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Abstract

The hydrogen and electricity markets are expected to become more strongly coupled in the future, and so the same can be expected for their infrastructure. This also calls for more integrated approaches for the design and sizing of different types of parallel energy infrastructure. Therefore, the decarbonization of the Dutch industry is investigated by the development of a hydrogen infrastructure. An important topic is the coupling of the development of a hydrogen market with the power market. The basis of this assessment is the ambition and formalised plans by the Dutch government to mitigate greenhouse gas emissions.

The objective of this document is to present and review a possible roadmap towards a low carbon industry in the Netherlands by the implementation of hydrogen in combination with carbon capture and storage (CCS). The work consists of two parts: Part One, the infrastructure that is required for the implementation of hydrogen with CCS all along its value chain. The study is addressing issues such as where hydrogen production facilities should be located, the types of processes these facilities should use, and whether the transportation of natural gas is preferred over the transport of hydrogen and CO_2 or not. Part Two is reviewing the corresponding market dynamics and an overarching view of the coupled hydrogen market and price dynamics.

For the first part, it is important to stress that the scope for the geospatial assessment has been limited: hydrogen and CCS, in combination with large scale renewable electricity production, was assumed as the only available technological pathway. This limited scope results in the fact that certain conclusions can be drawn with certainty, while others cannot. What cannot be concluded from this study is how hydrogen as a technological pathway compares to other solution pathways, such as electrification or renewable liquid fuels. What also has not become clear is how large scale water electrolysis can be rolled out in a commercially viable way in the long term (up to 2050). In the geospatial modelling work, electrolysis was assumed to be operated at a baseload, provided with renewable electricity buffered with utility-scale batteries. From a perspective of system efficiency, it would be more energy-efficient to provide this baseload electricity to electrified industrial processes without conversion to hydrogen. Although, given the implications on the electrical infrastructure, clarification of the cost-effectiveness of these two routes remains work for another study. Due to the nature of the chain tool, the dynamic response of electrolysers could not be modelled. Thus the possible advantage of running electrolysers at low electricity prices only was not investigated in relation to infrastructure.

What can be concluded is the following:

- First, CCS is required in order to achieve the Climate Agreement emission reduction targets for the industry of up to 95% less CO_2 emissions by 2050 with respect to 1990. Incineration of waste (7Mton

CO$_2$ in 2017) requires post-combustion capture and CCS for abatement of emissions not to exceed the target in 2050. Steel production, oil refining, and steam cracking processes release fuel gases that require ATR processes with CCS for decarbonization. And even in the ambitious high wind scenario (60GW in 2050), the availability of renewable electricity up to 2040 will not be sufficient to achieve the emission reduction targets with hydrogen from water electrolysis alone, not even considering the increase of cost of all energy demand (electricity, industrial heat, and hydrogen-based chemical products) that would follow.

- Consequently, the implementation of a hydrogen network in the southern part of the Netherlands was found as a no-regret pathway for decarbonization of the refining and cracking processes in this region, connecting the clusters of Rotterdam and Zeeland to those in Noord-Brabant and Limburg. Natural gas and fuel gases can be replaced in the short term in a cost-effective manner.
- But, the limited nature of CO_2 storage capacity in offshore gas fields and aquifers require alternatives to natural gas-based hydrogen production. A little under 900Mton of CO_2 storage capacity that was considered in this study would not be sufficient to accommodate an industrial energy transition and achieve the emission reduction targets based on CCS solely. An important aspect of this that should not be forgotten is that not only should the reduction targets be achieved, but they should also be maintained beyond 2050.
- As such, incineration of waste, recovery of industrial off-gas, and other production processes such as steel production should be given priority for usage of the available CO_2 storage capacity until mature alternatives have presented themselves.
- Furthermore, as the simulations show, costs along the whole value chain can be minimized if alternative energy carriers are developed alongside scaling up of the CCS network such that utilization of assets is maximized. In this study, this alternative was water electrolysis from renewable electricity sources. But given the cost of hydrogen from water electrolysis, the results were not convincing that, economically, this should be the only alternative.

The second part of the work focused on the market dynamics in situations where electricity and (local) hydrogen markets are coupled via electrolyzers and hydrogen power plants. Three 2030 scenarios for the Rotterdam industrial cluster were studied using a cascading electricity-hydrogen model: a situation where only blue hydrogen is used (the Blue scenario), a situation where 200 MW electrolyzers are added (the Celeste scenario), and a situation where 500 MW electrolyzers are added and 50 MW hydrogen demand for feedstock is introduced (the Viridian scenario).

From the scenario analyses, it can be concluded that:

- Fuelling hydrogen powerplants with blue hydrogen is possible, but the business cases for both the powerplant and the ATR have a high-risk profile: they are highly dependent on the electricity market dynamics. Hedging these risks in a proper way requires both parties to study the exact dynamics of the electricity market. From a system perspective, hydrogen powerplants may have additional value; via these plants, some seasonal storage ('cold winter scenarios') options become available, and they can provide other balancing services. This value should also be taken into account but is again also highly dependent on the dynamics of the electricity market in 2030.
- Adding green hydrogen consumers to the system, one should make sure enough renewable energy is available in the system, which an obvious conclusion, but practically it is hard to coordinate a required co-implementation for the development of renewables, electrolysers, and hydrogen storage.
- As long as there is not a lot of surplus of renewable energy, there will be only a market for blue hydrogen, and when the tipping point is reached and in addition, CCS capacity limits are reached, only green hydrogen will succeed. Based on the market dynamics analysis, it is expected that in the transition period, these dynamics will lead to a slow-down of the development of the hydrogen 'economy'. A hydrogen roadmap requires coordination of both the blue and green supply chain, and competition between the two just slows down the development.

For the business case for hydrogen applications in the industry, it will be crucial to identify all the value drivers and the opportunities offered by hydrogen for the (industrial) stakeholders. Hydrogen production, CCS, and hydrogen distribution infrastructure are capital intensive, and such investment is risky and challenging to rationalize without a long-term outlook on hydrogen demand. Governmental commitment and direction are needed to ensure the hydrogen market is there for the long term.

TABLE OF CONTENTS

Page

1 INTRODUCTION 1
1.1 Hydrogen 1
1.2 Report focus and content 2
2 OBJECTIVE 3
3 APPROACH AND METHODOLOGY 4
4 RESEARCH FOCUS AND DEVELOPMENT OF TOOLS 6
4.1 The Elegancy chain tool 6
4.2 EYE market model 7
5 ENERGY TRANSITION PATHWAYS IN THE NETHERLANDS 8
5.1 Today: energy and greenhouse gas emissions in the Netherlands 10
5.2 Setup of the Elegancy chain tool model 26
5.3 Tomorrow: deep decarbonization of industry 37
5.4 Conclusions on the chain modelling 51
6 HYDROGEN MARKET DYNAMICS IN THE ROTTERDAM INDUSTRIAL CLUSTER 52
6.1 Scenarios 52
6.2 Bid behaviour of actors 55
6.3 Market dynamics 59
6.4 Simulation results 62
6.5 Summary of results and discussion 65
7 BUSINESS CASES ROTTERDAM INDUSTRIAL CLUSTER 66
8 CONCLUSIONS 68

1 INTRODUCTION

To be able to achieve the emission reduction targets, the Netherlands has to change the energy system radically. Closely related to infrastructure are the commodity markets. By enabling the physical exchange of goods, infrastructure provides the hardware on which commodity markets can be run. Network capacities should be closely tailored to suit the needs of a market, preferably at minimum cost.

In traditional energy markets, market price and volume fluctuations have always existed to some extent, but have been relatively easy to account for when designing infrastructure. With increasing, intermittent energy sources, such as wind and solar-based electricity production, the fluctuations inherent to production hereof will pose additional constraints to the required network capacities. On the electricity market, while demand-side response technologies such as electrical, industrial boilers, or electrolysers may be expected to play an increasingly important role in addressing this issue, energy-intensive industrial processes are often designed to be run continuously. As a consequence, there is an increasing need for carbon-neutral dispatchable power, such as batteries or hydrogen-fuelled gas turbines, to supply the continuously operated industrial processes. Similarly, if the industry is to switch to hydrogen as a replacement for the carbon-based gas on which it heavily relies today, the supply of this hydrogen should be guaranteed. For example, this could be done by dispatchable hydrogen production from natural gas or large scale storage.

1.1 Hydrogen

It is obvious that there is an important role to play for hydrogen in the energy mix for the industry. There are different technologies for hydrogen production that will have a broad range impact on the mitigation of greenhouse gas emissions and relative competitiveness. As such, these production pathways are depending on the status of the technology, scalability, the energy source used, and have different cost implications and material requirements. Therefore an overview has been made based on the variety of processes to produce hydrogen as currently is defined in the EU hydrogen strategy document.

See below for hydrogen production methods:

Electricity-based hydrogen:

> Hydrogen is produced through the electrolysis of water in an electrolyser, that is powered by electricity regardless of the electricity source. The full life-cycle greenhouse gas emissions of the production of electricity-based hydrogen depend on how the electricity is produced using fossil and renewable sources.

Renewable hydrogen:

> Hydrogen is produced through the electrolysis of water in an electrolyser, powered by electricity stemming from renewable sources. The full life-cycle greenhouse gas emissions of the production of renewable hydrogen are close to zero. Renewable hydrogen may also be produced through the reforming of biogas (instead of natural gas) or biochemical conversion of biomass, if in compliance with sustainability requirements.

Clean hydrogen:

> Reference is made to renewable hydrogen.

Fossil-based hydrogen:

> Hydrogen is produced through a variety of processes using fossil fuels as feedstock, mainly the reforming of natural gas or the gasification of coal. This represents the bulk of hydrogen produced today.

Fossil-based hydrogen with carbon capture:

Hydrogen is produced from fossil-based sources, but greenhouse gases emitted as part of the hydrogen production process are captured.

Low-carbon hydrogen:

Reference is made to fossil-based hydrogen with carbon capture and electricity-based hydrogen, with significantly reduced full life-cycle greenhouse gas emissions compared to existing hydrogen production.

The production pathways of hydrogen for this study are brought back to two main categories, namely Clean Hydrogen (based on renewable energy) and Low-carbon hydrogen (based on fossil-based energy input with CCS).

1.2 Report focus and content

The hydrogen and electricity markets are expected to become more strongly coupled in the future, and so the same can be expected for their infrastructure. This also calls for more integrated approaches for the design and sizing of different types of parallel energy infrastructure. Therefore, the decarbonization of the Dutch industry is investigated by the development of a hydrogen infrastructure. An important topic is the coupling of the development of a hydrogen market with the power market. The basis of this assessment is the ambition and formalised plans by the Dutch government to mitigate greenhouse gas emissions.

The work consists of two parts: Part One, the infrastructure that is required for the implementation of hydrogen with CCS all along its value chain. The study is addressing issues such as where hydrogen production facilities should be located, the types of processes these facilities should use, and whether the transportation of natural gas is preferred over the transport of hydrogen and CO_2 or not. Part Two is reviewing the corresponding market dynamics and an overarching view of the coupled hydrogen market and price dynamics.

The authors of this document acknowledge the fact that the scope of this study is not all-encompassing, and it is mainly focussed on the role of hydrogen. There are many other promising technologies for decarbonizing industrial processes. However, those are not considered in the infrastructure optimisation study. Specifically, the electrification of industrial processes is a technological route that may impact the results of this study. On the other hand, process-related emissions such as off-gases from refineries, steam cracking, or steel production are inherent to the existing processes. Hence, until such processes have either been replaced or have become obsolete, for a lot of Dutch industrial clusters, fossil-based hydrogen, and CCS as a decarbonization pathway remain relevant.

In Chapter 2 of this report, the objective of this study has been given. In Chapter 3, the approach and used methodology are presented, and in Chapter 4, the background on the used tools is given. The core of the report can be split into two main parts: 1) the optimal infrastructural changes, reported in chapter 5, and 2) the corresponding market dynamics reported in Chapter 6. The study will be concluded with observations and remarks on the potential business cases in Chapter 7. An overarching conclusion of the work is given in Chapter 8.

2 OBJECTIVE

The objective of this document is to present and review a possible roadmap towards a low carbon industry in the Netherlands by the implementation of hydrogen in combination with carbon capture and storage (CCS).

The work consists of two parts: In Part One, the objective is to define the infrastructure that is required for the implementation of hydrogen with CCS all along its value chain. The objective of Part Two is to provide an overarching view of the coupled hydrogen market and price dynamics and to show the implications of these dynamics on individual business cases and the successful implementation of hydrogen in the Netherlands.

3 APPROACH AND METHODOLOGY

Part One of this study addresses the implementation of a hydrogen and CCS infrastructure and operation of a hydrogen market using numerical modelling. The spatial optimization tool for hydrogen value chains has been developed by Imperial College London (ICL) under WP4 of the Elegancy project. The ICL tool is used for the infrastructural assessment, specifically for the Dutch case. The scope of the work is limited to industry, electricity production, and waste incineration in the Netherlands; sectors that have been indicated in the Dutch Climate Agreement to be suited for hydrogen and/or CCS for abatement of greenhouse gas emissions.

For the analysis of the Dutch Case, spatial data is collected on natural gas, electricity and hydrogen consumption, emissions, and existing or planned infrastructural capacities, including gas production and import, the storage potential of CO_2 in empty gas fields, and renewable energy sources (on- and offshore). All data has been taken from public sources for the year 2017. This year serves as a reference year, as for many sources, this is the latest year for which consolidated data is available. The time horizon for this study ranges from 2030 until 2050.

While the original scope of this deliverable focused only on the Rotterdam area, this scope in Part One was extended to the Netherlands as a whole. This has to do with the straight forward spatial planning of the Rotterdam harbour, which developed parallel to the Maas river, where most of the city its industrial activity takes place. Therefore it is more appealing to study the infrastructural developments for the Dutch energy transition in conjunction with the Rotterdam Industrial Cluster and other relevant industrial clusters. The Dutch industry is spatially represented by six chemical clusters, one in each of the provinces of Zuid-Holland (Rotterdam Rijnmond area), Noord-Brabant (Moerdijk area), Zeeland, Limburg (Chemelot), Groningen (Eemshaven), and Noord-Holland (Ijmond).

In part Two, the EYE model has been used to study the power market and hydrogen market dynamics. The scope of the study on market dynamics is slightly different than the chain tool from ICL. The technical solution space for the study on market dynamics is wider and more detailed, and all promising electrification options for industry and the build environment are taken into account, including the application of H_2 electrolysers. Hence, although the input data is consistent in terms of energy demand and power production, et cetera, the larger range of options might result in some deviation in study results.

Table 3.1: List of organizations and portals frequently referred to in this study.

Organisations	
Ministerie van Economische Zaken en Klimaat (EZK)	Dutch Ministry of Economic Affairs and Climate
PBL	Netherlands Environmental Assessment Agency
CBS	Netherlands Statistics
RIVM	Netherlands Public Health and Environmental Agency
Rijkswaterstaat	Netherlands Infrastructure and Water Management Agency
EBN	Energy Management Netherlands
Gasunie	National gas grid TSO
TenneT	National electricity grid TSO
ICL	Imperial College London

Portals	
Klimaatmonitor.nl	Dashboard for regional data on climate and energy transition maintained by Rijkswaterstaat
Emissieregistratie.nl	Dashboard for data on greenhouse gas emissions maintained by RIVM
Noordzeeloket.nl	Governmental website for topics regarding the Dutch part of the North Sea
CBS Statline	Dashboard for national statistics maintained by CBS
Enegieinnederland.nl	Dashboard for statistics on energy and emissions maintained by EBN

Abbreviations	
ATR	Autothermal reforming
BFG	Blast Furnace Gas
CAPEX	Capital Expenditure
CCS	Carbon Capture and Storage
ETS	Emission Trading System
KPI	Key performance indicator
MILP	Mixed Integer Linear Programming
OPEX	Operational Expenditure
PCC	Post-combustion capture
POX	Partial oxidation
PPA	Power Purchase Agreement
PV	Photovoltaics
RES	Renewable Energy Source
SMR	Steam methane reforming

4 RESEARCH FOCUS AND DEVELOPMENT OF TOOLS

The research reported in this document is focused on the implementation of hydrogen and CCS for deep decarbonization of industry, including electricity production and waste incineration. The research was conducted by means of modelling software, specifically, one for optimization of value chain networks and infrastructure called the Elegancy chain tool, and one for modelling of future electricity and hydrogen markets called the EYE tool. Both models are explained in the following sections.

4.1 The Elegancy chain tool

The Elegancy chain tool is a spatial planning and investment tool developed within the Elegancy project. A MILP algorithm in the Python programming language is used to find a minimal cost hydrogen network, including supply and storage nodes and transmission lines, to supply-demand nodes with the required commodities, like electricity or heat.

The tool can install new infrastructure and assets in geographical locations in order to meet the energy demand criteria, as well as the emission constraints. These technologies have a certain cost in terms of capital expenditure (CAPEX) and operational expenditure (OPEX). Commodity conversion rates are used to model the processes of each technology. For example, an industrial gas boiler will consume 1 unit of natural gas while producing 0.9 units of heat and 80.6e-6 units of emitted CO_2.

All energy carriers have units in terms of energy [MJ], while CO_2 has units in terms of mass [ton]. In the grid cell where an industrial gas boiler is placed, these units of natural gas, heat, and CO_2 must be accounted for. Natural gas can be transported to the cell using a pipeline (technology that is defined between two grid cells and "consumes" a unit of natural gas in cell 1 and "produces" a unit of natural gas in cell 2. This means that somewhere in the grid, natural gas should be "created". This is done by defining certain import locations, which can be an LNG terminal in a harbour or a gas production field. The emitted CO_2 is added to the emission balance, the total of which has to be kept below the upper limit defined by the emission reduction target. Using CCS technology, this CO_2 could also be captured, transported, and stored in an empty gas field. Finally, the produced heat is consumed by defining a certain heat demand in a grid cell.

The routine iteratively minimizes an objective function that describes the total yearly cost of the network, including investment cost of assets (CAPEX), yearly operational costs (OPEX), and cost related to the volume flow of a resource, such as emission costs[1] or cost of electricity consumption required by a process. CAPEX is translated to an annual cost using a capital recovery factor, based on an assumed interest rate and investment window.

$$C_t = R_{capital}C_{CAPEX} + C_{OPEX} + C_{resources}\ [\frac{€}{annum}]$$

During the iterative process, the number of assets and their respective process volume is varied until a convergence criterion is reached. To illustrate, imagine two industrial sites with chemical plants on either side of a country and in the middle a wind farm and a site for the production of natural gas. These chemical plants require hydrogen, which can be produced by water electrolysis

[1] Based on the European Emission Trading System (ETS)

or reforming of natural gas. These technologies can be implemented by installing a number of user-defined electrolysis or gas reforming facilities, each with their respective cost and performance characteristics. Now imagine the country is represented by a grid of 3 square cells. The tool can iterate between the number of plants in each grid cell to meet the required hydrogen demand of the chemical sites (0, 1, 2, 3…), to reduce cost. Similarly, the means of energy transport can be varied: the hydrogen production facilities can be installed close to the energy source in the middle cell, from which hydrogen is then transported to the chemical sites. Alternatively, electricity or natural gas can be transported to the sites first, where hydrogen is then produced locally. The solution will depend on the cost of transmission of one energy carrier relative to the cost of transmission of the other energy carrier (power cables vs. natural gas pipelines).

In each grid cell, a mass and energy balance is kept for each commodity or energy carrier, meaning that the total sum of production, consumption/conversion, and transportation into and away from a cell of a specific resource should be zero[2]. Technology can either be used for transmission, conversion, or storage of energy.

Final energy demand is only one of many constraints. Another important constraint is the total emitted CO_2 allowed in a specific time frame. This constraint is implemented as a percentage of a reference number, which can be reduced over time to simulate increasingly stringent emission reduction targets. For example, a boiler fuelled by natural gas will produce an amount of CO_2 per unit of heat produced, while a boiler running on hydrogen will not. While a boiler running on hydrogen is more expensive to operate, it still may be chosen over a natural gas boiler to respect the emission constraint. Other constraints relate to the distinction between onshore and offshore regions. Production facilities can only be built in the cells of the first category, while, e.g., offshore pipelines can only be built offshore. A more detailed description of the Elegancy chain tool can be found in WP4 of the Elegancy project under which the tool was developed.

4.2 EYE market model

The EYE model is a simulation model of electricity systems, based on flat unit-based marginal cost of production and flexible consumption. Given a certain electricity demand profile, a renewable electricity production profile and a marginal cost-based merit order of electricity production and flexible consumption, the least-cost dispatch of electricity production is simulated on an hour-by-hour basis, establishing a proxy for least-cost system dispatch and system marginal cost (= power price) on an hour-by-hour basis. The EYE model can analyse the behaviour in the energy systems as a result of changes in fuel prices, changes in renewable energy capacity, and changes in demand response capacity.

Within Elegancy, the EYE model is further developed to be able to simulate the power market in conjunction with a growing Hydrogen market. The result is cascading multi-carrier market model than can be used to study the Market Dynamics in markets that play a role in Sector Coupling. See deliverable D4.2.5 Chapter 4.2 for a description of the EYE model. In Section 6.2 the cascading market model and the bid behaviours of Hydrogen market participants are explained.

[2] Please note that while the model uses a mass balance, all resources are expressed in terms of their energy content [MJ] or [MWh], where the mass [kg] can be obtained by division of the energy by the specific energy of a resource [MJ/kg].

5 ENERGY TRANSITION PATHWAYS IN THE NETHERLANDS

The Netherlands is undergoing an energy transition. Driven by climate change, a direct result of too high concentrations of greenhouse gas emissions in the atmosphere, the Dutch government has come to a Climate Agreement (Klimaatakkoord) to address this issue. In this agreement, targets for reducing greenhouse gas emissions, of which more than 70% is CO_2 (1990), have been formulated for each economic sector. The emissions related to electricity production and industry with respect to the total greenhouse gas emissions of the Netherlands are presented in Figure 5.1.

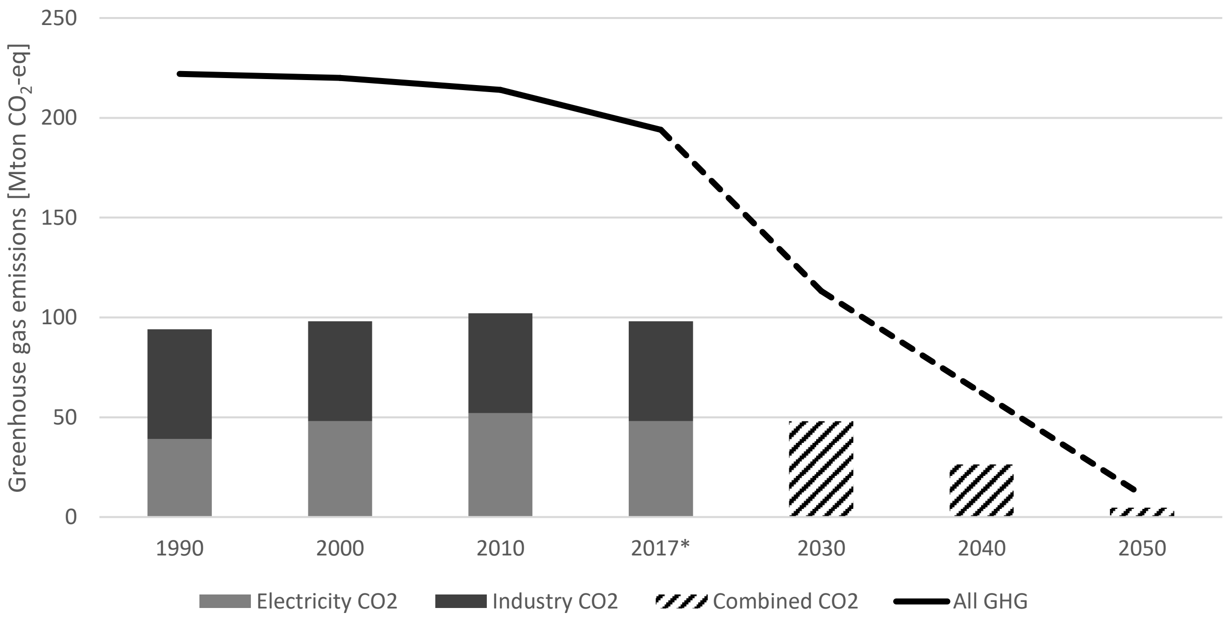

Figure 5.1: Development of all greenhouse gas emission in the Netherlands as a whole, and CO_2 emissions of industry and electricity production specifically. Beyond 2017, the trends are interpolated, assuming a 95% reduction by 2050 w.r.t. 1990. Source: www.energieinnederland.nl (Dutch only). 2017 is the reference year in this study.*

Hydrogen has been identified as a promising option that can play a prominent role in achieving emission reduction targets. As a gaseous compound containing no carbon atoms, it is often regarded as the perfect substitute for the widely used energy carrier natural gas. Existing infrastructure, industrial processes, and domestic equipment, all relying on the combustion of gas to deliver (high temperature) heat, could be repurposed for hydrogen. But as is the case with many renewable energy carriers, the climate impact of hydrogen is not defined by its application, but by its origin.

Today, in the Netherlands, almost all hydrogen (according to DNV GL up to 1.45Mton[3]) serves as a feedstock in (petro-)chemical processes and is produced from steam methane reforming (SMR) or as a by-product from hydrocarbon-based processes. Hydrogen is never produced as an end product, and the processes are always integrated with other industrial processes (although transport via pipeline may be part of the integration chain). The CO_2 that is produced during these

[3] Source: https://www.dnvgl.nl/news/filling-the-data-gap-an-update-of-the-2019-hydrogen-supply-in-the-netherlands-162721, site accessed August 2020

activities is emitted into the air. There are several ways of producing carbon-neutral hydrogen, and these all heavily impact the value chains (Table 5.2).

Table 5.2: Hydrogen production: opportunities and challenges for the hydrogen value chain.

Process feedstock	Process	Opportunities	Challenges
Natural gas/ industry fuel gases	SMR/ATR/POX + CCS	The exploitation of existing energy infrastructure, decarbonization of industry off-gases	CCS infrastructure
Electricity, water	Water electrolysis	Zero-emission process	Carbon neutral electricity production, integration of industrial site Scale of production
Biomass	Gasification + CCS	Negative emission process	Origin of feedstock, impact on biodiversity, CCS infrastructure

Decision making on which route to take forward is complex. Furthermore, the stakes in this energy transition are high, and the investments that are required for the implementation of any of these routes incur high costs on industry and society. By means of an optimization model,

In this chapter, the optimal pathway is explored in which the Dutch industry can decarbonize and achieve the Climate Agreement emission reduction targets at minimum cost. Three steps are taken in unravelling the energy transition pathways for the Dutch industry using hydrogen and CCS. First, the existing Dutch energy system is mapped in Section 5.1. Quantities of production, conversion, and import of energy carriers are combined to provide the Elegancy chain tool with the right input. In Section 5.2, the technical details of the modelling work are explained: what assumptions have been made, and what are the scenarios played out. Finally, in Section 5.3, the results of the optimization are presented, and the resulting hydrogen-CCS network that could allow for deep decarbonization of industry is discussed.

While gasification of biomass for the production of negative emissions sounds very promising, in the Netherlands, political support for biomass is very low. This also applies to biomass for electricity production in coal-fired power plants, although the technical application hereof is much more mature. Due to the uncertainties around this topic, biomass gasification was not included in this study as a technical route. The application of biomass for electricity production has been included according to the announced plans of coal plant owners, see Section 5.1.

5.1 Today: energy and greenhouse gas emissions in the Netherlands

This section starts with an introduction to carbon dioxide emissions in the Netherlands: what are the main emission sources and where are they located. Then the energy carriers that provide the energy for the processes behind these emissions are discussed in terms of supply and demand. Finally, data on existing Dutch energy infrastructure and the potential for CO_2 storage in the Netherlands is presented. In Section 5.2 is explained how the data presented in this section were implemented into the model.

Of the 189Mton of CO_2 emitted in 2017[4], 54% is produced by industrial activity and electricity production. More than 90% of this share is emitted in 6 of 12 provinces, bundled in and around so-called chemical clusters. These central locations provide a convenient case for a geographical, infrastructural study.

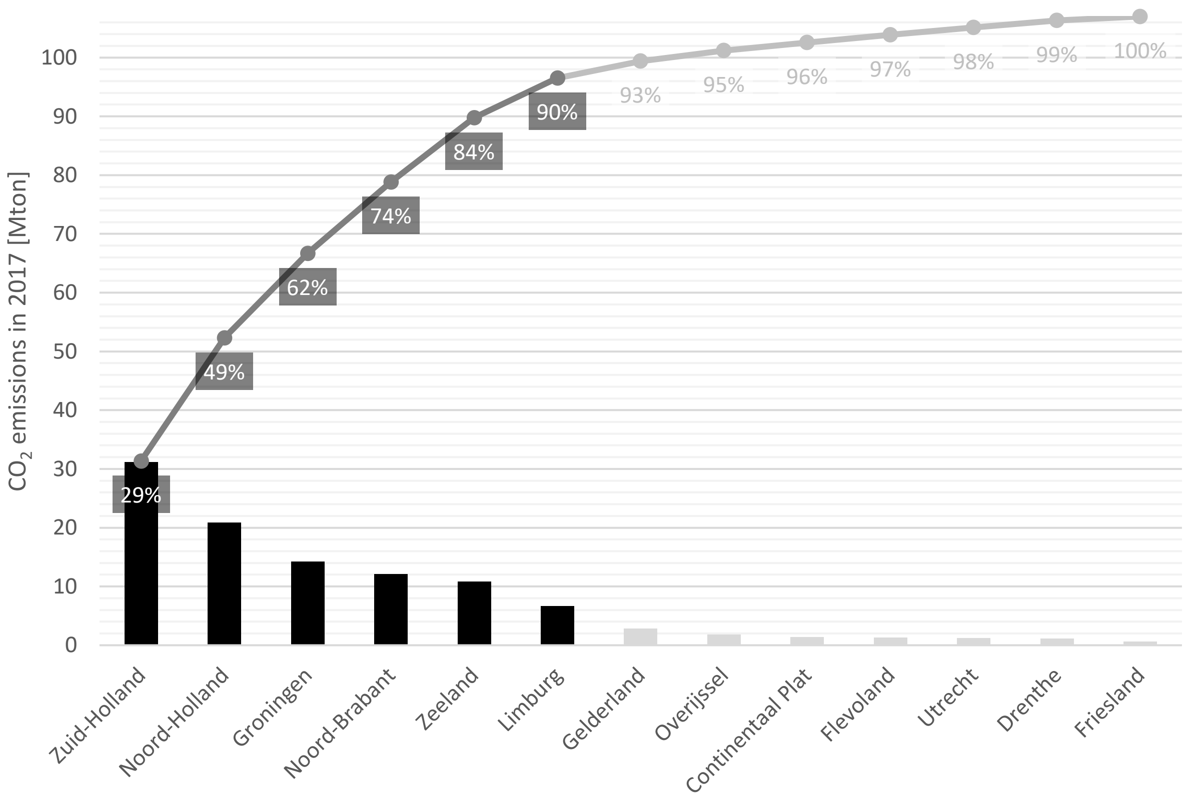

Figure 5.2: Provinces sorted by 2017 CO_2 emissions from industrial activities. 90% of emissions occur within six out of 12 provinces. The Continentaal Plat (Dutch for the continental shelf) is the subsea surface area of the Dutch part of the continent. Source: EBN.

Industrial CO_2 is a result of carbon-based fuels and feedstocks. Considering the energy, chemical, steel, refinery and waste incineration industries, a total of about 91Mton CO_2 annually is to be considered for decarbonization.

[4] EBN

Table 5.3: Activities and corresponding CO_2 emissions in 2017 per region.

CO_2 emissions in 2017 per sector and region [Mton]	Zuid-Holland	Noord-Holland	Groningen	Noord-Brabant	Zeeland	Limburg	Total
Energy sector	**15.9**	**10.2**	**12.3**	**5.4**	**2.6**	**-**	**46.4**
Production of electricity	15.9	10.2	12.0	5.4	2.6	-	46.1
Oil- and gas production onshore	-	-	0.3	-	-	-	0.3
Chemical industry	**3.1**	**0.2**	**0.7**	**3.2**	**6.3**	**4.9**	**18.4**
Chemical industry base products	3.0	0.1	0.6	3.1	2.7	4.9	14.4
Chemical industry fertilizer	-	-	-	-	3.6	-	3.6
Chemical industry other	0.1	0.1	-	0.1	-	-	0.3
Refineries	**8.9**	**-**	**-**	**-**	**1.6**	**-**	**10.5**
Refining and processing	8.9	-	-	-	1.6	-	10.5
Other industry	**0.1**	**7.0**	**0.1**	**0.4**	**-**	**1.0**	**8.5**
Base metals	0.1	6.9	0.1	0.1	-	-	7.2
Cement	0.1	-	-	0.3	-	0.9	1.3
Waste disposal	**2.2**	**2.6**	**0.6**	**1.9**	**-**	**-**	**7.0**
Waste incineration plants	2.1	2.6	0.5	1.8	-	-	7.0
Total	**30.2**	**20.0**	**13.7**	**10.8**	**10.5**	**6.0**	**91.1**

The following sections in this chapter are divided into two categories. The first category deals with energy carriers in the Netherlands and the way these are produced or imported, converted, and used. The second category deals with the energy infrastructure that currently exists or is announced for transmission of hydrogen and natural gas and storage of CO_2.

Figure 5.3: CO_2 point emitters in the Netherlands. The red circles indicate the locations of the chemical clusters, including other large emission sources in close proximity. Source: www.emissieregistratie.nl (RIVM).

5.1.1 Production of energy carriers

In 2020, the Netherlands had two main ways of producing energy: oil and gas production in the North Sea, onshore gas production from the Groningen gas field, and RES such as onshore and offshore wind and solar PV. Things are about to change, though.

Natural gas

For political reasons, the Groningen gas field production will be seized in 2030 at the latest, where production is scaled down gradually over the coming years. For the end of 2019, the limit was set to 12bcm[5]. In the Klimaat- en Energieverkenning (KEV) 2019[6], the production is assumed to make a drop-down to 5bcm in 2022 first, then continue to steadily decline, reaching half of this volume by 2025.

The production from other fields, onshore and offshore combined, is expected to sum up to 11bcm in 2030. This is also the total volume of annual gas production that was used in this study. A major share of this is produced from gas fields in the North Sea. Although multiple small gas fields onshore contribute to this total volume, it is not exactly clear how much each individual field produces. For geographical simplification, the assumption is made that all inland gas production takes place offshore and lands onshore in the province of Noord-Holland.

Another source of energy that becomes increasingly important is renewable energy. The two most prominently regarded sources in the Netherlands are wind and solar energy. Three distinct types of renewable electricity production are identified: onshore solar PV, onshore wind and offshore wind.

Onshore wind and solar energy

The distinction between onshore and offshore production is important. While in the Climate Agreement, the overall target for total onshore wind and solar installed capacity by 2030 is defined, the whereabouts of this production are not. Instead, the contribution to this by each province is defined provincially in so-called regional energy strategies. The regional energy strategies of Dutch provinces have not been presented yet, and it is therefore unsure how much renewable electricity can be expected per province. For the period 2030, the prognosis as described in the KEV 2019 are used totalling up to 41TWh of combined onshore wind and solar PV (5.4GW_{peak} and 27.7GW_{peak}, respectively[7]).

For an outlook up to 2050, a scenario presented in the combined study “Infrastructure Outlook 2050” by TenneT and Gasunie[8] has been considered. In the national scenario, a total of 34GW_{peak} solar PV and 14GW_{peak} onshore wind is assumed, totalling to 74.4TWh of renewable electricity production in 2050.

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[5] Kamerbrief “Akoord op Hoofdlijnen met Shell en ExxonMobil”, min. E. Wiebers, 25 Juni 2018

[6] https://www.pbl.nl/publicaties/klimaat-en-energieverkenning-2019, site accessed August 2020.

[7] Using full load hours of 854 and 3237 per annum for solar PV and onshore wind, respectively, as assumed in the Climate Agreement.

[8] https://www.gasunie.nl/en/expertise/system-integration/infrastructure-outlook-2050, site accessed August 2020.

Offshore wind energy

Regarding offshore wind, the Dutch subsea surface region of the North Sea, called the continental shelf, is under the direct national government. For the development of offshore wind farms, until 2030, a fairly detailed roadmap exists, totalling up to 45TWh of production in 2030, see Table 5.4 and Figure 5.5. This also includes the result of the exploration as to where the power cables will be brought to shore.

Table 5.4: Roadmap of Dutch offshore wind farms. A conversion factor of 4260 full load hours per year was used (the figure used in the Climate Agreement).

Status	Name	Connection (expected)	Capacity [MW]	Annual yield [TWh]	Expected year of operation
Existing[9]	OWEZ	Noord-Holland	108	0.5	-
	PAWP	Noord-Holland	120	0.5	-
	Luchterduinen	Zuid-Holland	129	0.5	-
	Gemini	Groningen	600	2.6	-
Planned before 2023[10]	Borssele	Zeeland	1,400	6.0	2020
	Hollandse Kust (zuid)	Zuid-Holland	1,400	6.0	2022
	Hollandse Kust (noord)	Noord-Holland	700	3.0	2023
Planned before 2030[11]	Hollandse Kust (west)	Noord-Holland	1,400	6.0	2025
	Ten noorden vd Wadden	Groningen	700	3.0	2026
	Ijmuiden Ver (midden)	Zuid-Holland	2,000	8.5	2028
	Ijmuiden Ver (zuid)	Zeeland	2,000	8.5	2028
Total			**10,557**	**45**	

For developments until 2050, offshore wind scenarios created by PBL are used. In the report “De Toekomst van de Noordzee”, PBL (2018)”[12], four scenarios are described. The yield is interpolated exponentially by matching the combined capacity of the existing wind parks (as of 2030) by multiplying by a factor to match the 2050 combined capacity. Data is presented in Figure 5.4.

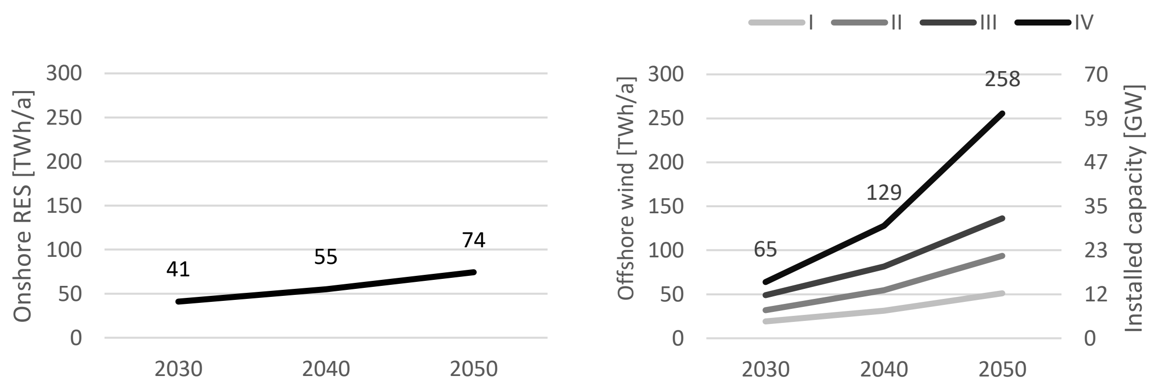

Figure 5.4: Left figure: Onshore wind and solar PV energetic volume scenario based on “Infrastructure Outlook 2050” study by TenneT and Gasunie. Data is interpolated exponentially between 2030 and 2050. Right figure: offshore wind scenario I to IV from PBL’s “De Toekomst van de Noordzee” (2018) with annual yield (left axis) and corresponding capacity installed.

[9] https://www.noordzeeloket.nl/functies-gebruik/windenergie-zee/interactieve-kaart/, site accessed April 2020.
[10] https://www.noordzeeloket.nl/functies-gebruik/windenergie-zee/in-ontwikkeling-op/, site accessed April 2020.
[11] Communicated by the minister of Economic Affairs and Climate in a letter to parliament on 5th of April, 2019, source: https://www.rvo.nl/sites/default/files/2019/04/kamerbrief-over-de-voortgang-uitvoering-routekaart-windenergie-op-zee-2030.pdf
[12] https://www.pbl.nl/publicaties/de-toekomst-van-de-noordzee, site accessed April 2020.

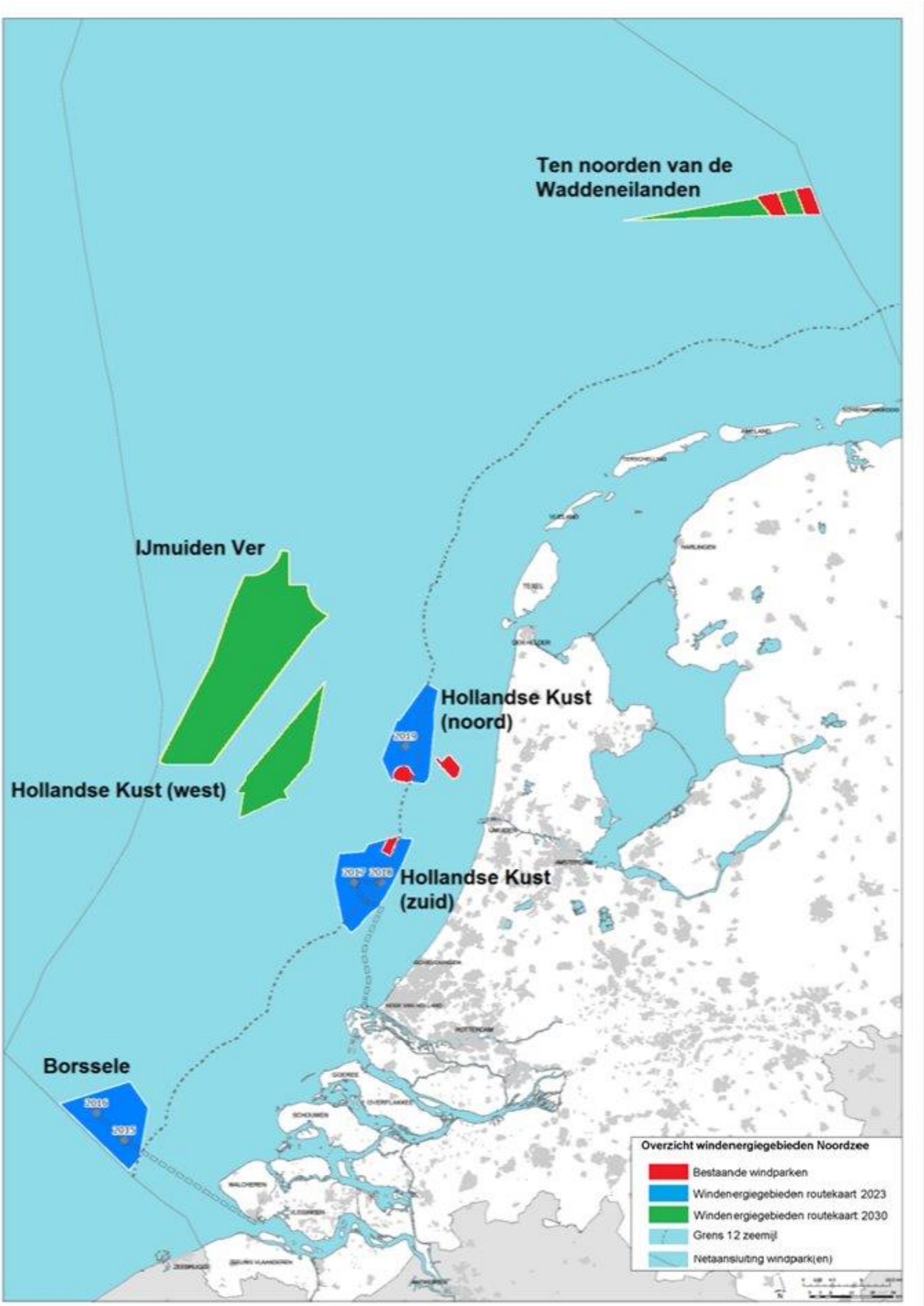

Figure 5.5: Geographical roadmap of Dutch offshore wind projects. Source: Noordzeeloket.

5.1.2 Import of energy carriers

According to CBS, in 2017, 360.9 TWh of natural gas was consumed in the Netherlands; 385.7 was produced while 451.2 was imported; 467 TWh of this was exported again. In other words, 451.2 TWh is imported, but not locally consumed, while 15.8 TWh of export was produced within the country borders. The natural gas balance of 2017 is shown in Figure 5.6. These transit flows limit the total capacity for cross-border transmission of natural gas and need to be accounted for.

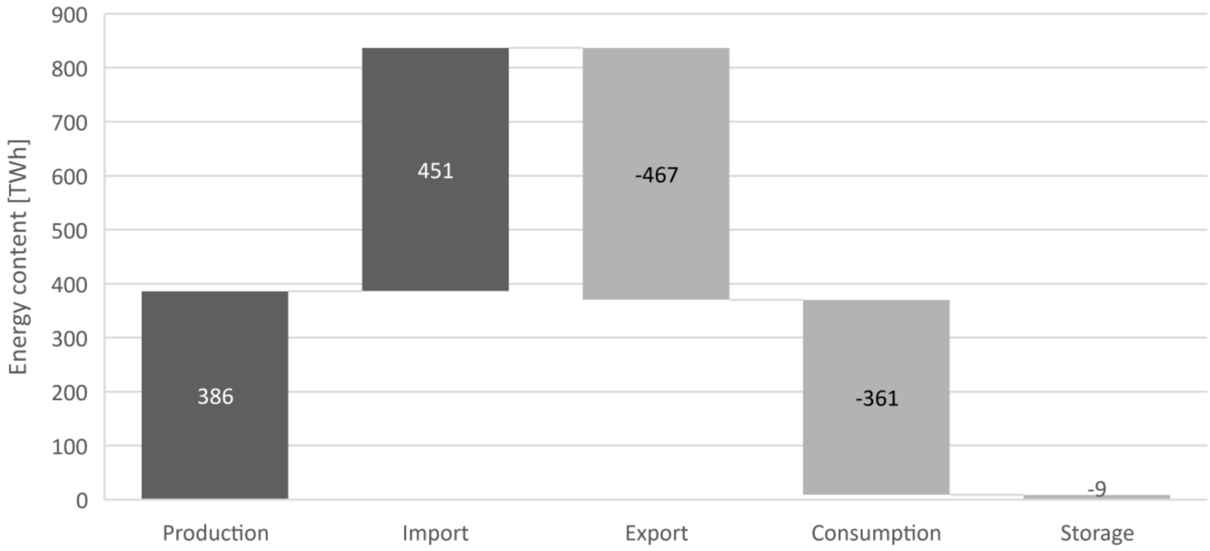

Figure 5.6: Natural gas import and export balance of the Netherlands in 2017 based on CBS data. Storage indicates the net volume of natural gas that was stored in this year. Part of the total cross-border capacity is used for transit.

The total corrected capacity per import location is presented in Table 5.5. The Netherlands has a natural gas import capacity of 958.0 TWh/a, see. According to ENTSO-G data, in 2017, 86% of the import took place in Emden and Bunde/Oude Statenzijl, 12% at location Zelzate and 2% at the LNG terminal in Rotterdam. The import limits at these locations are corrected according to these volumes.

In the modelling, these transit volumes, as well as the cross-border capacities, are assumed to remain constant over time. This leaves 506.8TWh available for net import. This should be sufficient cross-border transmission capacity to counter the reduction in inland production (see Section 5.1.1) and to foresee in the demand of other economic sectors. Natural gas export is not of further interest in this study.

Table 5.5: Import locations and cross-border capacity as indicated by ENTSO-G. Figures in brackets () indicate the original, uncorrected capacity of a connection.

ENTSO-G reference	Location	TSO (NL)	Neighbouring country	Import [TWh/a]	Export [TWh/a]
002	Zelzate	GTS	Belgium	46.9 (98.9)	149
		Zebra		44.5	-
003	Zandvliet	GTS		-	17.2
004	Hilvarenbeek	GTS		-	234
005	's Gravenvoeren	GTS		-	124
011	Bocholtz	GTS	Germany	-	145
012	Zevenaar	GTS		-	120
013	Winterswijk	GTS		-	65.2
016	Bunde/ Oude Statenzijl	GTS		285 (674)	184
316	LNG GATE terminal	GTS	Intercontinental	131 (140[13])	
Total				507 (958)	1038

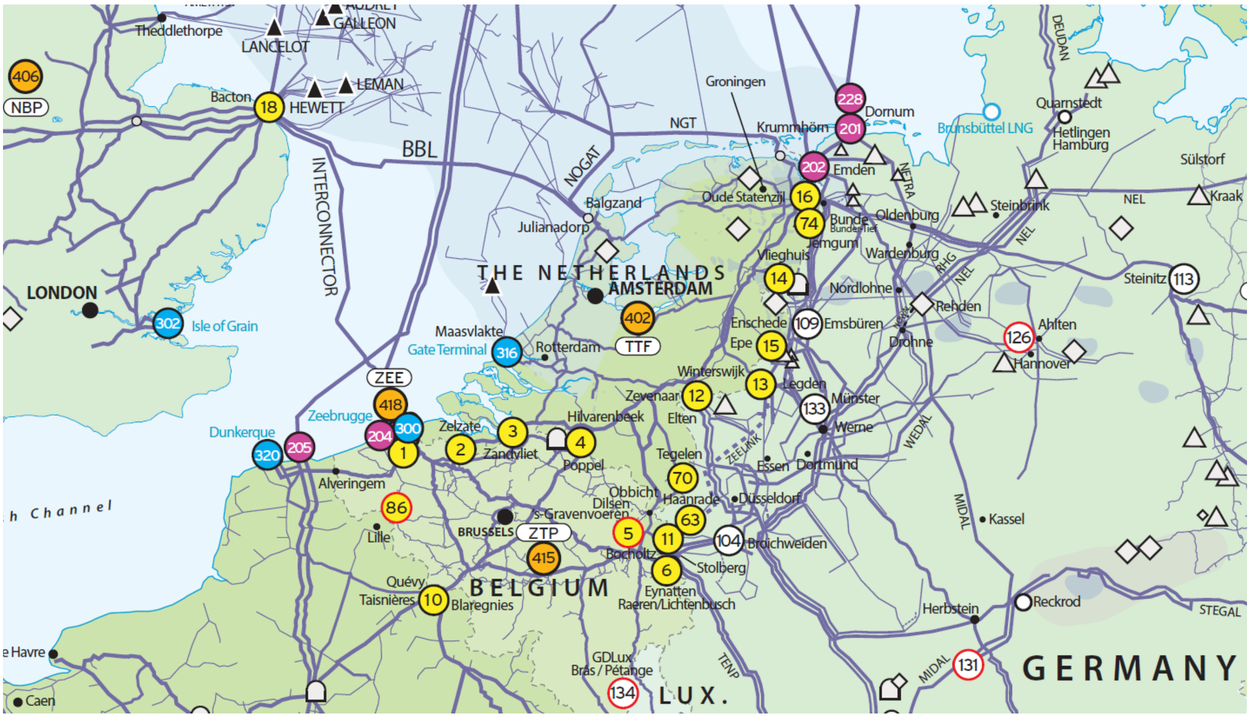

Figure 5.7: Map with cross-border connections of natural gas infrastructure. Locations not referred to in do not represent relevant transmission crossings, but for example, lead to an end-user or storage location across the border. Source: ENTSO-G[14].

[13] Gate terminal website indicates a through put of 12 bcm/a, ENTSO-G indicates an limit of 15.9 bcm/a; the higher value is used in this study. Source: https://www.gateterminal.com/en/gate-terminal/profiel/facts-figures/

[14] https://transparency.entsog.eu/#/map, site accessed April 2020

5.1.3 Conversion of energy carriers

The production of one energy carrier from another energy carrier is called a conversion. The most prominent example is that of electricity production. The Netherlands relies on a range of resources for its electricity production, most notably coal, natural gas, industry off-gases, nuclear and renewable sources such as wind, solar PV, and biomass.

Today, four coal-fired power plants are still operative. But, as coal-fired power plants are all phased out before 2030, there will be a shift in the electricity mix. While one coal plant (Maasvlakte 3 and 4 owned by EON) will shut down, the other three plants are expected to make a shift to biomass (see Table 5.6). Currently, biomass is deemed as a zero-emission fuel under the ETS[15]. It is assumed that all three plants will have made the transition to biomass completely before 2030.

Furthermore, a set of gas-fired power plants are operative on the electricity market. A list of power plants that are known to provide baseload to the grid is given in Table 5.7. This list is not exhaustive, and many industrial players have some form of electricity production on their industrial sites. To be able to implement the model, a selection has been made of the most important plants. Each plant listed has an expected phase-out date somewhere between 2030 and 2050, subject to its operational lifetime.

One plant, Velsen-25, runs on blast furnace gas released by steel production processes in Ijmuiden, Noord-Holland. One combined heat-power (CHP) plant, Elsta, is included, which partially runs on hydrogen produced by the steam cracker in Terneuzen, Zeeland. Of the Magnum plant in Eemshaven, Groningen, one STEG is converted to run on hydrogen as the main fuel and is expected to be available by 2025. Before 2030, all three turbines are expected to run on hydrogen.

Another source of electricity and heat is waste incineration plants. CBS estimates that in 2017, around 4.5 TWh electricity was produced from the incineration of waste[16].

Existing hydrogen production facilities were not considered.

[15] RVO, "The Netherlands: list of fuels and standard CO2emission factors version of January 2020" (p4), https://english.rvo.nl/topics/sustainability/national-inventory-entity

[16] Source: Klimaat- en Energieverkenning 2019

Table 5.6: List of coal fired plants in scope of this study

Owner	ID	City	Province	Fuel	Capacity [MWe]	Capacity [MWth]	Efficiency	Date of decommissioning
RWE-ESSENT	RWE-EEMS-1 RWE-EEMS-2	Eemshaven	Groningen	Biomass	900	-	40-45%	-
Onyx	Maasvlakte-Onyx	Maasvlakte Rotterdam	Zuid-Holland	Biomass	600	-	40-45%	-
RWE-ESSENT	Amer-91	Geertruidenberg	Noord-Brabant	Biomass	420	-	37-41%	2040

Table 5.7: List of gas fired power plants in scope of this study (NG = natural gas, BFG = blast furnace gas)

Owner	ID	City	Province	Fuel	Capacity [MWe]	Capacity [MWth]	Efficiency	Date of decommissioning
Vattenfall-NUON	Velsen-25	Velsen-Noord	Noord-Holland	BFG	361	-	36-40%	2032
Vattenfall-NUON	Hemweg-9	Amsterdam	Noord-Holland	NG	440	-	52-58%	2040
Vattenfall-NUON	Diemen-34	Diemen	Noord-Holland	NG	440		52-58%	2040
Electrabel	Eems-30 Eems-40 Eems-50 Eems-60 Eems-70	Eemshaven	Groningen	NG	1675	-	50-54%	2040
Vattenfall-NUON	Magnum-1 Magnum-2 Magnum-3	Eemshaven	Groningen	H_2	1300	-	51-56%	-
EnecoGen	Rotterdam EP1 Rotterdam EP2	Europoort Rotterdam	Zuid-Holland	NG	840	-	52-56%	2040
Air Liquide	Pergen-1 Pergen-2	Pernis Rotterdam	Zuid-Holland	NG	260	-	57%	2040
Intergen-Maascentrale	Rijnmond-1	Vondelingenplaat Rotterdam	Zuid-Holland	NG	790	-	50-55%	2045
Intergen-Maascentrale	Rijnmond-2 (Maasstroom)	Vondelingenplaat Rotterdam	Zuid-Holland	NG	420	-	50-55%	2050
RWE-ESSENT	Moerdijk-2	Moerdijk	Noord-Brabant	NG	400	-	51-56%	2050
DOW	Elsta	Hoek	Zeeland	NG/H_2 (3:1)	370	90	52-57%	2040
PZEM/EDF	Sloe-10 Sloe-20	Ritthem	Zeeland	NG	870	-	52-57%	2040
Vattenfall-NUON	L.Weide-6	Utrecht	Other	NG	250		48-53%	2040
Electrabel	Flevo-1 Flevo-2	Lelystad	Other	NG	860		52-59%	2050

5.1.4 Consumption of energy carriers

Three forms of final energy demand are considered: industrial heat, electricity, and hydrogen feedstock.

Industrial heat

All industrial heat is assumed to be produced locally. As data on industrial heat demand was found to be available only on a national level (117TWh in 2017, CBS), but not on a local level, some assumptions were made to obtain a spatial distribution of industrial heat usage. The Klimaatmonitor provides data on natural gas delivery to industry on a regional level, see Figure 5.8. This amounts to a total of 12.9bcm, or 113.5TWh assuming an energy density of 31.65MJ/m^3 (as indicated on the Klimaatmonitor website). Because not all-natural gas is used for heat and heat may be produced from other energy carriers such as refinery fuel gases, it cannot be said that gas consumption quantities represent industrial heat production. This dataset does provide a relevant spatial distribution of scale of industrial activity over the provinces with roughly the same total volume as the heat demanded by the industry, as indicated by CBS. And so the assumption is made here that the industrial heat demand has the same spatial distribution as the industrial gas consumption and can be used to represent the industrial heat demand in this specific situation.

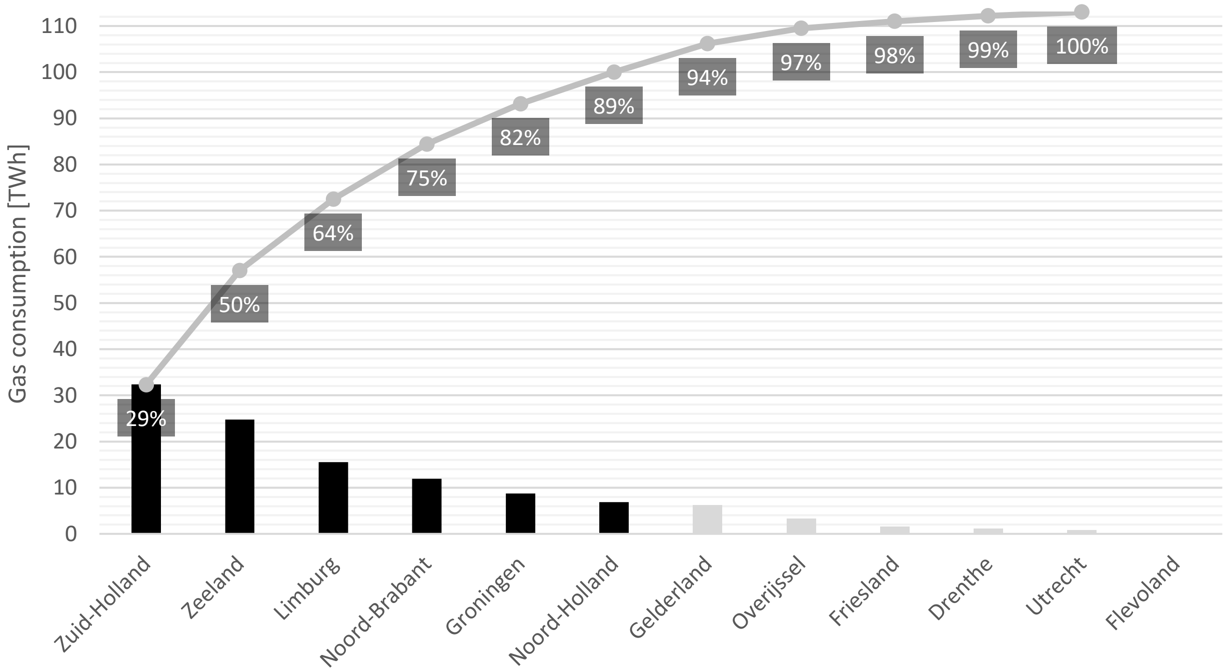

Figure 5.8: Gas delivered to the industry in 2017 per province. The data in black is modelled spatially, while the light grey data is not considered in this study. Source: Klimaatmonitor.

Electricity
For electricity, spatial data from Klimaatmonitor on total electricity consumption can be used without any manipulation. This data represents consumption from all economic sectors.

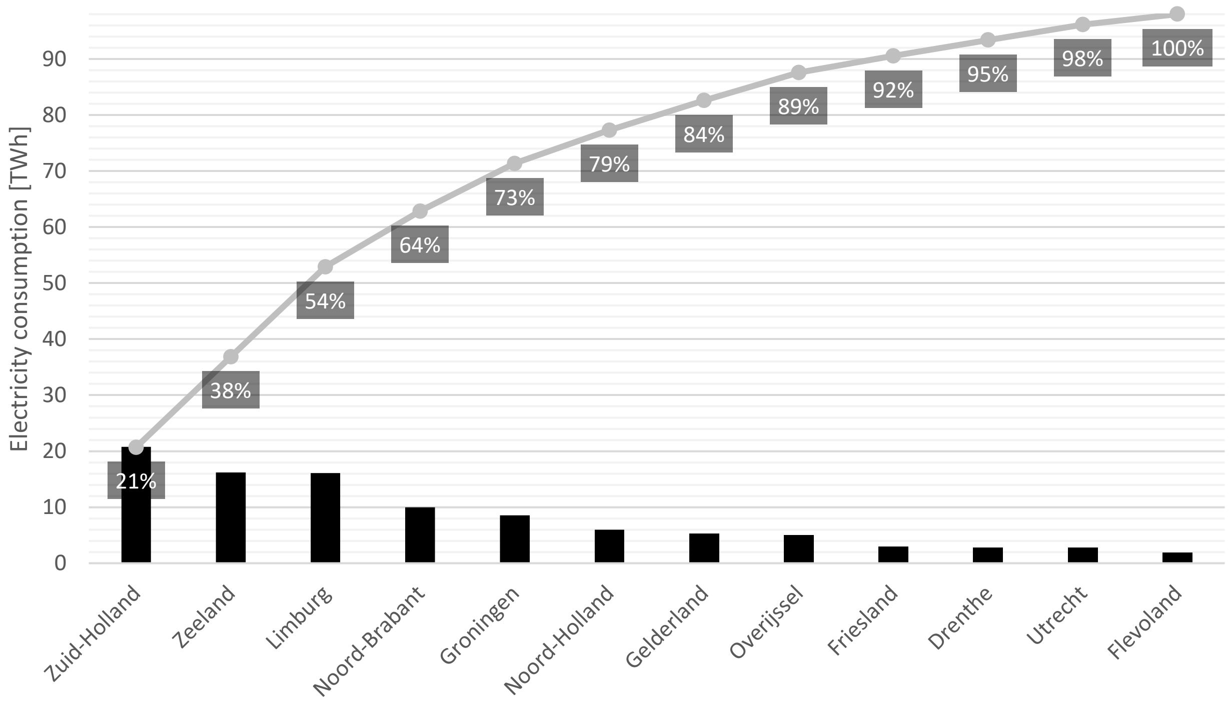

Figure 5.9: Electricity consumption per province. The data in blue is modelled spatially, while the data in orange data is modelled in the virtual grid cell. Source: Klimaatmonitor.

Hydrogen feedstock
In some processes, hydrogen is required as a feedstock, most of which in refinery processes and for ammonia production. DNV-GL came to some first estimations. However, they not mentioned how the quantity produced in the Maasdelta is distributed over Zuid-Holland and Noord-Brabant. The assumption is made that all hydrogen is produced in Rotterdam.

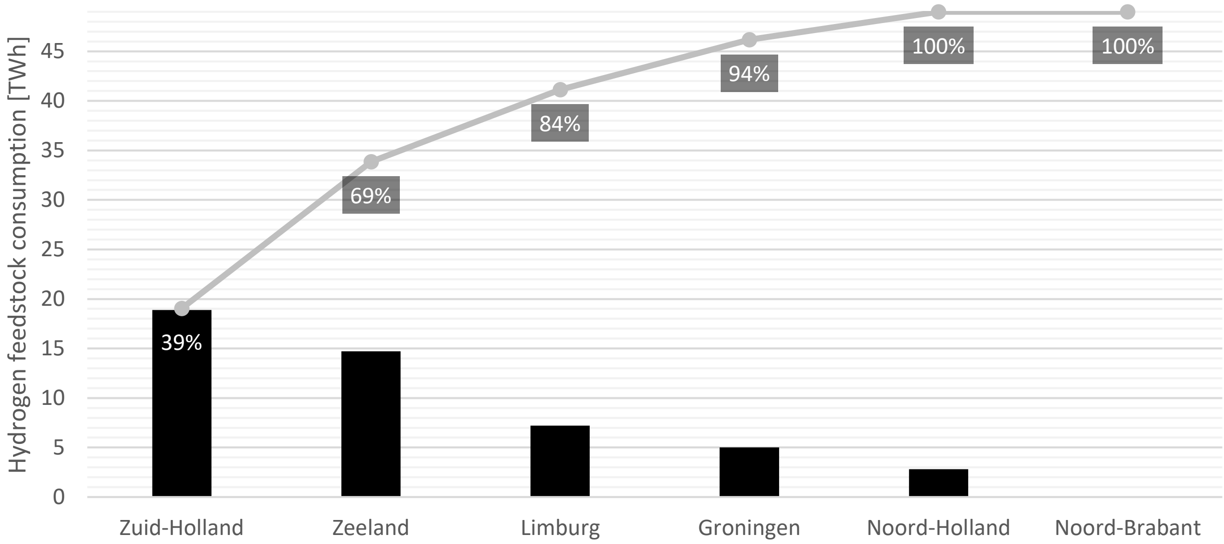

Figure 5.10: Estimation of hydrogen feedstock supply in the Netherlands. Source: DNV-GL[17].

5.1.5 Gas and hydrogen backbone

The Netherlands has several energy infrastructural networks for the transmission of oil, chemicals, technical gases, natural gas, and electricity. After the discovery of the Groningen gas field in 1960, a gas infrastructure network was developed by Gasunie (for which it was specifically founded). Gas from the Groningen field s typically referred to as low calorific gas. Imported gas has a higher calorific value (for which a different parallel network has been developed. As production of the Groningen gas field is seized, the Dutch government wants no large industrial parties to be using Groningen gas by 2022[18], meaning the lower calorific network becomes increasingly available. This network can be transformed into a hydrogen network, and both a gas and hydrogen backbone can be operated simultaneously. Gasunie estimates the cost that is required for this around €1.5bn[19], including the transformation of the compressor stations. The layout of the two parallel backbones is shown in Figure 5.11.

[17] https://www.dnvgl.nl/news/filling-the-data-gap-an-update-of-the-2019-hydrogen-supply-in-the-netherlands-162721, site accessed August 2020.
[18] https://www.rijksoverheid.nl/documenten/kamerstukken/2018/03/29/kamerbrief-over-gaswinning-groningen
[19] http://www.dewereldvanwaterstof.nl/gasunie/infrastructuur/

Figure 5.11: A map with the natural gas and hydrogen backbone of Gasunie. In ***black****, the existing gas backbone (only pipes shown with a diameter of 24 inch or more). In red, the incomplete hydrogen backbone as proposed by Gasunie (only pipes shown with a diameter of 48 inch). The hydrogen backbone can be realised by converting the parallel low calorific natural gas infrastructure to hydrogen infrastructure. Interrupted routes are to be completed by Gasunie and are within the scope of the hydrogen backbone.*

5.1.6 CO_2 storage in offshore gas fields

CO_2 storage requires geographical storage locations, such as empty oil and gas fields and aquifers. In a report by EBN and Gasunie[20], a total of 1700Mton CO_2 offshore and 1100Mton CO_2 onshore "practical" storage potential was identified. This includes only empty gas fields and one aquifer field. Oil fields and other aquifers were not considered because of a lack of storage potential or because of geological challenges that first require more research before a realistic potential can be determined. Onshore CO_2 storage is not covered in the Climate Agreement and is in the Netherlands politically very sensitive. Therefore, only offshore storage is considered. In a study by Neele et al. (2018) under the Align-CCUS project, end of life dates of offshore gas fields and aquifers and their potential storage capacity for CO_2 have been presented. The upper limit of these estimates (995Mton) have been used in this study and are in accordance with results of the Align-CCUS project[21].

Table 5.8: Capacity estimations by Neele et al. (2018)[22] performed under the Align-CCUS project.

Field	Location on map (Figure 5.12)	Capacity [Mton]	Year of availability
P18/P15	1/2	75	2020/2025
Q1/Q4	3	135-235	2020
K14/K15	4	165	2020
K7/K8(/K10)	5	195	2020
L10/K12	6	175	2022
K04/K05	7	150	2028
Total		895 – 995	

[20] EBN en Gasunie, "Transport en Opslag van CO2 in Nederland", 2018
[21] https://www.aligncсus.eu/project-outputs, site accessed August 2020.
[22] Neele, Filip and Gittins, Chris and Wildenborg, Ton and Mikunda, Tom, Initiating Large-Scale Storage in the Netherlands Offshore. 14th Greenhouse Gas Control Technologies Conference Melbourne 21-26 October 2018 (GHGT-14) . Available at SSRN: https://ssrn.com/abstract=3366065

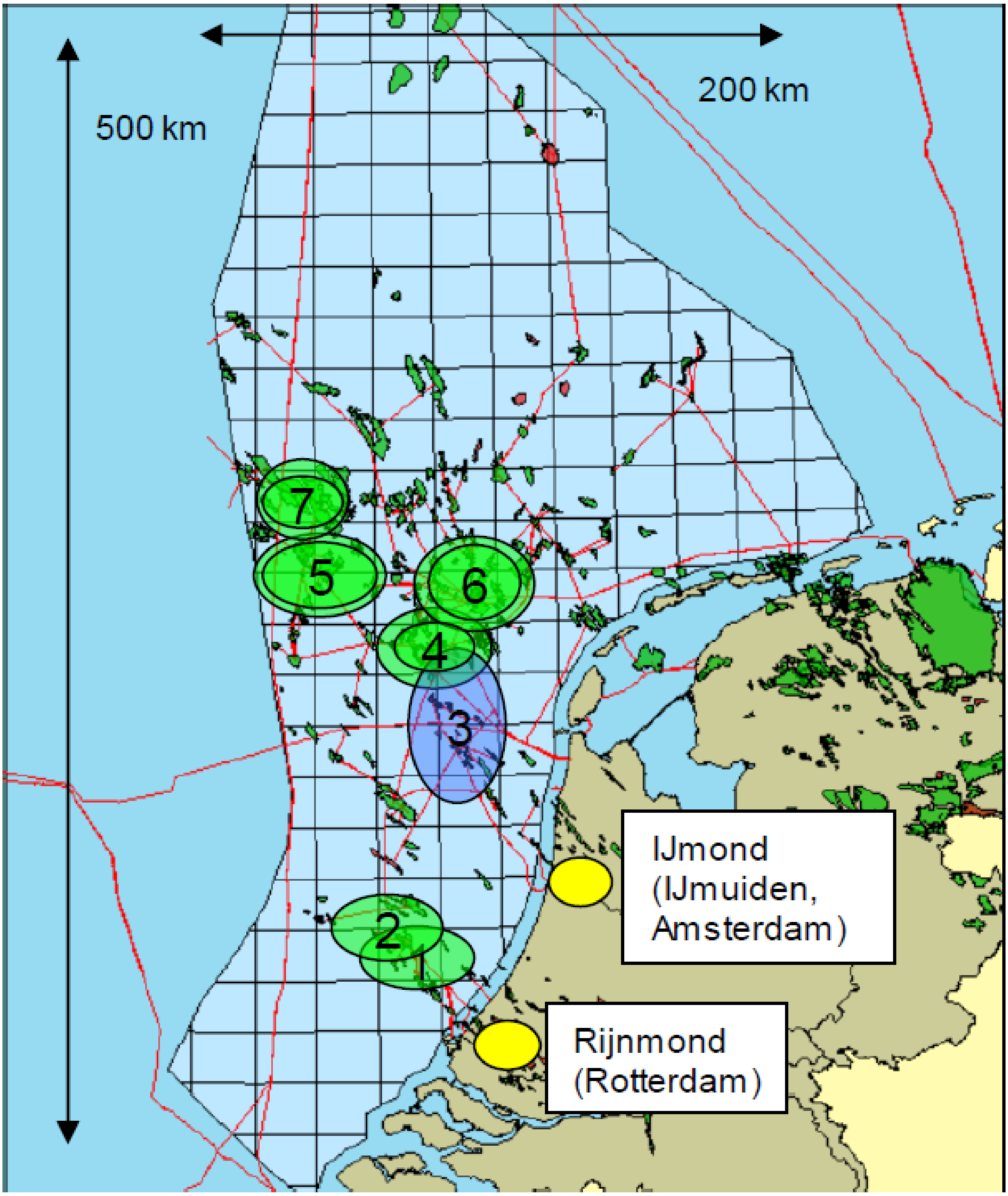

Figure 5.12: Clustering of offshore depleted gas fields and aquifers in the Dutch sector (Neele et al. 2018).

5.2 Setup of the Elegancy chain tool model

The Elegancy chain tool model was set up to simulate deep decarbonization of industry and electricity production by the implementation of a hydrogen and CCS network. To be able to investigate the long term developments of such a transition, three periods of 10 years are simulated: from 2025 to 2055, denoted by the midpoint years 2030, 2040, and 2050, using yearly averaged data on energy production, conversion, and consumption as described in Section 5.1.

By taking into consideration the stable energy demand of the industry (baseload off-take). The assumption was deemed sufficient to describe the global developments that are required to achieve the emission reduction targets up to 2050. To make sure the tool does not only optimize the network until 2050, possibly creating a situation that would not last for another year, the simulation is also extended ten years beyond 2050 up to 2060. In this section, general assumptions on implementing the data presented in Section 5.1 and commodity price are discussed, followed by technological solutions that are available to the tool and cost parameters related to these technologies.

5.2.1 General modelling assumptions

The model grid is shown in Figure 5.13, which represents the Netherlands divided over 32 hexagons. Some regions consist of multiple clustered hexagons, which was done for regions that do not require spatial resolution to reduce the computational burden. The virtual grid cell V is explained later in this section. Some grid cells represent specific geographical areas as indicated by the abbreviations around a cell, see Table 5.9. Shaded grid cells are off-limit for any infrastructure (e.g., due to Natura2000 protected status). In the grid cells with industrial sites, demand for industrial heat, electricity, or hydrogen as a feedstock is specified according to what is applicable. In this setup, certain gas fields are clustered, and their respective CO_2 storage capacity is aggregated.

Table 5.9: Grid cells and their characteristics.

		Industrial site	Empty gas field	Natural gas production	Natural gas cross-border connection	Offshore RES production	Onshore RES production	Electricity grid connection
B	German border area				X			
C	Coastal area			X				
V	Virtual electricity grid						X	X
GR	Groningen	X				X		X
LB	Limburg	X						X
NB	Noord-Brabant	X						X
NH	Noord-Holland	X				X		X
ZH	Zuid-Holland	X			X	X		X
ZL	Zeeland	X			X	X		X
K4	K4/K5 + K7/K8/K10		X					
K14	K14/K15		X					
L10	L10/K12		X					
Q1	Q1/Q4		X					
P15	P15/P18		X					

Figure 5.13: Discretization of the Netherlands over 32 grid cells. The shaded cells represent regions which are off limits for construction of any type of asset, for example because of a Natura2000 protected status.

Assumptions on energy consumption

Final energy consumption in the Netherlands was discussed in Section 5.1.4. Here, the assumptions on energy consumption made during the implementation of the model are summarized.

In the model, electricity is generated for all sectors and all regions. Apart from any newly installed plants, the assumption is made that only power plants in Table 5.6 and Table 5.7 supply baseload electricity production (in case activated by the model).

Heat is supplied to industry only, meaning heat demand for other sectors is not included. The only demand for the industry in the top 6 provinces is included (corresponding to the six industrial sites). Industrial heat is always consumed locally, meaning there is no transmission of heat.

The existing annual volume of hydrogen is included in the relevant grid cells. CO_2 demand is not considered in this study. For every type of demand, the assumption is made that this demand remains constant all along the simulation time horizon, meaning no increase or decrease is included.

Table 5.10: Assumptions on infrastructure in this study. N.A. = not applicable

Assumptions on infrastructure	Produced industrial heat	Produced electricity	Produced feedstock
For industry	Local consumption only	Local consumption only	Transmission of CO_2 and H_2 through pipeline infrastructure
For other sectors	N.A.	Copperplate approach	N.A.
For other countries	N.A.	N.A.	N.A.

Assumptions on electricity infrastructure

The Elegancy chain tool was developed for the transport of molecular energy carriers, not electrons. In fact, where a hydrogen molecule can be transported from point A to B, power is transmitted by exchanging electrons between points A and B in a closed loop. This is a more complex type of infrastructure and not within the scope of the tool its functionalities. The Elegancy chain tool is in principle not able to deal with optimization of electricity infrastructure, however electricity does play an important role for two reasons:

- Electricity production facilities are within the scope of the Dutch emission reduction pathway;
- Water electrolysis depends on electricity; therefore, electricity needs to be available to the model as a commodity.

To include electricity in the Elegancy chain tool the TenneT electrical infrastructure is modelled by adding a virtual grid cell to the spatial grid depicted in Figure 5.13. This cell represents the national high voltage electricity network. This copper plate approach is a simplified way of modelling of electricity hardware and infrastructure.

In the copper plate model each power plant or wind farm can either feed into the local electricity network or into the national electricity network. When in a region, demand for electricity exists, and energy infrastructure is available, electricity is fed into the local electricity network of the cell in which the electricity is produced to meet electricity demand in that particular cell. This is the case for cells representing any of the provinces of Groningen, Limburg, Noord-Brabant, Noord-Holland, Zeeland or Zuid-Holland (containing an industrial cluster). On the other hand, for any region with electricity demand but no means of electricity production (either from offshore wind farms or power plants, see Section 5.1.1 and 5.1.2), the demand is specified on the virtual cell representing the national electricity grid. This is the case for all other provinces. Renewable electricity production onshore (wind and solar PV) is assumed to feed into the copper plate and is therefore only available for domestic electricity demand in the provinces. Electricity can only be transmitted one way, i.e. electricity demand defined in a grid cell cannot consume from the high voltage grid. This would correspond to an infinite transmission capacity of the electricity network and is prohibited.

For the electricity sector, intermittent energy sources by nature will pose an increasing challenge to supply this baseload energy demand in the future. The way the Elegancy chain tool is set-up in this study, unfortunately, does not address this issue, which would require further work. The implicit assumption is made that all renewable electricity produced in a year is harvested and buffered using utility scale electricity storage to provide the baseload energy demand on which this model currently relies. Similarly, electrolysers are operated in baseload mode only.

In Figure 5.14, the total installed capacity of existing assets per time period is shown. Please note that this does not include any RES capacity, nor any additional capacity that can be added by the tool. For biomass and BFG, no limit has been imposed on the annual volume that is available. Natural gas and hydrogen have to be supplied to a plant. All plants are assumed to be available 8760 full load hours per year.

Power plants that are phased out in a certain year are still included in the simulation, up to and including that year, e.g., a plant that phases out in 2040 is active in the time periods 2030 and 2040, but not in 2050.

Assumptions on gas infrastructure

The natural gas and hydrogen backbone are implemented as existing infrastructure. The pipelines are implemented into the Elegancy chain tool as existing infrastructure, assuming that the hydrogen backbone has been completed at the start of the simulation. The gas backbone is assumed to consist of up to seven 48inch natural gas pipelines in parallel, dependent on the location. The hydrogen backbone consists of a single 48inch pipeline on each route. Gas is assumed to be able to flow in both directions within a pipe.

Assumptions on waste incineration plants

Waste incineration for electricity production is not included, considering the relatively small production capacity of individual waste incineration plants. Emissions related to this activity, though, are significant and were included by adding the accumulated annual CO_2 emission per province to the relevant grid cell, see Figure 5.15. In the model, emissions from incineration of waste can be abated by post-combustion capture.

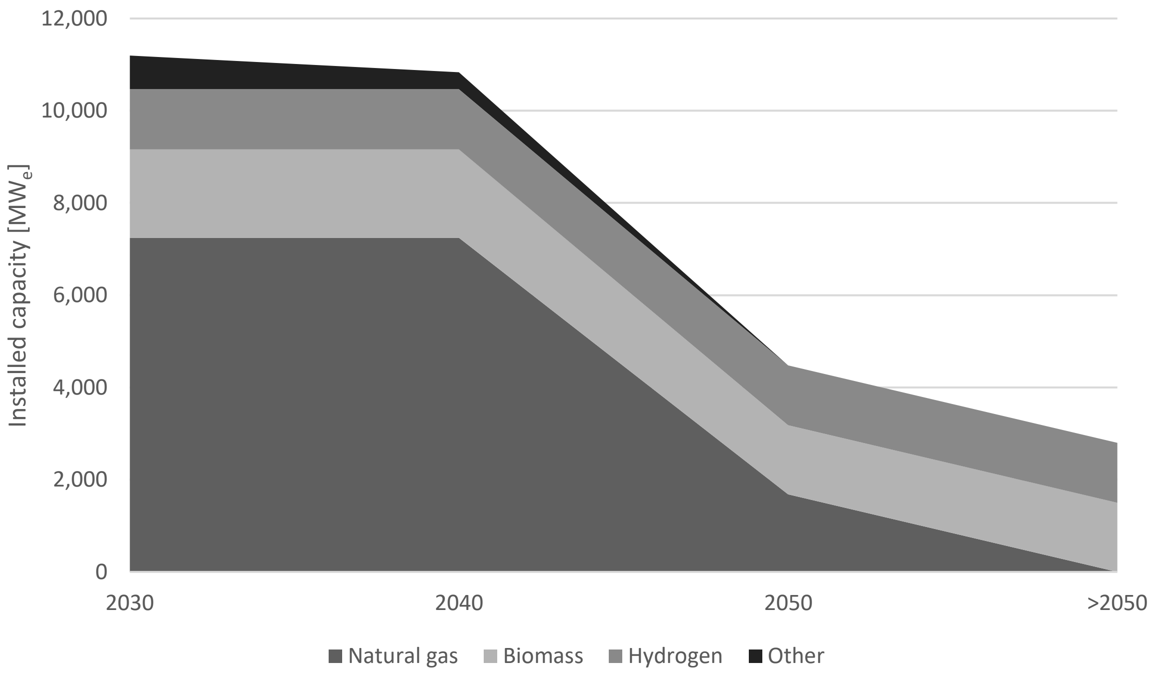

Figure 5.14: Availability of electricity production capacity per fuel type. Other fuel types cover blast furnace gas (Velsen-25) and hydrogen-natural gas mixture (Elsta).

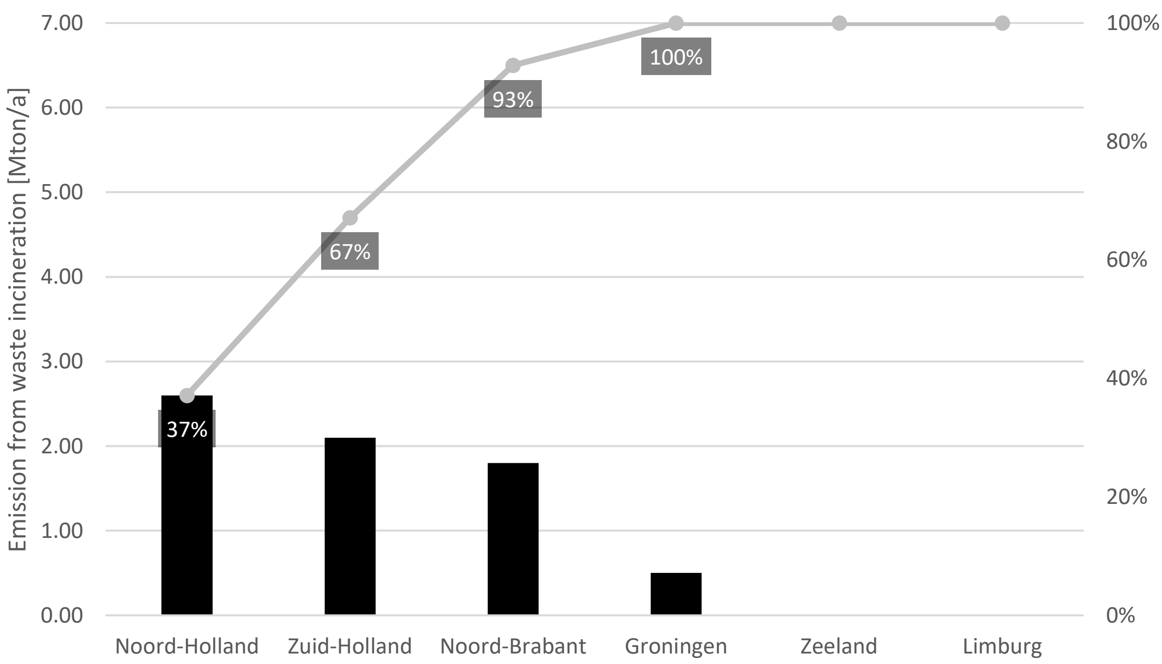

Figure 5.15: Emissions from the incineration of waste in the provinces with an industrial cluster.

Assumptions on commodity prices

Besides the input data presented in Section 5.1, a number of other parameters need to be defined as input for the chain tool to run, namely the price of natural gas, electricity, biomass, and CO_2. There is no distinction made in price between natural gas produced from a gas field, imported from a cross-border pipeline connection or from an LNG terminal. The price of electricity represents a price that includes production and buffering/storage of renewable electricity. The CO_2 price is increased gradually over time from €35 to €87 per ton in 2050. For 2060, the same data was used as for 2050.

Table 5.11: Commodity key assumptions. For 2060, the same data was used for 2050.

Resource	Year	Quantity	Unit
Natural gas	Fixed	28	€/MWh_{th}
Electricity	Fixed	57	€/MWh_e
Biomass	Fixed	26	€/MWh_{th}
CO_2 (ETS)	2030	35	€/ton CO_2
	2040	61	€/ton CO_2
	2050	87	€/ton CO_2

Optimization KPIs

The optimization process minimizes the total annual cost of the complete network, including:

- All CAPEX and OPEX of conversion, transmission and storage technology;
- All resource costs related to production and import of resources;
- Emission costs, according to assumed ETS prices, limited by the emission reduction targets (Table 5.12).

The optimization was terminated when the variation in the solution per iteration step was below 0.5% - 1%. In Table 5.13, the variables are listed, which are iterated over during the optimization process.

Table 5.12: Emission reduction targets over time. For 2060, the same data was used as for 2050.

CO_2 emission reduction w.r.t 1990	2030	49%
	2040	72%
	2050	95%

Table 5.13: Iteration variables and their types. Discrete variables are always integers, and continuous variables are always real. For computational performance, storage technology *was set to real.*

Number of assets	Variable type	Volumetric rates	Variable type
Process technology	Discrete	Production rates of process technology	Continuous
End-use technology	Discrete	Production rates of end-use technology	Continuous
Storage technology	Continuous	Resource storage rates	Continuous
Distribution technology	Discrete	Flow rates	Continuous
		Import rates	Continuous
		Emission rates	Continuous

5.2.2 Technological solutions

The tool is provided with a number of ways to abate emissions related to industry and electricity production. These options are presented in Figure 5.16 and can be summarized in the following way:

- Decarbonization of existing value chains by the introduction of CCS;
- Development of new carbon-free/neutral value chains based on renewable energy carriers (renewable electricity and biomass).

Technologies can be categorized by their value chain, which is typically the final energy carrier of that specific chain. Chains can be connected to one another, for example, hydrogen produced from natural gas by an ATR plant, which is then used in hydrogen fired power plants.

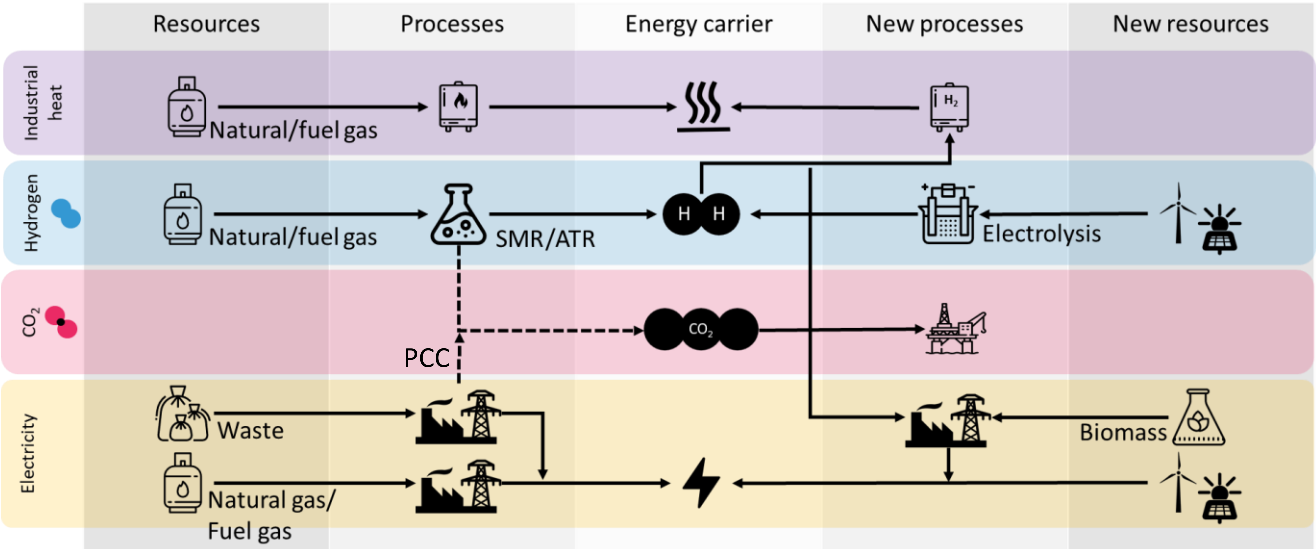

Figure 5.16: Technology pathways available to the chain tool for decarbonization of industry.

The technological routes presented in this section represent assumptions made in the modelling work and may not represent any actual limits or constraints in reality. For example, post-combustion capture technology can be applied in a variety of cases to abate process emissions, but in this model, post-combustion capture technology can only be applied to waste incineration installations.

5.2.3 Technology cost and operational data

Technology investments made by the tool add to the total cost of the network. In Table 5.14 to Table 5.18, cost parameters and resource conversion factors for the different technologies are presented as they were implemented into the Elegancy chain tool. Cost data was supplied by ICL and are therefore presented in pounds.

To be able to calculate the yearly financial burden of CAPEX investment, a capital recovery factor is used. By assuming a time horizon equal to that of a simulation time step (10 years) and an interest rate of 7%, the capital recovery factor totals to 14%.

When comparing the cost of assets, it is clear that the cost of a depreciated asset is significantly lower than that of a non-depreciated one. This is as expected, but given the relatively short period of 10 years, this may negatively influence the quality of the results and overestimate the financial impact of an asset in the period its built, while underestimating the cost in the period after.

Capital Expenditure (CAPEX) relates to any cost that is required to install the specific asset. Fixed Operational Expenditure (OPEX) relates to any cost that is required to keep the asset operative, regardless of the productivity of the asset. Variable OPEX relates to the cost per unit of product, in particular cost for energy carriers and CO_2 emissions.

A number of assumptions were made on the network cost. The learning curves for e.g., technological advancements or cost reduction by experience (per installed MW) have not been included. For CO_2 storage, the investment cost of an injection well is fixed and does not depend on the location and type of gas field. Furthermore, the cost of offshore assets other than pipelines or injection wells is not included. It is implicitly assumed that, e.g., gas production platforms remain in place until put to use for CO_2 storage, without any additional incurred costs.

Table 5.14: Cost parameters of different transmission pipelines per kilometre per energy of hydrogen produced by an ATR plant. Figures would change for a different plant. Conversion factors used: capital recovery factor 14%/year for calculation of yearly CAPEX, CO_2 captured by SMR 62.5 g CO_2/MJ H_2.

Resource	**Type**	**CAPEX**	**Annual CAPEX**	**Annual OPEX**	**Annual total cost**	**Transmission capacity**		**Non-depreciated cost**	**Depreciated cost**
		k£/km	*k£/km/yr*	*k£/km/yr*	*k£/km/yr*	*Mton CO_2/yr or PJ_{th}/yr*	*PJ_{th} H_2-eq/yr*	*k£/PJ_{th}/km*	*k£/PJ_{th}/km*
H_2	48 inch	2,792	391	140	531	978	978	0.54	0.14
H_2	36 inch	2,024	283	100	383	469	469	0.82	0.21
H_2	20 inch	1,000	140	50	190	46	46	4.12	1.08
H_2	14 inch	616	86	31	117	18	18	6.35	1.67
H_2	12 inch	488	68	24	93	12	12	7.49	1.97
H_2	6 inch	200	28	10	38	2	2	17.70	4.66
NG	48 inch	2,200	308	140	448	1,397	1,092	0.32	0.10
NG	36 inch	1,620	227	100	327	670	524	0.49	0.15
NG	20 inch	800	112	50	162	66	52	2.46	0.76
NG	14 inch	493	69	31	100	26	21	3.80	1.17
NG	12 inch	390	55	24	79	18	14	4.51	1.39
NG	6 inch	200	28	10	38	3	2	12.39	3.26
CO_2	48 inch onshore	1,600	224	8	232	18	294	0.79	0.03
CO_2	26 inch onshore	1,300	182	7	189	11	178	1.06	0.04
CO_2	12 inch onshore	600	84	3	87	3	44	1.96	0.07
CO_2	48 inch offshore	2,000	280	20	300	18	294	1.02	0.07
CO_2	26 inch offshore	1,690	237	17	254	11	178	1.43	0.10
CO_2	12 inch offshore	780	109	8	117	3	44	2.63	0.18

Table 5.15: Cost parameters of different hydrogen and CO_2 technologies.

	Size	CAPEX	Annual CAPEX	Annual OPEX	Annual total cost	Production capacity	Non-depreciated cost	Depreciated cost
Hydrogen technology		*k£*	*k£/yr*			*PJ_{th}/yr*	*k£/PJ_{th}*	
SMR + syngas capture	Large	378,000	52,920	25,400	78,320	31.5	2,484	805
SMR + flue gas capture	Large	529,000	74,060	25,400	99,460	31.5	3,154	805
ATR + capture	Large	554,000	77,560	24,400	101,960	31.5	3,233	774
ATR + GHR + capture	Large	540,000	75,600	24,400	100,000	31.5	3,171	774
SMR + syngas capture	Small	192,000	26,880	10,160	37,040	12.6	2,936	805
SMR + flue gas capture	Small	258,800	36,232	10,160	46,392	12.6	3,678	805
ATR + capture	Small	297,600	41,664	9,760	51,424	12.6	4,077	774
ATR + GHR + capture	Small	286,000	40,040	9,760	49,800	12.6	3,948	774
Water electrolysis	-	90,000	12,600	2,772	15,372	3.2	4,874	879
CO_2 technology		*k£*	*k£/yr*			*Mton CO_2/yr*	*k£/ton CO_2*	
CO_2 compressor	Large	19,500	2,730	78	2,808	11.1	252	7
CO_2 compressor	Small	1,950	273	780	1,053	1.11	946	701
Injection well	-	66,320	9,285	0	9,285	1.50	6,190	0
Post-combustion capture[23]	-	-	-	-	-	-	-	

[23] This technology is only applicable to waste incineration processes.

Table 5.16: Cost parameters for electricity production plants.

Power technology	Size	CAPEX	Annual CAPEX	Annual OPEX	Annual total cost	Production capacity	Non-depreciated	Depreciated
		k£	*k£/yr*			*PJ_e/yr*	*k£/PJ_e*	
CHP plant		188,889	26,444	15,000	41,444	7	5,914	2,140
Hydrogen plant		378,000	52,920	30,788	83,708	14	6,069	2,232
Gas plant	-	378,000	52,920	30,788	83,708	14	6,069	2,232

Table 5.17: Conversion factors of technologies per unit of hydrogen production. CO_2 technology is assumed to be lossless and require no energy.

Hydrogen technology	Hydrogen [MJ]	Natural gas [MJ]	Electricity [MJ]	CO_2 (emissions) [ton]	CO_2 (storage) [ton]
SMR + syngas capture	1	-1.367	0	0.000029	0.000037
SMR + flue gas capture	1	-1.455	0	0.0000066	0.000059
ATR + capture	1	-1.279	-0.059	0.0000036	0.0000625
ATR + GHR + capture	1	-1.2	-0.048	0.0000036	0.0000625
Water electrolysis	1	0	-1.4	0	0

Table 5.18: Conversion factors of technologies per unit of electricity production.

Power technology	Electricity [MJ]	Industrial heat [MJ]	Natural gas [MJ]	Hydrogen [MJ]	CO_2 (emissions) [ton]
CHP plant	0.56	0.44	0	-1.429	0
Hydrogen plant	1	0	0	-1.887	0
Gas plant	1	0	-1.852	0	0.000149

5.3 Tomorrow: deep decarbonization of industry

The implementation of new technology for decarbonization of industry, electricity production, and waste incineration was simulated over a time period from 2030 to 2060. The total energy system was optimized for cost related to the investment and operation of the network (production of industrial heat, electricity, and hydrogen, CO_2 capture, transmission, and CO_2 storage), consumption of resources, and CO_2 emissions. Existing infrastructure such as the hydrogen[24] and gas backbone are directly available for the transmission of energy carriers. Emissions are limited by the emission reduction targets defined in the Climate Agreement. The following technological options were available to the tool for investment:

- Industrial heat switching to hydrogen as a fuel;
- Phasing in of renewable electricity sources, including storage for baseload supply;
- Power plants switching to biomass or hydrogen;
- Production of hydrogen from SMR/ATR with CCS or from water electrolysis;
- Post-combustion capture of waste incineration emissions.

The results of one simulation are presented extensively in this chapter. In this simulation, the high wind scenario IV of PBL's "Toekomst van de Noordzee" was used, running up to 2060. Other simulation runs resulted in infeasible solutions. Infeasible means that no valid solution could be found: e.g. in case a scenario does not provide enough carbon-free energy to achieve the climate reduction targets given a specific volume of available CO_2 storage capacity.

First, a general overview is given of the simulation results on a national level over time, addressing the question if deep carbonization of the industry can be achieved using hydrogen as a single solution pathway. Second, a decentral angle is taken, and the simulation results per province are compared to one another. Thirdly, both the national and the regional results are interpreted integrally to come to a roadmap for deep decarbonization of industry up to 2050. Finally, some remarks are made on how to proceed beyond 2050.

5.3.1 Achieving climate reduction targets

According to the simulations, the climate reduction targets for the industry can indeed be successfully achieved by the implementation of a hydrogen and CCS network, but only supported by large scale offshore renewable electricity production. By 2050, 59Mton of CO_2 can be avoided annually with respect to baseline emissions in 1990 by the production of carbon-free electricity produced by offshore wind, onshore wind, and solar PV. In 2050, another 30Mton of CO_2 per year is to be captured and stored in offshore gas fields. By then, a little under 5Mton is still emitted each year, mostly from the incineration of waste (2.7Mton), emissions released from ATR processes for the production of hydrogen (1.5Mton), and production of electricity (0.5Mton).

From the results, it can be concluded that the CO_2 storage capacity of offshore gas fields is utilized to a maximum and that this is the more cost-effective option for the decarbonization of industry. The limited storage capacity of these fields require additional avoidance of emissions by renewable energy carriers like biomass, on- and offshore wind, and solar PV. The CO_2 prices that were used in this study have not been a decisive factor in decarbonization beyond the emission reduction targets, judging by the fact that no more emissions were abated than strictly required.

[24] Today (2020), this backbone does not exist yet, but is assumed to be finished and available at the start of the first simulation year 2030.

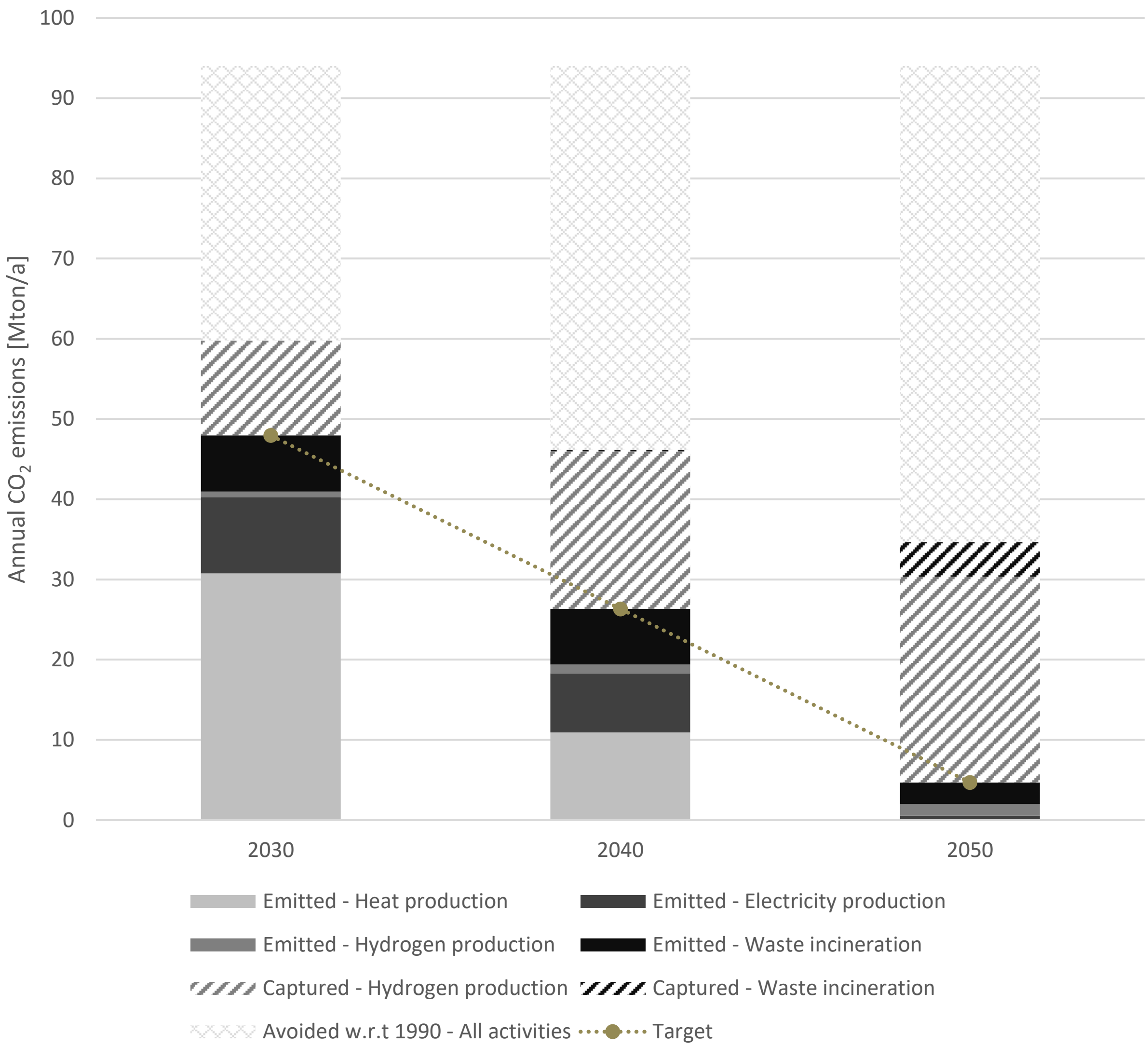

Figure 5.17: Annual emissions per production activity. The abatement of emissions is successfully achieved up to the reduction targets (dotted line). These emissions are avoided on the one hand by the introduction of carbon-free energy from RES, resulting in a decline of total CO_2 produced (60 Mton/a reduced as of 2050 w.r.t 1990) and by capture and storage of CO_2 (30 Mton/annum as of 2050) on the other hand. The result for 2060 is identical to that of 2050.

During the simulation, two transitions take place in two consecutive time periods, as shown in Figure 5.18. Please note that these trends have been obtained by assuming one single solution space, namely hydrogen, as a carbon-free energy carrier. These distributions may look significantly different when, e.g., electrification of industrial processes is included.

First, emissions from electricity production are significantly reduced in 2030 by scaling up of renewable energy carriers biomass, onshore and offshore wind, and solar PV. In 2030, the only 17.6TWh is still produced from natural gas (15% of annual production), while 5.9TWh and 3.7TWh is produced from hydrogen fuelled CHP plants and biomass plants, respectively. Simultaneously, hydrogen production is scaled up only slightly from 1.6Mton in 2020 to 1.9Mton in 2030 to meet the additional demand for hydrogen by hydrogen-fuelled CHP plants.

Beyond 2030, the scaling up of the hydrogen production capacity accelerates to accommodate the second transition: of industrial heat. The national production capacity of hydrogen is scaled up dramatically from 1.9Mton in 2030 to 4.2Mton in 2040 and further up to 6Mton in 2050. ATR plants are developed according to the available offshore CO_2 storage capacity, while water electrolysis production capacity is scaled up to close the gap with the actual demand. This is likely to increase the general price of hydrogen compared to today as the market is not saturated with hydrogen from natural gas, but depends on more costly hydrogen from water electrolysis as well.

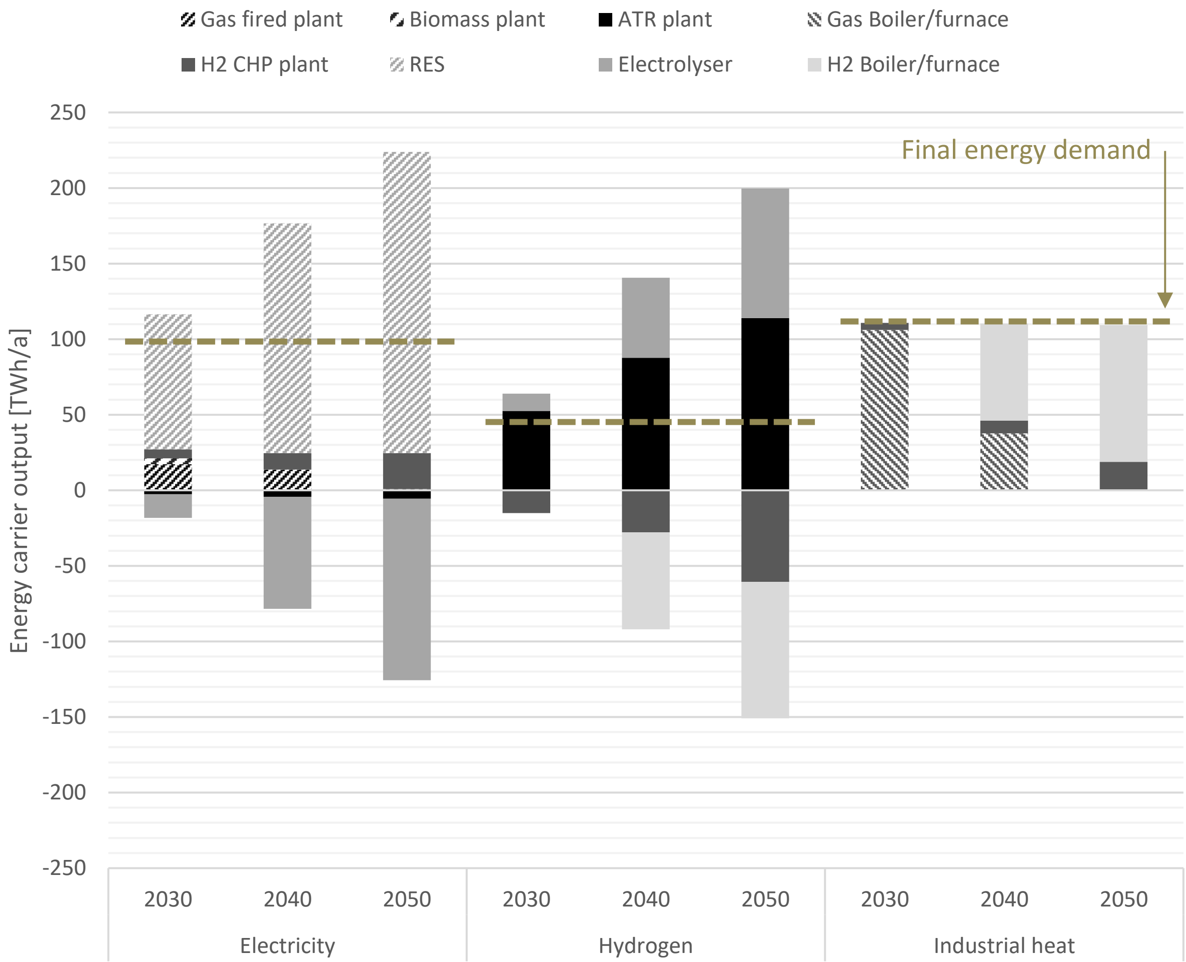

Figure 5.18: Transition in energy carriers for industry and electricity production over time. The positive values indicate the total production of each carrier, while the negative values indicate the corresponding volumes of an intermediate product, i.e., the energy that is used in another process. Electricity production increases as a result of an increase in electrolysis, while hydrogen production increases as a result of an increase in hydrogen-based heating. The result for 2060 is identical to that of 2050.

The simulation results indicate that hydrogen can be produced against an average cost of €2.31/kg (€70/MWh) in 2030 up to €2.00/kg (€64/MWh) in 2050[25]. Despite the increasing average resource cost (as a result of the increasing share of water electrolysis), total costs drop over time due to the depreciation of network assets. These prices include CO_2 storage costs, which are estimated to amount to €18/ton in 2030 down to €4/ton in 2050. The average cost of industrial heat remains not unaffected, rising from €18/MWh in 2030 up to €71/MWh in 2050. It should be noted again that cascading of hydrogen was not included and that all costs are averaged over the total national production. In the simulation, hydrogen cost from a natural gas-only drop below €1.40/kg by 2050, resulting in a cost of a heat of €46/MWh. Still, this is a strong increase compared to natural gas-based industrial heat production €31/MWh (+46%). The price of electricity production was not evaluated as an assumption on an electricity price was made a priori.

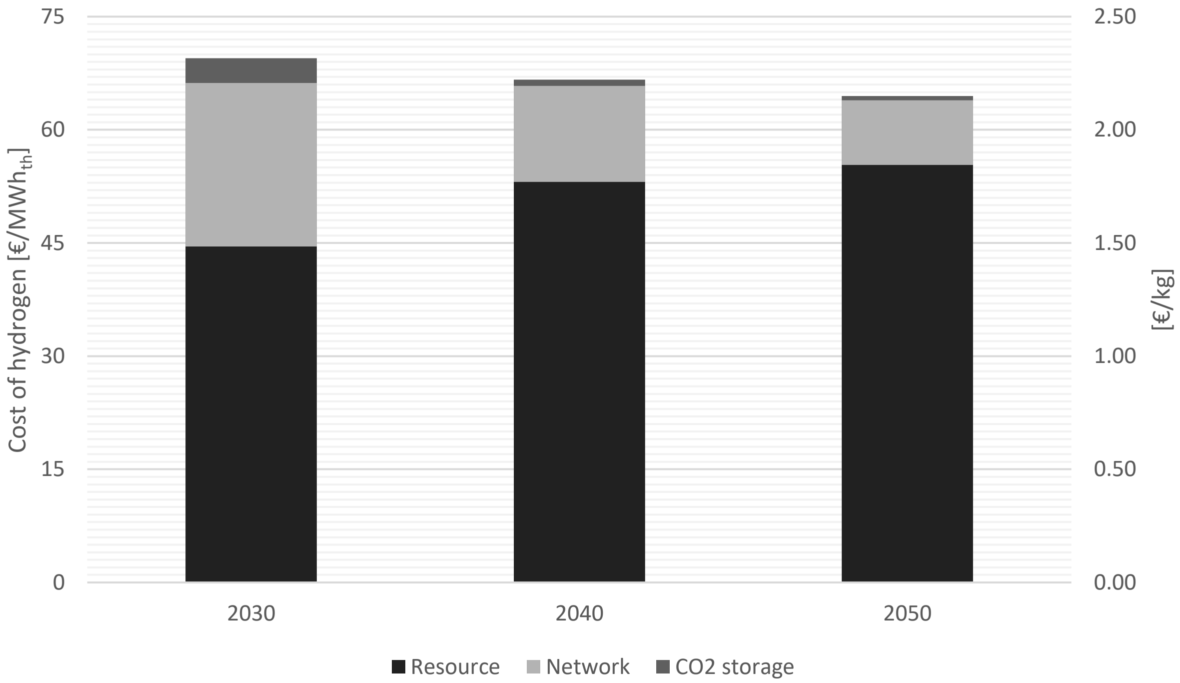

Figure 5.19: Average cost of hydrogen production over time. Network cost covers investment in hydrogen production facilities (ATR and water electrolysis) and transmission network (hydrogen backbone), including a one-time investment of €1.5 bn. by Gasunie in 2030. Resource cost includes cost of natural gas (28 €/MWh), electricity (57 €/MWh) while storage refers to CO_2 storage cost according to Figure 5.21. Excluding transmission cost of gas backbone.

[25] Under the assumptions presented in Section 5.2.3, hydrogen production cost is €1.23/kg and €2.66/kg for ATR and water electrolysis, respectively, excluding network costs.

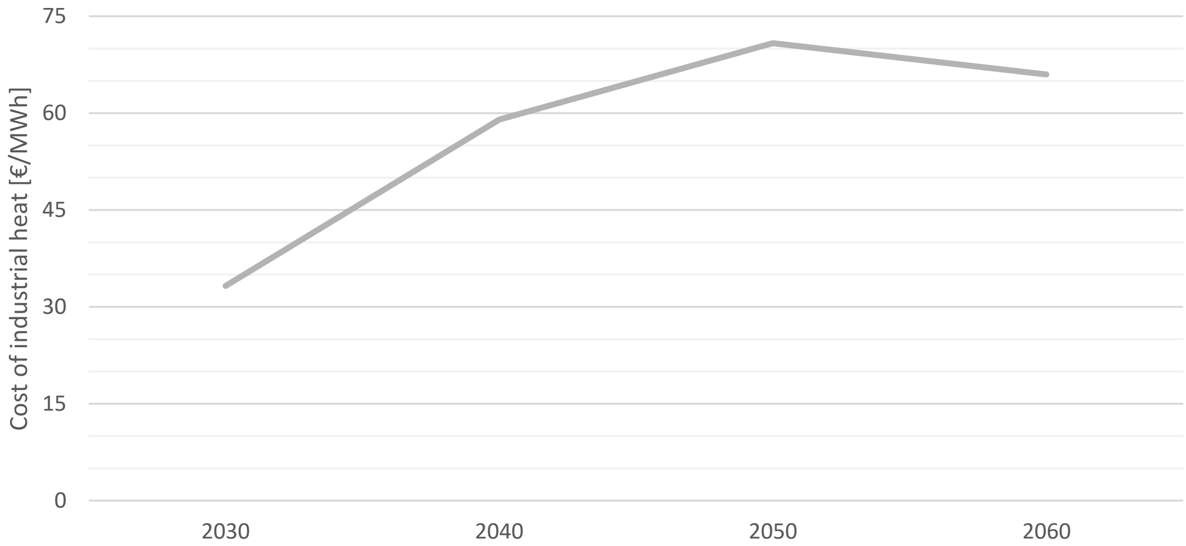

Figure 5.20: The average cost of a unit of industrial heat. Increasing costs are to be expected when phasing out natural gas and phasing in hydrogen as a fuel. Costs may be expected to be lower when industry off-gases are used for the production of the hydrogen. Cascading of hydrogen was not included in the analysis.

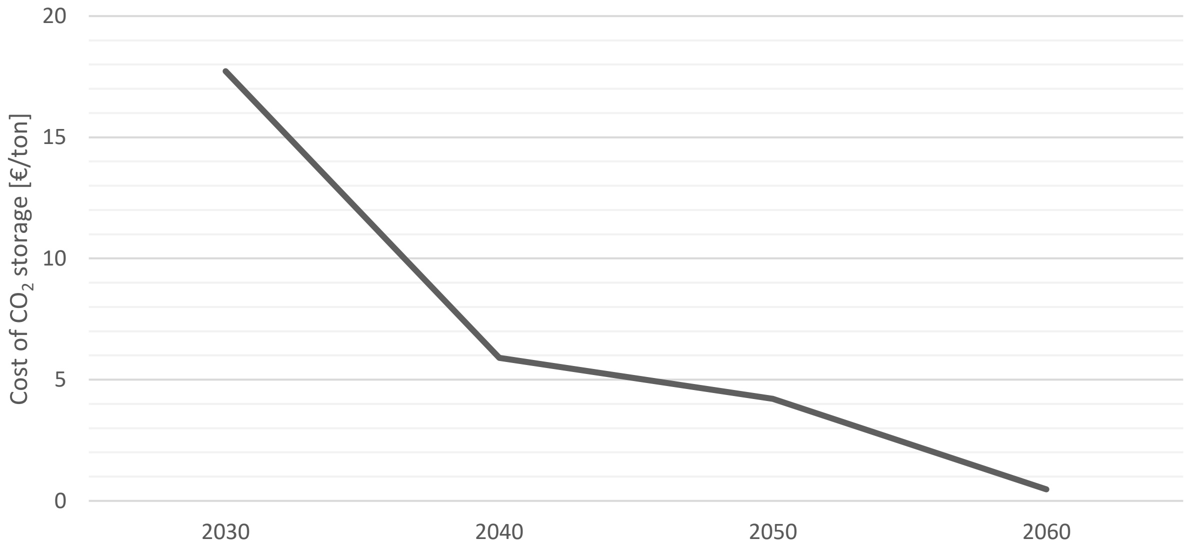

Figure 5.21: Cost per volume of stored CO_2 decreases as a result of increasing network utilization (storage rates) and decreasing costs by the depreciation of pipeline, compression, and injection well assets.

5.3.2 Regional developments in chemical clusters

Where the former section discussed the results of the national network, the regional aspects of the transition are presented below. When inspecting the geographical distribution of CO_2 emissions in Figure 5.22, the following can be noted. The abatement of emissions in a cost-effective way does not necessarily take place synchronously for each individual region. While the cluster in the Rotterdam area (ZH) decreases emissions steadily with a factor 3 to 4 each decennium, the cluster in Limburg (LB) takes an initial step in 2030, continues its business until 2040, to finally completely decarbonize in 2050. Another example is Zeeland, which decreases emissions by 95% in 2040, to increase slightly again in 2050.

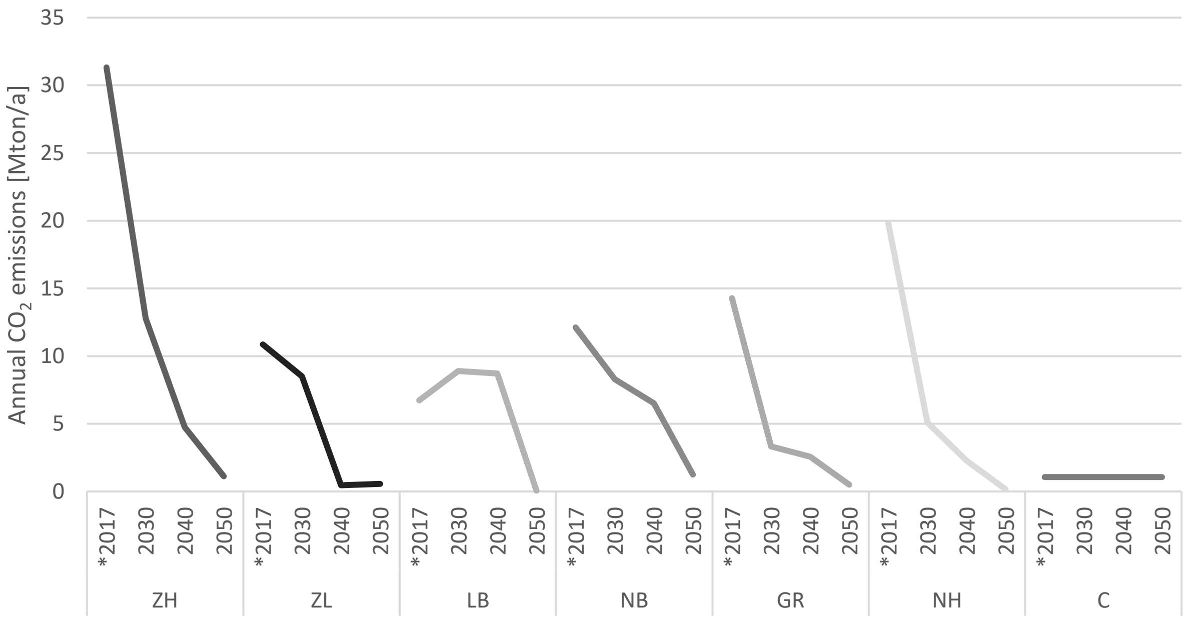

*Figure 5.22: CO_2 emissions per region. The result for 2060 is identical to that of 2050. Values for *2017 have been taken from Klimaatmonitor and are not a result of the simulation.*

These differences have their root in the different types and volumes of energy demand (industrial heat, electricity, and hydrogen feedstock) as well as in their respective locations. Limburg depends on the development of hydrogen production capacity in other regions before it can decarbonize its industrial heat. In Figure 5.23, the regional distributions of energy use by process and carrier are shown.

For the production of industrial heat, natural gas and industry off-gases are phased out and gradually replaced by hydrogen. Please note that the fuel mixing of hydrogen and natural gas was not included, so replacement is done by installing new or repurposing existing hardware. In the case of Limburg and Noord-Brabant, decarbonization of heat and electricity is combined with the installation of CHP plants, leading to a minor efficiency increase.

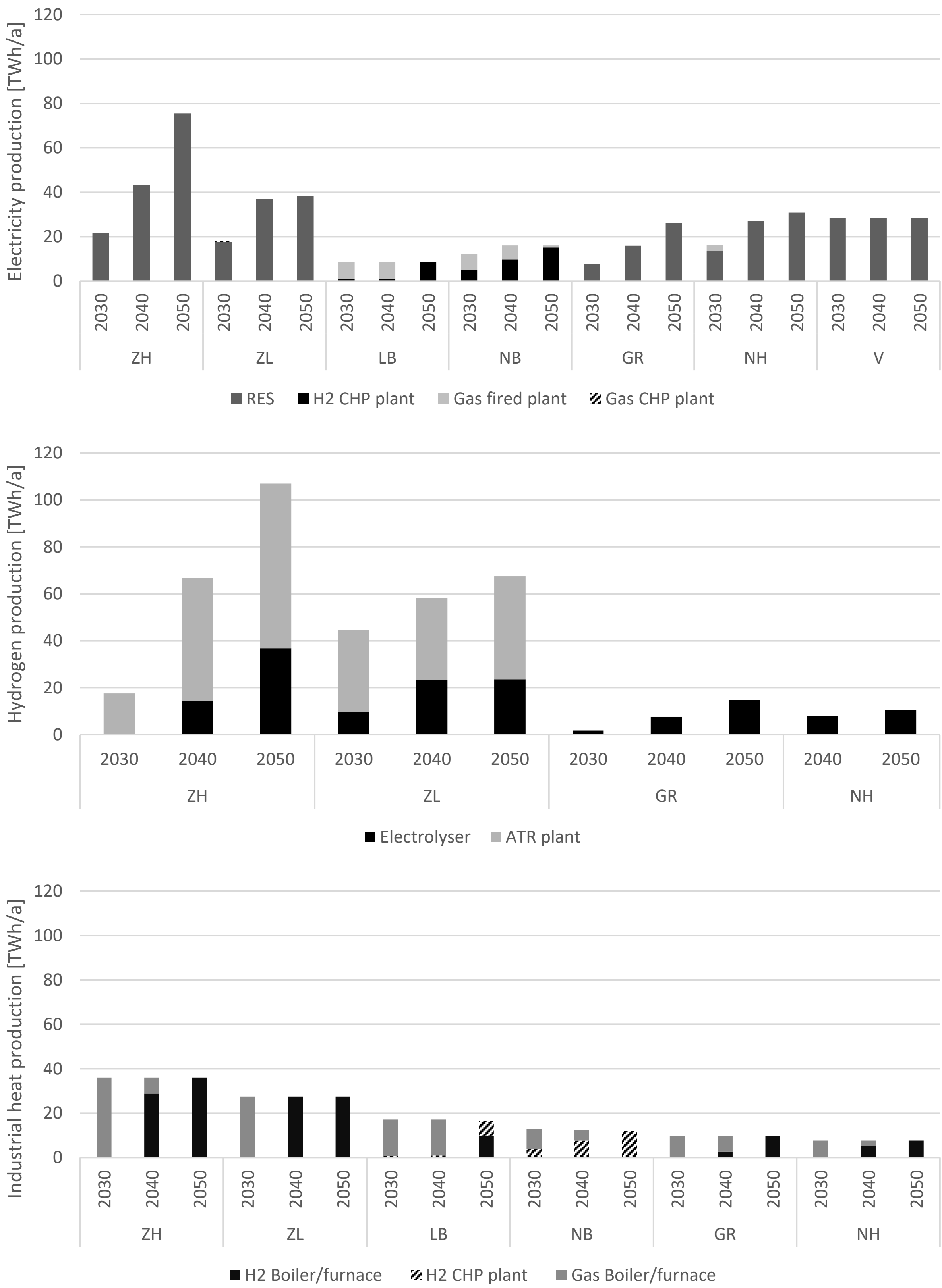

Figure 5.23: Regional distributions of industrial heat, electricity, and hydrogen production. The result for 2060 is identical to that of 2050.

Hydrogen production takes place in two mayor hydrogen hubs: Zuid-Holland and Zeeland. These two mostly supply the clusters in Noord-Brabant and Limburg. The clusters in Groningen and Noord-Holland become self-sufficient in terms of hydrogen as of 2040 with the production of hydrogen from offshore wind. These results are in accordance with D5.2.4 of the Elegancy project, in which is described how industry fuel gases, such as refinery fuel gas, can be used as feedstock in ATR processes, with significant potential in the Zuid-Holland cluster of 1.7GW_{th} to 2.2GW_{th} (15 to 20TWh/a). These fuel gases would replace the natural gas indicated in Figure 5.23.

The simulation resulted in the deployment of new power plants in Limburg and Noord-Brabant. As can be seen from Figure 5.24, the potential of onshore RES, represented in the virtual grid cell V, is not utilized fully. This means that in reality, there is still renewable electricity to be harvested, potentially also in these regions. Thus this specific result should not be interpreted too literally.

Also from Figure 5.24, it can be seen that the simulation depends on the dramatic increase of RES yield. For comparison, the total production in 2017 was 8.5TWh onshore wind and solar PV and 3.4TWh offshore wind. This means production should increase by a factor of 8 until 2030, and by another factor of 2 until 2050.

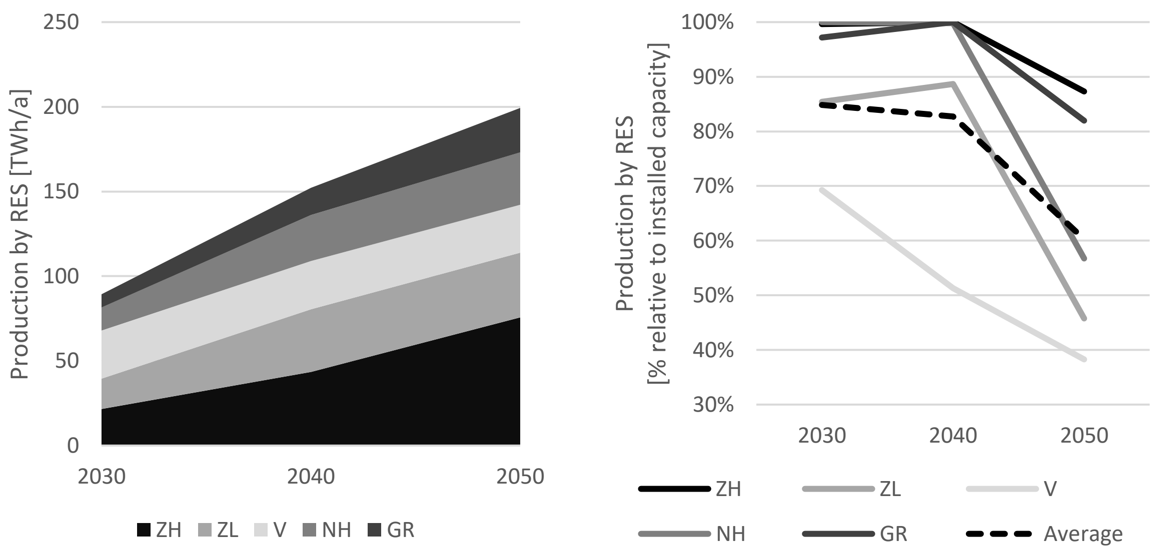

Figure 5.24: Production volumes (left) and relative utilization of the supply potential of renewable electricity (right). It can be seen that onshore wind and solar PV are not utilized fully in the simulations.

5.3.3 Development of a hydrogen and CCS network

In this section, the development of the infrastructure that should accommodate the transitions, as described in the former section, is laid out. These developments are the result of the simulations run in this study and represent only a single solution pathway of hydrogen as carbon-neutral fuel and feedstock for industry, painting one of the possibly many feasible pictures for decarbonization of the Dutch industry. In Figure 5.25, the CO_2 storage rate and final cumulative storage volume per gas field cluster are depicted. Maps of the network for each time period can be found in Figure 5.26 to Figure 5.28.

2030

The assumption was made that in 2030 the hydrogen backbone would be fully available. This network is used extensively, albeit not to its full capacity. It is mostly used to transmit hydrogen produced in Zeeland to all other clusters, after installing an annual production capacity of up to 1.3Mton in the Zeeland cluster. In this cluster, hydrogen is required for fertilizer production, but the availability of a cross-border natural gas connection and offshore wind provides a suitable location for the overproduction of hydrogen, which can be distributed over the other clusters.

Simultaneously, a CO_2 backbone is installed to connect Zeeland and Zuid-Holland to the furthest cluster of gas fields K4 (which in the simulation includes fields K5/K7/K8/K10 with a total storage capacity of 345Mton). The initial investment may be high due to the relatively long distance of the pipeline, but this way, the field can be fed with a constant flow of captured CO_2 for as long as possible, maximizing utilization of the network while minimizing the required transmission capacity.

Only one route of the gas backbone is still in use, from Rotterdam to Limburg, to provide natural gas for industrial heat and electricity production. Total annual gas consumption of industry in 2030 amounts to 23bcm (compared to 34bcm in 2017 as reported by EBN[26]).

2040

Towards 2040, the CO_2 storage rate is increased (by 8Mton/a to nearly 20Mton/a) following an increase in ATR production capacity in Rotterdam. Fields K14 and L10, both along the route of the offshore CCS backbone, are put to use for additional storage capacity.

Local consumption of hydrogen is increased in Zeeland, reducing the net export of hydrogen to other clusters. The clusters in Noord-Holland (Ijmuiden) and Groningen (Eemshaven) have become self-sufficient in their hydrogen production by the implementation of water electrolysis, while the clusters in Noord-Brabant and Limburg rely on the hydrogen network for supply of hydrogen. The gas backbone, its main functionality in 2040 is to provide natural gas to Limburg for most of its processes. The only hydrogen required as feedstock is supplied by the hydrogen backbone.

2050

In 2050, the CO_2 network is extended to provide waste incineration plants the possibility to apply post-combustion capture. The aquifer Q1/Q4 is added to the network by connecting a branch to the CO_2 backbone. The total CO_2 storage rate is ramped up to nearly 30Mton/a, which can last for 20 years up to 2060 until the gas fields in scope are full.

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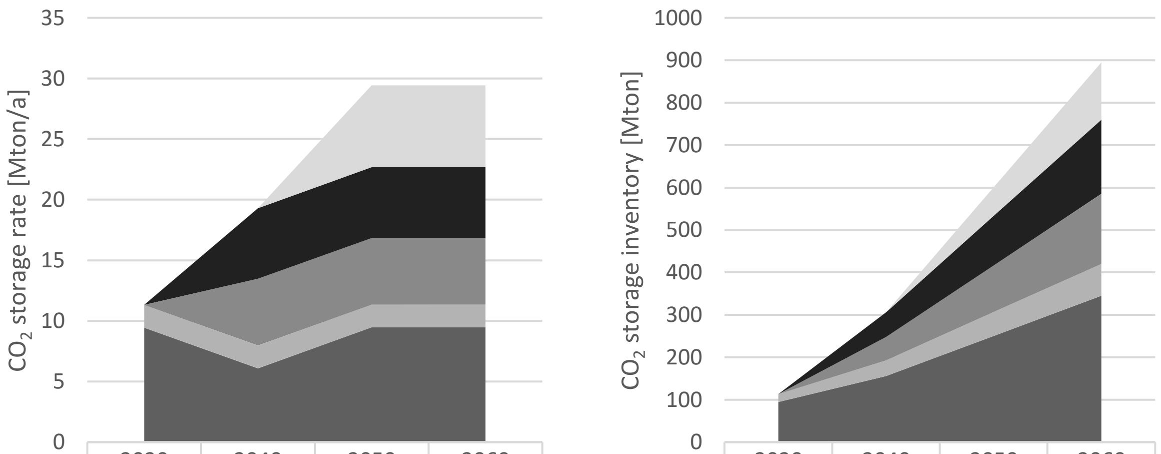
[26] https://www.energieinnederland.nl/feiten-en-cijfers/uitgebreid/2017/energieverbruik/industrie

In the northern clusters in Groningen and Noord-Holland, natural gas has been phased out completely and replaced by hydrogen from water electrolysis. The average utilization of national renewable electricity production has dropped from 83% in 2040 to 60% in 2050, meaning that only 60% of potential RES production is actually consumed. This indicates that the full-scale deployment of RES in this simulation is not exploited fully. Only in Groningen and Zuid-Holland is the utilization factor still above 80%.

These results indicate that by 2040 an extensive part of the network may not be required for the transmission of natural gas any longer. In this work, only gas consumption for the industry was considered. This network may still be useful for providing other economic sectors with natural gas. But considering the ambitions in other sectors (most notably the built environment) to phase out natural gas, repurposing or decommissioning of the northern part of the network may have to be considered. In any way, the southern part of the backbone, stretching from Zuid-Holland and Zeeland to Limburg, continuous to play an important role, and the conversion of natural gas lines to hydrogen seems to be a no-regret option here.



	2030	2040	2050	2060
Q1			7	7
L10		6	6	6
K14		6	6	6
P15	2	2	2	2
K4	9	6	9	9

	2030	2040	2050	2060
Q1			68	135
L10		58	117	175
K14		55	110	165
P15	19	38	56	75
K4	95	155	250	345

Figure 5.25: CO_2 storage rates (left) and cumulative volume stored (right) per gas field cluster.

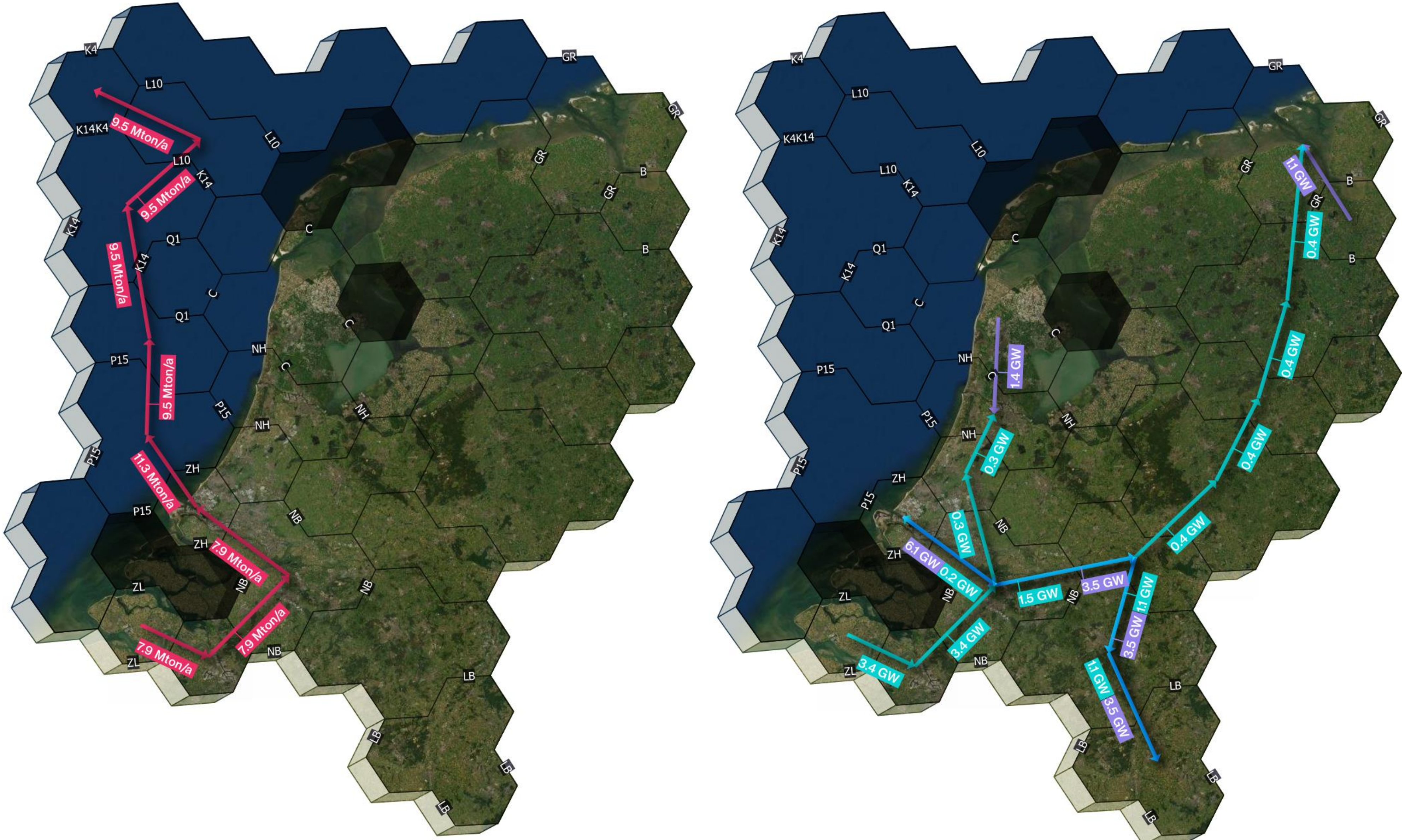


Figure 5.26: Simulated network infrastructure in 2030 for CO_2 (left) and Hydrogen and Natural gas (right, routes may

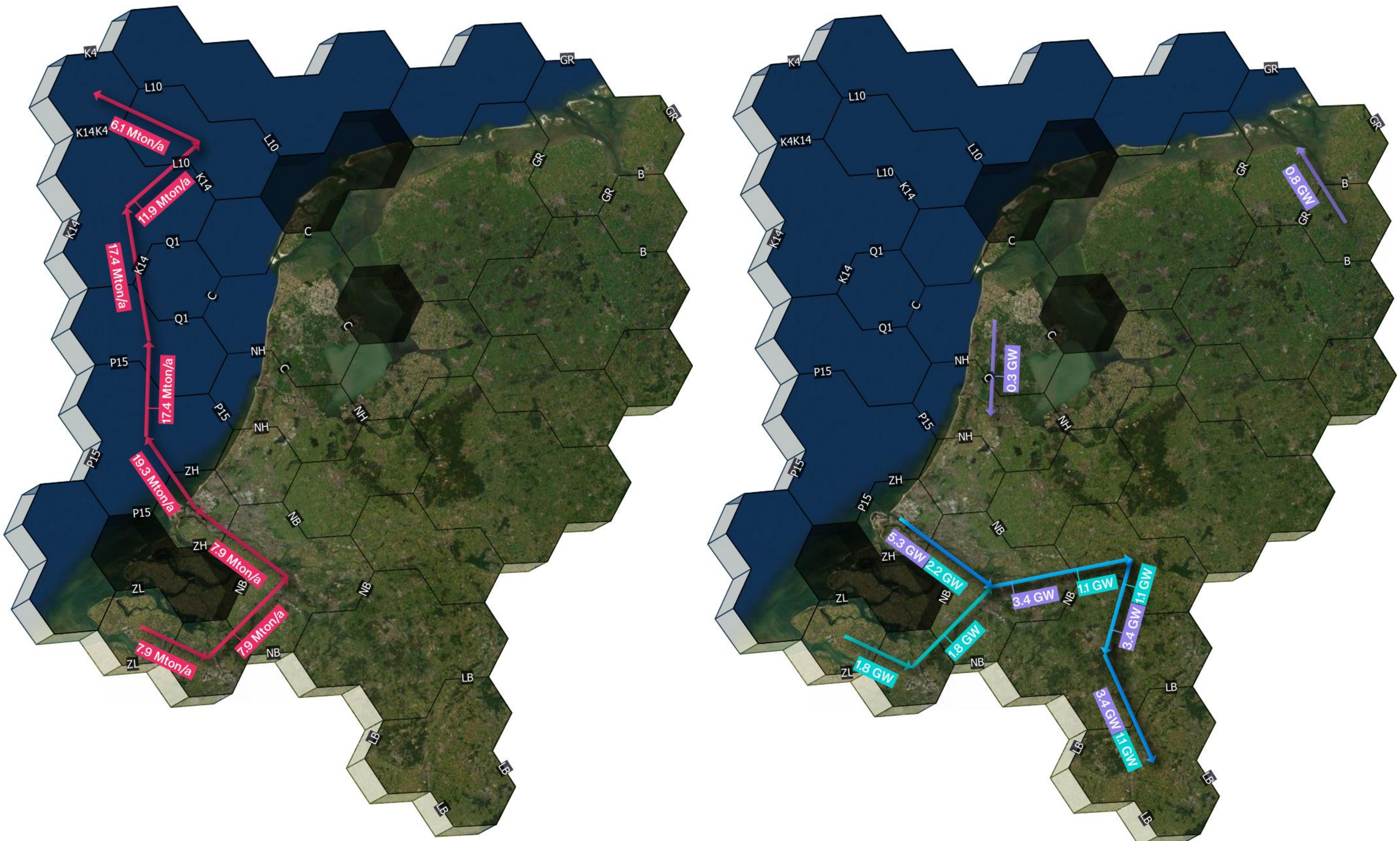


Figure 5.27: Simulated network infrastructure in 2040 for CO_2 (left) and Hydrogen and Natural gas (right, routes may overlap)

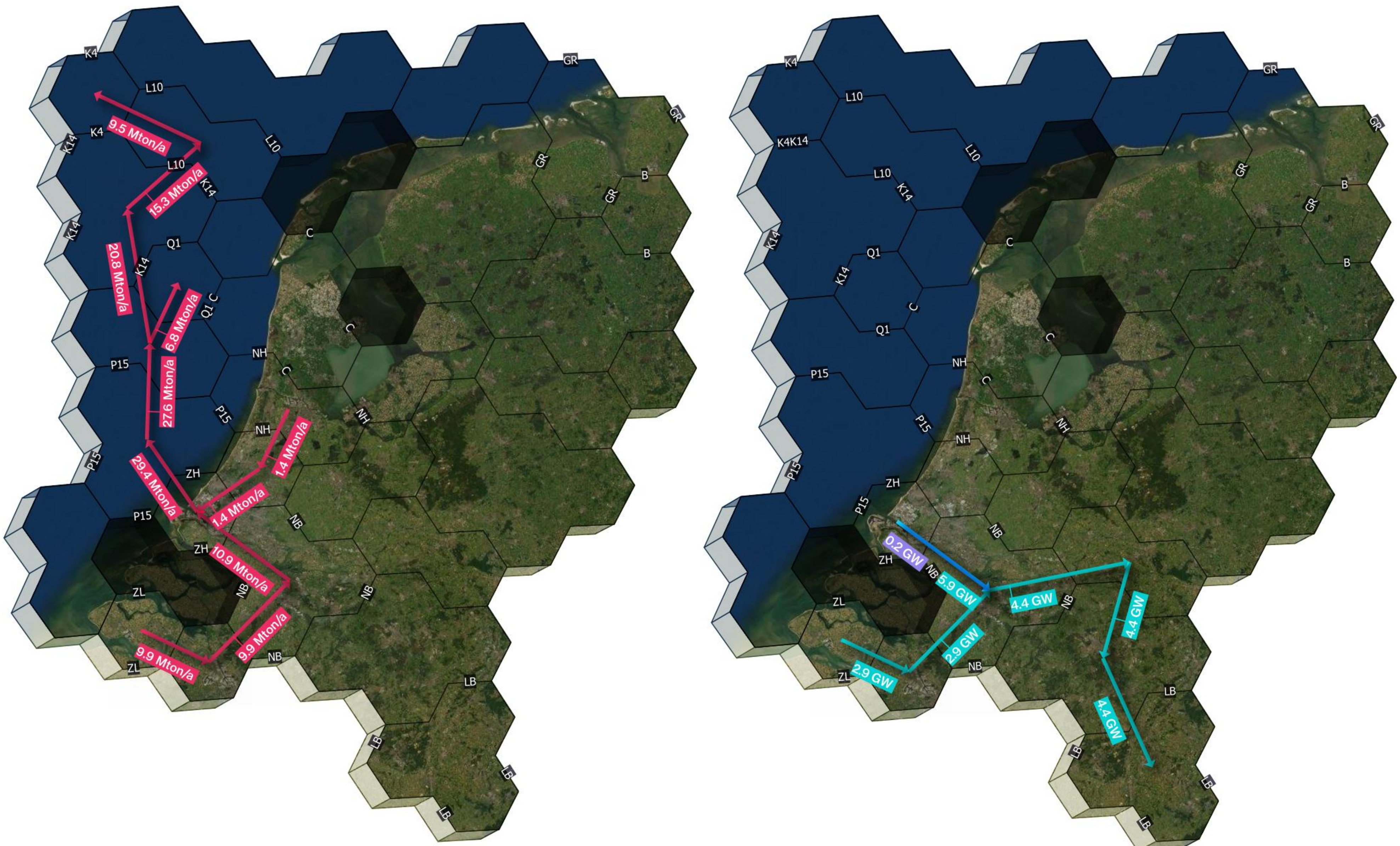


Figure 5.28: Simulated network infrastructure in 2050 for CO_2 (left) and Hydrogen and Natural gas (right, routes may overlap)

5.3.4 Looking beyond 2050

It was observed that the storage capacity of offshore gas fields is a limiting factor in the deployment of natural gas-based hydrogen production technology. This was found by comparing the results presented in this chapter with that of simulations with shorter and longer time horizons (-10 and +10 years, respectively. When confronted with a longer simulation period, the tool installs a higher production capacity of water electrolysis technology in the first time period to maximize the use of each asset. In reality, this may translate into a reduction in stakeholders willing to invest in a CCS network when the usage of such network draws to an end, for example, because storage capacity runs out. In this case, the more costly production of hydrogen from water electrolysis needs to be scaled up quickly. This may require financial stimuli from the national government for the industry to overcome cost barriers when adopting hydrogen from electrolysis.

Developments of new gas fields

Developments of new gas fields could prolong the phase-in of water electrolysis production capacity, making the transition initially cheaper. Another advantage this could bring is storage capacity for CO_2 imported from Germany. Today, CCS in Germany is a political non-topic, and they need to look for cross-border solutions if this is to be a serious option for the decarbonization of German greenhouse gases. While EBN indicated a total estimated capacity of 1700Mton CO_2 is "practically" available (Section 5.1.6), it is not known if all of this capacity is both technically and economically suitable for CO_2 storage.

Short term versus long term

The simulations show that by considering the cost of the network over the complete time horizon, the tool aims for maximum utilization of all assets. This results in the installation of assets, of which it can be sure these assets can remain active until the end of the time horizon. Intuitively, it may be tempting to look at what is more affordable in the short term, which today is hydrogen from natural gas with CCS. But as the results show, when considering time horizons of 40-60 years, which is similar to the lifetime of an industrial plant, it is more cost-effective to create a solution that can last until the end of the considered time period than to put all the eggs in one basket (CCS) until the gas fields are full before turning to electrolysis as the main hydrogen production method. The simulation results insinuate that hydrogen production from electrolysis and natural gas should be scaled up simultaneously, although not necessarily at the same pace.

5.4 Conclusions on the chain modelling

During the simulations, decarbonization of 95% by 2050 was successfully achieved in two transition phases. From 2025 to 2035, the electricity production was decarbonized first by scaling up both onshore and offshore renewable energy sources. By 2030, only 15% of electricity production was still fossil fuel-based. Second, beyond 2035 and up to 2055, industrial heat production was decarbonized gradually by the replacement of natural gas and fuel gas by hydrogen as a carbon-free fuel.

The simulation results indicate a prominent role for both natural gas and renewable electricity in the production of hydrogen. ATR plants can be deployed early on to provide the industry with relatively cheap hydrogen compared to hydrogen from renewable electricity. Relative, as energy prices are expected to increase in both cases with respect to the situation today. Water electrolysis can start to play an increasingly important role once the utility sector has been decarbonised and increasing amounts of renewable electricity would come available.

In the simulation, by 2050, a total of 6Mton hydrogen is required each year to provide the industry its emission-free energy. The emission reduction targets are achieved by avoidance of CO_2 (60Mton/a) as well as by the capture and storage of CO_2 (30Mton/a). The simulation was set up such that the situation in 2050 can be maintained for at least 20 years (from 2045 to 2065). As gas fields run full and, CO_2 storage capacity runs out, this is the period in which other means of energy supply should gradually take over the 57% share of the total 200TWh of annual hydrogen production from ATR processes. Options for this were not explored.

6 HYDROGEN MARKET DYNAMICS IN THE ROTTERDAM INDUSTRIAL CLUSTER

The Rotterdam industrial cluster is one of the first areas where a hydrogen market will emerge from an self-sufficient local blue hydrogen market to a dynamic local market linked to the Dutch electricity market and various other local hydrogen markets. This evolution towards a dynamic market is driven by electrolysers and hydrogen storage via the backbone.

This chapter demonstrates the cascading electricity-hydrogen market model that has been developed as an extension to the TNOs EYE tool in Elegancy. The model has been developed to get detailed insights into the influence of electricity and hydrogen market dynamics on the business cases of various stakeholders. The market dynamics in the Rotterdam industrial cluster are evaluated as a first use case.

6.1 Scenarios

To be able to evaluate the evolution of the local hydrogen market in the Rotterdam industrial cluster, three scenarios were developed:

- 'Blue' (base case): Only blue hydrogen produced by ATRs fired on refinery fuel gas, and natural gas is considered. In this case, demand and supply are balanced by the flexibility of the ATRs: the Rotterdam industrial cluster has a self-sufficient blue hydrogen market.
- 'Celeste': 200MW electrolysers are installed to produce hydrogen for the local market. The hydrogen surplus is fed into the hydrogen backbone. Here it is assumed to be stored (e.g., in the caverns 'Zuidwending') so it can be offered at the local hydrogen market at a later moment. The ATR capacity developed in the blue scenario is still available in the Celeste scenario.
- 'Viridian': 500MW electrolysers are installed to produce hydrogen for the local market. As in the Celeste scenario, it is assumed that the hydrogen backbone functions as a virtual storage for the local hydrogen market and that the ATR capacity, as developed in the Blue scenario, is available in the Viridian scenario. Furthermore, $50MW_{th}$ continuous baseload renewable hydrogen demand for feedstock is introduced.

The Blue base case scenario is based on the latest known plan (project H-Vision) for the development of hydrogen production and demand in this area. The Celeste and Viridian scenarios are successors of the Blue base case. This requires, in all scenario's an investment in ATR capacity that covers all hydrogen demand, both of the refineries and the powerplants.

In all three scenarios, the Dutch electricity market scenario, as described in Elegancy Deliverable 5.2.4, is considered with a gas price (31 €/MWh) and a CO_2 price (54 €/ton) such that both electrolysers and hydrogen-based powerplants have a good position on the electricity market. For the analysis of the local hydrogen market dynamics using the cascading electricity-hydrogen market model, the Dutch electricity market scenario is combined with the local hydrogen market scenarios Blue, Celeste, and Viridian.

Table 6.19: Parameters of the Dutch electricity market scenario modelling for 2030.

Energy Mix [GW]	
Wind Onshore	8.1
Wind Offshore	14.5
Solar	21.1
Natural Gas	13.0
Nuclear	0.0
Coal	0.0
Hydrogen	1.5
Biomass	1.9
Demand [GW]	
Baseload	22.9
Flexibility Options [GW]	
Hybrid Boiler	1.60
Heat Pump	1.40
Electrolyzers	1.40 + local
Storage	2.04
Commodity Prices [€/MWh]	
Gas price	31
Coal price	9.7
Biomass price	36.0 - 28.8
CO_2 price [€/ton]	
CO_2 price	54

The local hydrogen market in the Blue scenario is defined in Table 6.20. The Onyx power plant is the only asset active on both the Dutch electricity market and the local hydrogen market. The only asset that can provide this power plant hydrogen is the flexible ATR capacity fuelled by natural gas. The refineries have long-term take-off contracts with the ATRs: they always balance each other and are assumed to be continuous baseload.

Table 6.20: Participants in the local blue hydrogen market in the Blue scenario.

Direction	Asset	Flexible	Driven by	Capacity (MW_{th})
Supply	ATR refinery fuel gas	no	Long term contracts	1510
Supply	ATR natural gas	yes	Hydrogen market	400
Demand	Refineries	no	Long term contracts	1370
Demand	Pergen powerplant	no	Long term contracts	140
Demand	Onyx powerplant	yes	Electricity market	250

The Celeste and Viridian scenarios are slight variations on the Blue scenario in which electrolysers, storage via a hydrogen backbone, and additional capacity of wind turbines are considered. See Table 6.21. Both electrolysers and the extra wind turbines participate in the Dutch electricity market and may have a PPA.

Table 6.21: Difference between the scenarios Blue (see Table 6.20), Celeste, and Viridian.

	Blue	Celeste	Viridian
Electrolysers (MW_{th})	0	200	500
Extra Wind Turbines (MW_e)	0	300	800
H_2 Backbone (GW_{th})	0	2	2
Feedstock hydrogen demand (MW_{th})	0	0	50

In Viridian also green hydrogen demand for feedstock is added. Hydrogen for feedstock processes should be green hydrogen according to the second Renewable Energy Directive (RED2). In the Rotterdam industrial cluster, 50MWh_{th} hydrogen demand is considered for 80 €/MWh_{th}. This is the price at which green hydrogen can compete with bioethanol.

In the Celeste and Viridian scenario, a separate 'green' (local) hydrogen market is introduced. In this hydrogen market, electricity produced by electrolysers is traded. How 'green' this electricity depends on the greenness of the electricity market at the moment the electrolysers takes off electricity. The electrolysers can also consume wind energy via a PPA contract; in this case, the greenness of hydrogen, according to the definition of 'renewable hydrogen' in RED2 is assured.

Table 6.22: Participants in the local green hydrogen market in the Celeste and Viridian scenario. Feedstock demand is only considered in the Viridian scenario.

Direction	Asset	Flexible	Driven by	Capacity (MW_{th})
Demand	Pergen powerplant	no	Long term contracts	140
Demand	Onyx powerplant	yes	Electricity market	250
Supply	Electrolyzer	yes	Electricity market and Wind PPA	200/500
Supply	Backbone	yes	Hydrogen market	2000
Demand	Backbone	yes	Hydrogen market	2000
Demand	Feedstock demand	No	Hydrogen market	50

The cost of storage via the backbone is assumed to be 25 €/$MWh_{th.,}$ which is realistic and in line with the scenarios in which it is assumed that there is a role for hydrogen power production. This means that the route of hydrogen storage (via power-to-gas and gas-to-power) can compete with (large-scale) storage of electricity in e.g., batteries. This study discusses only the market dynamics under this assumption, and the competition between various large-scale storage facilities is not studied.

In all scenarios, the behaviour of all actors under regular conditions are studied. A situation with any outages (N-1) is not considered under the assumption that such a situation is solved in a way that has no impact on the position of any stakeholder in the market given regular conditions.

6.2 Bid behaviour of actors

This section describes the bidding behaviour of the actors participating in the Rotterdam Industrial cluster hydrogen market. Some of these assets also participate in the Dutch electricity market. See Table 6.23 for an overview.

Table 6.23: Markets and their participants.

Market	Participants
Wind PPA	Wind park and electrolysers in the Rotterdam industrial cluster.
Dutch electricity market	Consumers/producers in the Netherlands, including the powerplants and electrolysers in the Rotterdam industrial cluster.
Green hydrogen market	Electrolysers, powerplants, hydrogen storage (backbone) and feedstock hydrogen demand in the Rotterdam industrial cluster.
Blue hydrogen market	Baseload hydrogen demand, ATRs and powerplants in the Rotterdam Industrial cluster.

The assumption is made that the electricity market is more volatile and dynamic and less predictable than the local hydrogen markets. Therefore the best option for assets active in both markets is to:

1) bid in the electricity market based on an estimation of the hydrogen market price and
2) bid into the local hydrogen market after knowing the clearing of the electricity market.

Furthermore, from Table 6.20 and Table 6.21 can be deducted that the green hydrogen market is more dynamic than the blue hydrogen market. The resulting order of bidding and clearing for all market participants is shown in Figure 6.29, as is the order of price forecasting in the other direction.

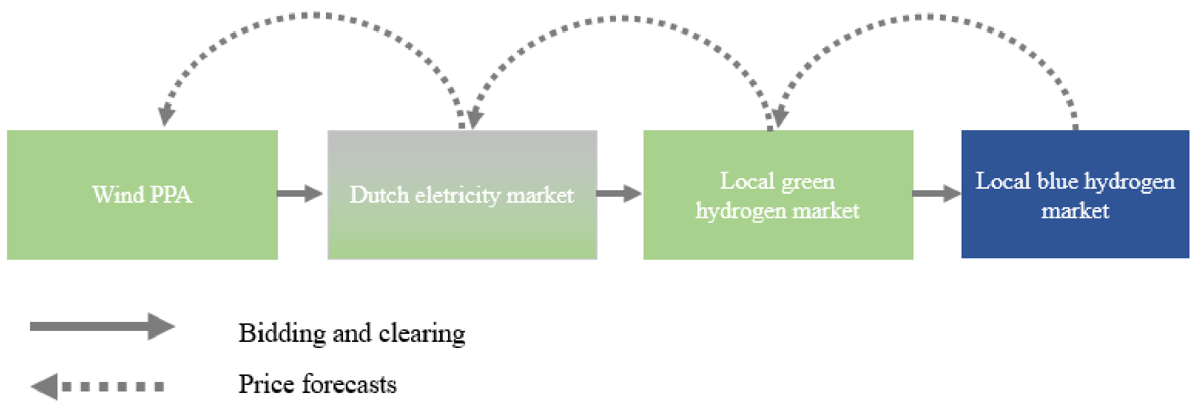


Figure 6.29: Cascading markets.

Figure 6.29 suggests a sequential relation between the markets, but the relationship between the markets is much more dynamic since the market participants take into account the knowledge they have about the dynamics of the later markets when bidding. In the Rotterdam Industrial cluster, the prices driving the dynamics – the reference prices - are assumed to be common knowledge (known by everyone): everyone is assumed to be able to forecast these prices well. In the bid strategy descriptions below, we explain how each stakeholder uses these reference prices. For an overview of all the reference prices, see Table 6.24.

Table 6.24: Reference prices in the Rotterdam industrial cluster scenarios.

Price	Known by	Description
BHB	Common knowledge.	The Blue Hydrogen Baseload price is defined as the bid price of the ATRs fuelled by refinery fuel gas (RFG). The price is defined in a long-term contract between baseload consumers (refineries) and the ATRs.
BHF	Common knowledge.	The Blue Hydrogen Flex price is defined as the bid price of the ATRs fuelled by natural gas (NG). The price is defined in a long-term contract between the flexible hydrogen powerplant and the ATRs.
HFS_{BHF} HFS_{FHD}	Common knowledge.	The sell price of the hydrogen storage, the Hydrogen From Storage price, is assumed to be defined by the bid price of green hydrogen consumers (the BHF price in the Celeste and FHD price in the Viridian scenario) and the efficiency / marginal cost of the storage.
HTS_{BHF} HTS_{FHD}	Common knowledge.	The Hydrogen To Storage price. This is the buy price of the storage. The price is derived from the sell price of the storage, which is in the price the hydrogen storage can think to sell for. In the scenarios, this is either the FHD price (Celeste scenario) or the FHD price (Viridian scenario).
FHD	Common knowledge.	Feedstock hydrogen demand price. This is the price at which green hydrogen can compete with bioethanol. Feedstock hydrogen consumers are assumed to be willing to pay this price for green hydrogen under the RED2 definition: produced directly from renewables.

6.2.1 Baseload hydrogen demand

The baseload hydrogen demand is continuous and uncontrollable. These consumers in this group have a long-term contract with the ATRs on refinery fuel gas for a fixed Blue Hydrogen Baseload (BHB) price and are thus always supplied by the ATRs that are sized equally.

6.2.2 ATR

ATRs are operated flexible or in baseload mode. In the Rotterdam industrial cluster, the refinery fuel stream should be used by the ATR directly, resulting in a baseload stream of 1.5GW.

When in baseload mode, the ATR places a must-run bid into the blue hydrogen market under the assumption that long-term contract customers (refineries) bid in for the BHB price. When the ATR is flexible, it provides a bid based on its marginal price, the Blue Hydrogen Flex (BHF) price:

- Fuel price / efficiency + gas emission * cost of CO_2 storage
- where
  - The fuel price is in €/MWh
  - The efficiency of the ATR is 80%
  - The gas emission is 0.20 ton CO_2/MWh
  - The cost of CO2 storage in €/ton CO_2

In the scenarios used in this report, only the ATR capacity fuelled by natural gas is flexible. The natural gas price is 30 €/MWh in all scenarios. Furthermore, it is assumed that the cost of CO_2 storage is 30 €/ton CO_2.

6.2.3 Hydrogen powerplants

Hydrogen powerplants come in two forms: must run and flexible. The must run powerplants have to supply baseload electricity (and/or steam/heat) and have, therefore, a baseload hydrogen demand profile. The flexible powerplants bid into the electricity market and place a bid on the hydrogen market accordingly. In the Rotterdam industrial cluster, Pergen is a must-run unit, and Onyx is a flexible unit.

The bid on the blue hydrogen market is a fixed price for all hydrogen powerplants, under the assumption that the hydrogen market is always available for this BHF price because of the long-term contracts. In the Rotterdam industrial cluster, this is always the case since the ATR generation has enough capacity to provide hydrogen to all consumers in the market. The bid on the electricity market is based on this BHF price: given this price for hydrogen, the marginal cost of electricity supply is determined.

The powerplants have a preference for green hydrogen over blue hydrogen if it has the same price or is cheaper. Therefore they bid first into the green hydrogen market before placing a bid in the blue hydrogen market. The BHF price is also the bid price in the green hydrogen market.

6.2.4 Electrolysers

Electrolysers place a bid in the electricity market based on the expected hydrogen price. If they are in the money on the electricity market, they place a must-run bid into the green hydrogen market, assuming that they get at least the expected hydrogen price.

In this market dynamics study, it is assumed that the refineries and Pergen powerplant have take-off obligations with the ATRs and will not buy hydrogen from the electrolysers. Since the flexible Onyx plant will not turn on if the electricity price is low enough for the electrolyser to turn on, the electrolysers always get the price of the hydrogen storage (backbone). Bidding on the electricity market based on the Hydrogen To Storage (HTS) price is, therefore, the bid strategy for the electrolysers in the Celeste scenario.

6.2.5 Gas storage (via backbone)

The business goal of the gas storage is to charge when prices are low and to discharge when prices are high. What charge prices are acceptable depends on the discharge prices and vice versa. Therefore we introduce reference prices for demand and supply. This is a simple way of operating the gas storage and could be easily made more intelligent, e.g., using a forecast such as the average price over a time window as the reference price. In the Rotterdam Industrial cluster scenario, we assume the reference prices are common knowledge, and therefore there is no need for a more intelligent approach.

In the Rotterdam industrial cluster, the storage knows that there are three situations possible:

- The electrolysers produce for the price they expect the storage is going to ask: the HTS price (see electrolyser bid strategy analysis under Section 6.2.5).
- The Onyx powerplant is on and is willing to take off from the storage if the price is below the Blue Hydrogen Flex (BHF) price.
- Both electrolysers and Onyx powerplant are turned off and place no bid in the market.

Because of these dynamics, the storage knows the maximum sell price he can offer on the green hydrogen market is the BHF price. Its demand bid price should be lower and cover the losses and operational costs of the storage.

Parameters of the gas storage model:

- Reference price in EUR/MW for either buy or sell. If the buy price is defined, the selling price is calculated and vice versa. In the scenarios for the Rotterdam industrial cluster, the selling price is given (the BHF price), and the buy price is calculated.
- Discharge rate and charge rate in MW.
- Initial fill level in MWh.
- Discharge and charge efficiency.
- Minimum fill level and maximum fill level in MWh. This can be used to define physical limitations to ensure that the storage can always supply a certain load. If the minimum or maximum fill level is not reached, the storage will add a higher supply and demand bid in the green hydrogen market. In the Viridian scenario these higher bid prices are defined by the FHD price.

6.2.6 Feedstock hydrogen demand

The feedstock hydrogen demand introduced in the Viridian scenario is also a baseload hydrogen demand, but this demand will only accept renewable hydrogen. The feedstock bid behaviour is that they bid at a fixed price in the green hydrogen market.

In addition, a guaranteed supply contract with the storage and/or electrolysers can be arranged. As a result, either the electrolyser or the storage will be able to supply green hydrogen at all times. If this guaranteed supply contract is required depends on market dynamics (such as the size and liquidity of the green hydrogen market).

6.3 Market dynamics

With the defined bid strategies and the description of the scenarios, we can analyse the dynamics of the cascading energy markets in the Rotterdam industrial cluster. In this section, a qualitative description is given that will provide insight into the 'tipping points' and their causes. In Section 6.4 the scenarios with EYE model simulations are evaluated.

In this section, the reference prices introduced in Section 6.2 are used. For an overview of all the reference prices and their abbreviations, see Table 6.24.

6.3.1 The Blue base case scenario

In the Blue base case, ATRs supply all hydrogen demand. The continuous baseload hydrogen production is fuelled by refinery fuel gas and can supply all baseload hydrogen demand, including the demand of the Pergen powerplant. The Onyx powerplant turns on if the electricity market prices are high and is supplied by hydrogen produced from natural gas. This results in two prices for blue hydrogen in the Blue base case scenario:

- The Blue Hydrogen Baseload price fuelled by RFG (the *BHB* price)
- The Blue Hydrogen Flex price fuelled by natural gas (the *BHF* price)

This situation in shown in Figure 6.30.

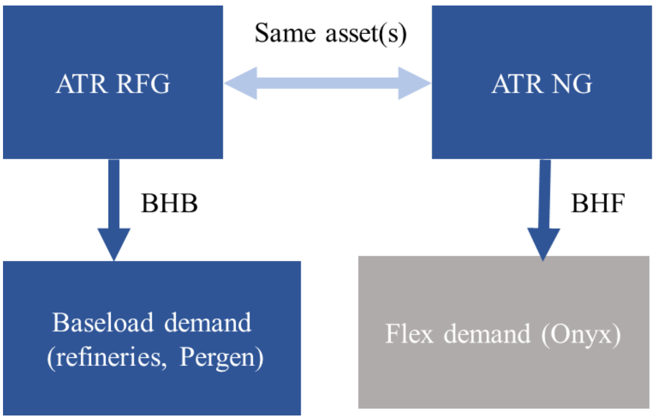


Figure 6.30: Dynamics in the Blue scenario.

The BHB is a fixed price and is determined in long-term contracts between the ATRs and the hydrogen consumers. The BHF price is also determined in a long-term contract and will likely be based on the expected take-off volume of the Onyx.

To explore the maximum operating hours possible for the Onyx power plant, we assume that the BHF price is equal to the marginal cost price taken into account only the fuel costs. In this case, we assume that the margins the power plant makes in the electricity market are high enough to cover all other costs.

6.3.2 The Celeste scenario

In the Celeste scenario, a 200MW$_{th}$ electrolyser capacity is added to the Blue scenario, as is a storage facility via the hydrogen backbone. This resulted in some additional dynamics shown in Figure 6.31 and explained in Table 6.25. The key insight is that electrolysers can only produce for a low Hydrogen To Storage price (HTS$_{BHF}$), assuming that the storage can only supply in competition with the Blue Hydrogen Flex (BHF) price to the Onyx powerplant.

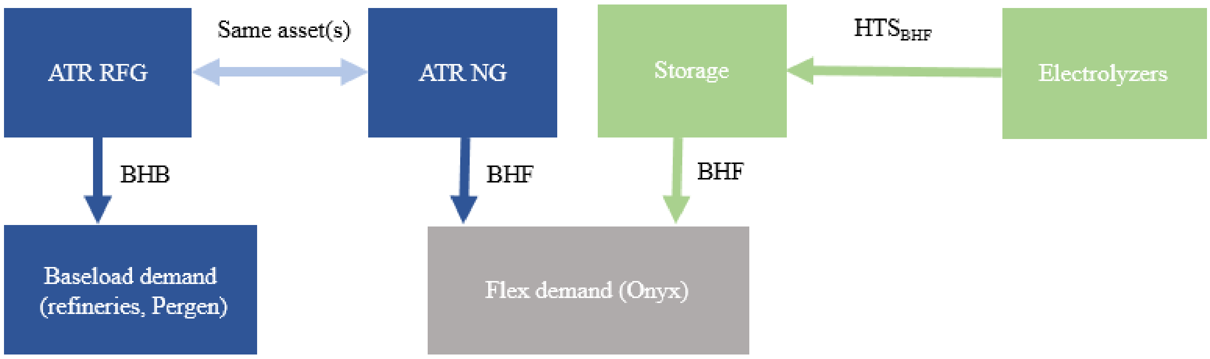


Figure 6.31: Dynamics in the Celeste scenario.

Green hydrogen producers have to deal with a low hydrogen price, the hydrogen to storage price (HTS$_{BHF}$), as long as:

- There are no or just a few consumers accepting renewable hydrogen only
- There is enough blue hydrogen (peak) production capacity

As long as this is the case, the blue hydrogen price and the cost of storage are determining the business case of green hydrogen.

Table 6.25: Dynamics in the Celeste scenario.

Electrolysers	Onyx	Storage	Dynamics
Off	Off	All states	ATRs supply all hydrogen demand. This situation is similar to the Blue base case scenario.
On	Off	Not full	Electrolysers supply the storage for the HTS$_{BHF}$ price. They cannot supply hydrogen to the Onyx powerplant directly because they have opposite behaviour on the electricity market.
Off	On	Not empty	The storage supplies Onyx. The price in the green hydrogen market is determined by the storage supply bid, which is equal to the Blue hydrogen flex price (BHF).
On	Off	Full	Infeasible: the electrolysers cannot supply the storage and thus cannot place a bid in the electricity market.
Off	On	Empty	ATRs supply all hydrogen demand. This situation is similar to the Blue base case scenario.

6.3.3 The Viridian scenario

In the Viridian scenario, 50MW$_{th}$ green hydrogen demand is introduced. This demand has a higher bid price: the Feedstock Hydrogen Demand (FHD) price of 80 €/MWh$_{th}$. This impacts the bid behaviour of the electrolysers and the storage since this new client can be supplied for a higher price resulting in more operating hours. Table 6.26 shows that this results in higher bid prices of the electrolyser. This looks promising for producers of green hydrogen, but only 50MW$_{th}$ demand in the Rotterdam industrial cluster is willing to pay the high FHD price.

Table 6.26: The effect of the hydrogen reference prices on the electrolyser bid price on the electricity market. The BHF price is 45 €/MWh hydrogen, the storage cost is 25 €/MWh and the efficiency of the electrolyser (used to calculate the bid price in the second column) is 67%.

H_2 reference price	H_2 reference price (€/MWh$_{th}$)	Electrolyser bid price (€/MWh$_e$)
FHD	80	54
HTS$_{FHD}$	55	37
HTS$_{BHF}$	20	13

The high FHD reference price for a continuous baseload demand of 50MW will be a good opportunity for electrolysers and wind parks to sign a PPA and even required so they can claim they supply (100%) renewable hydrogen under the RED2 definition. There are hours where green hydrogen cannot be supplied directly from electrolysers, e.g., there is no wind available. In this case, renewable hydrogen should come from the (renewable) hydrogen storage.

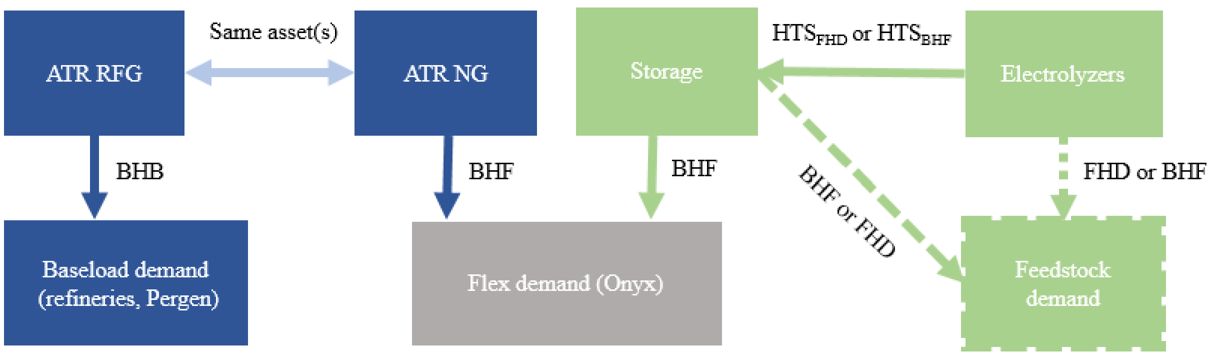


Figure 6.32: Dynamics in the Viridian scenario.

It is a question of how the financial agreement between electrolysers, storage, and feedstock demand will be. They need each other, but it is unsure who needs who more. On the one hand, there is an overcapacity of electrolysers and storage; on the other hand, the feedstock demand needs a guarantee of green hydrogen supply since it cannot use blue hydrogen.

If we approach the green hydrogen market as a daily/hourly auction (like the day-ahead electricity market), the best approach for the feedstock demand would be to bid in at their willingness-to-pay price of 80 €/MWh. When enough green hydrogen is available, they get supplied for the lower BHF price; when there is a shortage, they get it for the higher FHD price. There is a risk that there is no green hydrogen available anymore, but since there is an overcapacity of electrolysers we can expect that there is always enough for a consumer paying the FHD price: the storage is likely going to buy green hydrogen for the HTS$_{FHD}$ price when his buffer volumes are decreasing.

It is likely that the feedstock demand, storage and/or electrolysers agree on a price in a long term contract: in which a price between the BHF and the FHD price is agreed. The analysis of the auction situation can be used to define whether this price is more close to the BHF price or to the FHD price. It all depends on the amount of overcapacity of electrolysers and the amount of consumers willing to buy green hydrogen when it is cheaper than blue hydrogen.

In this study we only consider the local situation, but interactions with other areas play a role. However, the dynamics stay the same: also in a connected system, the price the electrolysers receive will be between the BHP or the FHD price. With only a few consumers with a higher willingness to pay, the price is going to be closer to the BHP price and with less overcapacity of electrolysers and ATRs closer to the FHD price. These dynamics will be explored in the simulations in Section 6.4.3.

6.4 Simulation results

In this section, we evaluate the scenarios with EYE model simulations. The simulation results show the effect of the dynamics on the number of operating hours of each asset in realistic scenarios. The Blue, Celeste, and Viridian scenarios and the underlying Dutch electricity market scenario (see Elegancy Deliverable 5.2.4) are based on recent studies and recent plans of stakeholders (such as Climate Agreement, TIKI study, and insights from interviews). From these plans, we know that creating the Blue base case is seen as a first step, but the next steps are not clearly defined. In the Celeste and the Viridian scenario, we explore two options.

6.4.1 The Blue base case scenario

The Blue base case scenario was already discussed in the Deliverable 5.2.4. In this deliverable, it was shown that the Onyx hydrogen turbine, in the scenario defined in Section 6.1, has approximately 3500 operating hours. This is also the number of operating hours for the flexible part of the ATR unit – the part fired by natural gas- since it only serves the Onyx hydrogen turbine in the Blue scenario.

The number of operating hours is on the low side for a sound business case of both the hydrogen power turbine and the ATR. Furthermore, Deliverable 5.2.4 shows that the number of operating hours of the hydrogen turbine is decreased already with a slight decrease in either the gas price or the CO2 price and it is increased when the development of these prices is in the other direction.

In the Blue base case scenario, the flexibility in the electricity system will mainly come from industrial flexibility (heat pumps, e-boilers) and cross-border flows. 2000 hours of demand is expected from 1.4 GW electrolyzers elsewhere in the Netherlands. However, this amount of hours is on the low side for a positive business case.

6.4.2 The Celeste scenario

In the Celeste scenario, the electrolyser + storage and the ATR compete to supply the flexible hydrogen power plant. In the electricity market, the electrolyser competes with other flexible demand. This scenario shows what happens if electrolysers are added to the market while there are no extra consumers added: are they going to beat the competitors on both markets?

Since the flexible hydrogen powerplant still assumes the same hydrogen reference price (the BHF price), its position on the merit order in the electricity market does not change. What does change is that the electrolysers start to produce hydrogen when electricity prices are below this same reference price minus the cost of storage (the HTS_{BHF} price), so the storage can supply hydrogen for the BHF price at a later moment.

The EYE simulation shows that the electrolysers turn on 1300 hours if driven totally by the electricity spot market. This is the number of hours the price of the electricity market is low enough. These 1300 hours are supplied to the hydrogen power plant, and the additional hydrogen needs to be supplied by the ATR (the flexible natural gas supplied part), which turns on 2000 hours. For both the electrolysers as the ATR, this number of operating hours is too low for a positive business case.

Effect of Wind-Electrolyser PPA
A solution for the electrolyser is to cooperate with renewable producers by defining a PPA. We assume a PPA of 80% take-off and that the wind park and electrolysers agree on a fixed price that takes into account hydrogen storage costs. It is assumed that the HTS_{BHF} price will be used in PPAs between wind and electrolysers because this is the price electrolysers in the Celeste scenario can get on the hydrogen market (see also Section 6.2.5).

The 80% Wind-Electrolyser PPA results in more operating hours (2700 equivalent full load hours) for the electrolyser, which means directly fewer hours for the ATR (now 1000 operating hours/y). The electrolyser-Wind PPA, does not change the fact that the electrolyser still produces for the low hydrogen to storage (HTS_{BHF}) price, and thus margins are low. Even with a PPA, the business case of supplying hydrogen customers that can also buy blue hydrogen is probably not positive.

Another effect of this PPA is that the wind energy supplied under PPA to the electrolyser will not be used by electricity consumers, and another supplier needs to supply this electricity. In the Celeste scenario, a biomass plant is turned on 2500 hours at a higher load instead of a minimal load. Summarizing: the direct result of adding electrolysers is: 1) too low margins for the electrolyser 2) a barely used ATR, and 3) more electricity production by biomass. This negative conclusion needs some context: this wind capacity could maybe not be installed without the PPA (e.g. the electrolysers produce off-shore and transportation costs are reduced).

Effect of hydrogen storage costs
The hydrogen storage costs are an important parameter for the business case of the electrolyser. However, the simulation results show that the place on the demand merit order does not change when the storage is subsidized lower than 100%: other flexible demand (industrial heat pump, e-boilers, electrolysers that don’t need storage) always have a better position and will turn on earlier. However, lower storage costs will not lead to more operational hours; it increases the margins of the electrolysers up to 6MEur/y.

Discussion
Hydrogen powerplants are the perfect customer for electrolysers that use renewables and that have the ability to store. There is little or even no overcapacity needed since their behaviour on the electricity market is asymmetric. However, the analysis above shows that a flexible hydrogen consumer kills the business case of both blue and green hydrogen producers. One could argue that this is just ‘the market’ striving for the best price for the consumer, but when we take a good look at the situation, we can conclude:

- Blue hydrogen is needed to meet the emission reduction targets, but when the competition of renewables kicks in, there is a risk that long term investments won’t pay off. Blue hydrogen producers have no other choice than to offer long-term contracts, which is, on the other hand, the risk for hydrogen consumers that will wait for their decarbonisation option until enough renewables are available. The government can push the industry by giving renewable targets for a certain year, but it is not optimal and even not feasible to give everyone a small target. A few frontrunners (using Blue Hydrogen) are required to start the decarbonisation now, but if they know they pay the price later, they will never make a move (investment decision).

- Green hydrogen is needed to meet the emission reduction targets, and electrolysers are fit for harvesting the relatively cheap renewable peaks. However, CAPEX is significant, and thus both operating hours and good margins are required. Because of the competition with Blue hydrogen, the margins are low. With renewable PPAs electrolysers can increase the number of operating hours, but this does not lead to better margins, and electrolysers using more renewables (via PPA) result in biomass or fossil fuel plants turning on to supply the electricity demand. Note that when more renewables are available, this effect is smaller and even not existing anymore beyond 2050.

6.4.3 The Viridian scenario

In the Viridian scenario, we add the perspective of the green hydrogen consumer. 50MW demand only willing to use green hydrogen takes part in the green hydrogen market. The willingness-to-pay price of this consumer is higher than that of the majority of the market (power plant, refineries, who have the ability to use blue hydrogen), but in Section 6.3.3, it was shown that if we let all consumers compete, the market price will go down to the blue hydrogen (BHF) price. In this scenario, we explore: what happens with the market dynamics in the Rotterdam Industrial cluster if we add a minority with a higher willingness-to-pay for green hydrogen?

From the analysis in Section 6.3.3, we learn that the storage adapts his strategy when a consumer enters the market with a higher willingness to pay and a baseload demand. The storage knows that this consumer wants to take of 50MW at all time, so this enables the storage to buy hydrogen from electrolysers for a higher price. This is implemented in the EYE-tool as follows:

- The electrolysers bids in the HTS_{FHD} price in the hydrogen market, as long as the storage is not full enough to supply the feedstock demand for 60 days. The electrolyser still has an 80% PPA with the wind park. We assume for simplicity that the mix of 80% PPA and 20% electricity mix (at low prices) results in a carbon emission lower than the threshold for 'green hydrogen'.
- The storage demand bid price is the HTS_{FHD} price, and the storage supply bid price is the FHD as long as the buffer is not full enough to supply the feedstock demand for 60 days.

As a result, the hydrogen buffer, which is empty at the start of the simulation, is charged until there is enough available to supply the feedstock hydrogen demand for at least two months. This takes 28 days. During the charging, the $50MW_{th}$ feedstock demand is either supplied for the HTS_{FHD} since this is the bid price of the electrolysers, or when there is not enough wind available, they are supplied by the storage for the FHD price.

The results show that there is enough green hydrogen available at all times to supply the feedstock demand. This hydrogen is delivered by the electrolysers in the Rotterdam industrial cluster. To secure the hydrogen demand for the feedstock demand, the hydrogen power plant is supplied for a few 140 hours by green hydrogen, which can easily be produced by green hydrogen as well. The ATR produces the rest.

6.5 Summary of results and discussion

Table 6.27 shows the operational hours for the electrolyser in the Blue, Celeste, and the Viridian scenario under all variations discussed above. We see that adding green hydrogen consumers – that are not able to buy blue hydrogen – are key to the business case of both electrolyser and hydrogen storage: It will lead to higher operating hours for the electrolysers. Only arranging PPAs won't be enough to make the business case successful.

Table 6.27: Operational hours of the electrolysers in the Rotterdam Industrial cluster.

Scenario	Operational hours electrolysers
Blue	0
Celeste, no PPA	1300
Celeste with PPA	2700
Celeste, with PPA and subsidised hydrogen storage	2700
Viridian with PPA	3600

From the market dynamics analysis presented in this chapter, we can conclude that creating an environment where electrolysers and blue hydrogen compete for a kg price will not help to reach the decarbonisation goals for the industry. In such an environment, both producers of green and blue hydrogen will have no other choice than to create lock-ins:

- Blue hydrogen producers can only produce under long-term contracts.
- electrolysers, together with hydrogen (or electricity) storage providers, can only produce under long-term contracts.

As long as there is not a lot of surplus of renewable energy, there will be only a market for blue hydrogen, and when the tipping point is reached, only green hydrogen will succeed. Based on the market dynamics analysis, we expect that in the transition period, these dynamics will lead to a slow-down of the development of the hydrogen 'economy'.

Ambitions for hydrogen are high and result in plans for large-scale production, consumption, and transportation of both blue and green hydrogen. The analysis from Chapter 5 shows that both production types are required to meet the emission reduction targets. The results of the analysis in this chapter show that for a successful hydrogen transition, one should start in parallel with the right supporting policies such that both the blue and green hydrogen markets are developed in a (time-) efficient way.

7 BUSINESS CASES ROTTERDAM INDUSTRIAL CLUSTER

Based on the results of both analyses on Chapter 5 infrastructure and Chapter 6 market dynamics, it is obvious that the business case for hydrogen as an energy carrier is a major challenge for the industrial stakeholders. The main conclusion from both assessments is that for a successful hydrogen transition, one should start in parallel with the right supporting policies such that both the blue and green hydrogen markets are developed in a (time-) efficient way. As such, a large scale hydrogen deployment is a complex exercise that requires a comprehensive approach by a large group of all stakeholders that have to move together in a coordinate pathway.

For a sound business case, the project scoping and ownership structure, etc., are essential topics that already need a lot of attention in the early stage of the project. Also, public perception, changing economics, emission reduction, and CAPEX estimates are considered critical risks. Based on the WP3 risk toolbox, the identified risks in all phases of the project approach are categorized, and mitigations are proposed. Especially the long-term uncertainties about commodity and CO_2 emission prices constitute a significant obstacle to get the Dutch case study in Rotterdam started as they have a substantial impact on the business cases for low-carbon hydrogen, see also D5.2.2., and switching from the traditional CO_2 intensive energy feedstocks is an expensive and risky undertaking. It worth noting that the value of potential additional services that hydrogen might provide has not been assessed in the analyses of Chapters 5 and 6. As such, both analyses are mainly based on the commodity markets and their dynamics. To be able to measure the added value of hydrogen in an industrial environment, it is important to address all the specific value drivers that hydrogen can provide as an energy vector in the energy transition.

The oil-refinery sector and petrochemical industry need to find ways to refine a ‘cleaner molecule’ while staying competitive in international markets. In a continued push for a low carbon economy, the need to reduce emissions intensifies. There are several mitigation options to reduce the CO_2 intensity: the optimisation of internal efficiency measures as well as new ways to integrate unit operations into local economic value chains (e.g., heat, electricity, low-carbon hydrogen, e-fuels, biofuels, and CO_2 capture). These mitigation options will decrease the CO_2 intensity whilst ensuring the demand of product supply. Using off-gas and refinery fuel-gas as feedstock for the production of hydrogen as an energy carrier provide pathways for other mitigation options, and thereby a further decrease of CO_2 intensity of the production processes. For the business case and strategic decision process, the role of hydrogen and off-gases need to be assessed by the industrial stakeholders on a case by case basis and is enormously depending on its available mitigation options.

Within the H-vision project, the overarching business case has been reviewed in an early stage of the Elegancy project. Currently, the business case is in the process of an update. Based on the results of the Elegancy project in general, it is highly recommended to assess the business case, of such a project like H-vision, in different slices to be able to address the full economic potential and value drivers for the end-users and allocate the costs between the private and public stakeholders. The proposed structure for the business case is as follows:

- The production plant of Low-carbon hydrogen (private sector),
- Cases by case end-user assessments, hydrogen applications and off-gas use (private sector),
- CO_2 infrastructure, utilisation, and storage, common use (public sector),
- Hydrogen infrastructure and storage, common use (public sector).

For a final investment decision for such a project like H-vision, the individual business case for the different slices has to be robust and financially sustainable. For the hydrogen applications, it will be crucial to identify all the value drivers and the opportunities offered by hydrogen for the industrial stakeholders. On the infrastructure side, hydrogen production and distribution infrastructure are capital intensive, and such investment is risky and difficult to rationalize without a long-term outlook on hydrogen demand. Governmental commitment is needed to ensure the hydrogen market is there for the long term.

8 CONCLUSIONS

In this report, deep decarbonization of the Dutch industry by means of implementation of a hydrogen and CCS network has been investigated. The analysis was done using two separate methods: a first study explores the optimal infrastructure for hydrogen deployment as an energy carrier. The second part of the work focused on the market dynamics in situations where electricity and (local) hydrogen markets are coupled via electrolysers and hydrogen power plants.

In the first method, data from public sources on energy infrastructure, energy consumption, and CO_2 emission were implemented in a spatial optimization chain tool. A high wind scenario was assumed based on PBL's study "Toekomst van de Noordzee" and TenneT and Gasunie's combined study "Infrastructure Outlook 2050", in which a total of 332TWh/a of renewable electricity is available in 2050 from onshore solar PV and onshore and offshore wind farms. This tool was then used to derive a cost-optimal approach for the development of a hydrogen and CCS network that allows a successful reduction of up to 95% of CO_2 emission by 2050 with respect to 1990 according to the Climate Agreement targets. These emissions were related to the industry, the utility sector, and incineration of waste and covered the demand of electricity, industrial heat, and hydrogen as feedstock. Cost optimality, in this case, means the lowest cost in terms of investment (CAPEX), operation (OPEX), import of resources, and CO_2 emissions as regulated by the ETS of the complete value chain, from production to consumption, until 2060.

It is important to stress the scope of this work again. In the modelling work in the first part of this work (Chapter 5), hydrogen and CCS, in combination with large scale renewable electricity production was assumed as the only available technological pathway. This limited scope results in the fact that certain conclusions can be drawn with certainty, while others cannot. What cannot be concluded from this study is how hydrogen as a technological pathway compares to other solution pathways, such as electrification or renewable liquid fuels. What also has not become clear is how large scale water electrolysis can be rolled out in a commercially viable way in the long term (up to 2050). In the geospatial modelling work, electrolysis was assumed to be operated at a baseload, provided with renewable electricity buffered with utility-scale batteries. From a perspective of system efficiency, it would be more energy-efficient to provide this baseload electricity to electrified industrial processes without conversion to hydrogen. Although, given the implications on the electrical infrastructure, clarification of the cost-effectiveness of these two routes remains work for another study. Due to the nature of the chain tool, the dynamic response of electrolysers could not be modelled. Thus the possible advantage of running electrolysers at low electricity prices only was not investigated in relation to infrastructure.

What can be concluded is the following:

- First, CCS is required in order to achieve the Climate Agreement emission reduction targets for the industry of up to 95% less CO_2 emissions by 2050 with respect to 1990. Incineration of waste (7Mton CO_2 in 2017) requires post-combustion capture and CCS for abatement of emissions not to exceed the target in 2050. Steel production, oil refining, and steam cracking processes release fuel gases that require ATR processes with CCS for decarbonization. And even in the ambitious high wind scenario (60GW in 2050), the availability of renewable electricity up to 2040 will not be sufficient to achieve the emission reduction targets with hydrogen from water electrolysis alone, not even considering the increase of cost of all energy demand (electricity, industrial heat, and hydrogen-based chemical products) that would follow.
- Consequently, the implementation of a hydrogen network in the southern part of the Netherlands was found as a no-regret pathway for decarbonization of the refining and

cracking processes in this region, connecting the clusters of Rotterdam and Zeeland to those in Noord-Brabant and Limburg. Natural gas and fuel gases can be replaced in the short term in a cost-effective manner.

- But, the limited nature of CO_2 storage capacity in offshore gas fields and aquifers require alternatives to natural gas-based hydrogen production. A little under 900Mton of CO_2 storage capacity that was considered in this study would not be sufficient to accommodate an industrial energy transition and achieve the emission reduction targets based on CCS solely. An important aspect of this that should not be forgotten is that not only should the reduction targets be achieved, but they should also be maintained beyond 2050.
- As such, incineration of waste, refining, and steam cracking should be given priority for usage of the available storage capacity until mature alternatives have presented themselves.
- Furthermore, as the simulations show, costs along the whole value chain can be minimized if alternative energy carriers are developed alongside scaling up of the CCS network such that utilization of assets is maximized. In this study, this alternative was water electrolysis from renewable electricity sources. But given the cost of hydrogen from water electrolysis, the results were not convincing that, economically, this should be the only alternative.

The second part of the work focused on the market dynamics in situations where electricity and (local) hydrogen markets are coupled via electrolyzers and hydrogen power plants. Three 2030 scenarios for the Rotterdam industrial cluster were studied using a cascading electricity-hydrogen model: a situation where only blue hydrogen is used (the Blue scenario), a situation where 200 MW electrolyzers are added (the Celeste scenario), and a situation where 500 MW electrolyzers are added and 50 MW hydrogen demand for feedstock is introduced (the Viridian scenario).

From the blue scenario, we learn that fuelling hydrogen powerplants with blue hydrogen is possible, but the business cases for both the powerplant and the ATR have a high-risk profile: they are highly dependent on the electricity market dynamics. Hedging these risks in a proper way requires both parties to study the exact dynamics of the electricity market. From a system perspective, hydrogen powerplants may have additional value; via these plants, some seasonal storage (‘cold winter scenarios’) options become available, and they can provide other balancing services. This value should also be taken into account but is again also highly dependent on the dynamics of the electricity market in 2030.

From the Celeste scenario, we learned that adding electrolysers to produce for the consumers who are able to buy blue hydrogen, like hydrogen power plants, will not lead to a successful business case: the low hydrogen prices result in 1) low operating hours, only if electricity prices are really low we can produce and 2) in low margins. With renewable PPAs, the latter can be improved but will not remove the first problem. In the Celeste scenario, both the electrolysers as the ATR are required to supply the hydrogen powerplant, but none of the two has enough operating hours to be successful.

From the Viridian scenario, we learn that adding hydrogen consumers that can or are willing to buy renewable hydrogen only, such as feedstock demand under the seconds Renewable Energy Directive (RED2) is key to a successful business case for electrolysers and hydrogen storage. However, before adding green hydrogen consumers to the system, one should make sure enough renewable energy is available in the system, which an obvious conclusion, but practically it is hard to coordinate a required co-implementation for the development of renewables, electrolysers and hydrogen storage.

As long as there is not a lot of surplus of renewable energy, there will be only a market for blue hydrogen, and when the tipping point is reached and in addition, CCS capacity limits are reached, only green hydrogen will succeed. Based on the market dynamics analysis, we expect that in the transition period, these dynamics will lead to a slow-down of the development of the hydrogen 'economy'. A hydrogen roadmap requires coordination of both the blue and green supply chain, and competition between the two just slows down the development.

For the business case for hydrogen applications in the industry, it will be crucial to identify all the value drivers and the opportunities offered by hydrogen for the (industrial) stakeholders. Hydrogen production, CCS, and hydrogen distribution infrastructure are capital intensive, and such investment is risky and challenging to rationalize without a long-term outlook on hydrogen demand. Governmental commitment and direction are needed to ensure the hydrogen market is there for the long term.