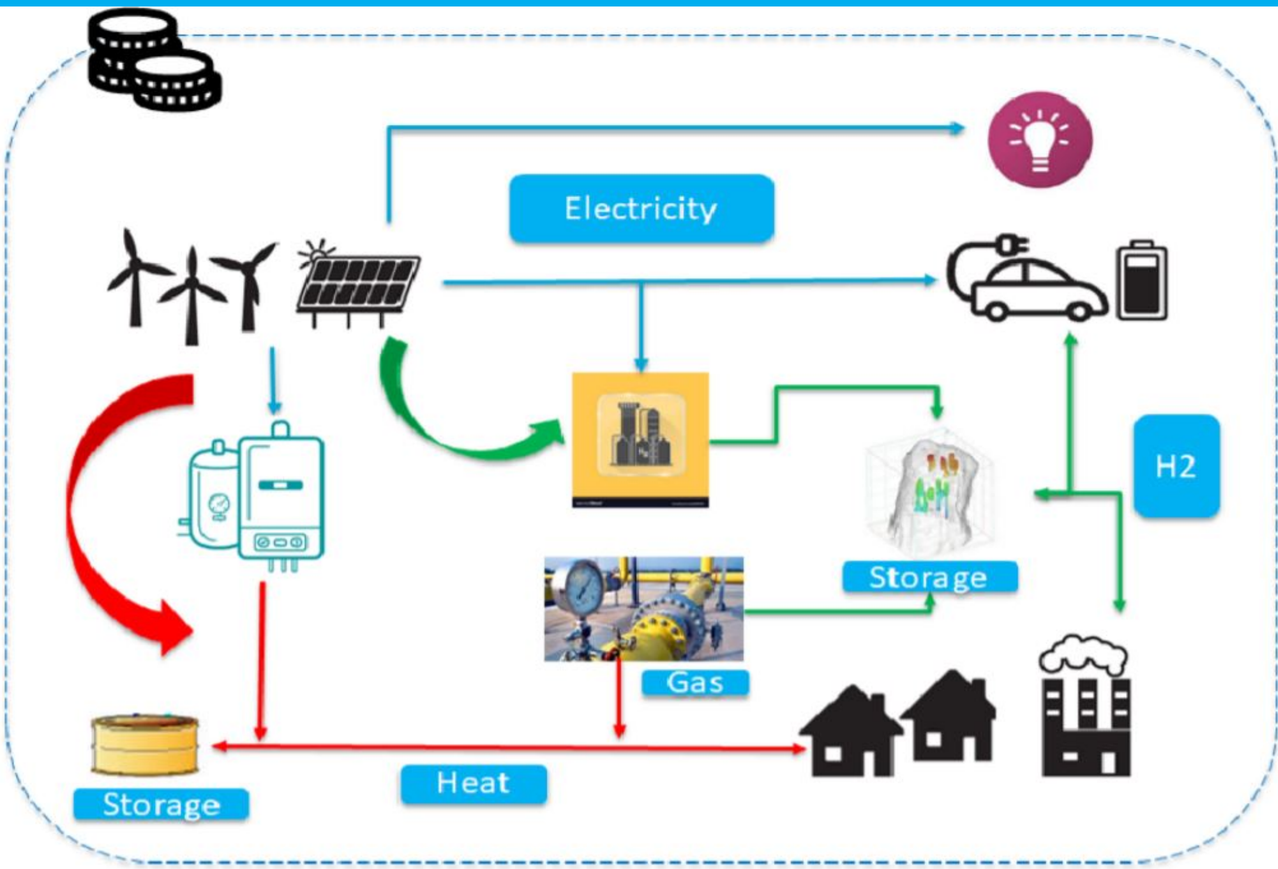
# Techno-economic assessment of grid connected Power to Heat and Power to Hydrogen technologies

An electricity market scenario approach

Priyanka Chintada

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# Techno-economic assessment of grid connected Power to Heat and Power to Hydrogen technologies

An electricity market scenario approach

by

**Priyanka Chintada**

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# PREFACE

This thesis work is a great opportunity for me to contribute towards sustainable transition happening in the Netherlands. First of all, I would like to thank Sjaak van Loo for listening to my proposal and accepting to work at the department of Energy markets and policy studies at ECN part of TNO. The daily support from German Morales and honest feedback from Edwin Wiggelinkhuizen helped me to refine the project statement during early stages. Especially, I learnt the important optimization techniques implemented in modelling energy system investment decisions from German. He encouraged me to proceed to create my own optimization model when the models at the company were not completely ready enough for my study. I really appreciate his help with the use of European electricity market model COMPETES with existing features in the most efficient way.

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*The choice we make, eventually becomes a habit. It better be green!!!*

*Priyanka Chintada*
*Delft, May 2019*

# Executive Summary

The national energy outlook 2017 of the Netherlands provides the basis for designing the energy system to meet climate energy goals set for 2030. The realization of which is dependent on the sustainable electricity production from increased capacity of solar photo voltaic (PV), offshore wind and onshore wind together with abandoning electricity generation in the Netherlands from coal. Decarbonization of industry is also a major implication from climate agreement. Heat and hydrogen sectors are identified as potential flexibility options to facilitate the de-carbonization of the energy system by 2050. The offshore wind farms Hollandse Kust Zuid 1 and 2 will not receive any subsidy for the generated energy in the Netherlands. The support is rather provided by socialising the offshore transmission cable costs. Thus, all the offshore wind energy will be injected into public grid and exposed to the regulated European wholesale electricity market.

The assessment of integration of the power sector with heat sector, especially residential district heat networks have proven benefits in countries like Denmark with the support of thermal buffers and demand side management techniques. With an experience of 80% wind share in the electricity consumption, a declining market value for offshore wind is observed in the Danish electricity market. These pros and cons of renewable energy sources create new opportunities for electrification of other sectors to support achieving climate agreement targets of the country. Industrial heat, domestic district heat networks currently provided by combined heat and power gas plants in the Netherlands and the developments in hydrogen market are taken as study cases for assessment. The synergies among these systems can be realized with detailed technical and economic assessment. In order to provide insights for investors in the power to heat or power to hydrogen technologies and their implications on national energy system, following research questions are formulated. The opportunities, threats and solutions for the involved stakeholders are identified through these questions.

1. How will the electricity sector develop for the given outlook of renewable penetrations in 2023, 2030 and 2050?

2. What are the volumes of heat and hydrogen demands in the Netherlands that can offer flexibility to the electricity system?

3. Given the above market scenario, what is the optimal size and operational strategy of these flexibility options with minimum system costs?

4. What are the implications of this extra electrification on the electricity system and the revenues of renewables (especially offshore wind)?

Three power system scenarios 2023, 2030 and 2050 are formulated to represent energy transition trends for the country. 2023 represents a low renewables and low electrification scenario, 2030 is called a high renewables and low electrification scenario and a high

renewables and high electrification market scenario in 2050. The existing models at The Netherlands Organisation for Applied Scientific research (TNO) are considered to evaluate the power to heat and power to hydrogen systems. European electricity market simulation model COMPETES is identified as potential tool to assess the integrated systems at national level. However, the flexibility of heat and hydrogen demands with thermal and hydrogen storage technologies is not part of the model directly. Therefore, initially, the power system is analyzed for these three scenarios years without coupled to the heat and hydrogen sectors. An optimization model is developed to determine the least cost system to meet the heat and hydrogen market load. The sizes of electric boilers, gas boilers, thermal storage tanks, polymer exchange membrane electrolysers, steam methane reformers and hydrogen storage are important design variables to determine operational costs of the systems. The results of optimization problem such as the capacities, costs serve as valuable indicators for defining the outlook for investments in power to heat or power to hydrogen technologies. The model also determines the operational strategy of these units. Consequently, the coupled implications of the emerging electricity loads from heat, hydrogen markets on the national power system is studied.

The important findings and conclusions of this research are presented below:

- In an energy system without dependence on coal in the scenario years 2023, 2030 and 2030, gas is still a part of the electricity supply. However, a decreasing trend in gas power plants capacity from 8 GW in 2023 to 5.5 GW in 2050 is observed. The high electricity demand in 2050 scenario is fulfilled with investments in interconnections instead of addition of extra gas capacities. Cross border interconnections increased from 13.8 GW in 2030 to 31.8 GW in 2050.

- The average price for offshore wind energy is less than the average power price in all scenarios. The difference in average market value for offshore wind and average power price is observed to be highest at 11 €/MWh in 2050, showing opportunities for offshore wind farms to produce heat or hydrogen over selling as electricity to the market. The average power prices increase from 35 €/MWh in 2023 to 46 €/MWh in 2030 due to the increase of gas prices and carbon emission taxes. Nevertheless, in 2050, they decrease to 28 €/MWh because of large volumes of renewables in the Netherlands as well as neighbour countries.

- Higher volatility in power prices is observed in 2050. The power price is as low as 2€/MWh for 2170 hours of the year in 2050 showing opportunities for thermal storage and hydrogen storage. Moreover, curtailment of wind energy is increasing from 157 GWh in 2030 to 21 TWh in 2050, resulting in decreased revenues for offshore wind energy.

- The heat demand of domestic district heat networks and industrial low temperature heat below 200° C are identified as potential sectors for electrification. An annual heat load of 6.25 TWh for residential district heat networks and 18.6 TWh for manufacturing industry is obtained. The hourly heat demands are modelled and used as study cases for economic assessment and analysis of power to heat system in the scenario years 2023, 2030 and 2050. A market demand of 184 TWh of hydrogen consumption is anticipated in 2050. Further, the hydrogen demands in 2023 and 2030 are obtained as 44 TWh and 84 TWh by extrapolating with the trend of developments in offshore wind capacity additions from 2023 to 2050.

- With a natural gas cost of 31 €/MWh and carbon emission costs of 16 €/ton, marginal costs of heat production from electricity and heat are compared in 2030 scenario. It is observed that at a power price below 32 €/MWh, it is profitable to produce heat with electricity than with natural gas boilers. In case of hydrogen, electrolysers can compete with steam methane reformer technology marginally below a power price of 27.8 €/MWh, 39.5 €/MWh in 2030, 2050 respectively. The power price was below this obtained tipping price for about 7000 hours in 2050 indicating there can be investments in power to hydrogen.

- In 2023, neither domestic district heat nor industry heat is economical to operate on electric boilers. The entire heat system runs on gas boilers with small capacities of storage whereas complete electrification is observed in 2050. A capacity of 1500 MW thermal electric boilers for domestic district heat and 5.6 GW for industrial heat sector are economical to operate in 2030 market scenario. The operational costs such as fuel costs for gas boilers, electricity costs and network tariff costs for electric boilers are dominant in hybrid heat systems.

- An increasing trend for electrification is observed for production of heat from 2023 to 2050. However, to supply same amount of heat, the hybrid heat system costs are higher in 2030 compared to 2023 and 2050. This might cause delayed electrification of domestic district heat and industrial heat sectors and prolonged use of gas boilers because of the investments in 2023. However, one should realize that the profits for hybrid heat system will be higher in 2030 than with a standalone gas boilers. Moreover, stakeholders can invest in electric boilers because of the decreasing trend observed in power prices towards 2050 holding the outlook for electric boilers investment positive.

- Thermal storage capacity values obtained from the optimization problem are 7.5 GWh, 18 GWh and 97 Gwh for district heat case for the scenarios 2023, 2030 and 2050 respectively. Similarly. the storage capacities increased from 6.5 TWh in 2023 to 61 GWh in 2030 to 620 GWh in 2050 for industry heat case. It is observed that the storage capacity values and utilization are increasing with increased share of renewables, increased volatility in power prices indicating its usefulness in providing buffer to the power system and providing flexibility in times of surplus wind electricity and low power prices.

- The hybrid hydrogen system comprising steam methane reformers, electrolysers and salt cavern storage units is capital investment driven from the observation that 1/3rd of the annual operational costs include equipment depreciation costs. Thus, only in 2050, when the capital investment of electrolyser is 57% less than that of the steam methane reformer, it is economical to produce hydrogen from electricity. The hydrogen cost per MWh is higher in 2030 than in 2050 creating a barrier for the development of hydrogen market. However, in 2050, it becomes economical to produce entire hydrogen demand of 184 TWh from electricity from the perspective of hydrogen producers.

- The obtained additional electrification from domestic district heat and industrial heat sectors is integrated with the power system in 2030 and 2050. The power system capacities in 2030 were able to manage the extra loads of 7.8 Twh from industry heat with support of decreased exports, increased imports and a decreased wind curtailment.

- The potential to increase market value and revenues for renewables is high for district heat sector when compared to industrial heat both in 2030 and 2050 scenarios. It is observed through higher utilization of wind energy for residential district heat sector due to the similarity in seasonal patterns whereas the industrial heat load is majorly met through international supply in form of imports and decrease of exports. Nevertheless, power to district heat load and industry heat do not influence average power prices and thus the new average electricity prices do not have bad feedback effects on the optimization solution of electrification of district heat system.

- The complete electrification of industrial heat and hydrogen sectors in 2050 resulted in extra investments in power system infrastructure. Especially, the interconnection capacities increased from 31.8 GW in base scenario to 34.3 GW and 59 GW to supply electricity needs for industry heat and hydrogen respectively. With these huge investments, the power system in 2050 scenario could supply electricity for heat and hydrogen sectors in the Netherlands completely.

- The profits of renewables in the Netherlands has increased by 1.4%, 40% and the wind curtailment has decreased by 28%, 78% in comparison to the base 2050 power system scenario due to the electrification of industrial heat sector, hydrogen demand respectively.

- After the new transmission capacity investments to supply electricity for industry heat and hydrogen market, it is observed that the average power price decreased in industry heat case implying the hybrid heat system costs can be less than the solution of optimization problem. From hydrogen electrification, power price has slightly increased which will not create negative feedback for power to hydrogen optimization solution. However, there is a possibility that hydrogen producers are willing to pay for higher power prices and overload the power system in 2050 because of the profitable hydrogen market. These results create a need for the introduction of new mechanisms in order to regulate the coupling of these sectors smoothly.

# Contents

# Abbreviations

| | |
|---|---|
| AEL | Alkaline Electrolyser |
| Avg | Average |
| BEV | Battery Electric Vehicles |
| CAPEX | Capital Expenditure |
| CCS | Carbon Capture Storage |
| CF | Capacity Factor |
| CCGT | Closed Cycle Gas Turbine |
| CHP | Combined Heat and Power plant |
| CO | Carbon Monoxide |
| CO2 | Carbon Dioxide |
| COMPETES | Comprehensive Market Power in Electricity Transmission and Energy Simulator |
| CRF | Capital Recovery Factor |
| CSP | Concentrated Solar Power |
| DC | Direct Current |
| DH | District Heating |
| EB | Electric Boiler |
| EVs | Electric Vehicles |
| GB | Gas Boiler |
| GJ | Gigajoule |
| GW | Gigawatt |
| GWh | Gigawatt Hours |
| HHV | Higher Heating Value |
| HL | Heat Load |
| HPs | Heat Pumps |
| IC(E) | Internal Combustion (Engine) |
| KG | Kilogram |
| LCOE | Levelized Cost Of Electricity |
| MAX | Maximum |
| MW | Megawatt |
| MWh | Megawatt Hours |
| MWth | Megawatt Thermal |
| ng | Natural Gas |
| OCGT | Open Cycle Gas Turbine |
| OWP | Offshore Wind Power |
| P2G | Power To Gas |
| PEM | Proton Exchange Membrane |
| PJ | Petajoule |
| PP | Power Price |
| PTS | Pit Thermal Storage |

| | |
|---|---|
| PV | Solar Photovoltaic |
| SMR | Steam Methane Reformer |
| SOC | State Of Charge |
| TES | Thermal Energy Storage |
| TW | Terawatt |
| TWh/y | Terawatt Hours Per Year |
| VOLL | Value Of Lost Load |
| VRE | Variable Renewable Energy |

**Organisations**

| | |
|---|---|
| DNV-GL | Merged organization of Det Norske Veritas (Norway) and Germanischer Lloyd (Germany). |
| ENTSO-E | European Network Of Transmission System Operators For Electricity |
| NIB | Northern Innovation Board |
| PBL | Planbureau voor de Leefomgeving (The Netherlands environmental assessment agency) |
| TKI | Top consortia for Knowledge and Innovation |
| TNO ECN | The Netherlands organisation for applied scientific research |
| TYNDP | Ten-Year Network Development Plan |

**Countries**

| | |
|---|---|
| BE | Belgium |
| DKw | Denmark |
| De | Germany |
| EU | European Union |
| GB | Great Britain |
| NED | The Netherlands |
| NO/NW | Norway |

# Nomenclature

| | |
|---|---|
| $\eta$ | Efficiency |
| $\lambda$ | Price |
| $\lambda_e$ | Hourly electricity market price |
| $\lambda_g$ | Fuel price for gas |
| $\lambda_{et}$ | Electricity network tariff |
| $\overline{C}$ | Maximum charging capacity of the heat storage |
| $\overline{D}$ | Maximum discharging capacity of the heat storage |
| C | Capital investment |
| E | Energy |
| FO | Fixed operational costs |
| H2 | Hydrogen demand |
| hd | Heat demand |
| i | Year |
| Ind | Industry heat demand |
| L | Loss |
| n | Lifetime in years |
| ng | Natural gas demand |
| P | Power |
| r | Interest rate |
| SOC | Storage |
| t | Time period |

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# 1

# INTRODUCTION

## 1.1. BACKGROUND

Wind energy is the most promising renewable energy source for the Netherlands in the energy transition period. However, the investment costs of the offshore wind are significantly large. Until now, the government was supporting the developments with subsidy schemes irrespective of the energy sector dynamics. The latest large scale offshore wind projects in Germany and the Netherlands (Hollandse-Kust Zuid) have been awarded zero-subsidy. However, in the Netherlands, the transmission costs of the offshore wind electricity are socialised. This would force the un-subsidised wind-farms to feed their electricity into the public grid exposing them directly to the whole sale electricity market. In Europe, the electricity market is liberalised and regulated. Day-ahead markets commit the generation units 24 hours before the actual dispatch based on their bids (considering economical and technical). However, as the marginal production cost of wind energy is negligible, the renewable energy is dispatched first in the wholesale market. With large shares of wind penetration in the market, the price of electricity is declining. At the same time, the intermittent nature of the renewable energy sources generate large demand for flexibility in the electricity system.

The flexibility is currently provided through flexible operation of thermal generation units. However, in a fossil-free energy future, the interconnections and demand side flexibility play a key role to balance the renewables. The existing electricity market models at ECN part of TNO contain modeling of flexibility offered by battery storage, imports, exports and shut down of thermal plants as designed for the operation of conventional power system. The flexibility provided by markets related to other sectors such as district heat, industry heat and hydrogen is not integrated into these models to assess the complementary effects of sector coupling. The combined pros and cons of renewable electricity opens up opportunities for integrated market assessment. Power to heat and power to hydrogen do not only offer demand side flexibility but also flexibility in the kind of product delivered, opening streams for additional revenues.

The synergies among these systems can be realised with detailed technical and cost analysis of the power to heat and power to hydrogen systems. Many studies have been performed globally, to evaluate the added value of these technologies in the energy system. The energy sector in Denmark utilises district heating networks as buffer for excess wind electricity with flexible operation of combined heat power plants and large electric boilers [1]. An extensive study by DNV-GL (Det Norske Veritas and Germanischer Lloyd) assessed the decarbonisation potential of integration of industrial heat with offshore wind energy as 30% above the targeted emission reductions for 2030. The climate agreement scenarios developed by a Dutch research institute "Planbureau voor de Leefomgeving" (PBL) show that a flexible heat demand of 33.4 TWh is possible in the Netherlands [2]. However, the economic feasibility of these systems with thermal storage has not been evaluated in these studies.

Hydrogen is identified as a green molecule with niche applications in transport, industry and heating sectors as a potential carbon-free fuel of the future. When it comes to the value of hydrogen produced from electricity, Gunther Glenk analysed the economics of hydrogen production from renewable wind electricity and concluded that it is competitive with the present small scale merchandise market for the niche applications where hydrogen costs around 3.23 €/Kg [3]. Gasunie and Tennet conducted a joint study on the integration of gas and electricity infrastructure for 2050 with hydrogen as buffer in the natural gas networks to provide flexibility for the entire energy system [4]. This study emphasized the importance of locating the Power to Gas (P2G) facilities near the renewable energy production sites to reduce the need for transmission grid expansion. However, the technical and economic feasibility of large-scale electrolysers is proposed as future scope of work. Nevertheless, the influence of these new technologies on the national energy market and the revenues of renewable generators has not been addressed so far for the Netherlands.

## 1.2. SCOPE

With this background, this thesis focuses on the assessment of technical potential of power to heat and power to hydrogen technologies to contribute to energy transition in the Netherlands. The scope is limited to the national power system in context of European electricity market. The economic analysis is carried out around 3 scenario years 2023, 2030 and 2050 with different levels of renewable energy penetrations in the electricity sector.

## 1.3. OBJECTIVE

The research aims to produce valuable insights for the investors in terms of the time of investment and the optimal capacities of flexibility options for each market scenario. The main aim of this thesis is to design a cost minimal flexible heat, hydrogen and electricity energy system by using an electricity markets model and optimization techniques.

### 1.3.1. Research questions

The work is split up into a series of questions to accumulate the knowledge required to achieve the main objective. In order to provide insights for investors in the power to heat or power to hydrogen technologies and their implications on national energy system, following research questions are formulated. The opportunities, threats and solutions for the involved stakeholders are identified through these questions:

1. How will the electricity sector develop for the given outlook of renewable penetrations in 2023, 2030 and 2050?

2. What are the volumes of heat and hydrogen demands in the Netherlands that can offer flexibility to the electricity system?

3. Given the above market scenario, what is the optimal size and operational strategy of these flexibility options with minimum system costs?

4. What are the implications of this extra electrification on the electricity system and the revenues of renewables (especially offshore wind)?

### 1.3.2. Approach

With regard to the main objective and the scope of the problem mentioned in Section 1.2, a pragmatic approach is adapted for the research. The method adopted to address each question and key activities in the scope of this research are outlined below:

1. A framework of scenarios is defined around which the entire research is formulated. An electricity market simulation model is used to obtain quantitative insights in the energy sector development.

2. A bottom-up method is adopted to model the hourly data of the heat and hydrogen demands.

3. An optimization problem is modelled to determine the capacity investments and optimal utilization of the components of heat and hydrogen systems. The results are analysed for each scenario year 2023, 2030 and 2050.

4. An analysis of the power system, once again with the market simulation model is performed to identify the consequences of electrification of heat and hydrogen demands.

## 1.4. REPORT LAYOUT

The report starts with an overview of methodological approach of the entire work. The key inputs and results of each segment of the research is briefly outlined in **Chapter** 2. An introduction to the European electricity market model is presented. In **Chapter** 3, the power system scenarios are described extensively. The required hourly database for generation and electricity load are prepared for the simulations. Outcomes of the electricity market simulations are also discussed in the same chapter. **Chapter** 4 describes the outlook for heat and hydrogen sector for the Netherlands. The approach for modelling hourly demand profiles of residential district heating, industry heat and hydrogen is given. In **Chapters** 5 and 6, the system design, economic analysis and optimization of the power to heat and power to hydrogen systems are discussed in detail. **Chapter** 7 presents a qualitative discussion about the consequences of integration of heat and hydrogen systems on the electricity sector. Emerging extra costs for the power system and any additional profits for renewables are presented in particular. Finally, in **Chapter** 8, conclusions of the present work and recommended scope for future extension of this work are presented.

# 2
# METHODOLOGY

The purpose of this chapter is to present briefly the overall methodology of thesis, the models used for assessment and the general assumptions involved. The important inputs and outputs at different stages of the work are highlighted in **Section** 2.1. The following **Section** 2.2 provides an introduction to the European electricity market model "COMPETES (Comprehensive Market Power in Electricity Transmission and Energy Simulator)" primarily focusing on the nature of market simulated by the model and the particular capabilities of the model used in the thesis. A brief explanation of features of the generation technologies is provided. Parameterization of the relevant input database utilised in the thesis is detailed in the final section **Section** 2.3.

## 2.1. OVERVIEW OF THE METHODOLOGY

The socio-economic aspects of power to heat and power to hydrogen technologies integrated with national power system are assessed in this study. For the analysis, a coupled power, heat and hydrogen market model is required. However, the COMPETES model used in this research does not contain use of electricity for heat and hydrogen purposes directly. Moreover, the technology parameters related to thermal storage and hydrogen storage are not modelled in COMPETES. Thus, in this thesis, the demand from potential heat sectors or hydrogen are added exogenously. The overall methodology comprises of 3 important stages (**Figure** 2.1).

I. Electricity market simulation with predefined power system scenarios.
II. Economic assessment of power to heat and power to hydrogen systems.
III. Post analysis of power system with additional electrification from heat or hydrogen sectors.

In stage 1, a pathway for the transition of electrical power system for the Netherlands is defined in the form of three scenarios for the years 2023, 2030 and 2050. The power system scenarios are characterized by the share of renewables in the electricity production fleet. In each scenario, the capacities of renewable energy installations in the Netherlands, fuel prices and power demand per hour are used as input to COMPETES model. COMPETES model generates capacity expansions of the conventional plants and investments details of the national transmission grid. A more detailed breakdown of scenarios is presented in

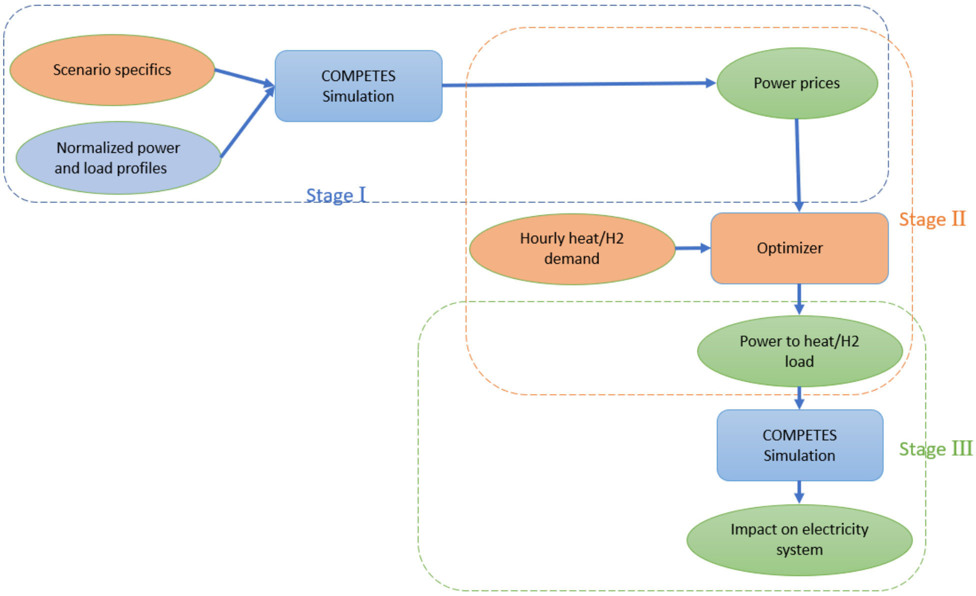



Figure 2.1: Conceptual overview of the thesis with the key inputs/outputs at each stage

**Chapter** 3 and the COMPETES model is elaborated in **Section** 2.2. The key output of stage 1 is an hourly time series of power prices with the available generation technologies. Any considerable amount of renewable energy curtailment is also noted down as a key output for further analysis.

The next stage involves assessment of power to heat and power to hydrogen potentials for the Netherlands. Different approaches are adopted per technology because of the limitations of current market conditions for the heat and hydrogen demands. For the power to heat system, the heat demand is modelled from the historic values in 2016 with a bottom up approach. The modelled heat load serves as an input to the second stage of the methodology along with the power prices obtained in stage 1. The heat demand has been distinguished in two categories, residential district heat load and industrial low temperature heat demand. Further, at the moment, the market for hydrogen in the Netherlands is not so high as for heat, electricity or natural gas. Hence, first a projection for hydrogen demand in 2050 is set as a target point and the demand in the transition years is estimated through interpolation. A detailed method to model the demand for hydrogen is presented in **Section** 4.2.2. An important note in this stage is that the modelled heat load is unchanged across all scenarios. However, the hydrogen load penetration in the system will be different in each scenario. An optimization problem is modelled for power to heat and power to hydrogen separately in this stage to solve for the optimal size of components of the systems with minimum investment costs and operational costs to meet the demands in each scenario. Therefore, this stage in the methodology yields the optimal electrification of the technologies from the perspective of heat and hydrogen production costs. The optimal solution to meet the heat (respectively hydrogen) demand will be supplied with either "a mixture of heat (respectively hydrogen) from electricity and gas" or "simply one of the technologies (such as only gas or only electricity)".

The power to heat and hydrogen are so far considered as only electricity price takers. However, because of the electrification and flexible nature of these units, the dynamics of the electricity system could be altering. In the final stage of the methodology, the optimal size and operation of the power to heat and hydrogen technologies obtained in stage 2 are given as electricity load input to the European electricity market model individually. These simulation results provide a first order insight on the kind of impact these technologies have on the national power system. The key indicators for analysis and comparison of electricity market simulation results before and after addition of load from heat and hydrogen sectors are established in **Section** 3.2.

## 2.2. DESCRIPTION OF COMPETES MODEL

COMPETES is an European electricity market model developed by ECN part of TNO (Netherlands Organisation for Applied Scientific Research) and PBL jointly for energy and environmental policy studies for the Netherlands and the European region. However, main theory behind the formulation is explained in detail in the research work by Hobbs and Rijkers [5].

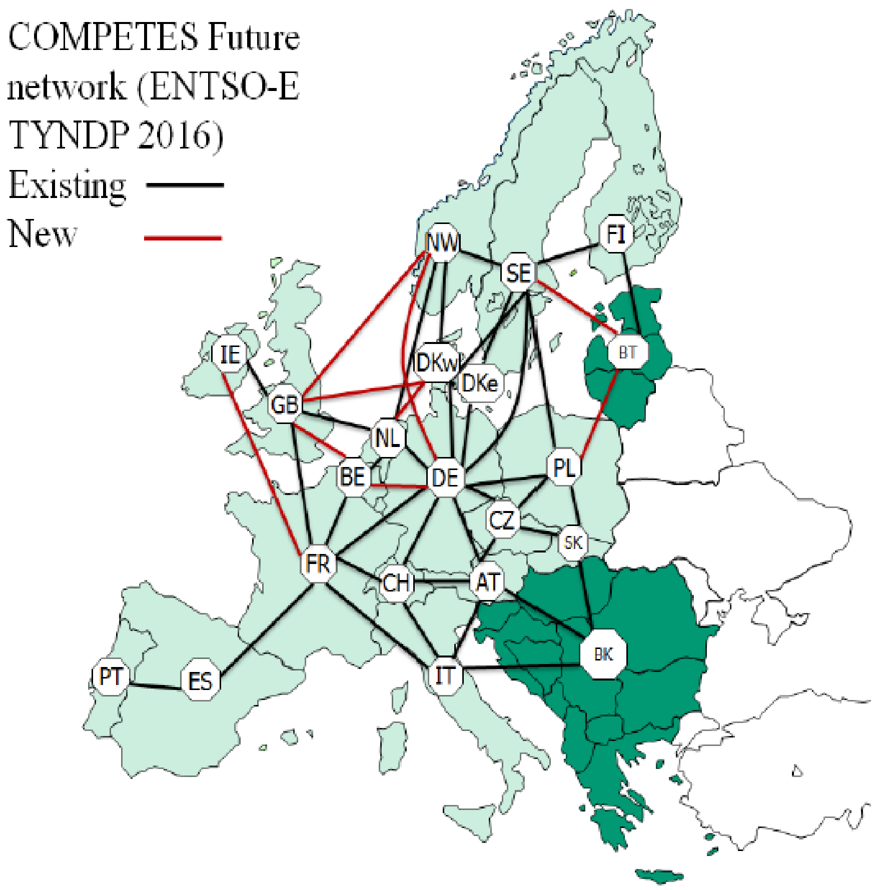



Figure 2.2: A physical representation of the COMPETES model showing the interconnected transmission networks [6]

The level of detail in the model is extensive with the power generation and consumption data of 28 European countries. The model includes detailed specifications of the power plants with respect to their capital costs, operating costs, start-up and shut down costs and the minimum capacities of production technologies. The model represents a country as a node and the interconnection between countries as an edge as shown in **Figure** 2.2. The power generation in each country is visible at its node and any exchange of power in between the countries takes place through this node [6]. The model follows a perfect competition among the generators and the market is simulated through unit commitment, similar to that of the regulated market operating in Europe.

The model is a multi-period optimization problem with two modules:

- Capacity expansion module
- Unit Commitment module

### 2.2.1. Capacity expansion module

Generation and transmission capacity expansion module is the first stage using a linear programming problem. The solution to this problem provides investment decisions for the generators in new power supply technologies and the emerging net transmission capacity expansion requirements for the country. The existing generation plants and already planned network capacity constraints are taken into account while solving this problem. The main inputs for this stage are policy driven choices for fuels from international outlooks, renewable energy developments especially solar photo voltaic (PV) and wind, transmission infrastructure plans from ENTSO-E (European Network of Transmission System Operators).

### 2.2.2. Unit commitment module

Unit Commitment module is a short term generation unit commitment and dispatch problem mimicking a day-ahead market. It is a mixed integer optimization problem where the solution contains binary variables representing the commitment of a generator at a given time period in the simulation. This problem aims to provide an economically minimum mixture of power supply units to meet the demand. The solver provides a socially optimum market clearing price for the electricity by taking into account the production costs consisting of fuel costs, carbon emission taxes, star-up costs, shut-down costs and other constraints like ramping limits and efficiency of the technologies. The input and output of this module in COMPETES is in time steps of 1 hour. The resolution of data used in all 3 stages of methodology is in steps of hours over a year. An overview of the technical specifications of the power production units is presented in **Appendix** A.

In this thesis, the second module of COMPETES model is adopted in the first stage of the methodology to obtain the power prices and generation mix for each scenario. Later, for stage 3 in the **Figure** 2.1, the investment module is used to evaluate the transformations required in the power system due to the electrification of heat and hydrogen demands.

## 2.3. COMPETES MODEL DATABASE

### 2.3.1. Electricity generation and transmission

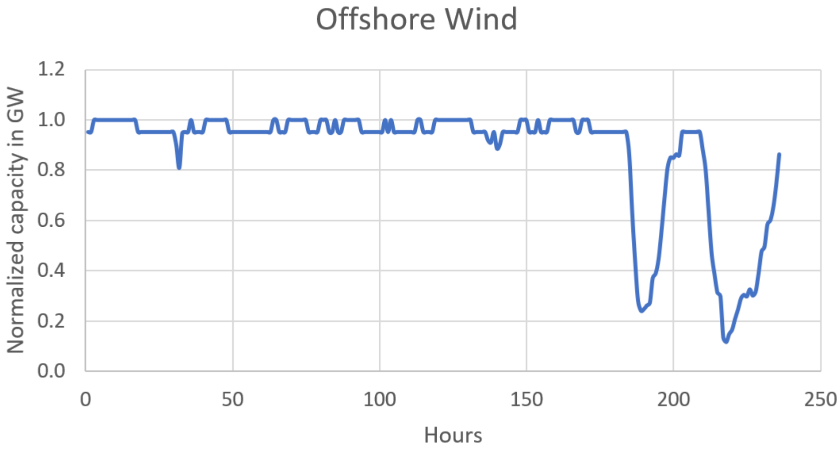
This section presents an explanation of the inbuilt database of COMPETES model which is relevant for the scope of work. Especially, it contains details about development in international electricity system in terms of aggregate capacities of generation technologies and more accurate information about the power system in the Netherlands.

- **International:** The model considers that electricity generation technologies in the neighboring countries are as per the Slow-progress scenario proposed by ENTSO-E for years 2013-2030. Nevertheless, the share of renewables in the EU electricity mix will constitute 47% by 2030, meaning a considerable growth of green energy solutions throughout Europe. The electricity demand grows at a rate of 0.37% per year outside the Netherlands. The interconnection across countries taken in the model follows from the results of ten-year network development plans determined by ENTSO-E network analysis 2018 [8]. Anticipating a slow rate of infrastructure building, the key interconnections shared with the Netherlands are considered as listed in **Table** 2.1 for the scenario years 2023 and 2030. For 2050, the net transmission capacities across countries is not available. It will be estimated by performing a capacity investment simulation with the scenario inputs in 2050.

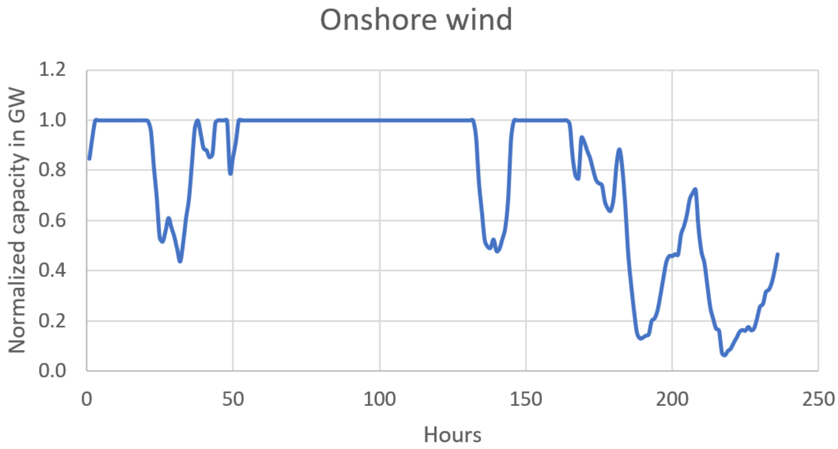
Table 2.1: The capacities of interconnection constraints of the Netherlands with neighbouring countries assumed in the model [8]

| **Interconnections (MW)** | **By 2025** | **By 2030** |
|---|---:|---:|
| BE-NL | 2400 | 4400 |
| De-NL | 4250 | 5000 |
| DKw-NL | 700 | 700 |
| GB-NL | 1000 | 3000 |
| No-NL | 700 | 700 |
| **Total** | 9050 | 13107 |

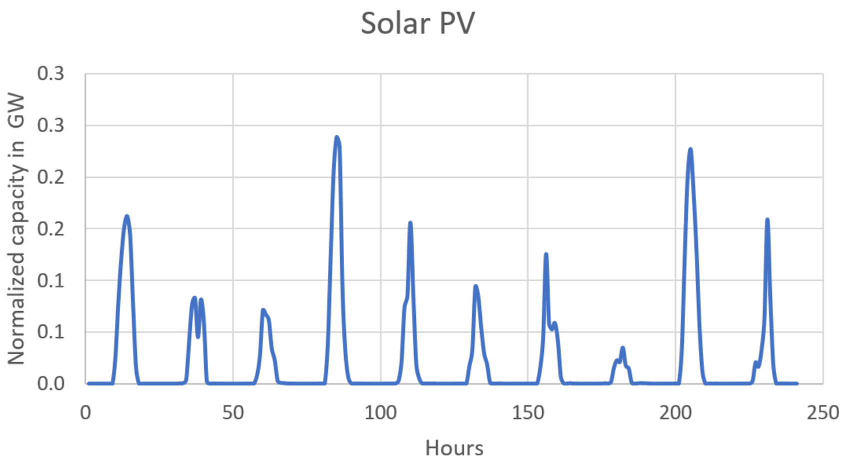
- **The Netherlands:** The important input data for the Netherlands is hourly time series of solar PV generation and onshore, offshore wind power supply. The database in COMPETES model related to above mentioned renewable energy generation technologies is described briefly below:




(a) Offshore wind




(b) Onshore wind




(c) Solar PV

Figure 2.3: Per unit hourly power output from onshore wind, offshore wind and solar PV technologies represented for 10 days. Basis for hourly renewable electricity production in COMPETES [12]

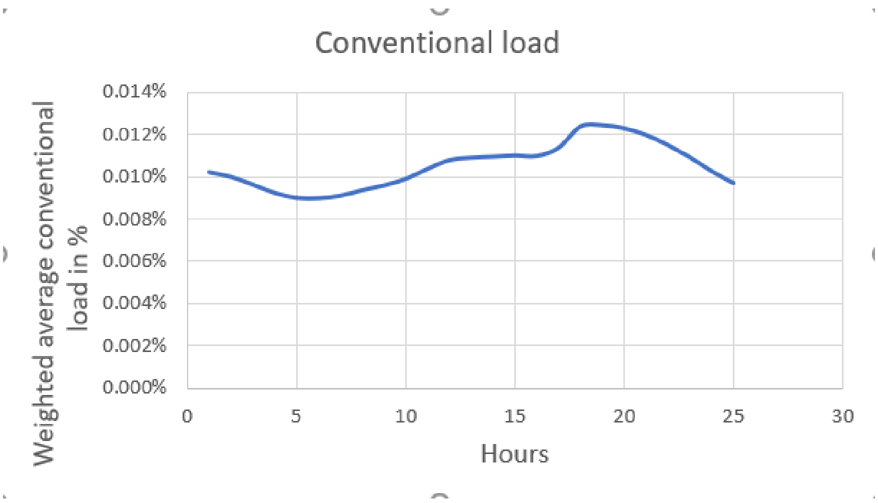
– Onshore Wind and Offshore wind: Normalized profiles of power generation from both wind onshore and wind offshore have been collected from the Hirlam database of the ECN unit Wind, based on the realized wind power output in 2012 per MW installed nameplate capacity [12]. The distribution over 10 days is shown in **Figure** 2.3. There is not any strong pattern for the power production from the wind generators. However, it shows that onshore wind output is more irregular in comparison with offshore wind. Nevertheless, the variability in the power production is clearly captured in time series.

– solar PV: The hourly profile of (forecasted) power generation from sun PV in 2015 is taken from a public transparency platform of ENTSO-E [9] for the Netherlands. Subsequently, it is normalised per unit installed capacity of solar PV in the country. The **Figure** 2.3 shows a stable pattern for the solar PV power generation with as high as 30% capacity factor falling in line with an average equivalent sun hour value of 2.7-3 hour per day for the Netherlands.

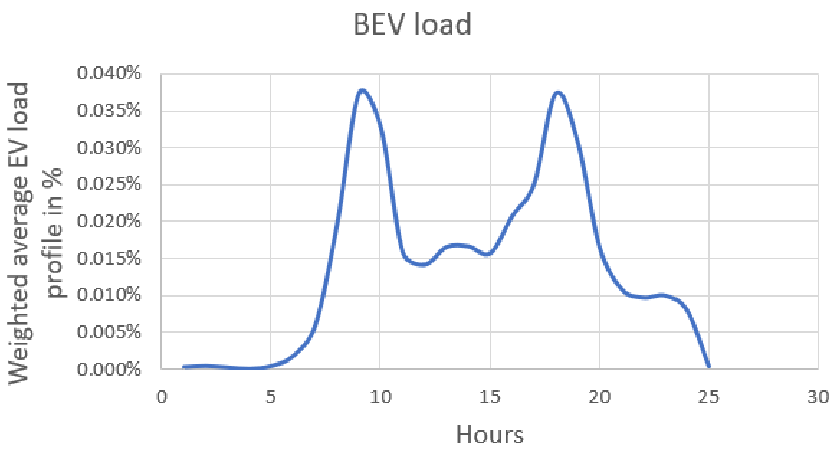
Therefore, the hourly power output from wind and solar PV used in the model are obtained by multiplying the assumed installed capacities of renewable energy in each scenario with the above mentioned hourly distributions. Particularly, for wind on sea, power generation volumes are estimated considering the technology developments in offshore wind turbines designed with higher capacity factors. The hourly offshore wind power production series has been corrected with the energy production values calculated with the assumed improvement in technology (capacity factor) provided in **Table** 3.2 **Chapter** 3.

### 2.3.2. Electricity load

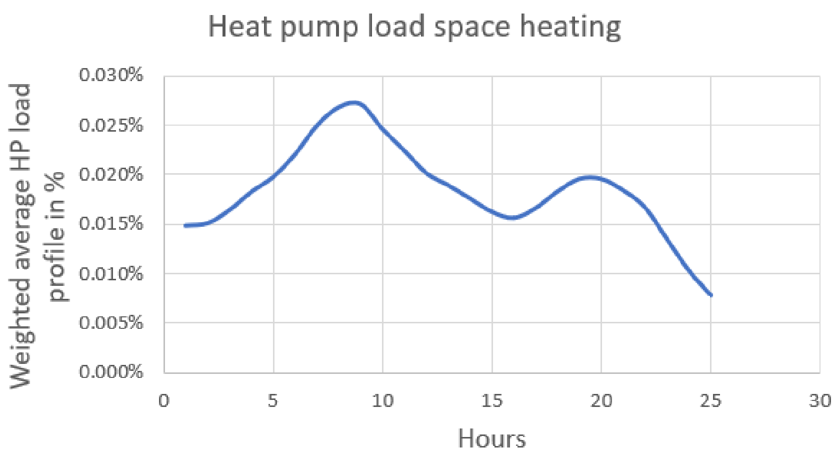
Next to this, the electricity demand is categorised separately as conventional load, electric vehicles, heat pumps for household heating. A brief explanation of how the load profiles of these consumers are modelled in the COMPETES database is given below and the hourly distribution across a day is shown in **Figure** 2.4.




(a) Conventional load




(b) Electric vehicle charging




(c) Heat pumps for house heating

Figure 2.4: Normalised hourly electricity load profiles for conventional consumption, EVs and HPs for one day. X-axis-hours [12]

- Conventional load: The conventional load in the model represents an hourly electricity consumption realised in the Netherlands in 2016 from ENTSO-E data [10]. The hourly consumption is normalised to create a standard time series. This hourly distribution is multiplied to annual conventional load in TWh for lighting and general needs assumed in the scenarios to obtain the hourly conventional electricity load. Further, the power load for electric vehicles (EV) and heat pumps (HP) is modelled and added as additional load.

- Battery Electric vehicles: The hourly load profile for electric passenger cars – used in the COMPETES model is developed by Liander by means of the data from 'Investigation Statistics in the Netherlands'[11]. Four different EV profiles have been constructed for distinguishable locations at home, work, public parking garages, and at fast charging locations. A definite percentage is assigned to the electric vehicles charging at these locations 53%, 29%, 5% and 13%, respectively based on the theory in the study 'Laadstrategie Elektrisch Vervoer'[13]. The charging stations data and the percentages are together used to construct an aggregated, weighted-average charging profile for EVs in time steps of an hour and in steps of 15 minutes. In this thesis, only the hourly EV distribution is used to construct the electricity demand of light vehicles.

- House heating: An aggregated, weighted average load for heat pumps is designed internally at ECN TNO. The load profile has been constructed by assuming 3 different technologies of heat pumps namely air-source HPs, ground-source HPs and hybrid HPs (i.e. both gas and electric). In order to calculate heat demand, two categories of houses are assumed based on the level of energy insulation of the building. The heat demand is modelled based on the hourly temperatures in the year 2012. A normalised load time series for HP is thus obtained by considering the number of houses and electricity consumption per technology assumed in Flex net project [12].

These normalised weighted average load profiles have been used to create hourly power demand for the simulations. The respective level of electrification of these sectors namely conventional, EVs and heat pumps assumed in the scenario years 2023, 2030 and 2050 is provided in **Table** 3.2.

# 3
# SCENARIO FRAMEWORK

In this chapter, a framework for the national power system transition is set up and the characteristic details of the scenario years are presented in **Section** 3.1. The renewable energy developments, fuel prices and degree of electrification are important parameters of the power system scenarios. Consequently, the outcomes of COMPETES simulations for the power systems are analysed to provide insights on the developments in the electricity market. The capacities of additional generation units and transmission network for the power systems are presented in **Section** 3.2.1. The dynamics of power prices and curtailment levels in the market scenarios 2023, 2030 and 2050 are discussed in and **Section** 3.2.3 and **Section** 3.2.2 respectively. The market value and profits for renewables in each scenario are calculated from the market clearing results of COMPETES simulations and presented in **Section** 3.2.4. The details of power production and traded electricity to meet annual electricity needs in each scenario are discussed in **Section** 3.2.5. The reliability of power system is also discussed in this section.

## 3.1. POWER SYSTEM SCENARIO SPECIFICS

The electricity market dynamics are dependent on different factors. The most important ones are a) electricity demand, b) production technologies, c) fuel prices, d) $CO_2$ emission prices, e) the cross-border transmission capacity and electricity trade. The characteristics of scenarios presented in this section are more specific to the Netherlands, whereas the scenario data related to the international power system is specified in **Section** 2.3. Fuel prices and carbon dioxide ($CO_2$) emission prices are important parameters in the decision of future generation mix to supply electricity load at each hour and thus in the determination of hourly electricity prices. However, the selection of fuel prices per scenario is neither direct nor can be estimated from historic trends. Thus, for the years 2023 and 2030, the values based on the 'National energy Outlook (NEV) 2017' have been taken as input for fuel prices and emission costs [14]. However, for 2050, it is highly uncertain how the global fuel markets influence the fuel costs for electricity generation in the Netherlands. Estimated prices according to the trend forecast by New Policies Scenario of the World Energy Outlook 2015 have been assumed for 2050 scenario [15]. **Table** 3.1 provides a summary of fuel prices used for the scenarios. Overall, an increasing trend for fossil fuel prices is observed both in the national and global energy outlooks.

Table 3.1: Natural gas price and $CO_2$ emission costs per each scenario as an input to the COMPETES simulations [14][15]

| Commodity [unit of price] | 2023 | 2030 | 2050 |
|---|---|---|---|
| Natural gas [€/MWh] | 17 | 31 | 29 |
| $CO_2$ [€/ton] | 7 | 16 | 93 |

The 3 future transition scenarios differ in quantities of renewable energy installations and electricity demand levels. Especially, the electrification of household heating sectors (HPs), transport sector (EVs) and emerging electricity demands from decarbonization of the industry. The power system scenarios are described below:

### 3.1.1. Near Future scenario 2023

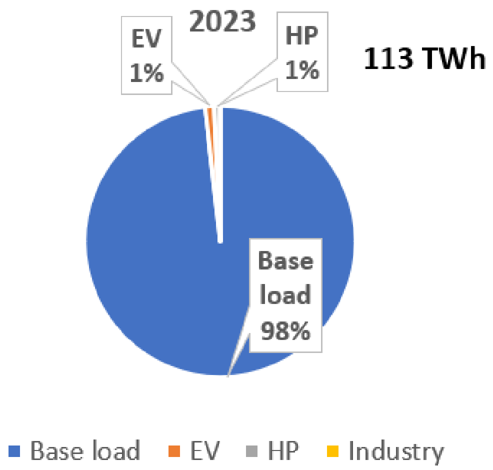
This year is of specific interest because the first un-subsidized offshore wind farm becomes operational in 2023. The assessment of how electricity market evolves and the dynamics of market price in that year is crucial. The capacities of renewable electricity are defined from the targets of the government in National energy outlook 2017 [14]. The capacity numbers are given in **Table** 3.1. The conventional electricity consumption is virtually the same as that of 2017 because of the energy savings measures. The conventional load is separated from the EV load and the load for heating houses. Power to heat pumps represents electrification of houses which are not connected to district heat networks and currently supplied with traditional gas heaters. The additional electrification from the mobility and heat pumps is as per the climate targets set in the National energy outlook 2017 [14] respectively 1.2 and 0.8 TWh. The total electricity load for this scenario amounts to 113 TWh. This scenario is classified as a low renewables and low-electrification scenario [14].

### 3.1.2. Scenario 2030

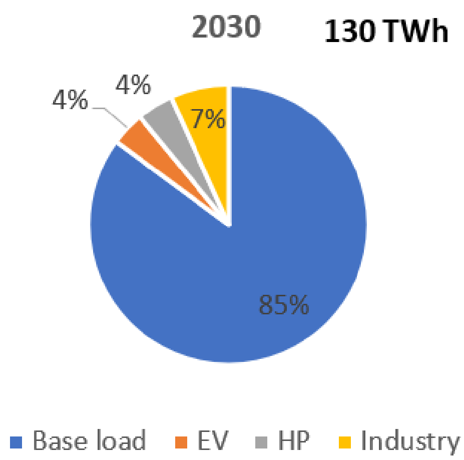
In 2030, with a further strong ambition to reach climate agreement goals, almost 12 GW offshore wind will be installed with a target of 1 GW addition per year. The wind on land is estimated to reach 8 GW with the barriers of availability of space and public acceptance. This scenario underlines the importance of reliability of the system with large shares of renewable integration. The total variable renewable electricity (VRE) production in this scenario is 84 TWh. Further, a low electrification is considered in the transport sector with 841,000 EVs in the total fleet of passenger cars as per climate agreement scenario developed by PBL to reach the emission reduction goals set for 2030 [14]. About 5.5 TWh of the low temperature heat needs for house heating currently supplied with direct natural gas is identified to be replaced with electrification contributing to the sustainable transition. The industrial electrification for 8.8 TWh of heat demands would add an inflexible constant load of approximately 1 GW to the grid. In total, in 2030, 130 TWh electricity load is anticipated. This scenario will be called high renewables and low electrification scenario.

### 3.1.3. Scenario 2050

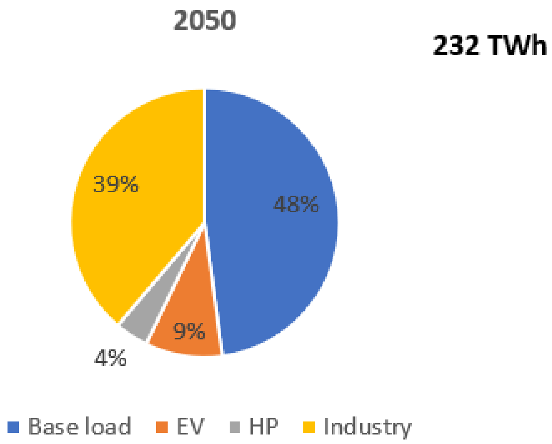
2050 scenario follows the trend of increasing share of renewables in the electricity sector. The full potential of offshore wind in the North Sea part of the Netherlands is assumed to be captured by 2050. The key goal of this scenario is to reach 85% reduction in emissions from the level of 1990 as described in the power to gas study conducted by ECN for the future carbon-free Dutch energy system [16]. Electrification in this scenario penetrates deeply into the transport sector for light vehicles and household heating needs with a load of 21.5 TWh and 9.3 TWh respectively. Power to industry represents electrification towards high temperature heating assuming that the required technology will be available. Power to industrial products for non-energy use in the form of fertilizers and other chemical products is also included in the power to industry load. An electricity requirement of 90 TWh is assumed for power to industry in this scenario. This will sum up together with a conventional load of 111 TWh to an amount of 232 TWh representing a high renewables and high electrification scenario.




(a) 2023 powersystem




(b) 2030 powersystem




(c) 2050 powersystem

Figure 3.1: The share of electricity load per sectors conventional load (base load), EV and HP in the scenario years 2023, 2030 and 2050

A graphical representation of electrification of the sectors EV, house heating and industry needs for all scenarios is presented in **Figure** 3.1. Electrification is witnessed as an efficient and clean source for achieving the climate goals as observed from the increasing demand for electricity through scenarios.

A striking feature of all the scenarios from the generation side is that the coal-power plants have been removed from the electricity supply fleet. In particular, inspired by the recent announcements to ban the Amber Power Plant in Geertruidenberg and 1560 MW Eemshaven Power Plant by the end of 2024, the development of any new coal plants is omitted in the Netherlands [17]. Moreover, for all scenario years, the existing coal plants are assumed to be decommissioned, thus they are completely removed from the simulations.The gas based generation capacity is an output of capacity expansion module of COMPETES model according to NEV 2017 and flexnet 2050 scenario. Thus, the obtained gas capacities for each scenario are presented in **Section** 3.2

Table 3.2: Renewable capacity installations, annual renewable energy generation and annual electricity load for scenarios 2023, 2030 and 2050

| | Unit | 2023 | 2030 | 2050 |
|---|---|---|---|---|
| **Generation** | | | | |
| Wind offshore | [GW] | 4.8 | 11.6 | 30 |
| Solar PV | [GW] | 9.0 | 16.2 | 56 |
| Wind onshore | [GW] | 5.4 | 8.0 | 8 |
| **Electrification** | | | | |
| Conventional load | [TWh] | 111.0 | 111.0 | 111.0 |
| EV | [TWh] | 1.2 | 5.1 | 21.5 |
| Power to heat pumps | [TWh] | 0.8 | 5.5 | 9.3 |
| Power to industry | [TWh] | 0 | 8.8 | 90.0 |
| **Technology (Capacity Factor)** | | | | |
| Wind offshore | [%] | 47.0 | 47.0 | 47.5 |
| Solar PV | [%] | 9.4 | 9.4 | 9.4 |
| Wind onshore | [%] | 30.5 | 32.6 | 33.1 |
| **Electricity Production** | | | | |
| Wind offshore | [TWh] | 19.7 | 47.9 | 124.8 |
| Solar PV | [TWh] | 7.4 | 13.4 | 46.1 |
| Wind onshore | [TWh] | 14.4 | 22.9 | 23.2 |
| Total VRE production | [TWh] | 41.5 | 84.2 | 194.1 |
| Total load | [TWh] | 113.0 | 130.0 | 232.0 |
| VRE share in load | [%] | 37.0 | 65.0 | 120.0 |
| Additional electrification relative to conventional load | [%] | 1.8 | 25.0 | 109.0 |

A technology parameter is indicated for renewable generation technologies wind and solar PV called capacity factor (CF). It is defined as the ratio of actual electrical output of a power plant over a period of time to the potential possible name plate capacity of the plant operating continuously for the same period of time. Here, it is represented in %. Capacity factor is a characteristic parameter of technology as well. A capacity factor of 47% is considered for offshore wind in scenario years 2023, 2030 and an increased CF 47.5% [12] is assumed for the scenario 2050. Similarly, a technology improvement represented with capacity factors of 30.5%, 32.6% and 33.1% for scenario years 2023, 2030 and 2050 are assumed for onshore wind. This assumption relates to the replacement of existing old small turbines with larger ones accompanied with installation of better turbines for the new projects on land. For solar PV, full load hours of 840 representing a CF of 9.4% are assumed for the installed capacities in all scenarios. The installed capacity of renewables when multiplied with capacity factor provides the annual electricity production from each technology in TWh. The total variable renewable electricity (VRE) production shown in **Table** 3.2 represents the sum of annual electricity production from wind offshore, solar PV and wind onshore. An overview of the assumptions relevant for all scenario years, VRE capacities and electricity load inputs are summarized in **Table** 3.2.

The overall electricity load is increasing with each transition year. Moreover, the total renewable electricity production in 2050 scenario is higher than the load. However, the degree of electrification in comparison to the renewable electricity supply is different per scenario. In order to visualise this, the absolute value of power load for EV plus power to heat pumps and industry in each scenario is compared with the conventional load. In 2023, the additional electrification is only 1.8%, whereas it increases to 25% in 2030 and 109% of the conventional load in 2050 scenario. This once again strengthens the categorization of first two scenario as low electrification cases and 2050 as high electrification scenario.

## 3.2. ANALYSIS OF ELECTRICITY MARKET SIMULATION RESULTS

With the assumptions described above, power system scenarios with the indicated level of renewables and electricity load are simulated with the electricity market model COMPETES. The investment module of COMPETES gives capacity investments in generation technologies such gas , nuclear and transmission lines across countries ensuring that given load in a scenario is fulfilled. The unit commitment module provides several results such as hourly power prices, annual generation costs and profits per technology, power system costs containing generation costs, revenues, profits. The model also gives generation mix for the Netherlands, neighbour countries, power flows between borders at each hour along with the electricity contribution to annual load by all the technologies. Moreover, the unit commitment module provides utilization of storage if any in neighbouring countries (especially hydro pumped storage) plus the curtailed wind, PV electricity per hour.

Finally, it provides quantity of $CO_2$ emission per country per technology in tonnes. In this section, only a few of the results useful for the economic assessment of power to heat or power to hydrogen markets are analyzed. The analysis follows with a brief explanation of these indicative criteria for the power system assessment. Therefore, these indicators will be used to compare the power system before and after the addition of power to heat or power to hydrogen loads providing insights about coupled heat and power, hydrogen and power markets. COMPETES simulation results of all scenarios are presented and discussed in the following sections.

### 3.2.1. Generation capacity gas and others

The power system in scenario years 2023, 2030 is a realization of National Energy Outlook (NEV) to reach climate agreement targets. Hence, the capacities of transmission lines of 9 and 13.8 GW with neighbouring countries mentioned in **Figure** 3.2 do not represent an output of the model but they rather represent already planned capacity for construction. However, for 2050, VRE supply and load are simulated in first module of COMPETES to obtain investments in gas plants and any other economically preferable generation technologies. The investment cost per MW of the technology is presented in **Appendix** B and an interest rate of 10% is assumed in the model for annualising investment costs [12] for investment module simulation.

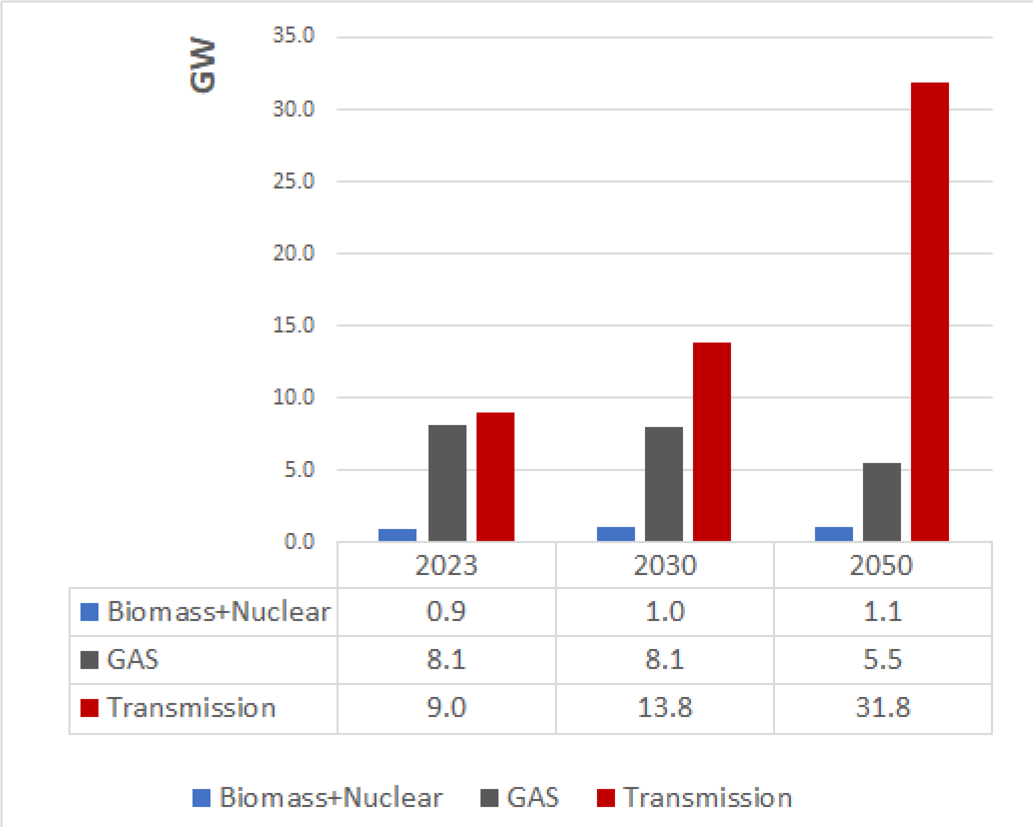



Figure 3.2: The capacities of generation and interconnection transmission lines for power systems in scenario years 2023, 2030 and 2050

The results of generation capacities for each power system scenario are presented in **Figure** 3.2. Minute capacity investments in biomass and nuclear upto 1.1 GW are observed in all scenario years. A capacity of 8 GW of gas plants are required in 2023 and 2030 to support increasing load with increasing VRE supply. However, the gas plant capacity in 2050 is reduced to 5.5 GW. The investments in high voltage interconnections is chosen over expansion of gas plant capacities because of the increased $CO_2$ emission costs meaning that the gas plants cannot recover their investment costs in 2050 from operational sales. Moreover, the availability of cheap renewable electricity in the neighbouring countries in 2050 scenario resulted in investments in interconnections. Interconnection capacity of 31.8 GW shown in **Figure** 3.2 represents the sum of existing 13.8 GW capacity in 2030 and the extra investment of 18 GW required to capture the high VRE supply and high annual load of 232 TWh in 2050. These results explain that transmission infrastructure will be an expensive part of the power system scenario 2050. With increased volumes of renewables and high electrification towards 2050, it is clear that larger investments are required to build cross border transmission lines in comparison to the investments in new domestic generation capacities to ensure a reliable national power system.

### 3.2.2. Utilization of renewables

Utilization of renewables is determined from the curtailed wind and solar PV generated as an output of the model. This explains whether the installed wind and solar PV capacities in each scenario has been utilised in full potential or not. The curtailment is expressed in terms of annual curtailed wind and solar PV energy in TWh. There is no curtailment in 2023, whereas 157 GWh of wind energy is curtailed in 2030. This is mainly because of the decommissioned coal-plants assumed in the scenario year 2023 and the capacities of gas is just sufficient to meet the load for the Netherlands in 2030. Although the same assumption holds for 2050, a significant amount of 21 TWh of wind energy is curtailed. This indicates potential for extra electrification in the country. Savings on curtailment through power to heat or power to hear seems to be most interesting in the far future scenario 2050 with high VRE capacities.

### 3.2.3. Power prices

Power prices are important indices to provide clear understanding of the development in the electricity market. Further, the potential implications of adding renewables to the system is directly expressed through these monetary values. This is a socio-economic indicator of the electricity system. The parameter provides an insight of the electricity market development trend. From results, the annual average power prices (Avg MP) in general and more specifically for offshore wind (OW) are presented in **Figure** 3.3. Average power price for the market is different from the average price for offshore wind in each scenario.

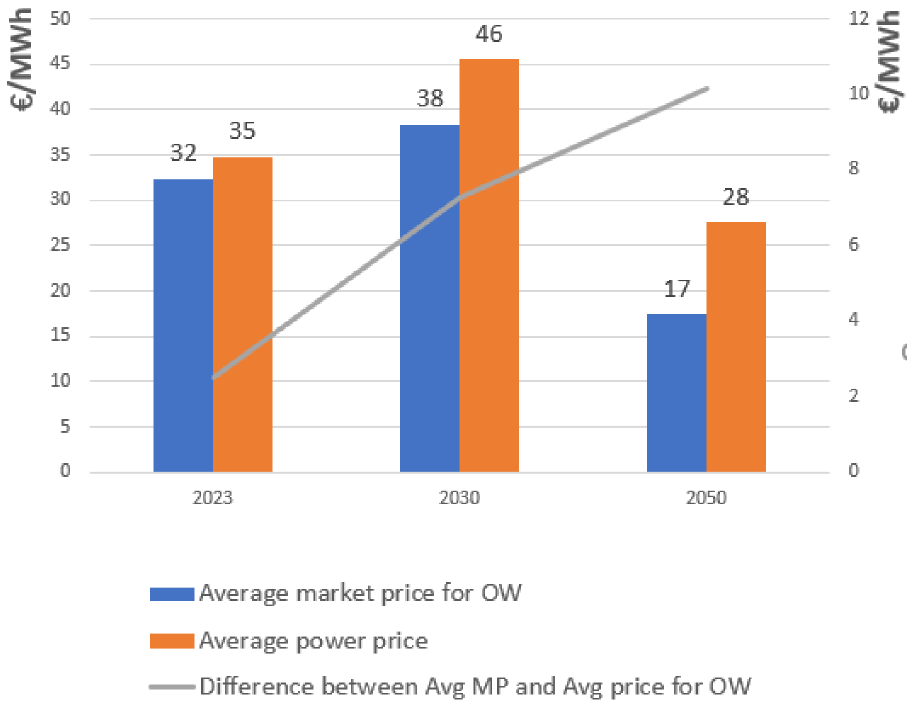



Figure 3.3: The average annual power prices in market scenarios 2023, 2030, 2050 together with representing the trend of difference between average price for electricity and average value of offshore wind electricity

Average market price for offshore wind is calculated by dividing the sum of hourly revenues from market with the total energy supplied by wind generators throughout the year. The power prices increased from 2023 to 2030 and then dropped in 2050 due to the increased amount of renewable electricity in the supply mix. In addition, the difference between average power price and the average market price for offshore wind is increasing with increasing share of VRE in supply mix. In 2050, the difference becomes higher indicating opportunities for offshore wind for selling power in form of heat or hydrogen outside the electricity market.

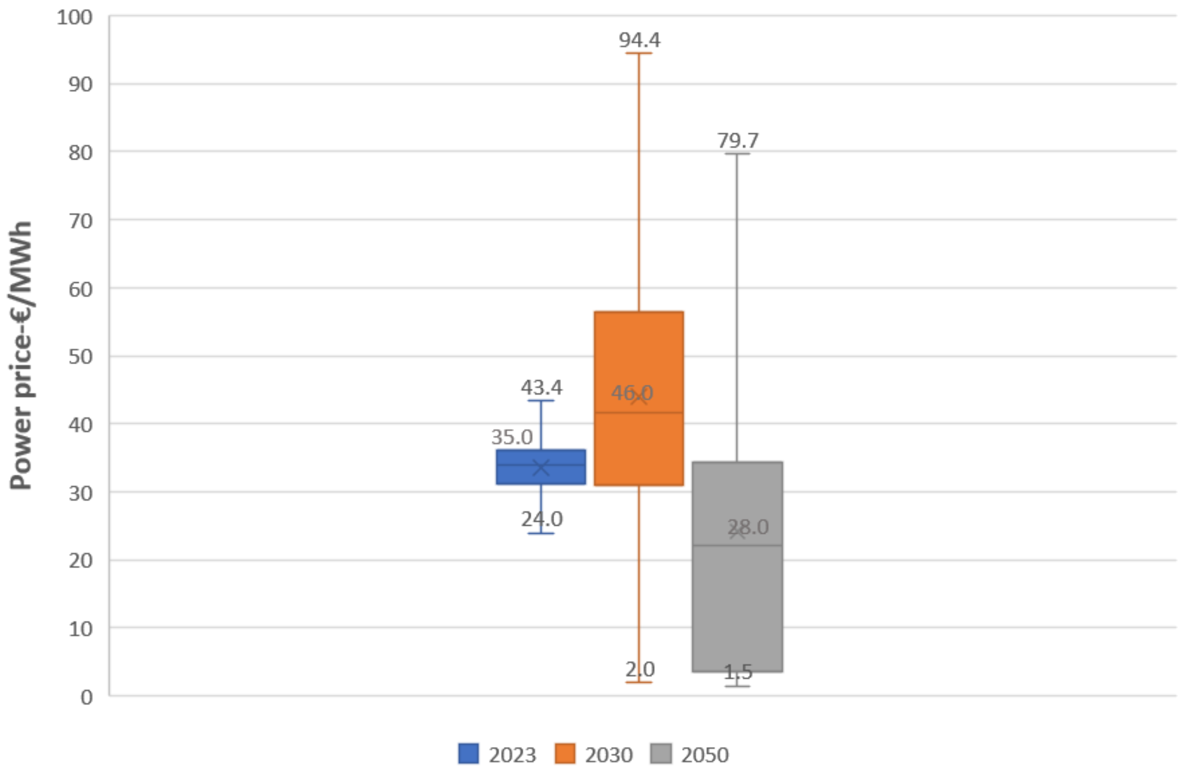



Figure 3.4: Volatility of the electricity market shown in box plot with mean power price 35 €/MWh (2023), 46 €/MWh (2030) and 28 €/MWh (2050)

It is evident from the **Figure** 3.3 that, with increased amount of renewables in the system, the market value for offshore wind is decreasing from 38 €/MWh in 2030 to 17 €/MWh in 2050. Moreover, highly fluctuating power prices are observed irrespective of the increasing electrification due to the intermittent nature of renewables. The power price ranges from 1.5 €/MWh to 125 €/MWh showing highest degree of volatility in 2050. Higher volatility in power prices creates a need for buffering electricity, increasing benefits for power to heat or power to hydrogen by storing the products at cheaper prices. The boundaries of power prices occurring in market scenarios are shown in **Figure** 3.4. The average market price determines the outlook for production of heat or hydrogen from electricity in comparison to heat production from natural gas. Higher changes in average power price by electrification from heat or hydrogen sectors will create a negative impact on the conversion technologies.

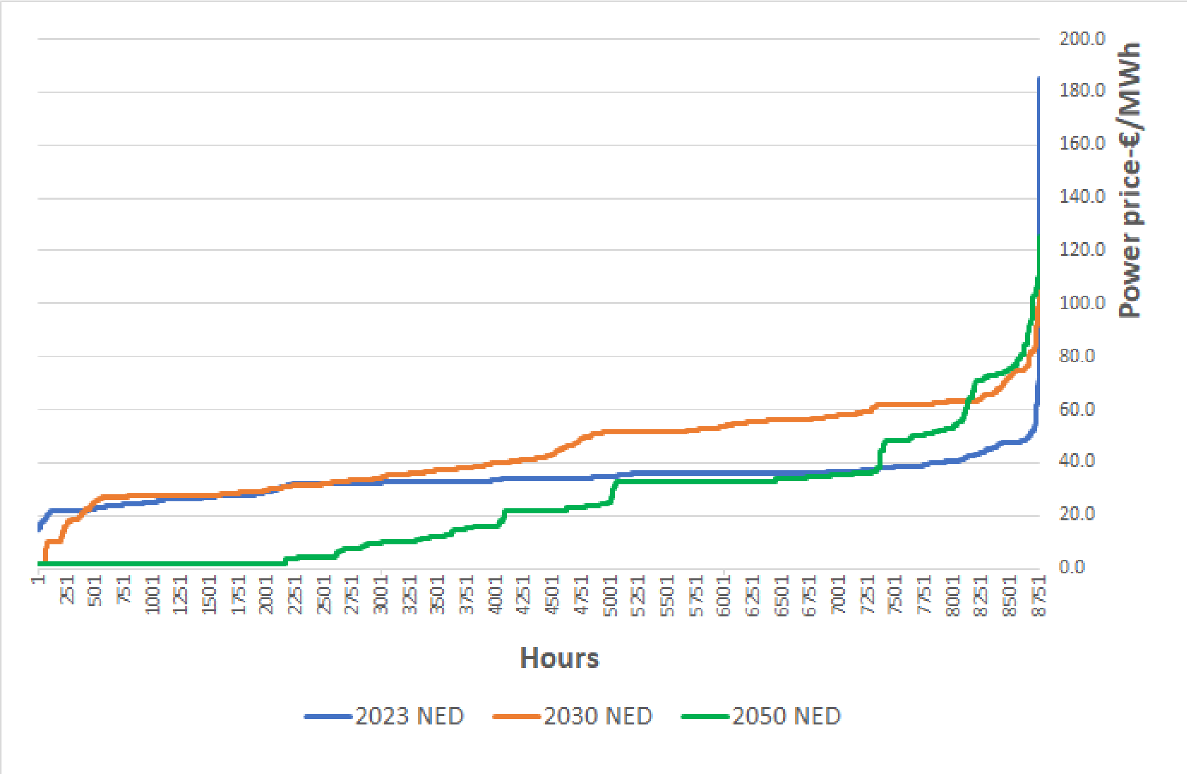
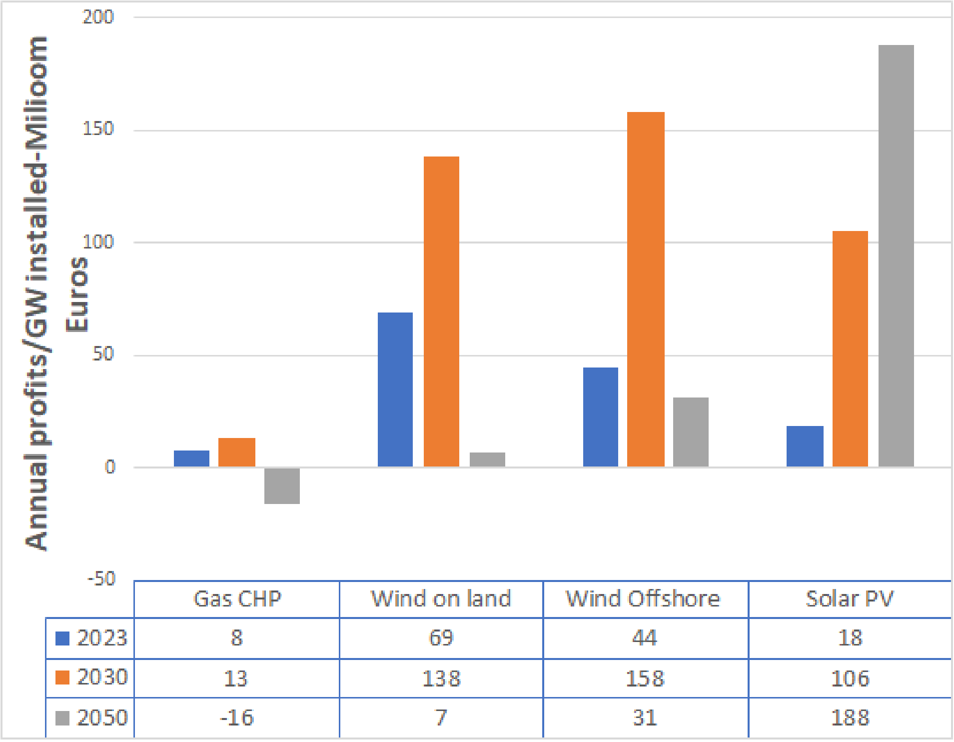



Figure 3.5: Power-duration curves for electricity markets in 2023, 2030 and 2050 showing the sorted electricity prices for 8760 hours of the year

**Figure** 3.5 shows the price-duration curves for 2023, 2030 and 2050 market scenarios. It represents the number of occurrences of certain power price in a year. It shows that in 2050, more than 2000 hours the power price is as low as 2 €/MWh. In 2023 scenario, the electricity price is less than 50 €/MWh for majority number of hours.

### 3.2.4. Profits of generation technologies

The renewable electricity share in total electricity supply mix is increasing . Thus, it is important to analyze the revenue outcomes of these suppliers. The revenues generated by offshore wind, solar PV and onshore wind are calculated separately and compared among scenarios. The hourly production from solar PV and wind are multiplied with respective power price in that hour and summed to obtain annual revenue. Profits earned through power sales is calculated by subtracting the operational costs from the sales revenues. An operational cost of 2 €/MWh is used for offshore and onshore wind. There are no operational costs for solar PV electricity considered in the model. The operational costs of combined heat and power plants (CHP) are as per the respective fuel costs in scenario years 2023, 2030 and 2050.



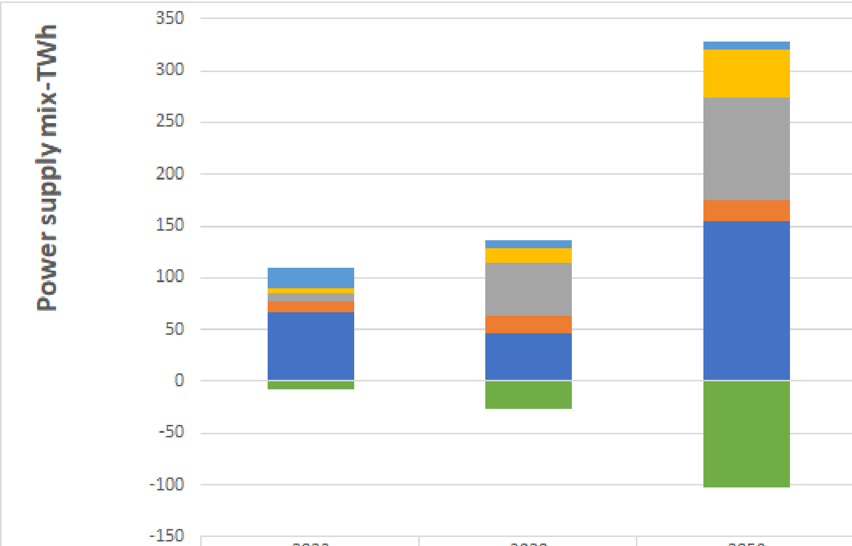

| | Gas CHP | Wind on land | Wind Offshore | Solar PV |
|---|---|---|---|---|
| 2023 | 8 | 69 | 44 | 18 |
| 2030 | 13 | 138 | 158 | 106 |
| 2050 | -16 | 7 | 31 | 188 |

Figure 3.6: The annual profits generated by offshore wind, wind on land, solar PV and CHP gas technologies per GW installed capacity in each market scenario

In **Figure** 3.6, the profits are summarized for renewables per GW installed capacity in each market scenario. A decreasing trend is observed in the profits of gas fired CHP plants. In 2050, the gas CHP plants operate with losses because of forced operation to provide heat at low power prices. In 2030, the profits for wind are better than in 2023 because of occurrence of higher power prices relatively for more number of hours than in 2050 as shown in **Figure** 3.5. Moreover, the profits for solar PV are the highest among renewables in 2050 surpassing offshore wind although its share in supply mix is less than that of the offshore wind;refer to **Figure** 3.7. It is because of two reasons: firstly, there are no operational costs considered for solar PV in the model. Secondly, there is a huge curtailment of 21 TWh of wind energy whose revenues are not be reflected in the profits for GW installed offshore wind. These lower profits for OW from electricity market show possibilities to earn incomes from other markets such as heat or hydrogen products.

### 3.2.5. Electricity supply mix and power balance

Electricity supply mix to meet the demand is noted down for each scenario from the results. The model gives a power supply mix for every hour. Nevertheless, here, the energy supplied from the most dominant technologies is presented in TWh over an year. The amount of power supply from solar PV, wind on land, wind on sea, gas plants and power trade is presented in **Figure** 3.7.




| | 2023 | 2030 | 2050 |
|---|---|---|---|
| Exports | -7 | -26 | -103 |
| Gas | 20 | 9 | 8 |
| Sun | 5 | 14 | 46 |
| Wind Offshore | 7 | 50 | 99 |
| Wind Onshore | 12 | 18 | 20 |
| Imports | 66 | 46 | 155 |

Figure 3.7: The contribution to electricity load from major generation technologies and interconnections in 2023, 2030 and 2050

As the energy content from renewables in power system is increasing, the dependence on natural gas power supply is decreasing from 20 TWh in 2023 to 8 TWh in 2050. Nevertheless, the decrease in power supply from gas plants from 9 TWh to 8 TWh is not so high compared to the increase in renewable capacity from 2030 to 2050 scenario. This is mainly because of the operation of gas plants at full capacity to balance the fluctuating renewable electricity supply in 2050 especially in times of poor VRE supply. The **Figure** 3.7 shows that exports and imports also occupy significant role in the future electricity system. In 2023, the Netherlands is a net importer of electricity, whereas in 2030 and 2050 it exports around 30 TWh and 104 TWh of electricity to neighbouring countries due to the interconnection additions and cheap renewable electricity. Moreover, these increasing numbers for international trade show higher possibilities for domestic electrification of heat or hydrogen sector with improved utilization of interconnections. Further, changes in these quantities of power supply mix from electrification of heat or hydrogen sectors will provide insights about whether investments should be considered in expanding generation or transmission infrastructure.

There is another interesting result from COMPETES to indicate reliability of the power system. When the available generation capacity along with supply from interconnection is not sufficient to meet load, there is a price assigned in the power system for this un-served load represented by VOLL (Value of Lost Load). In that particular hour, certain amount of power demand is unmet representing a black out period. Thus, this parameter indicates whether the designed power power system can take the additional electrification loads from heat or hydrogen sectors. This result is noted for each scenario and used for further analysis in **Chapter** 7. In 2023, there is one hour of unmet load of 186 MWh because of low renewable supply from wind and solar PV. Similarly, for 2030 scenario, there is an unmet demand of 0.045 GWh for one hour in the year during night time accompanied by low wind. However, there is an unmet demand for 5 hours in 2050 summing to 3040 MWh especially arising from low domestic supply whereas the imports from interconnections are used in full capacity. This unmet load observed in each scenario is mainly because of the removal of coal plants from the first stage investment decisions of COMPETES model.90

# 4

# OUTLOOK FOR HEAT AND HYDROGEN

This chapter establishes outlook for heat and hydrogen demands for the country in the scenario years 2023, 2030 and 2050. The electrification potential of heating sector in the district heat network and low temperature heat needs of the industry is estimated and the procedure for modelling hourly heat demands of the respective consumers is detailed in **Sections** 4.1.2 and 4.1.3. **Section** 4.2 provides a detailed projection of the hydrogen demand in 2050. A brief procedure for hydrogen demand estimations for the transition scenario years is given and the characteristics of hourly hydrogen demand is discussed in this section.

## 4.1. POWER TO HEAT POTENTIAL

### 4.1.1. Low temperature heat demand up to 200°

In the Netherlands, heat is a major part of energy consumption derived from diverse sources especially natural gas. The total heat demand of the country is about 316 TWh/y. A major portion of this demand involves low temperature heat, meaning up to 200° C. The share of heat utilization per sector in 2016 is shown in **Figure** 4.1 .

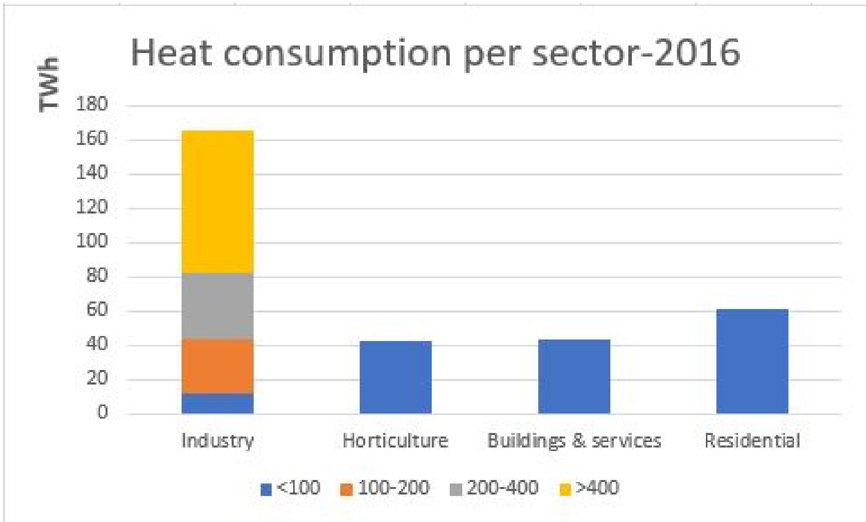



Figure 4.1: The final heat consumption per sector at different temperature levels in the Netherlands in 2016 [36]

The residential space heating, agriculture and commercial services fall under low temperature category which is about 50% of the total heat demand. This heat demand of 158 TWh is considered as preliminary potential for electrification because of the availability of power to heat technology limited to low temperatures up to 200° C. CHPs and natural gas boilers are common sources to provide low temperature heat in the Netherlands [36]. There are two types of CHP plants: decentralized for the heat requirements in glass house cultivation and the other industrial local needs and centralized CHP for power generation accompanied with heat to heat networks supplying for space heating and industries. CHP is an interesting option for low temperature heat production in terms of economics, particularly because of its high overall efficiency considering the electricity and heat outputs [38]. Since electric boilers can produce heat up to 200° C, these CHP plants could be replaced by electric boilers, showing the potential for electrification. However, only the space heating residential heat networks and process industry sector supplied by CHP plants are explored further to define actual potential for power to heat analysis because these heat users already have connections to electricity grid, whereas horticulture industry is more connected to gas grid.

### 4.1.2. Residential district heat demand

The heat for space heating, hot water in residential areas and public service buildings is usually provided by natural gas boilers on one hand and the district heating networks on the other. About 2 GW of natural gas CHP plants provide heat to the district heat network in the Netherlands whereas the rest is from residual waste heat from industries [38]. About 5-10% of the heat demand of the residential and public services together is provided by district heating. Thus, the energy provided for city heating by the CHP plants through district heating (DH) networks is estimated as 6.25 TWh/year. The correlation of high district heat demands in the winter to the high wind energy production is advantageous for integration. In addition, the flexible operation of electric boilers enables their integration into the district heat networks in times of high wind power. However, the ability to switch depends on the threshold for the electricity price. The electricity price shall be lower than gas price for heating including the $CO_2$ price associated with gas usage to replace them with electric boilers.

**Approach for modelling residential district heat (DH) demand:** For modelling the hourly heat demand of the district heating sector, the real time heat supply to the city heating network in the region Enschede in the Netherlands for the years 2015-2017 is collected by request to Twence. The main source of heat to this network is a biomass fired CHP plant. The high temperature steam produced by biomass boilers is converted to electricity and the low pressure steam extracted from turbine is used for district heat supply. This is a typical operation of any CHP plant to supply the exhaust steam from turbine in form of heat. The heat demand data is normalised to obtain a profile representing a pattern of heat load for residential purposes. It is observed that the residential heat requirements are naturally seasonal dependent with peak demands in winter. However, space heating needs are also highly dependent on the external temperatures. The temperature in Eschede may not be similar to that in Amsterdam or Utrecht. Nevertheless, the temperature effects on heat demand are neglected in the thesis.

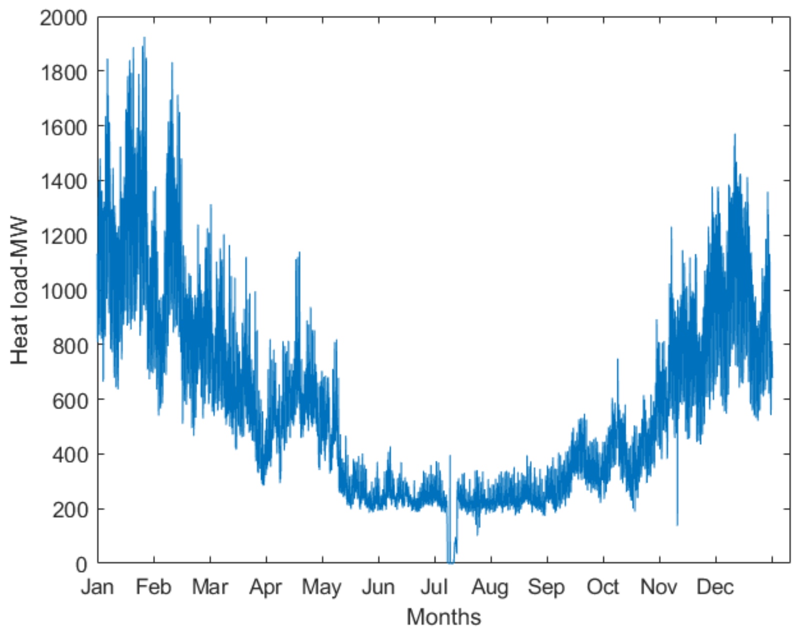



Figure 4.2: The hourly heat demand of the district heat networks in the Netherlands modelled from historical data 2016

Hence, the overall hourly energy demand for household heating through DH networks is obtained by multiplying the heating load of 6.25 TWh provided by gas CHP plants with the hourly normalized profile, without any temperature dependant modifications. The energy savings that arise from increased insulation is disregarded because the district heat networks are mostly connected to new constructions which are designed with better insulation. The hourly modelled heat demand for residential DH networks for the entire country is presented in **Figure** 4.2. More district heat networks might emerge in the transition years. However, the potential for power to residential district heat networks is assumed same for scenario years 2023, 2030 and 2050 as 6.25 TWh.

### 4.1.3. Industrial low temperature heat demand

Manufacturing Industry is another major consumer for heat accounting for 38% of the country's total heat demand as represented in **Figure** 4.1. The various levels of temperature demand in the Dutch process industry are shown in **Table** 4.1. As the industrial infrastructure in the Netherlands has not changed since 2016, it is assumed these figures also represent the present needs of heat in the industry. Approximately 4 GW of industrial CHP is installed to supply heat up to 250° C [38]. Due to the intensive capital investments and technical difficulties, CHP is not suitable for high temperature process heat. Instead, direct thermal conversion of fossil fuels like coal, oil and natural gas to heat is deployed [38]. This demand for high temperature heat cannot be met by electrification with current technologies. About 55 TWh of low temperature heat is required by the industry as demonstrated in **Table** 4.1. This heat is for low-temperature process purposes up to 200° C. With the assumption that this heat is provided by the full load operation of CHP installations throughout the year, a capacity of 6 GW is required. The gap between the CHP installation capacities could be because some portion of the heat is from the byproduct waste heat of other processes. This indicates that only 75-80% of the CHP installations can be fitted with electric boilers.

Table 4.1: The heat demand of Dutch manufacturing industry categorised at different temperature levels [20] [19]

| **Sector** | **Unit** | **<100** | **100-200** | **200-400** | **>400** | **Total** |
|---|---|---|---|---|---|---|
| Food and processing | PJ | 35 | 29 | 0 | 0 | 64 |
| Basic Metal | PJ | 3 | 4 | 0 | 74 | 81 |
| Chemicals | PJ | 0 | 80 | 45 | 100 | 224 |
| Paper | PJ | 1 | 13 | 1 | 0 | 14 |
| Other metals | PJ | 0 | 0 | 0 | 12 | 12 |
| Textile | PJ | 1 | 1 | 0 | 0 | 17 |
| Other industries | PJ | 1 | 1 | 0 | 0 | 2 |
| Refineries | PJ | 3 | 3 | 1 | 2 | 9 |
| **Total** | PJ | 42 | 151 | 153 | 219 | 567 |

**Approach for modelling hourly industrial heat demand:** A bottom-up approach is adopted to prepare hourly demand of low-temperature heat in the industry. The heat produced by natural gas operated CHP is assumed to be the source for low temperature heat for industrial sector. The current data of natural gas supply to industries is collected from the national gas transport services for the year 2016 [40]. The hourly natural gas supply is represented with ng(t). Out of the total supply of natural gas to process industry, only 35% of the energy content is utilized for low-temperature heat needs [32]. Thus, only 35% of the hourly natural gas consumption of industry is used to calculate the production of heat from CHP plants. A thermal efficiency of 40% is considered for the production of heat from CHP plants ($\eta_{CHP}$) [32]. In this approach, it is assumed that the low temperature heat demands for the process industry follow similar distribution to that of the gas consumption by the firms. Thus, hourly heat demand series Ind(t)for industry is formulated as per **Eq** 4.1.

$$Ind(t) = ng(t) * .0.35 * \eta_{CHP} \tag{4.1}$$

It is observed from **Figure** 4.3 that industrial natural gas consumption and thus the heat demand is constant and continuous based on the operation of a typical manufacturing industry. However, there is a weekly pattern observed from the nature of operation of food industry and a decrease in consumption during summer due to the firms not functioning. For the most energy intensive industries like chemicals, iron and steel, the heat demands are almost stable but major chunk of it is for high temperature levels. The hourly heat demand of 80 PJ for chemical industry is also part of the demand shown in **Table** 4.1. Nevertheless, the modelled heat demand profile is matching more with the operational nature of a food and processing industry.

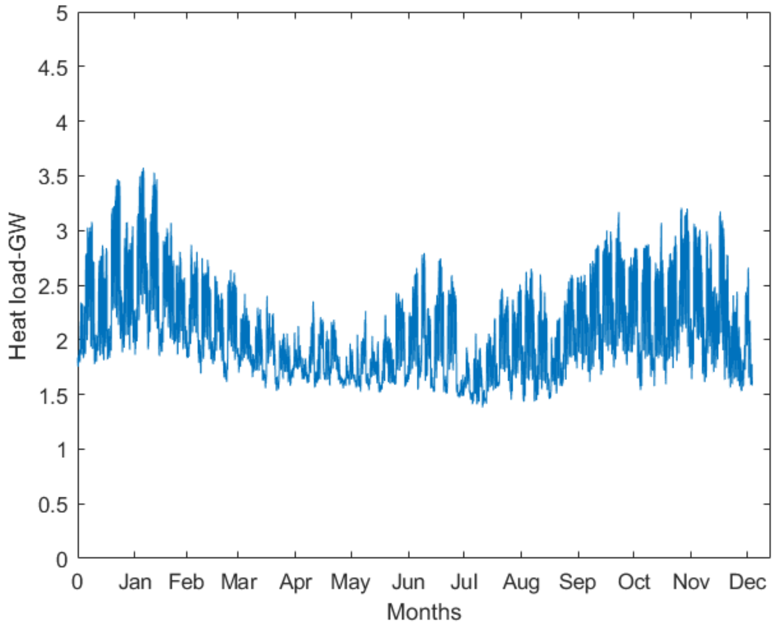



Figure 4.3: The hourly heat demand of the industry sector in the Netherlands modelled from the natural gas consumption data in 2016 [40]

Hence, a total annual load of 18.6 TWh is obtained as potential electrification for industry heat. As the electric boilers can provide temperatures till level of 250° C, the potential derived above is conservative. Nevertheless, it is assumed that this heat demand does not increase in transition scenario years because of the efficiency improvements expected in industries to meet emission targets. Moreover, an optimistic assumption that the operation of industries mentioned in **Table** 4.1 remains same without any further developments is applicable. Thus, this assessed annual heat demand for industry and modelled profile will be applicable for 2023, 2030 and 2050 for further economic assessment in **Chapter** 5.

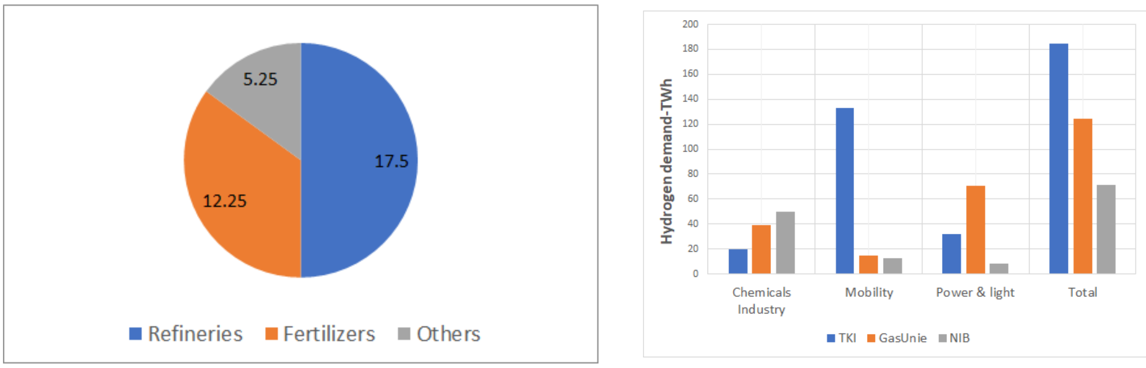
## 4.2. HYDROGEN DEMAND

### 4.2.1. Current

The hydrogen molecule is widely used as feedstock for the production of ammonia and methanol. Hence, it falls under non-energy related use. The Netherlands is the second largest producer of hydrogen with 35 TWh energy content. Most of the hydrogen is produced at the location of demand. In the Netherlands, this demand is concentrated at the industrial zones of refineries (Ijmuiden, Rotterdam Port, Vlissingen, 50%) and fertilizers (Geleen, Delfzijl, 35%) [21]. At the moment, the entire production is from steam methane reforming technology using natural gas as primary feedstock. In addition, because these reformer industries operate at a capacity factor more than 90%, the hydrogen demand is characterised by the production. Current demand for hydrogen in the Netherlands is negligible in comparison to the total electricity, heat or natural gas consumption. However, the demand for green hydrogen is evolving with the decreasing costs of renewable electricity and decarbonization goals of the industrial sector.

### 4.2.2. Future

Research centres in the Netherlands have projected the demand for hydrogen in 2050 through diverse methods ranging from scenario analysis to setting road maps. Especially, the conclusions from Top Sector Energy [22], Northern Innovation Board (NIB) [23] and Gasunie [21] are compared and analyzed to frame a logical outlook for hydrogen demand. The key common sectors identified for hydrogen consumption are as follows:




(a) Current 2016

(b) Future 2050

Figure 4.4: Hydrogen demand in 2016 in TWh and projections for the hydrogen demand in 2050 for industry, transport and power sectors from market study

**Non-energy Use :** The current dominant method of using hydrogen in the manufacturing process of chemical compounds is estimated to increase. Especially, power to hydrogen emerges in industry to eliminate the $'C'$ (carbon) component in the process chain. As the northern Netherlands is seeing a decline in gas production from Groningen gas fields, NIB estimates huge potential for hydrogen use in the Northern Netherlands. Hydrogen is an important by-product in steel making. The coke oven gas used in the blast furnace for reduction of iron ore comprises of 60% hydrogen. Currently, companies like TATA steel separate the hydrogen and sell it to hydrogen market. Nevertheless, hydrogen can also be used as a feedstock for sustainable production of steel. A pilot project by Hybrit in Sweden aims to produce fossil-free steel by reducing the iron ore with hydrogen. As the Netherlands produces about 20% of the global steel market share. In order to convert the steel production in the Netherlands to carbon-free by 2050, 1 ton of steel making would require 75 kgs of hydrogen creating an additional demand of 21 TWh for hydrogen [24][22].

**Heating :** The heating sector is another major consumer of natural gas as discussed in **section** 4.1. The low-temperature space heat is most likely to be served by heat-pumps and electric boilers will substitute the low-temperature needs of industry. However, the industrial heat needs which falls under the temperature category above 250° C are expected to require 28 TWh of renewable heat from hydrogen [22].

**Mobility :** The market for transportation is already diverse with liquid fuels, hybrid vehicles, battery electric vehicles (BEV) and fuel cell cars. The rail transport in the Netherlands admits that it completely runs on green electricity. The country has plans to ban diesel vehicles beyond 2030. The scenarios proposed by Gasunie postulate 75% of the road transport to be electric and the remaining would be hydrogen fuel cell cars. Already, heavy duty vehicles such as municipality vans and city buses run on hydrogen fuel.

The studies assessed a demand of 14 TWh for the road transport in 2050 [21]. However, the fuels for sea and air freight cannot be neglected. The marine industry can be operated with ammonia as fuel in the existing internal combustion (IC) engines. The above studies have not considered the air and water transport system. In this thesis, 50-50% share for bio based vs hydrogen based synthetic fuels is added to the hydrogen demand based on the local hydrogen production scenario developed by DNV-GL to assess electrical and gas infrastructure developments in 2050 [4]. Therefore, a total of 114 TWh hydrogen demand is projected for transportation needs itself.

**Power and Lighting**: Hydrogen is also projected to be part of the electricity sector. Electrolysis is fortunately bi-directional. Hydrogen can be produced from electricity through water electrolysis and hydrogen in a fuel cell generates electricity. However, this route for electricity production is not efficient if hydrogen is produced from electricity [22]. The round-trip efficiency is currently 37% [25]. Nevertheless, power plants like Nuon Magnum constructed a future proof gas plant that can run on multiple type of fuels. It envisages to combust green hydrogen in the close cycle gas turbine to provide flexible power supply to the grid by 2023 [23]. This will develop an interesting market for hydrogen in the power sector. Thus, the studies estimate a demand of 70 TWh hydrogen for electricity industry by 2050 for grid balancing purposes.

In **Figure** 4.4b, a comparison of the hydrogen demand for different sectors from the conclusions of above mentioned studies is shown. Although the projections for hydrogen market in 2050 have different outcomes for various applications, it is very clear that the market for renewable hydrogen is vast. The estimations from Gasunie and NIB are less than those of TKI because they have not included the sustainable fuel requirements for aviation and shipping industry.

In literature, power to hydrogen projects are correlated to the potential of solar PV and wind across the globe. It is evident from the development plans in the Netherlands that wind power will be a promising potential supplier for hydrogen production. Thus, the demand for hydrogen for the years 2023 and 2030 is estimated by interpolating in between the current hydrogen demand in 2017 and 2050 projected demand. The interpolation follows a similar growth rate as of the development of offshore wind in the scenarios. Therefore energy numbers for hydrogen demand for the scenario years 2023, 2030 and 2050 are shown in **Figure** 4.5.

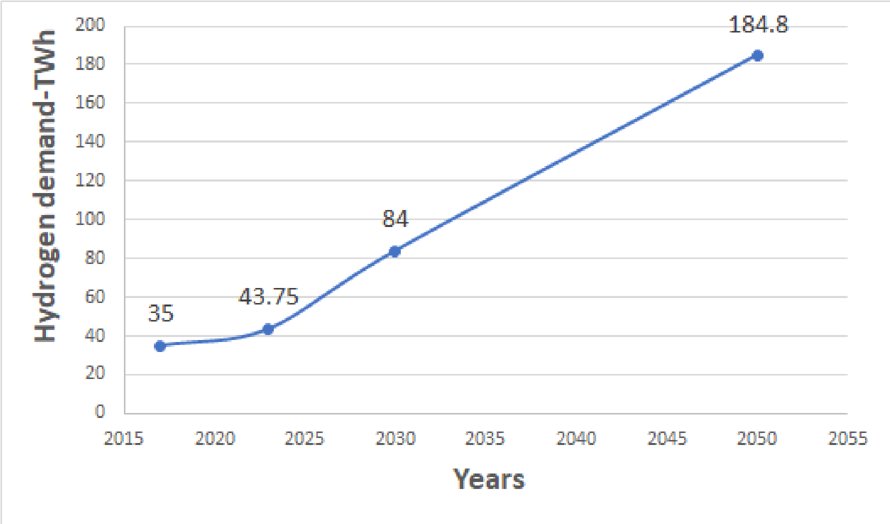



Figure 4.5: Estimated hydrogen demand projections for the Netherlands in the years 2023, 2030 and 2050

However, the realization of the hydrogen production from electricity shall be assessed in terms of the available electricity potential. The demand in each scenario is divided by 8760 to obtain an hourly demand for hydrogen. This will create approximately an extra electricity capacity of 5 GW in 2023, 9.6 GW in 2030 and 21 GW in 2050 if producing hydrogen from electricity is economical in respective scenarios.

## 4.3. SUMMARY

In this chapter, technical potential for electrification of heat in residential heat networks and industry heat is assessed. A technical power to heat potential of 6.25 TWh is observed in residential DH system. Out of 55 TWh, 18.6 TWh of industrial heat is identifies to be electrified. The modelled heat demands in this chapter serve as input for economic assessment in **Section** 5.3. Similarly, a potential demand for hydrogen has been framed through market study. Different levels of hydrogen demand is anticipated in the energy market for the transition years 2023, 2030 and 2050. An optimistic hydrogen demand of 44 TWh in 2023, 84 TWh in 2030 and 184 TWh in 2050 is attained. The summary of the heat and hydrogen demand to be analyzed per each market scenario is provided in **Table** 4.2.

Table 4.2: The estimated potential for power to heat and power to hydrogen in the Netherlands for the transition scenarios 2023, 2030 and 2050

| Scenario/Sector | Residential DH[TWh] | Industry low-temperature heat[TWh] | Hydrogen[TWh] |
|---|---|---|---|
| 2023 | 6.25 | 18.6 | 34 |
| 2030 | 6.25 | 18.6 | 64 |
| 2050 | 6.25 | 18.6 | 140 |

# 5

# POWER TO HEAT SYSTEM

The main objective of this chapter is to create a model to assess the technical and economic behaviour of power to heat systems. First, in **Section** 5.1, a preliminary assessment is presented to show the need for analyzing economic potential for electrification of heating sector. In **Section** 5.2, a definition for power to heat system is provided with supporting arguments for selection of components of power to heat system. A detailed description of the model is given in **Section** 5.3 explaining the parameters used and constraints of the model. Finally, in **Section** 5.4, the model is applied to two kinds of heat load in the Netherlands namely residential district heat and industrial heat. The model results containing costs of power to heat systems and the capacity values of heat production components for the power system scenarios 2023, 2030 and 2050 are discussed in **Section** 5.5. Further, this chapter determines the additional load from heat sector to power systems for the following analysis.

## 5.1. ASSESSMENT OF TIPPING PRICE

In the previous chapters, characteristics of power system and the market for low temperature heat for the Netherlands are defined. It is observed that, with increasing renewables in the system, the business case for gas CHP plants is deteriorating as shown in **Figure** 3.6. Hence, the trend to supply low temperature heat through gas CHP plants will slowly decrease. Moreover, electrification of heating helps industrial sector achieve the goal of decarbonisation. The low power prices due to renewables in the electricity market can further reduce the price per MWh of heat produced with electricity. A brief preliminary assessment is carried out for 2030 scenario to show when it is beneficial to provide heat with electricity over other technologies based on marginal costs alone. A detailed economically optimum system size is further determined in **Section** 5.3.

Operational costs include especially fuel costs, taxes, tariffs and the $CO_2$ prices to provide heat. Capital investment costs and number of operational hours of the technologies are neglected in this assessment. Three technologies, to supply heat namely electric boilers, gas boilers and CHP gas plants are compared. The next paragraphs discuss the marginal cost components of providing heat with the three technologies.

**Fuel Tax:** Consumption of electricity is subject to a tax in the Netherlands. Different levels of tax are collected based on the amount of electricity usage. For calculations, the current tax value of 0.57€/MWh is assumed for production of heat from electricity. In case of a CHP plant providing electricity and heat, tax on the fuel is exempted. If gas is used only for proving heat, energy tax of 0.01265€/m3 is applicable for large scale consumers. The fuel tax for direct gas heating in gas boilers to provide heat arrives at 1.3 €/MWh with an energy content of 0.001 MWh per m3 of natural gas [18]. District heat providers also come under industrial scale consumers. Further, additional cost for electricity is collected in terms of network tariff and the components of network tariff are explained below.

**Network Tariff:** The transport tariff for electricity consumed in the Netherlands contains a fixed fee and a variable fee based on the energy consumed apart from the electricity tax. If the actual volume consumed exceeds the contracted peak load capacity, additional charges are imposed. On the other hand, distribution tariffs are also applicable depending on how far the costumer is located from the centres. Finally, the energy part of bill depends on the number of hours of utilization of the connection in the year as well. Based on the tariffs calculation sheet from TenneT, high infrequent consumption of electricity costs in between 10 €/MWh - 30 €/MWh inclusive of all the terms indicated above [32]. Thus, an optimistic network tariff of 10 €/MWh is assumed in this assessment for heat production from electricity.

**Maintenance costs:** Variable operation and maintenance costs per MWh heat are also included in the estimation of marginal costs for heating with electric boilers and gas boilers. Refer to **Table** 5.1. They are very low compared to the variable operational costs which mainly include fuel costs and power prices in case of power to heat. The maintenance costs correspond to existing level of technologies in the market [31].

**Fuel costs:** The electricity costs to provide heat with electric boilers depend on power price at the time of usage. The cost for gas consumption in gas fired CHP plants is calculated based on the price of commodity natural gas as assumed in the scenario years 2023, 2030 and 2050. The thermal efficiency of CHP plant range from 10 to 40%. A per unit efficiency of 0.4 is considered for CHP plants and 0.9 for gas fired boilers [31]. The total revenues of CHP plants come from sales of heat and electricity together. Impact of electricity price on the actual cost of heat production from CHP technology is shown in **Figure** 5.1. When the spot power prices are high, the cost per MWh of heat from CHP is less and vice-versa. In other words, the spot market power prices have an influence on the operation of CHP plants.

Table 5.1: Calculation of marginal costs for heat production with EB, gas fired CHP and GB including taxes and fuel costs

| €/MWh-2030 | EB | Gasfired CHP | GB |
|---|---|---|---|
| Fuel Tax | 0.57 | 0 | 1.3 |
| Network tariff | 10.0 | 0 | 0 |
| Maintenance costs | 0.5 | 0.3 | 0.5 |
| Fuel costs | power price | 87.5 | 39.0 |
| $CO_2$ costs | 0 | 3.2 | 3.2 |
| Total | 11.07 | 91.0 | 44.0 |

**$CO_2$ emission costs:** For energy production technologies in the Netherlands, a definite price per ton of $CO_2$ emitted is included while calculating final revenues. This is applicable for companies part of European Emissions Trading Scheme (ETS). In this thesis, a cost is added to the $CO_2$ emissions from the heating technologies because it is an important aspect in the energy transition period. About 0.203 ton of $CO_2$ is emitted for 1 MWh of heat production from gas [18]. Equivalent $CO_2$ emission is considered for CHP heating and gas boiler heating. An addition of $CO_2$ price for heat determines the actual value of power to heat technology. The $CO_2$ prices as assumed in the market scenarios for the years 2023, 2030 and 2050 in **Section** 3.1 are also applicable here. So, a value of 3.2 €/MWh is added as emission cost for production of heat from gas based on the $CO_2$ price of 16 €/ton assumed in 2030 scenario.

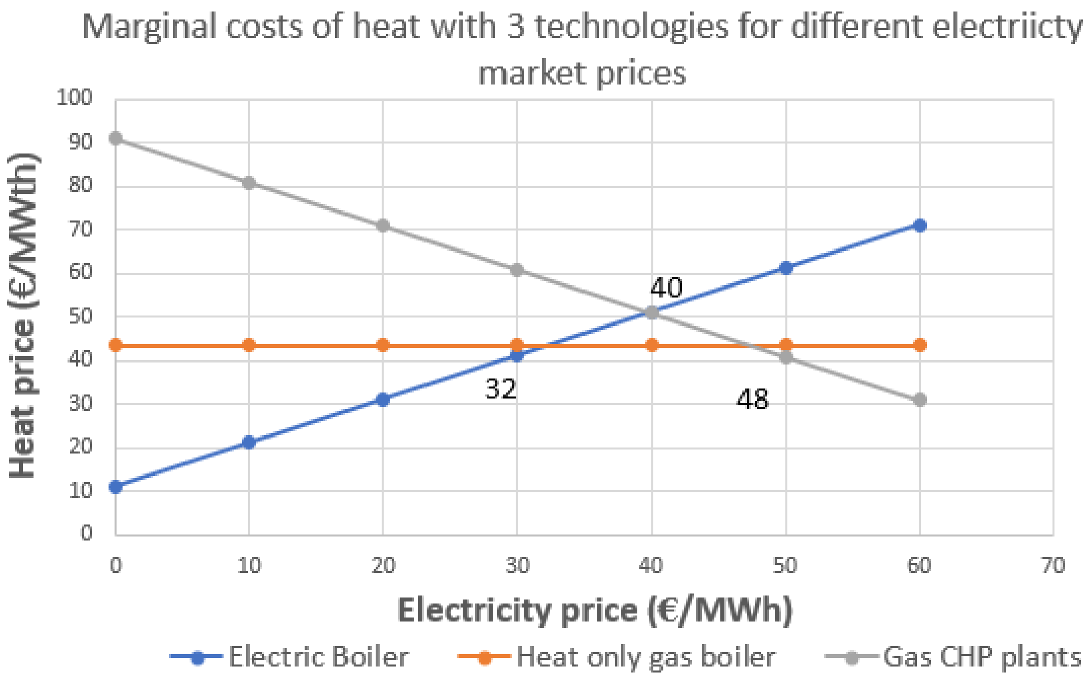



Figure 5.1: Marginal costs of providing 1 MWh heat with electric boiler, gas boiler and CHP gas plant in 2030, estimated without including capital investment costs

**Figure** 5.1 shows marginal costs of heat production from three competing technologies at various possible power prices in a virtual electricity spot market. Electric boilers have high marginal costs for heat at higher power prices. For power prices less than 40 €/MWh, it is more economical to operate electric boilers than a gas CHP plant for providing heat. In comparison with gas boilers, marginal costs for electric boiler heat production breaks-even at a power price of 32 €/MWh. This means, as long as the price for electricity is equal or less than 32 €/MWh, it is profitable to produce heat with electricity.

It is also evident from the graph that at higher electricity prices, CHP plants make higher sales from electricity and heat together. In general, gas boilers are available at CHP plants to provide peak-heat loads [33]. However, in future they might operate most of the time as the prices are less likely to be so high as required for economic operation of CHP plants. So, only beyond a power price of 48 €/MWh, it is profitable to use CHP in place of heat only boilers.

Thus, by analyzing the price duration curve of 2030 market scenario **Figure** 3.5, about 2500 hours in the year, power price is less than 32 €/MWh demonstrating it is beneficial to produce heat with electricity compared to gas marginally. Thus, the business case of power to heat might be economical when there are more number of operational hours of electric boilers with low power price hours. 2030 scenario has high average power price. However, there are still reasonable amount of hours below 32 €/MWh. Power system in 2050 clearly has many more number of such hours and for 2023 it is very sensitive to the tipping point referring to the flat curve between 30-35 €/MWh in **Figure** 3.5. However, the investment costs play a role in taking decisions together with the operational fuel costs and $CO_2$ costs. Thus, a detailed economic analysis of the system is crucial to take decision on the design of future heating system.

## 5.2. COMPONENTS OF THE HYBRID HEAT SYSTEM

Production of heat from natural gas CHP is considered as a reference situation for the Netherlands in each scenario year 2023, 2030 and 2050. Besides natural gas, biomass could have potential economic benefits to supply the heat demands. Nevertheless, in this thesis, provision of heat is limited to direct gas fired heating and electricity. From now on, it is termed as hybrid heating system. The main components of hybrid heat system and the justifications for selection of the technologies are explained below:

### 5.2.1. Heat only boilers (Gas Boilers)

Heat only boilers are usually installed at the CHP plants in order to provide peak heat loads. The fuel in these boilers can be coal, oil or natural gas depending on the availability and costs of the system. These boilers can be utilised to transform the existing CHP plants into partially clean hybrid heat systems by up scaling the heat only gas boilers (GB) along with electrification. The gas boilers are efficient with 90% conversion rate of the high heating value of gas into heat [34].

### 5.2.2. Heat with electricity (Electric Boilers)

Heat is provided with electricity through many technologies. High voltage electric heaters are available for commercial heating applications. Heat pumps are also driven by electricity with an additional heat source like air or ground heat to provide required temperatures for house heating and hot water needs. However, the technology of heat pumps is limited to individual house heating needs rather than a centralised heat supply [33]. Moreover, capacities of heat pumps are not as high as to be installed in DH networks. Heat pumps are in general less expensive than electric boilers (EB). However, they are restricted to rather low temperatures [12]. Therefore, in this thesis, the highly efficient electric boilers with an efficiency of 99% are considered as a design choice in addition to gas boilers in the hybrid heating systems.

### 5.2.3. Thermal storage

There are different methods to store heat in form of sensible heat and latent heat. The sensible heat method will conduct heat from a high temperature source and store it with increased temperature from hours to days. Latent heat materials store energy through phase change, by solidifying while discharging and melting while charging. In district heating plants, the thermal storage is usually of the sensible heat type with hot water tanks (TES), pit thermal storage (PTS). The specific investment costs for PTS are higher than TES because of high space requirement [35]. Nevertheless, both technologies have similar capacities of supplying thermal power. In this work, thermal energy storage in form hot water tanks is assumed for the analysis.

The potential benefits of power to heat are enhanced by adding thermal energy storage to the system. First, through thermal storage, it is possible to store excess electricity in the form of heat from hours to days. It will act as a buffer to the heat and electricity system simultaneously. Furthermore, it enables to store heat at lower power prices and later to supply heat when power prices are higher (or) it is costly to supply heat with gas. This will bring additional savings on gas fuel. However, the investment cost per MWh of storage should outweigh the savings on natural gas.

## 5.3. ECONOMIC ASSESSMENT AND OPERATIONAL STRATEGY

To assess the economic feasibility of providing heat with hybrid heat system, a detailed cost optimization model is formulated . One of the objectives of this thesis is to determine the optimal size of electrification of heat in each market scenario providing flexibility to the electricity system.

The heat to be supplied is assumed same in all the scenario years 2023, 2030 and 2050. The formulated optimization problem is deterministic, it means that heat load and power prices for all the hours in a scenario year are known initially as an input. The solution to problem will provide capacity investment decisions in electric boiler, gas boiler and thermal storage units and the operation schedule for the respective units. The operational strategy of the thermal storage units is also an output of the model. The physical functional limitations of the hybrid heat system are formulated as constraints. The objective function and constraints are explained in the following subsections.

### 5.3.1. Objective function:

The objective of this optimization model is to minimise the cost of heat production from available components of hybrid heat system mentioned in **Section** 5.2. The objective function includes two terms, first one is capital investment cost of the equipment and consequent operational costs of providing heat with electric boiler or gas boiler is the second term. The capital investment (CAPEX) values for EB, GB and TES are given in **Table** 5.2. The CAPEX costs and efficiency of the 3 technologies are considered same for all scenario years 2023, 2030 and 2050. The $CO_2$ price is already included in gas price ($\lambda_g$) term in the equation 5.2. The equivalent annual capital expenditure is calculated by multiplying an annuity factor to capital investment costs. In this thesis, it is termed as capital recovery factor (CRF) represented with **Eq** 5.1.

$$Min \quad \underbrace{CRF.(C^{EB}.P^{EB} + C^{GB}.P^{GB} + C^{SOC}.E^{SOC})}_{InvestmentCosts} + \sum_{t=1}^{8760} \underbrace{(\frac{(\lambda_e(t) + \lambda_{et}).E^{eb}(t)}{\eta_{eb}} + \frac{\lambda_g.E^{gb}(t)}{\eta_{gb}})}_{OperationalCosts} \tag{5.1}$$

*Where:*
$P^{EB}$ *Capacity of electric Boiler [MW]*
$P^{GB}$ *Capacity of gas Boiler [MW]*
$E^{SOC}$ *Total capacity of heat storage [MWh]*
$E^{eb}(t)$ *Hourly heat production with electricity [MWh]*
$E^{gb}(t)$ *Hourly heat production with gas[MWh]*
$E^{soc}(t)$ *State of charge of the heat storage unit at time t [MWh]*
$\overline{C}$ *Maximum charging capacity of the heat storage [MW]*
$\overline{D}$ *Maximum discharging capacity of the heat storage [MW]*

The efficiencies of production units electric boiler, gas boiler and thermal storage are expressed in per unit values. The technical and financial parameters used as input in the model are summarized in **Table** 5.2.

Table 5.2: The units and values of important technical and financial parameters used as input to optimization model

| Parameter | Definition | Unit | Value | Reference |
|---|---|---|---|---|
| $C^{EB}$ | CAPEX of Electric Boiler | [€/MW] | 40000 | [31] |
| $C^{P^{GB}}$ | CAPEX of Gas Boiler | [€/MW] | 50000 | [31] |
| $C^{SOC}$ | CAPEX of Thermal Storage | [€/MWh] | 2000 | [31] |
| $\eta_{EB}$ | Efficiency of Electric Boiler | [p.u] | 0.99 | [31] |
| $\eta_{GB}$ | Efficiency of Gas Boiler | [p.u] | 0.90 | [31] |
| $L_{SOC}$ | Heat Storage loss | [p.u/h] | 0.00005 | [34] |
| hd(t) | Hourly heat demand | [MWh] | - | Scenario input |
| $\lambda_e$ | Hourly electricity market price | [€/MWh] | - | Simulation COMPETES output |
| $\lambda_g$ | Fuel price for gas | [€/MWh] | - | Scenario input |
| $\lambda_{et}$ | Electricity network tariff | [€/MWh] | 10 | [32] |

$$\mathrm{CRF} = \frac{(r.(1+r)^n)}{((1+r)^n - 1)} \tag{5.2}$$

Here, n is the lifetime of equipment in the hybrid heat system and r is the interest rate. An interest rate of 7% and a life time of 25 years is assumed to calculate the annuity factor for all the heat producing equipment in the hybrid heat system. CRF is multiplied with the CAPEX terms of heat production units in the objection function. The investment costs term in **Eq** 5.1 represents only the annual depreciation costs of the equipment. The hybrid heat system is not analysed over its lifetime rather the economic operational situation in a given transition year is assessed to determine the possible electrification from heat market. The operational costs include only power prices for producing required heat from electricity or fuel price for gas at a given hour of the year along with filling thermal storage if economical in that given hour. The operational costs term in **Eq** 5.1 represents a sum over one year.

### 5.3.2. Constraints

The operational and technology constraints of the hybrid heat system are explained below:

**Heat demand balance constraint:** The objective function is subject to a set of constraints. The most important heat demand balance constraint ensures that heat production from electric boiler, gas boiler and the discharge from storage shall be equal to the heat load hd(t) at a given hour and is formulated as shown in **Eq** 5.4. This contraint ensures that heat load is fulfilled completely at all periods in the year with economical dispatch of production units. The term $E^{soc}(t)$ in **Eq** 5.3 represents energy content of thermal storage at time 't' in the simulation in MWh. The difference between energy content of the storage at time 't' and 't-1' represents the amount of heat delivered by storage unit. If this difference is positive, it means the storage tanks are getting filled. Otherwise, it represents storage is discharging. Moreover, a thermal loss of 1% of the available capacity is assumed for a period of 10 days [33]. The per unit loss $L_{SOC}$ of thermal storage at an hour is calculated as $\frac{1}{100*10*24}$.

$$E^{soc}(t) - (1 - L_{SOC}).E^{soc}(t-1) - E^{eb}(t) - E^{gb}(t) = -hd(t) \qquad \forall t \tag{5.3}$$

**Capacity limitations:** The constraints in **Eq** 5.4 and **Eq** 5.5 ensure that the heat production units always operate in between their minimum and maximum capacity limits. Minimum operational limit of EB and GB are set as '0'. The maximum capacity values $P^{EB}$ and $P^{GB}$ are design variables for optimizer.

$$0 \leq E^{eb}(t) \leq P^{EB} \qquad \forall t \tag{5.4}$$

$$0 \leq E^{gb}(t) \leq P^{GB} \qquad \forall t \tag{5.5}$$

**Thermal storage constraints:** The first constraint in **Eq** 5.6 is similar to the capacity limitation of EB and GB units, but in energy terms. In addition, the difference in energy content of the storage representing charge or discharge of the storage tanks is also constrained. Not only that storage cannot contain energy higher than its maximum installed capacity at each time period, but also there is a power limit for the hot water tank storage unit. This power capacity limit represents how fast the energy can be stored in the tank. Hence, $\overline{C}$ and $\overline{D}$ has units in MW and $E^{SOC}$ has units in MWh in **Eq** 5.7. Moreover, the maximum charge and discharge thermal power capacities are assumed equal.

$$0 \leq E^{soc}(t) \leq E^{SOC} \qquad \forall t \tag{5.6}$$

$$\overline{D} \leq E^{soc}(t) - (1 - L_{SOC}).E^{soc}(t-1) \leq \overline{C} \qquad \forall t \tag{5.7}$$

$$\overline{C} = -\overline{D} \tag{5.8}$$

$$E^{SOC} = (12.\overline{C}) \tag{5.9}$$

Last constraint for thermal storage describes a physical limitation of the thermal storage technology. **Eq** 5.9 conveys that the hot water storage tank system can be filled in 12 hours at full charging capacity [37]. However, the hourly charging and discharging strategy of the thermal storage is an explicit output of the optimization problem.

$$E^{soc}(0) = E^{soc}(8760) \tag{5.10}$$

Further, a constraint is modelled to ensure the energy content in thermal storage at the beginning hour of simulation is equal to that of thermal storage content at last hour of the year. This constraint will make sure that initial storage in the system is not available at free of cost. It is represented with **Eq** 5.10. In addition to the constraints explained in above equations, certain logical constraints are endogenous to the model such as: 1) A heat production unit cannot be on and off at the same time. 2) The thermal energy storage is not charged and discharged simultaneously. The "$\forall t$" term in the equations represents that the constraints are valid during all time periods in the simulation.

## 5.4. OPTIMIZATION RESULTS AND ANALYSIS

The optimization problem is implemented in MATLAB 8.0. The problem is solved for a year in time steps of hours. The optimiser uses simplex method inbuilt in MATLAB. The optimization model is applied to heat demand case of the Netherlands modelled in **Section** 4.1.

### 5.4.1. Residential district heat

The hourly residential district heat demand modelled in **Section** 4.1.2 and the underlying cost parameters mentioned in **Table** 5.2 for each scenario are given as input to the model. The hourly power price term is derived from electricity market simulations in **Section** 3.2. The model is run for 8760 hours to obtain optimum investment decision on the capacities of heat production technologies and the hourly dispatch of these units.

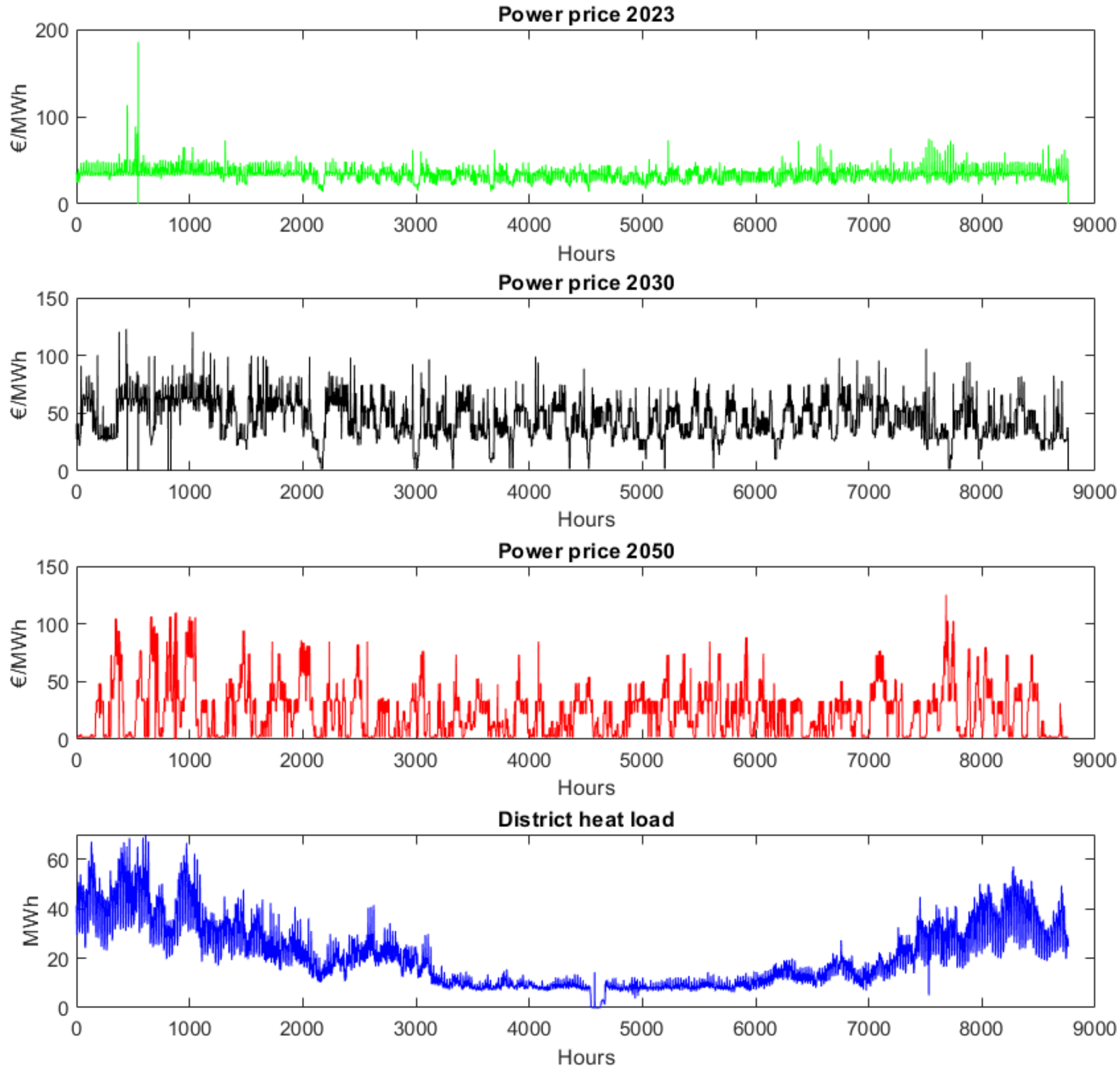



Figure 5.2: Hourly power prices from the electricity market simulations in 2023, 2030 and 2050

At first, hourly power prices in scenarios 2023, 2030 and 2050 along with the residential heat demand are plotted in **Figure** 5.2 to observe for any similarities in the pattern of heat load and power prices. There is not any striking similarity in the patterns. However, the power prices in general are highly fluctuating in 2050 and the profile effect of wind is clearly seen in winter in power prices.

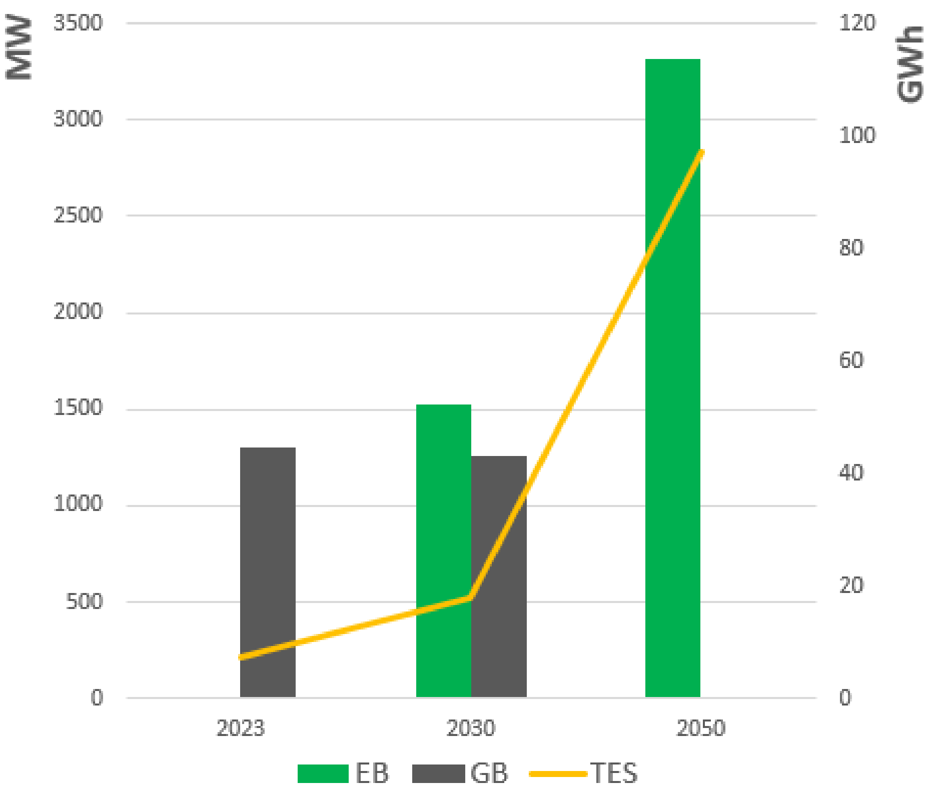



Figure 5.3: The capacity of EB, GB in MW and TES in GWh to meet annual residential district heat load in scenario years 2023, 2030 and 2050

**Figure** 5.3 shows the capacity investments in EB, GB and TES obtained from the optimization problem for scenarios 2023, 2030 and 2050. A GB capacity of 1.4 GW is required in 2023 whereas it reduced to 1.2 GW in 2030 to completely zero in 2050. An increasing size of storage from 7 GWh to 97 GWh is observed clarifying the use of the high power price volatility in 2050. Higher capacities of EB, GB and TES are required in 2030 because of relatively less number of low price hours along with higher prices for fuel. Although GB is not used in full capacity during summer time, **Figure** 5.4 shows gas costs are dominant in total hybrid heat system costs irrespective of electricity and network tariff costs together. In 2030, TES is used at full capacity for longer hours because EB and GB are simultaneously competitive to feed the thermal storage. Moreover, the difference between average cost of heat from electricity and average cost of heat from gas is less in 2030 than in 2050.

A higher capacity value of 3.4 GW is obtained for EB and 97 GWh TES to make use of the low power prices in scenario 2050. Although the system is completely running on electricity, the network tariff costs are two times that of actual electricity bill. A clear transition is observed in heating sector from natural gas in 2023 to full electrification in 2050 as shown in **Figure** 5.3. In order to improve the profitability of hybrid heat system, the network tariff should be lowered. Further, the increased storage capacity in 2050 represents higher scope for flexibility to the power system. It can also reduce the curtailment of renewable electricity. Moreover, partial investments in EB in 2030 are profitable in long term considering the positive low price trend seen for electricity from 2030 to 2050.

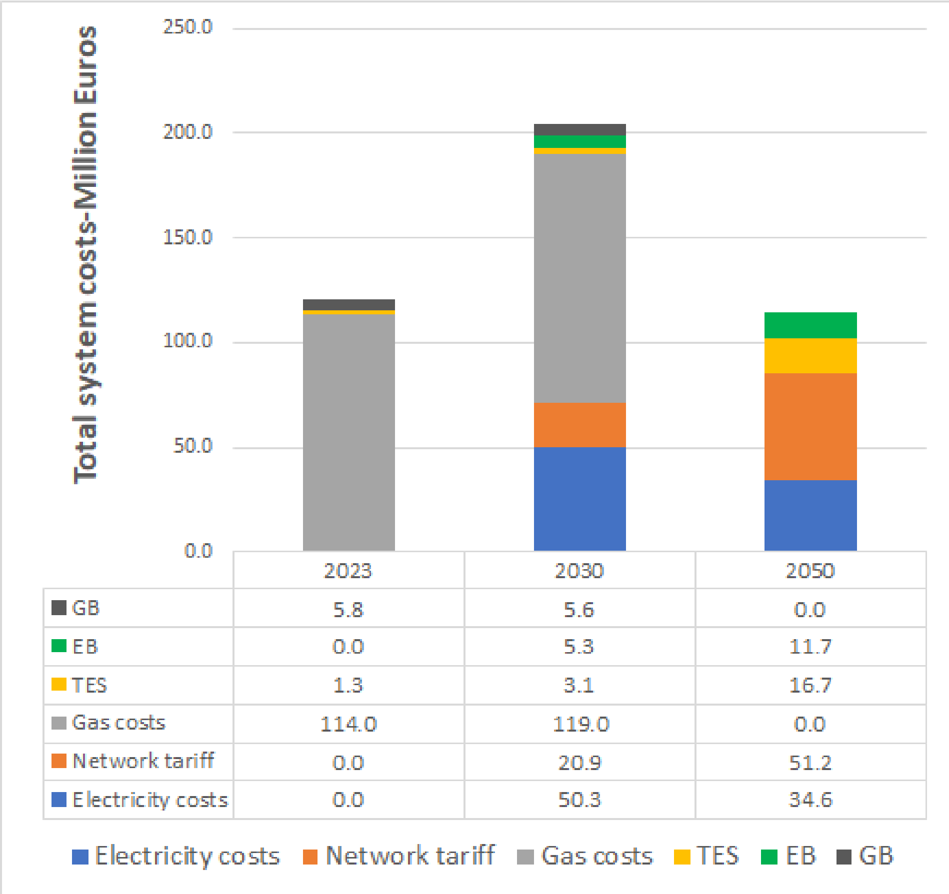



Figure 5.4: The hybrid heat system costs to supply residential district heat in 2023, 2030 and 2050, EB, GB and TES representing annual capital depreciation costs and others are annual operational costs

**Figure** 5.4 presents costs for residential district heat production with hybrid heat system calculated by the optimization model. The costs of heat production are 121 million euros comprising of CAPEX investment and operational costs in 2023. These costs also include the costs for filling storage to maintain the capacity same at beginning and end of the year. The heating system in 2030 is costlier than in 2023 and 2050 because of higher natural gas price and power prices together. Further, about 60% of the system costs in 2030 still involve gas costs. It is evident that, in 2050, it is economical to completely shift to electric heating irrespective of high network tariff costs. Nevertheless, the total hybrid heat system cost in 2050 is less than in 2030 because of the fact that lower operational costs in 2050 have surpassed the higher investment cost for EB and TES capacity together.

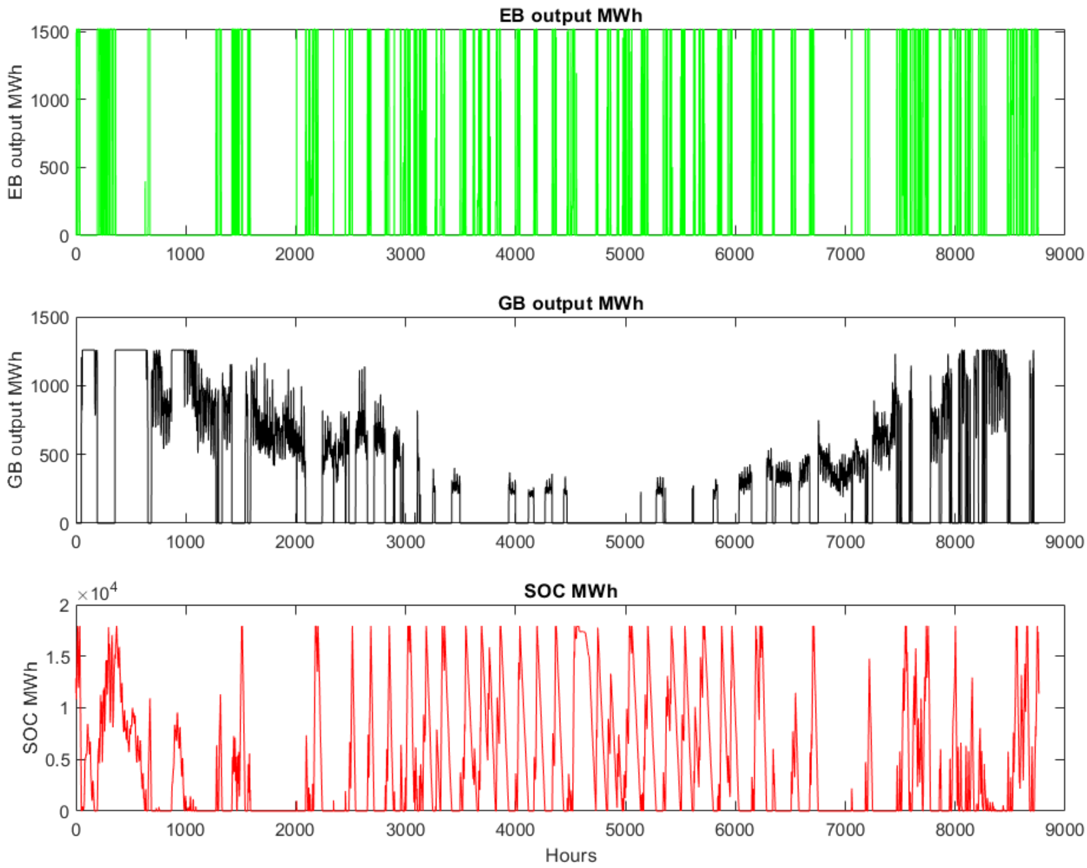



Figure 5.5: Hourly operation of hybrid heat system in 2030 for residential district heat case

With reference to **Figure** 5.5, the district heat system in 2030 is provided with 59% natural gas and 41% electricity. In winter, it is seen optimal to provide heat with GB, because of high power prices. A higher capacity for EB is required to make maximum use of cheaper prices for 2500 hours in the year. Storage is more frequently used in summer than in winter. To conclude, this hybrid heat system will add a peak load of 1500 MW to electricity demand and an annual electricity consumption of 2 TWh in 2030.

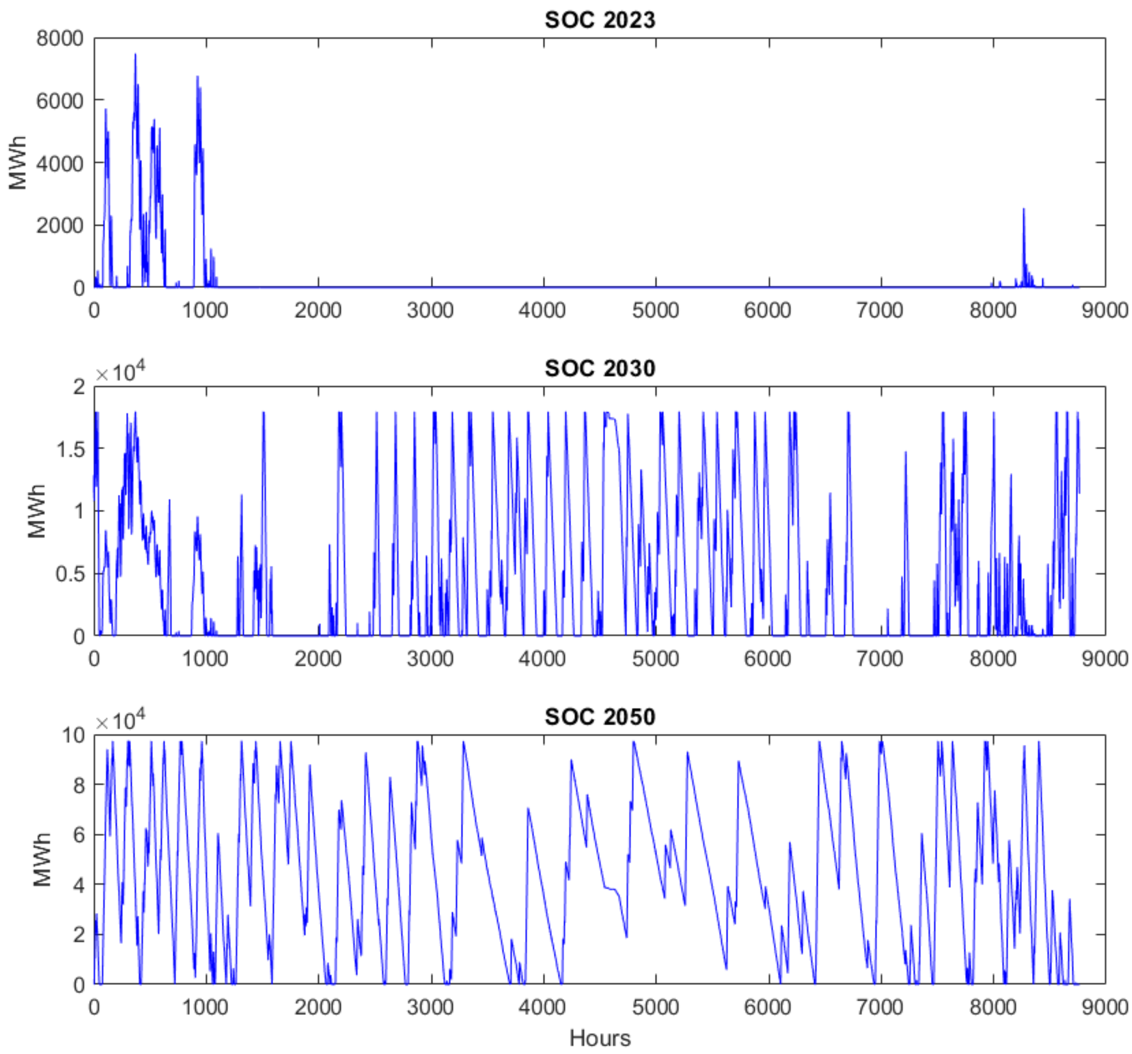



Figure 5.6: The charge and discharge cycles of TES for residential district heat case in market scenarios 2023 (Max 7.5GWh), 2030 (Max 18GWh) and 2050 (Max 97 GWh)

With reference to **Figure** 5.3, in 2023 the EB capacity is 0 and in 2050 the GB capacity is 0. The hybrid heat system relies on the remaining counter components to meet the heat load. However, a value for TES is part of solution in all market scenarios due to its low investment costs. Thus, utilization of TES has been evaluated. **Figure** 5.6 shows that, the TES unit is barely used in 2023 and is moderately used in 2050 in comparison with 2030 scenario. A lesser capacity and utilization of storage in 2023 is due to the low constant price for natural gas making the GB itself sufficient to serve almost all the heat load. GB size '$P^{GB}$' could have been higher enough to meet the peak demand in winter, however, the outcome of optimization shows that a small capacity of TES is preferred over the investment cost per MW addition of GB. Thus, a small amount of thermal storage 7.5 GWh is obtained rather than going for a larger GB.

### 5.4.2. Industry heat

**Figure** 5.7 presents the results of optimization problem for EB, GB and TES capacities for industry heat case.

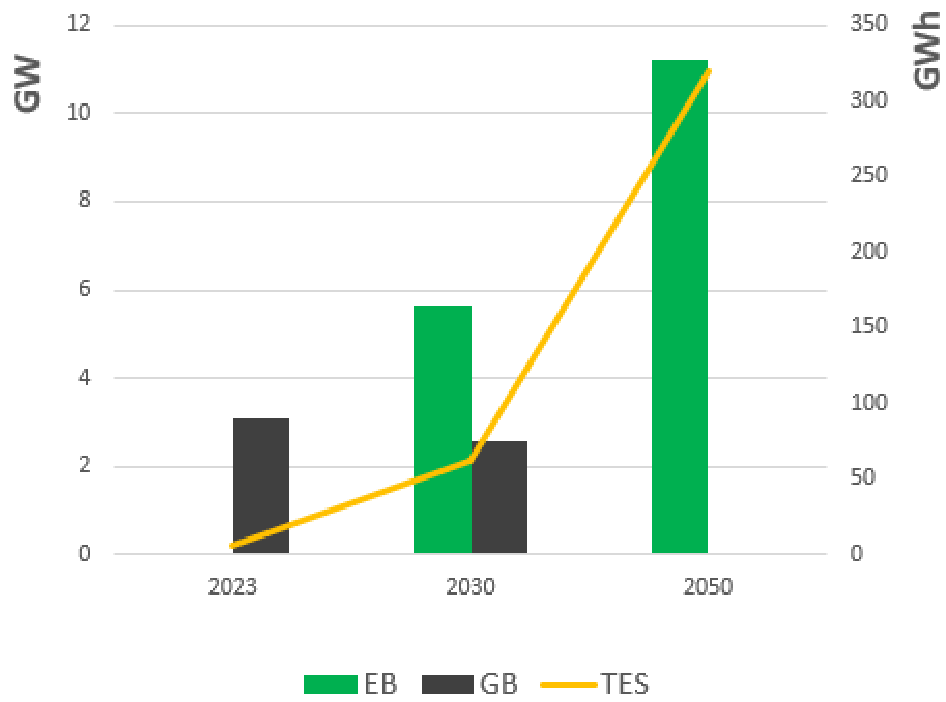
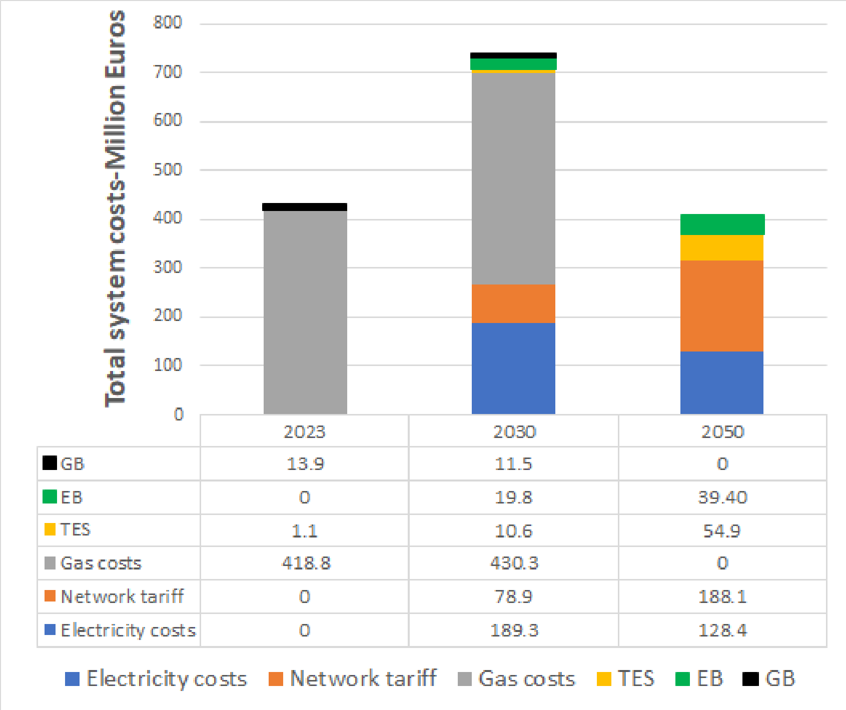



Figure 5.7: The optimal capacities of EB, GB in GW and TES in GWh of hybrid heat system for industrial heat

The peak load of industry heat is around 3.6 GW and so is the capacity of GB in 2023 due to completely running on natural gas boilers with almost no storage. In the market scenario 2030, there is an opportunity to go for higher capacity of GB to benefit from the low operational costs along with usage of TES. Higher capacity investments are seen in EB and GB size in 2030 similar to that of DH heat case. However, the hybrid heat system costs are still higher than 2023 scenario because of higher electricity prices and natural gas price in 2030 compared to 2023. Nevertheless, in 2050, larger size of EB is obtained because of more number of low power price hours. Further, together with TES, the price volatility is being used to attain less overall system costs.




| | 2023 | 2030 | 2050 |
|---|---|---|---|
| GB | 13.9 | 11.5 | 0 |
| EB | 0 | 19.8 | 39.40 |
| TES | 1.1 | 10.6 | 54.9 |
| Gas costs | 418.8 | 430.3 | 0 |
| Network tariff | 0 | 78.9 | 188.1 |
| Electricity costs | 0 | 189.3 | 128.4 |

Figure 5.8: Costs of hybrid heat system providing heat for industry in market scenarios 2023, 2030 and 2050

The costs of hybrid heat system for providing heat to industry sector is shown in **Figure** 5.8. The benefits of adding storage in 2023 are negligible compared to contribution of TES in DH case. From the results, it is observed that the costs of hybrid heat system are almost same as that of a standalone GB heat system because of the negligible annualised costs of TES. Hence, for industrial heat purposes, electrification is not economical in 2023. However, in 2030, around 42% of the heat load is electrified. This includes meeting heat load directly and filling thermal storage. The TES begins with 60% initial state of charge (SOC), so a part of heat production costs also include the costs to fill TES. However, the solution of optimization problem determines when it is best to charge the storage back to its initial capacity.

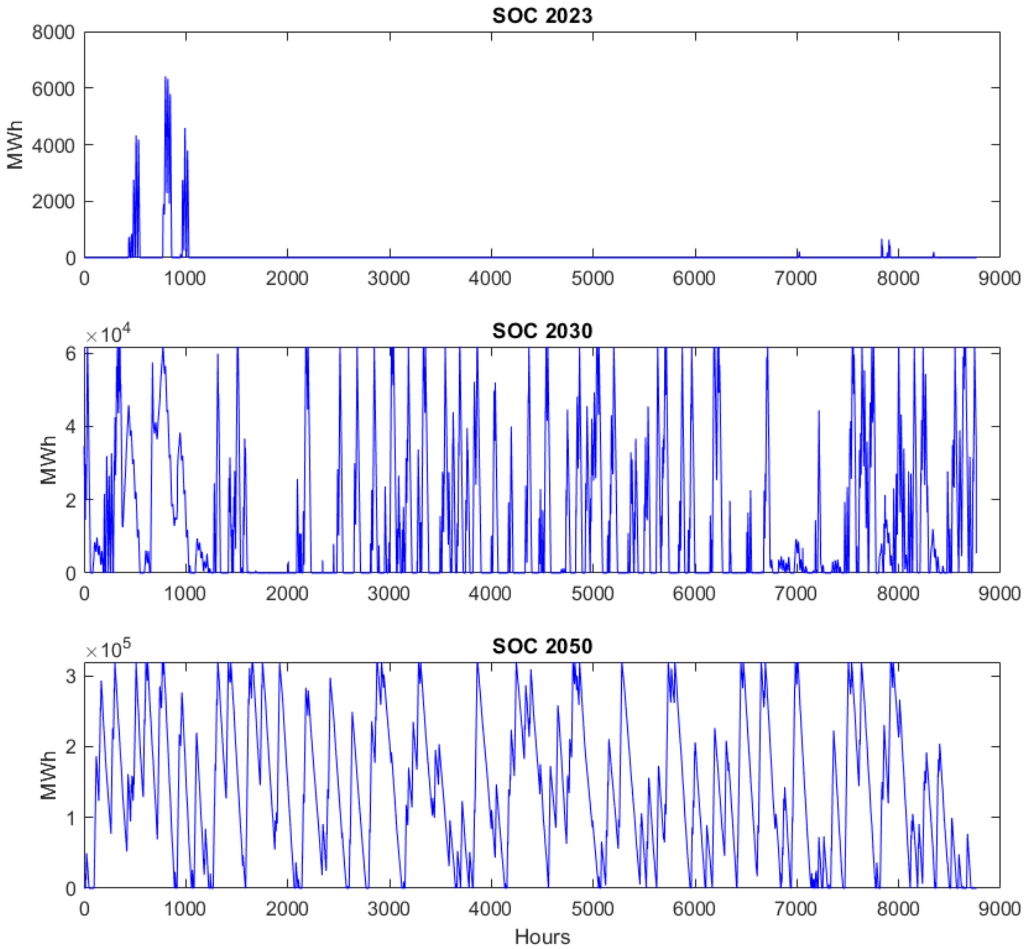



Figure 5.9: The charge and discharge cycles of TES in market scenarios 2023 (Max 6.5 GWh), 2030 (Max 61 GWh) and 2050 (Max 320 GWh) for industrial heat case

The investment in storage capacity in 2023 is less. However, it is not frequently utilized as seen in **Figure** 5.9. A capacity of 320 GWh thermal storage obtained for 2050 scenario is not a big number for a nation and this heat storage investment will act as a buffer to both power system and heating sector. Because of the continuous nature of heat demand in the industry, large storage capacity is required in addition to large investment in EB in 2050 to fill the storage benefiting from fluctuating power prices. Moreover, for TES in 2050, broad charge and discharge cycles are observed due to its large capacity. Hence, TES is neither charged to its full capacity nor completely discharged at full capacity in midst of the year whereas in 2030, TES is charged to full capacity and discharged at full capacity more frequently.

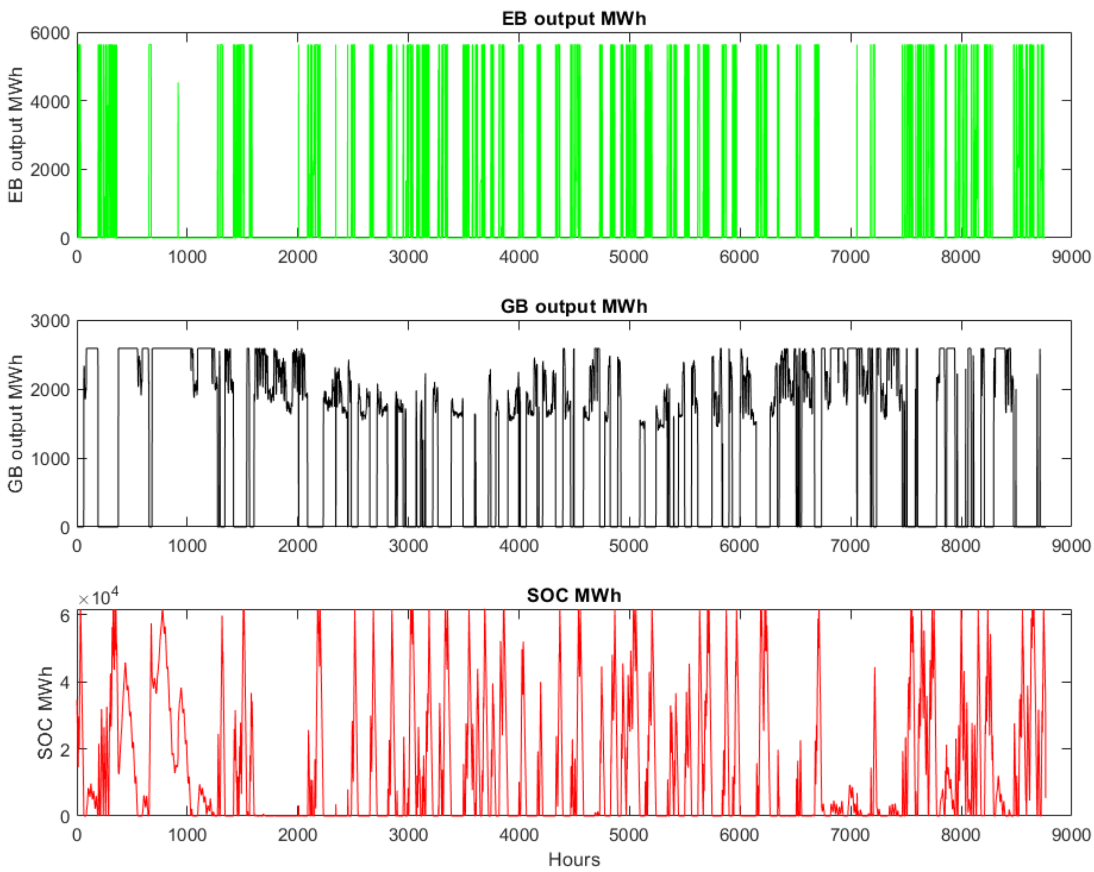



Figure 5.10: Hourly operation of hybrid heat system in 2030 for industry heat case

In 2030, TES has been utilized for larger number of times at full capacity. It is seen in **Figure** 5.10 that all the components in hybrid heat system have been used efficiently. Thus, it is analyzed further. In between 1500 and 2000 hours, it is evident that storage is empty and system is supported completely by GB. This represents times of high power prices, it is neither suitable to provide directly heat with EB nor fill storage. TES is rather filled mostly at extremely lower power prices with EB. Thus, EB is operating at full capacity at all times of low power prices to charge TES on top of meeting heat load at that hour.

## 5.5. DISCUSSION

This chapter provided definition for hybrid heat system and assessed the system costs in each electricity market scenario. 2030 scenario year is the most costly system among the transition years with 200 million euros for residential DH load and 720 million euros for industry heat. An increasing trend for electrification of heating sector is observed. It is not economical to electrify any load of DH and industry heat in 2023. Further, the size of GB for DH and industry heat slightly decreased from 2023 to 2030. Nevertheless, the dependence on GB is not completely removed. GB is profitable only in combination with EB in 2030. In 2030, 7.81 TWh (42%) of the industrial heat and 2.07 TWh (33%) of residential district heat can be electrified considering the investment costs of equipment and operational costs. In 2050, for the given electricity market condition, complete electrification is economical along with TES capacities of 320 GWh and 97 GWh for industrial heat and residential DH respectively. Nevertheless, the hybrid heat system is less expensive in 2050 compared to 2030 and 2023.

A rapid increase in EB and TES capacities is observed in hybrid heat system for both DH and industry heat case indicating an opportunity for electrification over transition period from 2023 to 2050. However, the costs of heat production in 2030 are higher with hybrid heat system due to higher power prices and natural gas price together. This might delay electrification of heat with prolonged use of GB because of the existing investments in 2023. Thus, this stimulates a need for supporting the investments in EB and TES in 2030 to set direction for rapid electrification of the heat sector. Further, the network tariffs could be lowered to encourage electrification of heat in 2030.

As this optimization problem takes into account all the knowledge of the demand and power prices over the entire year, it might give a more optimistic solution than that would have been possible in reality. Therefore, to investigate this, a causal strategy is implemented in Simulink to mimic the system in a more realistic way. Especially, the decision about operation of EB, GB and TES is taken with the knowledge of heat demand and power price at that particular instant of time.

The set up of strategy and results are explained in more detail in **Appendix** B. The causal strategy is applied to residential district heat case and capacities, costs of the system are compared with the results of optimization problem. The system costs with causal strategy is higher by only 1.3% than the costs obtained with optimization problem. These results confirm that the deterministic optimization problem modelled is representative of what can be achieved in reality.

# 6

# POWER TO HYDROGEN SYSTEM

The main objective of this chapter is to create a model to assess economic behaviour of power to hydrogen systems. First, in **Section** 6.1, a preliminary economic assessment is carried out to visualize when producing hydrogen from electricity would be beneficial over a steam methane reformer (SMR) technology. In **Section** 6.2, a definition for power to hydrogen system is provided by supporting arguments for selection of components of power to hydrogen system. A detailed description of the model is given in **Section** 6.3 explaining the parameters used in model and constraints of the model. Finally, in **Section** 6.4, the demand cases for hydrogen in scenario years 2023, 2030 and 2050 are simulated with the proposed model. The model results containing costs of power to hydrogen system and the capacity values of production components are provided in **Section**6.4. Further, this chapter determines the additional load from hydrogen sector to power systems for the following analysis.

## 6.1. ASSESSMENT OF TIPPING PRICE

The hydrogen demand is assumed to develop at the rate of offshore wind addition to the power system in **Chapter** 4. It is shown in scenario 2050 that, even with high electrification, the market prices are as low as 2 €/MWh for about 2000 hours per year. This indicates a possible business case to produce hydrogen from electricity. Further, as seen in scenario assumptions, an increasing trend is observed in $CO_2$ price. The current technology of steam methane reforming produces 9 kg of $CO_2$ to make 1 kg of hydrogen. Hydrogen is rather seen as a green gas for replacing natural gas for many applications discussed in **Section** 3.2. To produce large volumes of hydrogen in future, SMR technique might not be the solution using natural gas as input. However, there are studies to incorporate carbon capture and storage (CCS) system into the current technology to produce blue hydrogen. Biomass gassification is another source for green hydrogen. However, large volumes of biomass availability could be an issue. Nevertheless, in this thesis, hydrogen production with natural gas and biomass along with carbon capture and storage (CCS) technology is not considered for comparison and discussion.

Marginal costs to produce 1 MWh hydrogen on the basis of short term operational costs are compared in this assessment. The operational costs mainly include fuel taxes, electricity tariffs and $CO_2$ prices to produce 1 MWh hydrogen similar to power to heat assessment. However, an additional operation cost for water treatment is usually involved in the production cost of hydrogen from electricity. However, water treatment costs are not considered in this analysis. Both technologies SMR and hydrogen from electricity are compared to supply 1 MWh of hydrogen. The capital investment costs for the equipment and number of operational hours are disregarded for the assessment. In the following paragraphs, the components of marginal costs are explained.

**Fuel taxes and tariffs:** Natural gas consumption for large scale industrial applications is taxed in the Netherlands. A tax of 0.01265€/m3 is levied on natural gas usage in the Netherlands. The tax per MWh of natural gas consumption is 1.3 €. A steam methane reformer plant operating for 8000 hours in a year has an efficiency of 72% of the HHV of natural gas. This would convert to a natural gas tax of 1.8 €/MWh of hydrogen production. Moreover, tax of 0.57 €/MWh is considered for electricity usage. In addition to this, similar to electricity use for heat supply, hydrogen production from electricity also falls under large scale consumers of electricity and a network tariff of 10 €/MWh is assumed for power consumption for hydrogen production.

**Maintenance costs:** Major portion of the maintenance costs for SMR and electrolyser are rather fixed operational costs directly related to the CAPEX investment of technology and capacity installed as mentioned in **Table** 6.1. The variable maintenance costs relevant to MWh of hydrogen produced are not considered for power to hydrogen case as done for power to heat case.

**Fuel costs:** Natural gas costs constitute about 80% of the hydrogen costs from SMR technology. Considering the HHV of natural gas, the efficiency of a SMR plant is only 72%. The unit price for MWh of hydrogen production from natural gas reformer is calculated by dividing unit price of natural gas with efficiency of steam methane reformer. The price for HHV of natural gas assumed in power system scenario framework **Table** 3.1 is used for calculating the production cost of hydrogen from natural gas. Thus, the fuel cost for 1 MWh hydrogen from gas is 43 €/MWh. The hydrogen cost is presented in €/MWh, for easy comparison with other products derived from electricity.

**$CO_2$ emission cost:** SMR is a carbon intensive method to produce hydrogen. For 1 Kg production of hydrogen, 9 kg of $CO_2$ is emitted from the steam methane reformer plant [22]. One kg of hydrogen represents 39.4 KWh energy considering the high heating value (HHV) of hydrogen gas. This would translate to a $CO_2$ emission cost of 3.65 €/MWh of hydrogen produced with the $CO_2$ price of 16 €/ton considered in 2030 scenario. The carbon costs for electricity used for hydrogen production is considered zero because the power prices already include $CO_2$ emission taxes.

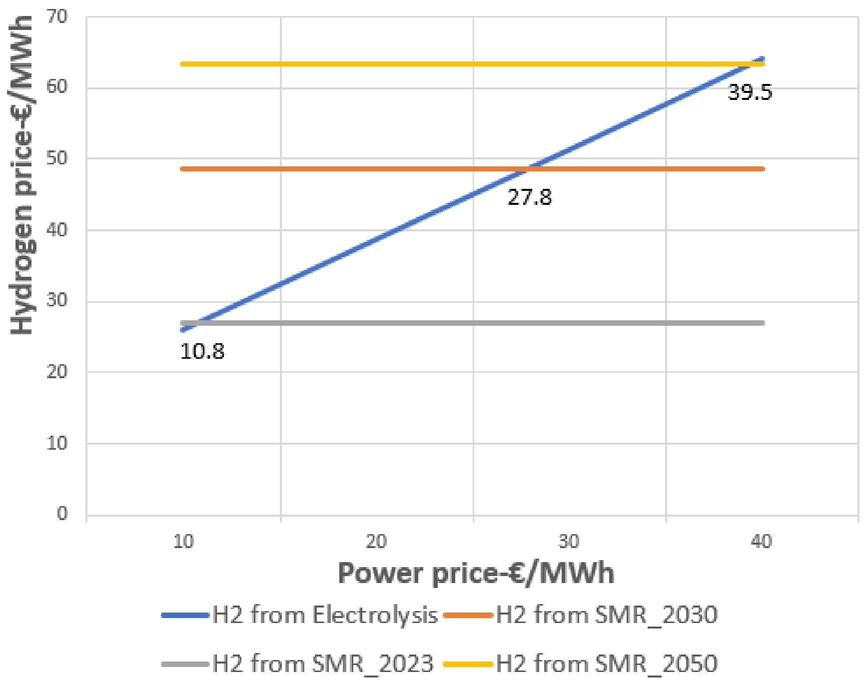



Figure 6.1: Marginal costs of hydrogen from SMR and PEM at different power prices, gas prices and $CO_2$ prices specific to scenario years 2023, 2030 and 2050 including fuel taxes and network tariff for electricity consumption

It is clear from **Figure** 6.1 that with increasing average price for electricity, the production price for hydrogen will increase linearly for electrolysis process. Looking at the marginal costs, hydrogen production from electrolysis cannot compete with SMR method in 2023. The power price should be as low as 10.8 €/MWh for electrolysis to compete with SMR technique. This situation does not occur in 2023 market scenario with reference to the price duration curve in **Figure** 3.5. In 2030, power prices below 27.8 €/MWh seems to be profitable for hydrogen production from electrolysis. However, the additional CAPEX investment for electrolysers should be supportive to create a positive business case for power to hydrogen. Nevertheless, there are only 500 instances in 2030 with power prices less than 27.8 €/MWh. Further in 2050, about 5500 hours per year, power price is below the break-even price with SMR technology indicating possibilities to produce hydrogen from electrolysis instead from natural gas. This is also because of the increased $CO_2$ costs in 2050, making power to hydrogen option competitive with fossil SMR technology.

## 6.2. COMPONENTS OF THE HYBRID HYDROGEN SYSTEM

Hydrogen outlook in **Section** 4.2.2 defines the market demand for 2023, 2030 and 2050 scenarios. This demand has to be met either with the current SMR technology or clean water electrolysis. Moreover, hydrogen can be stored easily and used when necessary without any major losses. Therefore, hydrogen storage is added to the system to identify if any extra benefits emerge from hydrogen storage. From here, the hydrogen production system from natural gas and electricity is termed as hybrid hydrogen system. The main technologies of hybrid hydrogen system used for power to hydrogen assessment in this thesis are described below:

### 6.2.1. Large-scale steam methane reformers

Hydrogen is produced in large-scales for ammonia fertilizer plants and chemical refineries from natural gas with steam methane reforming process. These plants operate at approximately 90% availability producing 9 tonnes of hydrogen per hour [22]. The process mainly involves a chemical reaction between high temperature steam and natural gas producing syngas, a mixture of Carbon monoxide (CO) and $H_2$ in the first stage. This is followed by a water-gas -shift reaction wherein the CO from first stage reacts again with low temperature steam ($H_2O$) to produce pure hydrogen along with carbon dioxide. However, $CO_2$ is separated and used for subsequent fertilizer manufacturing. Nevertheless, steam used in the process is obtained by combustion of natural gases resulting in emission of flue gases containing $CO_2$. Overall, it is possible to capture only 50-60% of $CO_2$ throughout the process [22]. Thus, $CO_2$ price is considered a crucial part of hydrogen production costs with natural gas. This technology is mature and active in the Netherlands from decades. Thus, no technology improvement in terms of efficiency and no reduction in investment costs are considered.

### 6.2.2. Electrolysis

Electrolysis is a technique in which hydrogen is produced by electro-chemical splitting of water. Production of hydrogen from electrolysis is considered clean because there is no $CO_2$ emission involved on one hand. Moreover, the expected operation of power to hydrogen system during low power price hours represents consumption of renewable electricity. Currently, there are two variants of electrolysis technologies in the market: Alkaline electrolysers (AEL) and polymer exchange membrane (PEM). The PEM electrolysis research proves that it will be more efficient for hydrogen production than AEL. Thus, suitable for large scale hydrogen market. However, PEM technology is more expensive than AEL. Nevertheless, PEM has other benefits such as lower start-up time, compact design, less specific material use and simpler system technology. It is expected that the costs of PEM will be eventually become lower than alkaline electrolysis [27]. Thus, PEM electrolysers are assumed to constitute the hybrid hydrogen system.

Unlike SMR and heating technologies mentioned in **Section** 5.2, a technology development factor is considered for the investment costs of PEM electrolysers. The prospects for PEM technology improvement are determined from a recent review on $H_2$ economics. In the research, an uni-variate regression is performed on the constant elasticity function of the type $CAPEX^i = CAPEX(0).\lambda^i$ from 70 historic observations for PEM technology development. Here, i represents year and CAPEX(0) represents the investment cost for PEM in 2016. The regression analysis yielded a price decline of 4.77% in the PEM electrolyser system costs per year. Therefore, the obtained regression coefficient $\lambda = 0.9523$ with a 95% confidence interval is used to determine the PEM investment costs for scenario years 2023, 2030 and 2050 [3]. The estimated learning curve for PEM and AEL technology costs is presented in **Figure** 6.2. In this thesis, only electrolyser costs are considered leaving out the costs for power connection, piping and compression. However, these costs are captured through a fixed operation costs of 2.2% of the CAPEX investments making them proportional to installed capacity. The CAPEX values are presented as parameters in the optimization model in **Section** 6.3.

Moreover, efficiency of the PEM units is also expected to increase from current 70% to 79% in the coming years [3]. However, in this thesis a constant efficiency of 79% for power to hydrogen is assumed for scenario years 2023, 2030 and 2050. Moreover, the financial benefits from economies of scale are considered through the learning curve as presented in **Figure** 6.2 for the increasing hydrogen demand from 2023 to 2050.

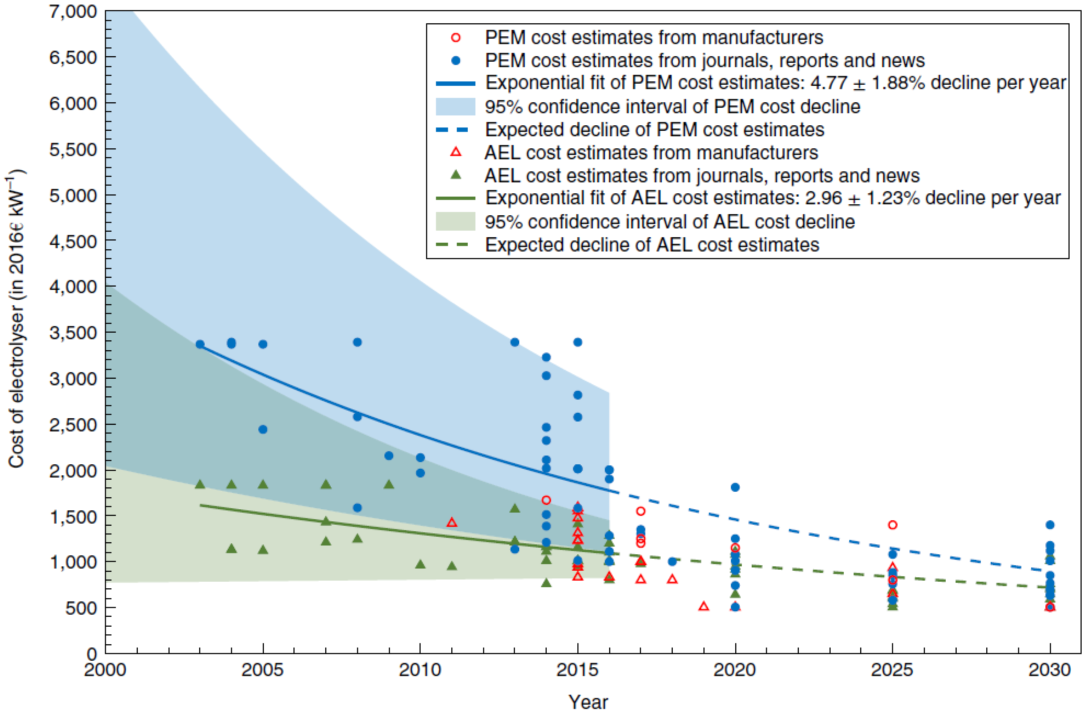



Figure 6.2: Learning curve parameters for the technology costs of PEM and AEL used to extrapolate investment costs of PEM for the transition scenarios 2023, 2030 and 2050 [3]

### 6.2.3. Hydrogen storage

Hydrogen is currently produced at production plant in large-scale as a process step in the fertilizer plant operation. So, storage is not part of these SMR plants. However, there is a hydrogen network existing in the Netherlands fed by hydrogen producers to the industrial areas. Moreover, hydrogen is stored and transported in pressure vessels for small demand levels. It is an expensive method of storage because of pressurization to 700 bar [29]. However, as the future hydrogen demand is large and rather distributed unlike present situation, infrastructure for transport and storage has to be developed. The current gas network is assumed to carry hydrogen in future. On top of it, for storage in scales of TWh market demand, compressed salt caverns and depleted gas fields are most suitable options [29]. Both kinds of storage have equal CAPEX investments. However, empty gas fields can store higher volumes than caverns. Further, gas fields are more suitable for seasonal storage. Nevertheless, salt caverns are assumed for storing hydrogen for the analysis because the pattern observed in power prices in the scenario years 2030 and 2050 is rather more of daily fluctuations. Moreover, the deliverability from salt caverns is much higher than from gas fields meaning that it is easy to store and withdraw gas more rapidly and quickly in salt caverns [28].

## 6.3. ECONOMIC ASSESSMENT AND OPERATIONAL STRATEGY

The economic assessment of hydrogen production is carried out by formulating an optimization model. This optimization problem will provide economical hybrid hydrogen system to supply hydrogen demand in each scenario. The mathematical characteristics of model are similar to hybrid heat system being deterministic. However, technological parameters of the system, charge and discharge capacity limitations of hydrogen storage are modelled differently. The optimization model and applicable constraints are explained in the following sections:

### 6.3.1. Objective function:

The main objective of optimization problem is to minimize hybrid hydrogen system costs for the given power market scenario and hydrogen demand. The objective function takes into account the new investment costs to meet hydrogen demand along with marginal costs. In the operational cost term of objective function, power price for MWh of hydrogen production and electricity network tariff are considered for electrolysis. For hydrogen production from SMR technology, natural gas prices and $CO_2$ costs per MWh of hydrogen production are included. The difference from power to heat optimization problem is that $CO_2$ costs are separated. In addition, there is a fixed operational cost per year added to objective function represented by FO term in **Eq** 6.1 .

$$Min \quad CRF.(\underbrace{C^{PEM}.P^{PEM} + FO^{PEM}.P^{PEM} + C^{SMR}.P^{SMR} + FO^{SMR}.P^{SMR} + C^{SOC}.E^{SOC}}_{InvestmentCosts}) + \sum_{t=1}^{8760}(\underbrace{\frac{\lambda_e(t).E^{pem}(t)}{\eta_{pem}} + \frac{\lambda_g.E^{smr}(t)}{\eta_{smr}} + \frac{\lambda_{CO_2}.\sum E^{smr}(t)}{\eta_{smr}}}_{OperationalCosts}) \tag{6.1}$$

*Where:*

| | |
|---|---|
| $P^{PEM}$ | *Capacity of Electrolyser [MW]* |
| $E^{pem}(t)$ | *Hourly hydrogen production from electrolyser [MWh]* |
| $P^{SMR}$ | *Capacity of Steam Methane Reformer [MW]* |
| $E^{smr}(t)$ | *Hourly hydrogen production from steam methane reformer [MWh]* |
| $E^{SOC}$ | *Capacity of $H_2$ storage [MWh]* |
| $E^{SOC}(t)$ | *Energy content in storage at time 't' [MWh]* |

Similar to power to heat system, the capital investment costs are annualized with a multiplication factor CRF defined in **Eq** 5.2. The interest rate is similar to power to hybrid heat analysis. However, a lifetime of only 20 years is considered for PEM and SMR units. Usually, the lifetime of fuel cell stacks in PEM electrolysers is limited to 50,000 hours equal to less than 6 years. A replacement cost for PEM stacks in general is considered while analyzing the LCOE costs of hydrogen production. Nevertheless, in this thesis, an optimistic number of operational years of 20 is considered for all components in the system. Moreover, the hydrogen systems are not analyzed over their lifetime rather the economic operational situation for power to hydrogen system in a give transition year is assessed to determine the possible electrification from hydrogen market. The descriptions and values of terms in the objective function are provided in Table 6.1

Table 6.1: The parameters and their values for hybrid hydrogen system optimization model

| Parameter | Definition | Unit | 2023 | 2030 | 2050 | Reference |
|---|---|---|---|---|---|---|
| $C^{PEM}$ | CAPEX of PEM Electrolyser | [€/KW] | 1624 | 1154 | 435 | [3] |
| $FO^{PEM}$ | Fixed operational cost of PEM elctrolyser | [%.$C^{PEM}$] | 2.2 | 2.2 | 2.2 | [26] |
| $C^{SMR}$ | CAPEX of Steam Methane Reformer | [€/KW] | 761 | 761 | 761 | [29] |
| $FO^{SMR}$ | Fixed operational cost of electrolyser | [%.$C^{SMR}$] | 3.4 | 3.4 | 3.4 | [29] |
| $C^{SOC}$ | CAPEX of hydrogen storage | [€/MWh] | 643 | 643 | 643 | [29] |
| $\eta_{pem}$ | Efficiency of PEM Electrolyser | [p.u/h] | .79 | .79 | .79 | [3] |
| $\eta_{smr}$ | Efficiency of Steam Methane Reformer | [p.u/h] | .72 | .72 | .72 | [29] |
| $L_{SOC}$ | Hydrogen Storage loss | [p.u/h] | .005 | .005 | .005 | [29] |
| $H_2(t)$ | Hourly hydrogen demand | [MWh] | - | - | - | Scenario input |
| $\lambda_{CO_2}$ | Variable operational costs for $CO_2$ emmission | [€/MWh] | | | | [3] |
| $\lambda_e$ | Hourly electricity market price | [€/MWh] | - | - | - | Market Simulation results |
| $\lambda_g$ | Fuel price for gas | [€/MWh] | - | - | - | Scenario input |

### 6.3.2. Constraints

In this section, the physical limitations of the operation of the hybrid hydrogen system are explained in form of constraints.

**Hydrogen demand balance constraint:** This constraint ensures that hydrogen demand $H_2$ formulated for each scenario is met at each hour of the simulation as per **Eq** 6.2. The hourly production from SMR or PEM or discharge of storage is determined by the optimizer. The energy content $E^{soc}(t)$ in hydrogen storage unit at time 't' is in MWh similar to heat system. However, the technical parameters of hydrogen storage are different from TES. A loss of 0.5% is applicable for hydrogen stored in salt caverns [29] over an hour at the time of usage. Thus, for every time of using hydrogen from storage, an efficiency term $(1-L_{SOC})$ is assigned to the hydrogen content in the caverns at time 't'.

$$E^{soc}(t) - (1 - L_{SOC}).E^{soc}(t-1) - E^{pem}(t) - E^{smr}(t) = -H_2(t) \qquad \forall t \tag{6.2}$$

**Capacity limitations:** The hourly production of hydrogen is restricted to the maximum capacity limits of PEM and SMR similar to power to heat system as formulated in **Eq** 6.3 and **Eq** 6.4.

$$0 \le E^{pem}(t) \le P^{PEM} \qquad \forall t \tag{6.3}$$

$$0 \le E^{smr}(t) \le P^{SMR} \qquad \forall t \tag{6.4}$$

**Hydrogen storage constraints:** Hydrogen storage constraints are similar to that of hybrid heat system meaning that the energy content in storage cannot be higher than the maximum capacity designed by optimiser. This is expressed in **Eq** 6.5. The maximum capacity of storage and hourly energy content are represented by same terms $E^{SOC}$ , $E^{soc}(t)$ respectively. In addition, a charging and discharging power limit for storage is assigned with unit MW, it is limited to the sum of maximum capacities of SMR and PEM together. However, the hydrogen storage modules are discharged for hours to weeks based on requirement. Nevertheless, in this thesis, the charge and discharge capacities of storage are assumed equal and restricted by the capacity of electrolyser and SMR maximum outputs as per **Eq** 6.6.

$$0 \leq E^{soc}(t) \leq E^{SOC} \qquad \forall t \tag{6.5}$$

$$-(P^{SMR} + P^{PEM}) \leq E^{soc}(t) - (1 - L_{SOC}).E^{soc}(t-1) \leq (P^{SMR} + P^{PEM}) \qquad \forall t \tag{6.6}$$

**Eq** 6.7 represents that initial and final energy content of the hydrogen storage in a year are equal. This constraint ensures that hydrogen in the caverns at beginning of the year is not available at free of cost and it is filled again during the course of year with PEM or SMR.

$$E^{soc}(0) = E^{soc}(8760) \tag{6.7}$$

Along with the constraints explained here, all variants of logical constraints related to hybrid heat system are also applicable for hydrogen system. The efficiency of hydrogen supply units are expressed in per unit values and assumed same throughout their operation for an year.

## 6.4. OPTIMIZATION RESULTS AND ANALYSIS

The optimization problem described above is implemented in MATLAB and solved for 8760 steps of each scenario year. The hourly demand for hydrogen 5 GW, 9.6 GW and 21 GW respectively for 2023, 2030 and 2050 scenarios obtained in 4.2.2 and power prices derived from COMPETES simulations are given as input to the optimization model.

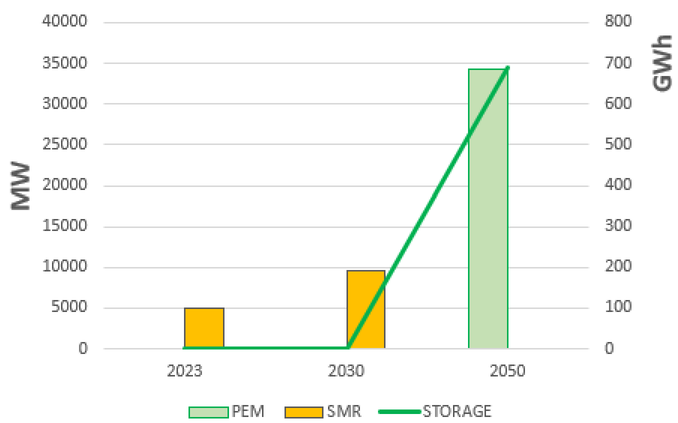
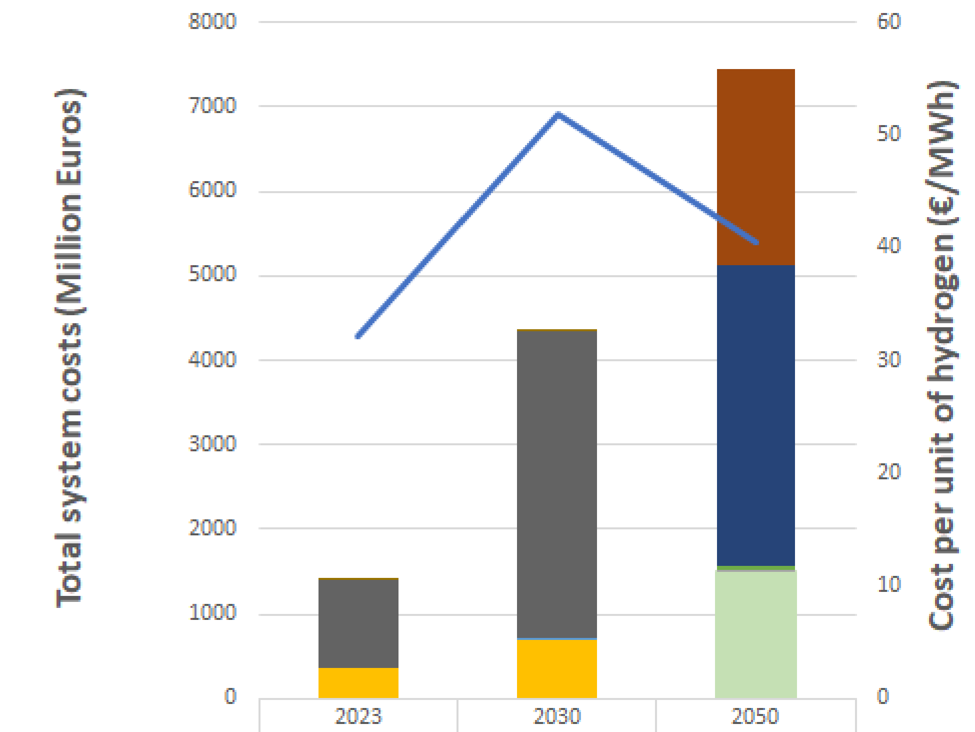



Figure 6.3: Economily optimal capacity of PEM, SMR in MW and storage in GWh for hybrid hydrogen system in 2023, 2030 and 2050

**Figure** 6.3 presents the results from hybrid hydrogen system model for scenario years 2023, 2030 and 2050. The optimization solution recommends to meet hydrogen demand in

2023 and 2030 completely with SMR technology. As anticipated for 2023 and 2030, the hydrogen production from electricity is proven uneconomical for the given market condition of power prices, natural gas prices and $CO_2$ costs. This is also mainly because of the higher CAPEX of PEM in 2023 and 2030 than SMR technology. The results show that hydrogen production capacity investments are rather CAPEX driven. It is concluded from the observation that the limited number of hours with sufficiently low power prices do not merit the investment in PEM whereas even for a somewhat low number of hours the investment was attractive enough for electrical boilers in hybrid heat system. Nevertheless, in 2050, there is a positive sign for PEM technology with lesser CAPEX accompanied by low power prices making it economical to completely meet the hydrogen demand. A storage capacity of 690 GWh is required to benefit from the low power price hours. However, this will add additional capacity to PEM technology beyond the hourly requirement to meet 21 GW of hydrogen load in 2050 as seen in **Figure** 6.3.




| | 2023 | 2030 | 2050 |
|---|---|---|---|
| CO2 costs | 4 | 28 | 0 |
| Gas costs | 1034 | 3621 | 0 |
| Network Tariff | 0 | 0 | 2329 |
| Electricity costs | 0 | 0 | 3542 |
| Storage | 0 | 0 | 42 |
| FO_SMR | 12 | 23 | 0 |
| C_SMR | 359 | 690 | 0 |
| FO_PEM | 0 | 0 | 33 |
| C_PEM | 0 | 0 | 1504 |
| Hydrogen Cost/MWh | 32 | 52 | 40 |

Figure 6.4: The hybrid hydrogen system costs to meet market demand in 2023, 2030 and 2050

The results of hybrid hydrogen system costs are shown in **Figure** 6.4 including the annualized investment costs of capacities and operational costs. In all scenarios operational costs are observed to be dominant in the system. Additionally, hydrogen price in each market scenario is estimated and shown on the right hand side Y-axis of **Figure** 6.4. These costs per MWh of hydrogen are calculated because hydrogen demand is different per scenario. The results represent that the per unit costs for hydrogen are higher in 2030 than in 2023 triggering a negative market sign for investors. Additional incentives might be required to stimulate infrastructure investment for hydrogen market. Though the cost for MWh of hydrogen in 2050 is less than in 2030, the operational costs towards electricity tariff payment constitutes more than 50% of the system costs indicating that network tariffs are potential factors to be reduced to further stimulate hydrogen production from electricity.


Figure 6.5: Hourly operation of hybrid hydrogen system for 2050 scenario, visualization of storage usage at high power prices to minimise system cost

Only in 2050 market scenario, when the PEM technology costs are 57% less than the CAPEX of SMR, hydrogen production from electricity becomes economical. The operation of hybrid hydrogen system in 2050 market scenario for first 200 hours of the year is shown in **Figure** 6.5. It is clearly seen that hydrogen is supplied to market from storage during high price hours and rest of the time, PEM electrolyser operates at full capacity of 34 GW to meet the instantaneous load on one hand and filling storage on the other hand. The charge and discharge cycles of storage unit are observed to be in coherence with power price pattern.

Unlike hybrid heat system, the optimization solution did not recommend any investments in hydrogen storage system in 2023 and 2030. This is caused because of the steady nature of load for hydrogen market. Either a variation in load or fuel prices resulted in storage investment. In case of hydrogen system, because of the huge price volatility, a capacity of 690 GWh storage is obtained. Nevertheless, if the power system can take these high additional loads from hydrogen market is assessed in next chapter by introducing this new load to electricity market scenario. **Section** 7.2 presents the impact of hydrogen on power system in 2050.

# 7

# IMPACT ON POWER SYSTEM

The electrification of heat and hydrogen loads are economical from the perspective of heat and hydrogen systems with assumption that they are only price takers. However, as mentioned in research questions, the impact of additional electrification from heat and hydrogen sectors has to be assessed before making stringent conclusions. In order to visualize the impacts in the operation of power system, the unit commitment module is simulated again with the electricity loads arising from heat sector and hydrogen without changing initial generation capacities and transmission capacities of the power system scenarios in 2023, 2030 and 2050.

In this chapter, the integration of heat and hydrogen demands in power system is studied separately for residential heat, industrial heat and hydrogen loads. The results from DH and industrial heat electrification are presented in 7.1 and for hydrogen in **section** 7.2. The chapter ends with a discussion of the results to gain insights on 3 important factors. First, which sector has potential financial benefits to both electricity and power to heat (or) power to hydrogen system with minimum impact on the power system infrastructure. Secondly, what are the additional revenues to renewables without major changes to the operation of electricity market. Lastly, to identify if the social security of power system fails so badly, creating a need to modify the power system infrastructure.

## 7.1. IMPACT OF HEAT ON ELECTRICITY SECTOR

The heat loads obtained through hybrid heat optimization model are converted to power load by dividing heat load with EB efficiency 0.99. The power system with new loads is simulated for scenarios 2030 and 2050. Because it is not economical to install EB for residential district heat supply in 2023, this scenario is not simulated. Thus, no changes to power system in 2023. Same parameters discussed in **Section** 3.2 are once again taken up for comparison to assess the impact of electrification of heat sector. However, only the parameters wherein a difference is observed are discussed elaborately. Remaining results are presented in **Appendix** A.1 and discussed briefly.

### 7.1.1. Residential District Heat results

The impact of residential district heat electrification in 2030 and 2050 power system scenario is presented below:

- **2030:**
  COMPETES simulation results for 2030 scenario year before and after adding electrification of 2 TWh DH load are presented in **Figure** 7.1.

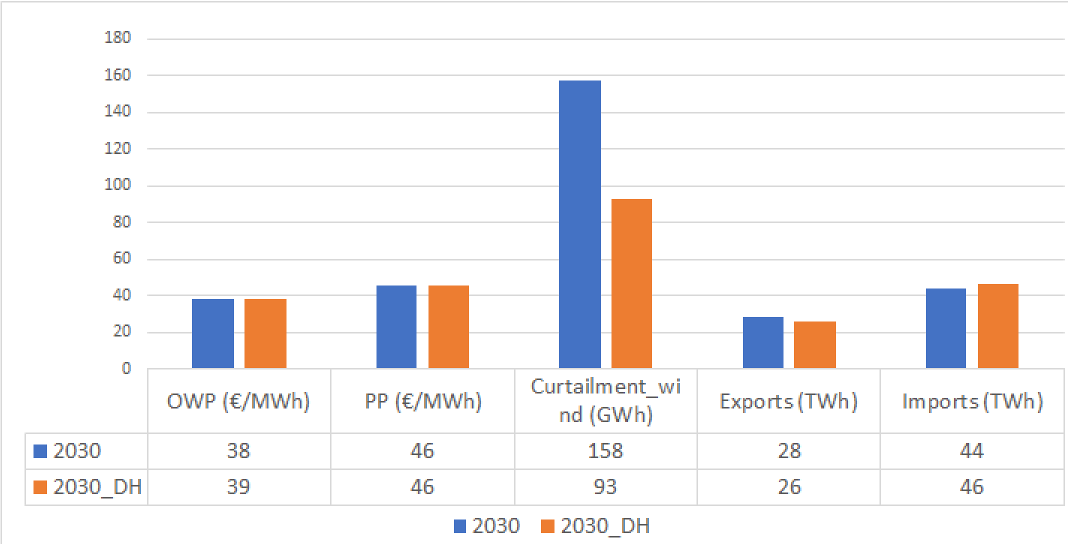



Figure 7.1: The changes in 2030 power system by addition of 1.5 GW power load from DH

The number of VOLL instances and unmet demand remained constant after the addition of load created by DH. The average power price (PP) remained same at 46 €/MWh. However, the curtailed wind energy decreased from 158 GWh to 93 GWh which is a good sign for renewables utilization. The market price for offshore wind (OWP) has improved by only 1 €/MWh, because during the instances of additional load from district heat, power system managed to supply from increasing imports. Moreover, power exports decreased by 2 TWh as shown in **Figure** 7.1 indicating an increased domestic utilization of electricity. There are only few instances summing to 65 GWh, the district heat system benefited from wind energy which was otherwise curtailed in base 2030 scenario. Overall, the VOLL hours have not changed indicating the addition of electricity load from DH will not cause any security of supply issues in 2030. These results convey that the designed power system in 2030 can suffice with the support of domestic electricity supply and international imports to electrify district heat demand.

- **2050:**
  The results from addition of 6.3 TWh of electricity load emerging from DH to 2050 power system are shown in **Figure** 7.2.

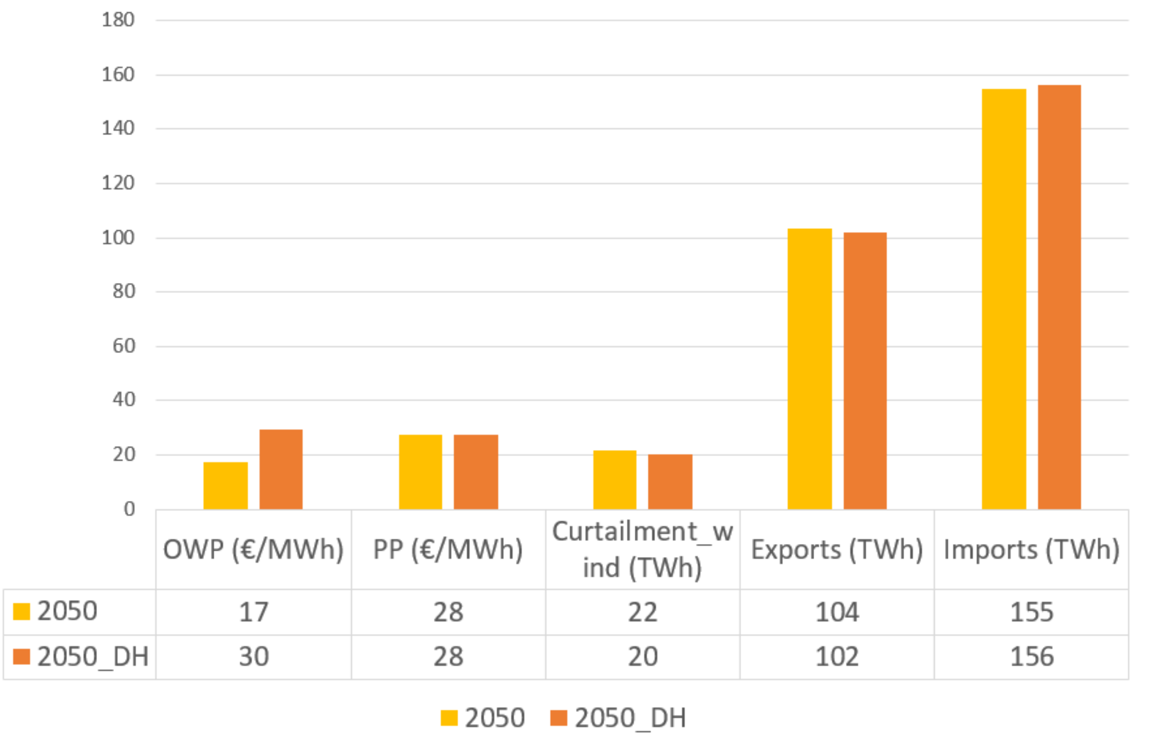



Figure 7.2: The changes in power system 2050 by addition of maximum load of 3.5 GW from DH

First of all, curtailed wind energy in 2050 is reduced from 22 TWh to 20 TWh. When all the DH load of 6.25 TWh is electrified in 2050, it is evident that almost 2 TWh is provided from offshore wind. A decline in curtailment complemented with 2 TWh decline in exports serves the electric load for DH network. Further, an increase of 1 TWh in imports is observed to meet the additional DH load. The instances of VOLL has not changed from base scenario conveying that DH load will not cause any additional problem to security of supply in 2050 as well. The average price for offshore wind increased from 17 €/MWh to 30 €/MWh because of 2 reasons: 1) Increase in utilization of offshore wind energy, 2) DH load is added to system in hours of high offshore wind in supply mix. There is an increase in average offshore wind price, while the average power price remained same at 28 €/MWh indicating DH load electrification is not socially harmful.

### 7.1.2. Industrial Heat results

The electrification of industrial heat effected the power system in 2030 and 2050 as follows:

- **2030:**
  The demand of 7.9 TWh electricity for industrial heat obtained through hybrid heat optimization problem is added to 2030 base scenario and results from COMPETES are presented in **Figure** 7.3.

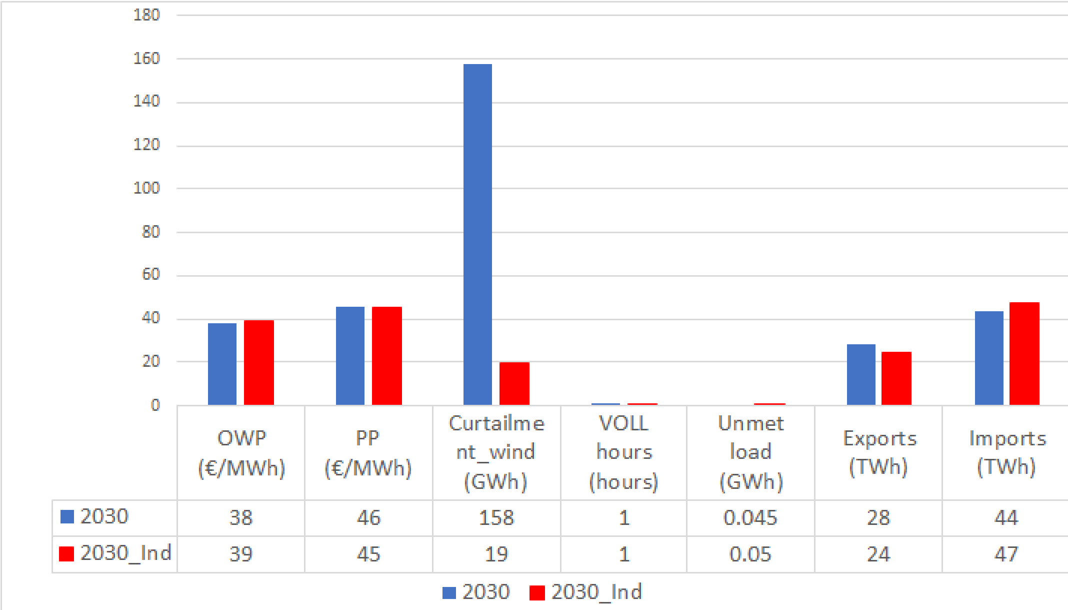



Figure 7.3: The changes in 2030 power system with 5.69 GW additional electrification from industry heat

  This additional load has been met through 88% reduction in wind curtailment along with increased imports by 3 TWh from base 2030 scenario. Similar to DH case, industrial heat load has not increased the power price in general. The VOLL hours remained same as base 2030 scenario indicating that there is no potential security of supply issues in 2030 by electrifying industrial heat load. Only, the volume of wind curtailment deceased is higher in industrial heat scenario than DH scenario because of higher total load from industry heat. Increase in imports from 44 to 47 TWh together with decreased exports presented in **Figure** 7.3 supported for the supply of electricity to industrial heat. Thus, electrification of industrial heat up to 50% of the total identified potential in the Netherlands is achievable without any changes to the proposed power system scenario 2030.

- **2050:**
  The results from addition of 18.8 TWh of electricity load from industrial heat to power system in 2050 are shown in **Figure**7.4. The simulation resulted in different effects compared to DH.

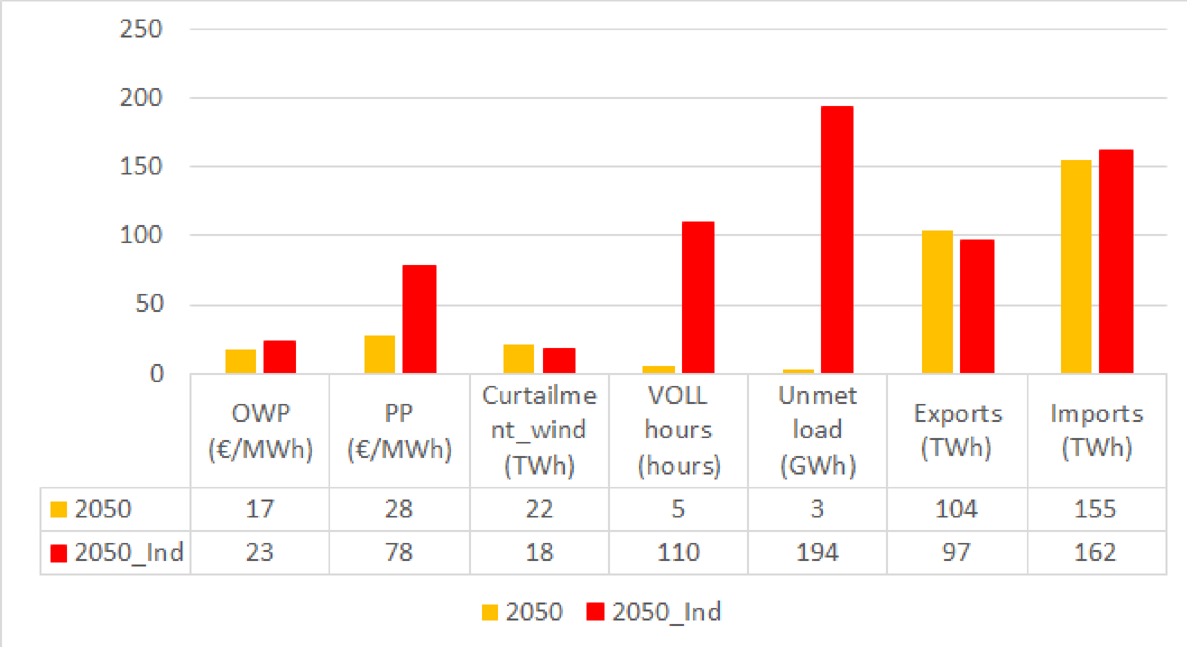



Figure 7.4: The changes in 2050 power system with 11.3 GW additional electrification from industry heat

To start with, the system is not secure because there is an unmet demand of 194 GWh. The instances of VOLL hours increased from 5 in base scenario to 110 in industrial heat scenario creating a considerable threat to conventional power supply. Overall, domestic supply along with international exports is not sufficient to meet the total load. A higher decrease in wind curtailment is observed by electrification of industrial heat load mainly because of higher volume of load. Nevertheless, there is still 18 TWh of wind curtailed. The market price for offshore wind has increased to a lesser extent from 17 €/MWh to 23 €/MWh compared to the increase to 30 €/MWh with DH load. This is because of only 21.6% of the industrial heat load has been served with offshore wind whereas the wind share in DH load stands at 32%. Higher utilization for DH load is mainly due to the correlation of offshore wind energy with high seasonal demand of district heat. On the other hand, a high difference of 50 €/MWh is observed in average power price. This is mainly caused by the increased VOLL hours from 5 to 110 representing a price of 3000 €/MWh for each VOLL hour included in the estimation of annual average power price.

## 7.2. IMPACT OF HYDROGEN ON ELECTRICITY SECTOR

Large hydrogen production from electricity is observed to be economical only in the market scenario 2050. The electricity load for hydrogen demand is calculated by dividing optimal hydrogen production from PEM obtained in scenario 2050 from the optimization problem considering an efficiency of 0.79. The addition of extra load from hydrogen demand changed the dynamics of power system drastically as shown in **Figure** 7.5. The instances of VOLL hours increased from 5 in base scenario to 2642 by adding hydrogen load. The VOLL hours represent an unmet demand of 37 TWh compared to a negligible unmet demand of 3 GWh in base 2050 scenario. Power exports reduced from 104 TWh to 49 TWh and im-

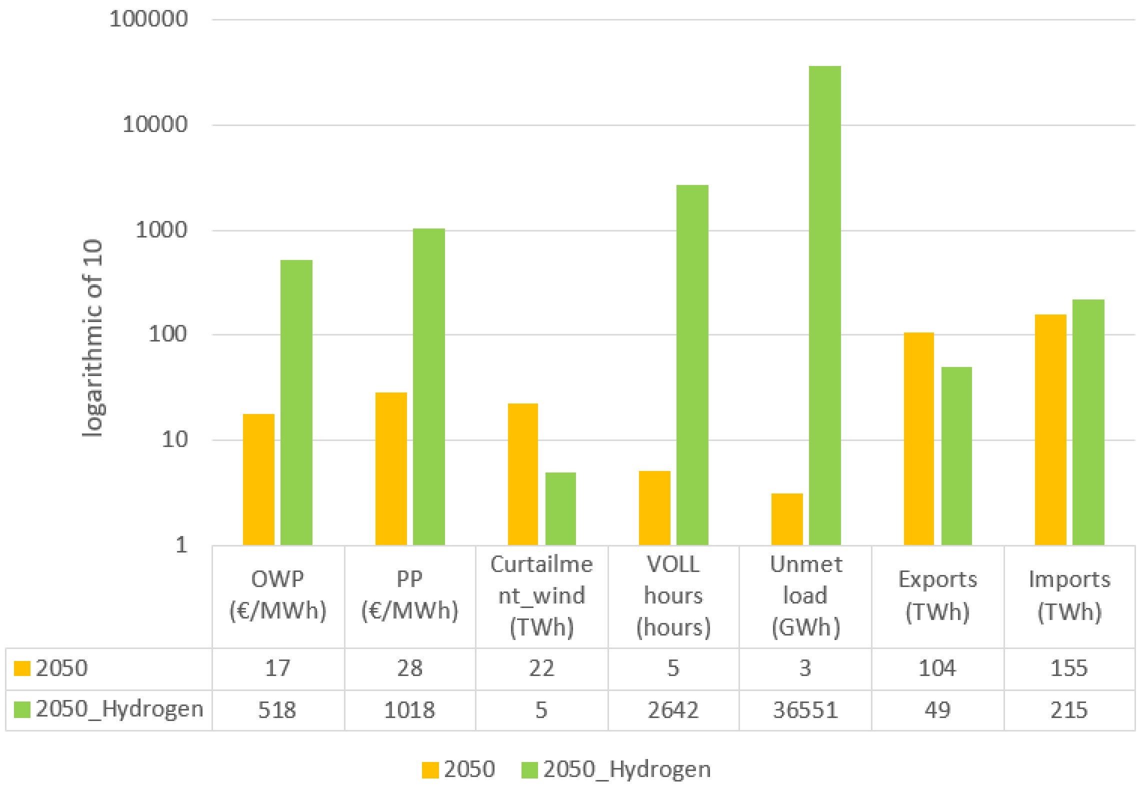



Figure 7.5: The changes in 2050 power system with additional electrification from 184 TWh hydrogen demand, Y-axis represented in logarithmic scale of 10

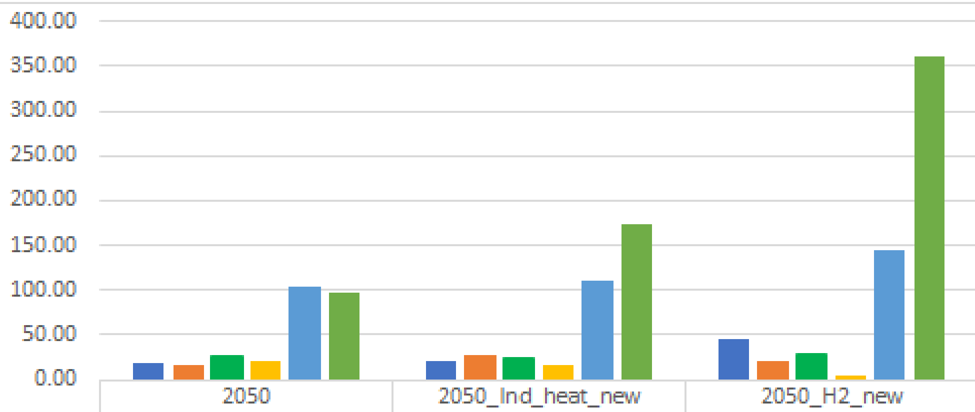
ports increased by 61 TWh to provide load for domestic hydrogen production. The wind curtailment has also decreased significantly from 22 TWh to 5 TWh contributing 17 TWh to hydrogen production. Thus, large volumes of domestic renewables along with international power transport cannot completely support the hydrogen market load of 232 TWh. A large difference is seen in average power price and price for offshore wind with reference to base 2050 scenario because of higher VOLL instances. All these 2642 VOLL hours represent a social cost of 3000 €/MWh each in the market and therefore also added to the market value of offshore wind average. The average market value for offshore wind and power price increased in folds of 25 and 13 times respectively. The power prices such as 518 and 1018 €/MWh doesn't actually represent a price for electricity rather a market failure with large quantities of unmet demand.

A peak load of 75 GW in the power system is analyzed further to identify the causes and implications of worst case scenario. At this peak load hour, available interconnection of 31 GW is operating at full capacity and wind capacities are generating at full capacity. Nevertheless, the supply from solar PV is 0 and thus most of the VOLL hours occurred at night time. This is an inevitable situation with high capacities of renewables in the power system. Nevertheless, solution to the above mentioned issues in terms of investments in generation capacity or transmission capacity is presented in **Section** 7.3.

## 7.3. NEW INVESTMENTS IN 2050

Due to the unmet load observed in 2050 scenario from the electrification of industry heat and hydrogen demands, capacity expansion module is simulated to determine the optimal capacity for the new power system. Moreover, the highly abnormal power prices obtained in **Section** 7.2 do not clearly convey the feedback effects on the optimization solution of power to heat and power to hydrogen systems. The investment module is simulated separately with the loads of industry heat and hydrogen electrification. First of all, the new investments completely remove blackouts and the capacities of generation or transmission infrastructure additions are obtained. The results indicated extra investments in the interconnections but not in any generation capacity.

The interconnection investments have increased from 18.1 GW in 2050 base scenario to 20.5 GW for heat electrification scenario and 45 GW for the entire hydrogen market electrification. The annual average power prices decreased from 27 €/MWh in base scenario to 24.4 €/MWh with industrial heat load whereas the annual average power price slightly increased to 27.85 €/MWh with power load from hydrogen system. The decline in power price with industry heat electrification indicates higher utilization of cheap renewable electricity for industrial heat demand.




| | 2050 | 2050_Ind_heat_new | 2050_H2_new |
|---|---|---|---|
| Interconnection (GW) | 17.66 | 20.51 | 45.37 |
| OWP (€/MWh) | 17.00 | 26.40 | 21.30 |
| PP (€/MWh) | 27.00 | 24.45 | 27.85 |
| Curtailment_wind (TWh) | 21.00 | 15.10 | 4.62 |
| Exports (TWh) | 104.00 | 111.79 | 145.56 |
| Imports (TWh) | 97.00 | 174.66 | 361.40 |

Figure 7.6: The new investments in 2050 with additional electrification from heat and hydrogen markets and the operation of power system

Further, the wind curtailment has decreased from 21.8 TWh in base scenario to 15.1 TWh with industrial heat electrification. With hydrogen electrification of 232 TWh, the curtailment has decreased to 4.62 TWh. Thus, even with high electrification from hydrogen load and huge investments in interconnections in 2050, the wind energy could not be completely used in the Netherlands without curtailment. The changes in the operation of power system in 2050 system with heat loads, hydrogen loads are summarized in **Figure** 7.6. Moreover, it is observed from the results that the extra loads from hydrogen market are majorly fulfilled with increased imports from neighbour countries. Nevertheless, as the average power price in 2050 power system with hydrogen load did not change a lot in comparison to 2050 base scenario, the decision on hydrogen electrification capacity obtained from the solution of optimization problem will not be influenced.

## 7.4. DISCUSSION

From the results of impact of DH, industry heat and hydrogen electrification on power systems 2030 and 2050, following conclusions are derived. DH sector has not caused any security of supply issues to the respective power systems in 2030 and 2050. On the other hand, the power system designed for 2050 scenario cannot deal with the complete electrification of industrial heat.

The VOLL hours from electrifying industry heat are more in 2050 scenario when compared to 2030. It is mainly because 2050 scenario is already a high electrification scenario. Moreover, in 2050, the entire heat load of 18.6 TWh is electrified whereas in 2030 it is only 7.8 TWh. Although the total renewable capacity and interconnections in 2050 are higher than in 2030, the annual generated energy together with imports was short by 36 TWh to supply actual electricity needs for hydrogen market. Hence, technically it is not possible to electrify the entire demand of 184 TWh hydrogen under the power system infrastructure set in 2050 scenario.

The potential to increase market value and revenues for renewables is high for DH sector when compared to industrial heat both in 2030 and 2050 scenarios. It is clearly seen through higher utilization of wind for DH sector, whereas the industrial heat load is majorly met through international supply in form of imports and decrease of exports. Nevertheless, the average power price is not influenced. Power to DH load and industry heat do not affect average power price and thus do not have bad feedback effects on the optimization solution in 2030. However, in 2050, the changed average power price might have an influence on the amount of electrification of industry heat obtained through optimization problem. The addition of hydrogen load has exploding influence on the power system with 36 TWh unmet load over 2642 hours. Thus, first of all, it might have similar kind of effect from industrial heat until 18.8 TWh of electricity load from hydrogen market because of the similar constant nature of heat and hydrogen load. Beyond this, not only the security of supply of power system is affected, but also the power to hydrogen business case will see negative feedback effects in terms of increased system costs. Consequentially, the separate assessment of electricity market and optimization of the hybrid hydrogen system is not allowed. Therefore that in a coupled power and hydrogen optimization, the growth of electrification of hydrogen production could be less.

The new capacity investments in interconnection for hydrogen electrification are higher than that of heat electrification in 2050. Moreover, the profits for variable renewables in the Netherlands has increased by 1.4%, 40% and the wind curtailment has decreased by 28%, 78% in comparison to the base 2050 power system scenario due to the electrification of industrial heat sector, hydrogen demand respectively. Nevertheless, even when electrification of hydrogen introduced high power loads, wind energy is yet again curtailed. Therefore, more electrification than hydrogen electrification is not economically attractive to reduce curtailment further.

# 8 CONCLUSIONS AND RETROSPECTION

In this chapter, the conclusions of research are presented. Throughout the previous chapters, coupling opportunities for power and heat sectors, power and hydrogen markets are assessed and discussed to gain insights on the development of these integrated systems. The trends, opportunities and threats are identified. The research questions are recollected to provide concise conclusions.

*How will the electricity sector develop for the given outlook of renewable penetrations in 2023, 2030 and 2050?*

According to electricity market model COMPETES simulation results, the capacity of gas plants decreased from 8 GW in low renewables, low electrification scenario in 2023 to 5.5 GW in high renewables, high electrification scenario in 2050 despite of the increased electrification. Higher renewable energy capacities in power system in 2050 with high electrification need support from interconnections. The investment in transmission capacity has proven beneficial over higher capacity investments in domestic gas plants. This is because of the higher natural gas prices and $CO_2$ costs associated with the operation of natural gas plants together with cheap renewable electricity available in neighbour countries. Cross border interconnections size increased from 13.8 GW in 2030 to 31.8 GW in 2050 to meet an annual power load of 232 TWh. Average market value for offshore wind is decreasing with increased renewables in power system creating opportunities to sell wind electricity outside electricity market for other products such as heat and hydrogen with higher market values. Moreover, higher volatility in power prices is observed in the time of transition from 2023 to 2050 creating a need for buffer in the form of electricity storage or store in other forms such as heat and hydrogen. There is no curtailed wind and solar energy in 2023 power system because of sufficiently enough supply to meet load. However, a wind curtailment of 0.157 TWh is observed in 2030 and it increases to 21 TWh in 2050 scenario with total annual renewable electricity production of 194 TWh. The profits for gas plants are decreasing from 2023 to 2050 because of the decreased operational hours in 2050 providing opportunities to supply heat from other sustainable sources.

*What are the volumes of heat and hydrogen demands in the Netherlands that can offer flexibility to the electricity system ?*

Heat sector, in order to supply flexibility to power system, should be a low temperature heat. The potential for electrification of industrial low temperature heat is identified by analysis of heat consumption in the Netherlands in 2016. Residential district heat network has a technical power to heat potential of 6.25 TWh whereas 18.6 TWh is determined for manufacturing industry for the scenario years 2023, 2030 and 2050. A potential demand of 184 TWh is established for hydrogen from market predictions for 2050 scenario. The demand for hydrogen market in 2023 and 2030 is obtained as 44 TWh and 84 TWh with a correlation to the capacity additions of offshore wind farms in the Netherlands. A tipping price of 32 €/MWh is obtained as an opportunity cost for power to heat system from a preliminary comparison of marginal costs to supply heat with gas boilers and combined heat and power plants. Similarly, for hydrogen, power prices below 27.8 €/MWh represented the break even price with steam methane reformer technology in 2030. Nevertheless, there were only 500 hours per year of such low power prices in 2030. However, there were about 7000 hours in 2050 with power prices less than the break even price of 39.4 €/MWh indicating that electrification of hydrogen market might be possible in 2050.

*Given the above market scenario, what is the optimal size of these flexibility options with minimum system costs?*

According to the economic assessment results obtained from the optimization problem, in 2023, neither domestic district heat nor industry heat are economical to be operated with electricity. Although the average electricity price in 2023 is less than in 2030, electrification of heat is not economically beneficial in 2023 because of the lower operational costs of heat production with natural gas. For the market conditions in 2030, it is not profitable to completely operate either with electric boiler or gas boiler. Nevertheless, the installed electric boiler capacity is higher than gas boiler to supply the thermal storage in low power price hours. Electric boiler operates at full capacity at all times to fill thermal storage in addition to meeting heat load at a given hour. A capacity of 1500 MW for district heat and 5.6 GW of industry heat is economical to be electrified from heat sector perspective in 2030. Moreover, an increasing trend for electrification of both residential district heat and industry heat with increased sizes of thermal storage is observed in the transition years from 2030 to 2050. Due to the increased system costs in 2030, there could be a delay in electrification of heat sector with continued use of gas for heating. In order to increase the rate of electrification of heat, two factors are identified. Firstly, electricity network tariffs can be lowered based on the end use of electricity for heating replacing direct $CO_2$ emissions. Secondly, investments in thermal storage and electric boiler has to be stimulated to complement the additional benefits offered, such as decreasing curtailment or providing demand side flexibility with the help of storage. The benefits from investments in gas boiler are observed to decrease from 2023 to 2050 evident from the decreasing trend of supply of heat with gas boiler. The thermal storage utilization is also increasing in the transition years indicating the capability of heat sector to provide flexibility to power system in times of surplus electricity.

The results of hybrid hydrogen system indicate that it is a capital intensive system based on the capacities of steam methane reformer in 2023, 2030 and electrolyser in 2050. It is evident from the observation that the limited number of hours with sufficiently low power prices did not merit the investments in electrolysers in 2030 whereas even for a somewhat low number of power price hours it was attractive enough for electric boilers. The large capital investment costs of power to hydrogen technology did not allow for investments in 2030. An increased capacity of storage for hydrogen is observed due to the high power price volatility in 2050. Only in 2050, because of the low power prices for electricity along with the assumed improvement in electrolyser technology through decrease of costs, it becomes cheaper to make hydrogen from electricity than from natural gas. It means, the hydrogen producers might prefer to pay a little more for electricity because of the lower capital investment in electrolysers than the steam methane reformers. The profitability of power to hydrogen creates opportunities for renewable energy suppliers to produce hydrogen instead of selling in the electricity market. On the other hand, these results provide higher level insights for national power system in terms of overloaded grid and potential threat for electricity supply to conventional load.

*What are the implications of this extra electrification on the power system and the revenues of renewables (especially offshore wind)?*

The additional electrification from residential district heat and industrial heat is majorly met by a combination of decrease in wind curtailment, decrease in exports and increase in imports. The power system capacity in 2030 is adequate to manage the additional load of 7.9 TWh from industrial heat. The electrification of district heat and industry heat does not create any security of supply issues in 2030 whereas the power system designed for scenario 2050 is inadequate with an unmet load of 194 GWh when the entire industrial heat was electrified. By observing the hourly power balance from COMPETES results, the load is mainly unmet during night times when PV production is zero wherein the wind and interconnections are operating at full capacity. In 2050, electrification of hydrogen demand resulted in inadequacy with the power system infrastructure set up in 2050 with an unmet power load of 37 TWh compared to 3 GWh in base 2050 case. However, the feedback effect of additional load on power price increase that is not modelled in the optimization problem will dampen the increase in hydrogen electrification. Further, these results signal that if hydrogen electrification is intended in 2050, it is economically feasible. However, it requires further growth in electricity supply capacity than foreseen in this study. This study also shows that it is not economically attractive to completely avoid curtailment. Even with large amount of electrification from hydrogen market, there is unmet demand, there is yet wind curtailment. From the capacity expansion simulations for 2050 power system, there is an increment of transmission capacity from 18.1 GW to 21 GW, 45 GW to meet the power load for industry heat and hydrogen demands without any security of supply issues. Even then the curtailment of wind energy in the Netherlands is not completely vanished. Therefore, curtailment is not the biggest issue with high renewables and high electrification. Moreover, electrification above the 2050 hydrogen scenario is not economically attractive to reduce curtailment further.

None of the heat or hydrogen sector electrification could completely remove the curtailed energy from offshore wind. Even higher capacities of electrolysers and electric boiler will be required to completely absorb the curtailed wind. District heat demand in general has the potential to increase market value for offshore wind creating extra demand in times of high wind due to the similarity in seasonal patterns. The influence of industrial heat is less in comparison to district heat due to the flattened nature of load. The investment outlook for electric boiler, thermal storage is positive beyond 2030 because of the not so high changes in the average power price after coupling heat in power sector. The new capacity investments in interconnection for hydrogen electrification are higher than that of heat electrification in 2050. After the new transmission capacity investments to supply electricity for industry heat and hydrogen market, it is observed that the average power price decreased in industry heat case implying the hybrid heat system costs can be less than the solution of optimization problem. From hydrogen electrification, power price has slightly increased which will not create negative feedback for power to hydrogen optimization solution. However, there is a possibility that hydrogen producers are willing to pay for higher power prices and overload the power system in 2050 because of the profitable hydrogen market. These results create a need for the introduction of new mechanisms in order to regulate the coupling of these sectors smoothly. Moreover, the profits for variable renewables in the Netherlands has increased by 1.4%, 40% and the wind curtailment has decreased by 28%, 78% in comparison to the base 2050 power system scenario due to the electrification of industrial heat sector, hydrogen demand respectively.

## 8.1. RECOMMENDATIONS

In this thesis, an assessment of integration of heat, hydrogen sectors in the electricity market is performed independently and individually by decoupling the sectors. This research develops a need to design an optimization model for the integrated system together with power generation technologies, conversion technologies containing electric boilers, gas boilers, thermal storage, electrolysers and hydrogen storage to determine the dynamics of integrated system. These technologies can be added to TNO model COMPETES. Moreover, the benefits from demand side flexibility offered by these technologies can be efficiently assessed with the coupled model.

The hybrid heat and hydrogen systems are financially assessed only over a period of year, to show which technology is operationally economical for the given market situation. Model can be extended for the entire operational lifetime of equipment to assess the economic feasibility accurately. However, in that case, the power prices shall be determined for throughout their operational lifetime. Moreover, there are several parameters assumed in the optimization such as technology costs, network tariffs and interest rates. A sensitivity analysis around these parameters can provide precise conclusions necessary for market policy suggestions supportive to stimulate the electrification of heat and hydrogen sectors smoothly. In this research, the analysis of integrated systems was majorly at national high voltage grid level considering the domestic distribution network as a single line. However, a detailed national internal electricity network assessment has to be performed to draw insights on the reliability of domestic distribution infrastructure and investment decisions and identify implementation bottlenecks.

The approach adapted in this research assumes the hourly power prices as input to determine the size and hourly operation of electric boilers and electrolysers. However, due to the additional power load for heat, hydrogen, the power prices will increase in reality. The new power prices can change the size of electrification and operational strategy of the hybrid system yielding a new power load profile to the electricity system. This is a continuous process until the optimization results converge. As this feedback is missing in the approach, an advanced electricity market model is required which can minimise the overall power system and hybrid system costs together.

# A

# Appendix A

The investment module in COMEPTES assumes an interest rate of 10% and life time of 30 years for all the conventional generation technologies and transmission lines to calculate the annualised investments in a year. If a technology can recover its annualised costs from the power sales in a given year, then the investment decision is made. The investment costs used in the COMPETES model per technology is given in **Table** A.1.

Table A.1: Capital investment costs for generation technologies used in capacity expansion module of COMPETES

| **Fuel Type** | **Technology** | **Euro/MW** |
|---|---|---:|
| Derived gas | IC (Internal Combustion) | 825 |
| Gas | CCS CHP (Carbon Capture and Storage Combined Heat and Power) | 1250 |
| Gas | CCS CCGT (Carbon Capture and Storage Closed Cycle Gas Turbine) | 1250 |
| Gas | CCGT (Closed Cycle Gas Turbine) | 700 |
| Gas | CHP (Combined Heat and Power) | 700 |
| Gas | OCGT (Open Cycle Gas Turbine) | 400 |
| Sun | PV (Photo Voltaic) | 1600 |
| Sun | CSP (Concentrated Solar Power) | 3500 |
| Waste | Standalone | 1900 |
| Wind | Onshore | 1100 |
| Wind | Offshore | 2625 |
| Nuclear | Nuclear fission | 3000 |

Table A.2: Flexibility assumptions for conventional generation technologies in COMPETES

| Technology | Nuclear | IC | CCGT | OCGT | CHP |
|---|---|---|---|---|---|
| Minimum load (% of max capacity) | 50 | 35 | 30 | 10 | 10 |
| Ramp rate (% of max capacity/hour) | 20 | 40 | 80 | 100 | 90 |
| Start-up cost (€/MW installed per start) | 46±14 | 46±14 | 39±20 | 16±8 | 16±8 |
| Minimum down time (Hours) | 4 | 4 | 3 | 1 | 1 |

The parameters mentioned in **Table** A.2 are applicable for the decision of offering flexibility to the renewables. When a CCGT power plant is switched on to balance the load, it is operational for one hour, but when it is switched off, it should be idle for 3 hours. It is also evident from the high start up costs involved with CCGT technology. Hence, a OCGT, CHP plant will offer good flexibility to renewables. Moreover, these technologies are also cheaper than GT and CCGT technologies. Therefore, 5.5 GW investments in GT technology is observed in 2050.

# B

# Appendix B

A model is designed in MATLAB/ Simulink with operational strategy as shown in **Figure** B.1 and applied to domestic DH case in order to validate the economic optimization problem. The technical parameters such as efficiency of EB, GB, TES and the financial parameters such as capital costs, lifetime, CRF and interest rates are same as in the optimization problem **Section** 5.3.

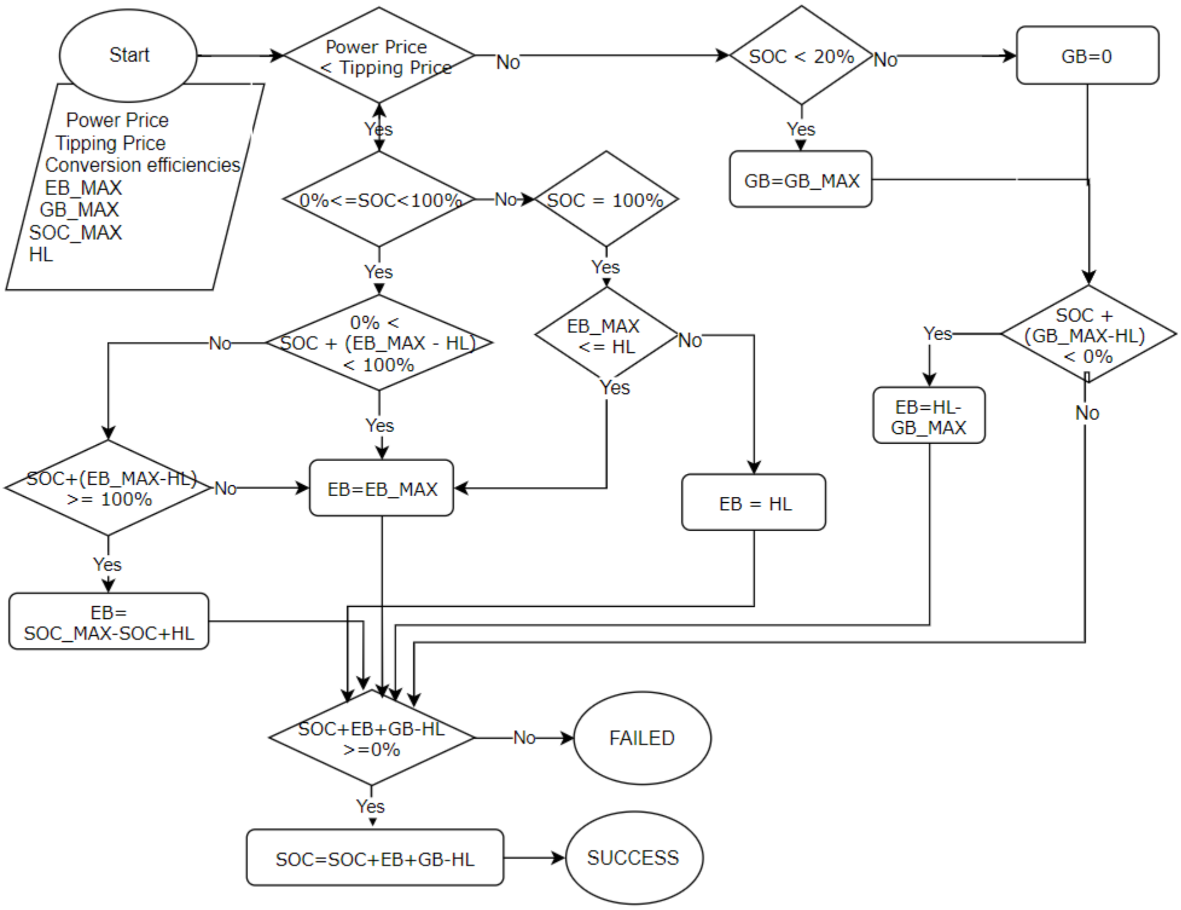



Figure B.1: Control flowchart representing the operation of EB, GB with TES

The electricity network tariff of 10 €/MWh is still applicable for production of heat from electricity. However, the important difference from optimization problem is that the simulink model does not know the entire hourly demand and power price throughout the year in advance. Moreover, the charge and discharge capacity of TES is restricted to the sum of maximum capacities of EB and GB together.

The model iterates in steps of 100 MW for the sizing of EB, GB and in steps of 1000 MWh for TES capacity. The simulink model takes decision about the operation of EB when the power price is below the tipping price and charges storage. Further, when the production cost of heat from gas is higher than the tipping price, first, the heat load is met by discharging the thermal storage. Otherwise, the heat load is met with gas boilers. The simulation is performed over a year with first set of capacities in the iteration. At the end, model checks for any instances of unmet demand and then update the capacities of equipment. This model produces a 3 dimensional matrix with capacities of EB, GB, TES with their costs of heat production. From this matrix, the minimal cost system is selected. The results of this model with minimum system costs are presented in **Table** B.1.

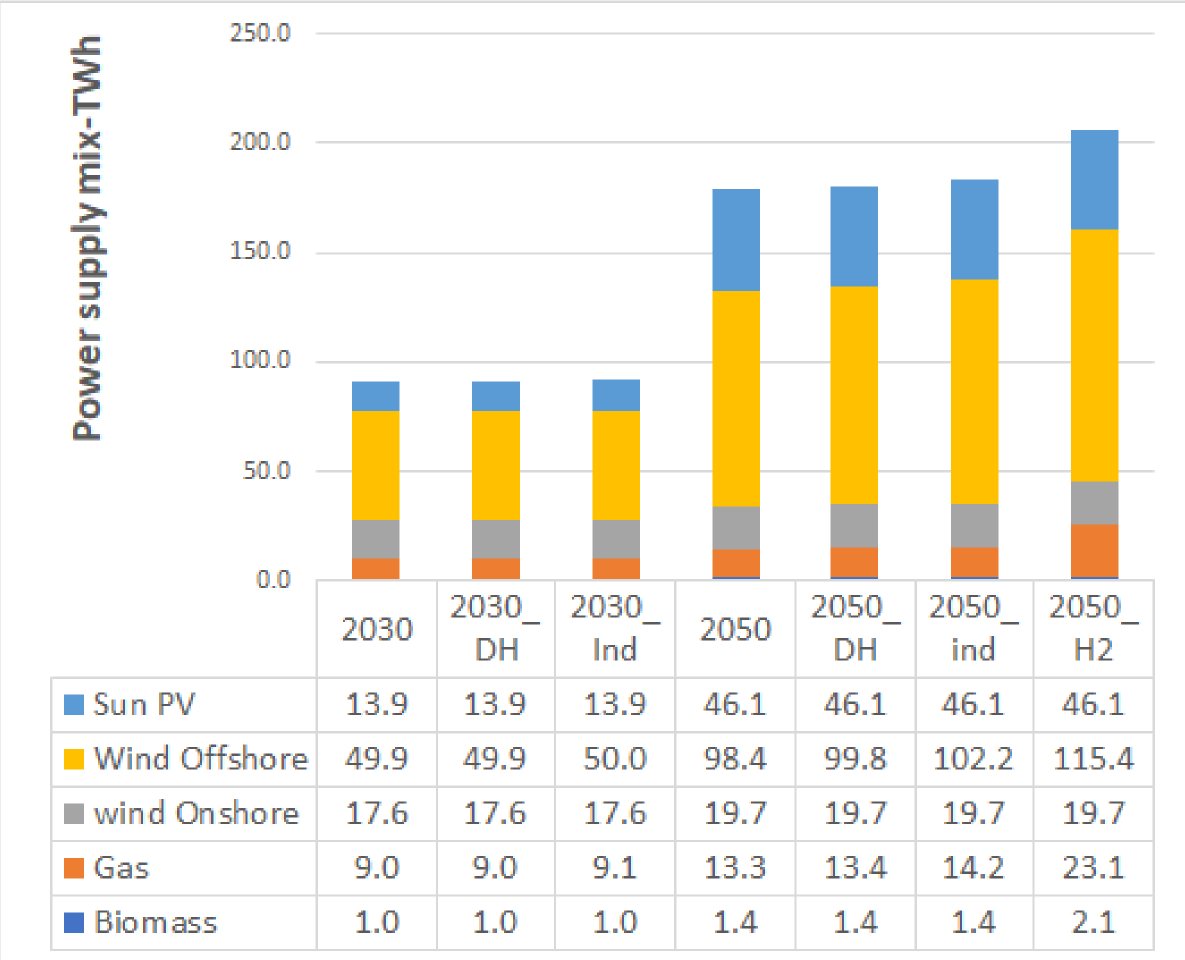
Table B.1: Capacity values and system costs to provide heat for DH case with causal strategy model

| | |
|---|---|
| EB capacity (MW) | 1500 |
| GB capacity (MW) | 800 |
| TES capacity (MWh) | 20000 |
| System cost (Million Euros) | 224 |

# C

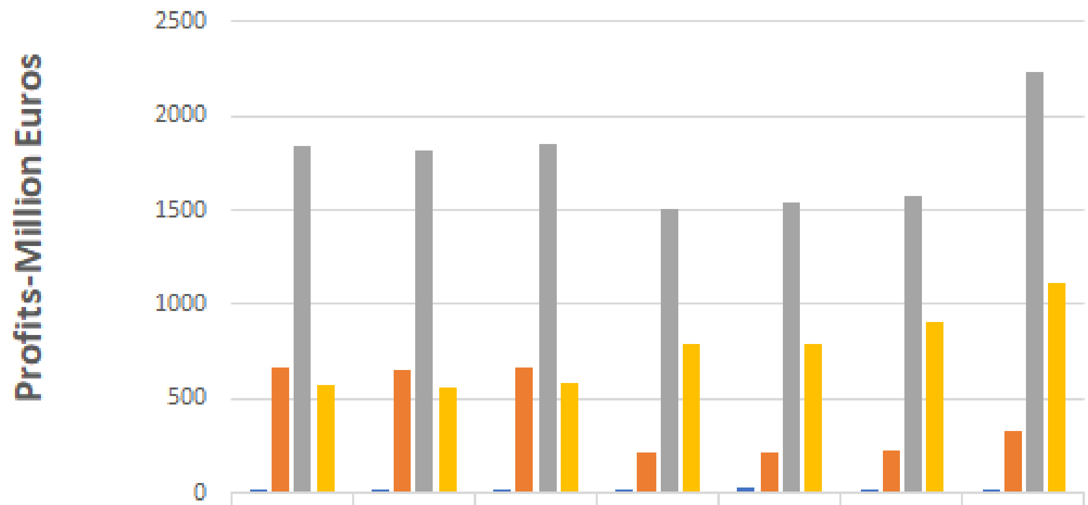
# Appendix C

The results of COMPETES simulations related to the profits of renewables after the addition of heat and hydrogen loads are presented in **Figure** C.1 and **Figure** C.2.




| | 2030 | 2030_DH | 2030_Ind | 2050 | 2050_DH | 2050_ind | 2050_H2 |
|---|---|---|---|---|---|---|---|
| Sun PV | 13.9 | 13.9 | 13.9 | 46.1 | 46.1 | 46.1 | 46.1 |
| Wind Offshore | 49.9 | 49.9 | 50.0 | 98.4 | 99.8 | 102.2 | 115.4 |
| wind Onshore | 17.6 | 17.6 | 17.6 | 19.7 | 19.7 | 19.7 | 19.7 |
| Gas | 9.0 | 9.0 | 9.1 | 13.3 | 13.4 | 14.2 | 23.1 |
| Biomass | 1.0 | 1.0 | 1.0 | 1.4 | 1.4 | 1.4 | 2.1 |

Figure C.1: The generation mix for power supply from renewables to meet the extra load from DH, industry heat in 2030 and 2050




| | 2030 | 2030_DH | 2030_Ind | 2050 | 2050_DH | 2050_Ind_new | 2050_H2_new |
|---|---|---|---|---|---|---|---|
| BIOMASS | 22 | 21 | 21 | 24 | 24 | 19 | 23 |
| Wind Onshore | 661 | 655 | 666 | 214 | 218 | 225 | 332 |
| Wind Offshore | 1838 | 1823 | 1854 | 1511 | 1541 | 1580 | 2235 |
| Sun PV | 570 | 564 | 581 | 786 | 788 | 902 | 1112 |

Figure C.2: The increased profits for renewables by electrification of DH, industry heat demands in 2030 and 2050

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