656,320	€ 35.66	€ 11.55	€ -
2035	85%	423	€ 277.02	€ 655,526	€ 35.54	€ 13.10	€ -
Changes 2021-2035	0%	3%	3%	-0.3%	-1.2%	49.4%	-

Natural gas furnace with carbon capture and storage							
Year	*Eff.%*	*Cap. (MW)*	*Capex(M€)*	*Capex/MW*	*Fuel (€/MWh)*	*CO2 (€/MWh)*	*CCS (€/MWh)*
2021	75%	460	€ 327.64	€ 711,644	€ 40.97	€ 1.70	€ 3.89
2025	76%	463	€ 328.58	€ 709,183	€ 40.70	€ 1.89	€ 3.66
2030	76%	467	€ 329.83	€ 706,177	€ 40.47	€ 2.18	€ 3.49
2035	76%	473	€ 333.52	€ 705,490	€ 40.33	€ 2.47	€ 3.34
Changes 2021-2035	1%	3%	2%	-0.9%	-1.6%	45.4%	-14.1%

Electrical heating furnace							
Year	*Eff.%*	*Cap. (MW)*	*Capex(M€)*	*Capex/MW*	*Fuel (€/MWh)*	*CO2 (€/MWh)*	*CCS (€/MWh)*
2021	99%	386	€ 471.26	€ 1,221,512	€ 68.49	€ -	€ -
2025	99%	390	€ 475.44	€ 1,220,455	€ 65.92	€ -	€ -
2030	99%	394	€ 480.71	€ 1,219,136	€ 60.17	€ -	€ -
2035	99%	399	€ 486.04	€ 1,217,818	€ 54.53	€ -	€ -
Changes 2021-2035	0%	3%	3%	-0.3%	-20.4%	-	-

Hydrogen furnace							
Year	*Eff.%*	*Cap. (MW)*	*Capex(M€)*	*Capex/MW*	*Fuel (€/MWh)*	*CO2 (€/MWh)*	*CCS (€/MWh)*
2021	85%	408	€ 266.00	€ 651,175	€ 62.74	€ -	€ -
2025	85%	412	€ 257.76	€ 624,910	€ 61.42	€ -	€ -
2030	85%	417	€ 247.81	€ 593,564	€ 60.31	€ -	€ -
2035	85%	423	€ 250.53	€ 592,846	€ 59.64	€ -	€ -
Changes 2021-2035	0%	3%	-6%	-9.0%	-4.9%	-	-

Table 28: Hydrogen feedstock production costs developments

Steam methane reforming							
Year	*Eff.%*	*Cap. (MW)*	*Capex(M€)*	*Capex/MW*	*Fuel (€/MWh)*	*CO2 (€/MWh)*	*CCS (€/MWh)*
2021	96%	362	€ 148.50	€ 410,580	€ 31.86	€ 7.81	€ -
2025	96%	365	€ 149.80	€ 410,183	€ 31.71	€ 8.85	€ -
2030	96%	370	€ 151.44	€ 409,686	€ 31.57	€ 10.31	€ -
2035	96%	386	€ 157.31	€ 407,960	€ 31.46	€ 11.67	€ -
Changes 2021-2035	0%	7%	6%	-0.6%	-1.3%	49.5%	-

Steam methane reforming with carbon capture and storage							
Year	*Eff.%*	*Cap. (MW)*	*Capex(M€)*	*Capex/MW*	*Fuel (€/MWh)*	*CO2 (€/MWh)*	*CCS (€/MWh)*
2021	91%	383	€ 278.15	€ 726,402	€ 33.98	€ 2.37	€ 3.17
2025	93%	375	€ 262.32	€ 699,206	€ 33.82	€ 2.65	€ 3.00
2030	93%	380	€ 252.20	€ 664,133	€ 33.67	€ 3.06	€ 2.87
2035	93%	396	€ 261.97	€ 661,335	€ 33.55	€ 3.46	€ 2.74
Changes 2021-2035	3%	3%	-6%	-9.0%	-1.3%	45.9%	-13.5%

Autothermal reforming with carbon capture and storage							
Year	*Eff.%*	*Cap. (MW)*	*Capex(M€)*	*Capex/MW*	*Fuel (€/MWh)*	*CO2 (€/MWh)*	*CCS (€/MWh)*
2021	85%	410	€ 267.04	€ 650,894	€ 34.63	€ 0.42	€ 4.54
2025	87%	402	€ 251.84	€ 626,525	€ 33.92	€ 0.47	€ 4.27
2030	91%	392	€ 234.06	€ 597,342	€ 33.46	€ 0.55	€ 4.06
2035	91%	409	€ 243.12	€ 594,825	€ 33.34	€ 0.62	€ 3.89
Changes 2021-2035	7%	0%	-9%	-8.6%	-3.7%	45.9%	-14.5%

Coal gasification							
Year	*Eff.%*	*Cap. (MW)*	*Capex(M€)*	*Capex/MW*	*Fuel (€/MWh)*	*CO2 (€/MWh)*	*CCS (€/MWh)*
2021	52%	668	€ 905.98	€ 1,356,791	€ 23.39	€ 2.31	€ 8.98
2025	52%	674	€ 913.91	€ 1,355,477	€ 23.39	€ 2.58	€ 9.02
2030	52%	682	€ 923.93	€ 1,353,837	€ 23.39	€ 2.98	€ 9.04
2035	52%	712	€ 959.71	€ 1,348,132	€ 23.39	€ 3.37	€ 9.04
Changes 2021-2035	0%	7%	6%	-0.6%	0.0%	45.9%	0.7%