Fuel cell electric vehicles & hydrogen balancing national 100% renewable integrated transport & energy systems

A scenario analysis for the year 2050

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Abstract

The Paris Agreement, adopted by virtually all 195 countries of the United Nations, is a binding deal with targets to keep global warming of the earth beneath 2°C, and reduce emissions of greenhouse gases in 2050 by at least 80% compared to 1990. These targets require significant reductions in energy consumption and switch to carbon free renewable energy sources.

Changing to renewable energy sources brings several complications to the electricity system. Supply and demand of electricity need to match at any time. The intermittent nature of renewable energy sources, such as solar and wind, requires energy storage and need to be balanced with dispatchable power generation. Passenger cars could offer dispatchable power as they are parked for 95% of the time. Especially fuel cell electric vehicles (FCEVs) connected to the grid could offer this service in a clean and efficient way. Could parked and unused grid connected FCEVs replace the positive dispatchable power plants to balance 100% renewable energy systems?

This research investigates how future 100% renewable national electricity, heating and transport systems can be balanced with the use of hydrogen production and storage, and grid connected FCEVs. A model is developed that simulates the future energy systems of Germany, France, Spain, Great Britain, Denmark and Belgium. The energy systems include electricity generation and consumption, road transport, hot water and space heating. Road transport vehicles are battery electric vehicles (BEVs), FCEVs or a combination of both. Electricity and hydrogen are the only energy carriers. Electricity is mainly supplied by solar and wind power. Hot water and space heating is mainly supplied by solar thermal energy and electric heat pumps. Electricity generation and consumption profiles and temperature data of 2014, 2015 and 2016 serve as inputs. The future 100% renewable energy scenarios are based on scenarios published by government agencies, research institutions or transmission system operators. Demand response heating (DRH) is analysed and applied to all cases. Interconnecting the electricity grids of Germany and France is also investigated.

Hydrogen production and grid connected FCEVs can balance national electricity grids. Electrolysers can act as negative balancing power consuming excess electricity of intermittent renewable energy sources to produce hydrogen. Roughly 0.4-0.6 GW of electrolyser capacity is required to balance 1 GW of renewables in the investigated countries. This requirement can be lower when curtailment is applied and the installed capacity of renewables is slightly increased. Hydrogen can be stored locally in high pressure storage tanks or at large scale in underground salt caverns. A typical salt cavern can store around 6 million kg of working gas. Per TWh of final energy consumption approximately 1-2.5 million kg of hydrogen storage capacity is required. Conventional positive balancing plants such as gas turbines could be replaced by FCEVs connected to the electricity grid. Peak backup demands can be balanced with 25 - 50% of the FCEV passenger fleet, which corresponds to 12.5 - 25% of the total passenger car fleet. The utilisation of FCEVs for V2G varies from 2.5 to 8%. Between 7% and 14% of the electricity consumption in a country is supplied by grid connected FCEVs. Hydrogen can be locally produced at hydrogen fuelling stations or electrolysers can be installed near large scale electricity generation sites or salt caverns where hydrogen can be produced and stored directly. Hydrogen fuelling stations need an average dispensing capacity of 3000 kg/day (~600 passenger FCEVs/day) to cover all fuelling demands except peak demands.

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Nomenclature

Abbreviations

AFC	Alkaline Fuel Cell
ATR	Autothermal Reforming
BEV	Battery Electric Vehicle
BoP	Balance of Plant
CaPP	Car as Power Plant
CcH2	Cryo-compressed Hydrogen
CFRP	Carbon Fiber Reinforced Plastics
CGH2	Compressed Gaseous Hydrogen
CHP	Combined Heat and Power
CPPP	Car Park Power Plant
CSP	Concentrated Solar Power
DRH	Demand Response Heating
DSM	Demand Side Management
EC	Electrolyser
EU	European Union
EV	Electric Vehicle
FC	Fuel Cell
FCEV	Fuel Cell Electric Vehicle
FCREEV	Fuel Cell Range Extended Electric Vehicle
GB	Great Britain
HDD	Heating Degree Days
HDV	Heavy Duty Vehicle
HE	Hydrogen Embrittlement
HFS	Hydrogen Fuelling Station
HP	Heat Pump
LCV	Light Commercial Vehicle
LH2	Liquid Hydrogen
LOHC	Liquid Organic Hydrogen Carrier
MCFC	Molten Carbonate Fuel Cell
OCGT	Open Cycle Gas Turbine
P2G	Power to Gas
PAFC	Phosphoric Acid Fuel Cell
PEM	Proton Exchange Membrane
PHEV	Plug-in Hybrid Electric Vehicle
PHS	Pumped Hydro Storage
POX	Partial Oxidation
RE	Renewable Energy
SCOP	Seasonal Coefficient Of Performance
SEC	Specific Energy Consumption
SMR	Steam Methane Reforming
SO	Solid Oxide
SOFC	Solid Oxide Fuel Cell
TSO	Transmission System Operator
TTG	Tank-To-Grid
TTW	Tank-To-Wheel
UGS	Underground Gas Storage
UK	United Kingdom
V2G	Vehicle-to-Grid

1 Introduction

1.1. The energy transition

At the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change (UNFCCC) the 'Paris Agreement' was adopted by virtually all of the 195 countries of the United Nations. The main focus of this agreement is to keep the global warming of the earth beneath 2°C and reduce emissions of greenhouse gases in 2050 by at least 80% compared to 1990. These targets require significant reductions in energy consumption and switch to carbon free renewable energy sources.

As a reaction on the Paris agreement, 13 big players in the energy and industry sectors such as Shell, Linde, Air Liquide, BMW group, Daimler, Honda, Hyundai and Toyota formed 'the Hydrogen Council'. They formed this council to underpin and leverage the role of hydrogen in the energy transition. "*We, the members of the Hydrogen Council, believe in the potential of hydrogen in making the energy transition happen.*"[1] Hydrogen could be the fuel for decarbonised transport and industry and act as buffer for the energy system.

In Japan for example, the focus lies on hydrogen within the energy transition. In June 2014, the Ministry of Economy, Trade and Industry (METI) published measures to be taken for a hydrogen society in the strategic roadmap for hydrogen and fuel cells [2].

Based on the targets in the Paris agreement, several future 100% renewable energy scenarios including road transport are developed for countries such as Denmark [3, 4], Germany [5], Belgium [6] and Great Britain [7]. These scenarios show that such a transition is technically and economically feasible in 2050.

The European Climate Foundation (ECF) published 'Roadmap 2050', a roadmap to achieve the targets of the Paris agreement [8] for Europe by 2050. This roadmap includes emission reduction scenarios varying from 40% to 80% and a feasibility study for a 100% renewable scenario for Europe [9]. The 100% renewable scenario replaces nuclear and fossil energy supply by concentrated solar power (CSP) from North Africa and requires extensive expansion of interconnections. The mix of installed capacity for this scenario is shown in figure 1.1. In this 100% renewable scenario intermittent energy sources have a share of at least 60%. As a result 215 GW of balancing power, 11% of the total installed capacity, is required for grid balancing.

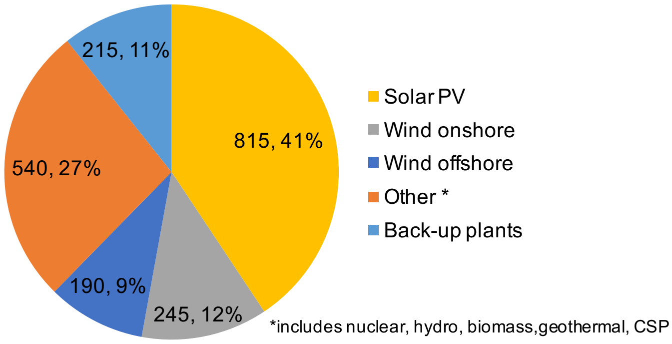


Figure 1.1: EU 100% renewable scenario 2050 - installed capacities in GW [9]

1.2. Electricity balancing

Changing to renewable energy sources brings several complications to the electricity system. Supply and demand need to match at any time. Non-dispatchable power sources such as wind and solar energy have a variable and intermittent nature. A low share of non-dispatchable power generation will not cause problems in the electricity system because conventional power plants can balance the system. Higher shares of non-dispatchable intermittent power sources and the decommissioning of the conventional dispatchable power plants, however, result in balancing issues. Positive and negative balancing plants and energy storage are required to balance the electricity system. Negative balancing power is required to balance an electricity surplus, positive balancing power compensates an electricity shortage. Unbalanced surpluses can results in an increased grid frequency which can damage electronic equipment. Unbalanced deficits decrease the grid frequency which could cause blackouts. A surplus causes the electricity price to drop, while a deficit makes the electricity price increase. In 2016, the electricity price dropped below zero twice in Germany, because of large electricity surpluses caused by the high share of solar and wind energy [10].

There are several technologies to balance electricity systems such as batteries, pumped hydro storage or hydrogen. This research focuses on hydrogen and fuel cells. Figure 1.2 shows an example in which the electricity system is balanced with the use of hydrogen. An electrolyser uses surplus electricity to generate hydrogen, a fuel cell consuming hydrogen compensates the power deficit by delivering electricity to the grid.

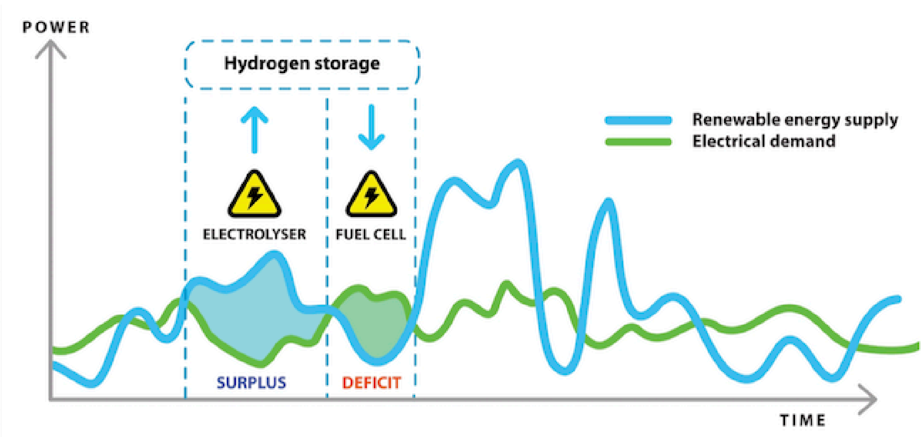


Figure 1.2: Example of how an electricity grid could be balanced with electrolysers, fuel cells and hydrogen storage.[11]

1.3. Seasonal storage

The increasing amount of renewables in the generation mix requires energy storage for short and long term. Short term is intra-day storage or storage for several days. A battery for example, can store excess solar electricity during the day to power a house in the night. Long term storage is storage for weeks or seasons. Areas with significant less solar irradiation in the winter (northern Europe) or a large share of wind energy requires seasonal storage to overcome larger periods of a generation shortage.

Energy storage in the form of hydrogen is a promising solution for large scale long term energy storage and can also be applied on the short term. Figure 1.3 shows various energy storage applications and technologies. For long term storage such as seasonal and inter-seasonal storage the available technologies are limited. Pumped hydro storage (PHS) and compressed air energy storage (CAES) can have large power outputs but these technologies are insufficient for seasonal storage. Batteries can be used for intra-day storage, load following or even frequency regulation but they are insufficient for long term storage [12].

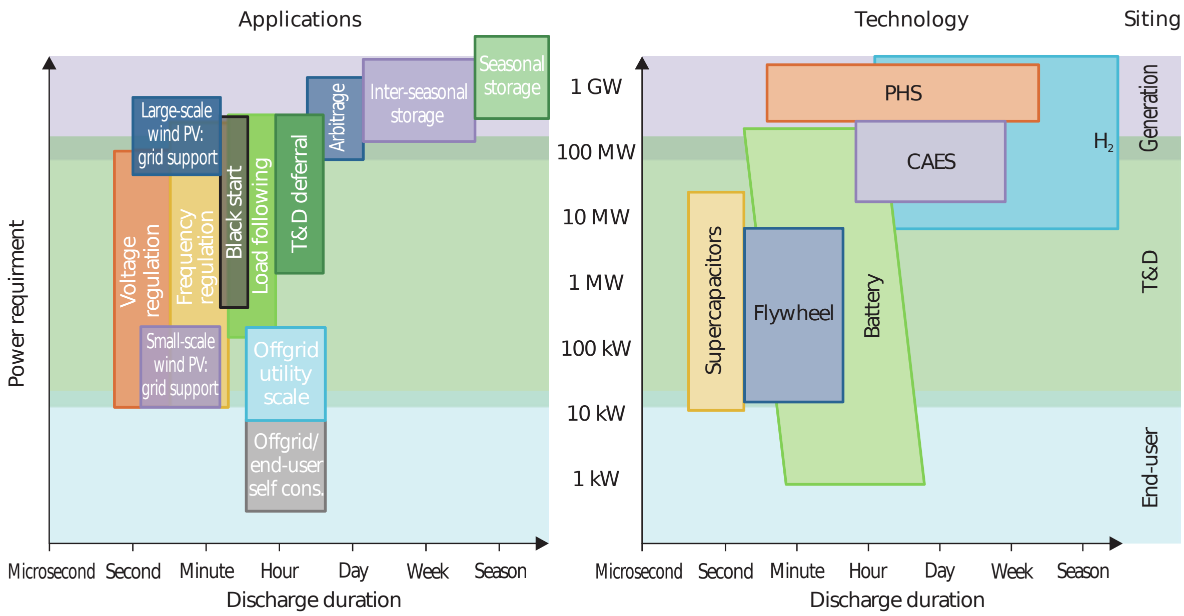


Figure 1.3: Electricity storages applications and technologies - IEA Hydrogen roadmap [13]

Hydrogen can be stored on large scale in underground salt caverns [14–17]. A typical salt cavern can store approximately 6 million kg of hydrogen as working gas resulting in an net storage capacity of approximately 200 GWh (see appendix B.5). This storage capacity is equivalent to almost 14 million Tesla Powerwalls of 14 kWh each [18], without taking into account the self-discharge of Lithium-ion batteries. The Guangzhou Pumped Storage Power Station in China is currently the largest PHS plant in the world with a head of 535 m and a volume of 24 million m^3 [19]. The volume of this reservoir needs to be enlarged over 6 times to match the stored energy of a 200 GWh salt cavern.

The 100% renewable scenarios for Germany [5], Belgium [6] and Denmark [4] (mentioned in section 1.1) also use hydrogen for seasonal storage. The Danish Energy Agency (DEA) developed four 100% renewable scenarios for Denmark. The hydrogen scenario leads to the lowest fuel consumption but more importantly, it results in the highest degree of energy self sufficiency.

1.4. Fuel cell electric vehicles & Vehicle-to-grid

Passenger cars are parked more than 95% of the time [20, 21]. A system where electric vehicles (EVs) are connected and delivering power to the grid is called a Vehicle-to-Grid (V2G) system. Trials in Denmark and Italy already showed how battery electric vehicles (BEVs) could help balance supply and demand [22]. Could parked and unused grid connected fuel cell electric vehicles (FCEVs) fuelled with hydrogen replace the positive dispatchable power plants? At the Delft University of Technology it has already been demonstrated that a Hyundai ix35 FCEV can deliver power to the grid [23]. Research also concluded that large-scale-grid-connected FCEV systems could balance fully renewable integrated transport and energy systems in smart city areas [11, 24].

Figure 1.1 from the ECF 100% renewable scenario showed that 215 GW of back-up power is required to balance Europe in that 100% renewable 2050 scenario. 21.5 million FCEVs, rated at 10 kW each, could possibly replace these backup plants. This is less than 10% of the passenger car stock in Europe at the end of 2015 [25]. This scenario requires intensive expansion of interconnections but gives an indication of how many vehicles are required for backup.

1.5. Research questions

The objective of this research is to get insight in how it is possible to balance a national electricity, heat and transport system of a country that is powered for 100% by renewables with the use of hydrogen storage and FCEVs connected to the grid. The objective is to provide insight in when V2G balancing is required and how much of the FCEV fleet should be available, how much storage capacity is required and how much hydrogen needs to be produced. Social and economical aspects are beyond the scope of this research. Multiple countries with their own consumption patterns, geographical differences and energy mixes will be evaluated. This results in the following research question:

How can 100% renewable national electricity, heating and transport systems be balanced with the use of hydrogen storage and production and grid connected fuel cell electric vehicles?

To answer this question the following sub-questions have been composed:

- How many FCEVs are required and when are they required?
- How much electrolyser capacity is required and when are electrolysers required?
- How much hydrogen needs to be produced and how much storage capacity is required on a yearly basis?
- What is the influence of demand response heating and interconnecting national electricity grids on balancing requirements and storage?

1.6. Research outline

Chapter 2 describes the used methodology to answer the research questions. Chapter 3 describes the future energy system and its components. Also a choice of technologies will be made. Chapter 4 elaborates on the modelling of the energy system and model inputs. Chapter 5 elaborates on the national energy systems of several countries in Europe. The current energy system is evaluated, 100% renewable scenarios will be analysed and country specific model inputs are defined. The results per autonomous country will be shown and discussed. In chapter 6, the similarities and differences between the countries will be shown and discussed. Chapter 7 shows and discusses the results of interconnecting countries in the future scenario. In chapter 8 the model and key assumptions are discussed. The work will be concluded in chapter 9. Finally recommendations are given in chapter 10.

2

Methodology

This chapter describes the approach in this research to answer the research questions from section 1.5. The research will be carried out through the following steps:

- A future national autonomous electricity, heating and road transport system will be designed which is 100% supplied by renewable energy and is fully balanced by FCEVs connected to the grid.
- All System components will be analysed and a choice of technologies will be made.
- A model will be made to asses the usage of grid connected FCEVs and electrolysers in the energy system. The model simulates a full year on an hourly basis.
- Several case studies for key countries in Europe will be done based on existing 2050 scenarios
- Other balancing methods will be investigated.

Design of an electricity, heating and road transport system
A 100% renewable powered autonomous national energy system will be designed for 2050. The system includes all electricity consumption, heating for residential and the commercial sectors and road transport. Road transport only consists of FCEVs, battery electric vehicles (BEVs) or a combination of both called fuel cell range extended electric vehicles (FCREEVs). Hydrogen and electricity are the only energy carriers. FCEVs in V2G replace positive dispatchable balancing power.

System components & Choice of technologies
First a literature study is performed. Components of the future energy system are defined and a choice of technologies is made. The system inputs such as conversion efficiencies, specific energy consumption of vehicles and the composition of the vehicle fleet are defined.

Modelling
A deterministic model of the system is made to asses the usage of FCEVs connected to the grid. The model simulates electricity generation and consumption, heating and road transport for a full year using hourly RE generation profiles, installed capacities and consumption profiles from the past years (2014, 2015, 2016). The components are sized to balance hourly electricity supply & demand. MATLAB is chosen as modelling software.

Country & Scenario analysis
Several key countries will be investigated. Figure 2.1 shows the investigated countries. These countries are selected for their availability of data, size of the energy system or renewable ambitions. Existing future energy scenarios for 2050 published by research institutions such as the DEA scenarios for

Denmark [3] and the scenarios for Germany by Fraunhofer [5] are analysed and modified to 100% renewable energy and transport scenarios. These scenarios are simulated with the model to asses the usage of FCEVs connected to the grid replacing conventional balancing plants.

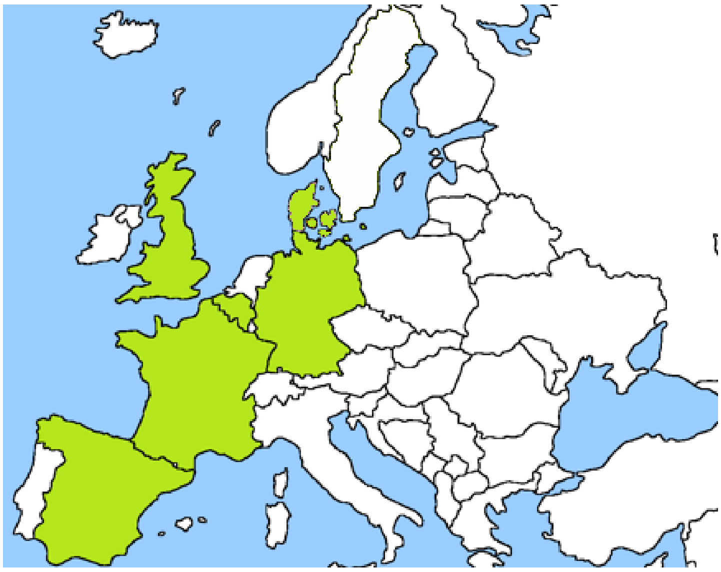


Figure 2.1: Investigated countries

Other balancing solutions

Two other solutions to balance and reduce the amount of backup are investigated. The electricity grids in Europe are already interconnected. The impact of interconnecting countries in a future scenario on the balancing requirement and storage will be looked at. The other solution is reducing the impact of electric heating with demand response heating (DRH).

3

System design & Components

This chapter describes the autonomous future energy system but first elaborates on previous work regarding designing and modelling of 100% renewable future energy systems.

3.1. Review of previous work

This section elaborates on previous work regarding balancing of energy systems, 100% or almost 100% renewable energy systems and the integration of V2G in the energy system.

3.1.1. Balancing techniques

Supply and demand of electricity in electricity grids need to match at all time. In conventional energy systems the electricity supply is adapting to demand through power plants with different response time. Slow responding power plants such as coal fired power plants has a large response time which could cover base loads while fast responding plants such as open cycle gas turbines (OCGTs) could cover peak demands [12]. Increasing the amount of variable renewable energy sources requires more flexibility in the energy system. Besides stronger variations on the supply side electrification of sectors such as industry, road transport and heating can also cause strong fluctuations and peak demands on the demand side of the electricity system.

Energy storage could add extra flexibility to the energy system, surplus energy is stored to be used later with an energy shortage. Besides supply side measures and energy storage the flexibility of the energy system could also be improved by demand side management (DSM). Examples of DSM are smart charging schemes for BEVs, intra-day management of electric heating systems but also load shifting of household appliances such as dishwashers washing machines and dryers. The advantage of DSM is that it could be 100% efficient since no energy conversion to and from a storable form is required. In addition, DSM can reduce price spikes, the average spot price and shit market power from produces to consumers [12]. Despite those benefits the implementation of DSM is slow due to a lack of ICT infrastructure and technology financing [12].

3.1.2. 100% Renewable energy systems

A literature review published by the Energy Innovation Reform Project [26] reviews 30 deep decarbonisation studies published since 2014.

They conclude based on the economy-wide studies that a low carbon power sector needs to expand to decarbonise greater shares of transportation, heating and industrial energy demand. The electricity end-use will increase by direct electrification of end uses, such as BEVs and heat pumps, or by creating hydrogen or synthetic natural for use a heating or transport fuel, or as industrial feedstock [26].

Deep decarbonisation of the electricity sector is significantly more difficult than more modest emission reduction targets. Decarbonising a half to one third of the electricity sector can be achieved with a mix of commercially available technologies such as replacing coal fired power plants for combined cycle gas turbines (OCGTs) and increasing the share of renewable electricity. Reaching near-zero emissions requires replacing virtually all coal and gas fired power plants by zero-emission sources.

Deep decarbonisation needs significantly different electricity mix than the more modest reduction scenarios which makes it important to have long term decarbonisation targets. Short term reduction targets could be achieved by replacing coal fired power plants by combined cycle gas turbine (CCGT) plants, but could result in a costly ‘lock-in’ of a suboptimal generation mix in the long term. Policy measures should consider the long term energy transition and avoid short term emission targets which might make deep decarbonisation more challenging [26].

The reviewed studies that explore 100% renewable energy systems, or scenarios with more than 80% renewable energy, indicate that deep decarbonisation primarily or entirely with renewable energy may be theoretically possible but is significantly more challenging and costly than pathways with low-carbon resources. The reviewed studies agree on several key features of the renewable energy system [26]:

- Energy systems dominated variable renewables such as wind and solar energy are physically larger requiring much greater total installed capacity.
- Wind and solar power systems require substantial dispatchable power capacity to ensure demand can be met at all times.
- Without a eet of reliable, dispatchable resources able to step in when wind and solar output fade, scenarios with very high renewable energy shares must rely on long-duration seasonal energy storage.
- Very high shares of wind and solar entail significant curtailment - even with energy storage, transmission, or demand response.
- High renewable energy scenarios also envision a significant expansion of long-distance transmission grids.
- High renewables scenarios are more costly than other options, due to the factors outlined above.

3.1.3. Integration of vehicle-to-grid

Ekman [27] investigates the synergy between a large scale BEV fleet and high wind penetration in a future Danish power system. Different charging strategies are investigated and V2G is considered. The results show that smart charging with BEVs help balance the mismatch between production and consumption and can decrease excess wind power significantly. However, a large fleet of BEVs on its own is not able to balance the fluctuating mismatch between wind power and consumption. Other balancing mechanisms are required for wind electricity penetrations higher than 50% [27]. V2G with BEVs can assist in balancing but the effects are limited and is more likely to be used only for regulation and reserve services.

The only known work combining FCEVs and V2G originate from the Car as Power Plant (CaPP) project [20] and the work of Cao and Alanne [28], investigating the technical feasibility of a hybdid on-site hydrogen and RE system for a zero energy building (ZEB) with a FCEV and V2G. The simulation results show that with the support of a 14 kW wind turbine the modelled building in Helsinki will be a nearly ZEB with full availability of the FCEV. With the support of 178m^2 solar PV panels the building could be an ZEB with 48 days annual unavailability of the vehicle [28].

The work of Alavi et al. [29] looks into the integration of FCEVs in a microgrid for synergies between hydrogen and electricity networks. A schematic representation of the modelled CaPP microgrid system can be seen in figure 3.1. FCEVs are provided with renewable hydrogen reducing the well-to-weel emissions, and the micro grid will benefit from storage of excess electricity increasing the system flexibility. Without the FCEVs the microgrid would require balancing plants, demand response and storage, or electricity should be imported from the public grid. As a result, the problem of congestion and fast variation in power generation can be solved without curtailment.

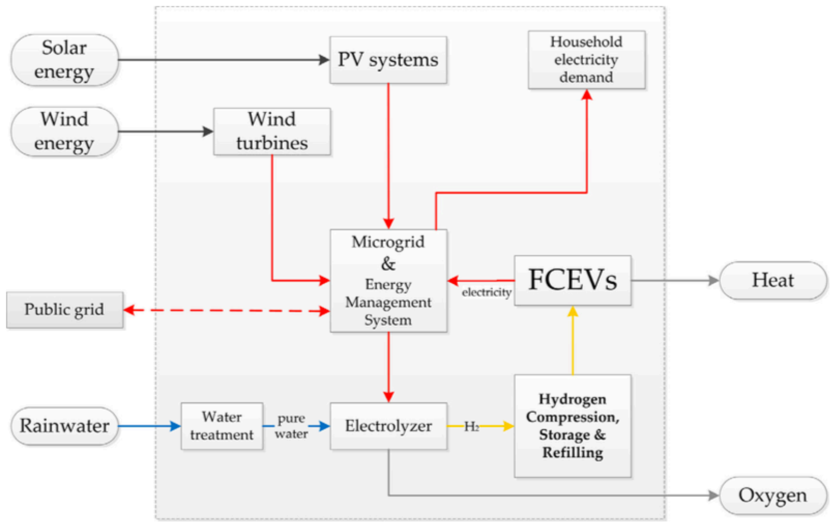


Figure 3.1: Schematic presentation of the CaPP microgrid system [29]

The work of Oldenbroek et al. [24] investigates whether for city areas, RE generation together with FCEVs as backup generators and hydrogen as energy carrier, can provide a 100% renewable, reliable and cost effective energy system, for power, heat, and transport. A smart city area is designed and dimensioned based on European statistics. An energy balance and cost analysis is performed for a near future and mid century scenario. The smart city can be balanced with 20% of the car fleet being a FCEV and available for V2G in a mid century scenario. The thesis of Smink [11] continued on this work with hourly simulations of two mid-century smart-city scenarios for Hamburg and Alicante confirming some of the results of [24].

3.2. System overview

Figure 3.2 shows an overview of the energy system. The system can be summarised by the following points:

- The system is powered by renewable sources only (section 3.3).
- Generated electricity is either directly consumed on the electricity grid (section 3.4) or surplus power is consumed for the production of hydrogen (section 3.7).
- Road transport consists of FCEVs, BEVs or a combination of both (section 3.5).
- Only FCEVs connected to the grid are considered to provide balancing power to compensate electricity shortages (section 3.5 & 3.6).
- Hydrogen is stored for road transport and V2G (section 3.8).
- The choice of technology is based on technologies that are commercial or will be commercial on the short term. Only the efficiency of these technologies improves.

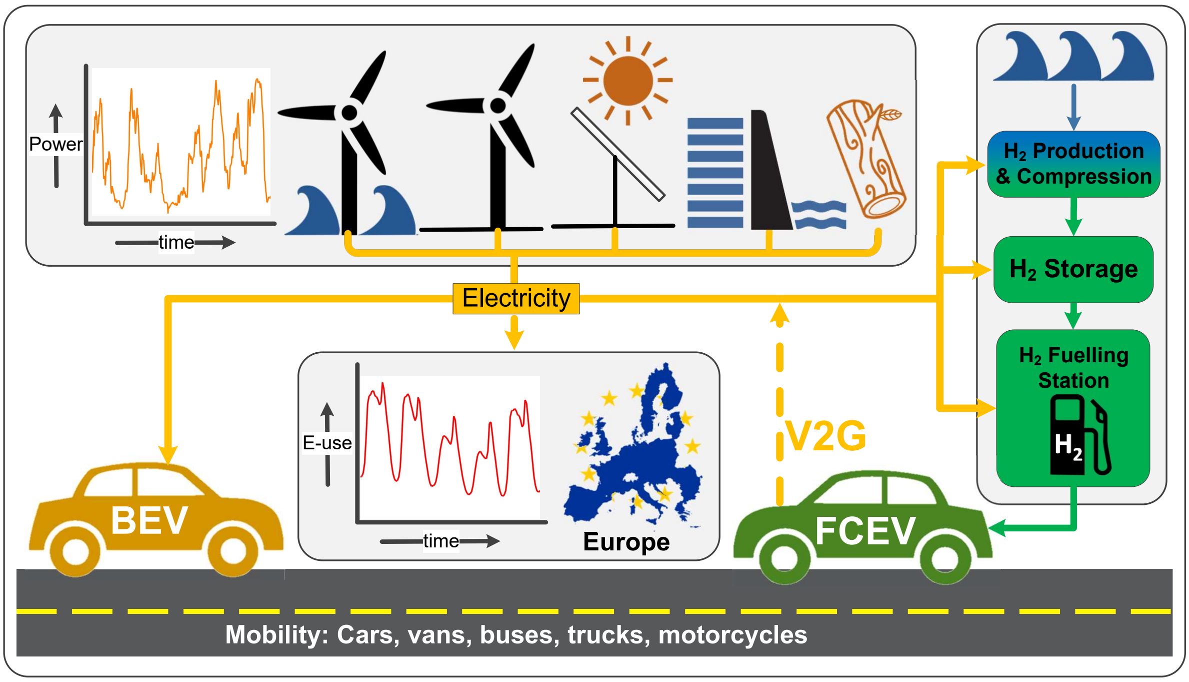


Figure 3.2: System overview

3.3. Electricity generation

Only renewable electricity generation is considered. Conventional power plants burning coal or natural gas and nuclear power plants are excluded. The main forms of electricity generation are solar PV, on- and offshore wind, and hydropower. In some scenarios Combined Heat and Power (CHP) plants burning biomass & biogas, concentrated solar power (CSP) or geothermal power are considered. Electricity generation can be centralised such as large hydro power plants or wind parks and decentralised such as onshore wind turbines or rooftop PV.

3.4. Electricity consumption & Heating

Electricity consumption is divided in three parts: classic electricity consumption, electricity for space heating and hot water and BEV charging. The classic electricity consumption or the traditional electricity consumption is the electricity consumption as it is today. This includes for example consumption of household appliances, (public) lighting, electric public transport such as trains and trams (no road transport) and the electricity use in offices and industry. There is additional electrification in several sectors especially in heat and transport. Electrification in the industry is not taken into account in this research. All road transport will be electrified with a shift to BEVs and indirect electrification with FCEVs. Section 3.5 elaborates further on the electrification of road transport.

The hot water and space heating sector needs to change significantly and requires a lot of electrification to decarbonise this sector. Gas boilers will be replaced by heat pumps and more buildings will be connected to district heating networks. District heating networks makes it possible to distribute, store and reallocate heat and use waste heat [30]. This can result in significant savings. Heat can either be supplied by heat pumps, geothermal power, solar thermal, or from CHP plants. Heat pumps could be installed in buildings or supply to the district heating networks. In most case studies heat supply from heat pumps is dominant.

Demand response heating
Since heat pumps (HPs) and district heating networks have buffers to store heat, supply and demand

of heat do not need to match at all time. Depending on the size of the buffer the load could be shifted for several hours or spread over the day [30]. Current electric boilers already have intra-day management [31] and there are already several heat pumps on the market with a 'PV ready' option. A connection between the HP and a converter for solar PV systems gives a signal to the HP to (pre-)buffer when there is a local electricity surplus [32, 33]. Local smart grids could also manage the consumption of heat pumps as is demonstrated in the Netherlands [34] for example. Several 100% renewable energy reports introduce solutions for peak shifting of electricity consumption. In the ADEME report for 100% renewable electricity in France [31] is for example assumed that hot water buffers and HPs have intra day management for demand-side management. In the future energy scenarios for Great Britain smart metering is an important factor in energy balancing [7]. The electricity consumption of heat pumps is assumed to be demand response heating (DRH). Heat pumps will adapt to the nationwide imbalance to minimise V2G back up and peak-shave the demand of electrolysers. Section 4.2.2 and appendix C will explain in detail how DRH works and how it is modelled.

3.5. Transport

In this system all forms of road transport are taken into account. Other forms of electric transport such as trains are already part of the classic electricity consumption. Non-electric transport such as ships, aeroplanes and non-electric trains are not taken into account. Shifts in transport mode such as a shift in freight from trucks to rail or passengers from cars to public transport are not taken into account.

3.5.1. Electric vehicles

There are several types of electric vehicles (EVs). The most common types are the battery electric vehicle (BEV), the plug-in hybrid electric vehicle (PHEV) and the fuel cell electric vehicle (FCEV). The PHEV however is not a zero emission vehicle (ZEV) since those vehicles have an electric motor and a combustion engine. Future PHEVs could be fuelled with biogas but is not within the scope of this research since only hydrogen and electricity are considered as energy carriers. The amount of EVs is growing rapidly. In 2016 750 thousand EVs were sold resulting in a global car stock of over 2 million vehicles. 1.2 million of these EVs are BEVs and 800 thousand are PHEVs [35]. The amount of FCEVs is still very small and therefore not included in the statistics of the IEA EV outlook [35].

Fuel cell electric vehicles
Just as the other EVs, a FCEV is powered by an electric motor. The difference is the energy carrier, energy is not stored in a battery but in the form of compressed gaseous hydrogen. A fuel cell (FC) in the car converts hydrogen to generate electricity for the electric motor. A FCEV can cary about 5-6 kg of hydrogen which results in a projected range of at least 500km. Table 3.1 shows the passenger FCEVs that are currently for sale and their specifications.

Table 3.1: Available FCEVs & specifications

Make/model	Hydrogen capacity [kg]	Power FC stack [kW]	NEDC[1] range [km]	EPA[2] range [km]	Battery capacity [kWh]	References
Hyundai ix35	5.64	100	594	427	0.95	[36–39]
Honda Clarity	5.6	103	650	589		[40–44]
Toyota Mirai	5	114	550	502	1.6	[45]

Figure 3.3 gives an overview of the working principle of a FCEV. At a hydrogen fuelling station (HFS) the tanks are filled with hydrogen. Hydrogen is stored under high pressure (700 bar) in tanks manufactured form Carbon Fiber Reinforced Plastics (CFRP). Hydrogen and air (oxygen) are fed to the fuel cell which

[1]New European Driving Cycle
[2]Driving range rating by the US Environmental Protection Agency (EPA)

produces electricity for the electric motor and other equipment. The only emission of the car is clean water. Kinetic energy can be recovered and stored in a (small) battery under braking.

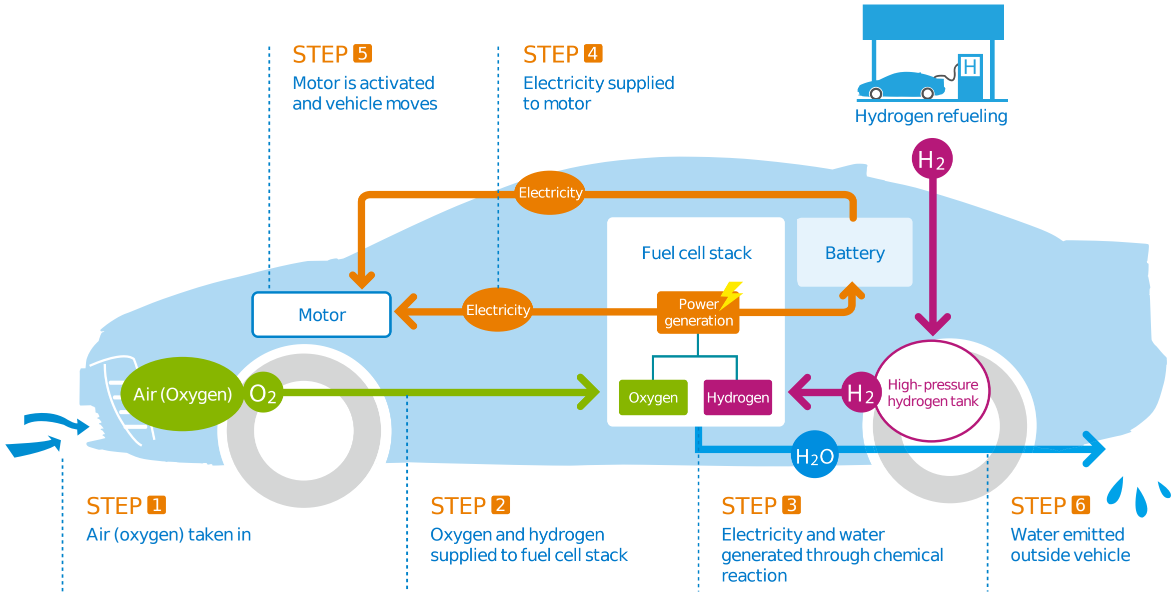


Figure 3.3: Working principle of a FCEV [45]

The advantage of using hydrogen instead of a battery is that it is much faster to refuel. Another advantage is the higher energy density which results in a longer range. The Honda Clarity for example has a curb weight of 1890 kg and has a range of 366 miles (589 km) according to the EPA cycle. The Tesla model S 100D weights at least 2100 kg [46] and has a range of 335 miles (539 km) according to the EPA cycle. It should be noted that the electric motor in the Tesla is stronger and therefore slightly heavier than the motor in the Honda.

FCEVs with a larger battery are called fuel cell range extended vehicles (FCREEVs). This type of vehicle is a combination of a FCEV and a BEV or a PHEV where the combustion engine is replaced by a FC. An example is the Mercedes-Benz GLC F-cell which will be presented in 2017 [47]. This vehicle combines a FC and hydrogen storage tanks which can hold 4 kg of hydrogen with a battery of 9 kWh. The range of this vehicles is around 500 km according the NEDC. The battery can be charged at a socked just as a PHEV or BEV.

3.5.2. Road transport

All road transport is considered to be powered by an electric motor. Hydrogen and electricity (in the form of batteries) are the only energy carriers. A combination of both a hydrogen storage tanks and a battery is possible. Batteries are sufficient for vehicles with a low annual driven distance. For vehicles driving a longer distance and heavy duty transport the range with a battery is simply too short or the vehicle becomes too heavy. Several 2050 scenarios predict a combination of hydrogen and methanol for heavy duty transport and conclude that batteries are not sufficient [4, 48, 49]. For passenger cars and motorcycles batteries and hydrogen will have an equal share in the fleet composition in this research. Heavy duty transport will be dominated by hydrogen. Section 4.3.1 will elaborate in detail on the fleet composition.

FCEVs can be fuelled at a hydrogen fuelling station (HFS). The Society of Automotive Engineers (SAE) introduced in 2010 a hydrogen fuelling protocol, the SAE J2601 [50]. This protocol describes the fuelling procedure and storage in FCEVs. The protocol is standardised so FCEVs can fuel at any HFS and speeds up the roll-out of new stations. Hydrogen can be produced on site or the hydrogen is supplied by a pipeline or tube trailers. In Germany for example the target is to have 100 HFSs in 2018 covering the large metropolitan areas and ensuring a hydrogen corridor. The goal for 2023 is to have 400 HFSs and a nationwide coverage across Germany [51]. Recent build hydrogen fuelling stations (2016) have a dispensing capacity of 450 kg/day. It is expected that larger stations will be build in the near future with dispensing capacities of 1500 kg/day (~ 300 passenger FCEVs/day) [52, 53] and ITM wil unveil new designs for large scale hydrogen fuelling stations at the Hydrogen + Fuel Cells North America exhibition in Las Vegas in September 2016 [54]. These fuelling stations can produce on-site up to 20 tonnes of hydrogen per day with 50 MW electrolyser capacity.

In the future energy system FCEVs could be fuelled at the HFSs or in car park power plants (CPPPs) where the vehicles can be connected to the grid and refuelled afterwards. BEVs could be charged at home, at the office or at fast charging stations.

3.6. System balancing & Vehicle-to-grid

Electricity generation and consumption need to match at all time. A part of the generation can directly be absorbed on the gird, all excess electricity will be used to produce hydrogen. If the electricity consumption is higher than the generation backup power is required. fuel cells in grid connected FCEVs turn on and generate electricity to balance the grid. The electricity generation should be sized in such a way that there is enough surplus electricity to produce as much hydrogen as is consumed on a yearly basis.

As mentioned before passengers cars are parked over 90% of the time. While electric vehicles are parked and grid connected they could also deliver electricity. BEVs and FCEVs can be used for V2G but here only passenger FCEVs are considered. The advantage of using FCEVs for V2G is that FCEVs can be refuelled fast after delivering to the grid while BEVs need to recharge via the same grid. BEVs with V2G could therefore be used on the really short term for load shifting but not for long term V2G. Research by Ekman [27] concluded that in a future Danish energy system with a wind electricity penetration of more than 50% could not be balanced with BEVs and V2G alone. Other balancing mechanisms would be required.

An example is the Car as Power Plant at The Green Village and the TU Delft. A Hyundai ix35 FCEV is equipped with a custom 10 kW DC outlet [23]. When the car is connected to the AC inverter it can deliver electricity to the grid. The Honda Clarity and Toyota Mirai also have an electricity outlet and require an external converter [45, 55] to connect to AC applications. There are several experiments with wireless inductive charging [56] and automated positioning [57] of an EV above an inductive charger. These techniques could also be used for delivering electricity instead of only charing which makes it easier for vehicle owners to make their vehicles available for V2G programs.

3.7. Hydrogen conversion processes

This section describes production, purification, compression, fuelling of the FCEVs and reconversion of hydrogen in the FCEV. This route from production to consumption of hydrogen is shown in figure 3.4.

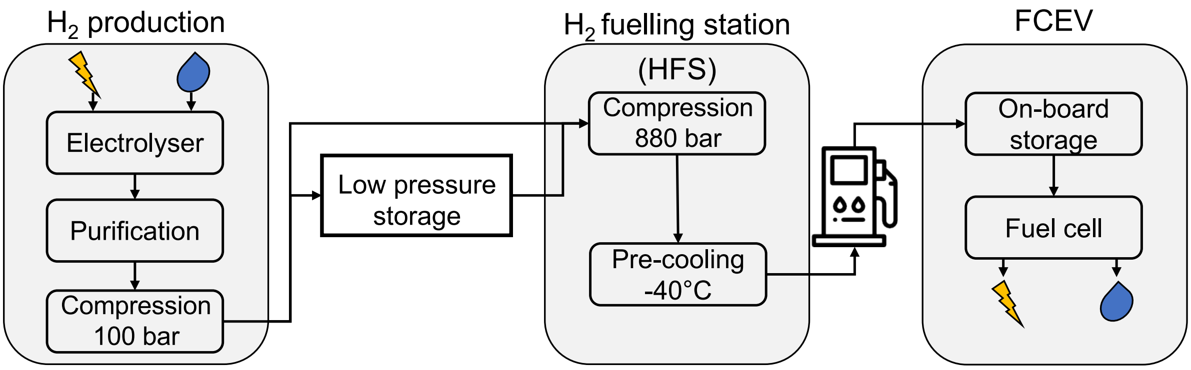


Figure 3.4: H_2 route from production to consumption

3.7.1. Hydrogen production from electricity

Hydrogen can be produced in several ways, from renewable sources or from fossil fuels. Only production of hydrogen from renewable electricity by electrolysers are considered in this research. More on all the types of hydrogen production can be found in appendix A.2 on page 117.

An electrolyser creates hydrogen and oxygen by splitting water with electricity. This process is the reversed process of a fuel cell. There are several types of electrolysers. The oldest and most mature type is the alkaline electrolyser. The downside of these electrolysers is the low power density compared to other types. The proton exchange membrane (PEM) and solid oxide (SO) electrolysers show a greater potential to reduce captial cost and increase efficiency [13]. The PEM electrolyser is also flexible with respect to ramp-up and load range which makes it suitable as balancing plant. The current efficiency of PEM electrolysers is 65-80% on HHV basis while the mid century (2050) efficiency is expected to be 86% on HHV basis [13]. That electrolysers can function as negative balancing power has already been demonstrated back in 2015. In Germany the first PEM electrolyser entered the balancing market to offer negative balancing power and produce hydrogen at the same time [58]. The plant operates at a load range from 50 to 320 kW with an efficiency of 77% on HHV basis.

Because of the flexible ramp-up, quick startup and load range it is chosen to use the PEM electrolyser in the future energy system to function as positive balancing plant and production of hydrogen.

3.7.2. Fuel cells

Fuel cells convert hydrogen and oxygen to electricity with heat and water as ’waste’ products. As mentioned in the previous section this process is a reverse electrolytic process. The fuel cell types are the same as the electrolyser types. More on all the types of fuel cells can be found in appendix A.1 on page 113. PEM fuel cells are mainly used in FCEVs because of the flexible operation and quick start up of the fuel cell. The current efficiency of stationary PEMFCs is 49% on HHV basis [13]. Mobile PEMFCs, in FCEVs for example, have a peak efficiency up to 60% on HHV basis according to [13, 59]. The peak efficiency for mobile PEMFCs is expected to be 65% in 2020 and 70% as an ultimate target [59].

3.7.3. Hydrogen route from production to consumption

Hydrogen could be produced directly at hydrogen fuelling stations (HFSs), near grid connections of large scale electricity generation, or at large scale storage sites where hydrogen can be directly stored after it is produced. Hydrogen is produced in the electrolyser by splitting water. Rain- or seawater needs to be demineralised before it can be used in electrolysers [24]. After production it needs to be purified from moisture and oxygen traces before it can be used in a fuel cell. After purification hydrogen is compressed to 120 bar. Compressed hydrogen could be directly stored or it is transported in pipelines to a large scale storage or to HFSs. Hydrogen could also be transported to fuelling stations by trailers but here it is assumed that all hydrogen is transported in pipelines and there are no losses during transportation. At the fuelling station hydrogen is compressed to 880 bar. Hydrogen has a reversed Joule Thompson effect which results in a temperature increase when it expands instead of a temperature drop. To ensure the safety of the storage tanks in a FCEV the maximum temperature in the tank is limited to 85°C [50]. To reduce the fuelling time hydrogen is pre-cooled to -40°C before fuelling. The energy consumption of all components can be found in table 4.2 in section 4.5.

3.8. Hydrogen storage

The storage of hydrogen is an important factor in this research. Especially storage in cars, at HFSs and large scale storage. Hydrogen can be stored physically or material based as can be seen in figure 3.5. Physical based storage means that the hydrogen is physically stored in a tank. This could be achieved by compressing the hydrogen, cooling it to a liquid, or the combination of both. Material based storage means that hydrogen is stored in another material by means of chemical storage or adsorption for example. All FCEVs on the market store hydrogen as a gas compressed to 700 bar. In this section only large scale hydrogen storage is discussed. More on all the different types of hydrogen storage can be found in appendix B on page 121.

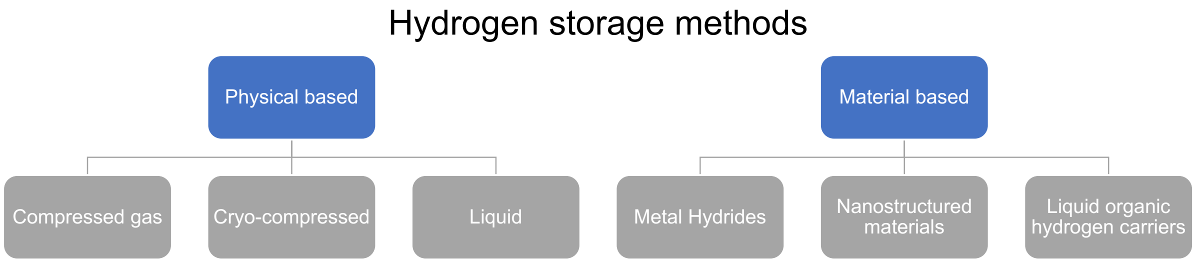


Figure 3.5: Overview of hydrogen storing methods

3.8.1. High pressure large scale storage

Large scale compressed gaseous hydrogen (CGH2) is mainly used at fuelling stations to store large quantities of hydrogen at low cost. Two types of storage vessels are used. Seamless hydrogen storage vessels are made from high strength seamless tubes but therefore limited in its diameter. The maximum volume of such a vessel is 0.411 m^3 with a maximum working pressure of 650 bar [60]. Using higher strength steel with higher working pressures is not an option because the risk of hydrogen embrittlement will increase and is thus unsafe [61]. Large fuelling stations or other large scale storage applications would require multiple vessels and additional piping and valves with these types of vessels.

Multifunctional layered stationary hydrogen storage vessels are developed to deal with the problems of seamless storage vessels. These multifunctional layered vessels consists of a flat steel ribbon wound cylinder and two reinforced rings surrounding the vessel. The ribbon wounded cylinder consists 3 different layer including a protective shell to prevent hydrogen embrittlement [60, 61]. Using such a vessel eliminates the restrictions in size and makes it feasible for large vessels with higher pressures. Theoretical analysis, and several experiments showed that failure of such tanks is always leakage rather than fraction of the vessel, 'only leak, but never burst' [61]. In 2012 the first multifunctional layered stationary hydrogen storage vessel was installed with a volume of 2.5m^3 ($\sim$ 105kg) at a working pressure of 770 bar [60]. In the following years several more of these vessels are installed with working pressures going up to 980 bar ($\sim$ 120kg) [60].

3.8.2. Large scale underground storage

A promising solution for large scale and seasonal storage of hydrogen is underground storage (UGS). Hydrogen can be stored in caverns, depleted oil fields and salt domes. This concept is often used for compressed air storage or natural gas storage but is also applicable to hydrogen storage. The main difference between storing natural gas and hydrogen in for example salt caverns is the selection of materials in the access well, cavern head and transportation piping [15].

Table 3.2, adopted from the IEA Hydrogen roadmap [13], shows that salt caverns have the best characteristics for UGS compared to the other methods, especially in terms of safety. The rock in salt caverns is practically impermeable and does not react with hydrogen which makes it safer. Depleted gas and oil fields are less favourable because of possible reactions between hydrogen and microorganisms or other mineral constituents. These reactions can lead to deterioration or depletion of the hydrogen storage or affect the surroundings [62, 63]. Salt caverns are typically used to meet peak load demands. UGS in general contains a cushion gas volume and a working gas volume. The cushion volume is the minimum volume required for reservoir management and to maintain a minimum storage pressure [62, 63]. In salt caverns this cushion gas is also required for stability. Depleted oil and gas fields have large storage capacities but also have a large cushion gas requirement. Salt caverns however have smaller storage capacities and relatively low cushion gas volume and allow high injection and withdrawal rates. In the future energy system hydrogen is assumed to be stored in salt caverns for seasonal storage and the multi-layered high pressure storage tanks are used for storage of hydrogen at the HFSs.

Table 3.2: Qualitative overview of characteristics of geological formations suitable for hydrogen storage. Adopted from the IEA [13] and HyUnder [64].

	Salt caverns	Depleted oil fields	Depleted gas fields	Aquifers	Lined rock caverns	Unlined rock caverns
Safety	++	+	-	-	-	-
Technical feasibility	+	++	++	++	o	-
Investment costs	++	o	o	o	+	+
Operation costs	++	-	o	+	++	+

Salt caverns
Several salt caverns for the storage of hydrogen are already operational. Three of these salt caverns are located in Texas, the Chevron Phillips Clemens Terminal, a storage facility owned by Air liquide and a facility owned by Praxair [15]. Another Gas Storage project in Tuz Golo in Turkey started in 2012. 12 caverns of 630,000 m^3 each will be built. The first 6 caverns should be finished in 2017, the other six in 2019 [15, 17]. Not all caverns will be used for hydrogen storage however. Another storage site is located in Teesside in the UK. The Energy Technologies Institute (ETI) completed an assessment of the potential to use salt caverns, traditionally used to store natural gas, to store hydrogen for grid balancing [65]. The UK is looking for options of energy storage because of the higher concentration of intermittent renewable power sources and because fossil fuel power stations run at lower efficiencies when operating in part load. The ETI believes that the use of hydrogen salt caverns has the potential to balance these fluctuations. The UK has over 30 large salt caverns where the largest caverns are about 600,000 m^3. An example of a site where the production with electrolysers and the storage of hydrogen will be combined is the HyStock pilot project in the northern part of the Netherlands where a 1 MW electrolyser produces hydrogen which could be stored in the salt caverns [14]. A schematic of this project can be seen in figure 3.6.

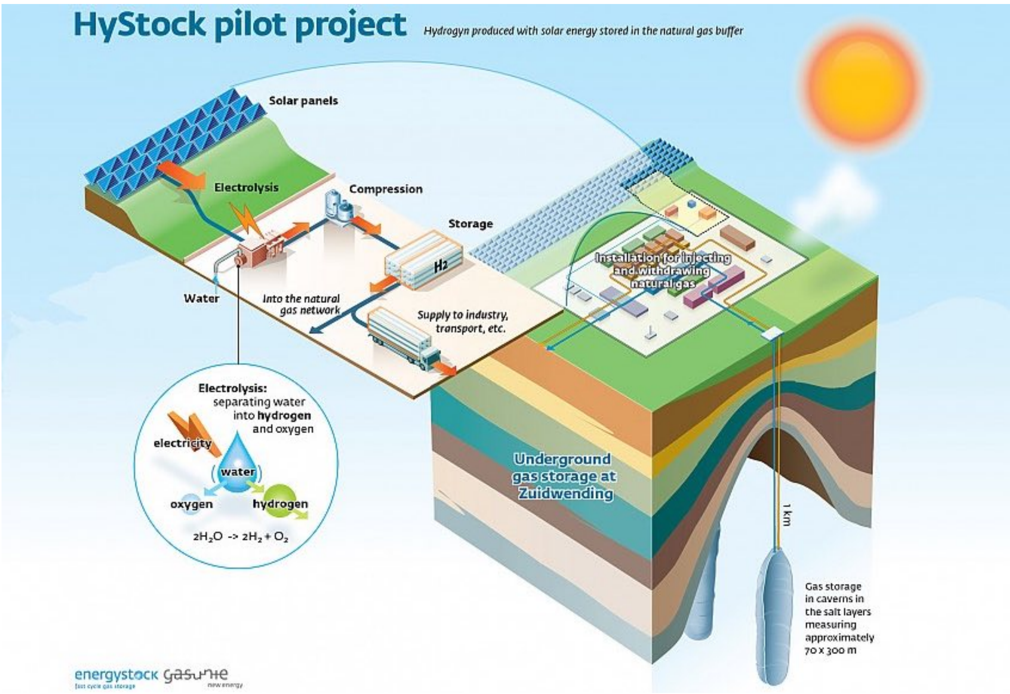


Figure 3.6: HyStock pilot project in the Netherlands [14]

For a representative salt cavern at one kilometer depth and a storage volume of 700,000 m^3 the net working gas capacity should be around 6 million kg of hydrogen with a maximum operating pressure around 200 bar [62]. 3 million kg remains as a minimum cushion gas volume, so the total mass is 9 million kg. This results in a (net) useable storage capacity of approximately 200 GWh. The calculation and the comparison with battery and PHS can be found in appendix B.5 on page 125.

Figure 3.7 from the work of Gillhaus and Horvarth [66] shows underground salt formations in Europe. The northern part of Germany, the Netherlands, Poland, Denmark and some locations in the UK and Spain are suitable for hydrogen storage in salt caverns. Salt caverns could be created in these salt formations or salt caverns already exist in those regions as a result of salt mining.

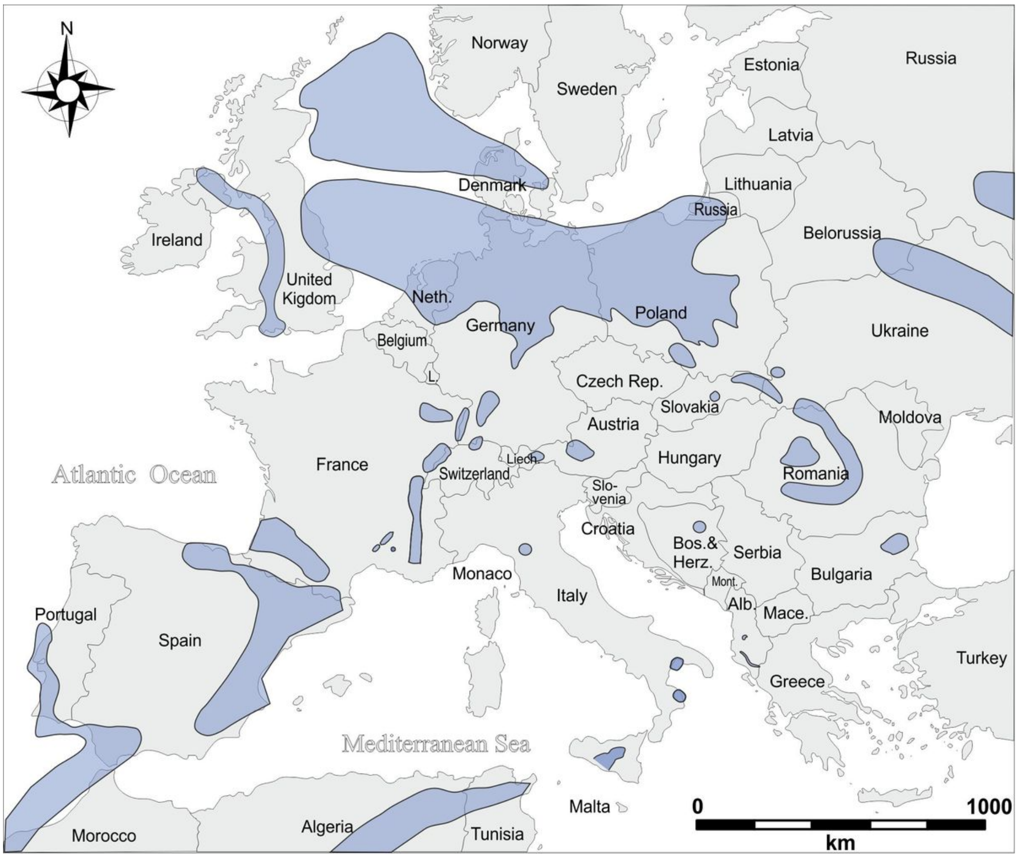


Figure 3.7: Salt formations in Europe [66]

4 Model

This chapter explains the mathematical model and the general model inputs that are independent off the country such as fleet composition, vehicle energy consumption and hydrogen conversion efficiencies. Country specific inputs such as the electricity mix, road transport data and energy consumption will be discussed in chapter 5 for every country separately.

The model evaluates a stand alone (autonomous) electricity grid, not connected to other countries. There is no import or export of electricity possible. Historic generation and consumption data of several years are used as input. The model can be divided in roughly four parts: Renewable electricity generation (section 4.1), electricity consumption (section 4.2), road transport (section 4.3) and balancing (section 4.4). This chapter elaborates on all those parts explaining the model. A schematic overview of the model can be seen in figure 4.1 and a short description is given below.

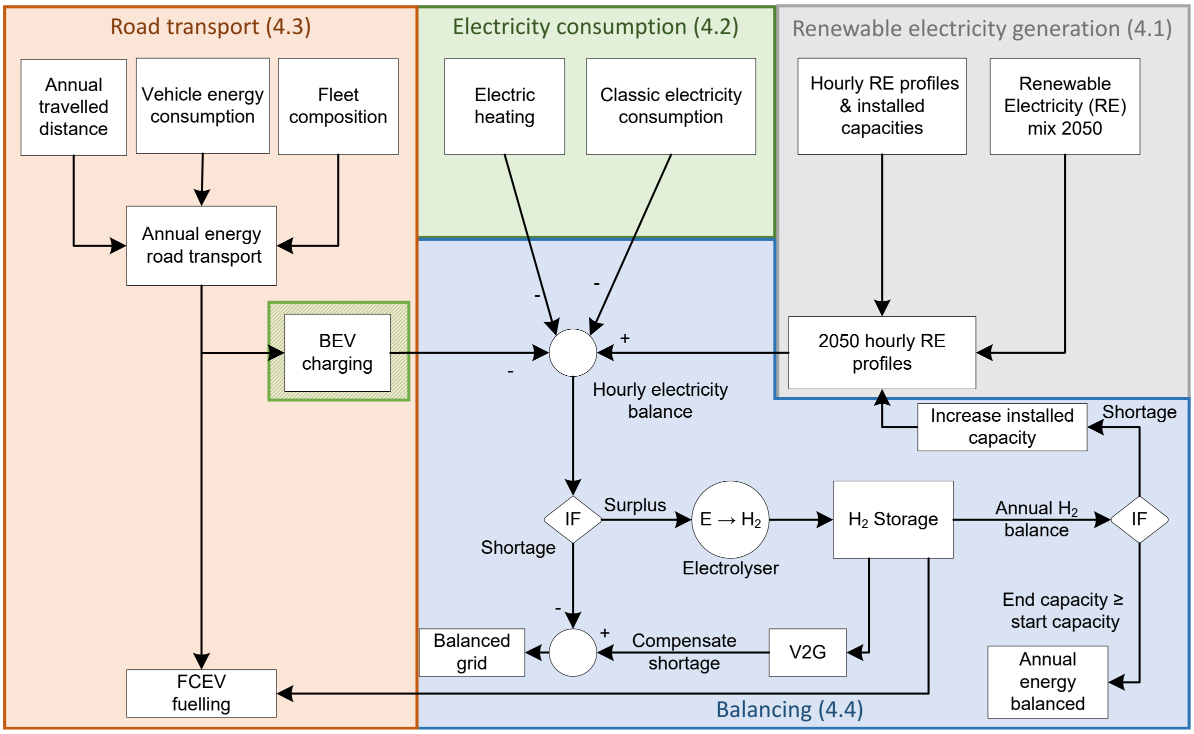


Figure 4.1: Schematic and simplified overview of the model. The parenthetical numbers correspond to the section numbers.

Every profile in the model is on an hourly basis and for an entire year. To make sure all profiles match, the model starts on the day of the base year. If 2016 for example is the base year and started on Friday, the ‘2050 scenario’ year will also start on Friday. Generation profiles such as solar and wind are not dependent on the day of the week but the consumption, charging and fuelling profiles are. The electricity generation at reservoir hydro power plants is in most cases also linked to consumption patterns. The model also takes leap years into account. The model could be summarised as follows:

- Electricity generation profiles of the past are upscaled to future installed capacities which is based on the 2050 scenarios published by research institutions, TSOs and government agencies. From now on these scenarios will be referred to as reference scenarios.
- Electricity consumption profiles such as the classic consumption, electric heating, and BEV charging in a future scenario are subtracted resulting in an hourly electricity (im)balance
- Current annual travelled distance and the number of vehicles is used to construct the future road transport fleet composition. With specific energy consumption per vehicle category and drivetrain type road transport energy consumption is determined.
- The hourly electricity imbalance is balanced by electrolysers and grid connected FCEVs. Surplus electricty is consumed to produce hydrogen and consumed by FCEVs in V2G mode to compensate deficits.
- The annual produced hydrogen should be enough for FCEV road transport and V2G purposes. The iteration process increases the installed capacity until this criteria is met.

4.1. Renewable electricity generation

An electricity mix is constructed based on the existing future scenario for the specific country. The mix of future installed capacity and mix of future generation is determined. Electricity generation profiles are based on the hourly annual generation profiles in the base year. Data is collected (mainly from TSOs) for the total generation per source in a country. All generation profiles will be normalised to the mean generation as demonstrated in figure 4.2. These generation profiles will be upscaled according the country’s future electricity mix which is based on a reference scenario. The generation profiles can be scaled in two ways, scaled to the future installed capacity or scaled to the future total generation. The intermittent weather dependent sources such as solar, wind and hydro are scaled to the future installed capacity to maintain the same capacity factors. The capacity factors are calculated with the generation and installed capacity in the base year (equation 4.1). Based on the 2050 installed capacity the actual generation is determined.

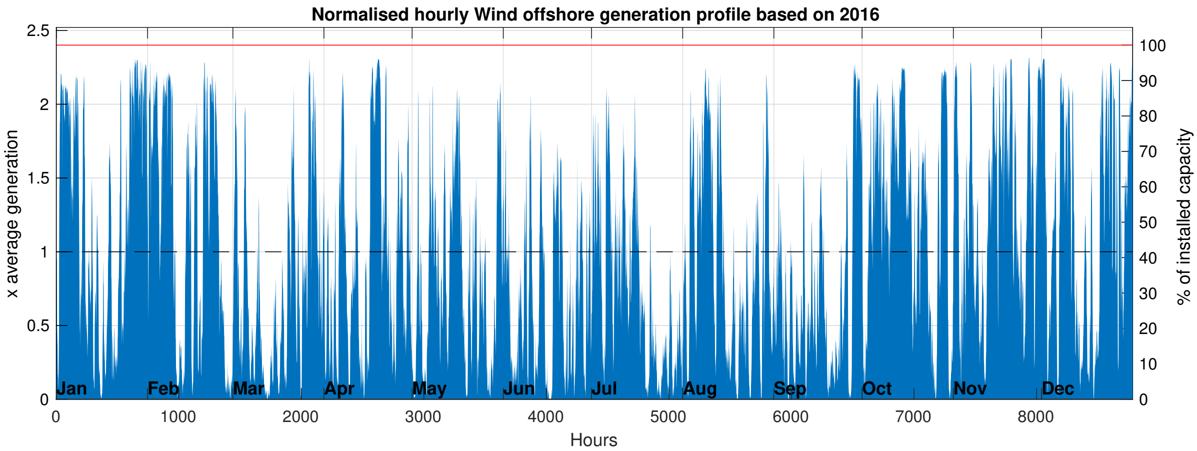


Figure 4.2: Normalised offshore wind electricity generation profile Denmark 2016

$$\text{Capacity factor} = \frac{\overline{P}}{P_{installed}} \tag{4.1}$$

Other profiles such as electricity generation from waste or CHP are scaled to a total annual generation. The normalised profile (normalised to the average) is scaled with the average generation, the total generation divided by the amount of hours in a year, to create a 2050 generation profile.

4.2. Electricity consumption

Electricity consumption consists of the classic consumption profile, a profile for electric heating and a charging profile for BEVs. The charging of BEVs is discussed in section 4.3. A cooling demand is not modelled. It is assumed that if there is a cooling demand it is already included in the classic consumption profile and will not increase significantly.

4.2.1. Classic consumption

The classic consumption profile is the yearly profile of the total grid load excluding transmission losses, the total electricity consumption in a country. A typical classic consumption profile shows a daily, weekly and seasonal variation. Figure 4.3 shows the classic consumption profile for Denmark in 2016. It shows a yearly seasonal fluctuation with a higher consumption in the winter, a weekly variation with lower consumption in the weekends and a daily fluctuation. It is assumed that the profile remains unchanged but will be scaled to future consumption as predicted in the scenarios. The profiles are normalised and scaled to the total future consumption. For some countries already a significant amount of electric heating is included in this profile. In France for example 18% of the total electricity is consumed for hot water and space heating (section 5.5.1). This has to be taken into account when the future consumption is scaled. BEV charing is still very small and therefore is assumed that it will not influence the classic consumption profile.

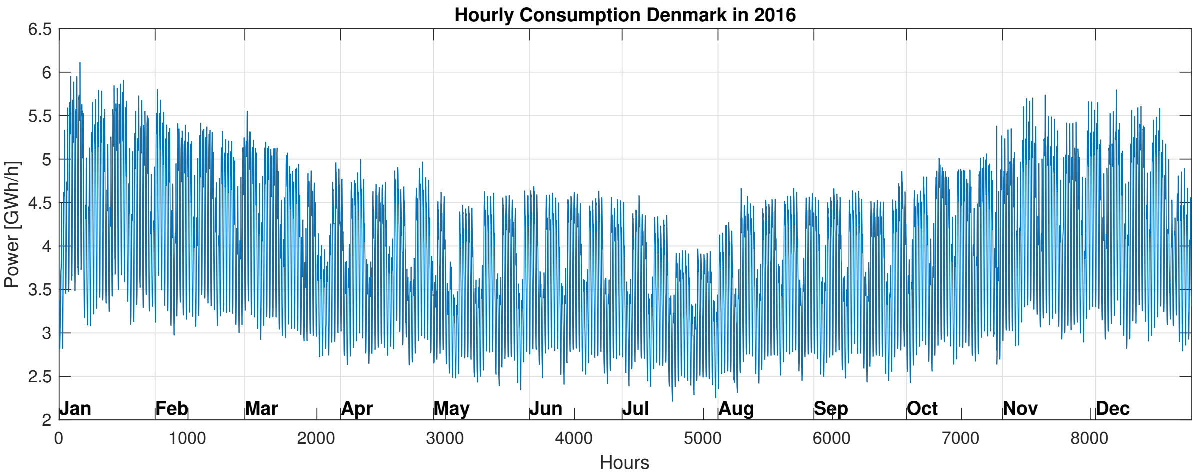


Figure 4.3: Classic consumption profile Denmark 2016

4.2.2. Electric heating submodel

As mentioned before it is assumed that almost the entire heating demand in the residential and commercial sectors will be electrified. Additional electricity consumption of heat pumps has to be taken into account. Here is assumed that all the heating devices are heat pumps. To calculate the electric heating demand the total heating demand is divided by the seasonal coefficient of performance (SCOP). The SCOP is estimated to be 3.5 based on [67–70]. This additional electric heating demand however can not be scaled as the classic consumption profile. The demand is strongly dependent on weather conditions. The heating demand consists of space heating and hot water demand. The hot water demand is assumed to be constant over the year. The daily space heating demand is dependent on the outside temperature. The fraction of hot water compared to the total heating demand is calculated with historic data from the Odyssee database [71]. It is thus assumed that the relation between space heating and hot water in the total heating demand will stay the same. The space heating demand is estimated with Heating Degree Day(s) (HDD). The mean temperature on a day is compared with a reference temperature, the outside temperature where there is no longer a heating demand. The HDD is calculated with equation 4.2 where $\overline{T}$ is the mean temperature. A typical reference temperature nowadays is 18°C. Increased insulation could reduce this temperature as suggested by [31] to a reference temperature of 16°C. This reference temperature is used in the model.

$$HDD = \begin{cases} 0 & \overline{T} > T_{ref} \\ T_{ref} - \overline{T} & \overline{T} < T_{ref} \end{cases} \tag{4.2}$$

The profile of HDD over a year will be normalised to scale it to a yearly space heating demand. Temperature data is collected from the European Climate Assessment & Data Project (ECA&D) [72] except for Belgium because there is only 1 station for Belgium available. Instead temperature data is taken from airports [73]. Daily mean temperature data is collected for several weather stations spread over the specific country. Maps with the locations of the weather stations can be found in appendix D on page 131. Figure 4.4 shows an example of the normalised daily heating demand and average outside temperature for Denmark with 2016 as base year. The total heating demand is based on the 'reference' scenarios and not on HDD. The amount of HDD per base year can be different but the total heating demand is the same for every base year. The total heating demand is modelled this way since HDD is not specified in the 'reference' scenarios and therefore the heating demand can not be related to the outside temperature.

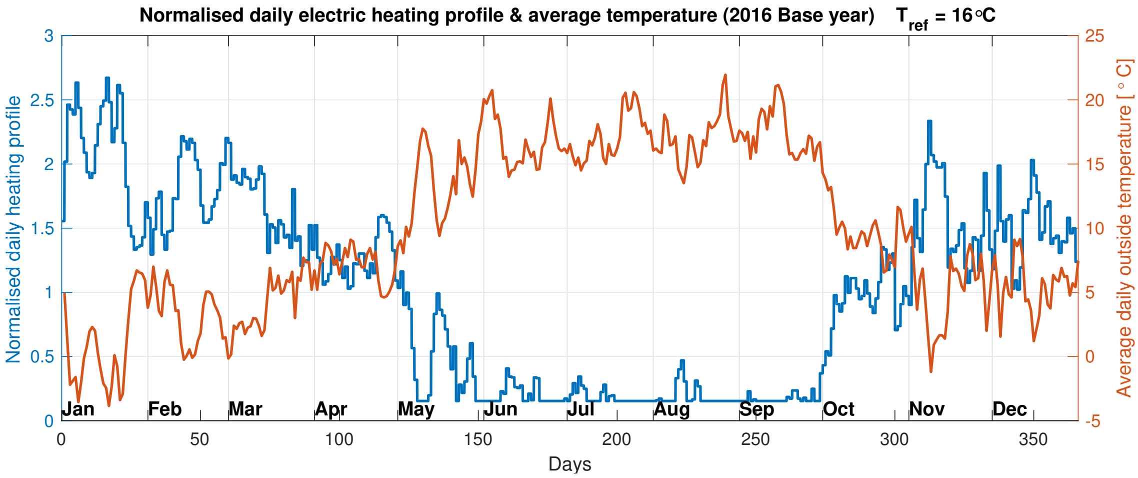


Figure 4.4: Normalized daily electric heating profile & average temperature in Denmark (2016 Base year)

Demand response heating

With the previous method the daily space heating demand was linked to the outside temperature but the heating demand does not have to be constant over the day nor does it have to be directly linked to the hourly consumption. Heat pumps and district heating require buffers which make a load shift possible. In section 3.4 was mentioned that heat pumps and electric boilers already have options for such load shifts. The electric heating demand will be demand responsive. Load shifting will be investigated on a daily basis from 0:00 am to 12:00 pm. Heat pumps will buffer in cases of an electricity surplus and buffer less or shut down if there is a electricity deficit. This results in lower peak power for electrolysers and a reduction in V2G demand. With forecasting can be determined when heat pumps need to (pre-)buffer or when the consumption should be reduced. The submodel also takes the installed capacity of heat pumps into account. If demand response heating (DRH) exceeds the installed capacity this consumption is reduced to the maximum installed capacity and compensates this evenly over the other hours of the day. A detailed description of the modelling of DRH and more examples can be found in appendix C at page 127.

Figure 4.5 shows an example of five random days in Denmark. The first plot shows the heating demand if it is modelled constant over the day. The second plot shows the imbalance without electric heating (electricity generation minus classic consumption and BEV charging). The third plot shows how DRH adjusts to the imbalance. At the third day it can be seen that DRH reduces the backup demand and electrolyser peak demand. In the morning there is an electricity surplus which is used to buffer heat. Later on the day there is an electricity deficit and heat pumps are turned off to minimise the backup demand.

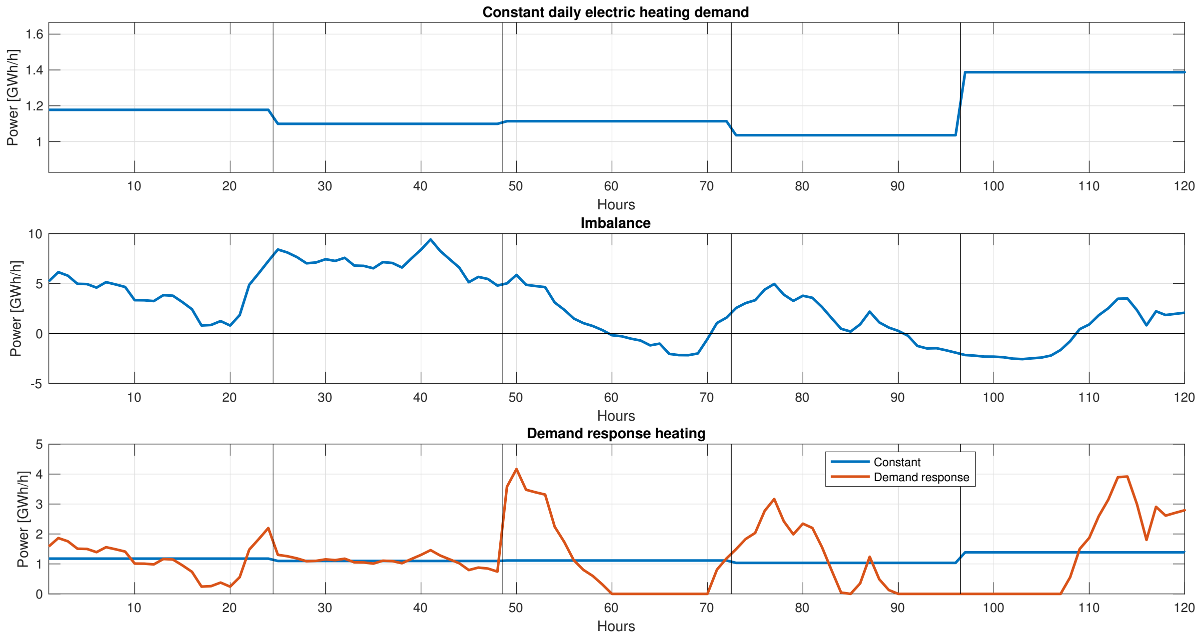


Figure 4.5: Example of demand response heating for 5 random days in Denmark in 2050

Figure 4.6 shows another example where DRH is applied in Denmark at the end of October with 2016 as base year. The left plot shows the breakdown of electricity generation, the right plot shows the consumption. It shows that V2G demand is minimised on the fourth day for example. Heat pumps buffer more during the surplus because it is forecasted that there will be a deficit later. The V2G demand can be seen in the left plot in yellow, the electric heating demand can be seen in the right plot in green. On the fifth day there is still a deficit. Now load shifting is applied to reduce peak V2G demands.

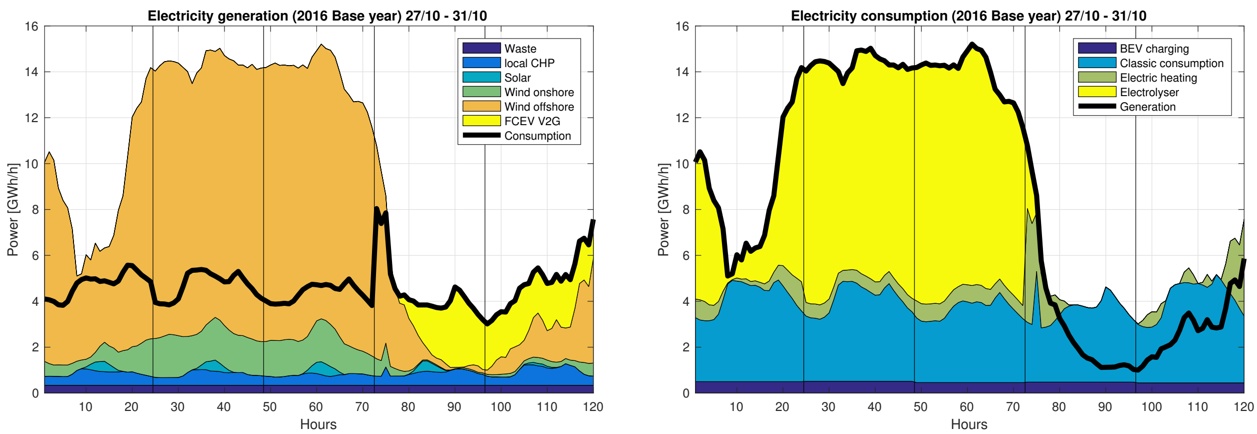


Figure 4.6: Breakdown of electricity generation & consumption example for Denmark in 2050 with 2016 as base year

4.3. Road transport

Only propulsion by an electric motor is considered for road transport. Electricity is supplied to the electric motor by a battery, a hydrogen and fuel cell system or a combination of both.

4.3.1. Fleet composition

Vehicles are classified in the following categories: Passenger cars, motorcycles, vans, lorries, trucks and buses. Commercial vehicles are sometimes named and categorised differently per country. Here vans are defined as Light commercial vehicles (LCVs) or light goods vehicles and can carry up to 3.5 tonnes. Heavy road transport or heavy duty vehicles (HDVs) are divided in lorries and trucks. Lorries are the rigid vehicles carrying 3.5 - 12 tonnes. Articulated vehicles or vehicles able to carry over 12 tonnes are defined as trucks.

In the model vehicles are divided in FCEVs and BEVs, FCREEVs are also categorised as FCEVs. The fraction of BEV and FCEV describes the travelled distance per energy technology and with the assumption that the average travelled distance is the same for both, also gives an indication of the number of vehicles per category. FCEVs will have most likely a higher annual travelled distance in practice but FCREEVs also have a on-board battery which also has to be charged and therefore is assumed that the annual travelled distance is equal for both. The distribution of distance traveled per vehicle type is shown in figure 4.7. This distribution is the same for every country and based on several reports and future scenarios [4, 5, 48, 49, 74]. In general, batteries are assumed to be sufficient for the vehicles with low weight and/or a low annual driven distance. Vehicles driving a longer distance and heavy duty transport is assumed to be mainly fuelled by hydrogen.

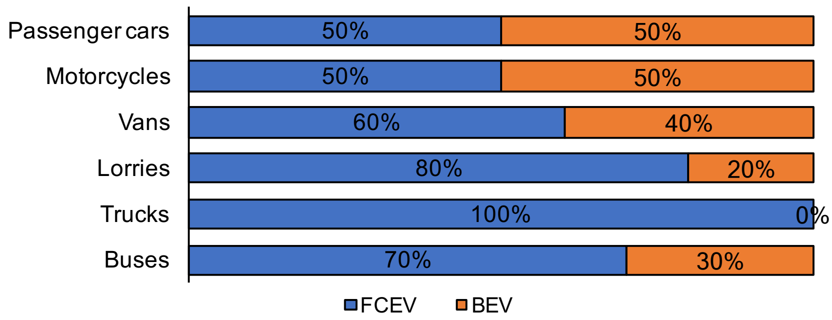


Figure 4.7: Distribution of vehicle types in 2050

There are various predictions in the analysed scenario's and studies of how the passenger fleet will look like. In Denmark for example the DEA predicts [4] that fuel cells will not be used in passenger cars but only in HDVs while the Danish Hydrogen & Fuel cell partnership predicted in their 'National implementation plan for hydrogen refueling infrastructure' [74] that 50% of all passenger cars will be a FCEV by 2050. In the German scenarios published by Fraunhofer [5] the fraction of FCEVs is assumed to be 46% in the H_2 passenger car fleet composition and 31% in the 'mix' passenger car fleet composition. Here is assumed that 50% of all passengers is a FCEV and 50% a BEV.

For motorcycles it is hard to make predictions of how the fleet will look like and therefore it is assumed that the fractions will be the same as the fractions for passenger cars. In practice the consumption of motorcycles is negligible because of the low energy consumption (section 4.3.2) and the low annual driven distance.

The type of energy carrier for Vans depends strongly on the application. Courier services carry more weight and require a long range where vans used by constructors for example require a shorter range and can be recharged several times. Here it assumed that 60% of the travelled distance is covered by FCEVs and 40% by BEVs.

For HDVs are expected that fuel cells will dominate this category [4, 48, 49]. The high weight and the high annual driven distance makes a battery inefficient because of the recharging times. In the published 2050 scenarios and studies only a very small fraction of the HDVs will be equipped with a BEV, the rest is fuelled by hydrogen, SNG or biofuels. In this case it is assumed that 20% of the energy consumption for the distance travelled by lorries is powered by batteries. Those lorries could for example be used for resupplying shops in city centres or other applications where a long range is not required. Trucks will only be fuelled by hydrogen, the use of batteries will be neglected.

For busses it depends on the usage. Batteries can be very useful for city buses. City busses require a shorter range and can regenerate more energy with regenerative braking. The busses could also recharge at bus stops or charge via catenary lines. Regional buses need a large range and don't have time to charge so batteries will most likely be insufficient. There are again varying predictions for the technology composition of the bus fleet. In the DEA scenario [4] for example it is assumed that half of the travelled distance is covered by batteries and the other half by SNG. Hydrogen could be an alternative for busses in terms of range. In the 'Renewables in Transport 2050' [49] report with several scenarios for transport in Germany and Europe in 2050, BEV busses are not even considered. Based on these reports it is assumed that 70% of the busses will be a FCEVs and 30% a BEV.

Furthermore it is assumed that the amount of vehicles remains the same. The amount of vehicles could increase for a predicted increase in population [75]. The amount of vehicles could also decrease by a growth of vehicle sharing or a shift from passenger cars to public transport for example. One effect could be bigger than the other or they can eliminate each other. In this research the amount of vehicles remains constant.

4.3.2. Specific energy consumption

This section elaborates on the specific energy consumption (SEC) per vehicle type and energy carrier. For some vehicle categories the SEC of a FCEV is coupled to the SEC of its BEV equivalent. The current consumption of the BEV is converted to the hydrogen consumption in a FCEV with an assumed current average fuel cell system tank-to-wheel efficiency (TTW) of 51.5% on HHV basis [13]. The mid century TTW efficiency will be 60%, the same as the tank-to-grid efficiency (section 4.5). An overview of the SEC for all road transport can be seen in table 4.1.

Table 4.1: Specific energy consumption road transport for 2050

	BEV kWh/km	FCEV kg/100km
Passenger cars	0.15	0.60
Motorcycles	0.056	0.28
Vans	0.206	0.90
Lorries	0.818	3.70
Trucks	1.227	5.50
Buses	1.61	6.90

Passenger cars
In the report 'Renewables in Transport 2050' [49] for Germany the SEC for C-segment battery passenger cars is estimated to be 0.1477 kWh/km. In the IEA EV & PHEV roadmap the 'current' consumption of BEVs was estimated at 0.2 kWh/km [76] in 2011. The IEA expected consumption savings of 25% for mid century resulting in an SEC of 0.15 kWh/km. Based on these estimations the SEC of passenger BEVs is assumed to be 0.15 kWh/km in 2050.

The current consumption of FCEVs is approximately 1kg/100km based on the vehicles in table 3.1 and the IEA hydrogen & fuel cells roadmap [13]. The expected mid century fuel consumption in the IEA hydrogen & fuel cells roadmap is 0.6 kg/100km. This consumption will also be used in the model.

Motorcycles
The SEC of motorcycles is based on the Zero S motorcycle [77]. The SEC of this bike is 0.075 kWh/km.

Assuming the same savings as BEV passengers the mid century SEC of electric bikes will be 0.056 kWh/km.

The SEC of a fuel cell bike is coupled with the SEC of the battery bike and it is assumed that the SEC of fuel cell bikes have the same savings (40%) for mid century as passenger FCEVs. This results in a SEC of 0.28 kg/100km.

Vans
Kreisel electric electrified a mercedes sprinter and equipped a 90 kWh battery pack which results in a range of 300km[78]. The SEC is 0.3 kWh/km. Emoss builds mini buses in several configurations [79]. With a battery pack of 52 kWh the range is 160km resulting in a SEC of 0.325 kWh/km. In the IEA Energy Technology Perspectives 2014 the 'current' consumption was estimated at 0.2 kWh/km [80]. The current consumption is assumed to be the average of the three mentioned SECs: 0.275 kWh/km. Assuming the same savings as passenger BEVs the mid century SEC is 0.206 kWh/km.

The current consumption of fuel cell vans is coupled with the SEC of battery vans. Somewhat lower savings than passenger FCEVs are assumed of 30% resulting in a SEC of 0.9kg/100km.

Lorries
The Emoss full electric truck is available in several configurations. The configurations carrying up to 12 tonnes have a SEC of 0.80 kWh/km [81]. The Mercedes-Benz urban eTruck has a 212 kWh battery pack with a 200 km range resulting in a SEC of 1.06 kWh/km [82]. In the IEA Energy Technology Perspectives 2014 the 'current' consumption was estimated at 0.93 kWh/km [80]. It is assumed that the current consumption will be the average of the mentioned SECs: 0.93 kWh/km. It is assumed that the savings for mid century are the same as for BEV buses: 12%. This results in a SEC of 0.818 kWh/km.

The current consumption of FCEV lorries is coupled to the consumption BEV lorries. Savings of 20% are assumed for mid century resulting in a SEC of 3.7 kg/100km.

Trucks
In the IEA Energy Technology Perspectives 2014 the 'current' consumption was estimated at 1.395 kWh/km [80]. The same savings as BEV buses are assumed. This results in a mid century SEC of 1.227 kWh/km.

The current consumption of FCEV trucks is coupled to the consumption BEV trucks. Savings of 20% are assumed for mid century resulting in a SEC of 5.5kg/100km.

Buses
In the IEA Energy Technology Perspectives 2014 the 'current' consumption was estimated from 0.9 to 1.9 kWh/km dependent on the application and region [80]. In the study 'Urban buses: alternative powertrains for Europe' initiated by the Fuel Cells and Hydrogen Joint Undertaking [83] the SEC of buses was assumed at 1.91 kWh/km with savings of 12% towards 2030 resulting in a SEC of 1.61 kWh/km.

The current SEC of FCEV buses of 8.6 kg/100km is taken from 'Fuel cell electric buses - potential for sustainable public transport in Europe' from the Fuel Cells and Hydrogen Joint Undertaking [84]. The savings towards mid century are assumed to be 20% resulting in a SEC of 6.9 kg/100km.

4.3.3. Vehicle fuelling & charging

For fuelling of hydrogen a weekly profile is taken from the US DOE [85]. The profile has a daily and weekly fluctuation. The normalised profile (where 1 is the average) can be seen in figure 4.8. Hydrogen consumption for V2G is assumed to be fuelled directly. To give an indication of the required daily hydrogen dispension capacity it is assumed that the amount of HFSs will be equal to the amount of petrol filling stations at the end of 2016 [86].

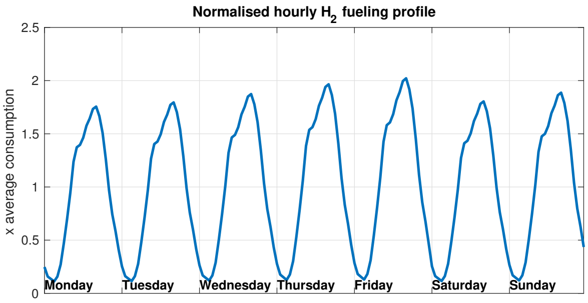


Figure 4.8: Normalised hourly H_2 fuelling profile

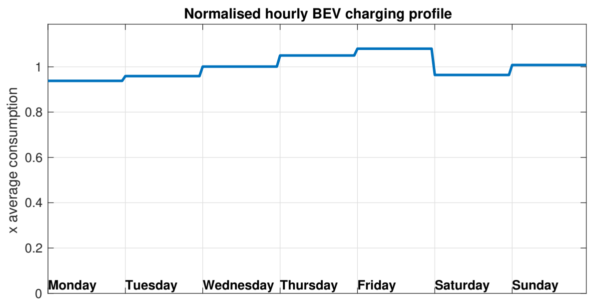


Figure 4.9: Normalised hourly BEV charging profile

Although hydrogen is compressed to 880 bar and cooled at the fuelling station this energy is in the model consumed during the production of hydrogen and not while fuelling. This approach is chosen because the distribution of hydrogen is not in the scope of this work, hydrogen could be delivered directly to a fuelling station or it could be stored in a large scale storage first. Also the time of electricity consumption for compression and cooling at the fuelling station is dependent on buffer sizes and the method of transportation. The energy consumption of compressing to 880 bar and pre-cooling are relatively small compared to the conversion of hydrogen (see section 4.5) and the impact on the results is therefore most likely negligible.

The BEV charging profile is constant throughout the day, similar to the scenario by the DEA [4]. The charging profile could also have been made demand responsive but the work of Ekman [27] that simple day and night charging schemes does not significantly contribute to balancing and smart charging requires more insight in usage and charging of BEVs and is therefore not applied. The weekly fluctuation is taken from the US DOE [85] hydrogen fuelling profile. The result can be seen in figure 4.9. The charging efficiency for BEVs is 95% and taken from Fraunhofer [5].

4.4. Balancing

The last part of the model is balancing of the entire system. The electricity grid needs to be balanced for every time step (every hour) and the hydrogen storage needs to be balanced over a year.

Figure 4.10 is a zoomed in version of figure 4.1 with the focus on the balancing part of the model. It can be seen that the renewable energy capacity will be increased until enough hydrogen is produced. At the start of the iteration the mix of installed capacity is scaled to 60% of the installed capacity in the constructed 100% RE scenario to make sure there is no over production of hydrogen. Since the installed capacity is iterated the final installed capacity could be different than the capacity in the constructed scenario.

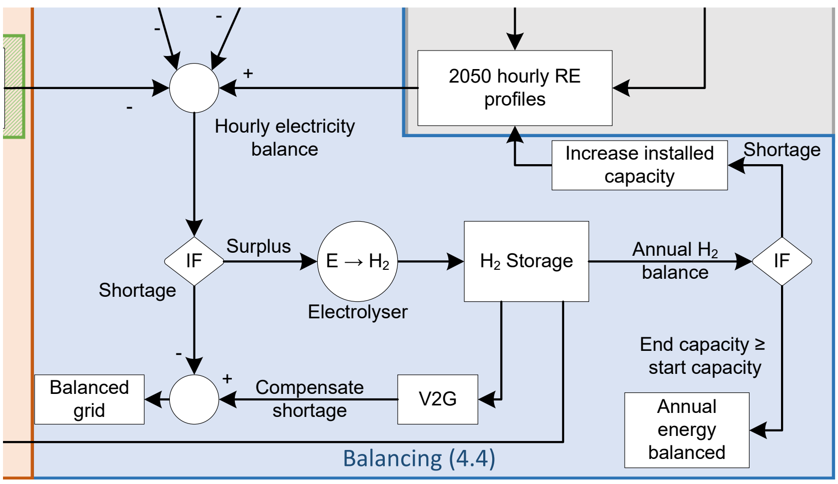


Figure 4.10: Schematic overview of the model zoomed in on balancing

First the hourly electricity (im)balance is calculated according to equation 4.3.

$$(Im)balance = \Sigma E_{production} - \Sigma E_{consumption} \tag{4.3}$$

An example of the imbalance for Denmark can be seen in figure 4.11. Surplus energy is converted to hydrogen. Deficits are compensated with passenger FCEVs in V2G mode using the hydrogen produced earlier. This results in the final hourly (im)balance in equation 4.4, which is equal to zero, a balanced grid.

$$(Im)balance = \Sigma E_{production} + FCEV_{backup} - \Sigma E_{consumption} - E_{electrolyser} = 0 \tag{4.4}$$

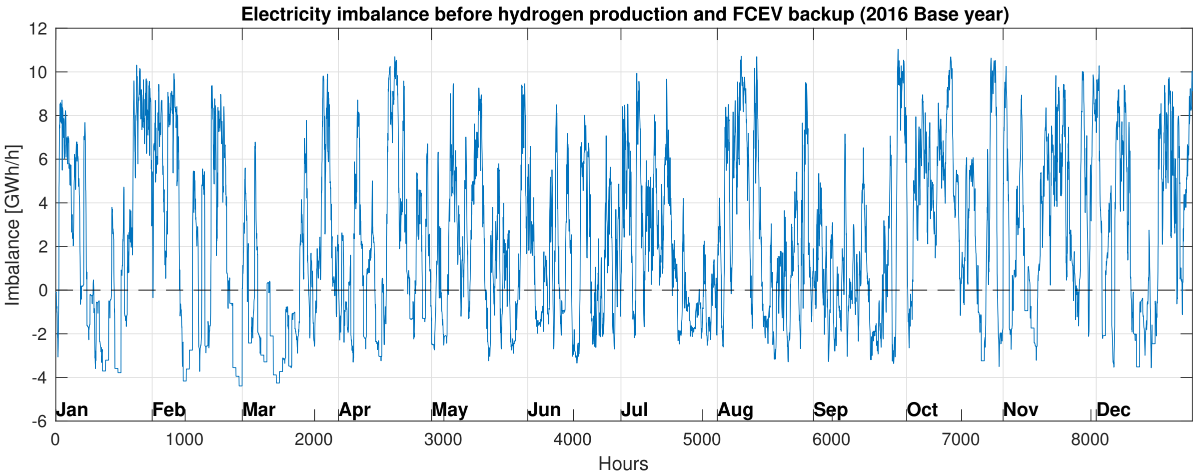


Figure 4.11: Imbalance for Denmark in 2050 with 2016 as base year

The storage of hydrogen also needs to be balanced. The storage capacity at the end of the year needs to be equal or higher than at the begin of the year. The hourly hydrogen storage capacity is determined with equation 4.5. The capacity of the storage is the capacity of the previous hour plus the net production/consumption of hydrogen. The initial storage capacity is zero.

$$m_{storage}(t) = m_{storage}(t-1) + m_{production} - m_{fueling} - m_{FCEV_{backup}} \tag{4.5}$$

To get the absolute amount of storage after the simulation, the inversed minimum capacity is added as a starting buffer to make sure the amount of storage is never below zero as demonstrated in figure 4.12.

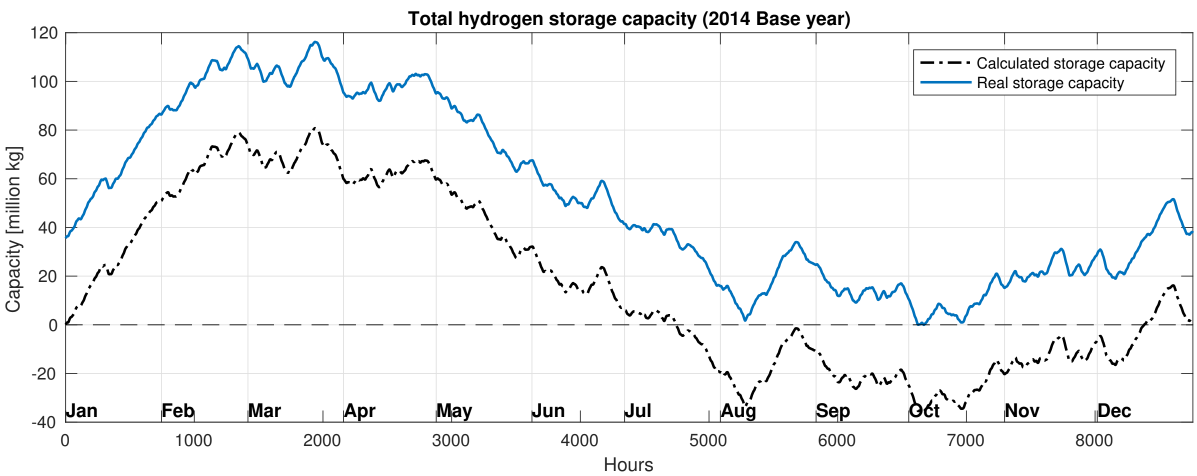


Figure 4.12: Storage capacity for Denmark in 2050 with and without starting buffer

If the capacity at the end of the year is lower than at the start of the year the installed capacity in the generation mix will be increased by $\frac{1}{500}$ (0.2%). When the installed capacity is increased the balancing process iterates until the annual hydrogen storage capacity is balanced. In some case studies the installed capacity of some energy sources is limited to the theoretical maximum in a country. If the limit is reached the installed capacity will increase no further and only the other sources are increased.

4.5. Hydrogen conversion & storage

In section 3.7 the entire process from production to consumption of hydrogen is described. Reverse osmosis of seawater and rainwater is neglected since this is only 0.04 kWh/kg or less [24]. The DOE ultimate target for compressor consumption at the electrolyser to 120 bar for the low pressure storage is 0.84 kWh/kg H_2, around 2% of the HHV [59] . The compressor consumption from 120 bar to the high pressure storage of 880 bar in the fuelling stations is estimated at 1.4 kWh/kg H_2, around 3.5% of the HHV [59]. Energy consumption for purification is currently 1.3 kWh/kg H_2 [87] and mid century (2050) is expected to be 1.1 kWh/kg H_2 [88], approximately 3% of the HHV of hydrogen. The mid century cooling demand is estimated to be 0.15 kWh/kg [89, 90]. The mid century PEM electrolyser efficiency is expected to be 86% (section 3.7). Table 4.2 shows the energy consumption of each component to produce 1kg of hydrogen. The total electricity consumption to produce, purify, compress and pre-cool 1kg of hydrogen is 49.31 kWh. This is modelled as the total energy consumption of the electrolyser. The fuel cell tank-to-grid (TTG) efficiency, when the fuel cell is operating in part load, is based on [13, 59] assumed to be 60% on HHV basis. The V2G power output of a FCEV is assumed to be 10kW, equal to the FCEV at the TU Delft.

Table 4.2: Overview of conversion efficiencies

	kWh/kg H_2	Efficiency
Compression to 120 bar	0.84	
Compression 120-880 bar	1.40	
Hydrogen purification	1.10	
Pre-cooling (-40°C)	0.15	
PEM Electrolyser	45.82	86.00%
Total consumption	49.31	79.91%
PEM Fuel cell (TTG)	23.64	60.00%
Round trip efficiency		47.95%

5

Case studies

Figure 5.1 shows the selected countries and in which section they are discussed. The countries are selected for their availability of data, size of the energy system or renewable ambitions. The investigated countries consumed 58% of the final energy consumption of all 28 countries in the European Union in 2015 [91]. The consumption of Denmark is small compared to the other countries but Denmark already has a large share of renewable electricity, four detailed 100% renewable scenarios [4] and a lot of data available.

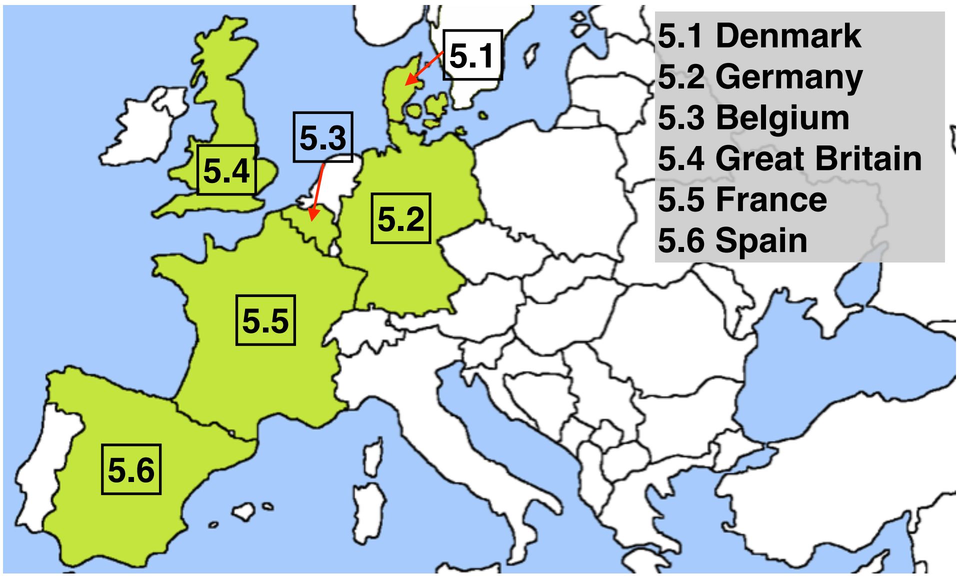


Figure 5.1: Investigated countries. Numbers correspond to the sections in this chapter

For every country the current situation will be evaluated first. The current final energy consumption, the electricity generation mix and road transport will be analysed. The country's vision for the future energy system and available 100% RE energy scenarios will be analysed. Based on the current situation and the 100% RE scenarios the model inputs will be determined. The results will be shown and discussed briefly for every country individually. In section 5.7 a case with and without DRH will be discussed. The case showed that the total V2G demand, the peak V2G demand and the electrolyser peak demand are reduced with DRH and is therefore applied to all cases. Chapter 6 compares and discusses the results of all countries.

Figure 5.2 shows the share of the final energy consumption per sector and the share of electricity consumption for all the investigated countries in 2014. The data is taken from the IEA Sankey diagrams [92]. For other statistics in this chapter the most recent data for the specific country is taken.

It is chosen to model the electricity, road transport and heat in the residential en commercial sectors. Electricity is the easiest part to deal with and has an average share of almost 22% of the final energy consumption. Road transport has the largest share of energy consumption in all of the investigated countries with a total share of 27%. Heat in the residential and commercial sectors is in total 25% of the final energy consumption. The modelled sectors cover in total 74% of the final energy consumption for the investigated countries. Industry also has a high share in the final energy consumption but is not taken into account because of the complexity and it requires more insight in consumption profiles. Most of the industrial heating demand can be electrified and for some processes the heating can be supplied by burning biomass. The ‘other’ energy consumption is mainly non-energy use. Especially in Belgium this is a large share because of the consumption of coal for the steel industry [6]. This sector is also not taken into account. The use of coal for the production of steel could be replaced by hydrogen [6].

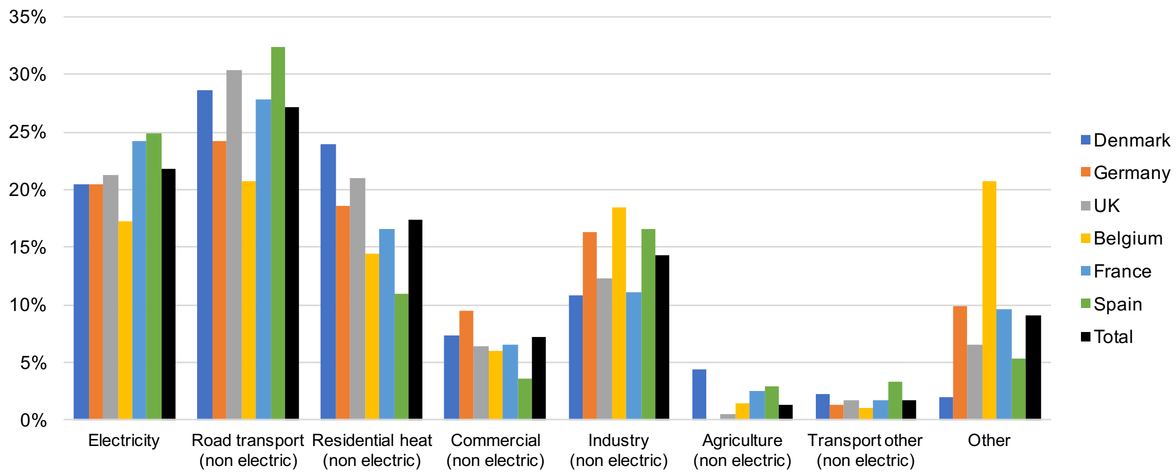


Figure 5.2: Share of final energy consumption per sector and share of electricity of final energy consumption for all investigated countries in 2014 [92]

Table 5.1: Country data 2015

	Unit	Denmark	Germany	GB	Belgium	France	Spain	Total	% EU 28	Source
Population 2015	million	5.66	81.20	64.88	11.21	66.42	46.45	275.81	54%	Eurostat [75]
Population 2050[1]	million	6.69	82.69	77.57	13.27	74.38	49.26	303.85	57%	Eurostat [75]
Country size	1000 km^2	43.16	358.33	247.76	30.67	549.06	498.50	1,727.5	40%	Eurostat [93]
Population density 2015	pop/km^2	131	227	262	365	121	93	160		Eurostat
Energy available for final consumption	TWh	164	2711	1619[4]	517	1865	967	7843	57%	Eurostat [91]
Final energy consumption[2]	TWh	150	2516	1429[4]	466	1717	914	7192		IEA [92, 94]
Share of renewable electricity	%	63%	32%	26%[4]	23%	16%	36%			IEA [94]
Final energy consumption per pop	MWh/pop	28.98	33.39	24.95	46.13	28.08	20.83	28.44		Eurostat
CO_2 emission/pop	tCO_2/pop	6.12	8.93	6.31	7.83	4.32	4.99			IEA [94]/Eurostat
Passenger cars[3]	million	2.27	43.96	30.25	5.66	31.90	16.93	130.97		
Passengers car per person	cars/pop	0.40	0.54	0.47	0.51	0.48	0.36	0.47		
Petrol fuelling stations 2016		2028	14510	8476[4]	3109	11200	11188	50511	44%	[86]
Fuelling station density	FS/km^2	0.05	0.04	0.03	0.10	0.02	0.02	0.03		
Passenger cars / fuelling station	cars/FS	1120	3030	3569	1821	2848	1513	2593		

[1] Statbank baseline projection
[2] Used in figure 5.2
[3] Based on most recent data, see country specific section
[4] UK data

5.1. Denmark

Denmark is the smallest of the investigated countries in terms of population and energy consumption. Denmark had only 5.6 million inhabitants in 2015 (table 5.1). Denmark has a widespread use of district heating and CHP. In 2015 63% of the heating in private houses was provided by district heat, not only space heating, but also hot water [30]. In 2011 the Danish government published the energy policy milestones up to 2050 [95]. In 2020 half of the traditional electricity consumption should be covered by wind. In 2030 coal and oil is phased out from all Danish power plants. All electricity and heat supply should be covered by RE in 2035 and in 2050 all energy supply should be covered by RE. Denmark has interconnections with Norway, Sweden and Germany.

5.1.1. Current situation

The final energy consumption in Denmark was 149.69 TWh in 2014. Figure 5.3 shows the final energy consumption per sector. The covered sectors, highlighted in figure 5.3, represent 80% of the final energy consumption in 2014. The largest energy consuming sector is road transport followed by residential heat. This share is relatively large compared to the other countries as can be seen in figure 5.2. This is most likely due to the colder climate in Denmark.

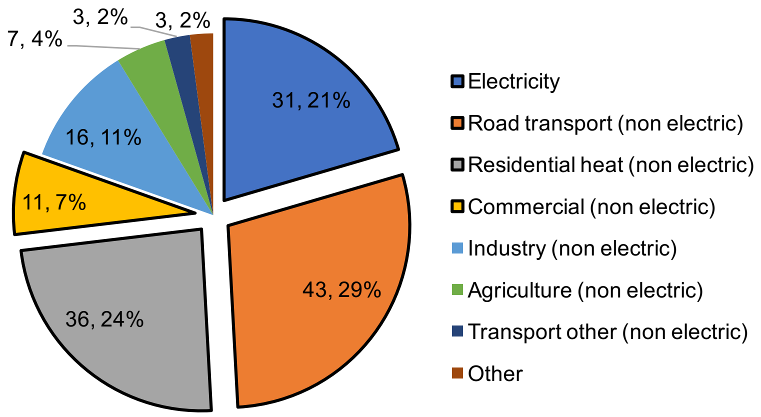


Figure 5.3: Final energy consumption Denmark 2014 in TWh (150 TWh total) [92]

The total electricity generation in 2015 was 28.9 TWh excluding system losses. 19.0 TWh (65%) comes from renewable sources, mainly wind [96]. Electricity generation from wind was 14.1 TWh, already close to the 2020 milestone of 50% of total consumption. Nett electricity imports were 5.9 TWh. The final electricity consumption was 30.7 TWh. Figure 5.4 shows the electricity generation mix and the share of renewable electricity. Figure 5.5 shows the historic installed capacity sorted by type. Installed

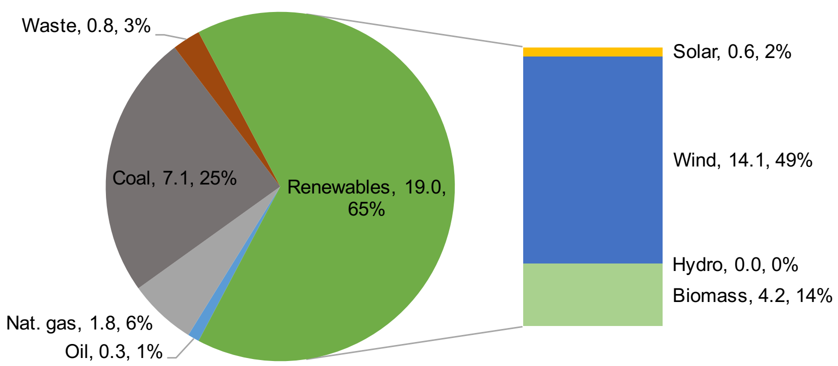


Figure 5.4: Electricity generation mix Denmark 2015 in TWh (28.9 TWh total) [96]

capacity data is collected from [96–98]. The installed capacity of renewables (solar, wind and hydro) was 5.9 GW in 2015, 42% of the total installed capacity (14.0 GW).

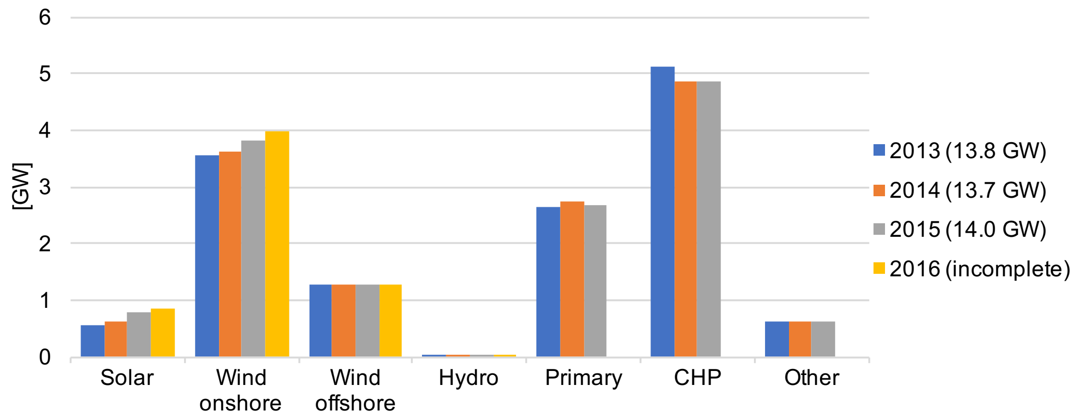


Figure 5.5: Installed capacity per source at the end of the year in Denmark [96–98]

Transport
Table 5.2 shows the total road traffic and the number of vehicles in Denmark in 2015. The data is gathered from Denmark Statbank [99]. Passenger cars are good for approximately 80% of all driven kilometers. Denmark had 2028 petrol fuelling station at the end of 2016 [86]. Denmark has the highest density of petrol fuelling stations of all the investigated countries, there is 1 fuelling station for every 1120 vehicles.

Table 5.2: Road traffic data Denmark 2015 [99]

	Annual km x10^6	# vehicles	km/vehicle
Passenger cars	38,489	2,270,797	16,950
Motorcycles	457	151,542	3,016
Vans	7,221	398,066	18,140
Lorries	977	28,628	34,127
Trucks	1,068	12,867	83,003
Buses	612	13,408	45,644
Total:	48,824	2,875,308	16,980

5.1.2. 100% Renewable energy scenario

The Danish Energy Agency (DEA) proposed in 2014 four 100% renewable energy scenarios to achieve the milestones set by the government [3, 4]:

- Wind:
  The wind scenario is designed to use bioenergy corresponding to what Denmark itself can supply. This requires massive electrification of transport, industry and district heating. It also requires a significant expansion of offshore wind turbines. To keep the consumption of bioenergy low, hydrogen is produced and used to upgrade biomass and biogas to make it last longer.

- Biomass:
  The biomass scenario is designed to almost double annual bioenergy consumption compared to the wind scenario. This entails a certain volume of net biomass imports in normal years. No hydrogen is involved in this scenario.

- Bio+:
  The Bio+ scenario describes a fuel-based system similar to what it is today with the only exception that coal, oil and natural gas are replaced by bioenergy. Fuel consumption will increase significantly. Again no hydrogen is involved in this scenario.

- Hydrogen:
  The hydrogen scenario is designed to simulate very small bioenergy consumption. This means considerable use of hydrogen and considerably more wind power than in the wind scenario.

Table 5.3 shows the fuel consumption, gross energy consumption and degree of self-sufficiency per scenario. A fossil fuel scenario, focussing only only on fossil fuels and disregarding all policy targets, is shown as a reference.

Table 5.3: 100% Renewable energy scenarios for Denmark in 2050 proposed by the DEA [3]

	Wind	Biomass	Bio+	Hydrogen	Fossil
Gross energy consumption (TWh)	160	164	187	156	152
Self-sufficiency	104%	79%	58%	116%	

The wind and hydrogen scenario are the most promising scenarios with the highest degree of self sufficiency. The DEA concluded that the hydrogen and wind scenario will have a good fuel supply security but will have problems ensuring a reliable electricity supply. The biomass scenarios on the other hand will have problems ensuring a reliable fuel supply. Because Denmark is a small country it is limited in producing bioenergy and will depend on imports of biomass. The model inputs are based on the Hydrogen scenario.

5.1.3. Model inputs

Electricity generation
The electricity generation mix in the hydrogen scenario is dominated by wind. The total installed wind power is 21 GW, 17.5 GW offshore and 3.5 GW onshore. The installed capacity for solar (PV) in 2050 is estimated at 2 GW. Combined heat and power is a combination of biogas fired CHP plants, industrial CHP plants, a by-product of fuel production and the burning of waste. Burning of waste is the only centralised production, the others are local CHP. The burning of waste has an installed capacity of 366 MW and generates 2.97 TWh electricity annually. The installed capacity of the local CHP is 1.23 GW and generates 4.39 TWh electricity annualy. Furthermore there is 4.6 GW installed capacity of gas turbines and fuel cells for backup in the hydrogen scenario which will be replaced by V2G connected FCEVs in the model. There are no other central power stations in 2050. Figure 5.6 and 5.7 show the modified mixes of installed capacity and electricity generation used as input in the model.

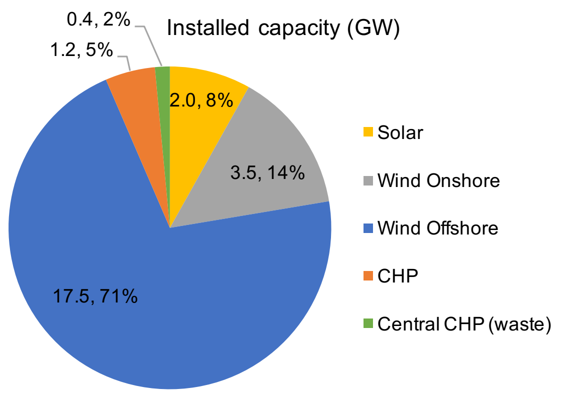


Figure 5.6: Installed capacity in Denmark in 2050 (29.2 GW total)

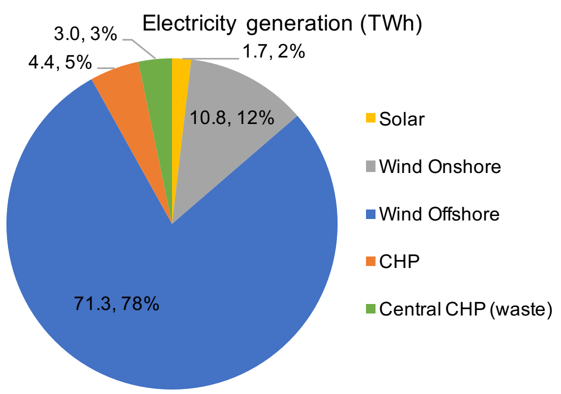


Figure 5.7: Expected electricity generation per source in Denmark in 2050 (92.3 TWh total)

The normalised generation profiles are based on the data of the Danish Transmission System Operator (TSO) Energinet.dk. Hourly electricity generation and consumption data is published on their website [100]. The data is available for 2014, 2015 and 2016 so the 2050 scenario can be modelled with three base years. The hourly solar and wind profiles are scaled to the 2050 installed capacity and can be increased by the iteration process in the model. Electricity generation from waste is assumed to be constant throughout the year since the capacity factor is almost 93%. The hourly local CHP profile will not be scaled to the installed capacity but to the annual generation. The capacity factors of all generation profiles can be seen in figure 5.8. All the normalised generation profiles per base year can be seen in appendix E.1 on page 137.

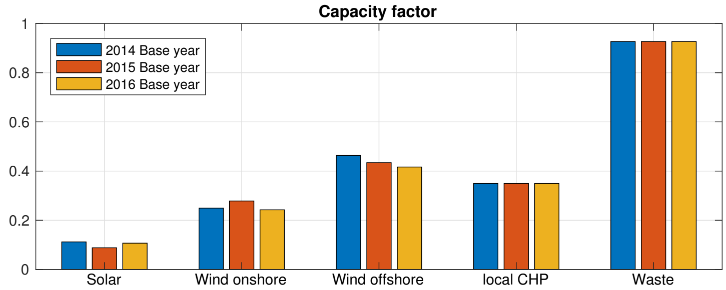


Figure 5.8: Capacity factors

The installed capacity of solar PV and onshore wind did not increase significantly in between years and the installed capacity of offshore wind did not increase at all (see figure 5.5) so the generation profiles do not need to be adjusted for increased installed capacity during the year.

It is assumed that scaling of the installed capacity will have no influence on the generation profiles. Solar systems are mostly installed at rooftops and therefore it is assumed that the distribution is spread evenly over the country. The same applies to onshore and offshore wind. A map of all power plants including onshore and offshore wind for Denmark by the DEA is included in appendix E. The map shows that onshore and offshore wind farms are spread over the country and Denmark already has large offshore wind parks. Therefore it seems unlikely that the generation profiles will significantly change for increased installed capacity.

Consumption
The classic consumption profile is based on the hourly consumption data from Energinet.dk and scaled to 2050 consumption. The classic consumption in the hydrogen scenario is expected to drop to 29.1 TWh, the electricity consumption of electric trains of 1.25 TWh is excluded in this classic consumption so the total annual classic consumption will be 30.36 TWh.

The hot water & space heating demand for the residential and commerces & services sectors is divided in 'Individual' heating and district heating. Table E.1 in appendix E shows the heat supply from all sources. Heat pumps supply 62% of all heat, 21% comes from the burning of waste, 3% is deep geothermal, 9% is solar thermal and 5% is from biogas and stray boilers. This heat supply is adopted in the model but heat from biogas, gas and stray boilers is replaced with an additional heat pump consumption. The total heat from heat pumps is 25.63 TWh, the total heat pump electricity consumption is 6.74 TWh. The installed capacity of heat pumps is 6.2 GW. Figure 5.9 shows the total heat supply for the residential and commerce & services sectors in Denmark.

Road Transport
The data from table 5.2 in section 5.1.1 will be used in the model for the number of vehicles and travelled distance per vehicle categorie. No adjustments are made.

5.1.4. Results & Discussion

Figure 5.10 shows the Energy flow diagram for Denmark in 2050 with 2016 as base year. The total generation is 61 TWh of which 35.6 TWh is directly consumed on the grid and 25.3 TWh is consumed by electrolysers to produce hydrogen. The total backup of grid connected FCEVs is 5.8 TWh, 14% of the total electricity consumption. 519 million kg of hydrogen is produced of which 273 million kg (53%) is consumed for road transport and 245 million kg (47%) is consumed for V2G. The final energy

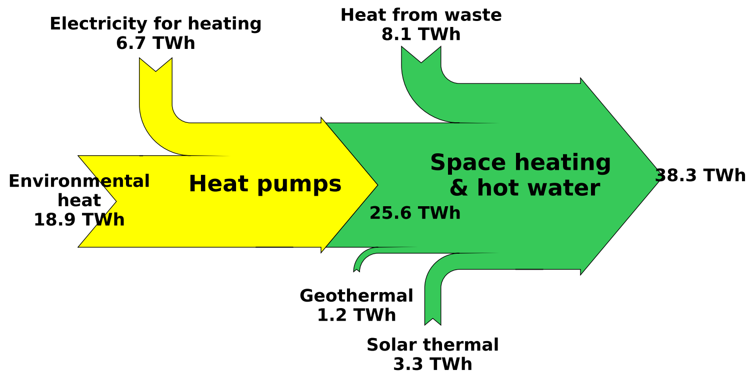


Figure 5.9: Heat flow diagram Denmark (TWh/year)

consumption (including hot water and space heating) is 79.2 TWh. All results and model outputs can be found in appendix E.2 on page 146.

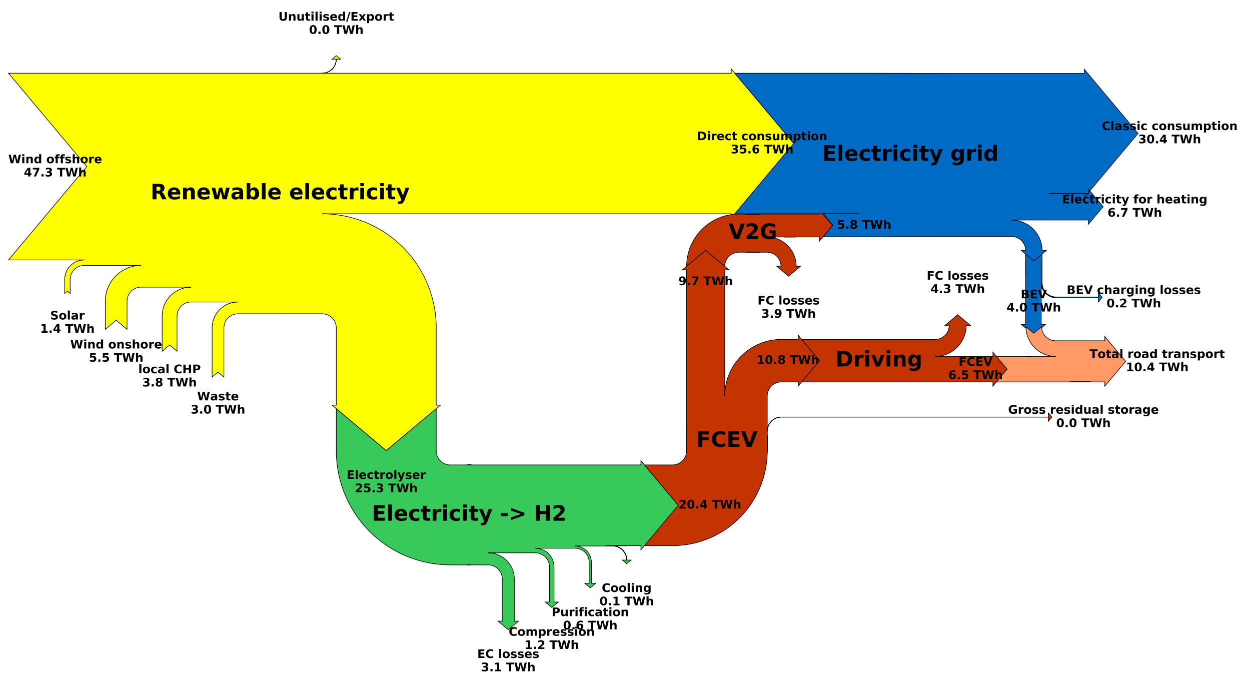


Figure 5.10: Energy flow diagram for Denmark with 2016 as base year (TWh/year)

The required installed capacity to be self sufficient for every base year is shown in figure 5.11, the corresponding electricity generation is shown in figure 5.12. The installed capacity is increasing for every base year. This could be explained by the decreasing capacity factor for offshore wind since 77-79% of the electricity is generated by offshore wind. Figure 5.11 also shows that the installed capacity is less than the 'reference'. This reference is the mix of installed capacity taken from the DEA hydrogen scenario. The modelled installed capacity is lower since the DEA scenario covers all energy consumption while the model does not cover all sectors. The DEA scenario for example has an electricity consumption of 10 TWh for the production of SNG which is used for transport and industry.

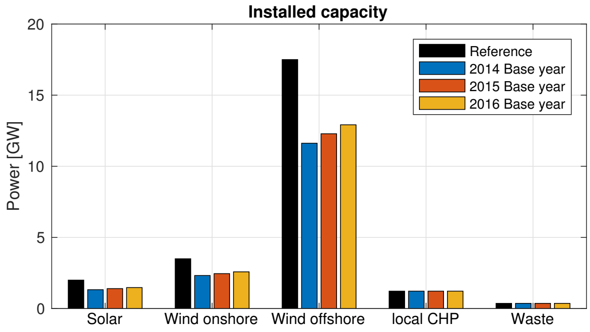


Figure 5.11: Installed capacity in Denmark in 2050

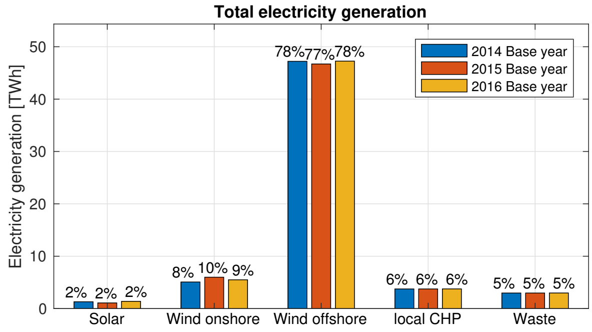


Figure 5.12: Total electricity generation in Denmark in 2050

Figure 5.13 shows the load duration curves of the imbalances without the production of hydrogen and FCEV backup. Surplus electricity will be absorbed for the production of hydrogen. Electrolysers are required approximately 5800 hours per year. The electrolyser peak demand is 11 GW. The electrolyser capacity factor varies from 26.1-29.0%.

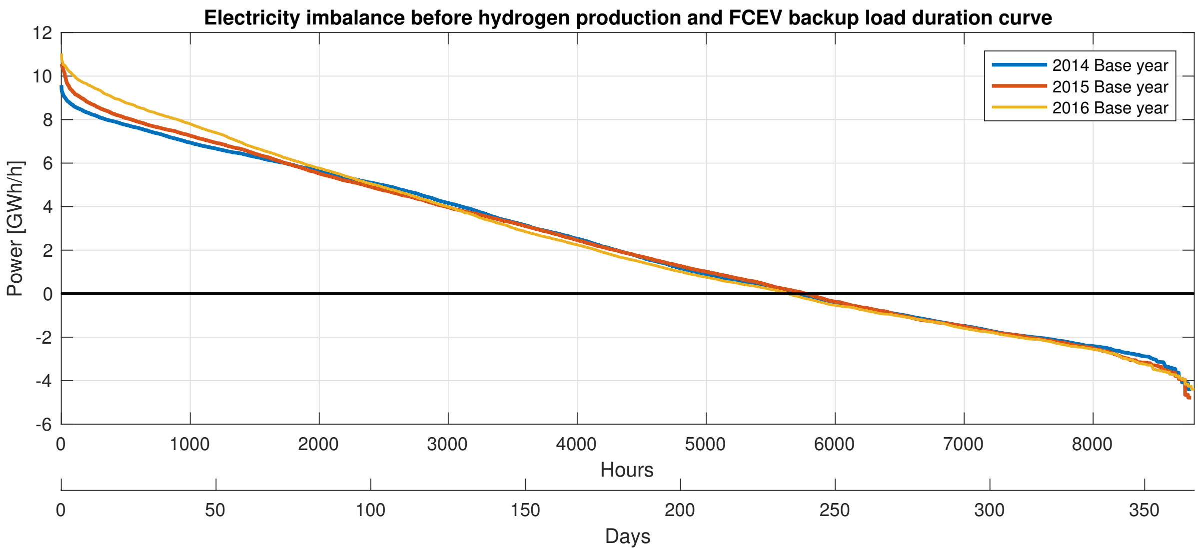


Figure 5.13: Imbalance load duration curve before hydrogen production and FCEV backup in Denmark in 2050

FCEV V2G demand

Figure 5.14 zooms in on the backup demand. It shows the load duration of the required passenger FCEVs for V2G. It can be seen that the maximum demand is around 42% of the FCEVs (21% of all passenger cars) and is only required for 2 days per year. V2G is only required for approximately 3100 hours (equivalent to 130 days) per year. For only 3 days per year more than 35% of all passenger FCEVs is required.

To get insight in when there is V2G demand a boxplot for all base years combined is shown with the V2G demand per hour of the day in figure 5.15. The plot shows that the demand is smoothened over the day where the average backup per hour and the outliers tend to follow the daily electricity generation profile. This behaviour could be explained by the high penetration of wind energy in the energy mix. Wind electricity generation is not dependent on the hour of the day and when the wind does not blow the electricity demand has to be met by FCEVs. It can also be seen that for all 3 modelled years only at 2 days more than 40% of the FCEVs are required. Figure 5.16 shows that the monthly backup shows no seasonal trends and that the amount of backup per month varies strongly per base year. This would suggest that the large scale hydrogen storage is required to compensate for periods with a lack of wind generation and seasonal storage.

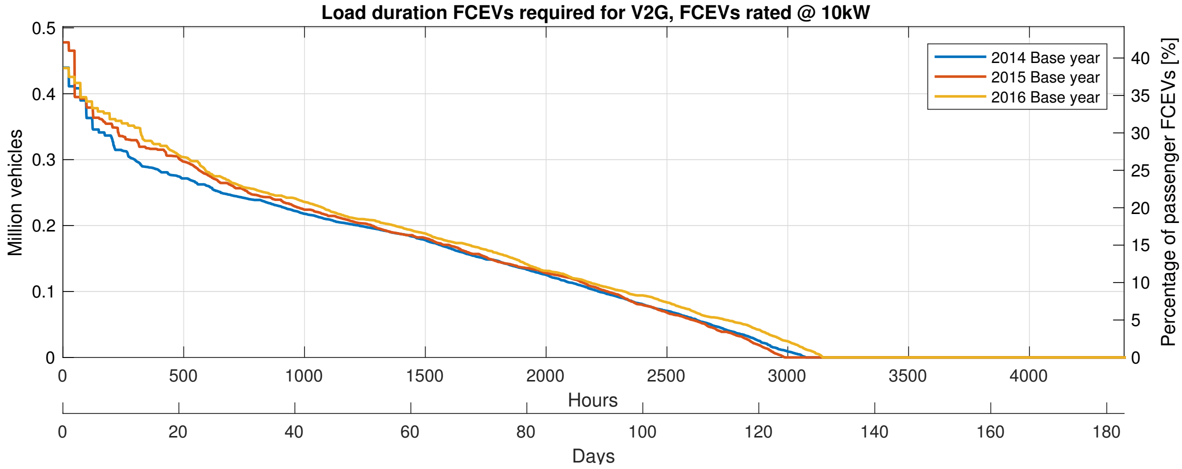


Figure 5.14: Load duration curve of FCEV backup in Denmark in 2050

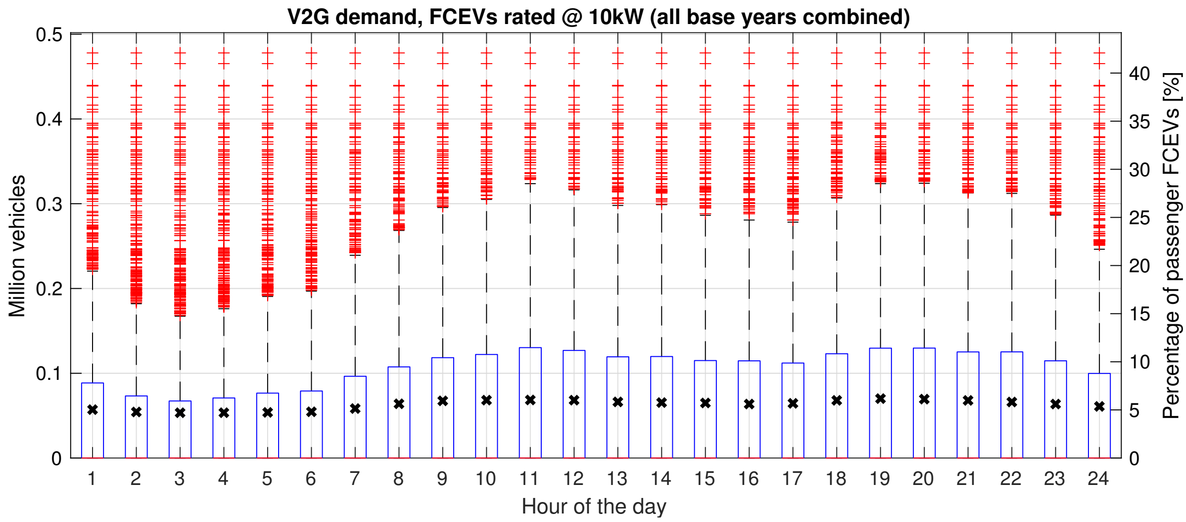


Figure 5.15: Distribution of backup power demand per hour of the day for Denmark in 2050 with all base years combined [1]

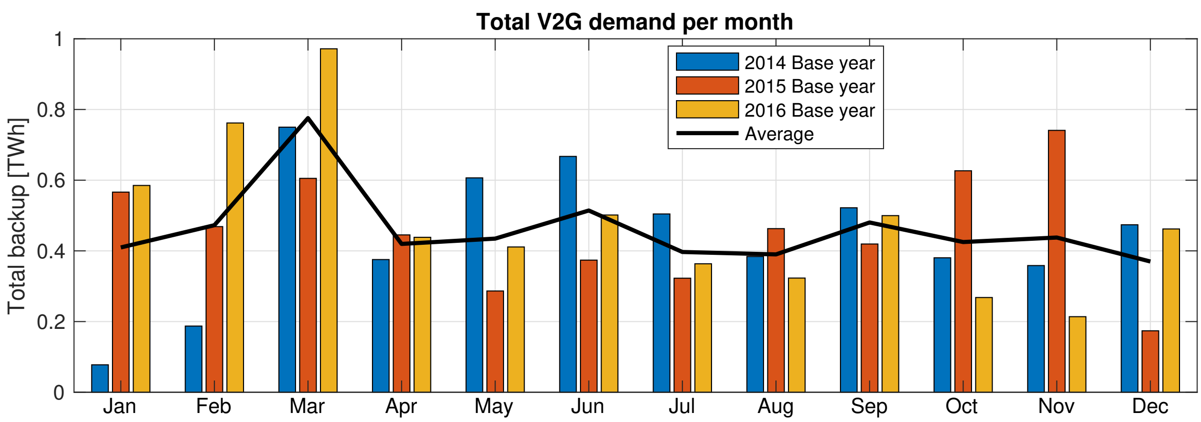


Figure 5.16: Total FCEV V2G backup per month for Denmark in 2050

[1] Points are defined as outliers if they are greater than $q_3 + 1.5(q_3 - q_1)$ or smaller than $q_3 + 1.5(q_3 - q_1)$

Hydrogen storage

Figure 5.17 shows the total hydrogen storage capacity. The 2014 base year has a lot excess electricity in January and February which is consumed in the summer. The 2016 base year shows the same behaviour but the peak in storage capacity is lower. The hydrogen buffer is charged in the winter months and discharged in summer. This trend can be explained by the seasonal behaviour of onshore and offshore wind which supplies 90% of the total energy. Figures 5.18 and 5.19 show the monthly boxplot of the normalised onshore and offshore wind generation based on 2014 data. It can be seen that there is more wind energy in the winter than in the summer. In 2015 this effect was more averaged over the year and explains why the hydrogen storage capacity for the 2015 base year shows a more constant behaviour. It can also be seen that the storage is emptied very quickly in March with 2016 as base year and in November with 2015 as base year for example. This confirms that besides the seasonal trend the buffer is also required to compensates for longer timers without wind energy. This can also be seen in figure 5.20 which shows the weekly charging and discharing of the buffers with 2016 as base year. Large peaks drain and fill the buffers. From week 9-12 there was no wind energy and the buffers were required for road transport and for V2G backup.

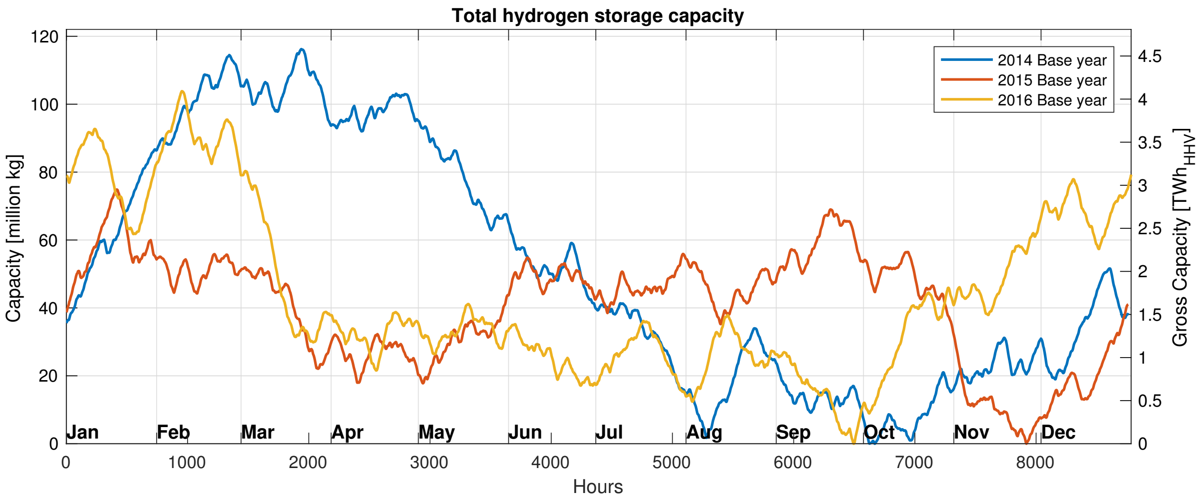


Figure 5.17: Annual hydrogen storage capacity for different base years

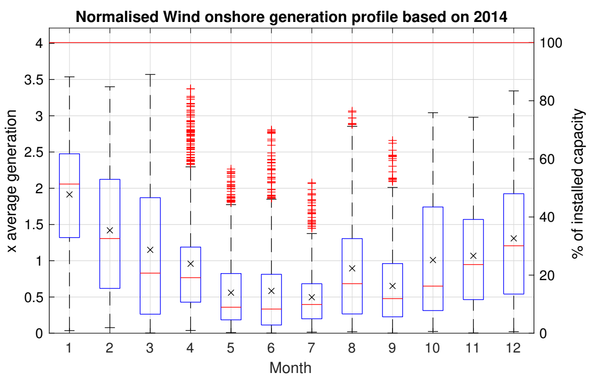


Figure 5.18: Monthly boxplot normalised onshore wind electricity generation profile Denmark, 2014 base year

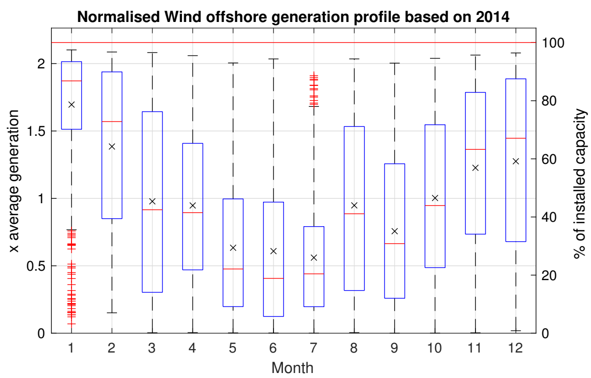


Figure 5.19: Monthly boxplot normalised offshore wind electricity generation profile Denmark, 2014 base year

At least 120 million kg of hydrogen storage is required. Recalling from section 3.8.2 a typical salt cavern of 700,00 m^3 has a net working gas volume equivalent to 6 million kg hydrogen. The Lille Torup storage facility north of Viborg has 7 of these salt caverns, currently used for the storage of natural gas, where one of these caverns has a geometrical volume over 700,00 m^3 [101, 102]. Assuming that all these caverns can hold approximately 6 million kg this site can facilitate around 30% of the required storage capacity.

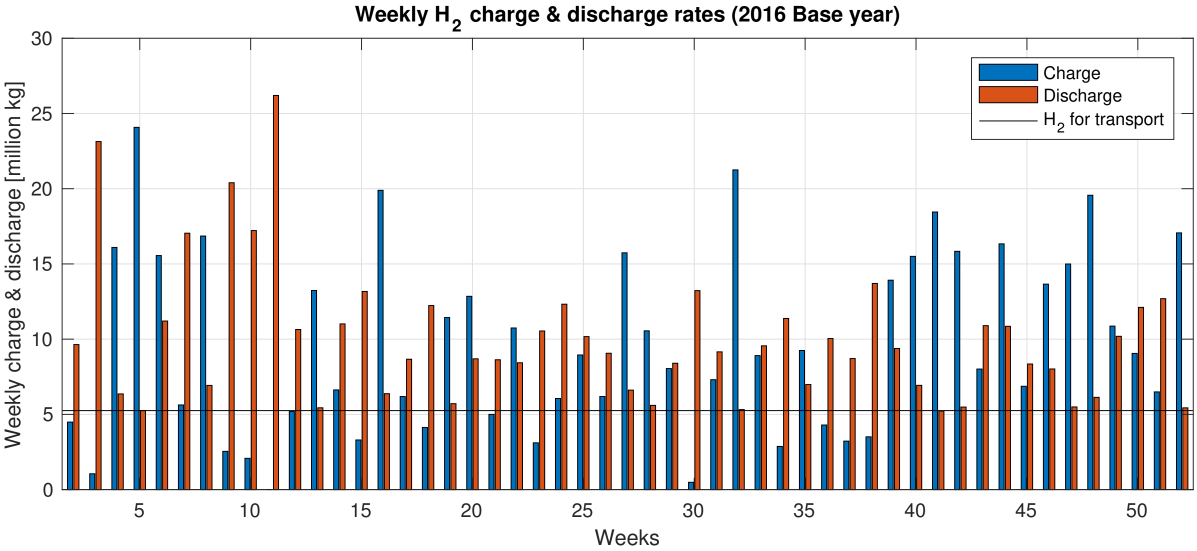


Figure 5.20: Hydrogen weekly charge and discharge rates in Denmark in 2050 (2016 base year)

Figure 5.21 shows the total daily hydrogen dispension at HFSs at the left axis and the dispension per HFS at the right axis. The black dashed line shows the capacity of current large HFSs (section 3.5.2). The yellow line shows the load duration curve of the total dispension and dispension per HFS. It can be seen that on normal days a capacity of less than 500 kg/day is required comparable to the capacity of current normal HFSs. At periods where there is more backup required larger or more fuelling stations are required or hydrogen dispensers need to be installed at CPPPs. Recall from section 3.5.2 that ITM will unveil HFSs with a onsite production capacity of 20 tonnes per day with 50 MW electrolysers. If the daily consumption for road transport of an average HFS will be produced on-site (~ 500 kg/day) a 1.25 MW electrolyser would be required. Assuming Denmark has 2007 HFSs approximately 2.5 GW of the total electrolyser capacity (9-11 GW) would be installed at HFSs. The remaining capacity could be installed near salt caverns or near the grid connection of onshore and offshore wind farms to prevent congestion on the electricity grid.

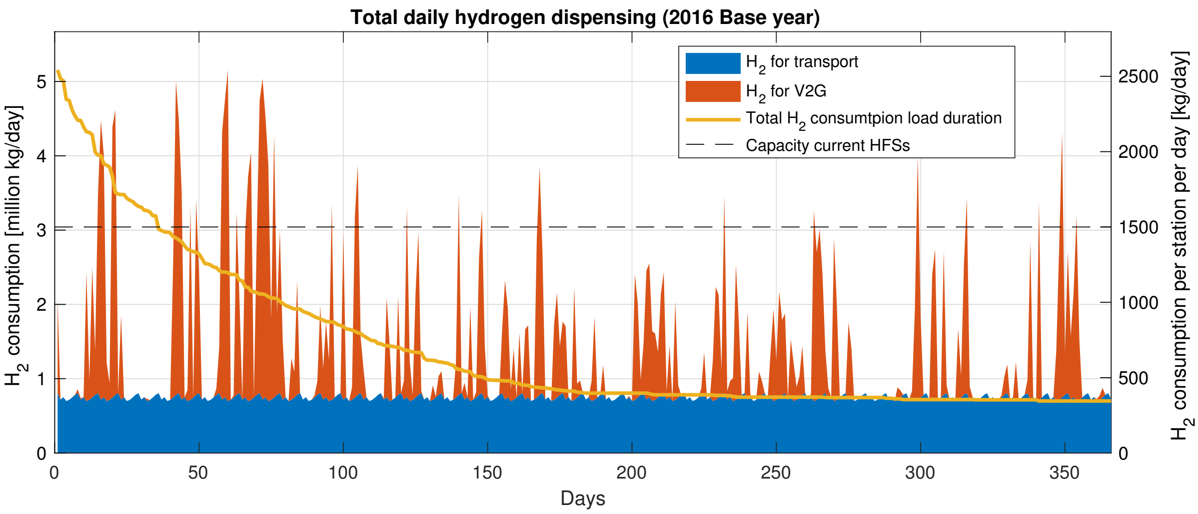


Figure 5.21: Total daily hydrogen dispensing and dispension per HFS in Denmark in 2050 (2016 base year)

5.2. Germany

Germany is the largest of the investigated countries. It is the largest in terms of population, land surface, electricity consumption and CO2 emissions (table 5.1). It is also the largest power system in Europe with the most interconnections. It lies in the heart of Europe and has interconnections with 10 countries with a total transfer capacity of more than 20 GW (in 2014) [103]. This makes it an important factor in balancing the European electricity grids.

5.2.1. Current situation

The final energy consumption in Germany in 2014 was 2516 TWh. Figure 5.22 shows the final energy consumption per sector. The covered sectors, highlighted in figure 5.22, represent 73% of the final energy consumption in 2014.

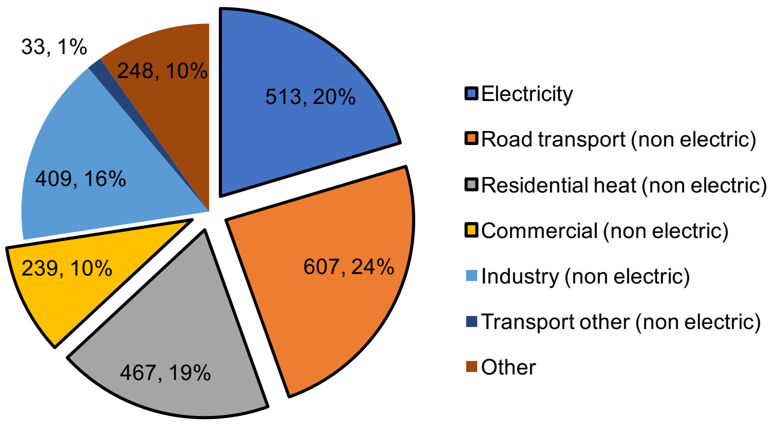


Figure 5.22: Final energy consumption Germany in 2014 in TWh (2516 TWh total) [92]

The total electricity generation was 648 TWh in 2016 of which 185 TWh is from renewables (29%) [104, 105]. The share of renewable electricity generation remains almost constant compared to 2015. Under the German Energiewende (energy transition), the share of renewable resources in the electricity mix is planned to grow to 40-45% percent of gross electricity consumption in 2025, and 55-60% in 2035 [103]. The electricity generation mix for all sources in 2016 can be seen in figure 5.23.

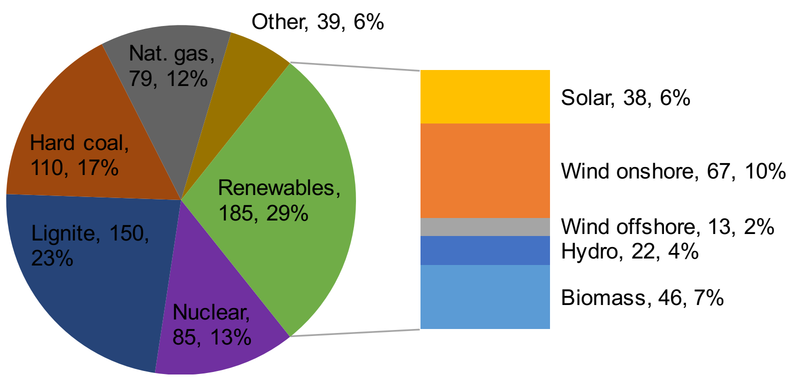


Figure 5.23: Electricity generation mix in Germany in 2016 (648 TWh total)

Figure 5.24 shows the installed capacity per source [106]. Although the share of renewable electricity generation remained constant in 2016 the installed capacity was still growing. This is similar to other countries such as Denmark and Great Britain where the capacity factors for renewables was also lower in 2016.

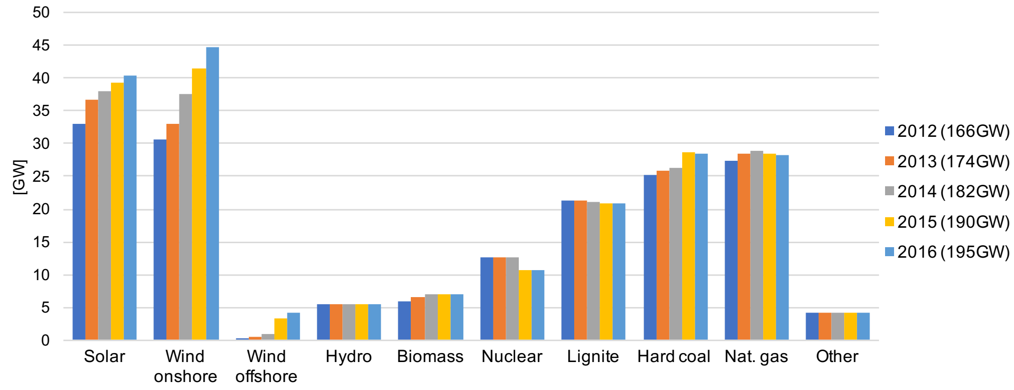


Figure 5.24: Installed capacity per source at the end of the year in Germany [106]

Offshore wind capacity and generation is relatively small in 2016 but is growing rapidly. In 2012 the installed capacity was no more than 270 MW but increased to 4.13 GW at the end of 2016. This increase in installed capacity can also be seen in the total offshore wind generation profile of Germany in 2015 [107] in figure 5.25

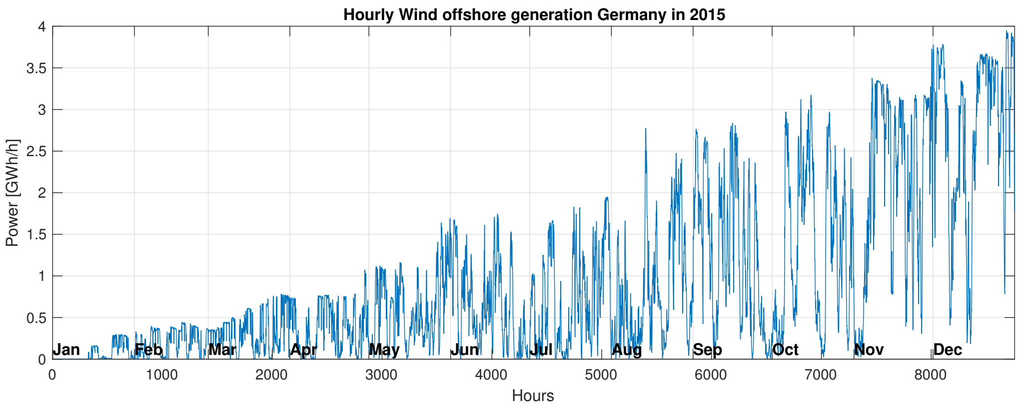


Figure 5.25: Offshore wind electricity generation in 2015

Transport Road transport data for 2015 is gathered from the Kraftfahrt-Bundesamt [108] which is a part of the Federal ministry of Transport and Digital Infrastructure (BMVi) and is responsible for road traffic. Germany had 14510 petrol fuelling station at the end of 2016 [86].

Table 5.4: Road traffic data Germany 2015

	Annual km x10^6	# vehicles	km/vehicle
Passenger cars	618,719.11	43,961,853	14,074
Motorcycles	9,611.55	4,175,303	2,302
Vans	42,568.89	2,195,631	19,388
Lorries	16,365.86	513,527	31,870
Trucks	18,702.13	185,355	100,899
Buses	4,378.19	76,394	57,311
Total	710,346	51,108,063	13,899

5.2.2. 100% renewable scenario

The 2050 scenario for Germany is based on the scenarios by Fraunhofer ISE. Fraunhofer modelled several 2050 scenarios that meet the objectives of the paris agreement in their report 'What will the energy transition cost' published in 2015 [5]. This a follow up of the study 'Energiesystem Deutschland 2050' published in 2013 [109]. The scenarios vary in CO_2 emission reductions of 80% to 90% compared to 1990. The scenarios consider all sectors and energy carriers. The 85% is described in detail in the report and on request also input data of the 90% scenario is made available. The 90% emission reduction scenario is taken as a basis. Since the CO_2 emissions are reduced by 90% since 1990 not all fossil fuels are banned. Coal power plants also need an accelerated exit by 2040 to achieve the emission reduction targets.

In this scenario is assumed that approximately 40% of the building stock is renovated and 60% is converted to 'highly efficient' buildings. In the 90% emission reduction scenario approximately 14% of the buildings is connected to a heating network. The rest of the buildings is equipped with a heat pump. Various energy storage techniques for heat and electricity are utilised. Batteries are used for intra-day storage, pumped-storage plants for inter-seasonal storage and several power-to-gas (P2G) technologies including hydrogen for seasonal storage and fuels. In the 90% emission reduction scenario 175 GW of P2G is required, in the 85% reduction this is only to 115 GW. The increase in the 90% scenario is caused by the limited use of fossil fuels.

The mix of installed capacity and expected electricity generation where the use of fossil sources is filtered is shown in figures 5.26 and 5.27. The original mix in the 90% emission reduction scenario also included 103 GW installed capacity gas turbines.

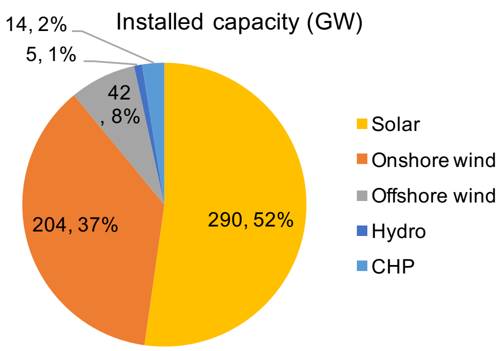


Figure 5.26: Installed capacity in Germany in 2050 (555 GW total)

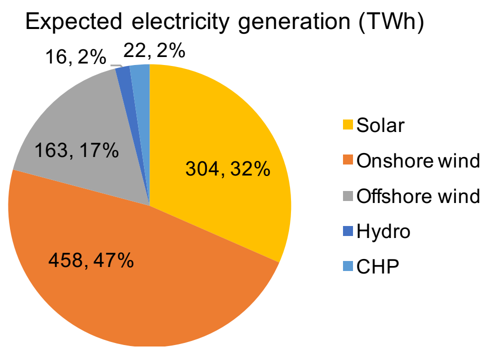


Figure 5.27: Expected electricity generation per source in 2050 (963 GW total)

5.2.3. Model inputs

Electricity generation

The normalised generation profiles are based on the data package of Agora Energiewende [107]. The raw nett generation data is published by the ENTSO-E transparancy platform and processed by Agora. The mix of installed capacity in the previous section will be applied. Solar, onshore wind and offshore wind can be upscaled in the model. The installed capacities of Hydro and CHP plants are fixed. For CHP the electricity generation profile of natural gas is used, this profile already adapts slightly to the intermittent sources. All the normalised generation profiles per base year can be seen in appendix F.1 on page 159.

Figure 5.24 already showed that the installed capacity of offshore wind increased significantly in the recent year and figure 5.25 showed that the generation profile is therefore not useable in the model. Instead the offshore wind generation profiles of Denmark for 2014 and 2015 are taken since the geographic locations of the wind farms are close to each other. For the 2016 base year the offshore wind generation profile of Agora is used. Figure 5.28 shows the capacity factors of all generation types. The capacity factor in 2016 was lower but this is also the case for the offshore wind in Denmark. The German capacity factor is 6% lower than Denmark in 2016. This might be due to a small increase in installed capacity in Germany. This effect can also be seen in figures 5.29 and 5.30. The figures show a boxplot of the normalised monthly offshore wind generation in 2016 for Germany and Denmark respectively. It can be seen that the profiles match but the generation is upscaled from October in Germany which is most likely caused by connecting new wind turbines.

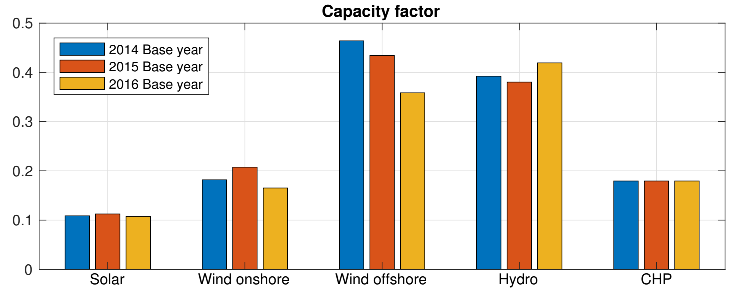


Figure 5.28: Capacity factors

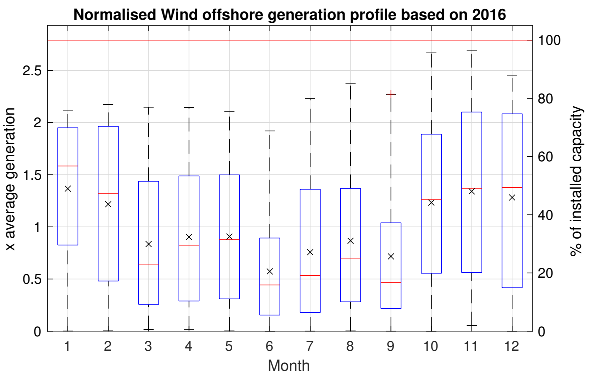


Figure 5.29: Monthly boxplot normalised offshore wind electricity generation profile Germany, 2016 base year

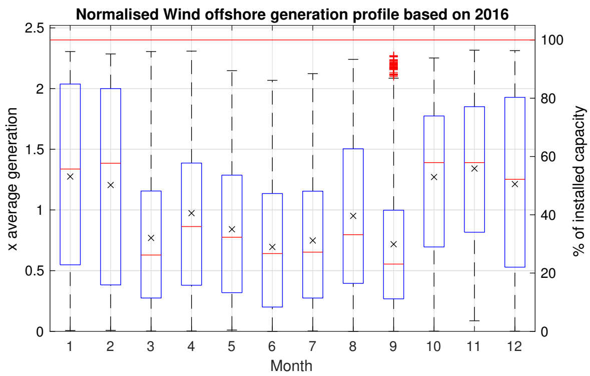


Figure 5.30: Monthly boxplot normalised offshore wind electricity generation profile Denmark, 2016 base year

Consumption
The classic consumption profile is based on the total electricity consumption profile from Agora Energiewende datapackage[107] and scaled to the total classic consumption in 2050. This classic electricity consumption is in the Fraunhofer scenarios estimated at 375 TWh, a 25% reduction compared to the total consumption in Germany in 2013 minus the electricity for space heating and hot water [5]. This classic consumption will be used in the model.

The total heating demand for space heating & hot water is 477 TWh based on the Fraunhofer 90% emission reduction scenario. It is estimated that 70 TWh of heat is supplied for space heating and hot water by solar thermal power in the Fraunhofer scenario. 407 TWh of heat is supplied by heat pumps. The corresponding electricity consumption with a SCOP of 3.5 (see section 4.2.2) is 116 TWh. The maximum heat pump capacity is determined with the same relation between heat pump electricity consumption and capacity as Denmark. This results in a heat pump capacity of 108 GW. The total heat supply can be seen in figure 5.31.

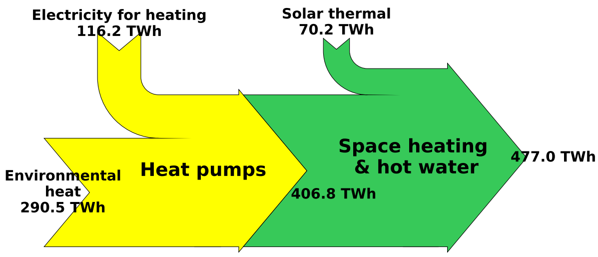


Figure 5.31: Heat flow diagram for Germany in 2050 (TWh/year)

Road Transport
The data from table 5.4 in section 5.2.1 will be used in the model for the number of vehicles and travelled distance per vehicle categorie. No adjustments are made.

5.2.4. Results & Discussion

Figure 5.32 shows the Energy flow diagram for Germany in 2050 with 2016 as base year. The total generation is 807 TWh of which 485 TWh is directly consumed via the grid and 322 TWh is consumed by electrolysers to produce hydrogen. The total backup of grid connected FCEVs is 66.3 TWh, 12% of the total electricity consumption. 6600 million kg of hydrogen is produced of which 3834 million kg (58%) is consumed for road transport and 2791 million kg (42%) is consumed for V2G. The final energy consumption (including hot water and space heating) is 999 TWh. All results and model outputs can be found in appendix F.2 on page 170.

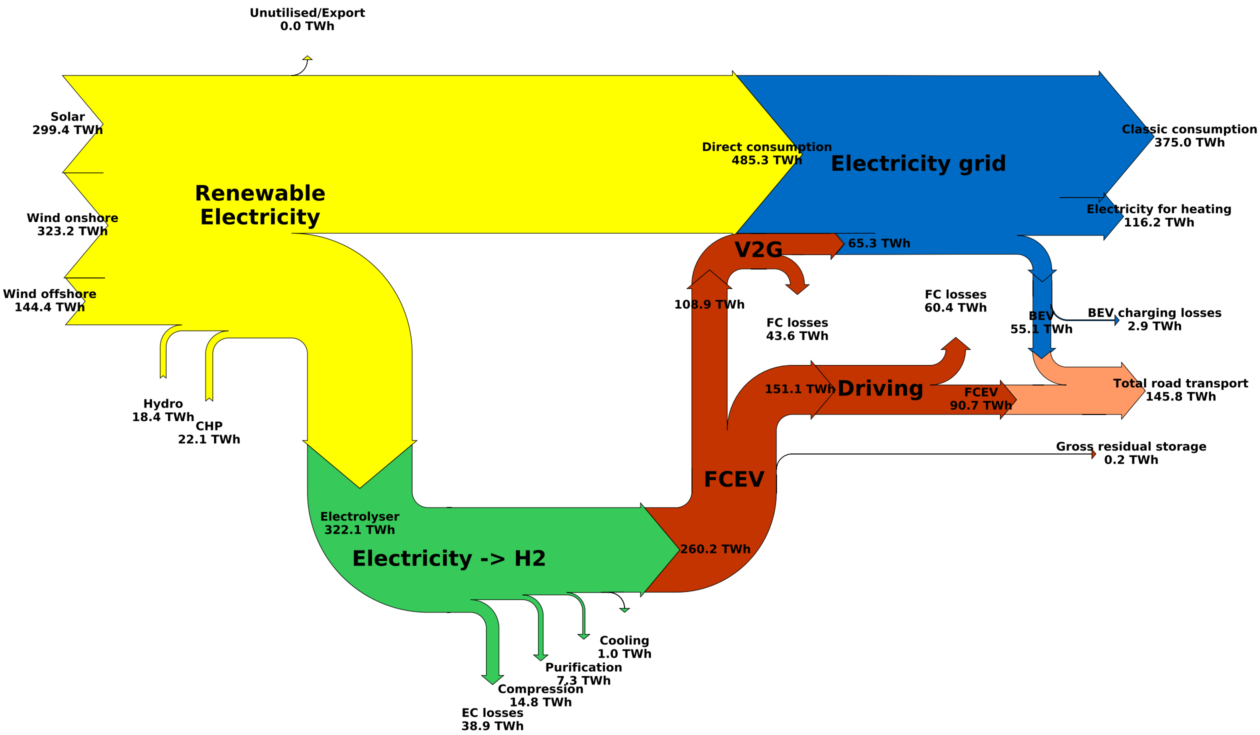


Figure 5.32: Energy flow diagram for Germany in 2050 with 2016 as base year (TWh/year)

The required installed capacity to be self sufficient for every base year is shown in figure 5.33, the corresponding electricity generation is shown in figure 5.34. The installed capacity is almost equal to Fraunhofer 90% emission reduction scenario [5]. The total generation is 807 TWh, approximately 160 TWh less than the reference scenario. The lower generation with approximately the same installed capacity can be explained by lower capacity factors of onshore and offshore wind in the model. Less electricity is required in the model which is mainly because (fuel based) heat in industry is not taken into account which accounts for 418 TWh in the Fraunhofer scenario.

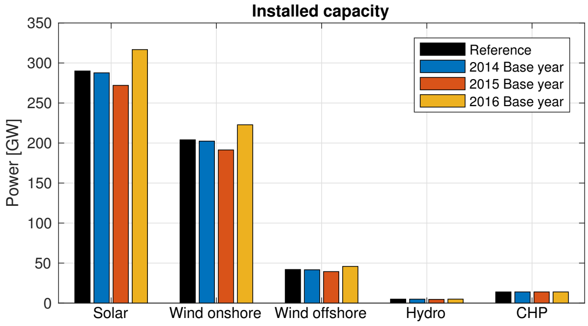


Figure 5.33: Installed capacity in Germany in 2050

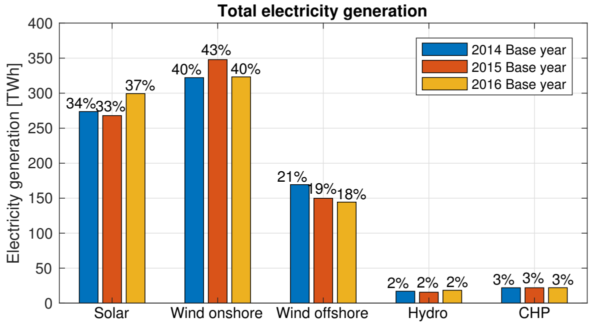


Figure 5.34: Total electricity generation in Germany in 2050

Figure 5.35 shows the load duration curves of the imbalances without the production of hydrogen and FCEV backup. Surplus electricity will be absorbed for the production of hydrogen. Electrolysers are required approximately 5800 hours per year. The electrolyser peak demand is 270 GW. The electrolyser capacity factor varies from 13.6-16.2%.

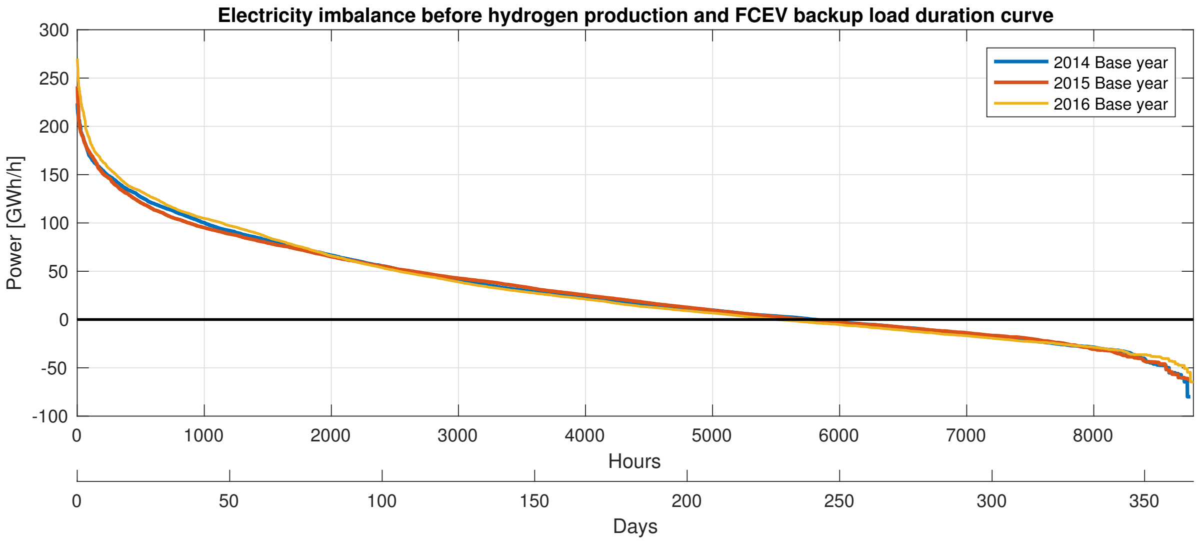


Figure 5.35: Imbalance load duration curve in Germany in 2050

FCEV backup

Figure 5.36 shows the load duration of the required passenger FCEVs for V2G. It can be seen that the maximum demand is around 36% of the passenger FCEVs (18% of all passenger vehicles) and is only required for 1 day per year. V2G backup is required for approximately 3000-3250 hours per year. For only 3 days per year more than 27% of all passenger FCEVs should be availble. Figure 5.37 also shows that the peak demand of 36% only occurred once in all three base years. This happened on a day in december with 2014 as base year on a cold day when there was no (offshore) wind. During the day only occasionally backup is required as can be seen in the figure. Backup is most required at night. The total backup demand per month is shown in figure 5.38. It can be seen that the backup demand is higher in the winter months and lower during the summer when there is more solar energy available. During the summer hydrogen is mainly consumed for transport and the net charging rates are positive. During the winter the net charging rates are mostly negative except a few weeks where there is a lot of wind energy (figure5.40)

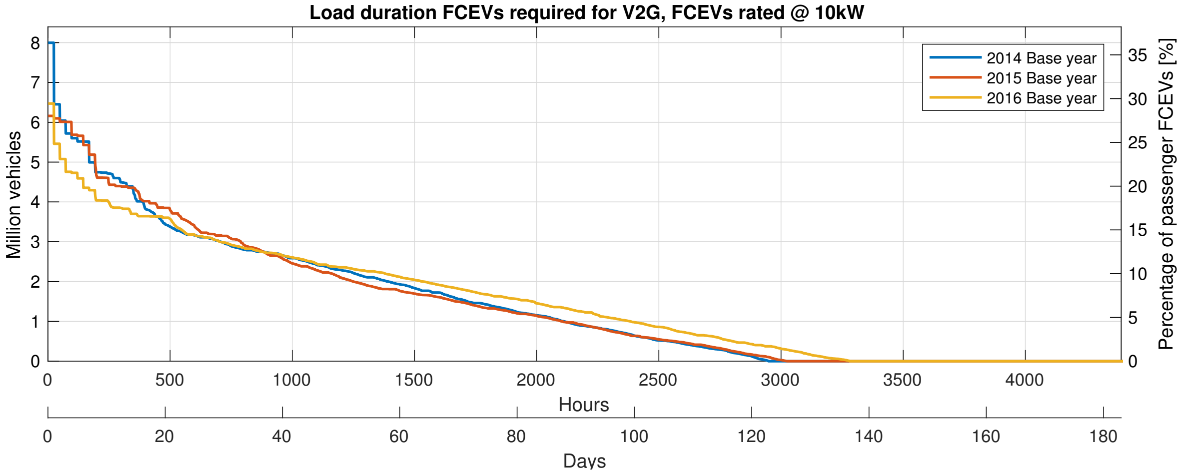


Figure 5.36: Load duration curve of FCEV backup in Germany in 2050

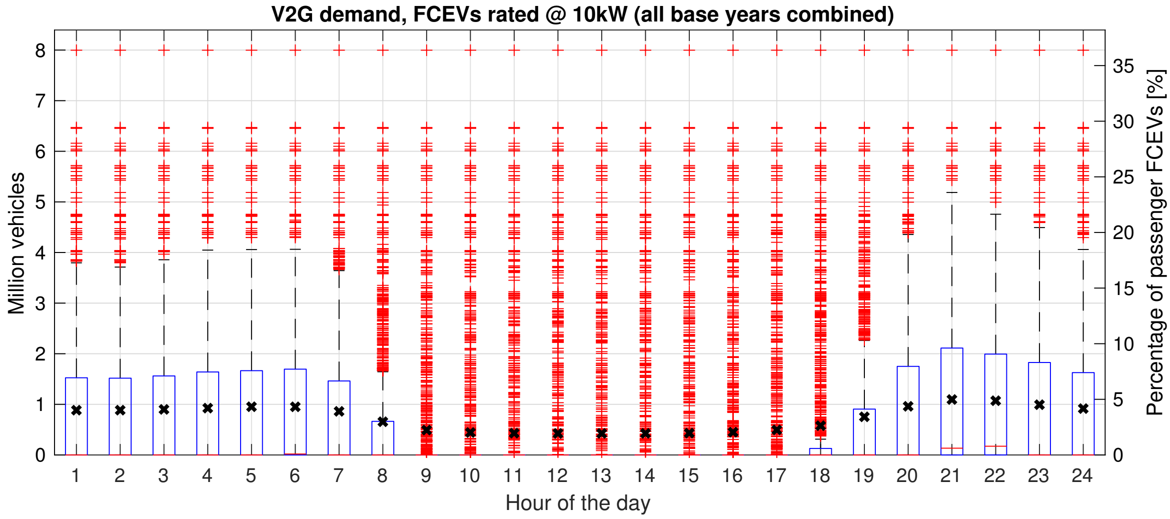


Figure 5.37: Distribution of backup power demand per hour of the day for Germany in 2050 with all base years combined

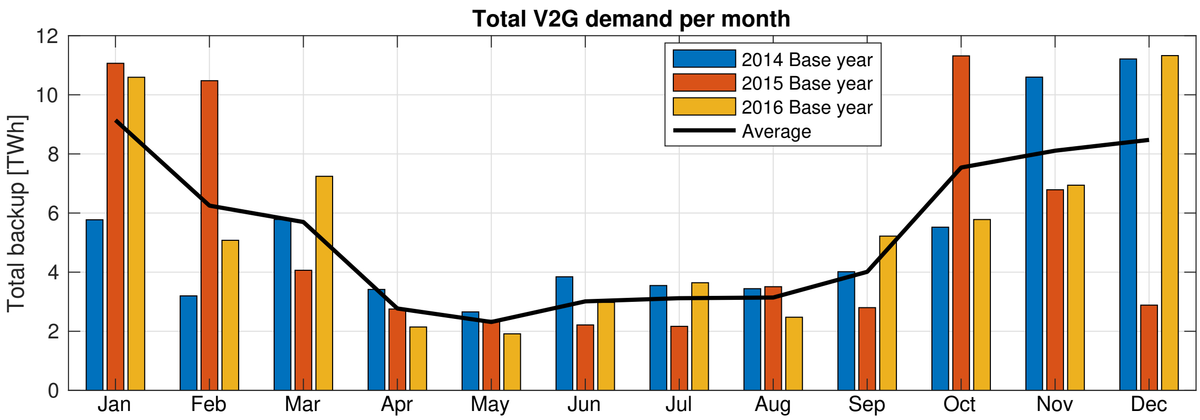


Figure 5.38: Total FCEV V2G backup per month for Germany in 2050

Hydrogen storage

The total hydrogen storage capacity is shown in figure 5.39. The peak storage capacity is 1.938 billion kg. Recalling that 6 million kg of working gas could be stored in an average salt cavern, at least 323 salt caverns are required. Assuming that one storage site can have 10 caverns means that at least

33 of those storage sites are required. The storage capacity shows a strong trend where hydrogen is buffered during the summer and consumed for backup and road transport in the winter. This pattern can be confirmed with figure 5.40 showing the weekly charge and discharge rates of hydrogen with 2016 as base year. It can be seen that the buffer is required for both V2G backup and transport at the end of the year.

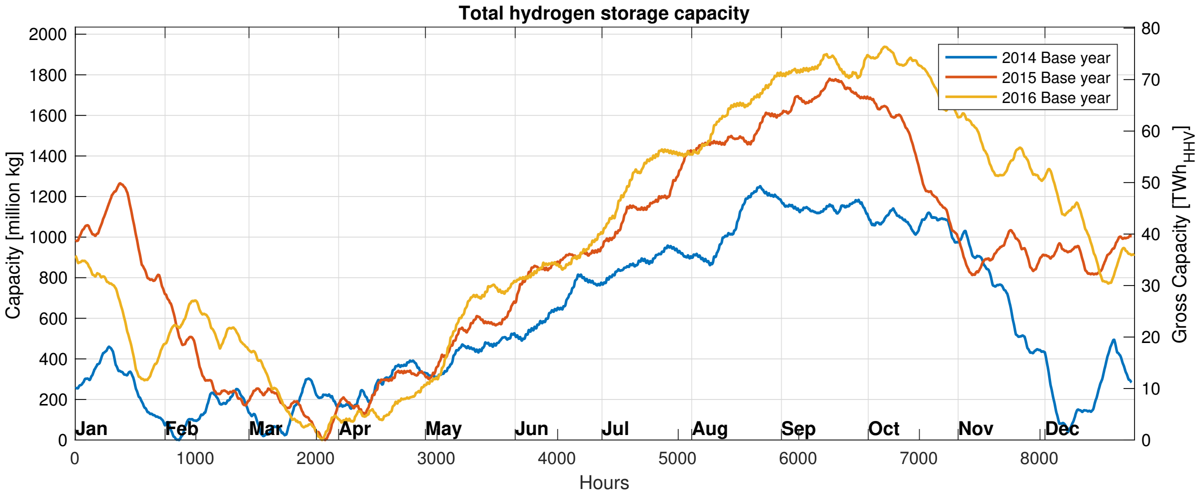


Figure 5.39: Annual hydrogen storage capacity in Germany in 2050

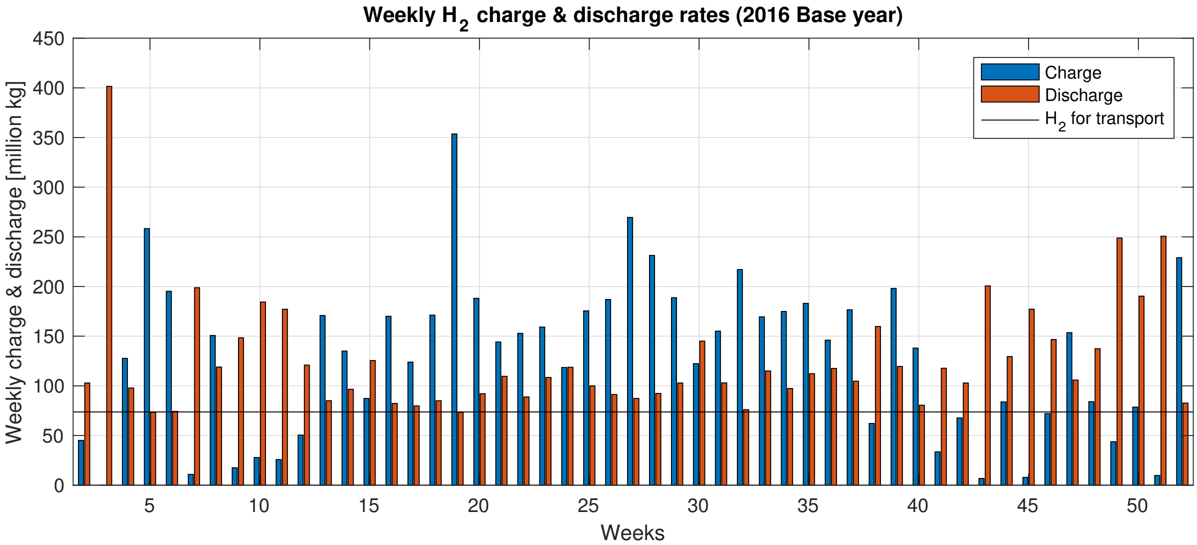


Figure 5.40: Hydrogen weekly charge and discharge rates in Germany in 2050 (2016 base year)

Figure 5.41 shows the total daily hydrogen dispension at HFSs at the left axis and the dispension per HFS at the right axis. The black dashed line shows the capacity of current large HFSs (section 3.5.2). The yellow line shows the load duration curve of the total dispension and dispension per HFS. It can be seen that on days where only hydrogen for road transport is fuelled approximately 750 kg/day is required. At periods where there is more backup required larger or more fuelling stations are required. Covering peak demands requires a significant increase in dispensing capacity. If the base load of 750kg/day would be produced on site approximately 1.9 MW electrolyser capacity would be required.

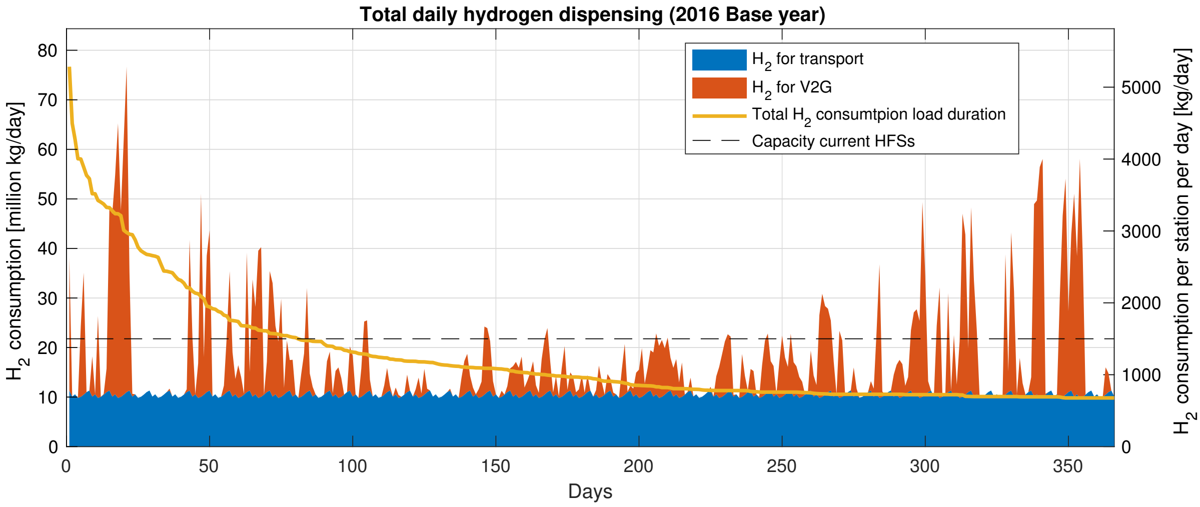


Figure 5.41: Total daily hydrogen dispensing and dispension per HFS in Germany in 2050 (2016 base year)

5.3. Belgium

Belgium is the smallest country in this analysis in terms of land surface and has the highest population density. The offshore territory is also significantly smaller than other countries which makes installation of sufficient renewable energy challenging [6]. Belgium has interconnections with the Netherlands, France and Luxembourg. An interconnection with Great Britain is under construction.

5.3.1. Current situation

The final energy consumption in Belgium in 2014 was 466 TWh. Figure 5.42 shows the final energy consumption per sector. The covered sectors, highlighted in figure 5.42, represent only 58% of the final energy consumption in 2014. This is caused by the high share of energy consumption by the industry. The energy consumption of industry is high but also the non-energy use is high. Non-energy use is the use of fuels for other purposes than energy generation. More than 99% of the non-energy use is consumed in industry.

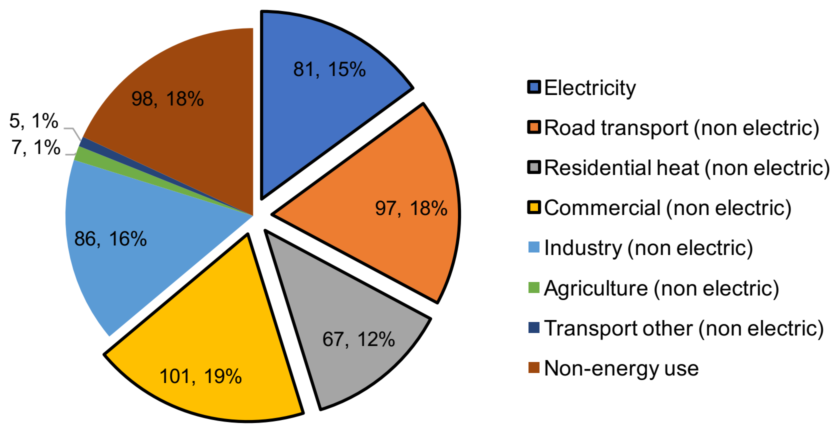


Figure 5.42: Final energy consumption in Belgium in 2014 (466 TWh total) [92]

An annual report of the Belgium electricity system is not published by the Belgian TSO, Elia, or any other institution so there is no clear overview of the current electricity generation mix or installed capacity. From the Elia electricity generation data [110] however, the installed capacities of solar and wind electricity can be determined. The installed capacity remained constant between 2015 and 2016. 2.95 GW of solar PV was installed, 1.25 GW onshore wind and 0.71 GW offshore wind. The total hydro capacity is only several Megawatts [6].

Transport
Transport data is based on the distance traveled by Belgium road vehicles. This data is gathered by the federal government for transport and mobility (Federale Overheidsdienst Mobiliteit en Vervoer) [111]. The report provides the total amount of vehicles at the end of 2015 and the total travelled distance per vehicle type. Belgium had 3109 petrol fuelling station at the end of 2016 [86].

Table 5.5: Road traffic data Belgium 2015

	Annual km x10^6	# vehicles	km/vehicle
Passenger cars	84,225	5,661,742	14,876
Motorcycles	-	460,173	-
Vans	11,456	680,834	16,826
Lorries	2,206	107,514	20,518
Trucks	3,339	49,741	67,128
Buses	659	17,064	38,619
Total	103,273	6,977,068	14,802

5.3.2. 100% Renewable scenario

ICEDD, VITO and the FPB published the report'Towards 100% renewable energy in Belgium by 2050' [6] in 2013 . The federaal plan bureau (FPB), the Institut de Conseil et d'Etudes en Dévelopment Durable (ICEDD) and the Vlaamse Instelling voor Technologisch Onderzoek (VITO) are all part of the Belgian government. The aim of this report is to investigate the feasibility and impact of a transition towards a 100% renewable energy system.

Four different pathways are chosen: GRID, BIO, PV and WIND. The high population density and the small offshore area makes the energy transition challenging for Belgium. The report describes the potential of renewable energy sources in Belgium, which is based on previous studies of ICEDD and VITO. Those studies concluded that the potential for renewables is limited. All the scenarios eliminate one of the limitations:

- GRID: The lack of local renewable energy is compensated by larger imports of electricity.
- BIO: A higher quantity of biomass can be imported.
- PV: A larger surface can be covered by solar panels in Belgium.
- WIND: Onshore and offshore potentials are increased.

The potential for onshore wind is slightly less than 9 GW. If some constrains are relaxed the potential capacity is increased to 20 GW in the WIND pathway, onshore wind turbines can be build closer to urban areas. The area on the continental shelf is also limited, based on the previous studies it is assumed that the potential of offshore wind is limited to 8 GW. For all pathways is assumed that up to 13 GW offshore wind capacity is installed in maritime areas of neighbouring countries. In the WIND pathway there is no limit to offshore wind installed capacity. Considering all the existing buildings in Belgium the potential roof surface that can be used for solar PV equals around 250 km^2. This corresponds to a installed capacity around 50 GW. In the PV pathway this restriction is removed.

In all scenarios there is a potential of 4 GWe geothermal power. The capacity factor is in all pathways 100%. In all pathways up to 300 PJ (83 TWh) of biomass can be consumed.

5.3.3. Model inputs

Electricity generation
Based on the four pathways a generation mix is constructed. The full rooftop area will be utilised resulting in 50 GW installed capacity. Onshore wind capacity is set to 9 GW with a restriction in the model to 20 GW. Offshore wind is assumed to be the maximum 8 GW on Belgium territory plus the 13 GW installed capacity on neighbouring territory. This capacity can not be increased any further. The installed capacity of geothermal power is fixed at 4 GW with a capacity factor of 100% resulting in a annual generation of 35 TWh. The mix of installed capacity and corresponding electricity generation can be seen in figures 5.43 and 5.44.

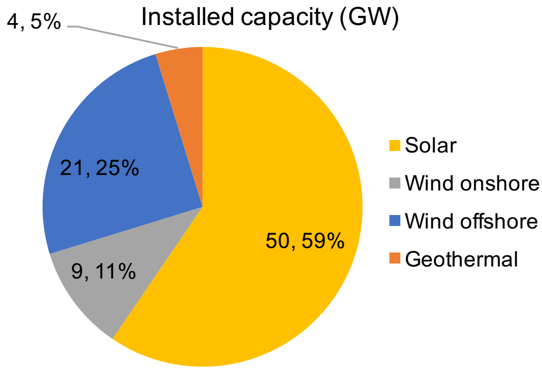


Figure 5.43: Installed capacity in Belgium in 2050 (84 GW total)

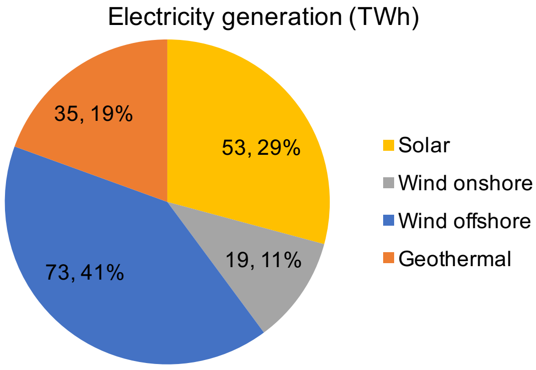


Figure 5.44: Expected electricity generation per source in Belgium in 2050 (180 TWh total)

15 minute solar and wind generation data per month is available for download on the website of the Belgian TSO, Elia [110]. This data is converted to hourly electricity generation to construct the solar, onshore wind and offshore wind electricity generation profiles. The geothermal generation profile is constant throughout the year. Since the installed capacity did not increase in 2015 and 2016 the profiles do not need adjustments. The capacity factors of al generation types can be seen in figure 5.45. All the normalised generation profiles per base year can be seen in appendix G.1 on page 183.

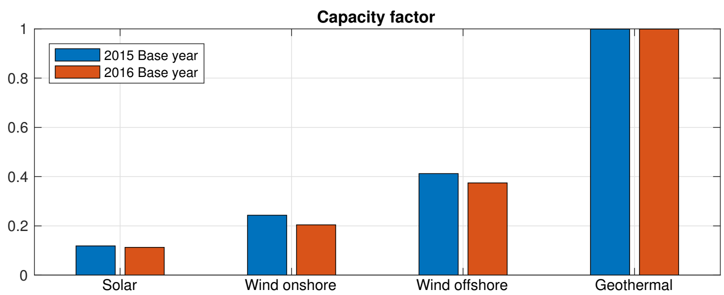


Figure 5.45: Capacity factors

Consumption

The classic consumption profile is based on the total load on the Belgium grid, downloaded from the Elia website [110], and scaled to the total classic consumption in 2050. The report is not detailed in the breakdown of consumption. The total electricity consumption in all pathways is 177 TWh but includes massive electrification in industry. The electricity consumption is based on the electricity consumption in the reference scenario which does not imply any renewable energy target by 2050 but only takes the objectives of the 2020 EU climate-energy package into account. The classic electricity consumption is 104.6 TWh.

The report does not specify a total heating demand or heat pump consumption. The heat demand will be based on the heating demand in Germany in 2050 and corrected for the amount of HDD (T_{ref} = 16°C) and the projected population in 2050 [75]. The Space heating demand is calculated according to equation 5.1 where the space heating demand in Germany is corrected with the difference of HDD of both base years and the projected population. The HDD for both countries with 16°C as refenrence temperature and the projected population from Eurostat can be found in table 5.6.

$$SH_{BE} = SH_{DE} \cdot \frac{HDD_{BE,2015} + HDD_{BE,2016}}{HDD_{DE,2015} + HDD_{DE,2016}} \cdot \frac{Pop_{BE,2050}}{Pop_{DE,2050}} \tag{5.1}$$

When the space heating demand is known the total heating demand can be determined with equation 5.2.

$$HD_{BE} = SH_{BE} + SW_{BE} = \frac{SH_{BE}}{1 - Fraction_{HW,BE}} \tag{5.2}$$

The total heating demand in Belgium in 2050 is 68 TWh. It is assumed that 10% of the heat is supplied by solar thermal energy (6.9 TWh). This is slightly lower than Germany (15%) because the roof area is limited in Belgium. The heat supply of heat pumps is 61.6 TWh which results in a electric heat pump consumption of 17.6 TWh with a SCOP of 3.5. The corresponding heat pump capacity is 16.4 GW. The heat flow diagram for Belgium can be seen in 5.46.

Table 5.6: HDD, projected population and heating demand for Germany & Belgium in 2050

	Germany	Belgium
HDD 2015	2305.5	2131.8
HDD 2016	2463.2	2226.8
Population (2050) million	82.7	13.27
Fraction hot water	14.86%	13.04%
Total heat demand TWh	477.00	68.49
Hot water (HW) TWh	70.88	8.93
Space heating (SH) TWh	406.12	59.56

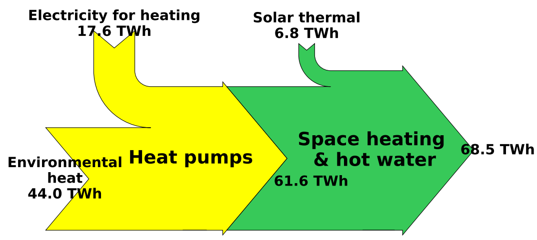


Figure 5.46: Heat flow diagram Belgium (TWh/year)

Road Transport
The data from table 5.5 in section 5.3.1 will be used in the model for the number of vehicles and travelled distance per vehicle categorie. The travelled distance for motorcycles is missing. The total travelled distance for motorcycles is calculated with the assumption that the kilometers per motorcycle is equal to the kilometers per motorcycle in Denmark. The total travelled distance and number of vehicles including motorcycles can be seen table 5.7.

Table 5.7: Road traffic data Belgium 2050

	Annual km x10^6	# vehicles	km/vehicle
Passenger cars	84,225	5,661,742	14,876
Motorcycles	1,387.73	460,173	3,016
Vans	11,456	680,834	16,826
Lorries	2,206	107,514	20,518
Trucks	3,339	49,741	67,128
Buses	659	17,064	38,619
Total	103,273	6,977,068	14,802

5.3.4. Results & Discussion

Figure 5.47 shows the Energy flow diagram for Belgium in 2050 with 2016 as base year. The total generation is 176 TWh of which 112 TWh is directly consumed via the grid and 68.1 TWh is consumed by electrolysers to produce hydrogen. The total backup of grid connected FCEVs is 18.8 TWh, 14.4% of the total electricity consumption. 1396 million kg of hydrogen is produced of which 598 million kg (43%) is consumed for road transport and 795 million kg (57%) is consumed for V2G. The final energy consumption (including hot water and space heating) is 195 TWh. All results and model outputs can be found in appendix G.2 on page 191.

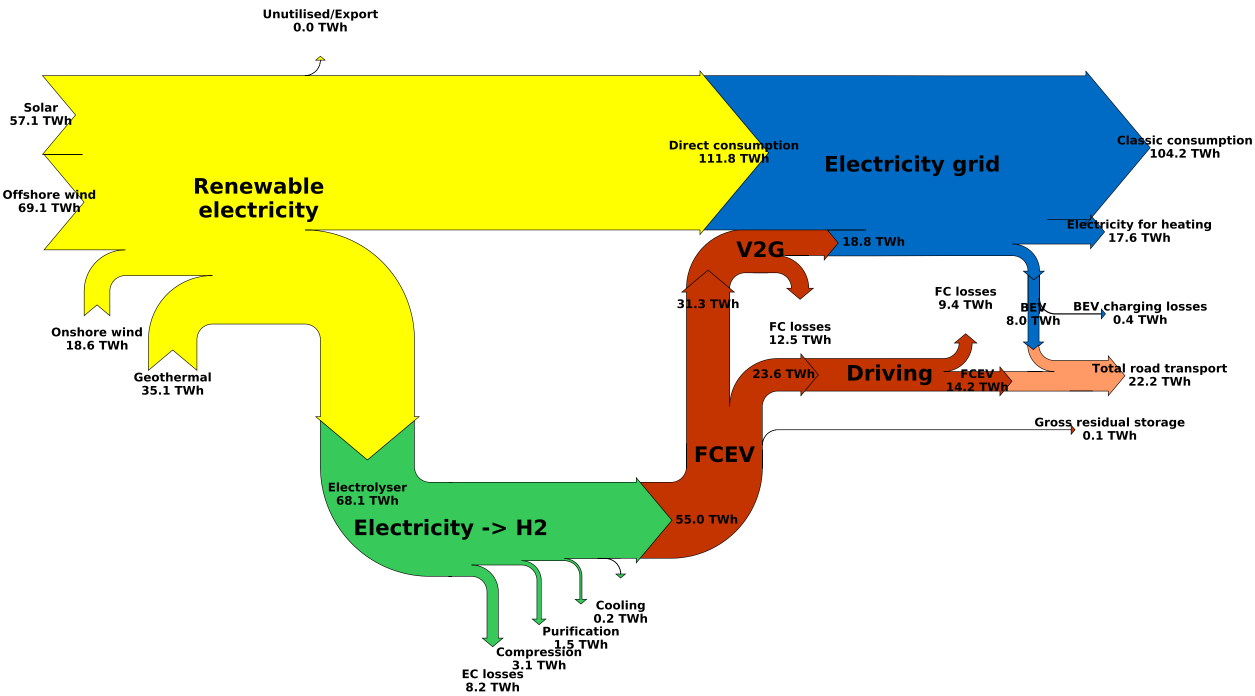


Figure 5.47: Energy flow diagram for Belgium with 2016 as base year (TWh/year)

The required installed capacity to be self sufficient for every base year is shown in figure 5.48, the corresponding electricity generation is shown in figure 5.49. The capacities are almost equal to the reference. In the 2016 base year onshore and offshore wind are limited to the maximum available capacity. The constraint of maximum 50 GW solar PV is widened because the simulation will not have a result otherwise. In all four scenarios one of the limits had to be widened and a significant amount of biomass is consumed. Keep in mind that it is already assumed that 13 GW offshore wind is installed in neighbouring territory and therefore self sufficiency is not really the case for Belgium. It could be beneficial in terms of cost, energy efficiency and public acceptance to import electricity and/or hydrogen from neighbouring countries rather than using all possible land surface and offshore areas to install renewables.

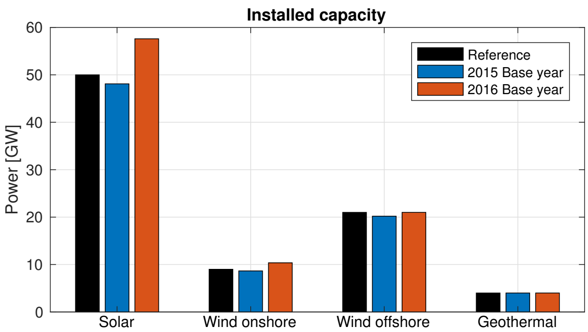


Figure 5.48: Installed capacity in Belgium in 2050

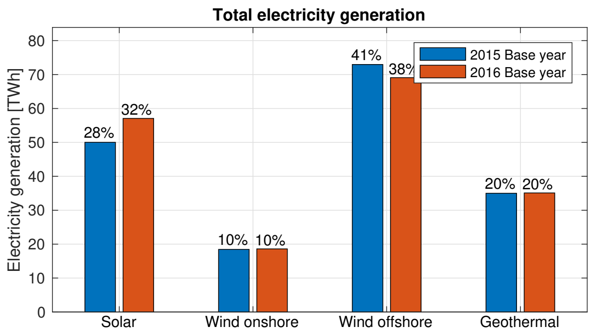


Figure 5.49: Total electricity generation in Belgium in 2050

Figure 5.50 shows the load duration curves of the imbalances without the production of hydrogen and FCEV backup. Surplus electricity will be absorbed for the production of hydrogen. Electrolysers are required approximately for 5400-5500 hours per year. The electrolyser peak demand is 53 GW. The electrolyser capacity factor varies from 15.3-14.6%. Larger differences between the base years can be seen compared to the other countries. The electricity surplus, peak surplus and backup demand (figure 5.51, are significantly higher with the 2016 base year. An explanation could be the lower capacity factor of onshore and offshore wind in 2016. The output of offshore wind was lower and since the installed capacity of wind is limited more solar PV needs to be installed with 2016 as base year. This shift from wind electricity to solar PV could explain the difference. Belgium has a higher consumption at night compared to the other countries (figure 6.1 in chapter 6) which makes extra capacity of solar PV instead of wind unfavourable.

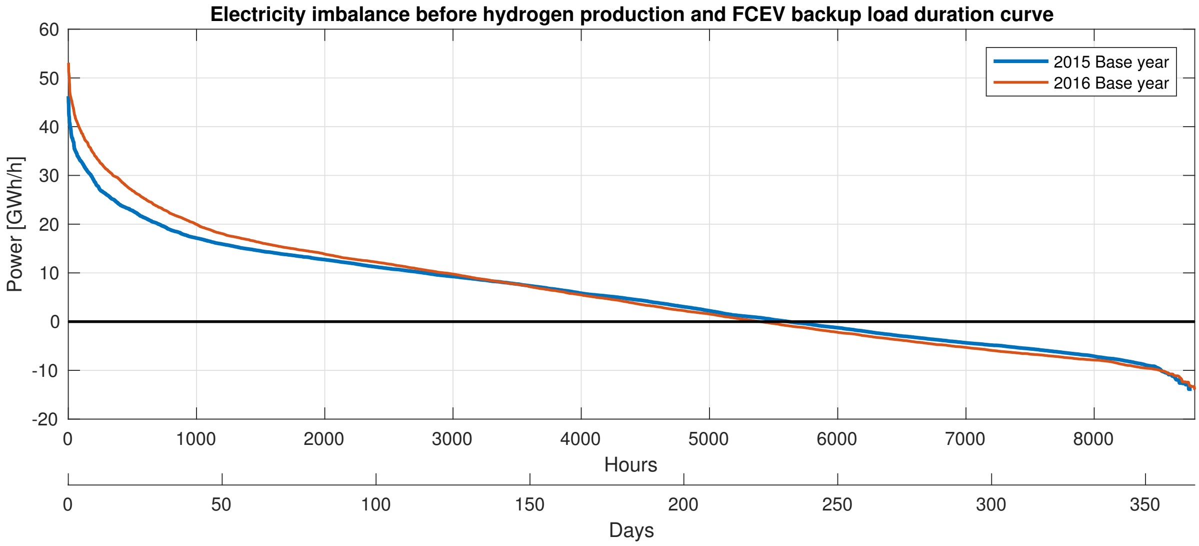


Figure 5.50: Imbalance load duration curve in Belgium in 2050

FCEV backup

Figure 5.51 shows the load duration of the required passenger FCEVs for V2G. It can be seen that the maximum demand is almost 50% of the passenger FCEVs (25% of all passenger vehicles) and is only required for 1 day per year. V2G is required for approximately 3100-3400 hours per year. For 10 days (240 hours) per year more than 35% of all passenger FCEVs is required. Figure 5.52 shows the distribution of FCEV backup per hour of the day. During the day only occasionally backup is required as can be seen in the figure, backup is most required at night, the same behaviour could be seen for Germany but the utilisation of the fleet is higher in Belgium. The monthly average V2G backup demand shows the same seasonal pattern as Germany.

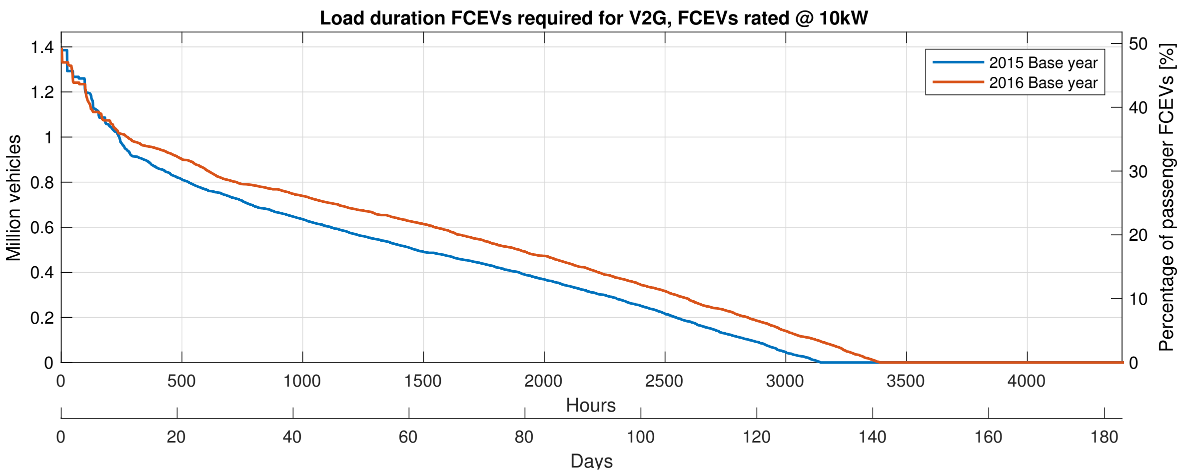


Figure 5.51: Load duration curve of FCEV backup in Belgium in 2050

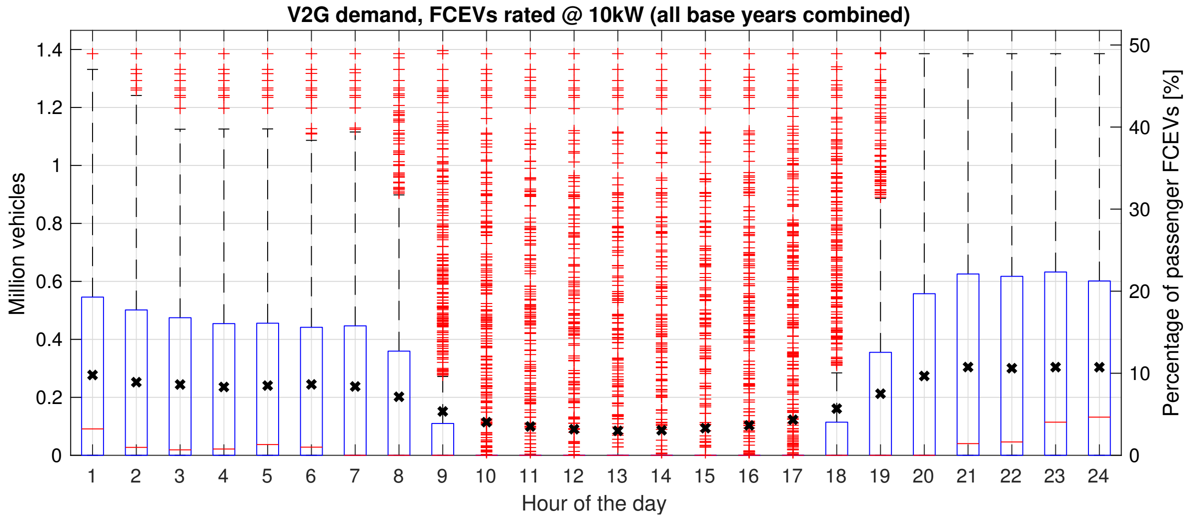


Figure 5.52: Distribution of backup power demand per hour of the day for Belgium in 2050 with all base years combined

Hydrogen storage

The total hydrogen storage capacity is shown in figure 5.53. The peak storage capacity is 419 million kg. Recalling that 6 million kg of working gas could be stored in an average salt cavern, at least 70 salt caverns are required. Assuming that one storage site can have 10 caverns means that at least 7 of those storage sites are required. It should be noted, however, that there are no salt formations in Belgium according to figure 3.7 in section 3.8.2. Hydrogen could be stored in neighbouring countries, or other storage solutions should be looked at. The storage capacity shows the same trend as the storage capacity in Germany where the buffers are filled during the summer and discharged during winter. The storage capacity is the lowest at almost the same period for both base years. With 2016 as base year the storage is almost completely emptied at the end of the year while with the 2015 base year the storage is emptied in the first months of the year. Although the storage is mostly charged with excess solar energy in the summer, wind energy has most likely influence on how fast the storage is emptied. This can be seen in figures 5.54 and 5.55 showing the monthly boxplots of offshore wind generation with 2015 and 2016 as base year. It can be seen that the wind electricity generation was significantly lower at the end of 2016 and the wind generation at the start of 2015 is slightly lower tan the start of 2016.

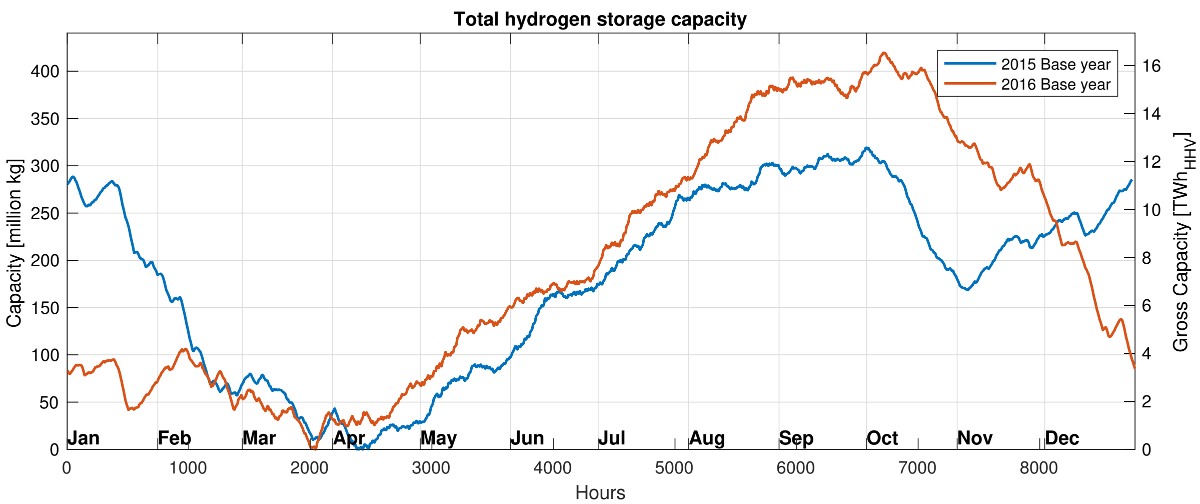


Figure 5.53: Annual storage capacity for Belgium in 2050

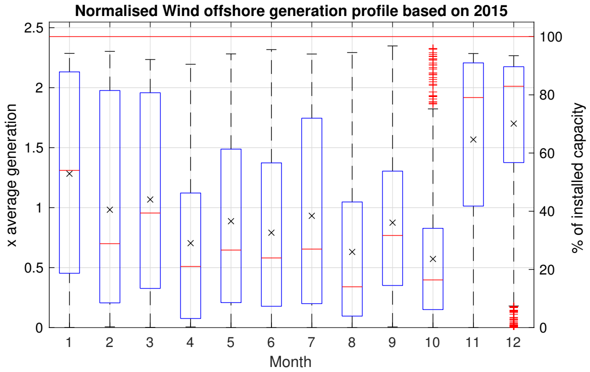


Figure 5.54: Monthly boxplot normalised offshore wind electricity generation profile Belgium, 2015 base year

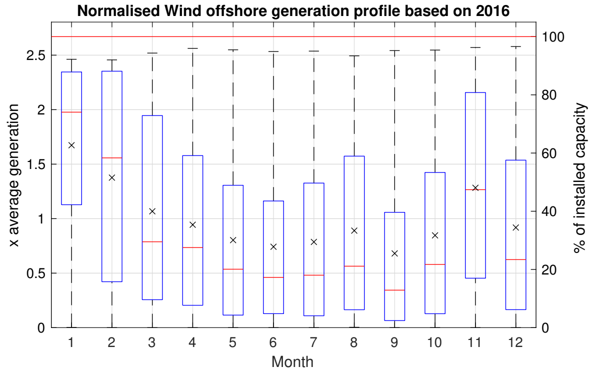


Figure 5.55: Monthly boxplot normalised offshore wind electricity generation profile Belgium, 2016 base year

Figure 5.56 shows the total daily hydrogen dispension at HFSs at the left axis and the dispension per HFS at the right axis. It can be seen that on days where only hydrogen for road transport is fuelled a capacity of approximately 500 kg/day is required. At periods where there is more backup required larger or more fuelling stations are required. Covering peak demands requires a significant increase in dispensing capacity. This is similar to the Germany case although the capacity for road transport fuelling is higher in Germany because the density of HFSs per passenger car is lower in Germany (the plot shows fuelling for all road transport).

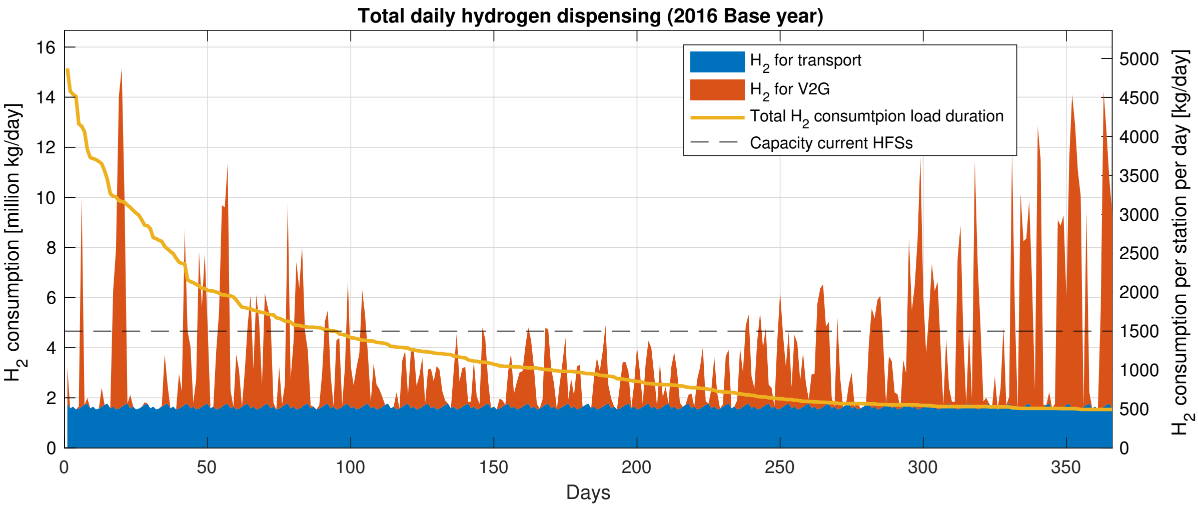


Figure 5.56: Total daily hydrogen dispensing and dispension per HFS in Belgium in 2050 (2016 base year)

5.4. Great Britiain

This case does not investigate the entire United Kingdom (UK) but only Great Britain (GB). The electricity grids of Great Britain and Ireland are separated. Although North-Ireland is part of the UK it is thus not taken into account. Great Britain has interconnections with North-Ireland, Ireland, the Netherlands and France with a total capacity of 4 GW [7]. Interconnections with Norway and Belgium are under construction. The capacity of interconnectors is still increasing but the decision of the UK to leave the European Union (EU) gives uncertainty to the future trade of energy between the UK and EU member states [7].

5.4.1. Current situation

Unfortunately the IEA Sankey diagrams only includes the UK, not Great Britain separately. The final energy consumption in the United Kingdom was 1429 TWh in 2014. Figure 5.96 shows the final energy consumption per sector. The covered sectors, highlighted in figure 5.96, represent 79% of the final energy consumption in 2014.

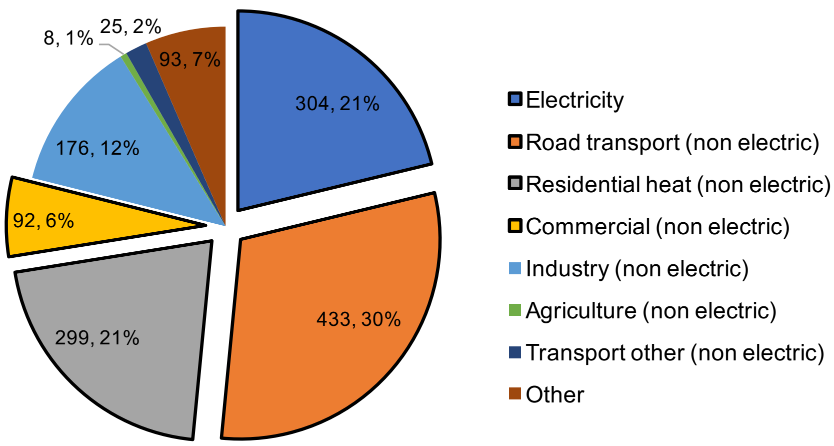


Figure 5.57: Final energy consumption in the United Kingdom in 2014 (1429 TWh total) [92]

The electricity generation mix for Great Britain in 2016 is shown in figure 5.58. 25% of the electricity generation is renewable with a high share of wind energy. Figure 5.59 shows that Great Britain had in the end of 2016 almost 15 GW installed wind capacity. The UK has the largest capacity offshore wind in Europe with 46% of the total installed capacity [112].

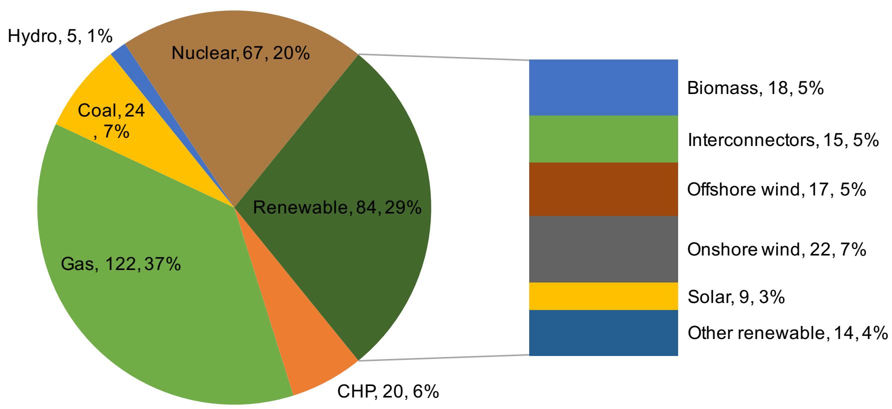


Figure 5.58: Electricity generation mix Great Britain 2016 (332 TWh total) [7]

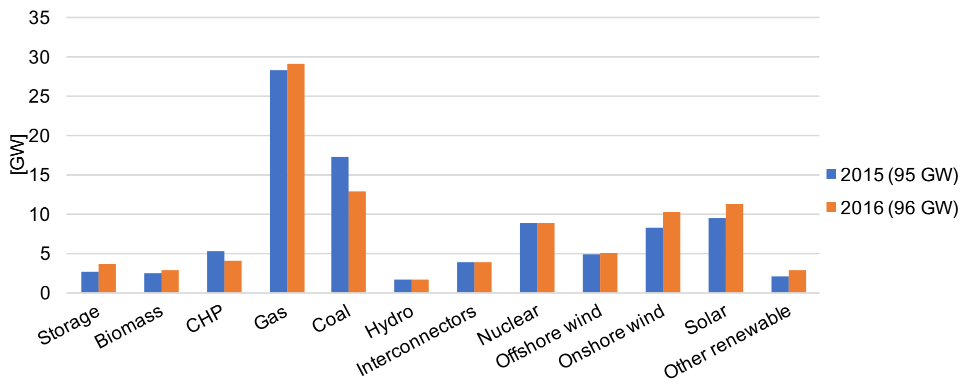


Figure 5.59: Installed capacity per source in Great Britain at the end of the year [7, 113]

Road transport

Road transport data of 2015 for Great Britain is taken from the Department for Transport of the UK government [114]. Table 5.8 shows the number of vehicles and annual distance travelled per vehicle category in Great Britain in 2015. The UK had 8476 petrol fuelling station at the end of 2016 [86].

Table 5.8: Road traffic data Great Britain 2015

	Annual km x10^6	# vehicles	km/vehicle
Passenger cars	398,600	30,250,300	13,177
Motorcycles	4,500	1,230,800	3,656
Vans	75,500	3,633,600	20,778
Lorries	12,060	338,380	35,640
Trucks	14,740	145,020	101,641
Buses	4,300	162,700	26,429

5.4.2. 100% Renewable scenario

The National Grid, the TSO of Great Britain, publishes annual updates of their Future Energy Scenarios (FES). The FES include four scenarios based on the green ambition and the prosperity. Since the 2017 update, the scenarios are modelled up to 2050. The four scenarios can be seen in figure 5.60 [7]. Another difference with the previous versions is that the impact of the Brexit is taken into account. The model inputs are mostly based on the ‘Two Degrees’ scenario (Gone Green in previous versions) since this scenario aims to achieve the targets of the Paris agreement. Not all model inputs however are base on the Two Degrees scenario. The installed capacity of solar PV for example is higher in the ‘Consumer Power’ scenario (figure 5.61), which is used in the model. In addition a sensitivity analysis is discussed with a high electrification scenario. More electricity is used in heating and transport is decarbonised and also includes FCEVs. The electricity consumption of this sensitivity scenario is used in the model.

Figure 5.60: Energy scenarios proposed by National Grid [113]

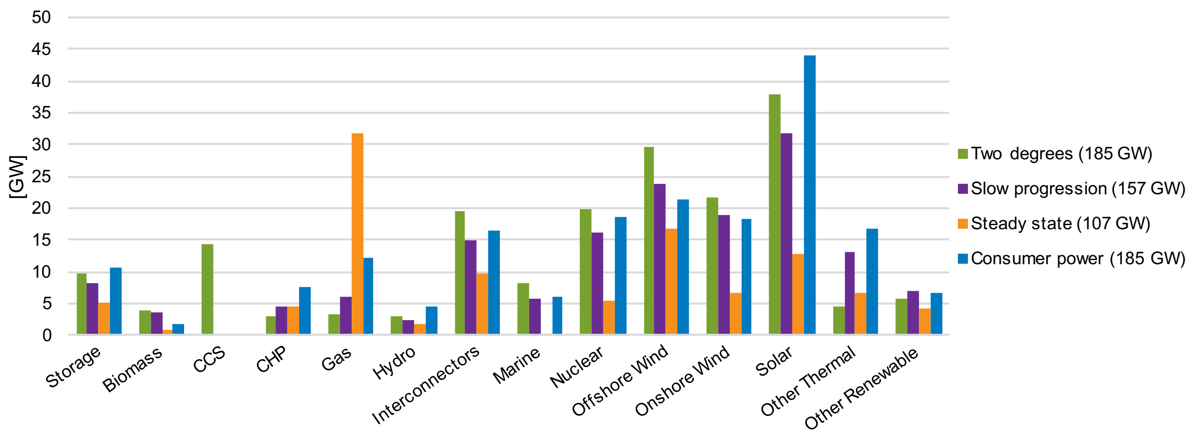


Figure 5.61: Installed capacity per source and scenario in the FES

5.4.3. Model inputs

Electricity generation

As mentioned before the electricity mix is roughly based on the electricity mix of the 'Two degrees' scenario. 35% of the total electricity generation however is still generated by nuclear power plants (31%) and carbon capture & storage (CCS) (4%). 15% of the total generation is Marine and other renewable which is not taken into account. As mentioned before the installed capacity of solar PV is slightly higher in the consumer power scenario (44 vs 38 GW) which is used in the model. The constructed mixes of installed capacity and expected generation is shown in figures 5.62 and 5.63. The modelled total installed capacity and total generation will most likely be much higher then the capacities and generation shown in the figures since at least 40% of the generation in the Two degrees scenario is filtered.

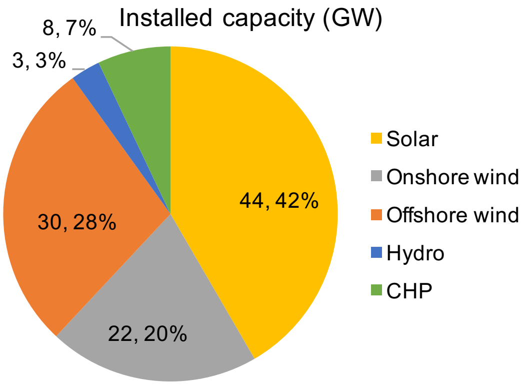


Figure 5.62: Installed capacity in 2050 (106 GW total)

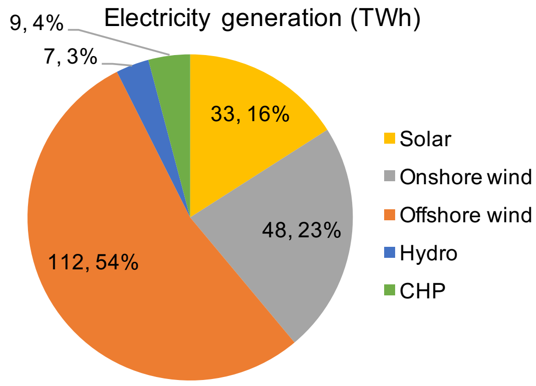


Figure 5.63: Expected electricity generation per source in 2050 (208 TWh total)

Generation data is gathered from different sources. Demand data is gathered from National Grid [115]. The demand data includes embedded solar and embedded wind generation and their capacity. Embedded solar and embedded wind is an estimation of the generation of wind farms and solar PV panels which do not have transmission system metering installed [116]. The embedded generation is used to determine the actual demand according equation 5.3.

$$\text{National Demand} = \text{Grid Load} + \text{Embedded solar} + \text{Embedded wind} + \text{Import} - \text{Export} \quad (5.3)$$

Embedded solar PV generation will be used in the model for solar electricity. The profiles are corrected for increasing installed capacity. Since embedded wind only includes the data which is not metered additional data is required to construct the wind generation profiles. Additional data is gathered from ELEXON [117], which is responsible for the balancing and settlement code and electricity market data, and the ENTSO-E transparancy platform [118]. ELEXON provides generation data of all metered power plants, data from the ENTSO-E platform is used to separate the wind generation profile into a onshore and offshore generation profile. First the wind generation profile from ELEXON is added to the embedded wind generation, which results in the total wind generation. Then the offshore generation profile is subtracted which results in the onshore wind generation profile. The onshore wind generation profile of the ENTSO-E platform could not be used since too much data is missing. For CHP, the natural gas electricity generation profile of ELEXON is used. All generation and consumption data is metered every 30 minutes which will be converted to hourly data in the model. All the normalised generation profiles per base year can be seen in appendix H.1 on page 201

Consumption

The profile of national demand provided by National Grid is taken for the modelling of the classic consumption profile [115]. Additional consumption data in the high electrification scenario is requested and is used in the model. The classic electricity consumption in this scenario is 226 TWh. The total heating demand is electrified except a small part of heat in industry and hybrid gas heat pump which is still supplied by natural gas. The electricity demands for hot water and space heating in the residential and commercial sectors are 56.4 and 34.5 TWh respectively which are used in the model. 18 TWh of heat is supplied by solar thermal energy. In the model is assumed that the heat supply by solar thermal is increased to 34 TWh (approximately 10% of the total heating demand) to compensate for the unknown gas demand in hybrid heat pumps. The total heat flow diagram can be seen in figure 5.64.

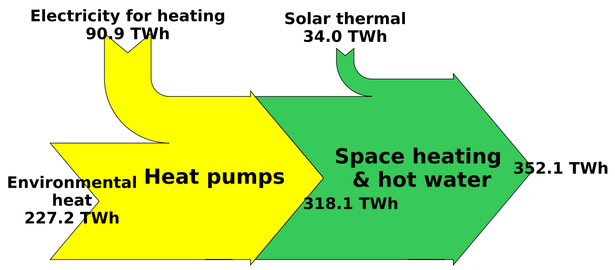


Figure 5.64: Heat flow diagram for Great Britain in 2050 (TWh/year)

Road transport

The data from table 5.8 in section 5.4.1 will be used in the model for the number of vehicles and travelled distance per vehicle category. No adjustments are made.

5.4.4. Results & Discussion

Figure 5.65 shows the Energy flow diagram for GB in 2050 with 2016 as base year. The total generation is 539 TWh of which 330 TWh is directly consumed on the grid and 209 TWh is consumed by electrolysers to produce hydrogen. The total backup of grid connected FCEVs is 30.6 TWh, 8.5% of the total electricity consumption. 4291 million kg of hydrogen is produced of which 2993 million kg (70%) is consumed for road transport and 1295 million kg (30%) is consumed for V2G. The final energy consumption (including hot water and space heating) is 690 TWh. All results and model outputs can be found in appendix H.2 on page 209.

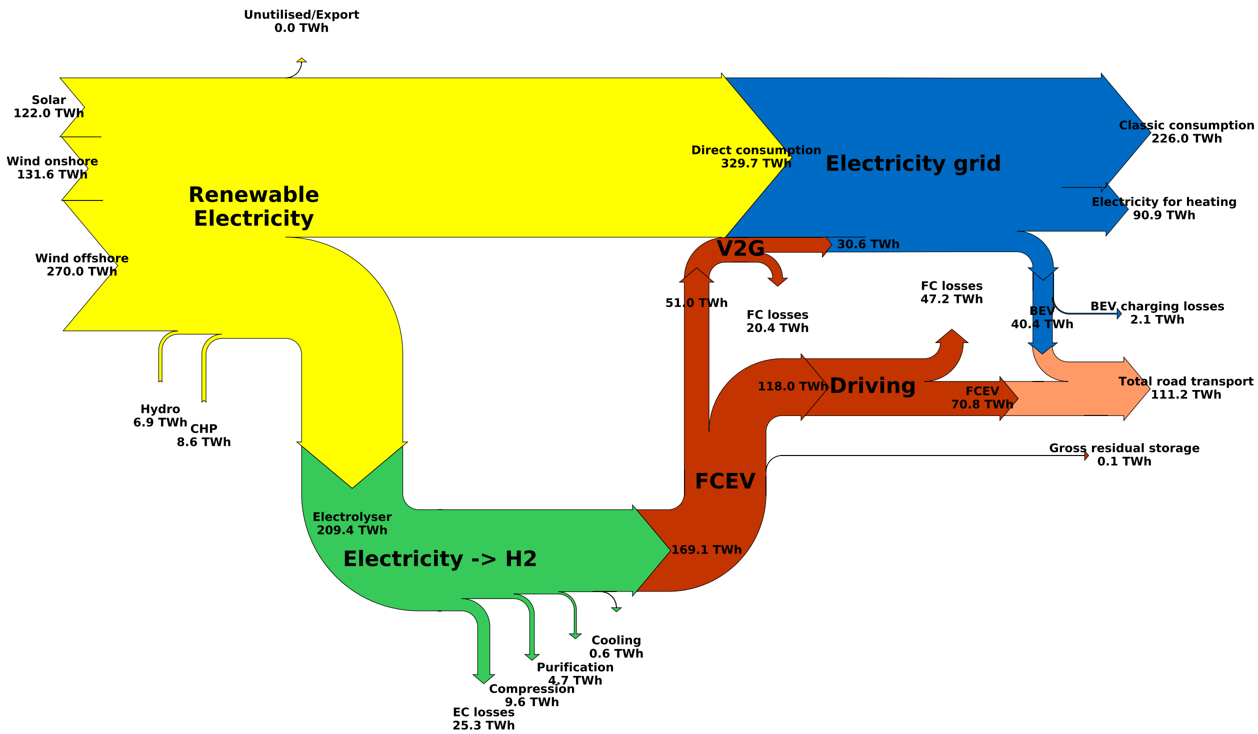


Figure 5.65: Energy flow diagram for Great Britain with 2016 as base year (TWh/year)

The required installed capacity to be self sufficient for every base year is shown in figure 5.66, the corresponding electricity generation is shown in figure 5.67. It can immediately be seen that the installed capacity is much higher than the reference. This is caused by the fact at least 40% of the generation of the two degrees scenario is filtered including a large share of nuclear power with a high capacity factor. It can also be seen that the required capacity for the 2016 base year is higher, similar to Denmark, Germany and Belgium. The total electricity generation in the simulations is approximately 330 TWh higher than the generation of the two degrees scenario which is caused by the higher electricity consumption which is taken from the high electrification scenario and not all energy consumption for heating and road transport is supplied by renewable energy in the two degrees scenario. The two degrees scenario also includes nuclear power providing a base load and CCS and therefore less storage is required (and thus less energy losses).

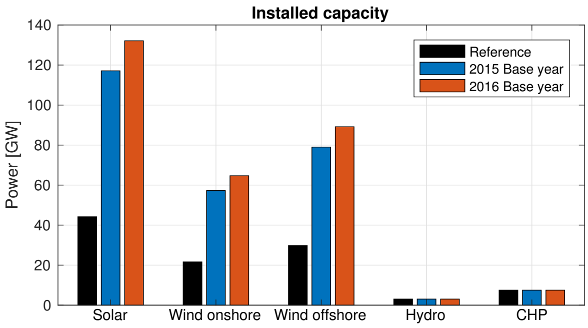


Figure 5.66: Installed capacity in GB in 2050

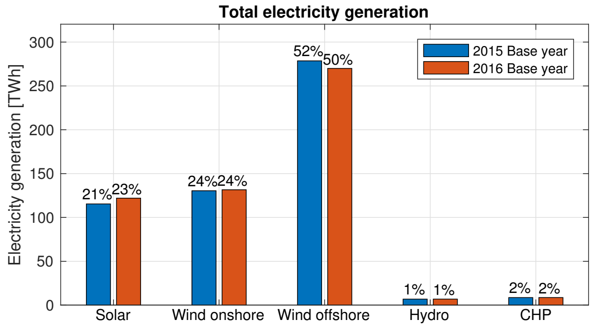


Figure 5.67: Total electricity generation in GB in 2050

Figure 5.68 shows the load duration curves of the imbalances without the production of hydrogen and FCEV backup. Surplus electricity will be absorbed for the production of hydrogen. Electrolysers are required approximately 6400 hours per year. The electrolyser peak demand is 131 GW. The electrolyser capacity factor varies from 18.2-18.9%.

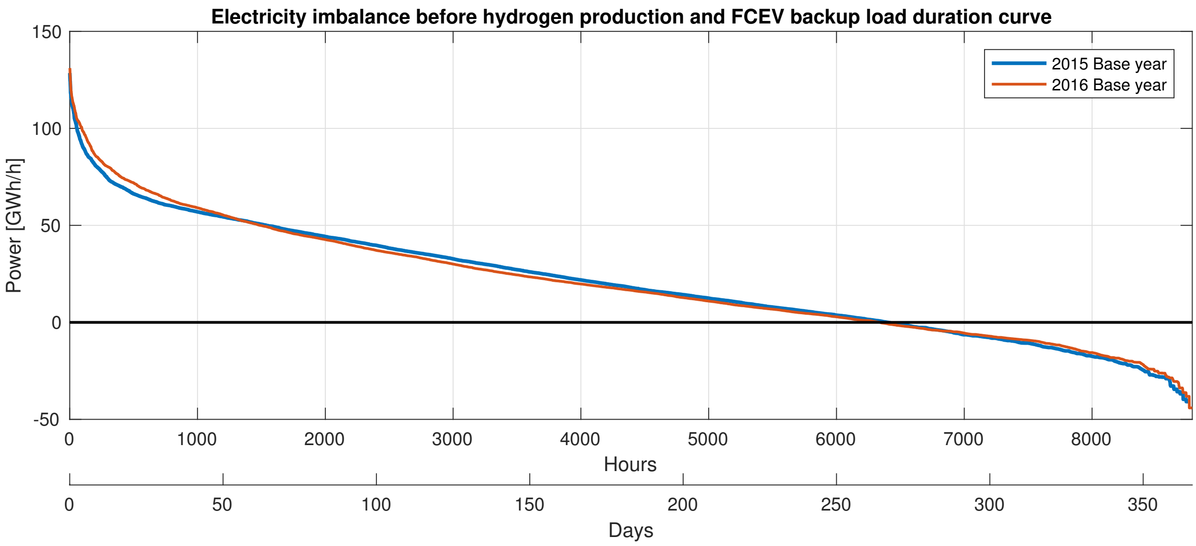


Figure 5.68: Imbalance load duration curve in GB in 2050

FCEV backup

Figure 5.69 shows the load duration of the required passenger FCEVs for V2G. It can be seen that the maximum demand is around 29% of the passenger FCEVs (15% of all passenger vehicles) and is only required for 1 day per year. V2G backup is required for approximately 2400 hours per year. For only 5 days per year more than 20% of all passenger FCEVs is required. The daily backup demand shown in figure 5.70 shows the same behaviour as Germany and Belgium but the backup demand in the morning and the begin of the evening is lower. The monthly backup demand in figure 5.71 also shows the same trend with more backup in the winter months. The only difference is a slight peak in backup demand in October for both base years.

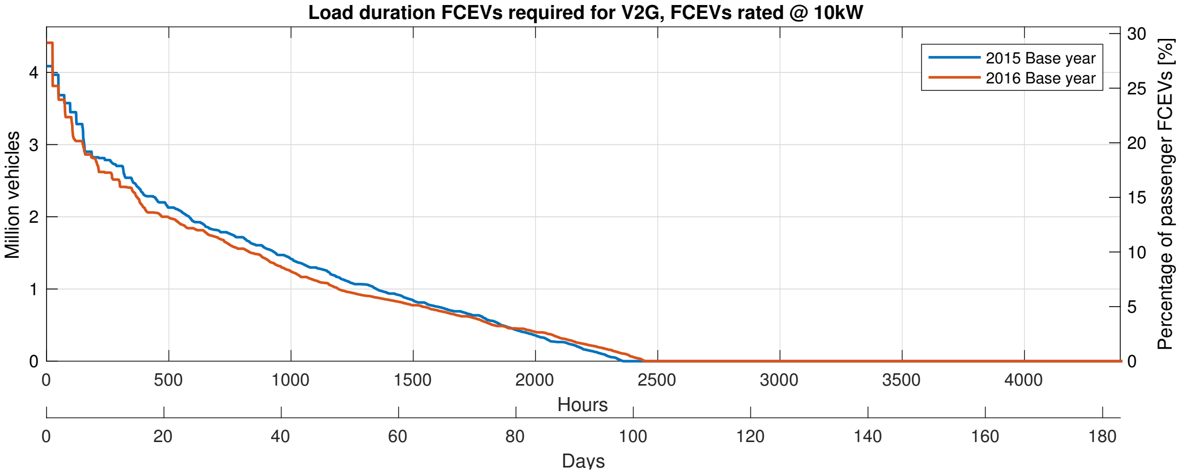


Figure 5.69: Load duration curve of FCEV backup in GB in 2050

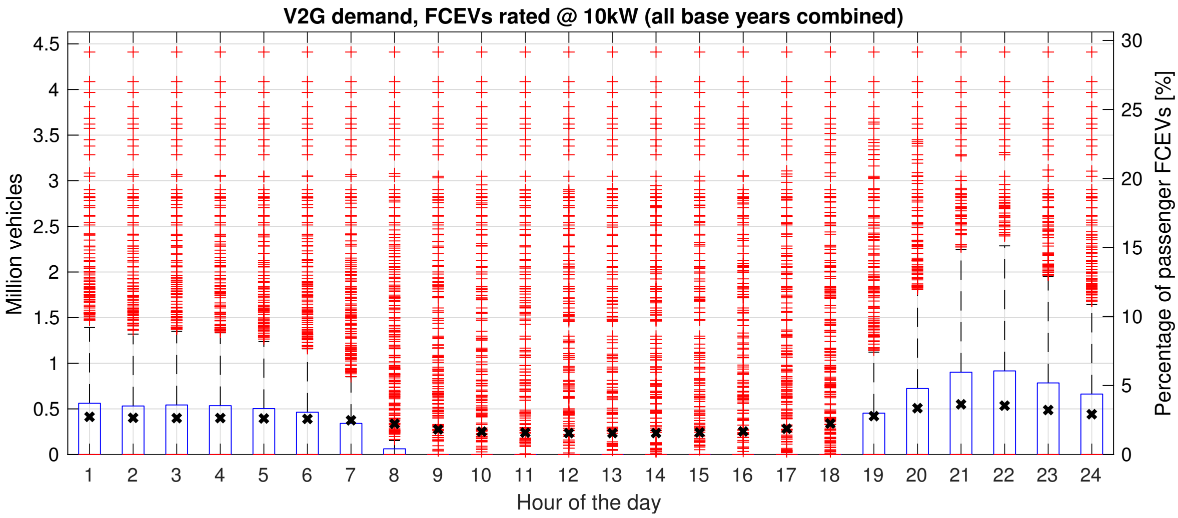


Figure 5.70: Distribution of backup power demand per hour of the day for GB in 2050 with all base years combined

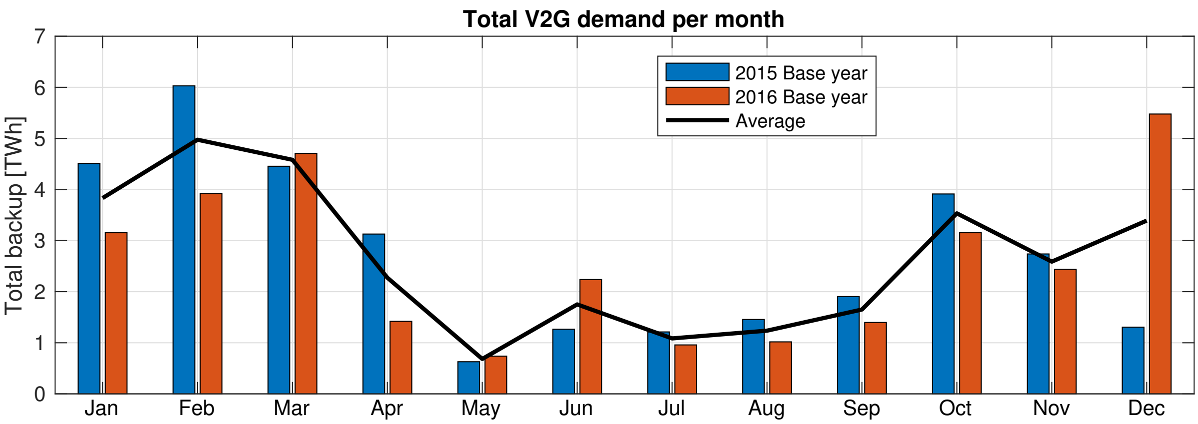


Figure 5.71: Total FCEV backup per month for GB in 2050

Hydrogen storage

The total hydrogen storage capacity is shown in figure 5.72. The peak storage capacity is 674 million kg. Recalling that 6 million kg of working gas could be stored in an average salt cavern, at least 112 salt caverns are required. Assuming that one storage site can have 10 caverns means that at least 12 of those storage sites are required. The total hydrogen storage capacity shows a seasonal trend but it differs from Belgium and Germany. It can be seen that the buffer is emptied almost twice per year. Figure 5.73 shows the charge and discharge rates of hydrogen with 2016 as base year. It can be seen that there are strong fluctuations in charging and discharging of the buffers which corresponds to the intermittency of the offshore wind profile (figure 5.75). The buffer is in Great Britain required for both seasonal storage and compensating of longer periods without wind.

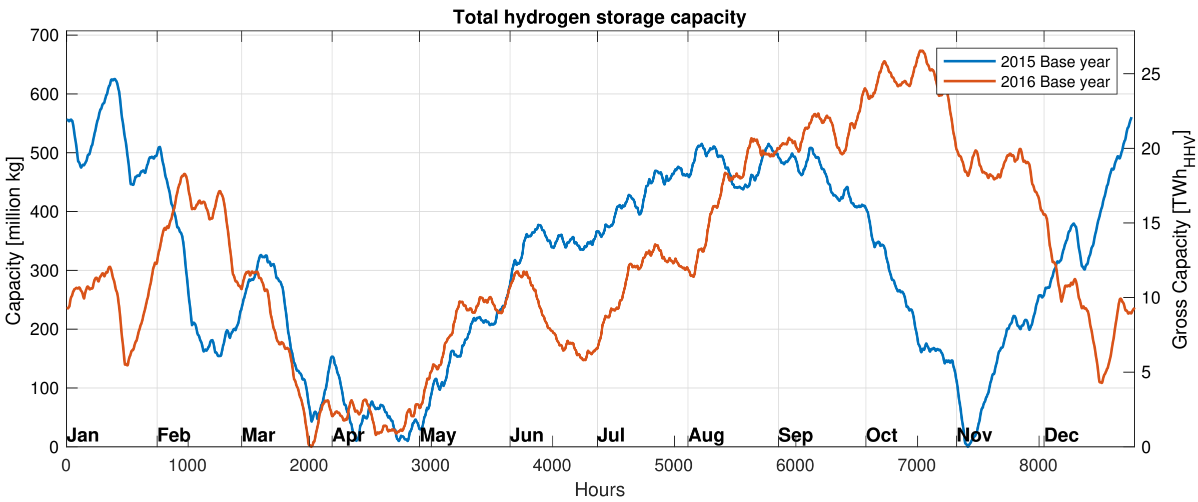


Figure 5.72: Annual storage capacity in GB for different base years

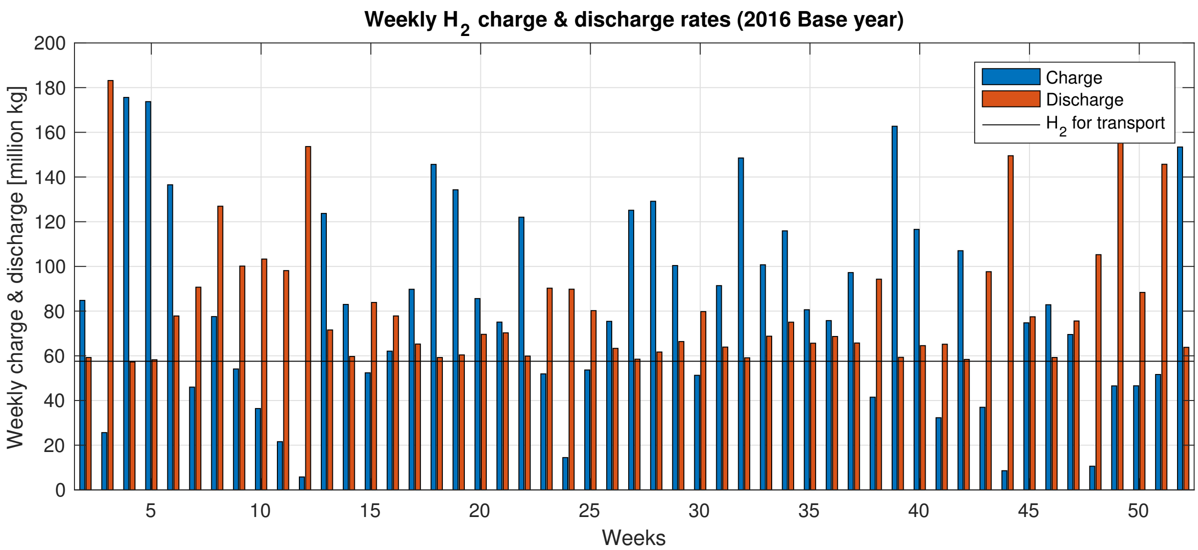


Figure 5.73: Hydrogen weekly charge and discharge rates in GB in 2050 (2016 base year)

Figure 5.41 shows the total daily hydrogen dispension at HFSs at the left axis and the dispension per HFS at the right axis. This figure also shows that the fuelling demand for V2G corresponds to the periods without offshore wind. It can be seen that on days where only hydrogen for road transport is fuelled approximately 1000 kg/day is required. This is higher than the other countries because GB has the lowest density of fuelling stations. At periods where there is more backup required larger or more fuelling stations are required. Covering peak demands requires a significant increase in dispensing capacity. If the base load of 1000 kg/day would be produced on site approximately 2.5 MW electrolyser capacity would be required. The load duration curve shows that he fuelling capacity is approximately 200 days per year below 1000 kg/day. The United Kingdom (No data for GB) had 8476 petrol stations at the end of 2016. Assuming that the amount of HFSs will be the same, 21.2 GW electrolyser capacity could be installed at HFSs to cover the fuelling demand for transport. The remaining capacity could be installed near the connections of (offshore) wind farms or near large scale storage sites.

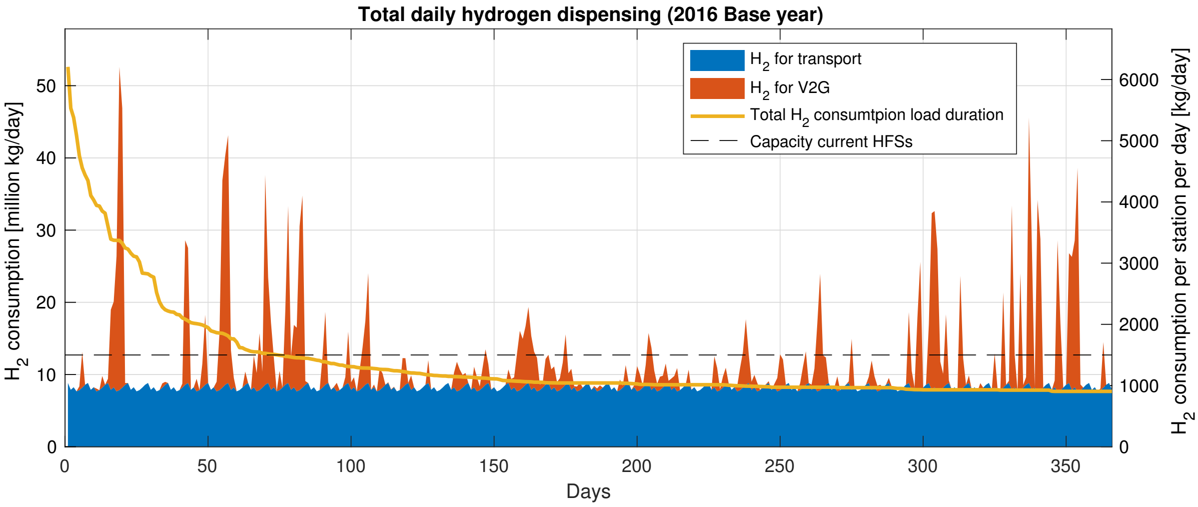


Figure 5.74: Total daily hydrogen dispensing and dispension per HFS in GB in 2050 (2016 base year)

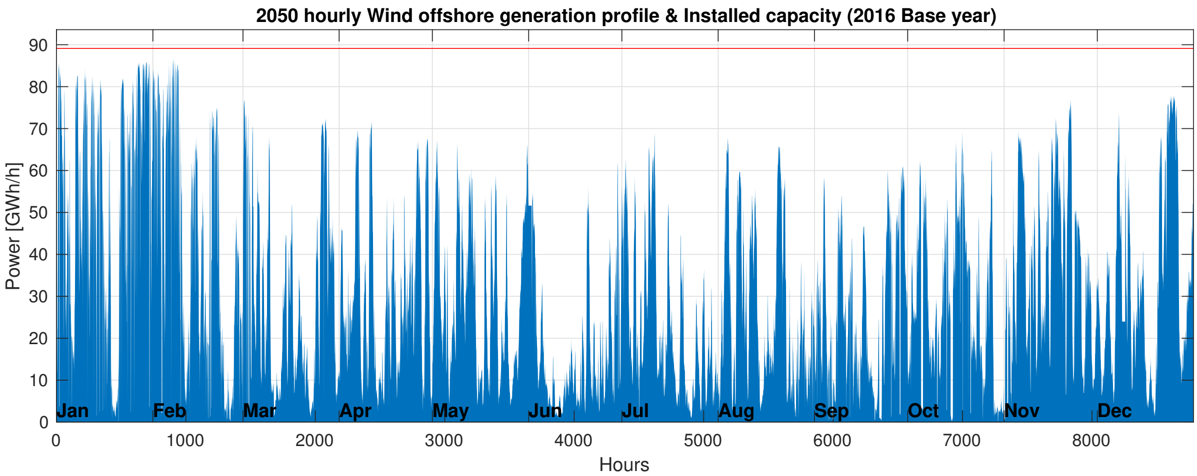


Figure 5.75: Hourly offshore wind generation profile in GB in 2050 (2016 base year)

5.5. France

France has the largest land surface of the investigated countries. Electricity in France is mainly supplied with nuclear power plants. France has interconnections with Great Britain, France, Germany, Italy, Switzerland and Spain.

5.5.1. Current situation

The final energy consumption in France in 2014 was 1717 TWh. Figure 5.76 shows the final energy consumption per sector. The covered sectors, highlighted in figure 5.76, represent 75% of the final energy consumption in 2014.

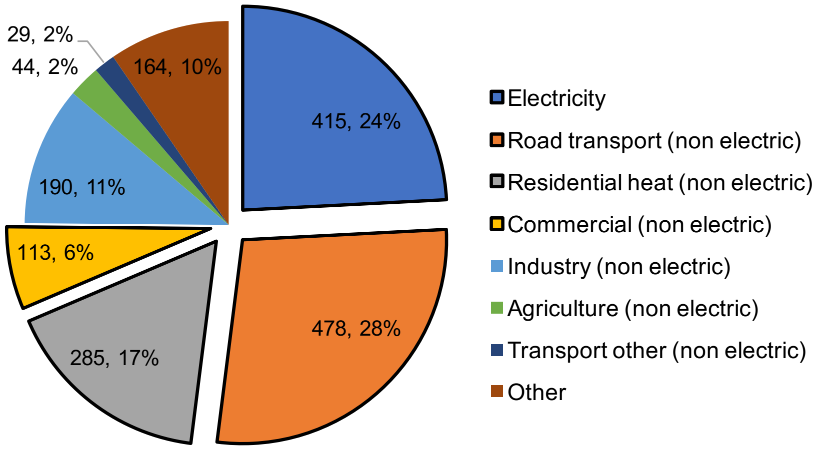


Figure 5.76: Final energy consumption in France in 2014 (1717 TWh total) [92]

The current CO_2 emissions are relatively low compared to the other countries despite the fact that only 16% of the electricity generation is from renewables. From figure 5.77 can be concluded that this is caused by the enormous amount of nuclear power.

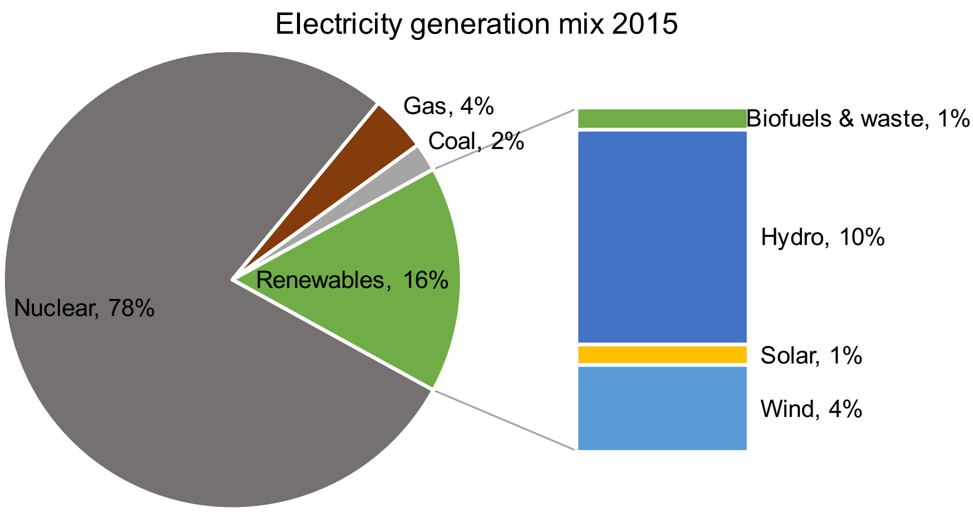


Figure 5.77: Electricity generation mix in France in 2015 [119]

The installed capacity is shown in figure 5.78. A part of the data is from the RTE, the french TSO, which only takes plants larger than 1 MW into account [119]. The installed capacity of solar and wind is taken from the Commissariat General au Developpement Durable [120, 121]. Obviously the largest share of installed capacity is nuclear power with a total of 63 GW.

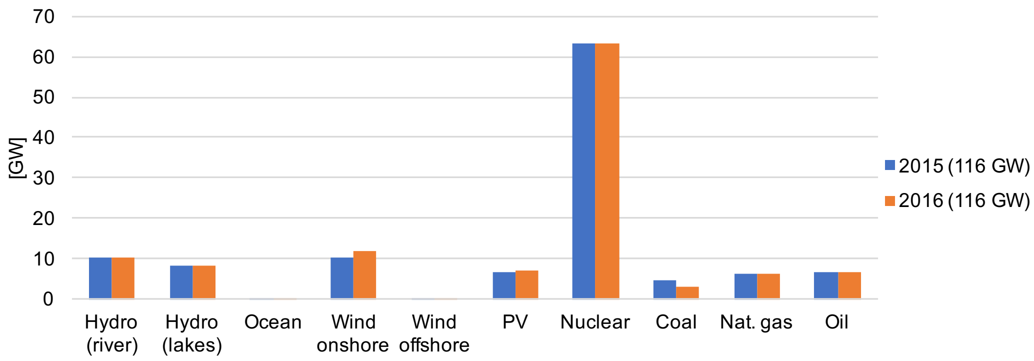


Figure 5.78: Installed capacity per source in France at the end of the year [119–121]

Transport
Road transport data of 2015 is taken from 'Les comptes des transports en 2015' [122] published by the Commissariat général au Développement durable, the commissariat for sustainable development in France. Table 5.9 shows the number of vehicles and annual distance travelled per vehicle category in 2015.

Table 5.9: Road traffic data France 2015

	Annual km x10^6	# vehicles	km/vehicle
Passenger cars	414,599.60	31,900,000	12,997
Motorcycles	16,394.23	3,844,800	4,264
Vans	97,454.78	6,020,000	16,189
Lorries	7,959.78	401,719	19,814
Trucks	8,975.92	148,581	60,411
Buses	3,419.97	93,000	36,774

5.5.2. 100% renewable scenario

The 100% renewable scenario is based on a report published by l'Agence de l'Environnement et de la Maîtrise de l'énergie (ADEME), the French Environment and Energy Management Agency, in 2016. The report 'A 100% renewable electricity mix? Analysis and optimisation' explores the technical aspects of renewable energy deployment in the electricity system [31]. The report is thus focused on a 100% renewable *electricity* system, not a 100% renewable *energy* system.

100% renewable electricity scenarios are developed with varying generation mixes. There is a baseline scenario, a 'very positive technology progress' scenario, a 'complex network reinforcement' scenario and a 'moderate public acceptance' scenario. The baseline scenario will be used to construct the electricity generation mix in section 5.5.3. The mix of installed capacity and annual electricity generation can be seen in figures 5.79 and 5.80 respectively.

France already has experience with high peak demands due to electric heating. The share of electric heating in residential building is 35% [31]. That is why demand side management of heating is introduced in the 2050 scenario for peak shaving. It is assumed that all hot water tanks in the residential sector have intra-day management and the heat pump load can be shifted.

Several storage techniques are considered in the ADEME report. Batteries and CAES are considered for short term storage. pumped storage and power-to-gas with methane are considered for long term storage.

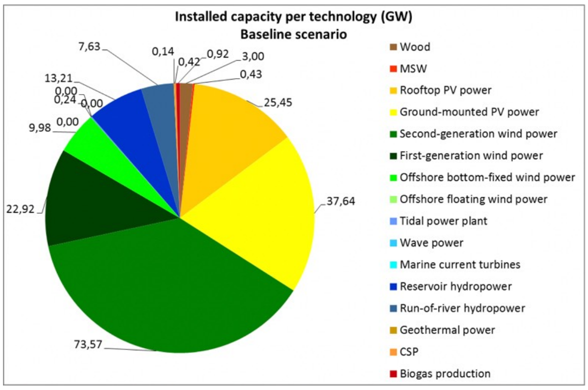


Figure 5.79: Installed capacity in the ADEME baseline scenario [31]

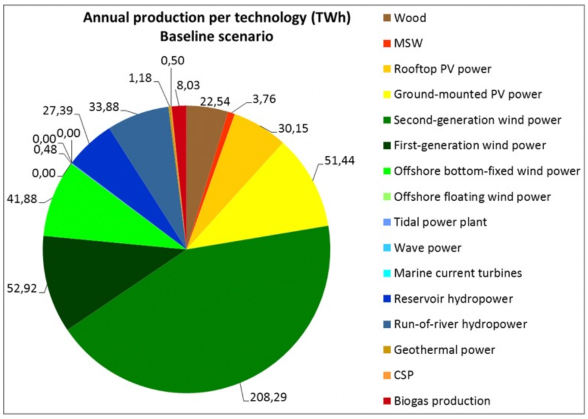


Figure 5.80: Electricity generation in the ADEME baseline scenario [31]

5.5.3. Model inputs

Electricity generation

The electricity generation mix is based on the mix of the ADEME baseline scenario. The amount of generation types is reduced to: Solar PV, onshore wind, offshore wind, hydro (river) and hydro (lake). The other generation types are left out because annual generation is negligible and there are no generation profiles available. The modified electricity mix with installed capacity and the expected annual generation can be seen in figures 5.81 and 5.82 respectively.

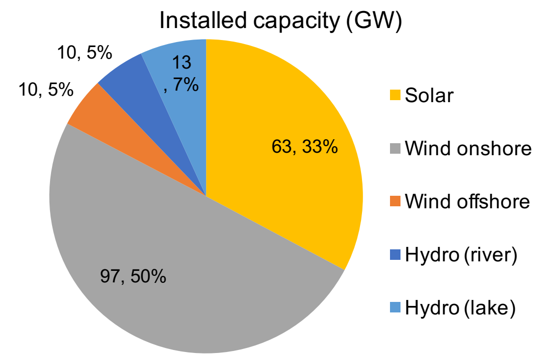


Figure 5.81: Installed capacity in France in 2050 (193 GW total)(451 TWh total)

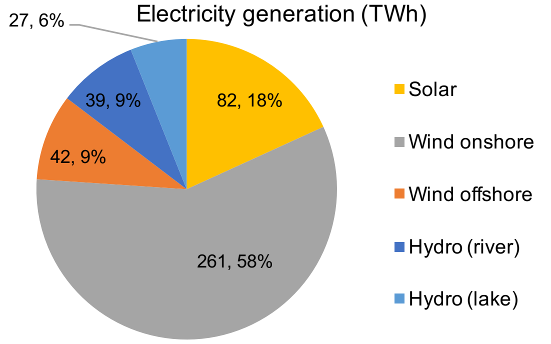


Figure 5.82: Expected electricity generation per source in France in 2050 (451 TWh total)

The generation are based on the annual generation profiles taken from the RTE [119]. Since there is no offshore wind in France it was not possible to create a profile for offshore wind electricity generation. The offshore wind profile will have the same profile as onshore wind generation. The offshore wind capacity factor will therefore be lower than expected. In the ADEME report a capacity factor of 48% is assumed while the capacity factor in the model is around 20% as can be seen in figure 5.83. The onshore wind capacity factor is also expected to be 10% higher in the ADEME report. All the normalised generation profiles per base year can be seen in appendix I.1 on page 219

Consumption

The classic consumption profile is based on the consumption profile from the RTE [119]. The consumption profile needs to be corrected before it is scaled to the 2050 classic consumption. As mentioned before a significant amount of heating in residences is electric. 18% of the total electricity was consumed for hot water and space heating [71, 91] in 2013. A daily electric heating consumption profile will be created based on HDD as described in 4.2.2. In this case a reference temperature of 18°C is taken. This normalised profile is scaled to a total consumption of 80.2 TWh (18% of 2013 electricity

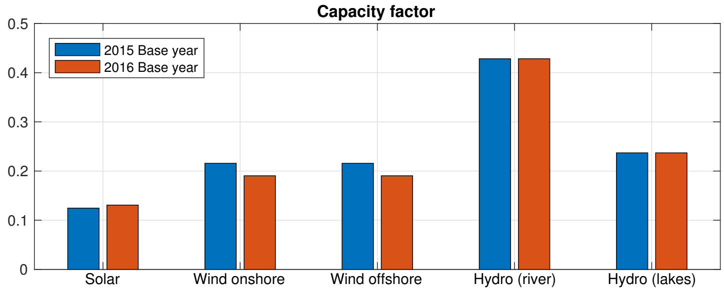


Figure 5.83: Capacity factors

consumption) and substracted from the consumption profile. The result for the 2016 consumption profile can be seen in figure 5.84. The blue profile is the original profile, the orange profile is the adjusted consumption profile.

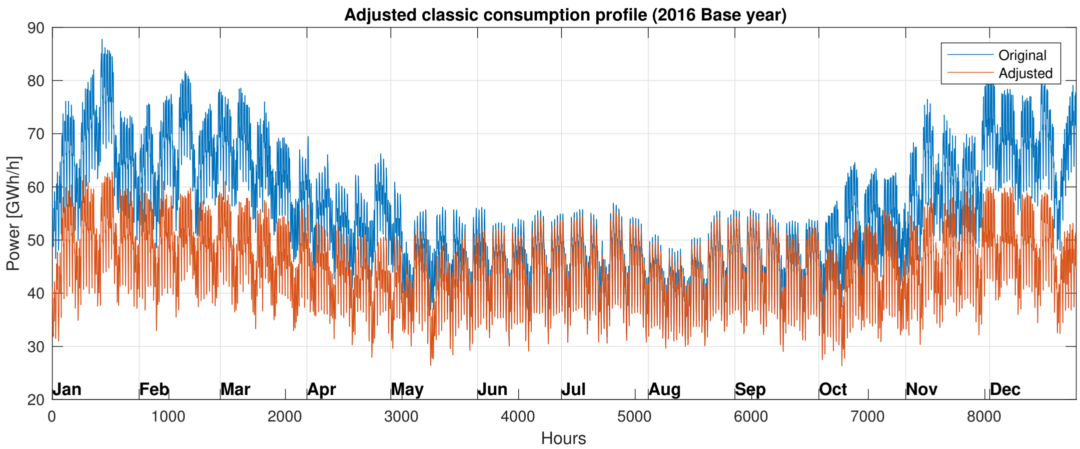


Figure 5.84: Original classic consumption profile and adjusted profile without electric heating in 2016

The adjusted consumption profile can be normalised and scaled to 2050 consumption. The total electricity consumption in the ADEME scenario is 422 TWh. 60 TWh is consumption in transport of which 27.1 TWh is the consumption of electric trains. Residential and tertiary heat counted for 56.9 TWh. The consumption for heat and road transport is subtracted from the total electricity consumption to find the classic consumption of 332.1 TWh.

Electricity consumption for hot water and space heating is 56.9 TWh in the ADEME scenario. It is however unknown if the entire heat sector is taken into account. The report gives no insight what the total heat demand is, how much is electrified and what other heat sources there are. Therefore it is chosen to determine the total heat demand the same way as is demonstrated for Belgium:

$$SH_{FR} = SH_{DE} \cdot \frac{HDD_{FR,2015} + HDD_{FR,2016}}{HDD_{DE,2015} + HDD_{DE,2016}} \cdot \frac{Pop_{FR,2050}}{Pop_{DE,2050}} \tag{5.4}$$

When the space heating demand is known the total heating demand can be determined with equation 5.5.

$$HD_{FR} = SH_{FR} + SW_{FR} = \frac{SH_{FR}}{1 - Fraction_{HW,FR}} \tag{5.5}$$

The total heating demand is 281 TWh. It is assumed that 20% of the heating demand is covered by solar thermal energy, slightly higher than Germany (15%). The total heat supply by heat pumps is then 225 TWh. Wit the SCOP of 3.5 the electric heat pump consumption is 64.3 TWh. The heat flow diagram for France can be seen in 5.85.

Table 5.10: HDD, projected population and heating demand for Germany & France in 2050

	Germany	France
HDD 2015	2303.5	1540.2
HDD 2016	2463.2	1689.1
Population (2050) million	82.7	74.4
Fraction hot water	14.86%	11.98%
Total heat demand TWh	477.00	281.23
Hot water (HW) TWh	70.88	33.70
Space heating (SH) TWh	406.12	247.52

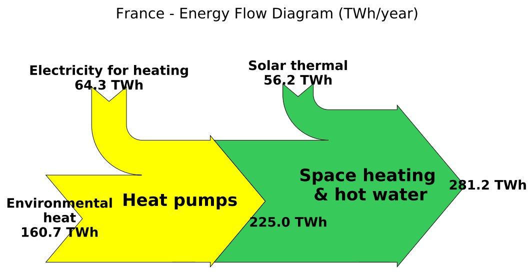


Figure 5.85: Heat flow diagram France

Road Transport

The data from table 5.9 in section 5.5.1 will be used in the model for the number of vehicles and travelled distance per vehicle categorie. No adjustments are made.

5.5.4. Results & Discussion

Figure 5.86 shows the Energy flow diagram for France in 2050 with 2016 as base year. The total generation is 614 TWh of which 405 TWh is directly consumed via the grid and 209 TWh is consumed by electrolysers to produce hydrogen. The total backup of grid connected FCEVs is 37.6 TWh, 8.5% of the total electricity consumption. 4289 million kg of hydrogen is produced of which 2695 million kg (63%) is consumed for road transport and 1590 million kg (27%) is consumed for V2G. The final energy consumption (including hot water and space heating) is 721 TWh. All results and model outputs can be found in appendix I.2 on page 228.

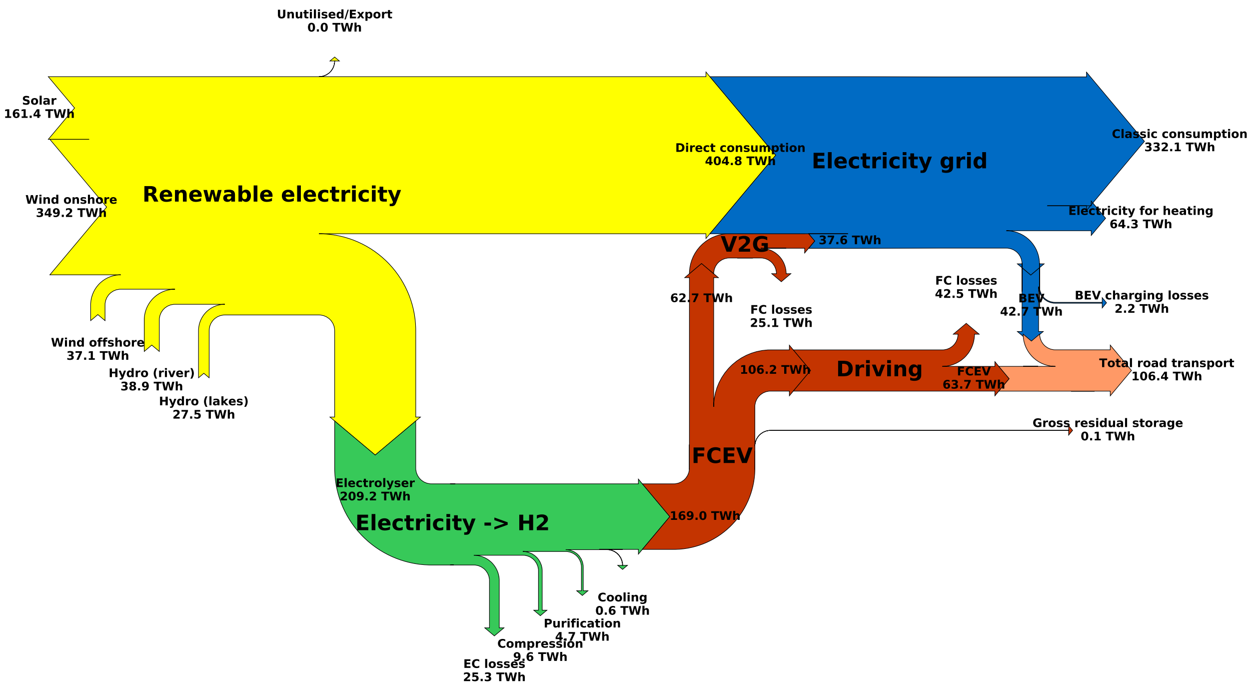


Figure 5.86: Energy flow diagram for France with 2016 as base year

The required installed capacity to be self sufficient for every base year is shown in figure 5.87, the corresponding electricity generation is shown in figure 5.88. The installed capacity is significantly larger than the reference scenario. This is caused by the lower capacity factors and the fact that the ADEME scenario does only take the electricity sector into account. The total generation is 610 and 614 TWh for 2015 and 2016 base year respectively. Although the charts show onshore and offshore wind, the profiles are the same since no offshore wind profile is available. An offshore wind profile would increase the electricity generation significantly with the same installed capacity. From the offshore wind profiles of other countries can be concluded that offshore wind generation is more continues and the capacity factor is higher.

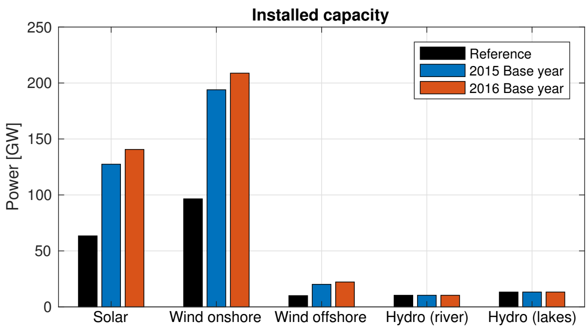


Figure 5.87: Installed capacity in France in 2050

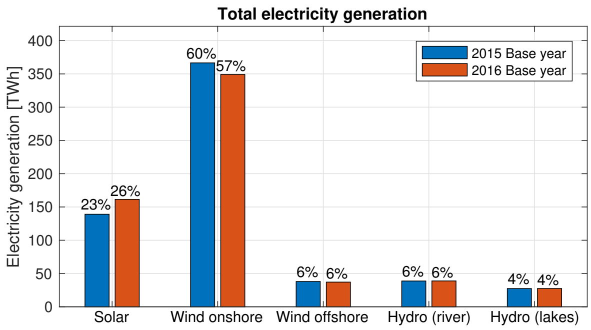


Figure 5.88: Total electricity generation in France in 2050

Figure 5.89 shows the load duration curves of the imbalances without the production of hydrogen and FCEV backup. Surplus electricity will be absorbed for the production of hydrogen. Electrolysers are required approximately 5900 hours per year. The electrolyser peak demand is 146 GW. The electrolyser capacity factor varies from 15.9-16.4%.

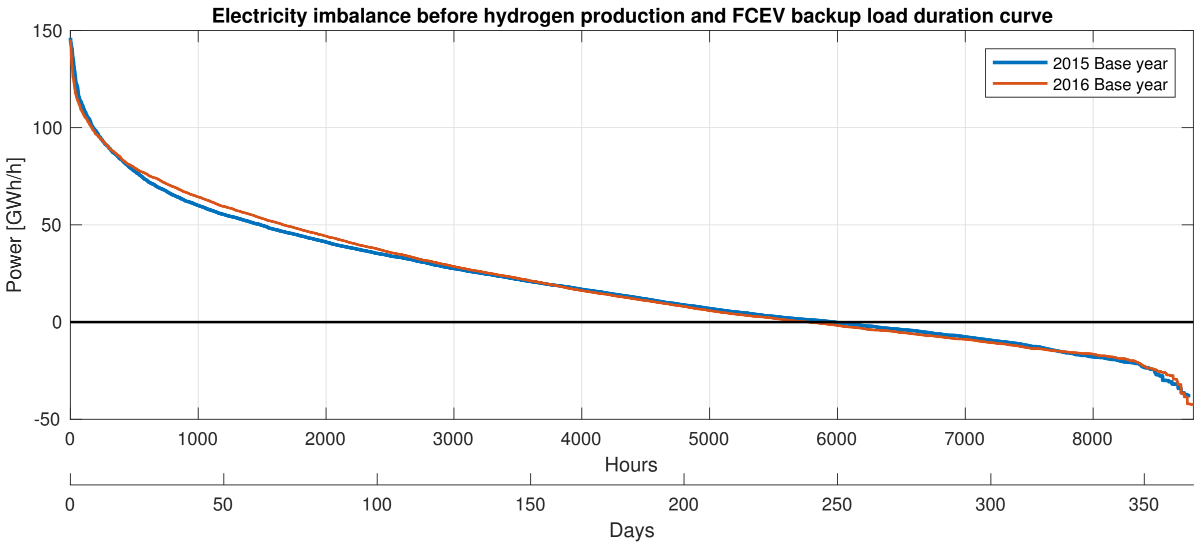


Figure 5.89: Imbalance load duration curve in France in 2050

FCEV backup

Figure 5.90 shows the load duration of the required passenger FCEVs for V2G. It can be seen that the maximum demand is 27% of the passenger FCEVs (13.5% of all passenger vehicles) and is only required for 1 day per year. V2G is only required for approximately 2750-3000 hours per year. For only 20 days per year more than 13% of all passenger FCEVs is required. Figure 5.91 shows the distribution of FCEV backup per hour of the day. During the day only occasionally backup is required as can be seen in the figure. Backup is most required at night. The same behaviour is seen in Germany, Great Britain and Belgium but the backup demand is higher during the morning and lower at the begin of the evening. The monthly V2G demand shown in figure 5.92, which also shows the same trend with more backup in the winter months.

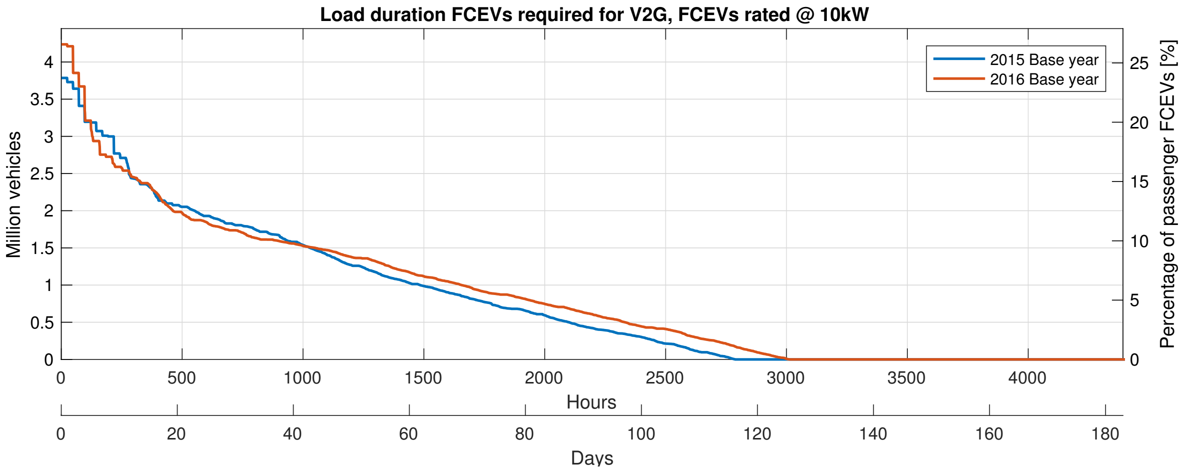


Figure 5.90: Load duration curve of FCEV backup in France in 2050

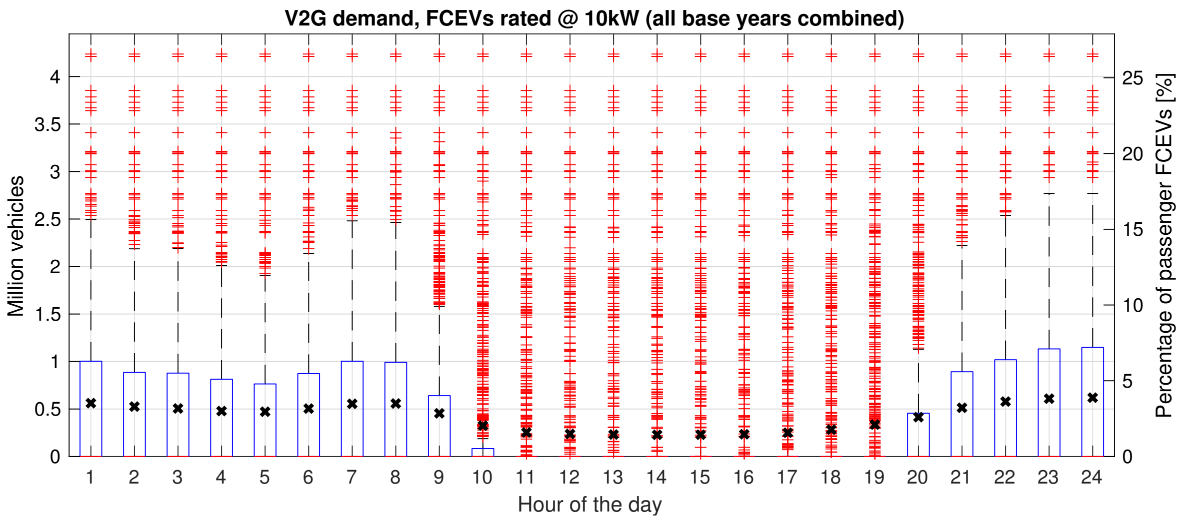


Figure 5.91: Distribution of backup power demand per hour of the day for France in 2050 with all base years combined

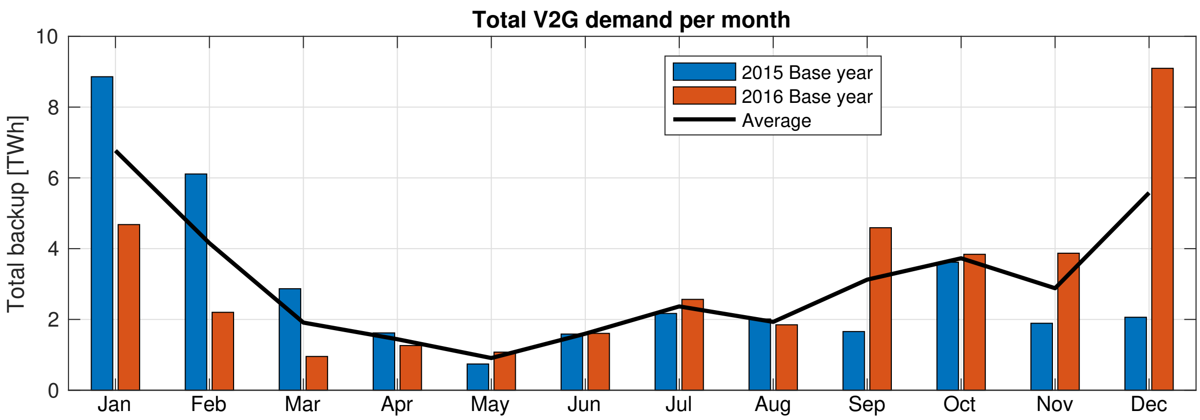


Figure 5.92: Total FCEV backup per month for France in 2050

Hydrogen storage

The total hydrogen storage capacity for France in 2050 with 2015 and 2016 as base year is shown in figure 5.93. The peak storage capacity is 1.005 billion kg. Recalling that 6 million kg of working gas could be stored in an average salt cavern, at least 168 salt caverns are required. Assuming that one storage site can have 10 caverns means that at least 17 of those storage sites are required. The storage capacity shows a similar trend as the storage capacity in Germany and Belgium. Hydrogen is buffered in the summer and consumed in the winter. For the 2016 base year this was mainly in november and december, for the 2015 base year mainly in January and February.

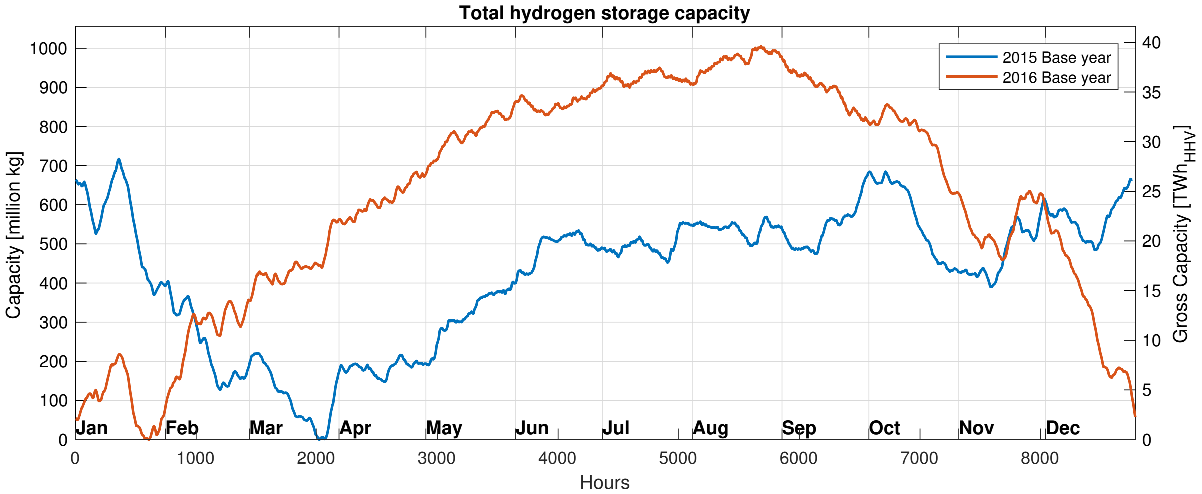


Figure 5.93: Annual storage capacity for France in 2050

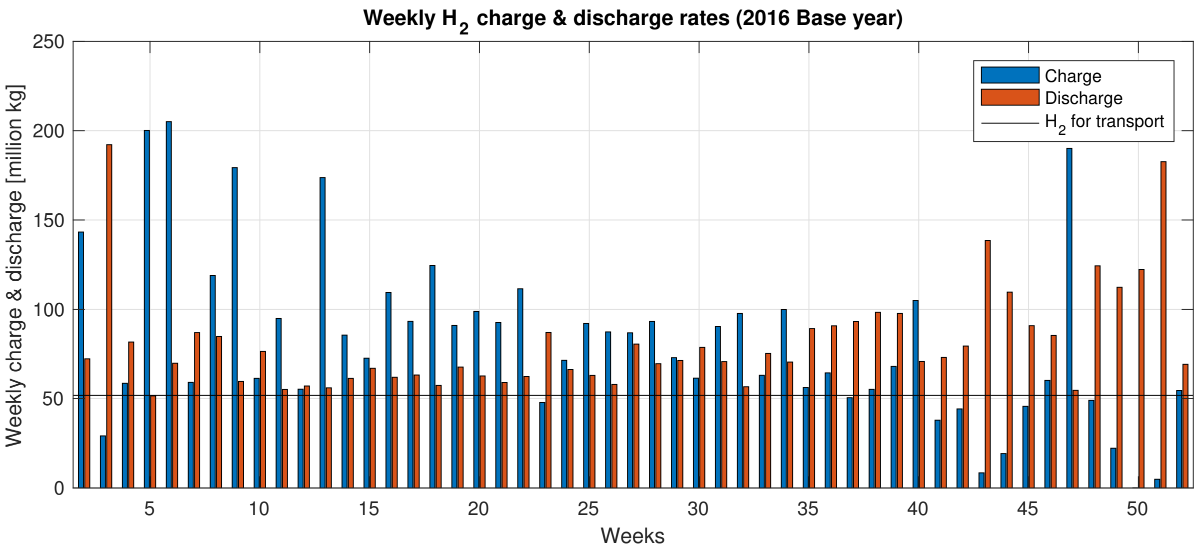


Figure 5.94: Hydrogen weekly charge and discharge rates in France in 2050 (2016 base year)

Figure 5.95 shows the total daily hydrogen dispension at HFSs at the left axis and the dispension per HFS at the right axis. It can be seen that on days where only hydrogen for road transport is fuelled a capacity of approximately 700 kg/day is required. At periods where there is more backup required larger or more fuelling stations are required. Covering peak demands requires a significant increase in dispensing capacity. This is similar to Germany and Belgium.

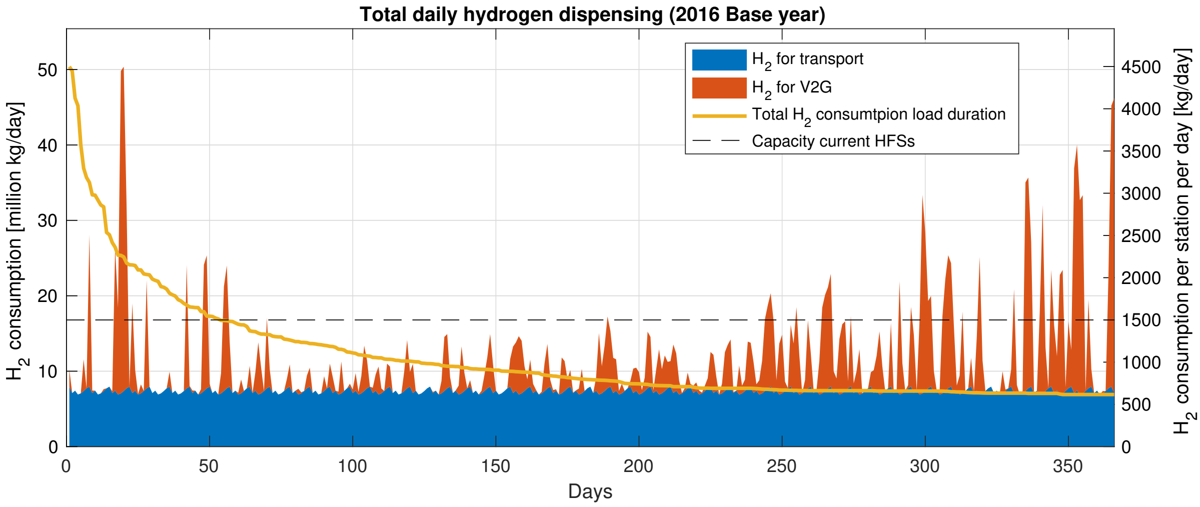


Figure 5.95: Total daily hydrogen dispensing and dispension per HFS in France in 2050 (2016 base year)

5.6. Spain

Spain has an enormous potential for renewable energy, especially solar energy. Spain is however limited in the interconnecting capacity with the rest of Europe. It only has a connection with France and Portugal.

5.6.1. Current situation

The final energy consumption in Spain was 914 TWh in 2014. Figure 5.96 shows the final energy consumption per sector. The covered sectors, highlighted in figure 5.96, represent 72% of the final energy consumption in 2014.

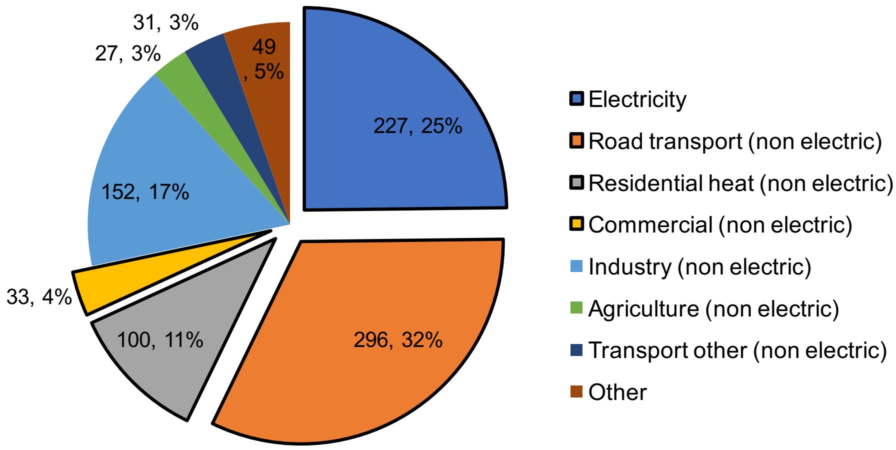


Figure 5.96: Final energy consumption in Spain in 2014 (914 TWh total) [92]

Electricity generation and installed capacity data is taken from the annual reports of the Red Eléctrica de España (REE), the TSO of Spain [123–125]. Renewable electricity generation counted for 40% of the total electricity generation with high shares of wind en hydro power. The share of solar energy is still relatively low with a share of 5% of the total generation. The electricity generation mix of 2016 can be seen in figure 5.97.

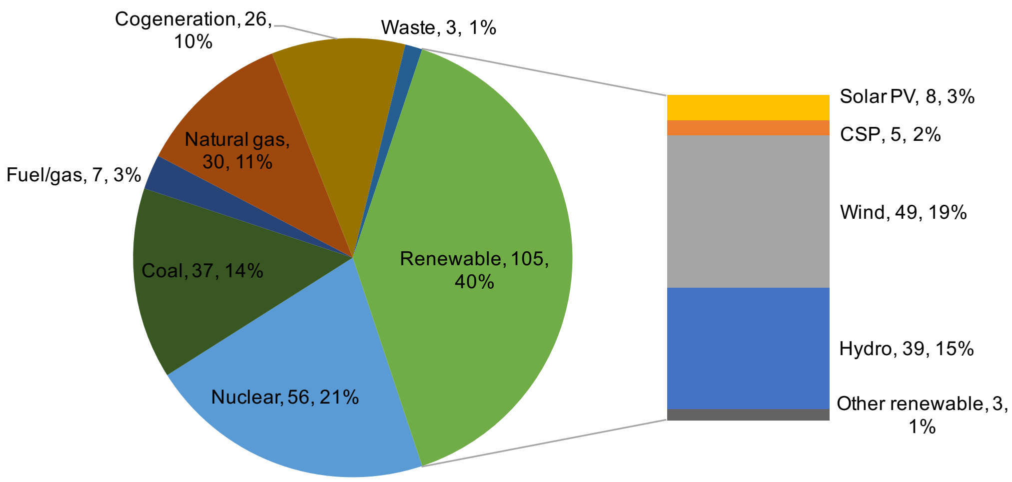


Figure 5.97: Electricity generation mix in Spain 2016 (263 TWh total) [125]

The share of renewable electricity is relatively high compared to other countries but the installed capacity of renewables dit not increase the past years as can be seen in figure 5.98. The installed capacity of gas turbines is relatively high with a low capacity factor (13%). This could be explained by the fact that Spain has only 2.8 GW of interconnectors to the European/French electricity grid [126]. A large part of the gas turbines is most likely only used as balancing plant. This balancing power could be replaced by grid connected FCEVs to balance the electricity grid.

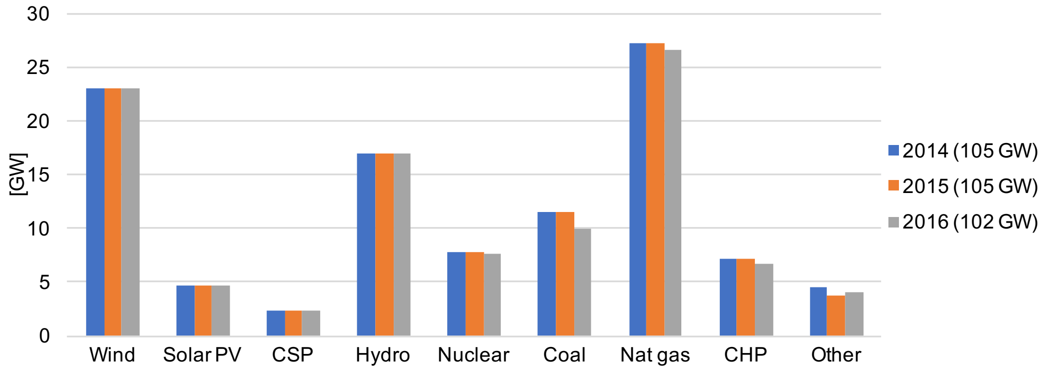


Figure 5.98: Installed capacity per source in Spain at the end of the year [123–125]

Road transport data from 2015 is taken from the Odyssee database [127]. The data does not distinguish lorries and trucks. The road transport data for 2015 can be seen in table 5.11.

Table 5.11: Road traffic data Spain 2015

	Annual km x10^6	# vehicles	km/vehicle
Passenger cars	212,203	16,928,900	12,535
Motorcycles	7,428	4,542,500	1,635
Vans	121,154	3,267,600	37,077
Trucks	59,378	391,900	151,513
Buses	6,132	41,600	147,398

5.6.2. 100% renewable scenario

A representative 100% renewable scenario for Spain could not be found. Greenpeace published in 2005 a report on the potential of renewable energies in Spain for 2050 but is not detailed enough and based on technology perspectives of 12 years ago [128]. The report gives a clear overview of the technical potentials of renewable energy. Spain has an enormous potential for solar energy. CSP could supply 650% of the projected 2050 total energy consumption (1525 TWh). Solar PV could supply 128% and wind could supply 172%.

The future electricity mix is taken from the Solutions Project and the work of Jacobsen & Deluchi [129, 130]. The Solutions project publishes the 100% renewable energy roadmaps for 139 countries in collaboration with Stanford university. The electricity mix is taken from the project and modified in section 5.6.3. The electricity generation mix from the roadmap can be seen in figure 5.99. Consumption data is not taken from this scenario but based on the other countries. The final energy and electricity consumption is significantly higher in this project compared to the other investigated countries.

5.6.3. Model inputs

Electricity generation

The electricity generation mix and installed capacity is based on the mix from the roadmap shown in section 5.6.2. Tidal turbines and wave energy are not taken into account since there are nog profiles available and the generation totals are less than 2% of the generation mix. Onshore and offshore wind are combined because an offshore wind generation profile is also not available. The capacity of Hydro

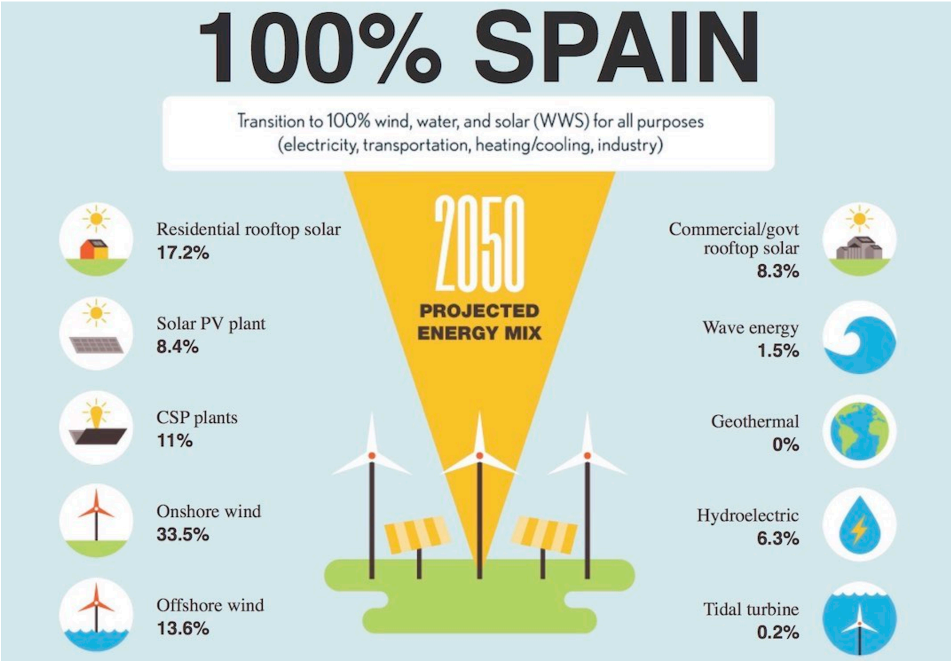


Figure 5.99: Electricity mix for 100% renewable energy in Spain [129]

plants is based on the current capacity since this is already fully utilised [125]. The installed capacities of solar PV, CSP and wind are taken from the roadmap. The mix of installed capacity and expected electricity generation is shown in figures 5.100 and 5.101.

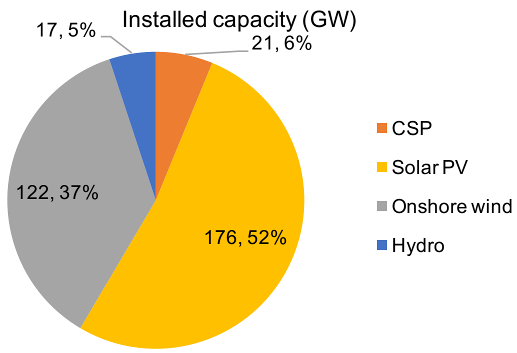


Figure 5.100: Installed capacity in 2050

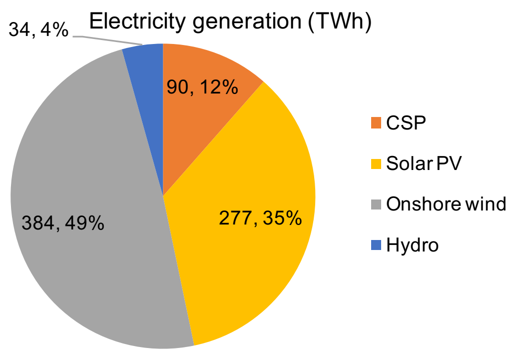


Figure 5.101: Expected electricity generation per source in 2050

The electricity generation and consumption profiles are taken from E.sios, the transparancy platform of the REE [131]. In 2015 the data of solar electricity is split up halfway the year in solar PV and CSP. Since the data is split up during the year it can not be scaled. Only 2016 data can be used. The installed capacity of wind, solar PV, CSP and Hydro remained constant, there are no adjustments required to the profiles. All the normalised generation profiles per base year can be seen in appendix J.1 on page 239.

Consumption

The total classic consumption is not based on the consumption of the roadmap [129, 130]. The electricity consumption in the roadmaps is significantly higher than the expected consumption in the published scenarios for all other countries and therefore not used. The total classic consumption will be 25% lower than the consumption in 2015, the same assumption as in the Fraunhofer scenario for Germany. The peninsular electricity demand was 248 TWh in 2015 [124]. The 2050 classic electricity consumption is 186 TWh.

The total heat demand is determined in the same way as for France and Belgium.

$$SH_{ES} = SH_{DE} \cdot \frac{HDD_{ES,2016}}{HDD_{DE,2016}} \cdot \frac{Pop_{ES,2050}}{Pop_{DE,2050}} \tag{5.6}$$

When the space heating demand is known the total heating demand can be determined with equation 5.2.

$$HD_{ES} = SH_{ES} + SW_{ES} = \frac{SH_{ES}}{1 - Fraction_{HW,ES}} \tag{5.7}$$

The total heating demand for Spain is 129 TWh in 2050. In line with the assumptions for the other countries, 25% of the heat is supplied with solar thermal energy (~10% Belgium, GB, Denmark, 15% Germany, 20% France). The heat supply by solar thermal power is 32.3 TWh. The heat pump supply is 96.7 TWh. The corresponding electricity consumption with a SCOP of 3.5 is 27.7 TWh. The heat flow diagram for Spain can be seen in 5.102.

Table 5.12: HDD, projected population and heating demand for Germany & Spain in 2050

	Germany	Spain
HDD 2016	2463.2	966.3
Population (2050) million	82.7	49.5
Fraction hot water	14.86%	26.22%
Total heat demand TWh	477.00	129.25
Hot water (HW) TWh	70.88	33.89
Space heating (SH) TWh	406.12	95.36

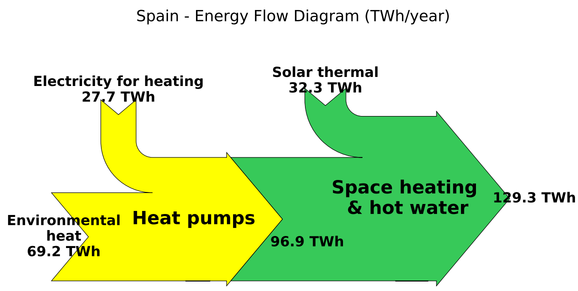


Figure 5.102: Heat flow diagram Spain

Road transport
The road transport data is based on 2015 road transport shown in the previous section. The travelled distance for trucks is split into lorries and trucks. It is assumed that the annual driven distance per vehicle is equal for both vehicle types. Furthermore is assumed that the fraction of distance travelled by lorries and trucks is the same for Germany. The modified road transport data for 2050 can be seen in table 5.13.

Table 5.13: Road traffic data Spain 2050

	Annual km x10^6	# vehicles	km/vehicle
Passenger cars	212,203	16,928,900	12,535
Motorcycles	7,428	4,542,500	1,635
Vans	121,154	3,267,600	37,077
Lorries	27,908	184,193	151,513
Trucks	31,470	207,707	151,513
Buses	6,132	41,600	147,398

5.6.4. Results & Discussion

Figure 5.103 shows the Energy flow diagram for Spain in 2050 with 2016 as base year. The total generation is 473 TWh of which 236 TWh (50%) is directly consumed via the grid and 236 TWh (50%) is consumed by electrolysers to produce hydrogen. The total backup of grid connected FCEVs is 18.0 TWh, 7% of the total electricity consumption. 4848 million kg of hydrogen is produced of which 4075 million kg (84%) is consumed for road transport and 760 million kg (16%) is consumed for V2G. The final energy consumption (including hot water and space heating) is 458 TWh. All results and model outputs can be found in appendix J.2 on page 243.

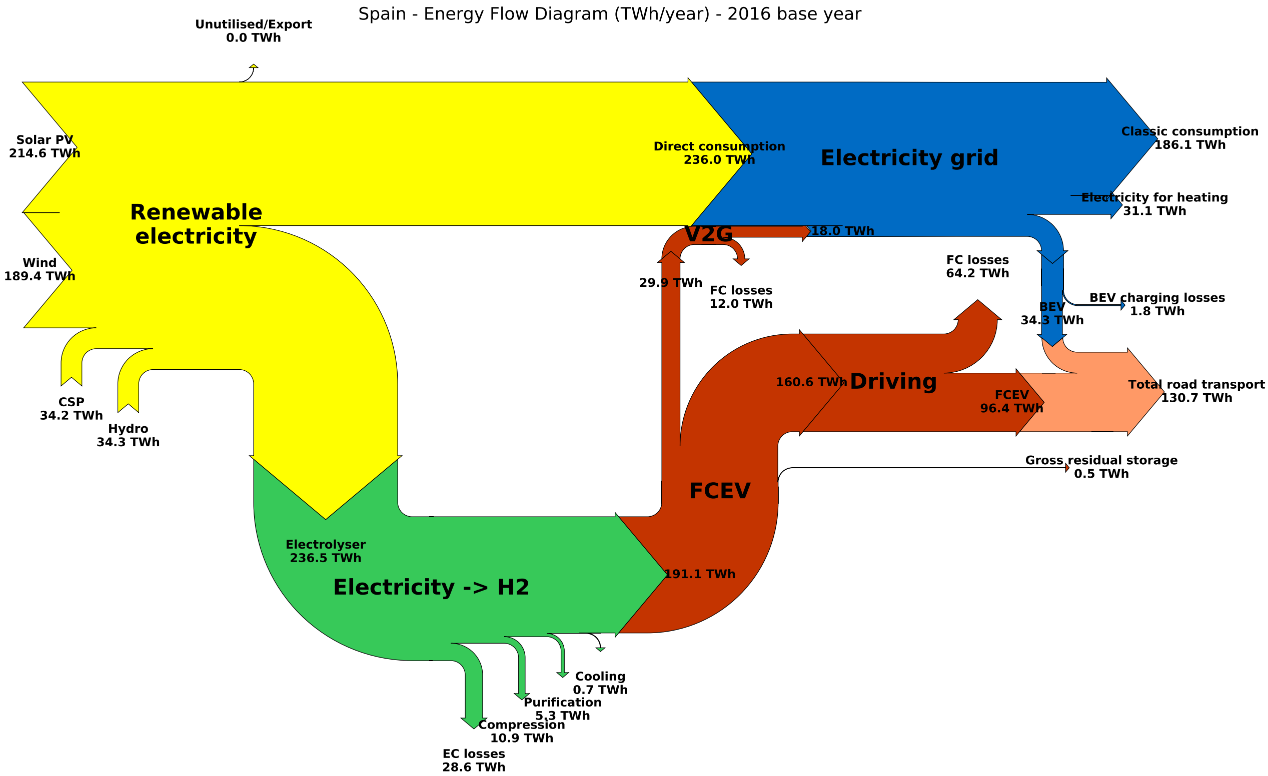


Figure 5.103: Energy flow diagram for Spain with 2016 as base year

The required installed capacity to be self sufficient for every base year is shown in figure 5.104, the corresponding electricity generation is shown in figure 5.105. The installed capacity is lower despite the low capacity factor of CSP and wind because the reference sector takes electrification of all energy consumption into account. The capacity factor of wind is lower since offshore wind is not taken into account. The CSP capacity factor is much likely lower because not all current CSP plants in Spain have storage which can be seen in figure 5.106. A more accurate CSP profile, including more plants with storage for generation at night, could have reduced the backup demand even further.

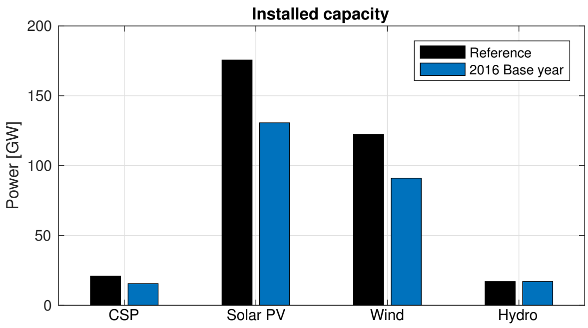


Figure 5.104: Installed capacity in Spain in 2050

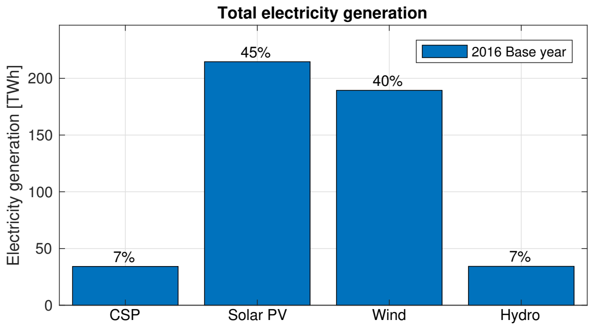


Figure 5.105: Total electricity generation in Spain in 2050

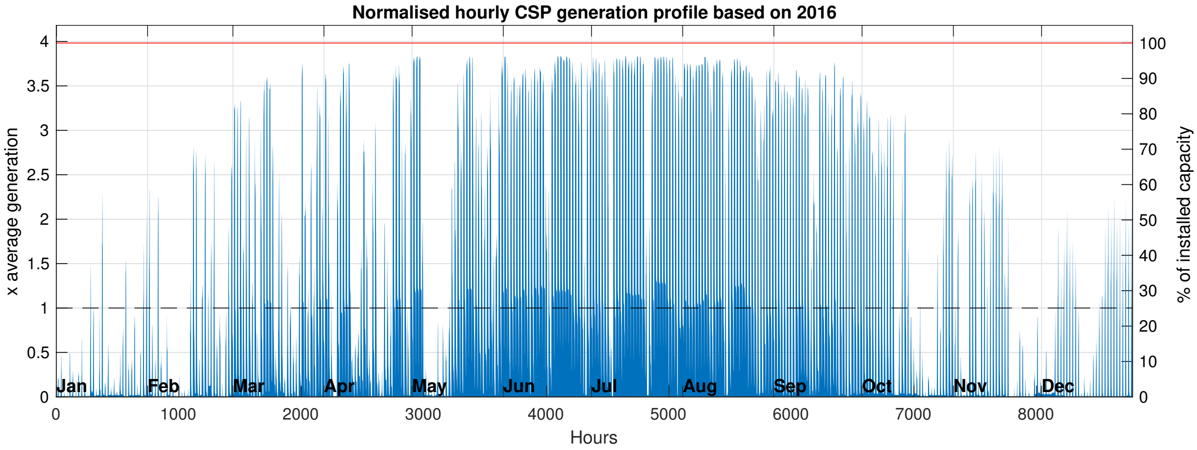


Figure 5.106: Normalised CSP electricity generation profile for Spain based on 2016 data

Figure 5.107 shows the load duration curve of the Imbalance. There is a surplus approximately for approximately 6400 hours with a maximum surplus of 133 GW. Roughly 2400 hours per year backup is required with a peak backup demand of 21 GW. The electrolyser capacity factor is 20.2%.

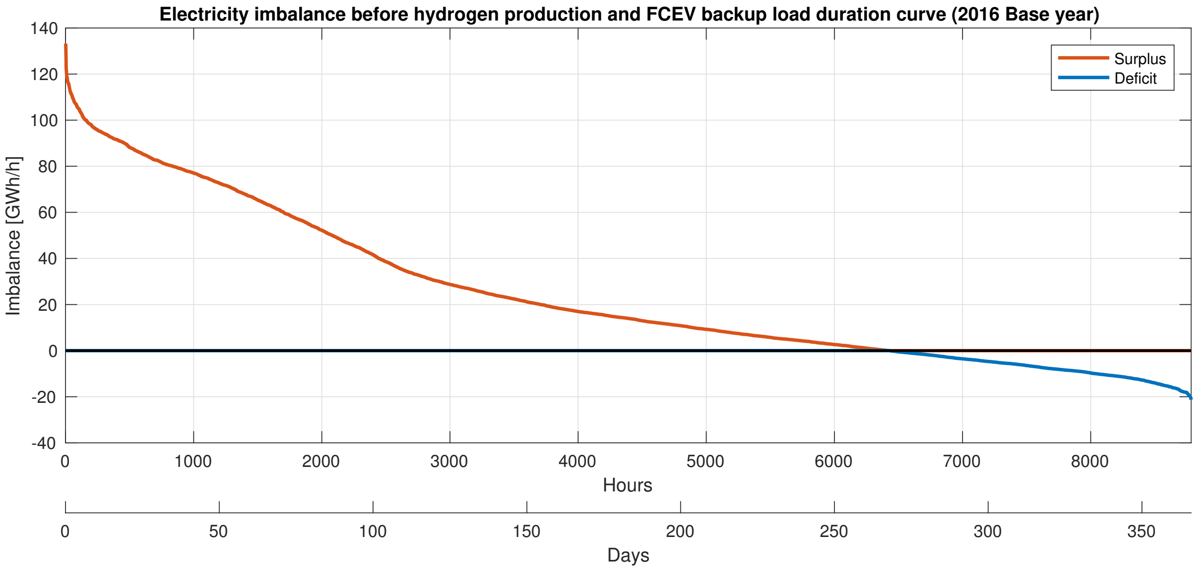


Figure 5.107: Imbalance load duration curve for Spain in 2050

FCEV backup

Figure 5.108 shows the distribution of backup power per hour of the day. It can be seen that the maximum backup demand can be powered with only 25% of the passenger FCEVs (12.5% of all passenger cars). The boxplot shows that the amount of backup during working hours is almost negligible. It can be seen that only a few times per year backup power is required. Figure 5.109 shows how many times backup power is required for ever hour of the day. It can be seen that between 11:00 and 15:00 less then 20 days per year backup is required.

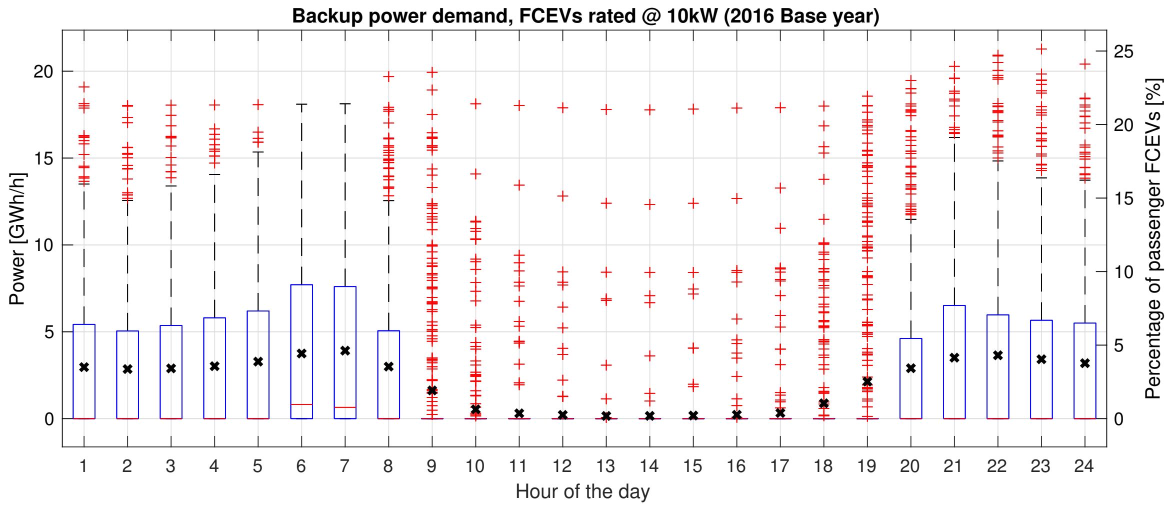


Figure 5.108: Distribution of backup power demand per hour of the day for Spain in 2050

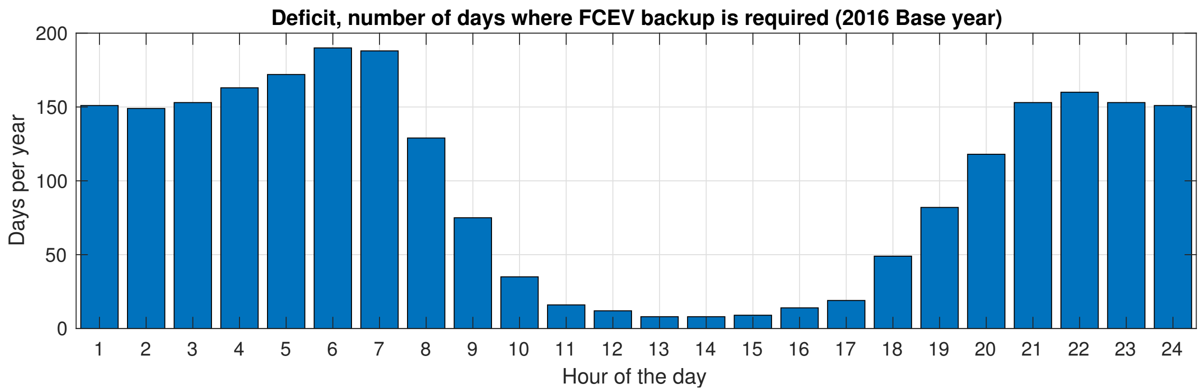


Figure 5.109: Days per year when FCEV backup is required per hour of the day in Spain in 2050

Hydrogen storage

Figure 5.110 shows the total hydrogen storage capacity. The peak storage capacity is 1.135 billion kg. Recalling that 6 million kg of working gas could be stored in an average salt cavern, at least 189 salt caverns are required. Assuming that one storage site can have 10 caverns means that at least 19 of those storage sites are required. It can be seen that buffering starts in the begin of February until mid September and is then completely emptied in the winter months. This behaviour can also be seen in figure 5.111 which shows the total weekly charge and discharge rates of hydrogen. It can be seen that the production of hydrogen is decreasing gradually and the backup demand gradually increases. The hydrogen buffers are mostly used for transportation in the winter months. This behaviour can be explained by the high share of solar energy in the electricity generation mix and the electricity consumption for space heating in the winter. The difference in solar electricity generation in the summer and winter can be seen in figures 5.112 and 5.113 which show the normalised electricity generation per month for CSP and solar PV.

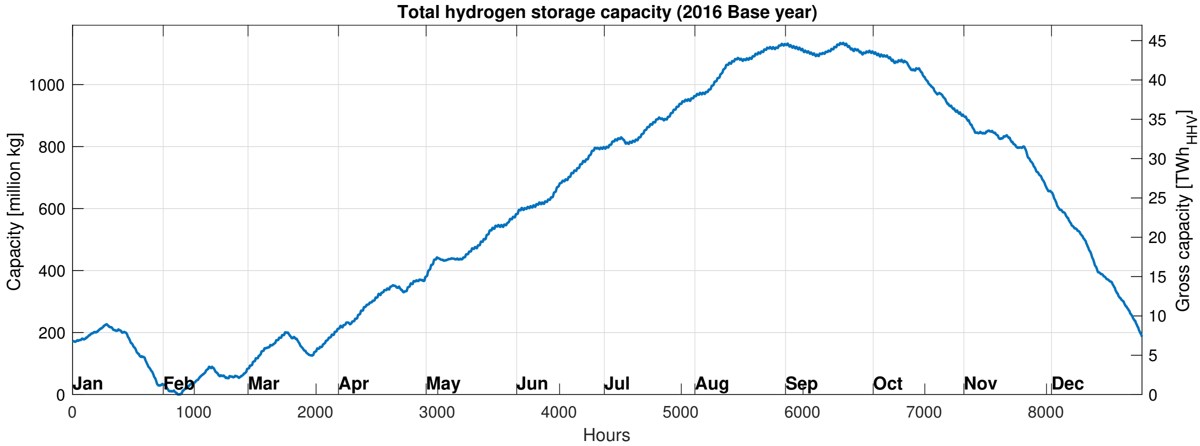


Figure 5.110: Annual storage capacity in Spain in 2050 with 2016 as base year

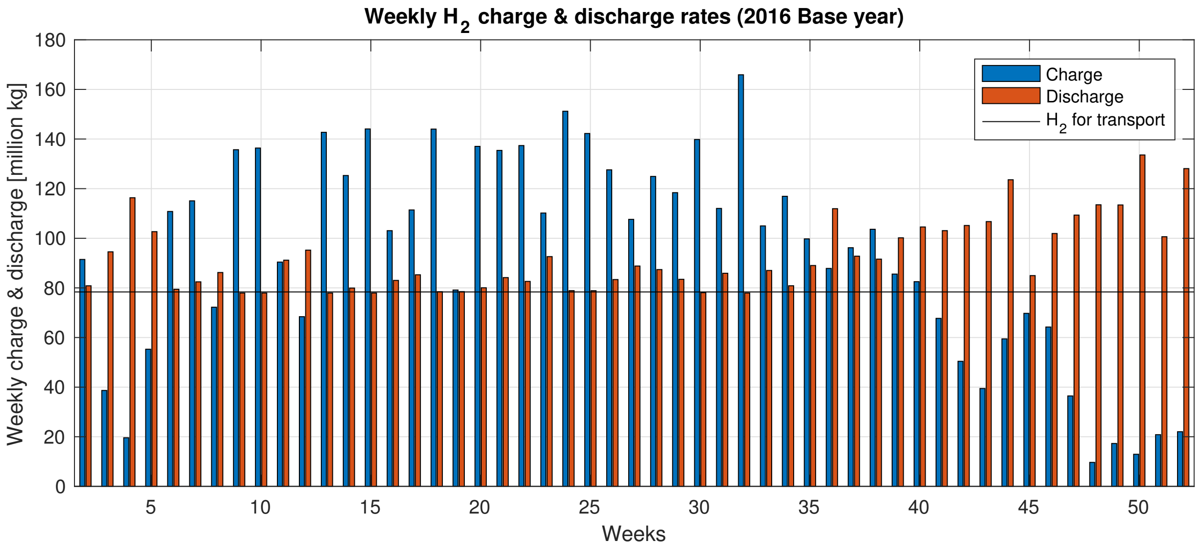


Figure 5.111: Hydrogen weekly charge and discharge rates in Spain in 2050 (2016 base year)

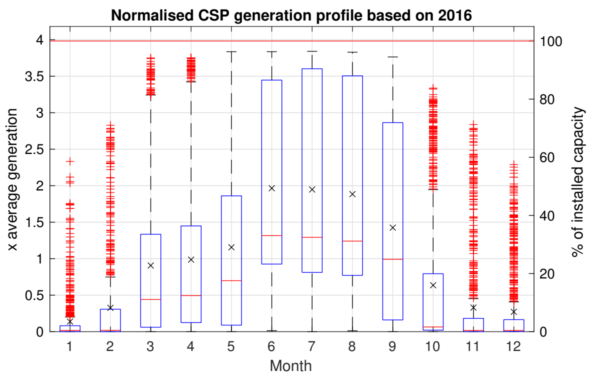


Figure 5.112: Monthly boxplot normalised CSP electricity generation profile Spain, 2016 base year

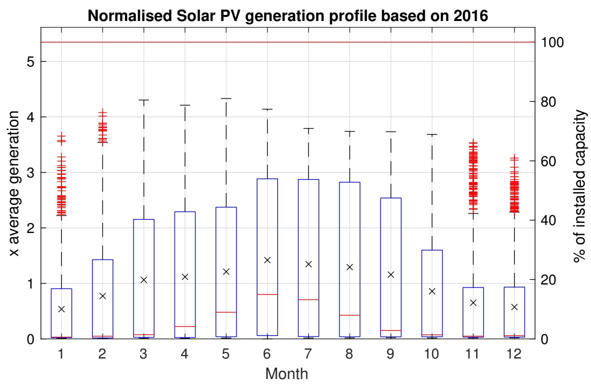


Figure 5.113: Monthly boxplot normalised Solar PV electricity generation profile Spain, 2016 base year

Figure 5.114 shows the total daily hydrogen dispension at HFSs at the left axis and the dispension per HFS at the right axis. This plot also shows that hydrogen is mainly used for fuelling and most backup occurs in winter months. The share of solar energy in the energy mix is 52%, 7% CSP and 45% solar

PV. The high share of solar PV indicates that a significant amount of the total generation in Spain is decentralised. Installing larger electrolysers at HFSs would most likely prevent congestion on the grid. If for example around 1500 kg/day would be produced per HFSs the demand for transportation and a part of the backup could be covered. Excess hydrogen could be transported to large scale storage. To produce 1500 kg/day, 3.75 MW electrolyser capacity would be required. Assuming that Spain has 11188 HFSs (same amount as petrol stations at the end of 2016), 42 GW of electrolyser capacity would be installed at the HFSs.

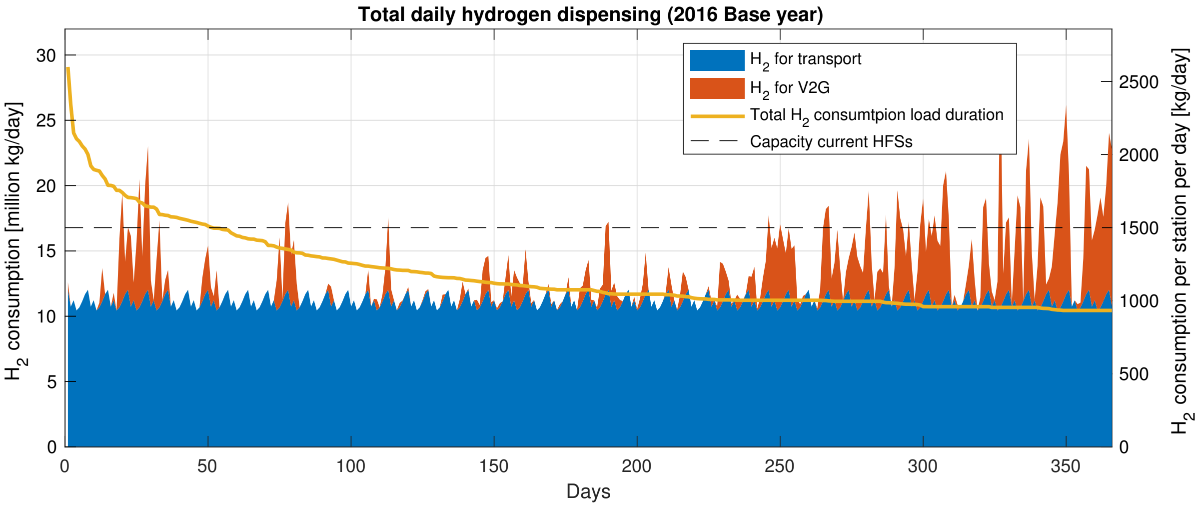


Figure 5.114: Total daily hydrogen dispensing and dispension per HFS in Spain in 2050 (2016 base year)

5.7. Demand response heating

In this section the impact of demand response heating (DRH) is analysed. DRH is applied in all cases because of the promising results of this case. DRH is applied to Germany in the future (2050) scenario and the results are compared with a situation without DRH where the heating demand is constant. The plots are shown for 2016 as base year. Figure 5.115 shows the constant electric heating profile in orange and the DRH profile adapting to the imbalance in blue. It can be seen that the heat pump demand is limited twice by the maximum heat pump capacity (107 GW).

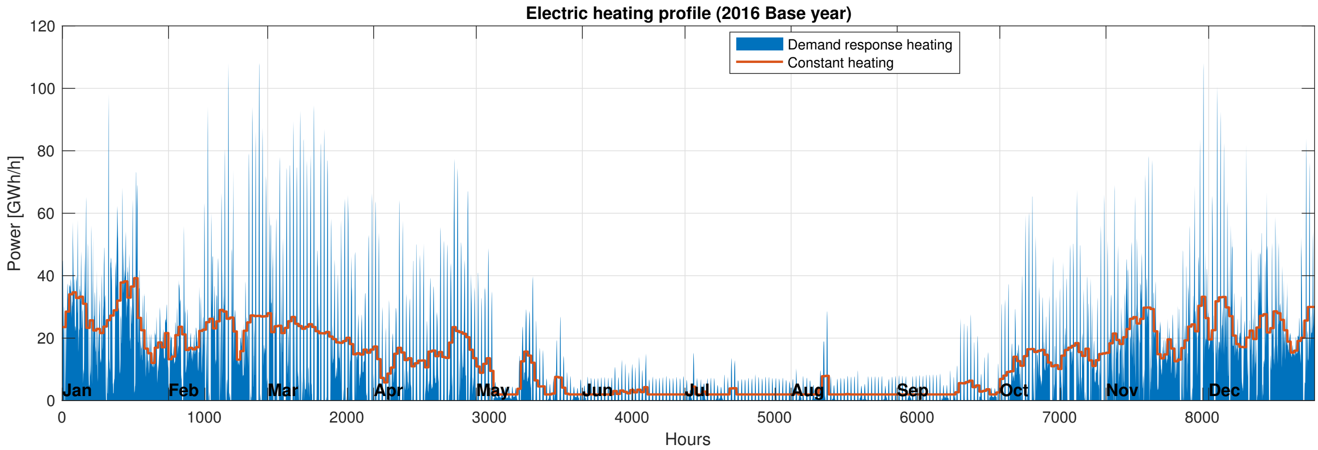


Figure 5.115: Electric heating profile with and without DRH for Germany with 2016 as base year

Figure 5.116 shows the impact on the V2G backup demand. The backup demand without DRH is displayed in orange, the backup demand with DRH is shown in blue. It can be seen that the peak demand is strongly reduced and the demand is spread more evenly to improve continuous operation. The difference in V2G demand with and without DRH is shown in figure 5.117. It can be seen that during the summer the heat load is shifted to the hours with excess solar electricity. In the winter there are power reductions but in some situations the backup power demand is increased to reduce the V2G demand at another hour of the day to achieve a continuous and constant operation.

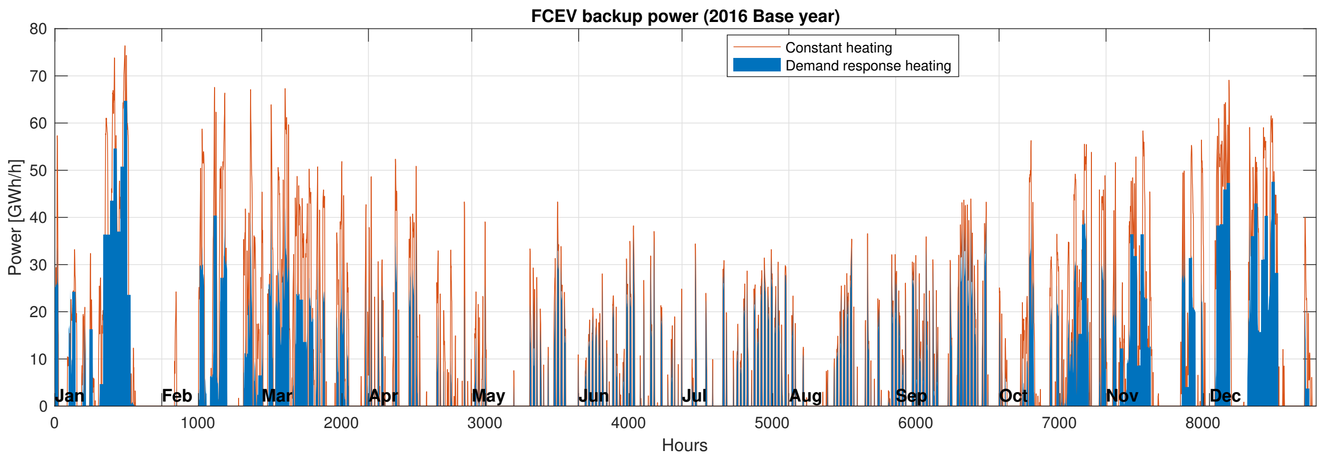


Figure 5.116: Impact of DRH on V2G backup power for Germany with 2016 as base year

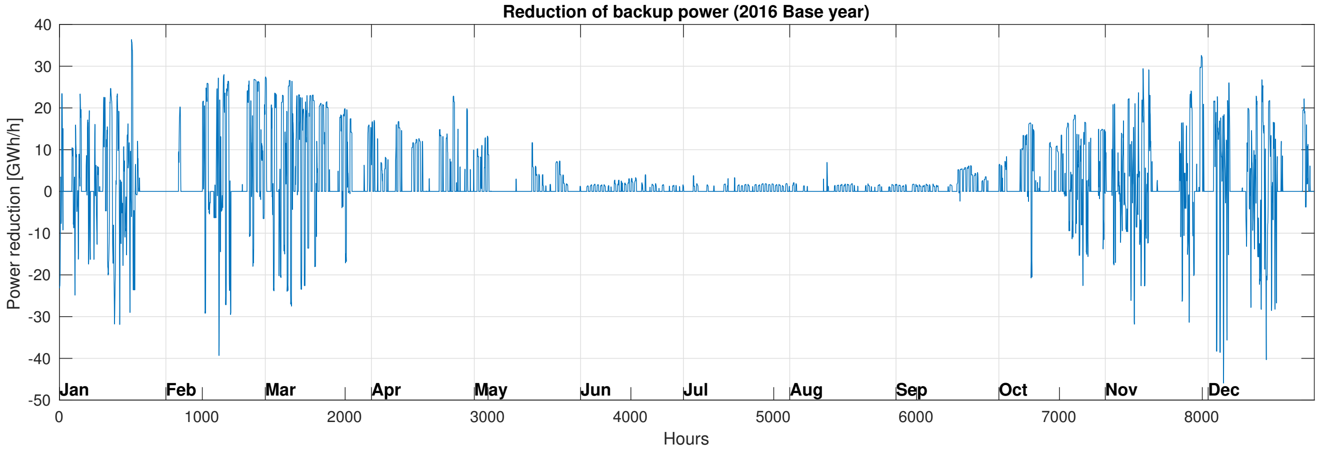


Figure 5.117: V2G power reduction caused by DRH for Germany with 2016 as base year

The results of implementing DRH for Germany in the future scenario are shown in table 5.14. The total electricity generation dropped on average by 17 TWh (2%). V2G peak demand is reduced by 10.93 GW (14%) on average. Recall that the V2G capacity of a FCEV is 10 kW which means that 1.1 million cars less are required for peak demand. The total V2G demand dropped by 20% which is now directly consumed on the grid and the peak demand of the electrolysers (ECs) dropped by 4% on average. The impact on the maximum storage capacity is relatively low with an average of 2% and an increase in capacity for the 2014 base year. The impact on the storage with 2014 and 2016 as base year can be seen in figures 5.119 and 5.120. Based on these results it is decided to implement DRH in all cases.

Table 5.14: Impact of DRH on V2G demand, electrolyser demand and storage capacity for Germany per base year

Base year		2014	2015	2016	Average
V2G peak demand reduction	GW	7.76	13.35	11.69	10.93
	%	8.84	17.82	15.30	13.99
Total reduction V2G demand	TWh	15.67	18.17	16.77	16.87
	%	19.92	22.55	20.42	20.97
EC peak demand reduction	GW	10.24	13.39	9.68	11.10
	%	4.38	5.25	3.46	4.36
EC demand reduction	TWh	31.24	36.50	35.03	34.25
	%	8.94	10.34	9.81	9.70
EC capacity factor reduction	% (rel)	4.78	5.37	6.58	5.57
Storage capacity reduction	million kg	-13.09	61.40	99.79	49.37
	%	-1.06	3.33	4.90	2.39
Electricity generation savings	TWh	15.56	18.32	18.26	17.38
	%	1.90	2.23	2.21	2.11
Installed capacity reduction	GW	10.76	11.90	13.94	12.20
	%	1.92	2.23	2.25	2.13

Figure 5.118 shows the Imbalance load duration curve. It can be seen that also the electrolyser peak demand and the load is reduced. The capacity factor of the electrolysers is reduced by almost 6% on average. The model has no optimisation criteria for the operation of the electrolysers which makes it difficult to discuss performance criteria such as the capacity factor. The capacity factor is defined as the maximum load divided by the average load. Since it is assumed that there is no curtailment, there is no restriction for the maximum capacity what makes the capacity factor strongly dependent on the maximum surplus. In this case the capacity factor decreased because the average load decreased stronger (9.7%) than the peak load (4.4%). If there was a criteria to avoid such high electrolyser peak powers the capacity factor would most likely increase.

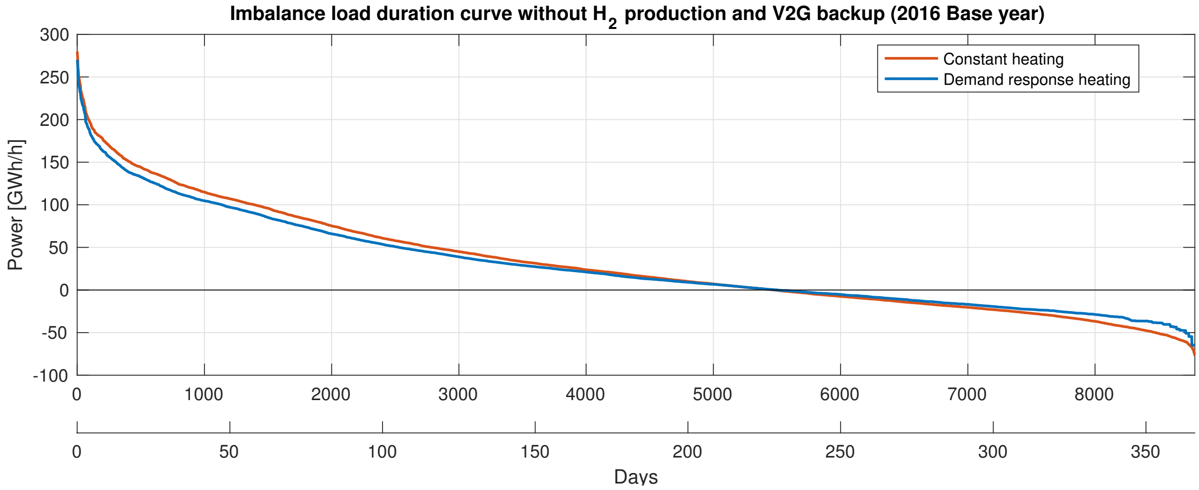


Figure 5.118: Electrolyser load duration curves with and without DRH for Germany with 2016 as base year

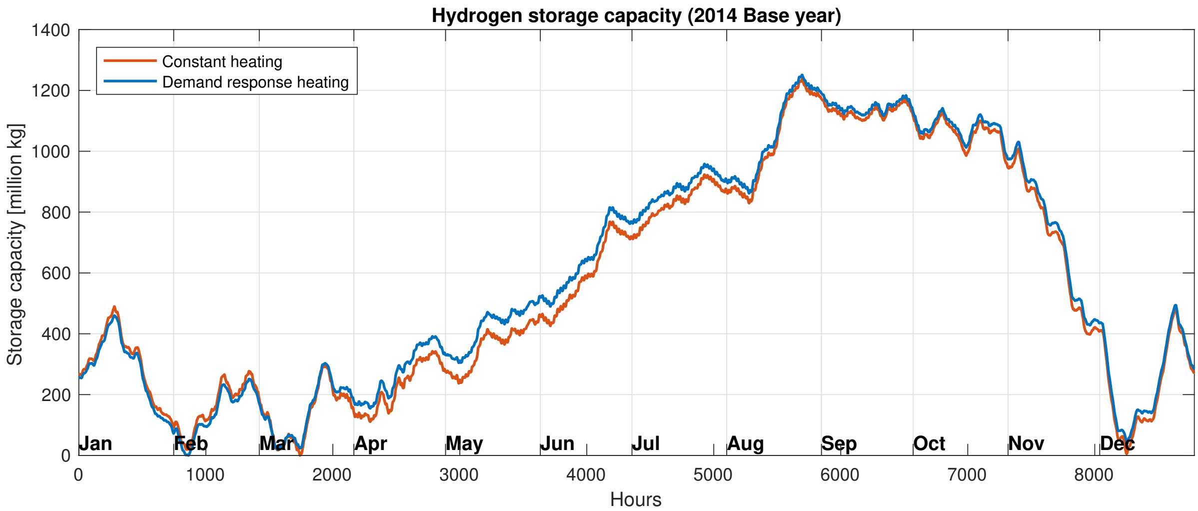


Figure 5.119: Hydrogen storage capaicity with and without DRH for Germany with 2014 as base year

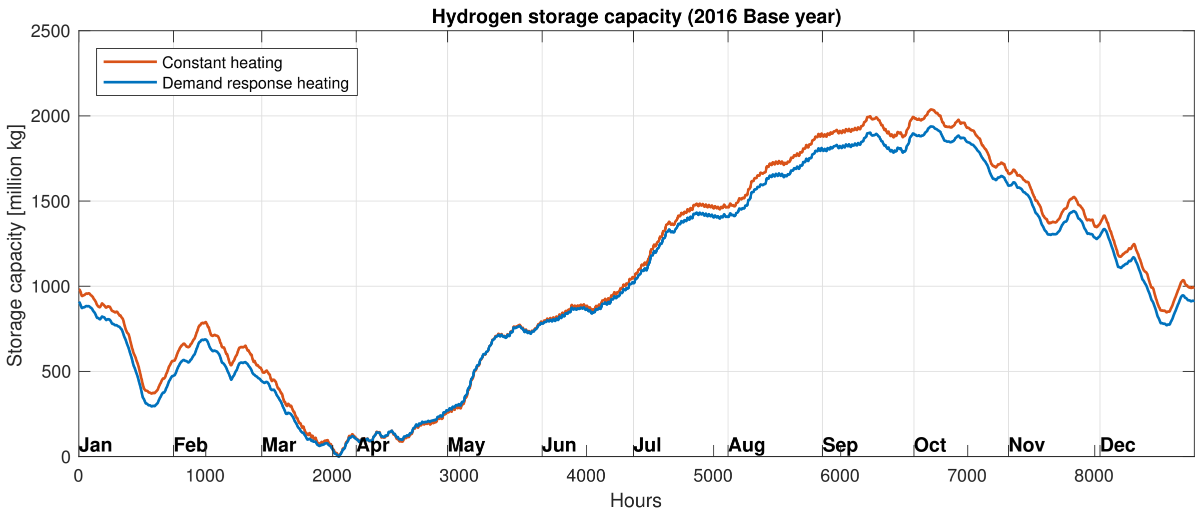


Figure 5.120: Hydrogen storage capaicity with and without DRH for Germany with 2016 as base year

6 Comparing countries

In this section the differences and similarities between countries are evaluated and discussed. The countries are compared based on the research subquestions but first the daily classic consumption patterns and the load duration curves without hydrogen production and V2G backup are compared.

The daily classic consumption patterns in figure 6.1 show a trend where the consumption is low at night, increases in the morning, slightly decreases in the afternoon, increases in the evening when people come home from work and decreases again in the night. An exception is Germany where there seems not to be an increased consumption at the begin of the evening. The other countries follow the pattern described earlier with some small variations. For example the peak in the evening is the highest in Great Britain and the evening peak starts later in Spain. The pattern is a bit smoothened for Belgium which is mot likely caused by the high base load of industry which is also operating at night.

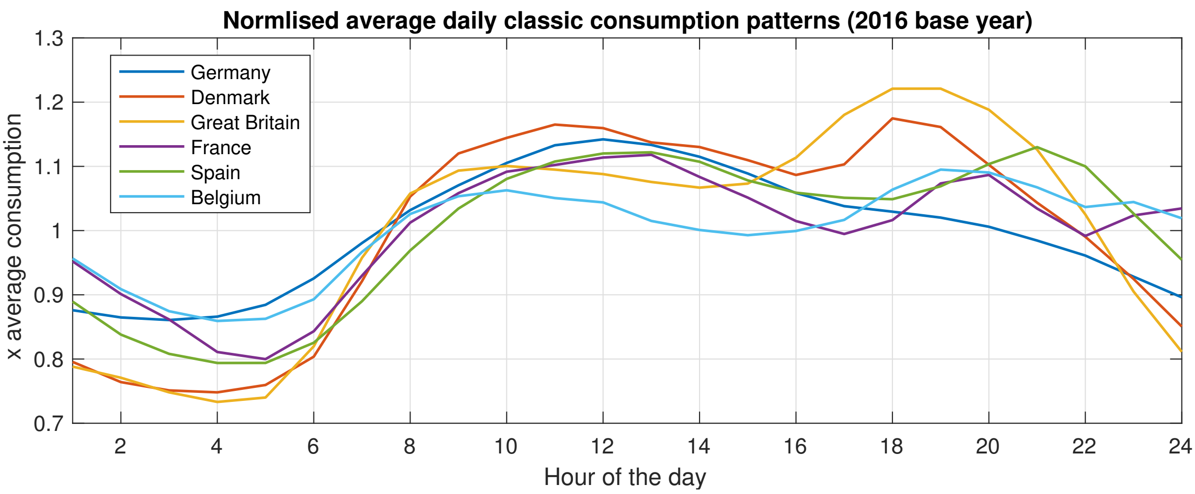


Figure 6.1: Normalised daily average classic consumption patterns for all countries with 2016 as base year.

Figure 6.2 shows the normalised imbalance load duration curves without hydrogen production and V2G backup. The imbalances have the same profile except for Denmark and Spain. In Denmark the peak surplus is lower which is caused by the lack of solar power. The imbalance of Spain also shows a slightly lower peak surplus and the shortages are less compared to the other countries. Great Britain and Spain have the most surplus hours. The surplus hours vary from 5400 in Belgium to 6430 in Spain.

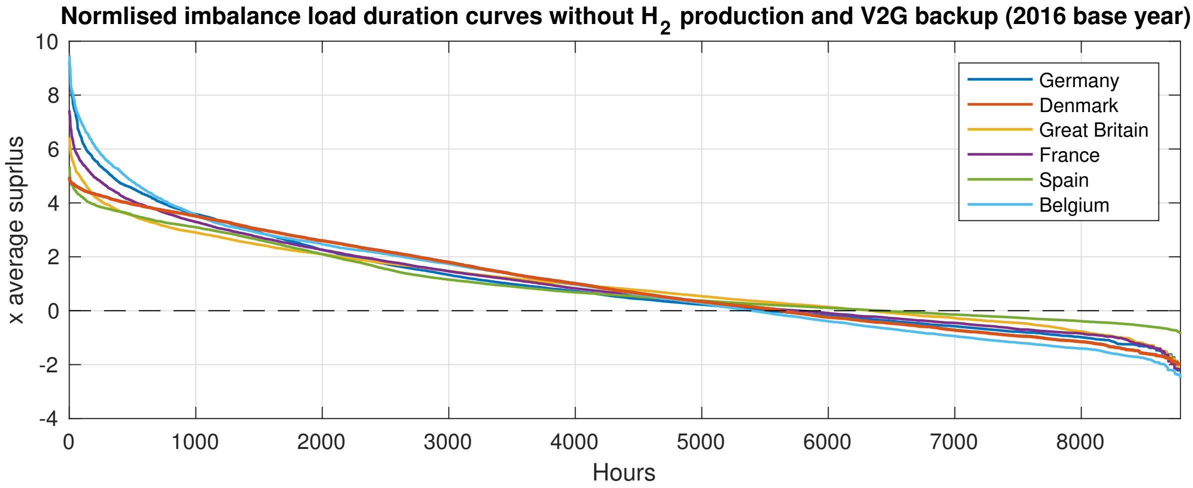


Figure 6.2: Normalised imbalance load durations curves without hydrogen production and V2G backup for all countries with 2016 as base year.

6.1. How many FCEVs are required and when are they required?

Figure 6.3 compares the fraction of V2G backup on the total electricity consumption for every country and base year. It can be seen that the maximum amount of V2G is 14% for Denmark and Belgium. In Spain the least amount of V2G backup is required. This can be explained partly by the large amount of solar energy in the generation mix as discussed in section 5.6.4. Another explanation is that the ratio of generation versus electricity consumption is higher because more hydrogen is required for transport in Spain due to the high amount of trucks. Figure 6.4 shows that the fraction of road transport hydrogen consumption of the total electricity generation is much higher than other countries. More capacity of renewables needs to be installed for the production of hydrogen which results in less potential imbalance on the electricity grid. This could also be seen in figure 6.2 where the load duration curve for Spain shows more surplus hours and lower backup demand compared to the other countries.

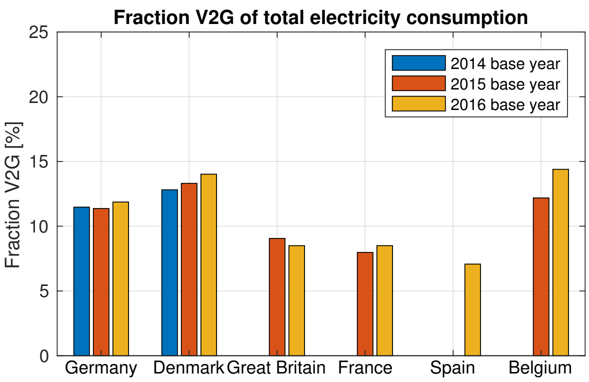


Figure 6.3: Fraction V2G of total electricity consumption per country

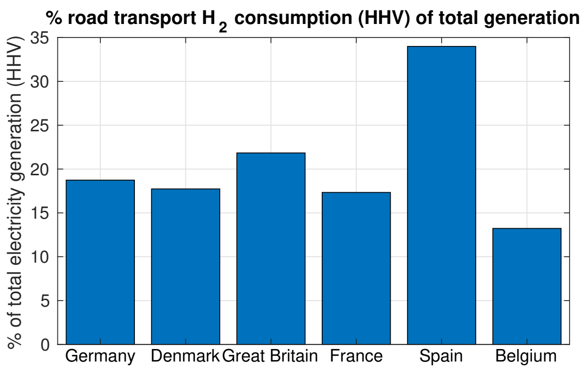


Figure 6.4: Percentage road transport hydrogen consumption of the total electricity generation

How many FCEVs are required for V2G?

The maximum amount of FCEVs that should be available for V2G per country is shown in figure 6.5. Recall that only passenger FCEVs are considered for V2G and that 50% of all passenger cars is a FCEV and that the V2G power per vehicle is restricted to 10 kW. The figure shows that the maximum amount of FCEVs that should be available for V2G lies below 50% of all passenger FCEVs in all countries. The average utilisation of the FCEV fleet for backup is 4% for all countries. The highest utilisation is in Belgium with an utilisation of almost 8%. In this work the power output is assumed to be 10kW based on the FCEV with V2G prototype at the TU Delft. This only 10% of the rated output of the fuel cell.

Increasing the power output could significantly reduce the amount of vehicles required for peak power and decrease the utilisation of the fleet. The V2G output could be increased if the cooling system is optimised when the vehicle is idling.

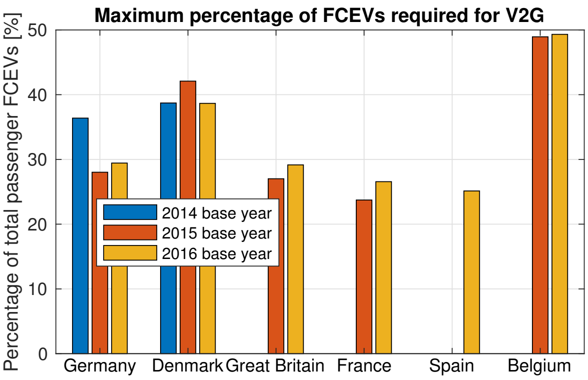


Figure 6.5: Maximum percentage of vehicles required for V2G per country

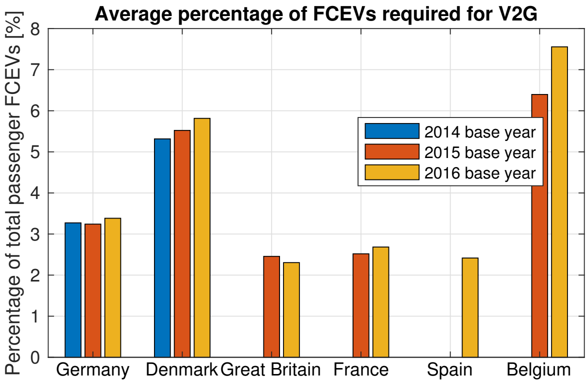


Figure 6.6: Average percentage of vehicles required for V2G per country

When are FCEVs required for V2G?
Figure 6.7 shows the annual V2G backup per hour of the day as a percentage of the total backup for all countries. For every country the average of all base years is taken. This plot is a combination of how many *FCEVs* are required per hour of the day and how many *times* they are required. It can be seen that all countries have a trend where the V2G demand is lower during the day and higher during the night. During the morning commute an increase in backup demand can be seen. For countries such as Spain where maximum 25% of the FCEV fleet is required this would most likely not give any problems but it might give complications for other countries. Figure 6.9 shows the driving of FCEVs by the time of the day in the United States [132], figure 6.10 shows car trips distribution by the time of the day for weekdays in European countries [133]. It can be seen that 20% of all trips in European countries is before 9:00 am. It does not give an indication of how much vehicles are on the road but it suggests that still enough vehicles can be available for V2G. Load shifting of the electricity demand could solve this problem.

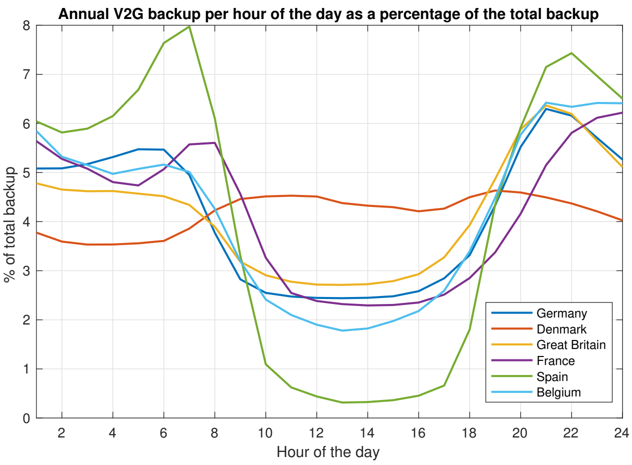


Figure 6.7: Annual V2G backup per hour of the day as a percentage of the total backup for all countries

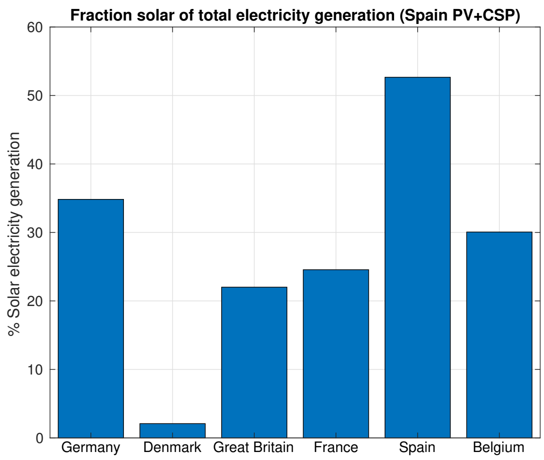


Figure 6.8: Fraction of solar electricity in the electricity generation mix per country

The backup demand of Denmark shows a different behaviour, Denmark is the country with the lowest amount of solar energy in the future electricity mix as can be seen in figure 6.8. The backup demand shows a similar pattern as the daily consumption profile shown in figure 6.1, suggesting that V2G backup fills the gap when there is no wind energy. It looks like the higher the share of solar energy in the electricity mix the lower the V2G demand is during the day. Figure 6.11 shows that there is higher backup demand in the winter than in the summer. In the summer hydrogen is mainly produced and stored with excess solar electricity which is used for transport and as backup during the winter.

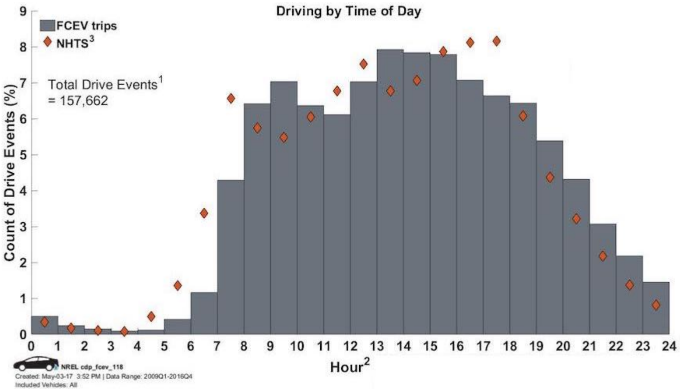


Figure 6.9: FCEV trips by time of day [132]

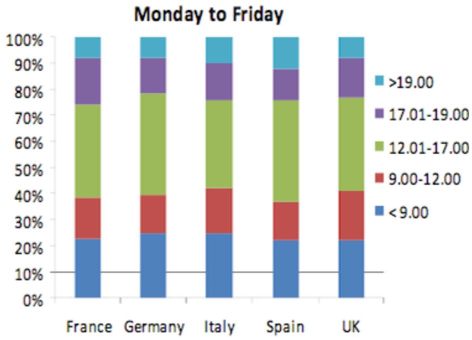


Figure 6.10: Car trips distribution by time of the day in European countries [133]

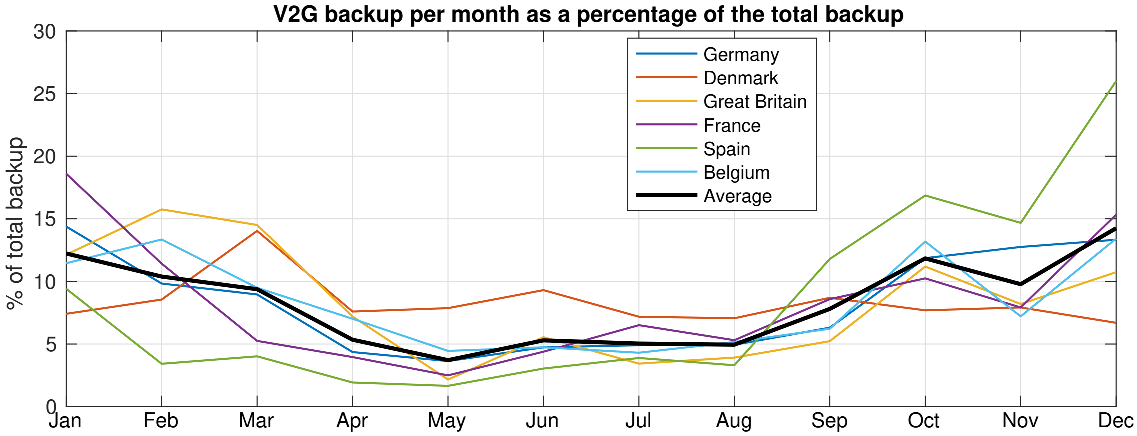


Figure 6.11: V2G backup per month as a percentage of the total backup for all countries

6.2. How many, and when are electrolysers required?

How many electrolysers are required?
It is difficult to determine how many electrolysers or which capacity is required. The capacity of electrolysers could be defined by the maximum electrolyser demand but this would basically be defined by the maximum surplus. The model is not optimised for electrolyser consumption and does not have any criteria for a minimum capacity factor. The relation between the electrolyser capacity and the total installed capacity of renewables can be seen in figure 6.12. The maximum is approximately 0.6 GW electrolyser per GW installed renewables in Denmark. This is most likely because of the high share of offshore wind capacity and the high capacity factor of offshore wind. Adding a constraint in the model that electrolysers should have a minimum capacity factor and apply curtailment or export will most likely result in a lower ratio.

To give an indication of how much the electrolysers are required the electrolyser consumption can be expressed as a percentage of the total electricity generation as shown in figure 6.13. The figure shows that roughly 40% of the total generation is consumed by electrolysers for the production of hydrogen. The rest of the electricity generation is directly consumed on the grid. The electrolyser consumption in Spain is higher than the other countries despite the fact that the V2G is lower. This is again caused by the relatively high hydrogen consumption in transport.

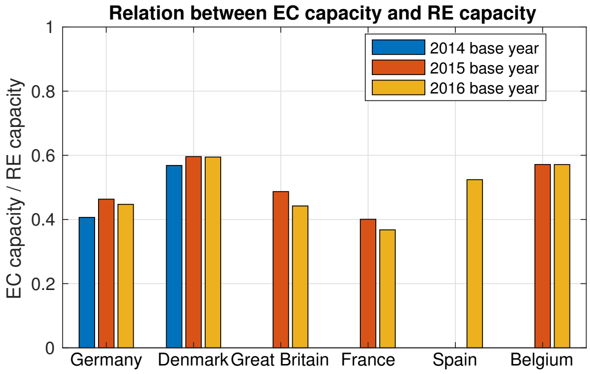


Figure 6.12: Electrolyser capacity divided by the total renewable electricity capacity

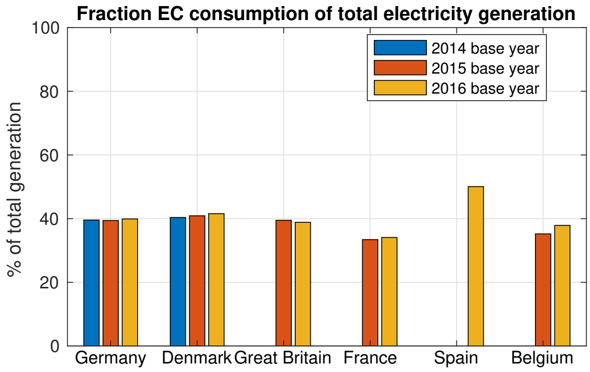


Figure 6.13: Fraction of electrolyser consumption of the total electricity generation

When are electrolysers required?

When electrolysers are required is the opposite of when V2G backup is required. When there is no V2G demand electrolysers produce hydrogen. Figure 6.14 shows the share of annual electrolyser consumption per hour of the day. The figure shows the opposite effect of figure 6.7. Most of the hydrogen is produced during the day with excess solar energy. Only in Denmark the daily pattern is differen. The monthly electrolyser consumption shows a more constant trend with slightly less consumption at the end of the year. This trend is not the opposite of the monthly V2G demand since hydrogen is not only produced for backup but also for road transport.

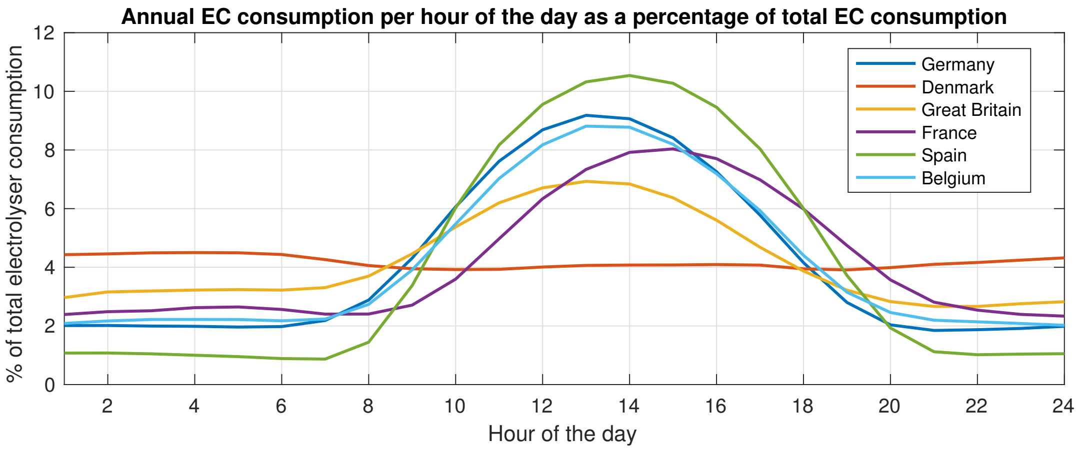


Figure 6.14: Annual electrolyser consumption per hour of the day as a percentage of the total electrolyser consumption

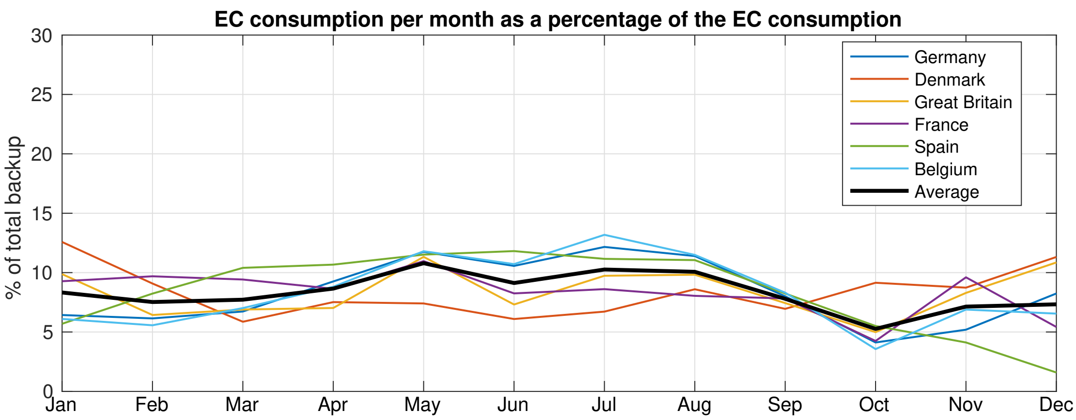


Figure 6.15: Electrolyser consumption per month as a percentage of the total electrolyser consumption

6.3. How much hydrogen needs to be produced and how much storage capacity is required on a yearly basis?

The first part of this question is strongly dependent on the V2G demand and the fraction of FCEVs in the fleet composition. How much hydrogen is produced as a percentage of the total electricity generation is directly coupled to the fraction of the electrolyser consumption in figure 6.13 which showed that roughly 40% of the total electricity generation is consumed by electrolysers. Figure 6.16 shows the hydrogen consumption per TWh final energy consumption. The hydrogen consumption per TWh final energy consumption is approximately the same for every country. The hydrogen consumption in Spain is higher because of the high consumption in road transport which is confirmed in figure 6.17 which shows that over 80% of all the produced hydrogen is consumed for road transport.

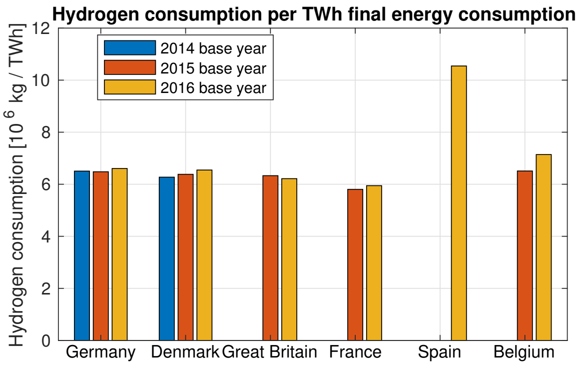


Figure 6.16: Hydrogen consumption per TWh final energy consumption

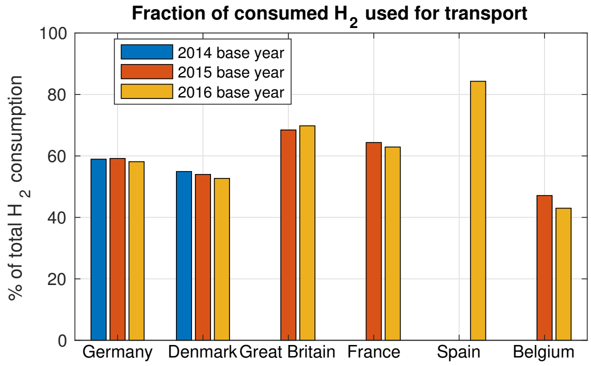


Figure 6.17: Fraction of the consumed hydrogen used for transport

Figure 6.18 shows the maximum hydrogen storage for all countries. To make the maximum storage capacity compare-able the maximum storage capacity is plotted versus the final energy consumption in a country in figure 6.19. Large differences can be seen between countries and base years and there seems not to be a trend. In Spain the required capacity is most likely higher because of the combination of high consumption of hydrogen and the large dependency of solar energy and the heating demand in the winter. Figure 6.11 shows that 55% of all V2G backup power is delivered in the last 3 months of the year which requires larger buffers than other countries. In Belgium the same behaviour is shown for the 2016 base year (section 5.3.4).

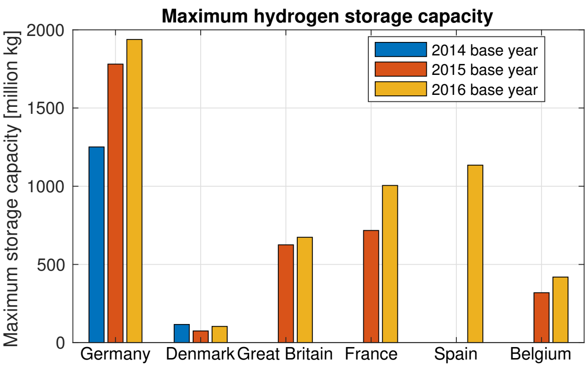


Figure 6.18: Maximum hydrogen storage capacity per country

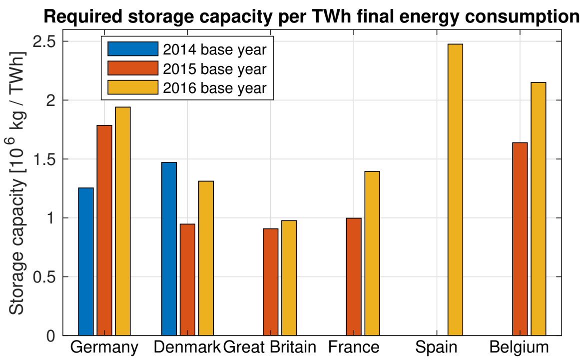


Figure 6.19: Required hydrogen storage capacity per TWh final energy consumption

6.4. Hydrogen fuelling and distribution

Figure 6.20 gives an overview of how much hydrogen needs to be fuelled on a daily basis. The boxplot shows the daily hydrogen dispension per hydrogen fuelling station (HFS). Recall that is assumed that the number of fuelling stations is the same as the number of petrol fuelling stations at the end of 2016 and the current capacity of large HFSs is approximately 1500 kg/day (section 3.5.2 & 4.3.3). It can be seen that with the same amount of HFSs as petrol fuelling stations the capacity is not sufficient. In Denmark and Spain the capacity only has to be increased for several days per year, for the other countries a significant increase in dispension capacity is required. An explanation for the higher demand at HFSs in Germany, Great Britain (UK) and France is that the density of fuelling stations in those countries is lower (more cars per fuelling station). To secure V2G backup at peak demands more or larger fuelling stations are required. If the average capacity could be doubled only some outliers could not be covered. This could be solved by converting conventional parking garages to car park power plants (CPPPs) equipped with V2G sockets and hydrogen dispensers or use stationary fuel cells or imports. Recall from section 3.5.2 that ITM will unveil HFSs with an on-site production capacity of 20 tonnes per day with 50 MW electrolysers. To cover the full demand excluding the outliers (the 25% highest values) for all countries 1500 kg/day is sufficient. To produce this hydrogen on-site electrolysers of 3.75 MW are required. More hydrogen to cover peak demands can be transported from the large scale storages (salt caverns) to the HFSs wit pipelines or tube trailers.

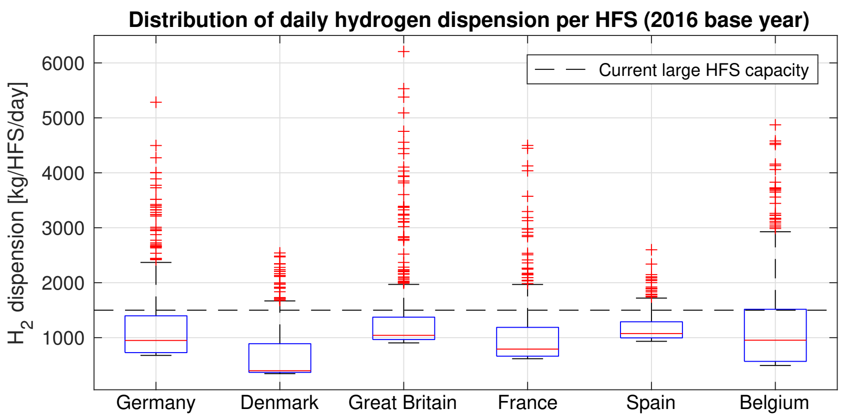


Figure 6.20: Distribution of daily hydrogen dispension per HFS for all countries[1]

[1]Points are defined as outliers if they are greater than $q_3 + 1.5(q_3 - q_1)$ or smaller than $q_3 + 1.5(q_3 - q_1)$

7 Analysis of combined countries

All national electricity grids in Europe are interconnected. The European union has a target that the capacity of interconnectors with neighbouring countries should be 10% of in the installed capacity [134]. The installed capacity was 190 GW in Germany at the end of 2016 which means that the target is 19 GW of interconnections in Germany. In 2030 this capacity should be increased to 12.5%. Interconnecting countries could help balancing the national grids and increase the utilisation of renewable energy sources.

A copper plate analysis is performed interconnecting France and Germany to see what the impact is of two countries being interconnected. First the moments of generation shortages are compared to see if the countries have common generation shortages or fill the gaps which is shown in figure 7.1. It can be seen that both countries have large common generation shortages in the begin and end of the year. This is most likely caused by a lack of wind energy. Since the countries are geographically close to each other the intermittent generation profiles have the same seasonal trends.

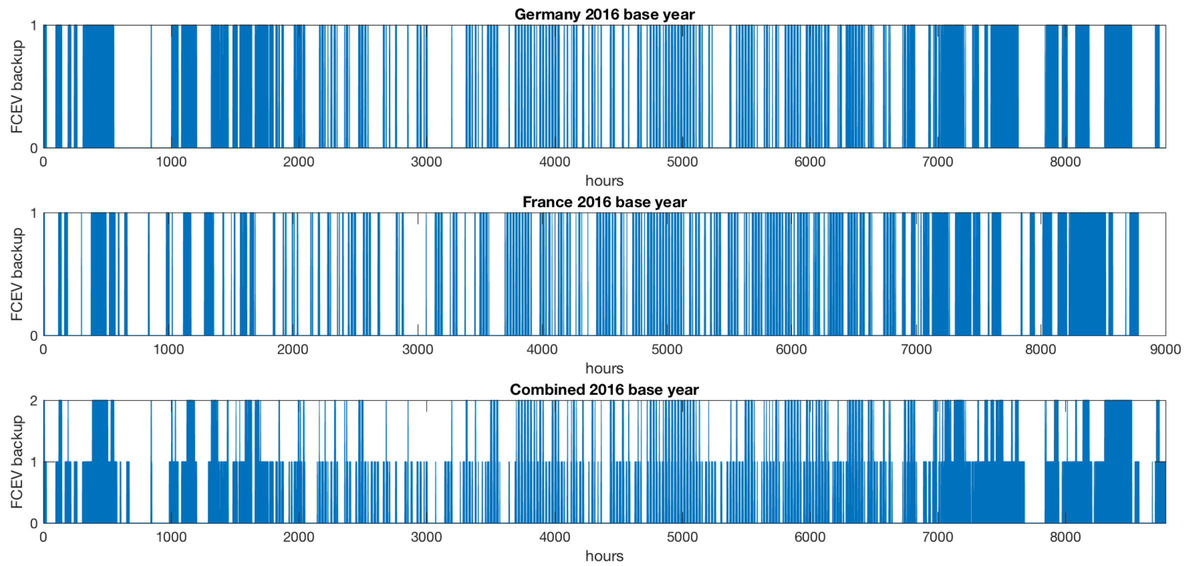


Figure 7.1: Comparison of electricity deficits between France & Germany

The copperplate analysis is performed with the same model that is used for the autonomous cases. The generation and consumption profiles are combined and the interconnected countries are modelled as one 'new' country. Since the countries are modelled as one country (copperplate) there is no restriction on interconnection capacity and shows an extreme case with savings and synergies. The comparison of results show an extreme with 'unlimited' interconnections and an isolated situation with more electrolysers, storage and backup demand. The results are shown with 2016 as base year. In both the autonomous and interconnected situations DRH is applied.

Figure 7.2 shows the load duration curve of the imbalance without hydrogen production and V2G backup for the interconnected situation and the sum of the imbalances for the autonomous countries. The orange lines show the combined surpluses and deficits of France & Germany. The blue line is the load duration curve of the interconnected situation. In the autonomous situation there was a overlap where one country had a electricity surplus and the other country had a electricity shortage. In the interconnected situation the surplus hours increased and the hours were backup is required is reduced.

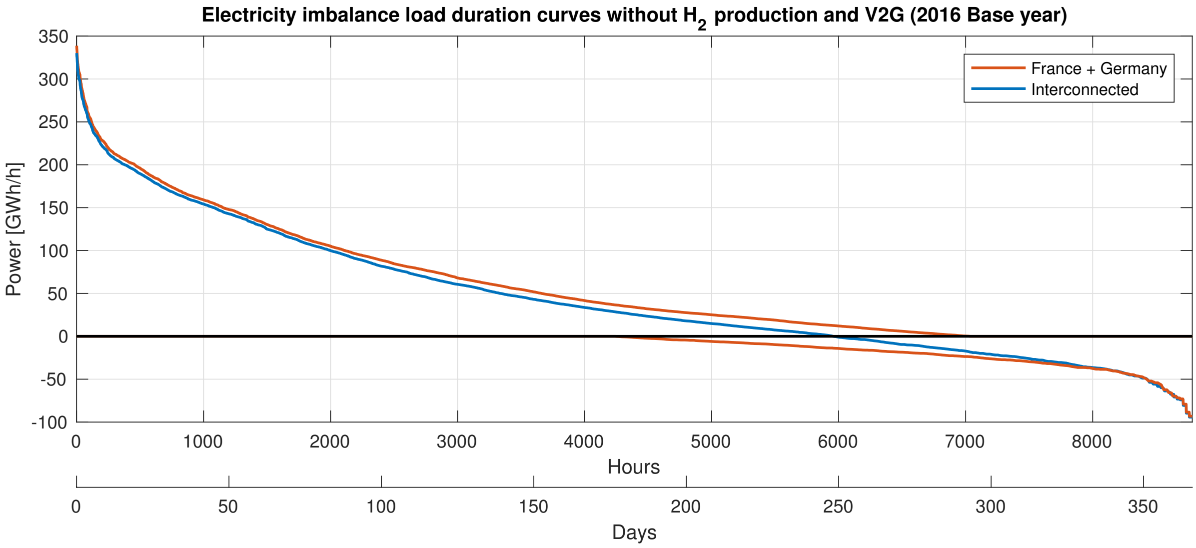


Figure 7.2: Imbalance load duration curves for the interconnected and autonomous situation, 2016 base year

FCEV backup
Figure 7.2 already showed that the deficit hours and the load was significantly reduced. The reduction of monthly V2G backup can be seen in figure 7.3. The amount of backup is reduced by 25 TWh, a reduction of 25% compared to the autonomous situation.

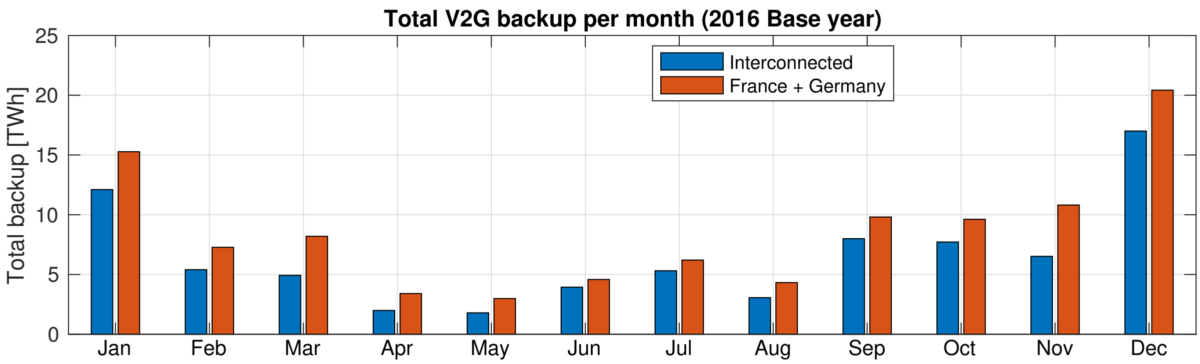


Figure 7.3: Monthly V2G backup demand for the interconnected and autonomous situation, 2016 base year

Figure 7.4 shows the backup load duration curves in the autonomous and interconnected situations. The orange line is the load duration curve of the combined backup in the autonomous situations (a summation of the yellow and purple line. Keep in mind that these are load duration curves and the backup demands do not have to occur at the same time. That also explains why the duration is longer for the combined curve. It can be seen that the average load is reduced and that also the duration of backup is decreased. In the interconnected situation the duration and the average backup demand is reduced. The peak load is almost equal to the autonomous situation. Less vehicles are required however in the interconnected situation. The peak load in France is 42 GW and in Germany around 65 GW. That means that in total 107 GW backup power (10.7 million vehicles) is required if the countries are isolated.

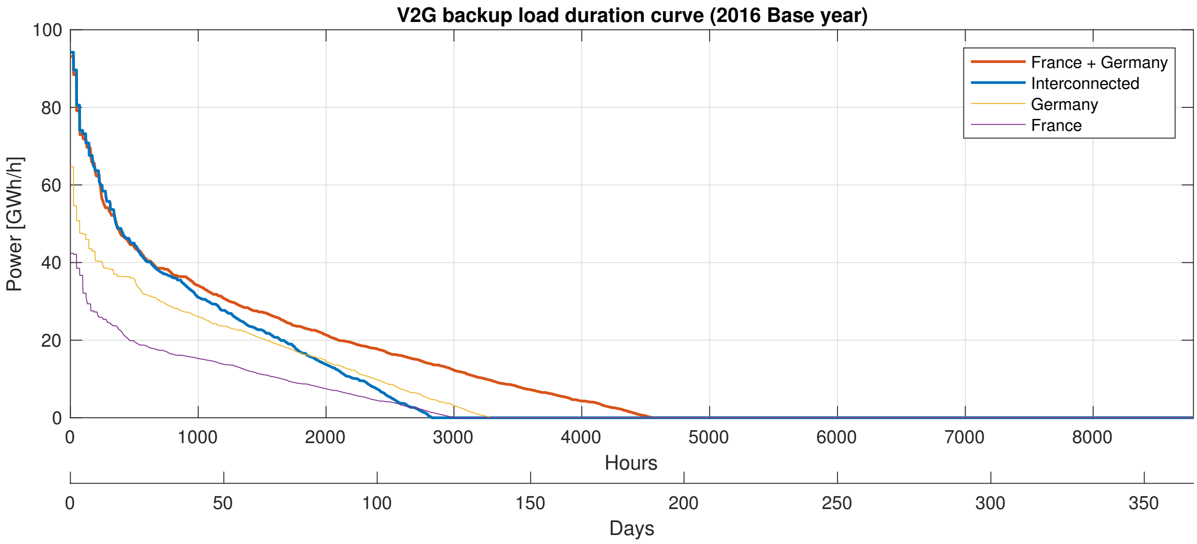


Figure 7.4: V2G demand load duration curves for the interconnected and autonomous situation, 2016 base year

Electrolyser demand

Figure 7.5 shows the electrolyser load duration curve in the interconnected situation, both autonomous situations and the combined electrolyser load duration curve of France and Germany. The duration, the peak load and the average load are reduced. It can also be concluded that less electrolysers are required. The peak load in the autonomous situation is 270GW and 150GW for Germany and France respectively. This requires 420 GW of electrolysers in total. The interconnected situation only requires 330GW.

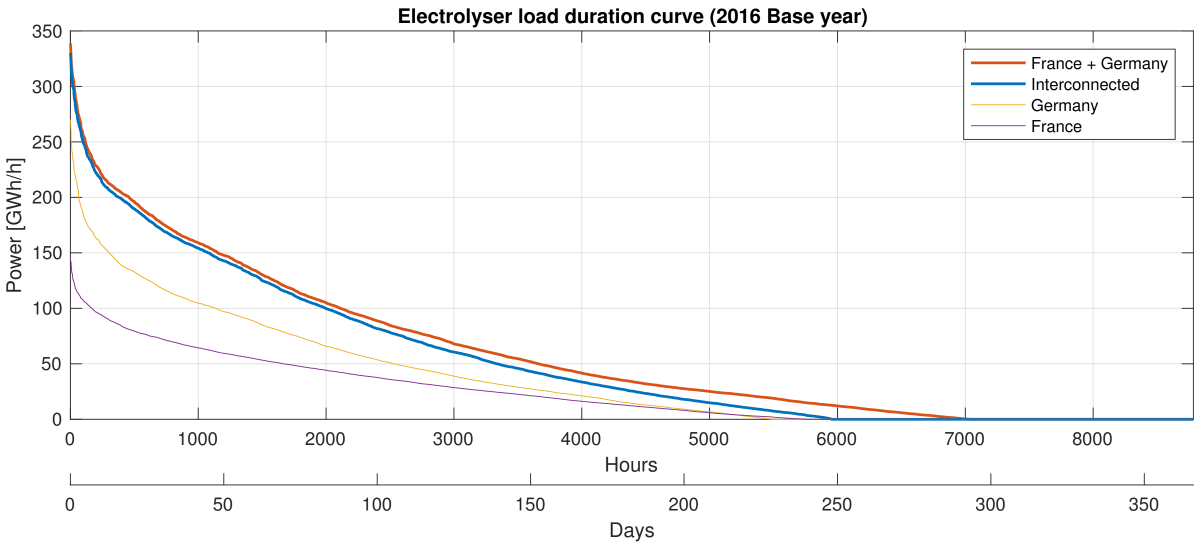


Figure 7.5: Electrolyser load duration curves for the interconnected and autonomous situation, 2016 base year

Installed capacities & Generation

The installed capacities for both countries are shown in figure 7.6. The first 5 columns are the installed capacities in Germany, the others are the installed capacities in France. The black bars represent the installed capacities in the autonomous situation. It can be seen that the required installed capacity slightly drops when the countries are interconnected. The average reduction of installed capacity is 18 GW (1.9%) the average electricity generation is reduced by 27 TWh (1.9%). All results can be seen in table 7.1.

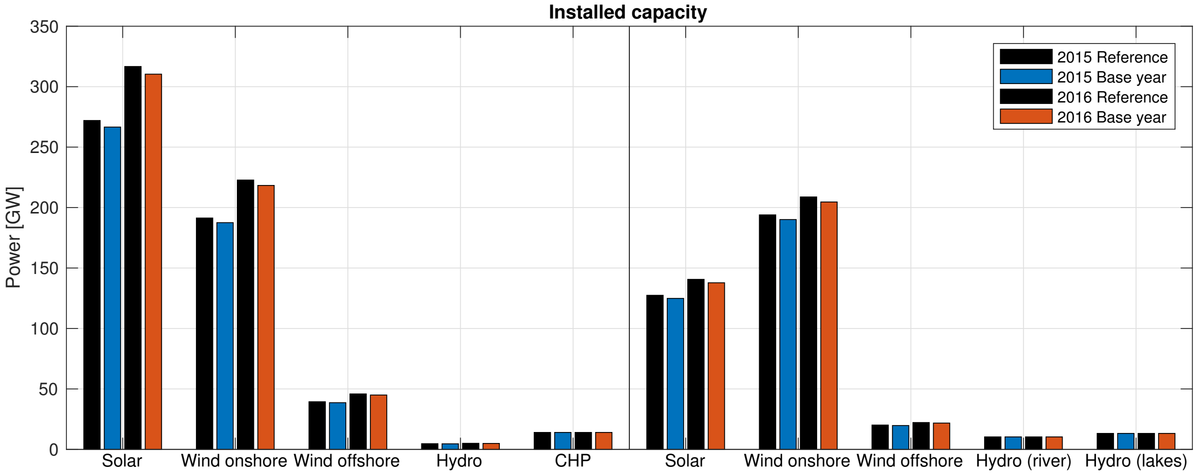


Figure 7.6: Installed capacities in Germany (left) and France (right) in the interconnected situation. References are the autonomous installed capacities.

Storage capacity

For the 2015 base year the annual storage capacity is almost the same in both situations while the annual storage capacity for the 2016 base year is significantly reduced (figure 7.7). There is less storage required in the interconnected situation because France can use the buffers of Germany in the end of January. The purple curve is the storage capacity of France in an autonomous situation. The storage is empty at the end of January while there is still 250 million kg in storage in Germany. This means that in the interconnected situation a lower starting buffer is required.

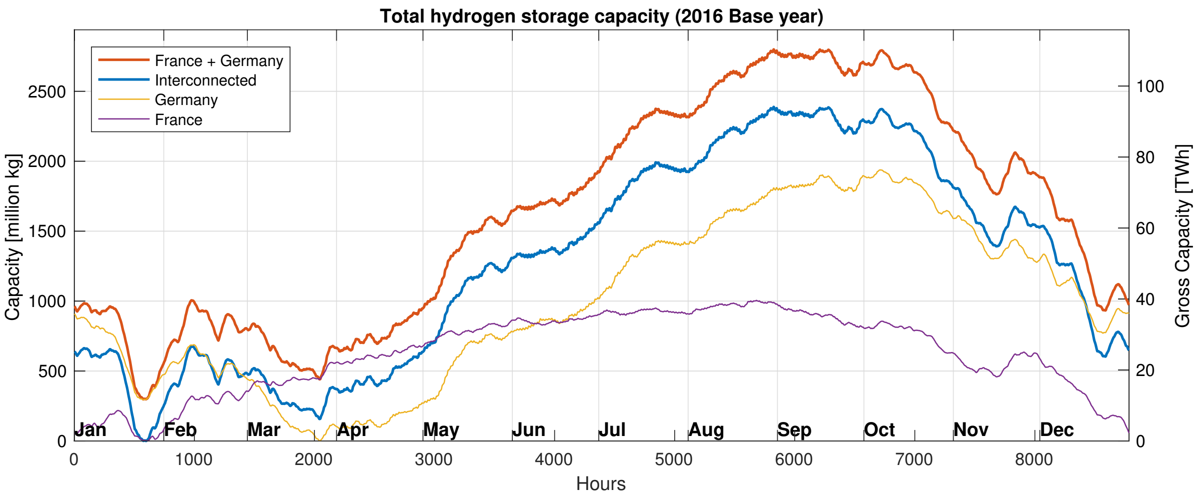


Figure 7.7: Total hydrogen storage capacity for the autonomous and interconnected situations

Overview results & Discussion

An overview of the savings and peak capacity reductions can be seen in table 7.1. The reductions in peak capacities are defined as the peak capacity of Germany plus France minus the peak capacity in the Interconnected situation (This is not the peak demand in the load duration curves!). The results differ strongly per base year. For the 2015 base year the V2G peak demand was only reduced by 2% while it is reduced by almost 14% in the 2016 base year. The same applies to the electrolyser peak demand and the peak storage capacity. It can be concluded that in the 2015 base year the peak deficits occurred at the same time while in the 2016 the peak deficit of one country could be (partly) compensated by the surplus of the other country. The total backup reduction was approximately the same for both base years. The total hydrogen storage capacities for the 2015 base years can be see in figure and 7.8.

Interconnecting France and Germany in a fully renewable energy system can reduce the total backup demand which results in an increased energy efficiency since less energy storage is required. It also slightly reduces the the peak capacity that needs to be available for backup. The required capacity of renewable energy is slightly lower. The most important difference is the reduced electrolyser capacity. The trade off whether countries should have more interconnecting capacity or more electrolysers and storage will most likely depend on the price per kW of electrolysers and the price of reinforcing interconnections.

Table 7.1: Results of Interconnecting Germany & France

Base year		2015	2016	Average
V2G peak capacity reduction	GW	1.26	12.87	7.06
	%	1.27	12.02	6.64
Total reduction V2G demand	TWh	24.35	25.14	24.75
	%	24.95	24.42	24.69
Electrolyser peak capacity reduction	GW	42.94	85.38	64.16
	%	11.07	20.55	15.81
Peak storage capacity reduction	million kg	200.19	554.53	377.36
	%	8.01	18.84	13.43
Electricity generation reduction	TWh	26.50	26.66	26.58
	%	1.88	1.88	1.88
Installed capacity reduction	GW	16.98	19.24	18.11
	%	1.92	1.92	1.92

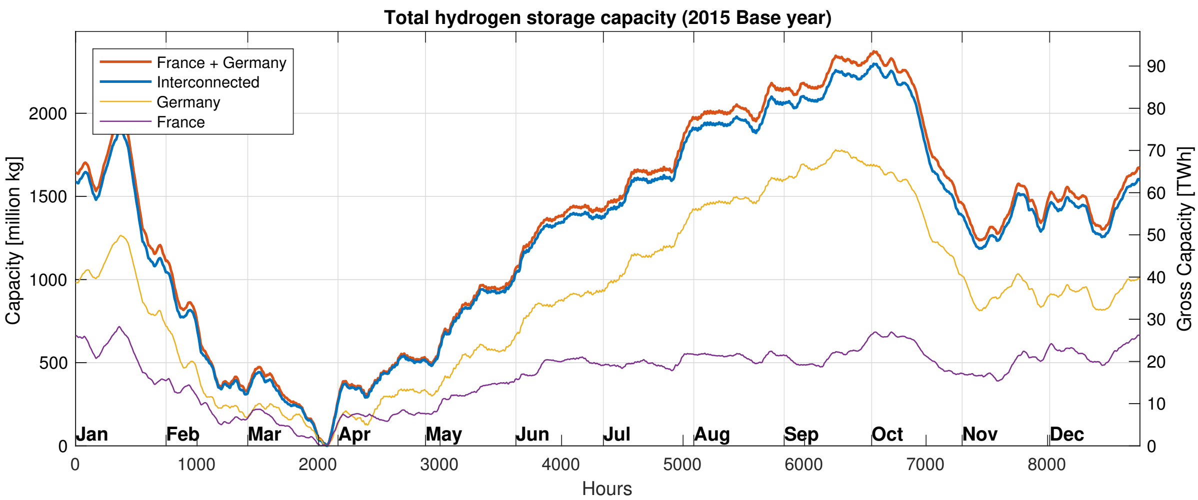


Figure 7.8: Total hydrogen storage capacity for the autonomous and interconnected situations

8 Discussion

The results per country are discussed in sections 5.1-5.6. The differences and similarities between countries are discussed in chapter 6 and the results of a copperplate analyses for interconnecting two countries are discussed in chapter 7. This chapter discusses the consumption profiles, the use of electrolysers and key assumptions in the model.

8.1. Consumption profiles

Classic consumption

The modelling of electricity consumption is divided in a classic consumption and electrification of additional sectors: Battery electric vehicle (BEV) charging and electric heating. In section 3.1 is discussed that demand side measures are getting more important to add system flexibility. Demand side management (DSM) is applied to electric heating but the classic consumption profile is assumed to be constant and is only scaled to future totals. Most likely this profile will change in the future when more DSM is applied to household appliances and industry for example. In the power system as it is today there is more or less fixed consumption pattern. The supply side adepts to the demand. This will most likely change when the penetration of renewables in the generation mix increases and demand needs to match supply. As mentioned earlier in section 3.4 several scenarios such as the future energy scenarios by National Grid [7] and the 100% renewable electricity scenario for France focus on the rollout of smart metering and intra-day management of electric boilers and heat pumps to manage the electricity demand. Therefore it seems unlikely that the classic consumption profile will remain unchanged for the next 30 years. Not all electricity consumption can be shifted so there will most likely be a base load and a part of the consumption that can be shifted.

BEV charging

Based on the work by the Danish Energy Agency (DEA) [4] constant profiles are assumed for BEV charging with only a small daily variation. This could be achieved by smart charging schemes. This is however a pre-defined charging scheme and one could argue if this really a 'smart' charging scheme. Charging of BEVs can have a significant impact on grid load. Figure 8.1 shows three user patterns of connecting BEVs to the chargers in Amsterdam [135]. The first profile is the profile of visitors, the second is the user pattern of people at work in Amsterdam and the third is the pattern of residents. It can be seen that residents tend to connect their charge during peak demands (between 17h and 20h). If those patters are not well managed it can result in huge peak demands on the electricity grid. The charging of BEVs could be modelled in the same way as the demand response heating (DRH). This requires extra insight in the consumption patterns. BEVs should have a minimum capacity (or fully charged) for driving so the load shift of BEVs is limited. BEVs could also be used for V2G but only on the short term. BEVs and V2G could increase the system efficiency when it is used for day-night V2G. In Spain for example, the backup demands during the summer were really low, as could be seen in figure 5.111, and could maybe be supplied by BEVs.

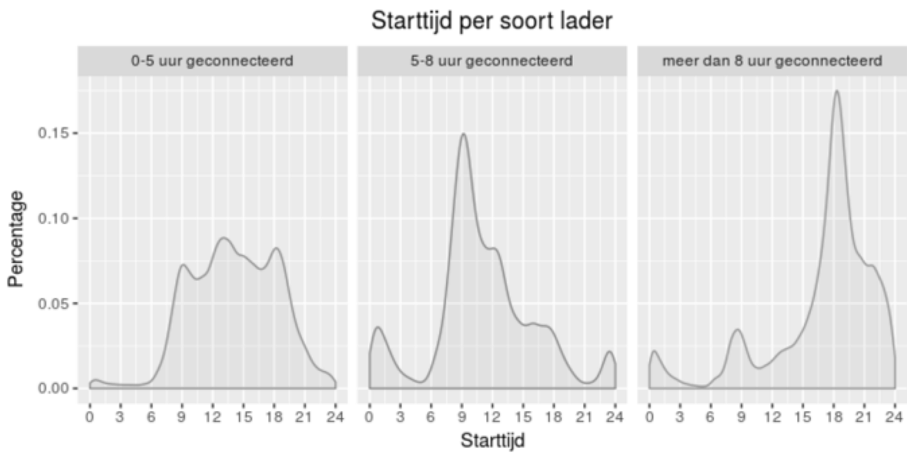


Figure 8.1: Distribution of starting time for charging per charging type in Amsterdam

8.2. Electrolyser consumption

As mentioned several times throughout the report there is no optimisation criteria used for the electrolyser capacity and consumption which results in high electrolyser capacities and low capacity factors. Applying curtailment could significantly reduce the electrolyser peak capacity, increase the capacity factor (and therefore increase profitability) and would slightly increases RE installed capacities. A quick analysis is performed for Germany with 2016 as base year where curtailment is applied to increase the capacity factor from 14% to 25%. The capacity of electrolyser is reduced from 270 GW to 143 GW (-46%) while the RE capacity only increased 15 GW (2%). The load duration curves of the total surplus and electrolysers (EC) can be seen in figure 8.2. 11.9 TWh is unitilised which could be exported for example. This analysis optimises to a minimum capacity factor, another and perhaps economical better solution could be to optimise to a minimum amount of full load hours.

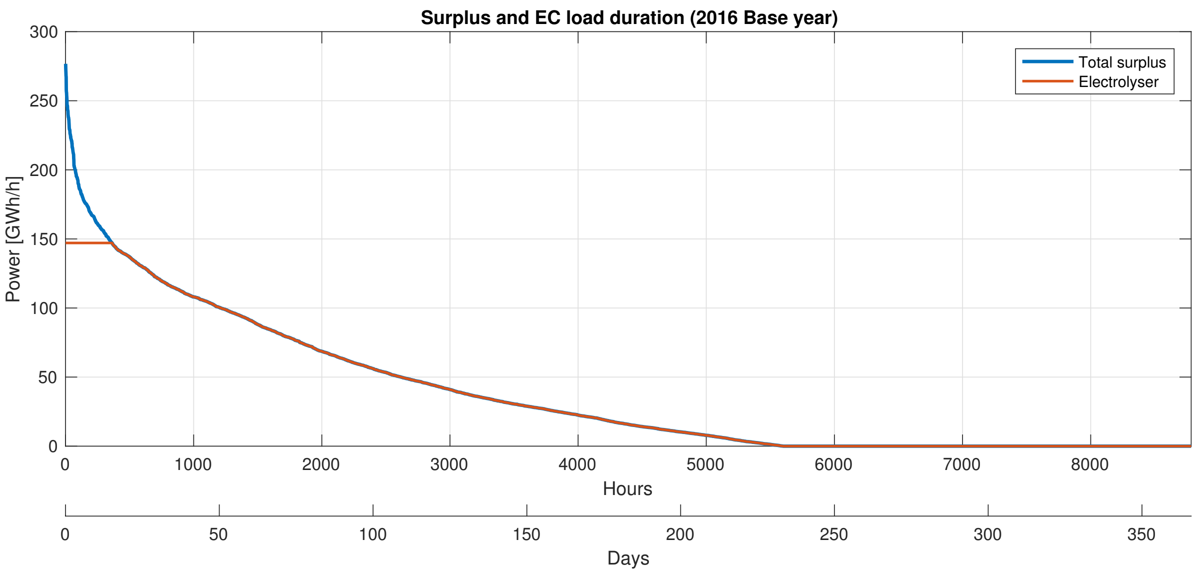


Figure 8.2: Total surplus and electrolyser load duration curves for Germany in 2050 with 2016 as base year

8.3. Key assumptions

Heating demand and HDD

The total heating demand is taken from the reference scenarios while the profiles are constructed with heating degree days. Although every base year has different HDDs the total heating demand is the same for every base year. The heating demand is constant for every base year since there is no relation between HDD and the space heating demand in the reference scenarios.

Another uncertainty is the reference temperature for the calculation of HDD. Only the 100% renewable electricity scenario for France specifies a reference temperature of 16°C which is used. It is debatable whether this is a realistic temperature. For highly efficient renovated buildings the reference temperature can be much lower while large and non-renovated buildings have most likely a higher reference temperature. The amount of building insulation also depends on the geographic location. In Denmark the average temperature is lower which makes it more important to increase insulation while in Spain the temperatures are much higher and insulation is less important. A lower reference temperature shifts the heating demand further from summer to winter which increases the total hydrogen storage capacity and the vehicle-to-grid (V2G) backup demand.

Furthermore it is assumed that the relation between space heating and hot water will remain the same. The heating demand in buildings can be reduced by increased insulation while hot water demands could be reduced by heat recovery systems in showers for example. It requires more insight to see whether this is really the case.

Road transport

The number of vehicles is kept constant because the predictions vary strong per analysed scenario. In the Fraunhofer scenarios [5] is assumed that the number of vehicles decreases while in the Hydrogen National Implementation plan for Denmark [74] is predicted that the number of passenger cars will increase.

The specific energy consumption (SEC) of BEVs and FCEVs is based on vehicles currently on the market, prototypes and long term expectations. For some vehicle categories there are no reliable sources of vehicle consumption, therefore the SEC of BEVs is converted to FCEV SEC with an assumed current tank-to-wheel efficiency. The more FCEVs and BEVs enter the market, the more accurate future SEC can be predicted. Also within vehicle categories there are large differences between vehicles, especially for passenger cars. BEVs currently on the market are rather heavy (Tesla model S and model X) and do not represent the current (or future) passenger car fleet. If possible the consumption of C-segment vehicles is taken (e.g. VW Golf, Ford Focus).

Hydrogen conversion processes

In section 4.5 is assumed that the consumption of compressing and pre-cooling of hydrogen at the fuelling stations is consumed when hydrogen is produced, and not before it is fuelled. The distribution of hydrogen and buffers at hydrogen fuelling stations is not taken into account, and therefore it is chosen to model this consumption at the same time as the production of hydrogen. The consumption of pre-cooling is only 0.15 kWh/kg H_2 (0.3% of the HHV) and the compression from 120 to 800 bar is only 5% of al losses in the process from production to the consumption of hydrogen. Therefore it will most likely not have any effect on the results.

9

Conclusion

The focus of this work is to get insight in how fuel cell electric vehicles (FCEVs) connected to the grid and hydrogen production and storage could balance entire autonomous countries fully powered by renewable energy (RE) sources in a future (2050) scenario. This is achieved by developing a model that simulates the energy systems of Germany, France, Spain, Great Britain, Denmark and Belgium. The energy systems include electricity consumption, road transport and hot water and space heating. Road transport vehicles are battery electric vehicles (BEVs), FCEVs or a combination of both. Electricity and hydrogen are the only energy carriers. Electricity is mainly supplied by solar and wind power. Hot water and space heating is mainly supplied by solar thermal energy and electric heat pumps. Electricity generation and consumption profiles and temperature data of 2014, 2015 and 2016 serve as inputs. The future 100% RE scenarios are based on scenarios published by government agencies, research institutions or transmission system operators (TSOs). Demand response heating (DRH) is applied to all cases and the impact for Germany is analysed. Also interconnecting the electricity grids of Germany and France is investigated.

The simulations show that it is technically feasible to balance autonomous countries with fuel cell electric vehicles connected to the grid, hydrogen production and large scale storage in salt caverns for example. How this is feasible will be explained by answering the research subquestions.

How many FCEVs are required and when are they required?
Only passenger FCEVs were considered for vehicle-to-grid (V2G) and for every country was assumed that 50% of all the passenger cars is a FCEV. The passenger FCEV fleet will from now on be called FCEV fleet. The V2G output of a FCEV is 10kW. 7-14% of the electricity demand is supplied by FCEVs, the rest is directly consumed from the grid. On average 33% of the national FCEV fleet (17% of total passenger car fleet) should be available during a peak shortage. In Belgium 50% of the FCEV fleet should be available during a peak shortage, the highest of all investigated countries. In Spain only 25% of the FCEV fleet should be available, the lowest of the investigated countries.

The average utilisation of the FCEV fleet for backup is 4% for all countries assuming that all passenger FCEV owners are willing to participate in a V2G program. The highest utilisation is almost 8% in Belgium and the lowest utilisation is in Spain with 3% of the FCEV fleet. Recall that cars are parked and unused for more than 95% of the time which means that FCEVs are used equally or less for V2G then they are used for driving. With on average 4% of the passenger FCEV fleet available and 33% during peak shortages positive balancing plants can be replaced by FCEVs connected to the grid. Increasing the V2G power of FCEVs could reduce this demand even further.

In all countries except Denmark the backup demand is the highest during the winter months. Hydrogen is mainly produced with excess solar electricity in the summer which is used for transport and as backup during the night and winter. The electricity mix of Denmark is dominated by wind, roughly 86%, and backup is mainly used to compensate longer periods without wind.

On a daily basis FCEV backup is mainly required at night and in the morning. Again Denmark is the exception where the average backup demand follows the shape of the electricity consumption profile. The backup demand is for most countries slightly higher than the demand at night. It is however unlikely that it will give problems during the morning commute since only 20% of all trips during weekdays is started before 9:00 am. The backup demand also slightly increases at the end of the day but the commute at night is wider distributed than the morning commute.

The simulations show that a higher share of solar electricity in the electricity generation mix results in a lower backup demand during daylight hours. In Spain 53% of the electricity is supplied by solar PV and concentrated solar power (CSP) in the future scenario. Between 10 am and 6 pm 6% of the total backup power is consumed in Spain while in Belgium for example 30% of the electricity is supplied by solar energy and 21% of the total backup power is consumed between 10 am and 6 pm. On average 33% of the total backup in a country is consumed during the day (between 8 am and 6 pm) and 66% during the night.

How much electrolyser capacity is required and when are electrolysers required?
The electrolyser capacity is dependent on two factors. Enough hydrogen needs to be produced for transport and FCEV backup, but electrolysers should also provide negative balancing power which makes it also dependent on the the electricity generation mix. 0.4-0.6 GW of electrolyser capacity is required to balance 1 GW renewable capacity. Curtailment is not applied in the model so all electricity surpluses are consumed by electrolysers which results in high peak capacities. A quick analysis applying curtailment in Germany showed that the electrolyser capacity could be reduced by 45% (-127 GW) while the installed capacity increases only 2% (15 GW). The relation between electrolyser capacity and RE capacity dropped from 0.45 to 0.24. The reduction of electrolyser capacity is higher than the increase in installed renewables which would make the system most likely cheaper. The results depend on the profile of the imbalance and can be different for other countries.

The average usage of electrolysers on a daily basis for all countries shows the opposite effect of FCEV backup. Hydrogen is mainly produced during the day and less at night. On average 71% of the total electrolyser consumption in a country is consumed during the day, and 29% at night. The seasonal effect shows a trend where there is slightly more production of hydrogen in the summer. This shows again an opposite trend of FCEV backup but the seasonal effect of FCEV backup is stronger. Hydrogen is not only produced for backup but also for transport what explains the difference.

How much hydrogen needs to be produced and how much storage capacity is required on a yearly basis?
For all countries between 35% and 42% of the total electricity generation is converted into hydrogen, except for Spain where it is 55%. This is caused by the relatively high hydrogen consumption for transport compared to the other countries. The countries consume on average 60% of the produced hydrogen for road transport, except Spain where it is 84%. The lowest consumption for road transport (50%) and thus the highest consumption for V2G is in Belgium.

Hydrogen can be locally produced at hydrogen fuelling stations to be directly fuelled or electrolysers can be installed near large scale electricity generation or salt cavern sites where hydrogen can be produced and directly stored. Hydrogen fuelling stations need an average dispensing capacity around 3000 kg/day (~600 passenger FCEVs/day) to cover all fuelling demands except peak demands.

A salt cavern storage site with a capacity of 30 million kg of hydrogen has a net storage capacity over 1 TWh. The peak hydrogen storage capacity is strongly dependent on the size of the energy system, varying from less than 100 million kg in Denmark to over 1940 million kg in Germany, which means that in Denmark approximately 4 of these sites are sufficient for large scale storage, while in Germany over 60 of those sites are required. Per TWh of final energy consumption approximately 1-2.5 million kg of hydrogen storage capacity is required. The storage capacity does not seem to be strongly dependent on the energy mix. A large share of solar power can result in a strong seasonal effect where hydrogen needs to be buffered for the winter while a mix with higher shares of (offshore) wind needs buffers to compensate periodes without wind.

The peak storage capacity varies strong per modelled base year. In Germany for example the peak storage capacity varies from 1250 to 1940 million kg of hydrogen. This is caused by the lower capacity factors of solar and wind energy in 2016. It seems that the peak storage capacity is strongly dependent on the weather conditions and therefore extra buffers should always be present.

What is the influence of demand response heating on balancing requirements and storage?
Demand response heating (DRH) adapts the consumption of heat pumps to the nationwide imbalance. With a forecast of the imbalance heat pumps can pre-buffer if for example a shortage is expected later on the day or shift the consumption when an electricity surplus is expected.

Applying DRH in the Germany case reduced the V2G peak demand by 13% (10GW /1 million vehicles) and reduced the total backup demand by 20% (15 TWh). During the summer the demand for hot water was shifted to moments where there is a surplus of solar electricity to smoothen the operation of the electrolysers and reduce backup demands at night. The peak demand of electrolysers was reduced by approximately 6%. Based on these reductions for Germany DRH was applied to all cases.

What is the influence of interconnecting national electricity grids on balancing requirements and storage?
All national electricity grids in Europe are interconnected. A electricity surplus in one country could be consumed by a neighbouring country with an electricity deficit which leads to reduced backup demands and increased utilisation of intermittent RE sources. In this work the electricity grid of Germany, the largest power system in Europe, is combined with the electricity grid of France in a copperplate analysis. Germany and France are modelled as one country, thus with ‘unlimited’ interconnection capacity and with 2015 and 2016 as base year. The annual backup demand is for both years reduced by 25%. The peak backup capacity is reduced by 1-14%. The peak electrolyser capacity was reduced by 11-20%. The peak storage capacity is reduced by 9-17%.

Interconnecting the national electricity grids of France and Germany could result in a significant reduction of total backup demand but does not always lead to significant reductions in V2G peak capacity, electrolyser peak capacity or hydrogen storage capacity. Further research should conclude if the integration is technically feasible and if the interconnection capacities are sufficient.

10 Recommendations

10.1. Electric vehicles & Vehicle-to-grid

In this work is assumed that 50% of all passenger cars is a FCEV and every FCEV could be available for V2G. Before FCEVs could be used for balancing a large scale market introduction of these vehicles should be realised. Accompanied with this market introduction a hydrogen refuelling and grid connection infrastructure should be realised.

The V2G output of FCEVs in the model is limited to 10 kW based on the Hyundai prototype at the Delft University of Technology. The limitation of 10 kW power supply could be increased. If the power output would be doubled (20% of rated fuel cell power) for example, only half of the FCEVs would be required for grid balancing. This requires further research into the heat production of the fuel cell and adjustments to the cooling system when the vehicle is not driving. Besides increasing the V2G power, other vehicle categories could also be used for V2G. Buses are not used at night for example and can be used as a base load for backup during the night.

In this work only FCEVs are considered for V2G. In the future however, the vehicle fleet would probably consist of FCEVs, BEVs and hybrid combinations such as fuel cell range extended electric vehicles (FCREEVs). BEVs or the battery in a FCEV could be used for balancing on the short term of several hours with a higher efficiency than fuel cells. The combination of battery and fuel cell technologies for V2G could increase the overall energy efficiency and adds a significant amount of vehicles to the 'V2G fleet'.

10.2. Demand side management

In section 3.1 was mentioned that besides energy storage and supply side management, flexibility could be added to the energy system with demand side measures (DSM). One demand side measure is already included in the model with demand response heating (DRH). DRH adjusts to the electricity imbalance to reduce the total and peak backup demand. It is modelled in such a way that the backup power is kept constant if the backup demand longer than one hour. It does not take the availability of FCEVs into account during morning commutes, for example. Advanced controlling of demand side management could control heat pumps or the charging of BEVs taking the availability of FCEVs or other backup plants into account.

10.3. Blockchain technology

Besides the large scale market introduction and realisation of fuelling and V2G infrastructure a lot of IT is required to manage balancing power. The same applies to the application of DSM discussed in the previous section. Blockchain technology, known as the technology behind Bitcoin, could be a promising solution for demand and supply side management. Blockchain technology allows consumers and suppliers to connect directly without a third party. Blockchain uses a decentralised database that is open to all the users on the network. Transactions of commodities are checked by all computers connected to the network. Stedin and Energy 21 designed a local energy market model for the Netherlands based on blockchain technology [136]. Small local geographical markets are created with their own balancing. The prices on the local market are lower and the local market is connected with a gateway to the wholesale market. The local market acts as one entity and behaves according the rules of the wholesale market. A schematic overview can be seen in figure 10.1. This system could add flexibility on a low level without significant changes on the wholesale market and can prevent congestion on the grid. This concept shows similarities with the Car as Power Plant microgrid [29] discussed in section 3.1.

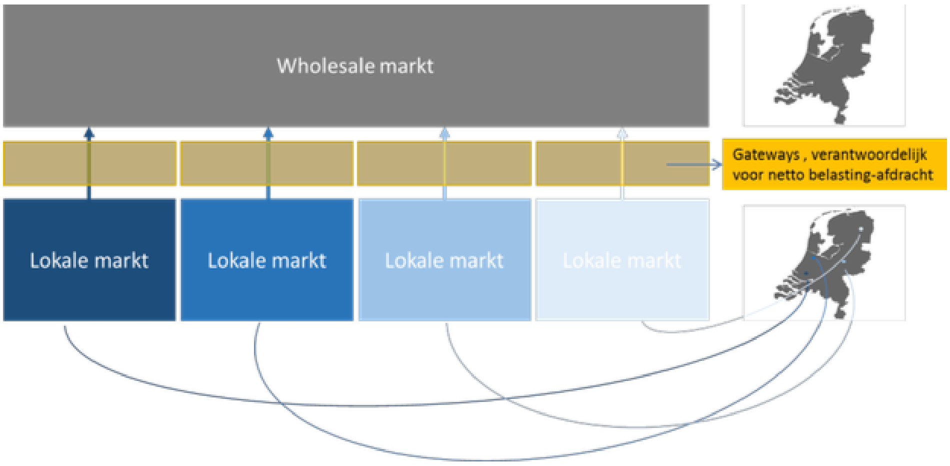


Figure 10.1: Schematic overview of local market model with blockchain technology

10.4. Electrolyser capacity

Economic aspects were not in the scope of this work and curtailment of energy sources was not considered. This resulted in high peak powers of electrolysers and therefore low capacity factors of electrolysers. The total cost of the energy system and the capacity of electrolysers could be lower if the capacity of RE sources is increased and curtailment is applied to optimise the electrolyser capacity factor to a certain minimum. A quick analysis is performed for Germany where the electrolyser capacity could be reduced. Further research is required to see if this is also the case for other countries and if this is also cost effective.

10.5. Hydrogen in industry

Hydrogen can be used as a fuel in fuel cells or it can be burned for process heat. Hydrogen can also be an alternative for coal with the reduction of iron ore in the steel industry [6]. The non-electric energy consumption and additional electrification in industry is not modelled in this work but the consumption of hydrogen could be implemented. Assuming that industry has small buffers for hydrogen the consumption of hydrogen for process heat and reduction of iron ore could be modelled as a base load. Producing additional hydrogen for industry requires a higher installed capacity of RE sources and therefore the electricity deficits will most likely decrease.

A

Hydrogen production & Fuel cells

This appendix elaborates further on section 3.7

A.1. Fuel cells

Fuel cells can convert several fuels into electricity without combustion by means of electrochemical conversion. Because fuel cells don't use combustion this conversion can be done very efficiently since it is not limited by the Carnot efficiency. Fuel cells can run on several fuels such as natural gas, biogas and methanol but hydrogen is used mostly. Because of the highly efficient conversion, no air pollution, fuel flexibility, low maintenance and high reliability fuel cells are applicable in almost every energy sector [59]. There are several types of fuel cells, suitable for different applications and some running on multiple fuels but in this report only fuel cells running on hydrogen will be considered.

The basic operation of a hydrogen fuel cell is very simple and can be explained by the experiment of Sir William Grove (considered as the father of fuel cells) in 1839. In this experiment water is being electrolysed in figure A.1(a) into hydrogen and oxygen by applying an electric current. In figure A.1(b) the power supply is replaced for a ammeter. Now the electrolysing process is reversed, water and oxygen are recombined and produce an electric current.

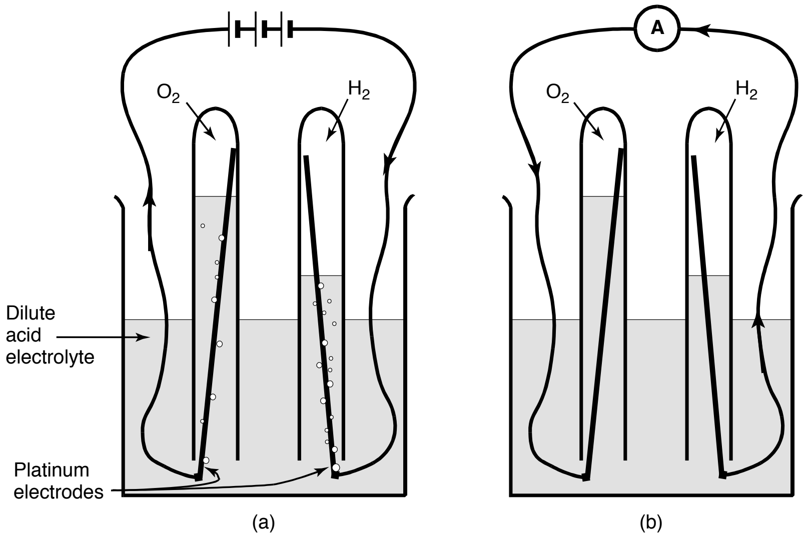


Figure A.1: Experiment by William Grove in 1839 [137]

The fuel cell consists of three main components: a fuel electrode, an oxidant electrode and an electrolyte between the two electrodes. The electrodes are porous materials covered with a layer of catalyst [138]. Hydrogen is delivered with a gas flow stream to the fuel electrode, the anode, where it reacts electrochemically. The electrode is porous so both the electrolyte and the gas can penetrate it [137]. The ions migrate through the electrolyte while the electrons have to travel to the cathode through the external circuit. Since the electrons travel from the anode to the cathode, the cathode is the positive terminal and the anode is the negative terminal. Oxygen is fed to the oxidant electrode (cathode) where it reacts with the ions and the electrons. This is the basic process of a fuel cell and it differs slightly for every fuel cell type. The final reaction always comes down to equation A.1, this basic principle can be seen schematically in figure A.2.

$$2\,H_2 + O_2 \longrightarrow 2\,H_2O \tag{A.1}$$

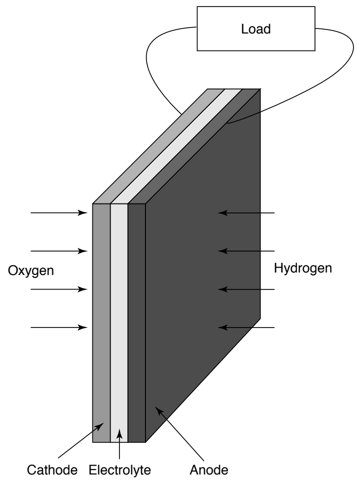


Figure A.2: Basic working principle of a fuel cell [137]

Fuel cells can be divided in two main groups, the low temperature fuel cells and the high temperature fuel cells. Low temperature fuel cells typically operate in a temperature range of 20-200 °C, high temperature fuel cells operate at temperatures typically above 500 °C. The article of O. Sharaf and M. Ohran ‘An overview of fuel cell technology: Fundamentals and applications’ [138] gives a good overview of all the different types of fuel cells and their applications and specifications. The book ‘Fuel Cell Systems Explained’ [137] by J. Larminie and A. Dicks discusses the basic principles, the operation and all the different types of fuel cells very detailed.

A.1.1. Low temperature fuel cells

- Proton Exchange Membrane Fuel Cell (PEMFC)
  The PEMFC or also called the solid polymer fuel cell (SPFC) is one of the first and now the most used type of fuel cell. The first PEM fuel cell is developed by General Electric in the 1960s for NASA to be used in their first manned space vehicles [137]. Since improving the water management in the electrolyte was considered too difficult at that time NASA later switched to alkaline fuel cells in the Apollo vehicles. PEMFCs are mainly being developed for portable applications and combined heat and power (CHP) systems. The first FCEVs on the road are all equipped with a PEMFC and the new space shuttles from NASA are again equipped with PEMFCs [137]. The popularity of the PEMFC is mainly due to the simplicity of the fuel cell. The reactions at the anode and cathode are described by equation A.2 and A.3.

  Anode:

  $$H_2 \longrightarrow 2\,H^+ + 2\,e^- \tag{A.2}$$

  Cathode:

  $$\frac{1}{2}O_2 + 2\,H^+ + 2\,e^- \longrightarrow H_2O \tag{A.3}$$

PEMFCs have the largest range of applications because they are very flexible. What makes them very suitable for portable applications is their fast start up time, they can have frequent starts and stops, have a high power density, have a high efficiency, operate at low temperature, and are easy and safe to handle [59, 137, 138].

Challenges in R&D of PEMFCs are the water transport in the cell, the minimization of precious metals, and the durability [59]. As described before water management in a PEMFC could be a problem. There must be sufficient water content in the polymer electrolyte since the proton conductivity is directly proportional to the water content [137]. Too much water content however can let the electrodes bound to the electrolyte which can block the pores in the electrodes.

- Alkaline Fuel Cell (AFC)
  The concept of the Alkaline fuel cell is also very old, going back to 1902 [137]. The PEMFCs were used in the first manned spacecraft but as mentioned before AFCs were used later by NASA. The use of AFCs in space led extensive R&D of these type of fuel cells in the 1960s and 1970s In that time it could however not compete with other energy conversion systems and therefore research was scaled down. The succes of the PEMFC in the recent years declined the interest in AFCs even more. As already can be inferred from the name, the AFC uses an alkaline solution as electrolyte. The working principle of the AFC is described by the anode and cathode reactions in equation A.4 and A.5.

Anode:

$$2\,H_2 + 4\,OH^- \longrightarrow 4\,H_2O + 4\,e^- \tag{A.4}$$

Cathode:

$$O_2 + 4\,e^- + 2\,H_2O \longrightarrow 4\,OH^- \tag{A.5}$$

The main advantage of an AFC is that the activation overvoltage at the cathode is less compared to other systems which results in a higher operating voltage and a higher electric efficiency. Another advantage is that the system cost are much lower compared to other systems because of the low cost of the electrolyte. The electrodes can de made from non precious metals so no exotic materials are needed [137]. The reason why the interest in AFCs is declining is that this system is extremely sensitive to contaminants especially CO_2. Pure hydrogen and oxygen are required for operation [138]. The system also has a rather low power density compared to other systems and electrolyte management is complex and expensive.

- Phosphoric Acid Fuel Cell (PAFC)
  The PAFC works in a similar way as the PEMFC. The PAFC uses a proton-conduction electrolyte with the reactions at the anode and cathode according to equation A.6 and A.7). Just as with PEMFCs platinum or platinum alloys are used as a catalyst at both the electrodes. As described in the name the electrolyte is a concentrated phosphoric acid which conduct protons [137].

Anode:

$$2\,H_2 \longrightarrow 4\,H^+ + 4\,e^- \tag{A.6}$$

Cathode:

$$O_2 + 4\,e^- + 4\,H^+ \longrightarrow 2\,H_2O \tag{A.7}$$

The technology in a PAFC is in a mature stage and vary reliable. Compared to the PEMFC the water management is rather simple and the system has a high tolerance for contaminants. The PAFC operates at higher temperatures than PEMFCs, they operate between 160 and 220 °C. The fuel cell has a relatively slow start-up time and low power density with a relatively low efficiency [138] which makes them unsuitable for portable applications. Because of the high grade heat and high electrical power output up to 11 MW it makes them very suitable for large scale CHP applications. R&D on PAFCs is mainly focussed on methods to decrease or eliminate anion adsorption on the cathode, lower cost of materials and Balance of Plant (BoP) equipment and minimize the use of precious materials such as platinum [59].

A.1.2. High temperature fuel cells

- Solid Oxide Fuel Cell (SOFC)
  In contrast to the other types the SOFC is a complete solid state device which uses an oxide ion-conducting ceramic material as electrolyte [137]. This design make it much simpler compared to the other types because there is only a solid and gas (hydrogen and oxygen) phase present. There are no issues with electrolyte management and there are no precious catalysts required because of the high operating temperatures. Because of the high temperatures the electrolyte becomes oxygen ion (O^{2-}) conducting. This results in the following reactions at the anode and cathode:

  Anode:

$$H_2 + O^{2-} \longrightarrow H_2O + 2\,e^- \tag{A.8}$$

  Cathode:

$$\frac{1}{2}O_2 + 2\,e^- \longrightarrow O^{2-} \tag{A.9}$$

  SOFCs have the potential to operate as a large scale power plant. The idea is similar to a CCGT but the SOFC replaces the combustion chamber of the gas turbine.

- Molten Carbonate Fuel Cell (MCFC)

  Anode:

$$2\,H_2 + 2\,CO_3{}^{2-} \longrightarrow 2\,H_2O + 2\,CO_2 + 4\,e^- \tag{A.10}$$

  Cathode:

$$O_2 + 2\,CO_2 + 4\,e^- \longrightarrow 2\,CO_3{}^{2-} \tag{A.11}$$

A.1.3. Overview of fuel cell types

Table A.1 adopted from the IEA Hydrogen Roadmap [13] shows an overview of the discussed fuel cell types and their current performance.

Table A.1: Current performance of hydrogen fuel cells. Adopted from the IEA Hydrogen roadmap [13]

Application	Power or capacity	Efficiency *	Initial investment cost	Life time	Maturity
Alkaline FC	Up to 250 kW	~50% (HHV)	USD 200-700/kW	5 000-8 000 hours	Early market
PEMFC stationary	0.5-400 kW	32%-49% (HHV)	USD 3 000-4 000/kW	~60 000 hours	Early market
PEMFC mobile	80-100 kW	Up to 60% (HHV)	USD ~500/kW	<5 000 hours	Early market
SOFC	Up to 200 kW	50%-70% (HHV)	USD 3 000-4 000/kW	Up to 90 000 hours	Demon-stration
PAFC	Up to 11 MW	30%-40% (HHV)	USD 4 000-5 000/kW	30 000-60 000 hours	Mature
MCFC	KW to several MW	More than 60% (HHV)	USD 4 000-6 000/kW	20 000-30 000 hours	Early market

Table A.2: Targets set up by the DOE for 80 kW intergrated transportation fuel cell power systems operating on hydrogen [59]

	Unit	2015 status	2020 targets	Ultimate targets
Peak energy efficiency	%	60	65	70
Power density	W/L	640	650	850
Specific power	W/kg	659	650	850
Cost	$\$/kW_{net}$	53	40	30
Start up time to 50 % power at -20°C	s	20	30	30
Durability for automotive cycle	h	3900	5000	8000

A.2. Hydrogen Production

Production of hydrogen can be done in several ways which can be divided in two categories, production from fossil fuels and production from renewables. These categories can again be divided into several subcategories as can be seen in fig A.3 [139]. Hydrogen production from fossil fuels meets almost the entire hydrogen demand. Up to date 48% of the hydrogen is produced from natural gas, 30% from heavy oils and 18% from coal. One reason for the dominant role of fossil fuels as a source is that the production costs are strongly correlated to the fuel price which are still at favourable levels. The fossil fuel processes are also more developed than the processes where renewable sources are used [139].

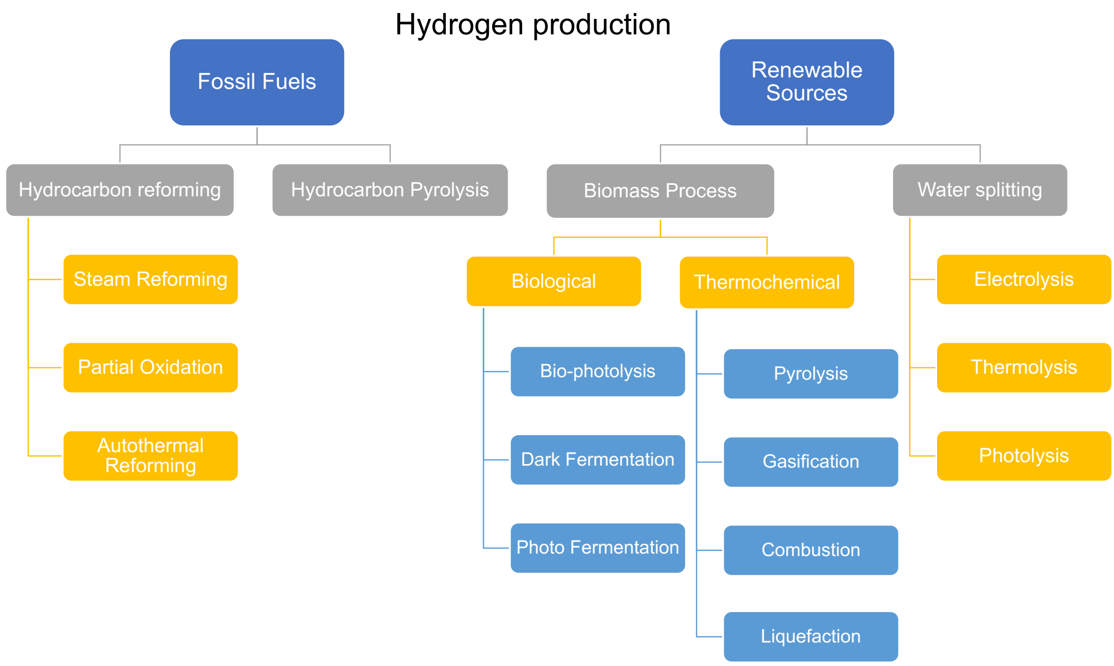


Figure A.3: Overview of hydrogen production methods [139]

A.2.1. Production from fossil fuels

Almost all the produced hydrogen comes from production with fossil fuels as mentioned before. It is however not in the interest of this research to produce hydrogen from fossil fuels so this will only be discussed briefly. A lot of information regarding the production from fossil fuels comes from the work of Nikolaidis and Poullikkas 'A comparative overview of hydrogen production processes' [139] which gives a good overview of all hydrogen production processes. The main and most developed techniques of hydrogen production form fossil fuels are hydrocarbon reforming and hydrocarbon pyrolysis. Hydrocarbon reforming is a process which converts hydrocarbon fuel into hydrogen through some reforming techniques. The other reactant in the process can be steam with the steam methane reforming (SMR) method or oxygen with the partial oxygen (POX) method. When both reactions are combined it is called an autothermal reforming (ATR) method .

The main steps of every reformation process are the reforming or syngas generation, water-gas shift and methanation or gas purification. This proces is described in figure A.4. The first step is the actual reforming process, then the gas mixture is fed to a water-gas shift reactor where CO reacts with steam to form additional H_2, then the mixture passes through a CO_2-removal and mathanation or a pressure swing adsorption (PSA) to seperate H_2 from the other components. The SRM method is the most

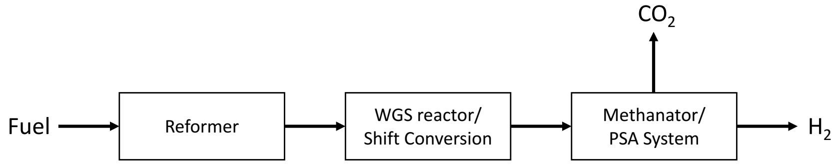


Figure A.4: Hydrocarbon reformation process

common and most developed reforming technique and has a conversion efficiency around 74-85%. It is however the most expansive form of production compared to the other two methods. The POX method is the best method for heavier feedstock such as heavy oils, oil residuals and coal and also explains why the production costs are lower. The investment costs for the ATR method are lower and in case of carbon capture this is the cheapest method to produce hydrogen compared to the SRM and POX method.

Hydrocarbon pyrolysis is a process with hydrocarbons as only reactant and hydrogen and carbon as (by)product [139]. The hydrocarbon undergoes the general decomposition reaction:

$$\mathrm{C_nH_m} \longrightarrow \mathrm{nC} + \frac{1}{2}\mathrm{mH_2} \tag{A.12}$$

Lighter liquid hydrocarbons are processed with thermo-catalytic decomposition and the heavy residual fractions wille be produced with a two-step hydrogasification and methane cracking reaction resulting in the same general decomposition reaction. The energy requirement of this process is much lower then the reforming processes and does not need Water-gas shift of CO_2 removal steps. The production costs are typically 25-30% lower compared to the reforming processes and there is no CO_2 emission. If there would be a marked for the huge amounts of generated carbon the the price of hydrogen could even go down further.

A.2.2. Production from renewable sources

Hydrogen can be produced from renewable sources by the use of biomass or splitting of water. Splitting of water is the most important way of producing hydrogen in the future and for this research. Water is available in abundance and can be converted to hydrogen with electrolysis, thermolysis and photo-electrolysis.

Electrolysis
Electrolysis is the reverse process of a fuel cell. The electrolyser types are the same as the fuel cell types. The reactions at the anode and the cathode are shown below:

- Alkaline water electrolysis
  Anode:

$$2\,\mathrm{OH^-} \longrightarrow \frac{1}{2}\mathrm{O_2} + \mathrm{H_2O} + 2\,\mathrm{e^-} \tag{A.13}$$

  Cathode:

$$2\,\mathrm{H_2O} + 2\,\mathrm{e^-} \longrightarrow \mathrm{H_2} + 2\,\mathrm{OH^-} \tag{A.14}$$

- Proton Exchange Membrane (PEM) electrolysis
  Anode:

$$H_2O \longrightarrow 2\,H^+ + \frac{1}{2}O_2 + 2\,e^- \tag{A.15}$$

  Cathode:

$$2\,H^+ + 2\,e^- \longrightarrow H_2 \tag{A.16}$$

- Solid Oxide electrolysis Anode:

$$H_2O + 2\,e^- \longrightarrow H_2 + O^{2-} \tag{A.17}$$

  Cathode:

$$O^{2-} \longrightarrow \frac{1}{2}O_2 + 2\,e^- \tag{A.18}$$

The thermolysis or thermochemical process heats water to a high temperature until it decomposes into H_2 and O_2. This process is feasible in general for temperatures above 2500°C. Since such temperatures could not be achieved by sustainable heat sources several thermochemical cycles are developed with multiple reactions to lower the temperature and increase the efficiency [139]. The temperature is still rather high but this could be supplied by (concentrated) solar of nuclear energy.

With photolysis water absorbs sunlight at a specific energy rate with the help of photo-catalysts to decompose water in H_2 and O_2 [140]. This method is direct, uses ordinary daylight but has a very low efficiency. With photo-electrolysis photovoltaic cells (PV) converts sunlight directly into daylight into electricity. The electricity is used for water splitting and this process is similar to electrolysis.

Another option is to use biomass as a fuel. Biomass is a organic material, such as wood where sunlight is stored with chemical bonds via photosynthesis. Although there is an emission of CO_2 when using biomass for energy production the same amount of emission is absorbed from the atmosphere during its lifetime [141]. Hydrogen can be obtained from biomass with a thermochemical or biological method.

Thermochemical processing of biomass mainly involves pyrolysis and gasification. Therefore it shows a lot of similarities with the processing of fossil fuels. After pyrolysis there is a reforming stage, a water-gas shift reaction and a pressure swing adsorption stage. The air gasification has a gasifier, gas clean up stage, shift conversion stage and a CO_2 absorption stage.
The use of a biological process to create hydrogen is getting more and more popular because it operates at ambient pressure and temperature and is thus less energy intensive. Another advantage is that waste material could be used as feedstock. The disadvantages compared to thermochemical processing is that the yield is much lower. Bio-photolysis requires that water will be converted to hydrogen and oxygen by bacteria or algae.

B

Types of hydrogen storage

This appendix elaborates further on the different types of hydrogen storage discussed in section 3.8. Currently storage in gaseous form is the most favoured and most developed method, liquid hydrogen is impractical for mobile applications but can have a high energy density, chemical storage needs a lot of development but is getting a more and more viable option. The U.S. Department of Energy (DOE) does extensive research in fuel cell technologies and developed targets for storage of hydrogen in automotive and portable applications. These targets are set up to 'meet customer performance expectations for range, passenger and cargo space, refueling time, and overall vehicle performance' [59]. The main system targets are shown in table B.1 for 2020 and the 'ultimate' long term target. Table B.2 coming from the 'multi-year research, development, and demonstration plan' report [59] of the DOE shows how the current storage systems perform and the year of the publication. It can be seen that Cryo-compressed storage is really close to the 2020 targets high pressure storage also has a good energy density on mass basis. The table confirms that still a lot of development is required for material based storage.

Table B.1: DOE targets for hydrogen storage on a system basis [59]

Target	Units	2020	Ultimate
Useable specific energy	kWh/kg sys	1.8 (5.5 wt. %)	2.5 (7.5 wt. %)
	kWh/L sys	1.3	2.3
System cost	$/kWh net	10	8
Minimum system fill time (5kg)	min	3.3	2.5

Table B.2: Projected performance of storage systems [59]

Hydrogen storage system	kWh/kg sys	kWh/L sys	Cost $/kWh	Year published
700-bar compressed	1.7	0.9	19	2010
350-bar compressed	**1.8**	0.6	16	2010
Cryo-compressed (276bar)	**1.9**	**1.4**	12	2009
Metal Hydride (NaIH4)	0.4	0.4	TBD	2012
Sorbent (AX-21 carbon,200 bar)	1.3	0.8	TBD	2012
Chemical storage	1.3	1.1	TBD	2012

B.1. High pressure storage

The traditional way to store hydrogen is in compressed gaseous (CGH2) form. In cars nowadays hydrogen is only stored as CGH2. Section 3.8.1 elaborates on the use of CGH2 storage for large scale purposes. The Society of Automotive Engineers (SAE) introduced a fuelling standard, the SAE J2601 [50]. This standard is introduced in 2010 in association with big companies in this field such as: Daimler, FCA, GM, Honda, Toyota, Hyundai and BMW. This standard describes the fuelling procedure and the storage in FCEVs. Hydrogen can be stored at 350 or 700 bar, storage at 350 bar is intended for heavy duty vehicles. All storage tanks must meet the ISO 15869 standard which 'specifies the requirements for lightweight refillable fuel tanks intended for the on-board storage of high-pressure compressed gaseous hydrogen or hydrogen blends on land vehicles'. This standard describes 4 types of storage tanks:

- Type I. Metal fuel tanks
- Type II. Hoop-wrapped composite fuel tanks with a metal liner
- Type III. Fully wrapped composite fuel tanks with a metal liner
- Type IV. Fully wrapped composite fuel tanks with no metal liner

Nowadays only the 4th type is used where the tank is fully wrapped with CFRP to guarantee the strength and a long life time and prevent leakages. The tanks are designed to withstand a pressure 2.25 times as much as the nominal working pressure. Hydrogen has a large energy density mass based but the volumetric density is very low compared to other fuels. On a system approach the energy density levels of CGH2 at 700 bar is really competitive for hydrogen storage in automotive applications [142] because less additional equipment is required and compared to liquid storage for example energy losses are much lower. The losses due to compression to 700 bar based on ideal gas compression are about 2.1 kWh/kg which corresponds to a loss of 7% based on the LHV of hydrogen [142]. Figure B.1 shows the required isothermal work for compression of hydrogen based on data from NIST. It can be seen that only a small amount of extra energy ($\sim$ 9%) is needed to compress hydrogen from 350 bar to 700 bar while the density is almost doubled (figure B.4). Storage at 700 bar in personal vehicles can is thus be more volume efficient then storage at 350 bar which also complies to table B.2. According to the DOE, R&D of materials for high pressure storage are the most important to achieve the targets for 2020 [59]. Figure B.2 shows the distribution of costs for a 700 bar Type IV hydrogen storage tank. 75% percent of the costs of a tank is in the composite layer.

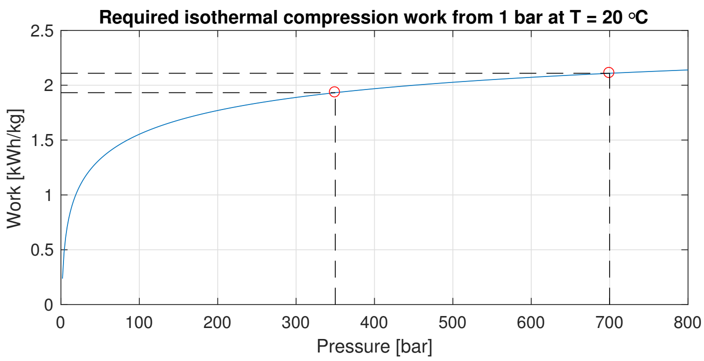


Figure B.1: Required isothermal work for compressing hydrogen

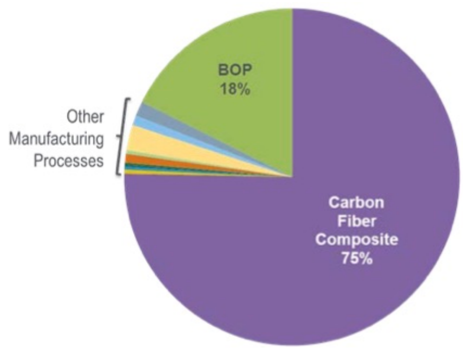


Figure B.2: Distribution of costs for a 700 bar type IV hydrogen storage tank [59]

There are some safety concerns with the use of hydrogen and especially in CGH2 form. For CGH2 there are the risks of explosion of the vessel, gas leakage, hydrogen embrittlement and the temperature rise in the tank during the fast filling process. Hydrogen has deleterious effects on the mechanical properties of metals, especially at high pressure and room temperature. This phenomenon is called Hydrogen Embrittlement (HE). Invasion of hydrogen atoms in the metal promotes local plastic processes and accelerates crack propagation rate in the metal [60]. This increased degradation increases the risk of a sudden failure of a high pressure storage tank. Extensive study have been performed to establish a prediction methodology for the tanks. Since the use of the Type IV tanks where there is no longer a metal liner present this is not so much of an issue anymore. Because CFRP is very expensive to use in the tanks (figure B.2) there is extensive research to find strong enough metals which are resistent to HE, austenitic steel is for example is such a metal [60]. A sudden mechanical failure of the storage tank or a collision can cause a hydrogen leakage. A high pressure jet will of fire will form under certain conditions. Hydrogen spreads in the air very fast, especially compared to petrol which evaporates much slower.

B.2. Liquid storage

Liquid hydrogen (LH2) storage, or cryogenic storage, has the potential to have a higher energy density as storage in gaseous form. Because of this high energy density this method for storage is used in space for years. Hydrogen has a boiling point of -253°C at ambient pressure so storage tanks require sophisticated insulation and therefore the research in this area is focused on high insulating materials and cooling methods [143]. BMW experimented with liquid storage in cars with the BMW Hydrogen 7, a BMW 7 series with a V12 combustion engine running on hydrogen [144]. To keep the hydrogen at this temperature the tank was 'super-isolated' achieving the same insulation effect of 17 metre thick styrofoam according to BMW [145]. The problem with this car was that a half full tank will run empty if the car is parked for approximately 9 days. To control the pressure in the tank, caused by a temperature rise, the car has boil-off management letting hydrogen, converted to water, escape if the pressure is getting too high. Because of this boil off problem and the amount of energy required to create liquid hydrogen it is impractical to use in mobile applications [143]. The losses with cooling and compressing hydrogen to a liquid can result in net losses of about 30-40% of the stored energy.

LH2 is a very light with density of 70 g/litre at -253°C. LH2 evaporates very quickly at room temperature, multiplying its volume by 845 times. Immediately after evaporation the gaseous hydrogen is still very cold and has approximately the same weight as air. For that reason it spreads out almost horizontally.

B.3. Cryo-compressed storage

The concept of Cryo-compressed Hydrogen (CcH2) storage is basically a combination of liquid and high pressure storage. Hydrogen is stored at cryogenic temperatures, which basically means at temperatures lower then -150°C, in a pressure vessel. It can include liquid or cold compressed hydrogen [146]. Cryo-compressed storage has a higher volumetric energy density then CGH2 and LH2 systems, which can also be seen in table B.2, and the boil off losses are much lower compared to LH2 storage [146]. These advantages can lead to lower system costs in terms of $/kWh. Especially compared to LH2 storage this is a good alternative. For long range it can be stored as a liquid, for shorter travel requirements hydrogen can be fueled at ambient temperatures which is in most cases cheaper.

Figure B.3 from a presentation of BMW in 2012 [147] shows the operating range and the density in the storage tank. It can be seen that the operating range is wider than LH2 and allows higher densities than CGH2. In that same presentation BMW also concluded that the problems with the concept car described in section B.2 such as the boil-off losses, the pressure and the complexity made it impractical for automotive applications. The efficiency of the modified V12 engine was also inefficient. Because on these problems they started a prototype in 2011 based on a 5 series GT with a fuel cell and CcH2 storage allowing up to 7.2 kg of hydrogen depending on the storage mode. CcH2 storage shows a huge potential for the automotive industry but is not yet commercially available. A disadvantage of CcH2 storage is that it uses another fuel dispenser than the standardised nozzle used for CGH2. Safety issues are comparable to those of CGH2 and LH2.

B.4. Material based storage

Material based storage is completely different compared to LH2 and CGH2 in terms of storing method. It is not physically stored in a tank but stored in a material to become a solid. One advantage of material based storage compared to physical storage is safety. When hydrogen is stored in a material it is much safer in terms of flammability and the risk of explosion. Table B.2 however shows that this type of storage still needs a lot of research in several fields to become competitive. The work of Rusman and Dahari 'A review on the current progress of metal hydrides material for solid-state hydrogen storage

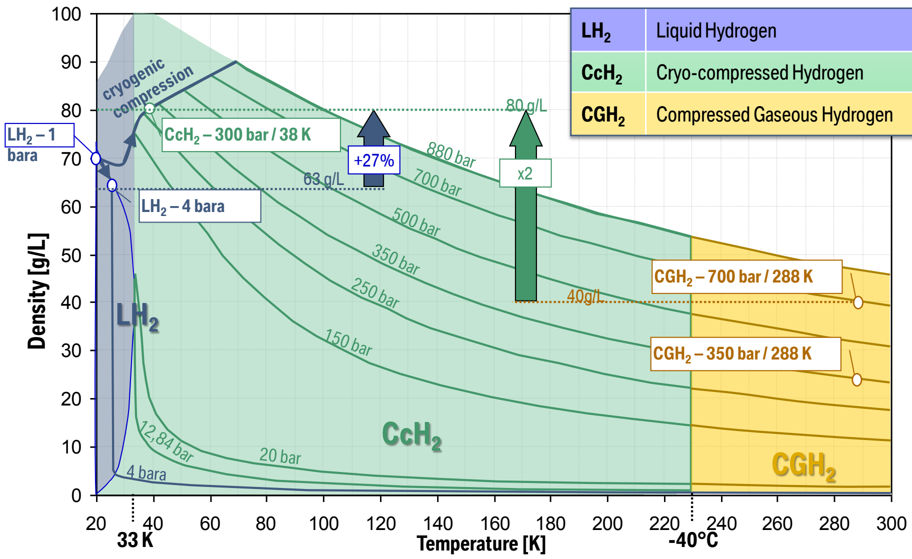


Figure B.3: Hydrogen density and operating range [147]

applications' [148] and the work of Sakintuna et al 'Metal hydride materials for solid hydrogen storage: A review' [149] give a good overview of all the material based storage methods. There are many methods for material based hydrogen storage, only the most developed and most promising methods will be highlighted.

Hydrogen can be combined with many metals to form a metal hydride. These solid hydrides will release hydrogen once they are heated. There a two ways of hydriding a metal, this can be done with direct dissociative chemisorption or electrochemical splitting of water. The first reaction is the reaction in equation B.1, the electrochemical splitting reaction goes according to equation B.2. Metal hydrides can have a higher hydrogen storage density than LH2 or CGH2 storage [148, 149]. Storage can take place under moderate pressures and low temperatures. The disadvantage of this type of storage is the slow kinetics and the high hydrogen desorption temperature of 300°C.[148, 149] Although there is the potential to achieve high densities, the weight of on board systems is still a disadvantage [148]. These disadvantages reduces the efficiency of the system and makes it less applicable for automotive purposes [149]. Much effort is being put into methods to achieve faster reactor kinetics ,lower thermodynamics and lighter materials to make metal hydrides competitive [148, 149].

$$\mathrm{M} + \frac{\mathrm{x}}{2}\mathrm{H_2} \longleftrightarrow \mathrm{MH_x} \tag{B.1}$$

$$\mathrm{M} + \frac{\mathrm{x}}{2}\mathrm{H_2O} + \frac{\mathrm{x}}{2}\mathrm{e^-} \longleftrightarrow \mathrm{MH_x} + \frac{\mathrm{x}}{2}\mathrm{OH^-} \tag{B.2}$$

Nanostructured materials can store hydrogen by physisorption or chemisorption. Hydrogen is adsorbed into the material and remains in physical forms. Carbon nanotubes and Metal Organic Frameworks (MOFs) are examples of such materials. Carbon nanotubes are graphite sheets rolled up in a cylinder shape [148]. Adsorption systems have the possibility to store at low pressure which leads to a safer system. The disadvantage of this type is that the density is rather low compared to other systems [148]. The downside of storage in nanostructured materials is the very low storage density.

Hydrogen can also be chemically stored in so called Liquid Organic Hydrogen Carriers (LOHCs). In such systems hydrogen does not exist in molecular form but is covalently bound with hydrogenation to a liquid substance. [148]. After the dehydrogenation to release hydrogen the carrier can be recharged and is not consumed. The disadvantage of such methods is the high pressure and temperature during hydrogenation and dehydrogenation, which also require different catalysts, and the high cost[148, 150]. In Nature Communications [150] however researchers reported of a promising LOHC system based on 2-aminoethanol (AE) which is inexpensive and abundant. This system uses the same catalyst for hydrogenation and dehydrogenation and regenerates the AE.

B.5. Storage capacity calculations

Nett storage Tesla powerwall
The second generation Tesla Powerwalls, the Powerwall 2, has a net storage capacity of 14 kWh [18]. The self-discharge of Lithium-ion batteries of 5% in the first 24 hours and 4-5% per month [151] is not taken into account.

$$E_{powerwall} = 14kWh \tag{B.3}$$

Nett storage capacity pump storage plant
The Guangzhou Pumped Storage Power Station in China is currently the largest PHS plant in the world with a head of 535m and a volume of 24.08 million m^3 [19]. The nett storage capacity of the plant is defined as:

$$E_{PSP} = m \cdot g \cdot H \cdot \eta_{turbine} = \rho_{water} \cdot V \cdot g \cdot H \cdot \eta_{turbine} \tag{B.4}$$

Where H is the Head, and $\eta_{turbine}$ is the turbine efficiency. This efficiency is assumed to be 90%.

$$E_{PSP} = 1000 \cdot 24.08 \cdot 10^6 \cdot 9.81 \cdot 535 \cdot 0.9 = 113.74 \cdot 10^{12} J = 31.60GWh \tag{B.5}$$

Nett hydrogen storage capacity in a salt cavern
The salt cavern from [15] discussed in section 3.8.2 has a volume of 700,000 m^3 with a working gas capacity around 6 million kg and a cushion gas capacity of 3 million kg. With this mass and volume the density would be approximately 12.8 kg/m^3. According to figure B.4 this maximum pressure would be around 160 bar. The gross energy storage used in .... is defined as:

$$E_{UGS} = m_{workinggas} \cdot HHV_{\mathrm{H_2}} \tag{B.6}$$

$$E_{UGS} = 6 \cdot 10^6 \cdot 141.87 \cdot 10^6 = 354.66GWh \tag{B.7}$$

The nett storage capacity is defined as:

$$E_{UGS} = m_{workinggas} \cdot HHV_{\mathrm{H_2}} \cdot \eta_{FC} \tag{B.8}$$

Where η_{FC} is the efficiency of the fuel cell. In this case assumed to be 55% comparable to current PEM fuel cells. The nett storage capacity is:

$$E_{UGS} = 6 \cdot 10^6 \cdot 141.87 \cdot 10^6 \cdot 0.55 = 702.26 \cdot 10^{12} J = 195.07GWh \tag{B.9}$$

In a mid century scenario the net storage capacity is:

$$E_{UGS} = 6 \cdot 10^6 \cdot 141.87 \cdot 10^6 \cdot 0.60 = 766.10 \cdot 10^{12} J = 212.38GWh \tag{B.10}$$

The storage capacity of this salt cavern is more than 6 times as large as the Guangzhou plant in China and over 13.9 million Tesla Powerwalls are required to have the same nett storage capacity.

Figure B.4 shows the hydrogen density as a function of pressure and temperature. Data is collected from NIST [152].

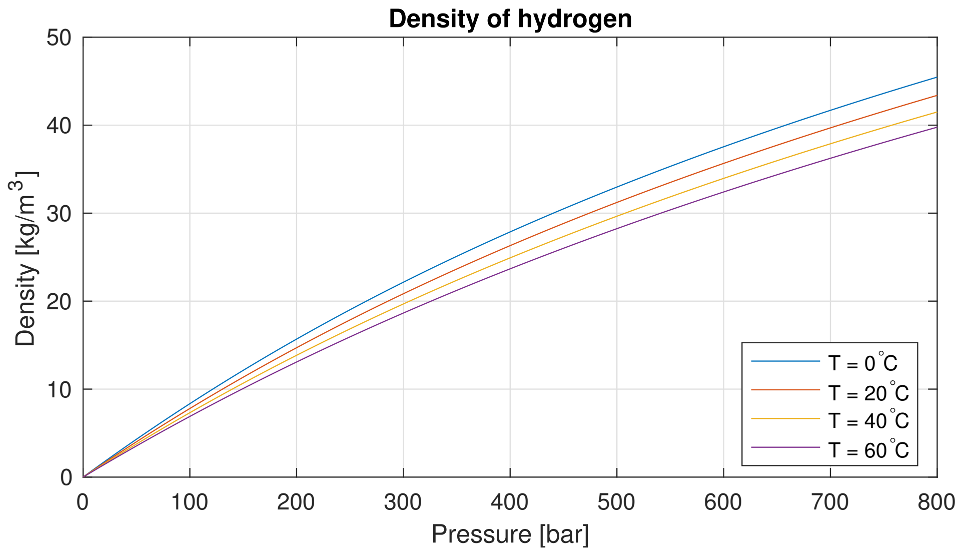


Figure B.4: Density of compressed hydrogen

C
Demand response heating

This appendix elaborates further on the demand response heating described in section 4.2.2. Figure C.1 showed the (normalised) daily constant heating profile based on HDD. This profile is scaled to the annual consumption to determine the average heat load over the day. This appendix describes how the heating demand is demand responding. The modelling of the demand response works in 24 hours, from midnight to midnight.

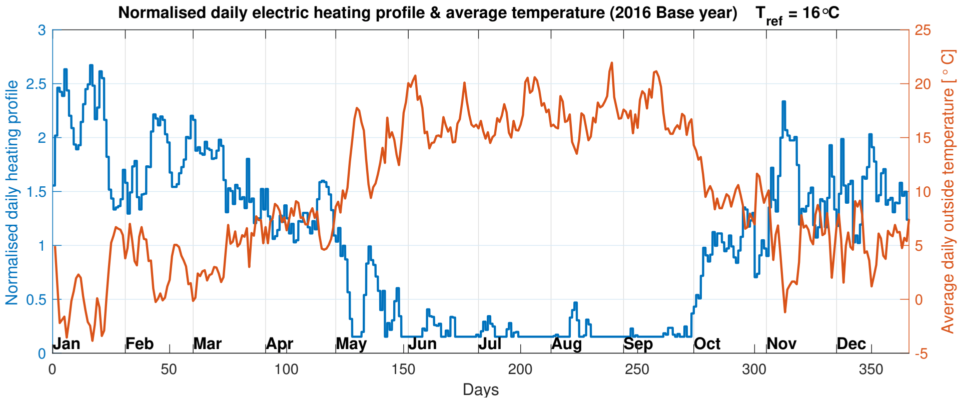


Figure C.1: Normalized daily electric heating profile & average temperature in Denmark (2016 Base year)

The hourly heating demand is calculated in several steps for every day of the year:

Calculate temporary hourly electricity imbalance:
First the hourly temporary imbalance is calculated. This imbalance is calculated according to equation C.1, the sum of all generation minus electricity consumption without electric heating.

$$P_{imbalance} = \Sigma P_{generation} - P_{cl,consumption} - P_{BEV,charging} \tag{C.1}$$

Make hourly profile:
Depending on the temporary imbalance there are two possibilities:

- The imbalance is positive all day
  If the imbalance is positive all day, the profile of the imbalance will be normalised and scaled to the average heating demand over the day. An example is shown below. figure C.2 shows the heat demand with constant heating, figure C.3 shows the imbalance. Figure C.4 shows the normalised imbalance, in figure C.5 the constant heating demand is multiplied with the normalised imbalance.

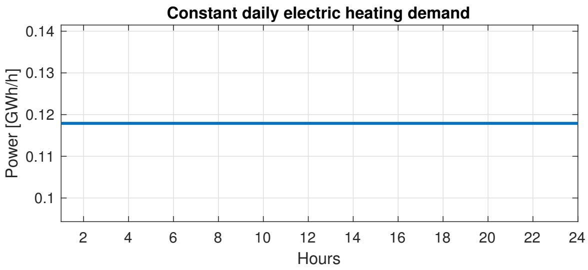


Figure C.2: Constant daily heating demand

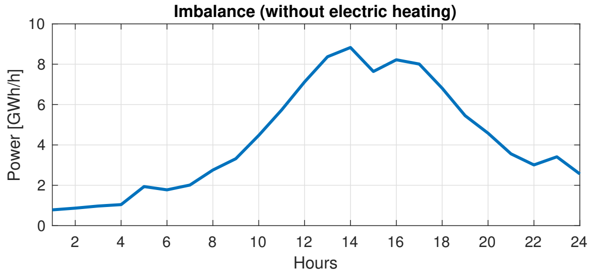


Figure C.3: Imbalance without electric heating

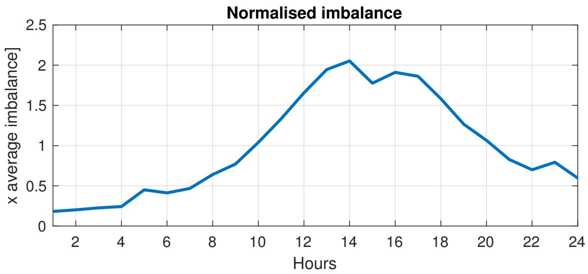


Figure C.4: Normalised imbalance

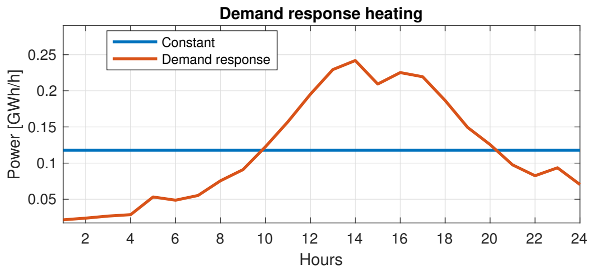


Figure C.5: Constant and DR heating profile

- The imbalance is at least one hour negative.
  If the imbalance is negative there is backup power required. The following method makes sure the amount of backup is as less and constant as possible. This applies for days were the imbalance is only a few hours negative or the entire day negative. The imbalance is corrected by subtracting the mean of imbalance, see figure C.7. The integral of this profile is zero.

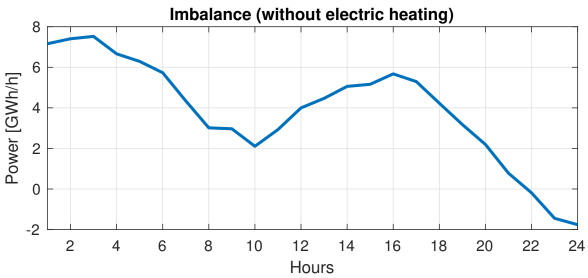


Figure C.6: Imabalance without electric heating

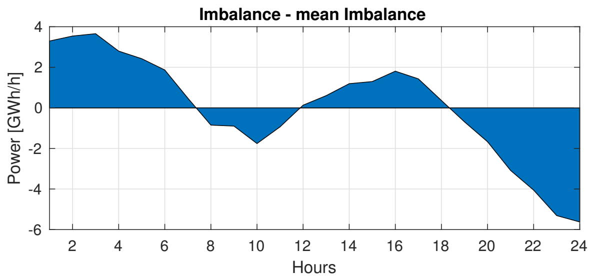


Figure C.7: Imbalance minus the mean of the imabalance

This profile is added to the constant heating profile as described in equation C.2 and which is shown in figure C.8.

$$P_{Heating} = P_{constant} + (P_{imbalance} - \overline{P_{imbalance}}) \tag{C.2}$$

In some cases it is possible that the heating profile is still negative for a few hours of the day. This should be set to zero since a negative heat consumption would mean the heat pumps are generating electricity. The result is the dashed curve in figure C.9. Since removing negative 'consumption' results in a higher consumption the profile needs to be scaled. The result is the orange curve with the same daily consumption as the constant heating profile.

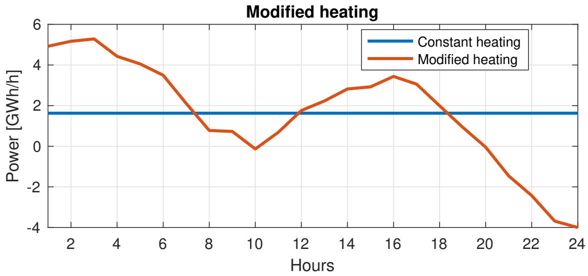


Figure C.8: Modified heating profile

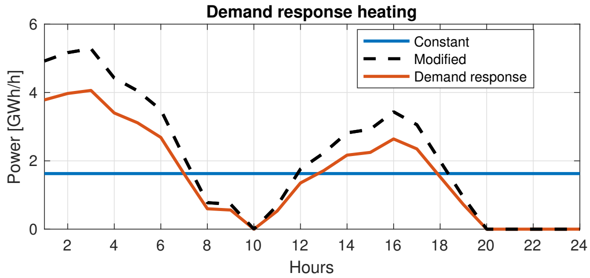


Figure C.9: DRH profile

Correct for maximum installed HP capacity:
The last step is to check if the consumption does not exceed the heat pump installed capacity.

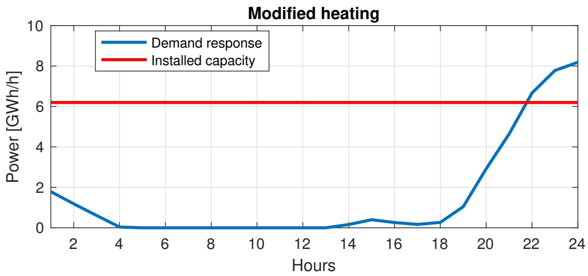


Figure C.10: Modified heating profile & installed capacity

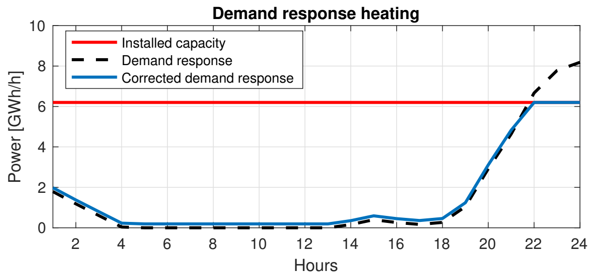


Figure C.11: Corrected DRH profile

D
Maps of weather stations

This appendix includes maps with the approximate location of all the used weather stations per country used for temperature data [72]. All maps are taken from Apple Maps.

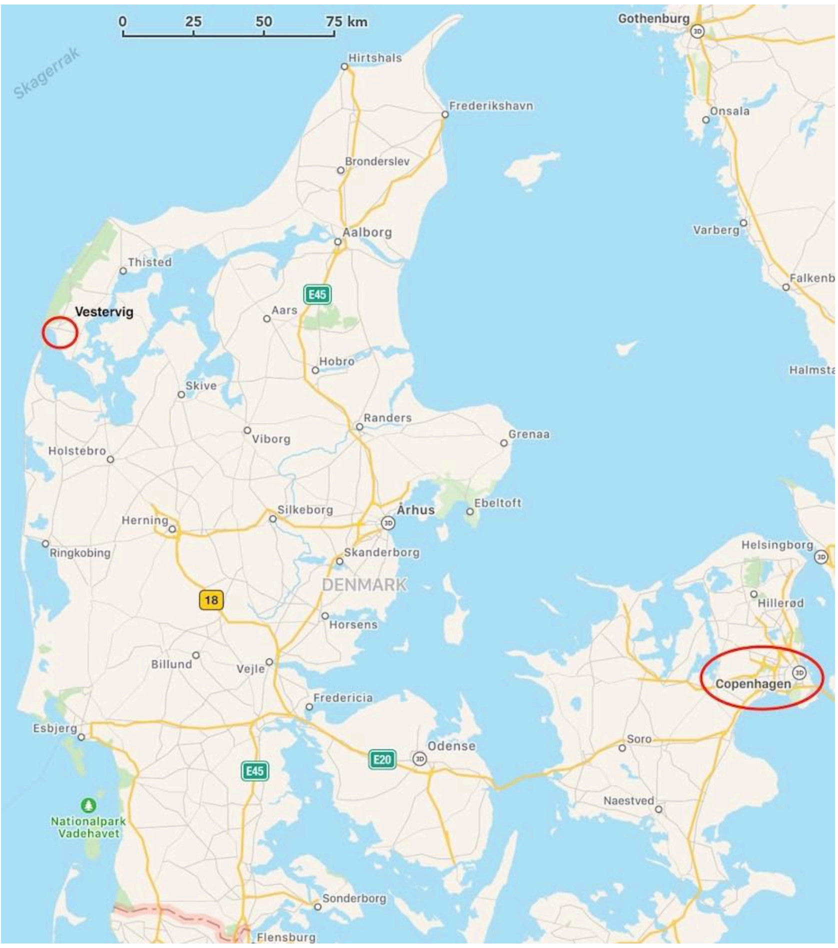


Figure D.1: Map of weather stations in Denmark used in the model

In Denmark unfortunately only 2 weather stations can be used. There are more stations available but two of them are on the small island Bornholm 150 kilometers to the east of Denmark where only 60.000 people live which is less than 1% of the population. Other stations are also located in Copenhagen or

Vestervig.

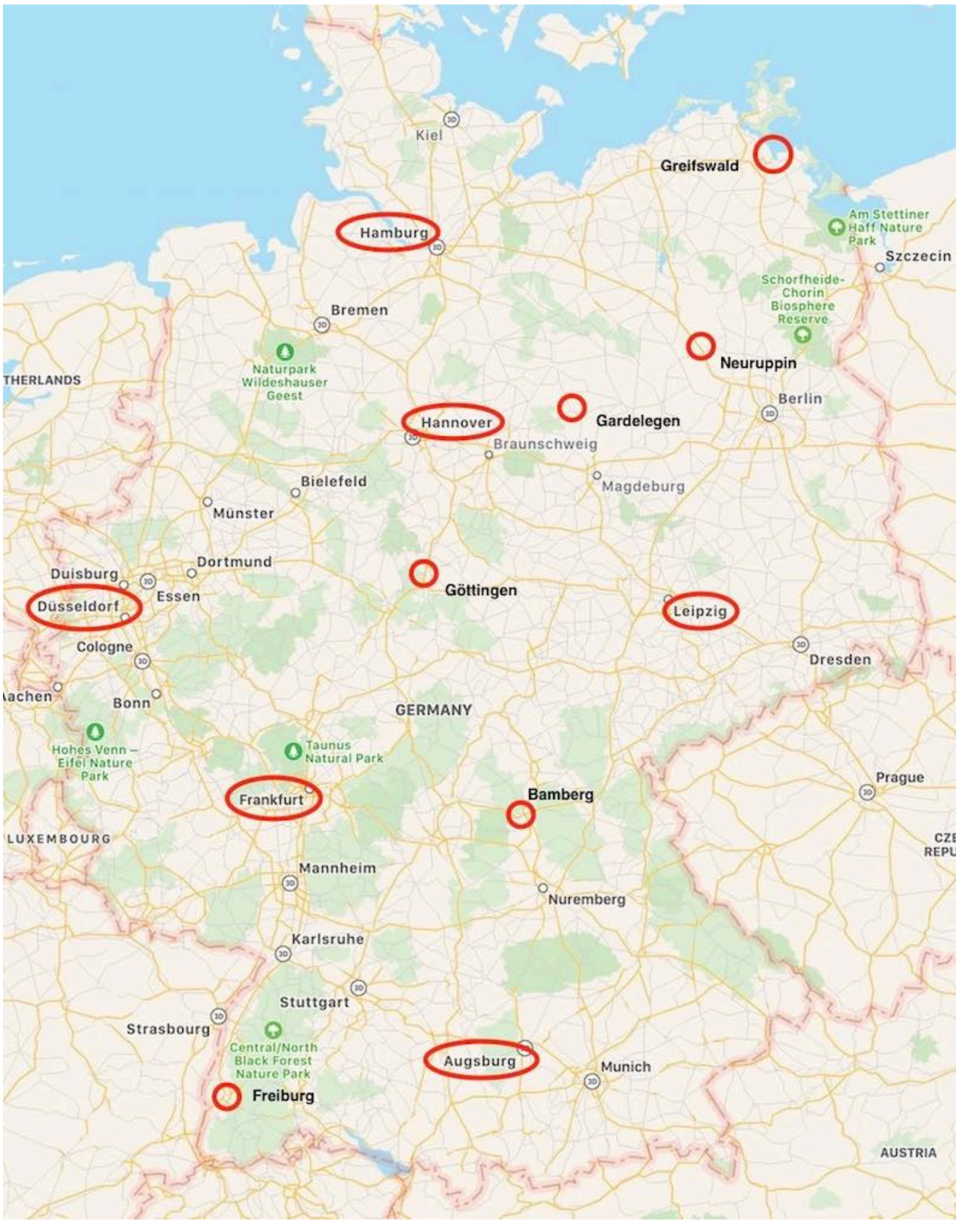


Figure D.2: Map of weather stations in Germany used in the model

Figure D.3: Map of weather stations in France used in the model

Figure D.4: Map of weather stations in Spain used in the model

The ECA&D has only data available of one weather station in Belgium [72]. It is therefore decided to use airport weather for Belgium collected from Weather Underground [73].

Figure D.5: Map of airport weather stations in Belgiums used in the model

E

Inputs, results & additional data Denmark

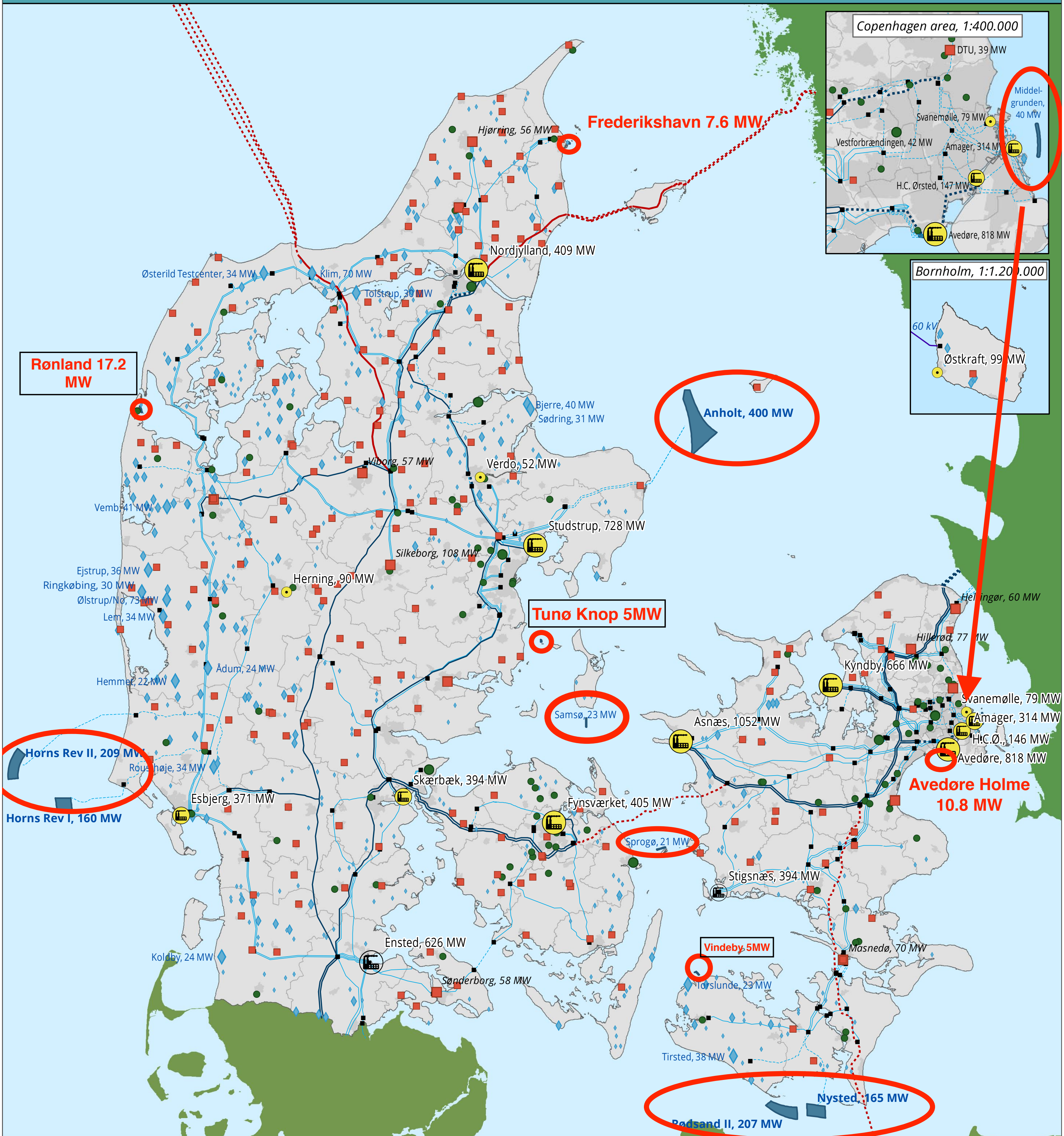
Table E.1 shows the heat supply in the DEA hydrogen scenario. The heat demand and installed capacity for heat pumps is based on this table determined in section 5.1.3.

Table E.1: Heat supply in the hydrogen scenario.

	MW	full load hours	TWh	% total heating
Individual heating				
Air heat pumps	1000	1099	1.10	2.87%
Ground heat pumps	2500	6072	15.18	39.63%
Biogas	3500	8	0.03	0.07%
Solar thermal			1.39	3.63%
Total			17.70	46.20%
Central district heating				
Waste	1000	8115	8.12	21.18%
Heat pumps	500	3304	1.65	4.31%
Geothermal	100	4567	0.46	1.19%
Stray boilers	2000	341	0.68	1.78%
Solar thermal			0.56	1.45%
Total			11.46	29.92%
Decentral district heating				
Gas	600	1828	1.10	2.86%
Heat pumps	2000	2933	5.87	15.31%
Geothermal	100	7762	0.78	2.03%
Stray boilers	1800	12	0.02	0.06%
Solar thermal			1.39	3.63%
Total			9.15	23.88%
Total			38.31	100.00%

The map by the DEA on the next page shows all electricity production plants in Denmark for 2016. Offshore wind parks are highlighted in red.

Power Production and Transmission in Denmark



Legend

Central plants (capacity)
- 20 - 100 MW
- 100 - 400 MW
- 400 - 1000 MW
- Shut down

Decentralized plants (cap.)
- 1 - 20 MW
- 20 MW +

Local and commercial (cap.)
- 1 - 20 MW
- 20 MW +

Onshore wind farms (cap.)
- 2 - 5 MW
- 5 - 20 MW
- 20 MW +

- Offshore wind farms
- Substations
- Power lines, direct current
- Cable, direct current
- Power lines, 400 kV
- Cables, 400 kV
- Power lines, 132/150/220 kV
- Cables, 132/150 kV

Kilometers
Scale 1:1.200.000
ETRS 1989 UTM 32 N

Danish Energy Agency

E.1. Normalised generation & consumption profiles

E.1.1. Solar PV electricity generation

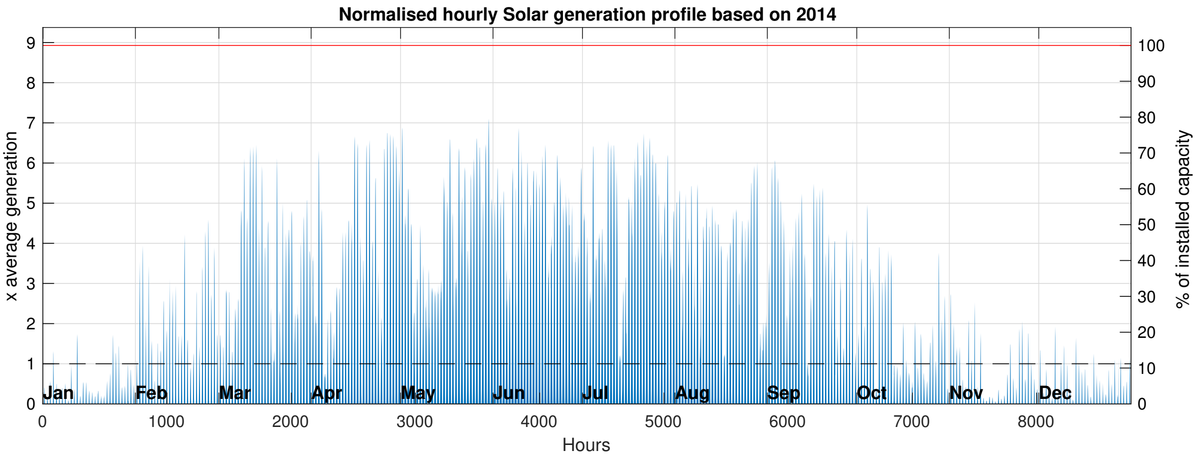


Figure E.1: Normalised hourly Solar electricity generation profile Denmark, 2014 base year

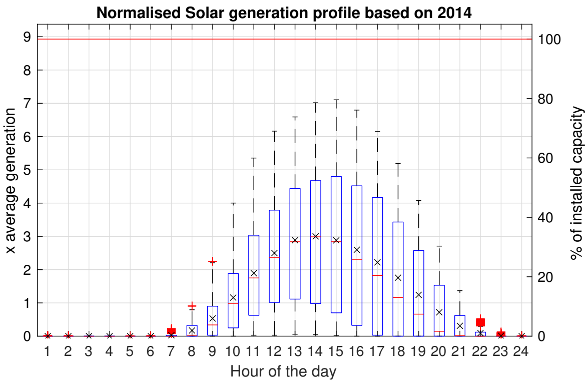


Figure E.2: Hourly boxplot normalised Solar electricity generation profile Denmark, 2014 base year

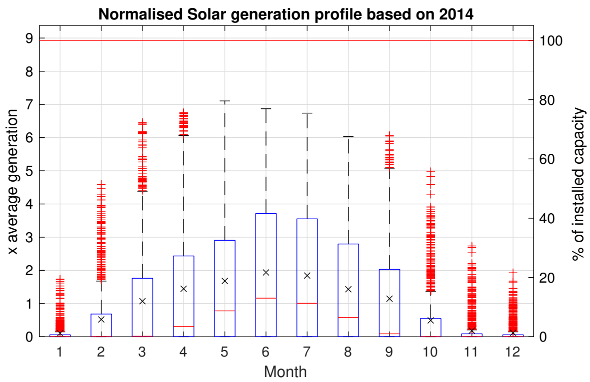


Figure E.3: Monthly boxplot normalised Solar electricity generation profile Denmark, 2014 base year

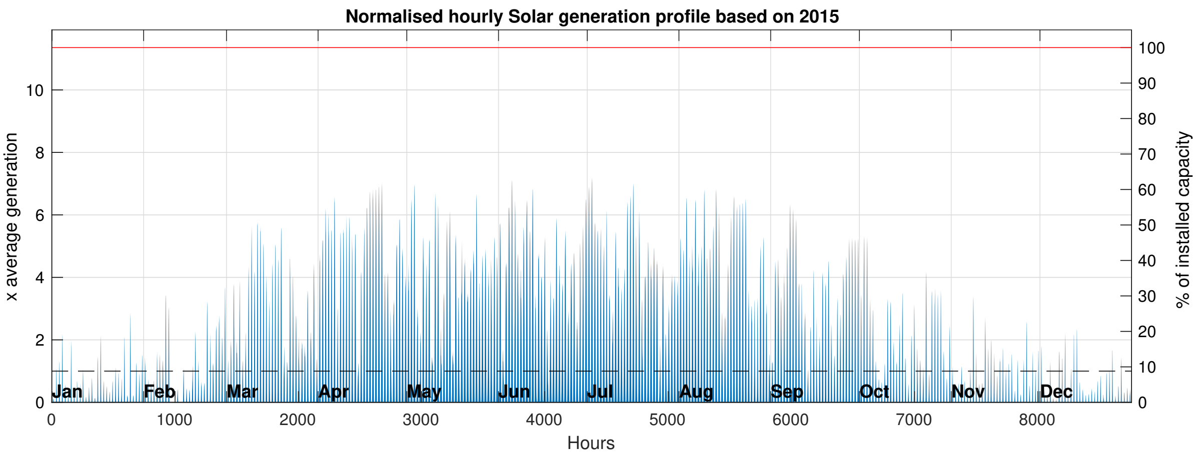


Figure E.4: Normalised hourly Solar electricity generation profile Denmark, 2015 base year

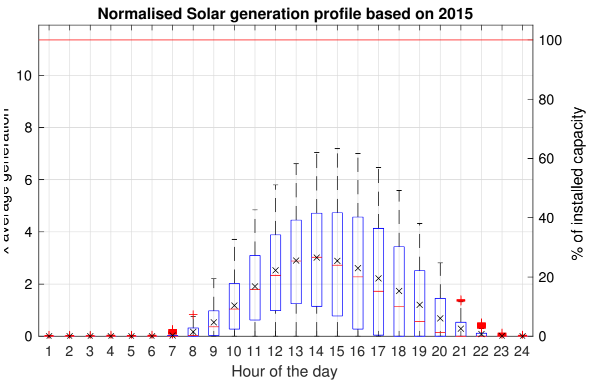


Figure E.5: Hourly boxplot normalised Solar electricity generation profile Denmark, 2015 base year

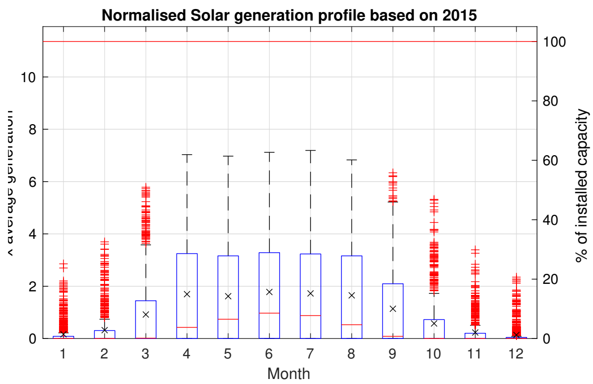


Figure E.6: Monthly boxplot normalised Solar electricity generation profile Denmark, 2015 base year

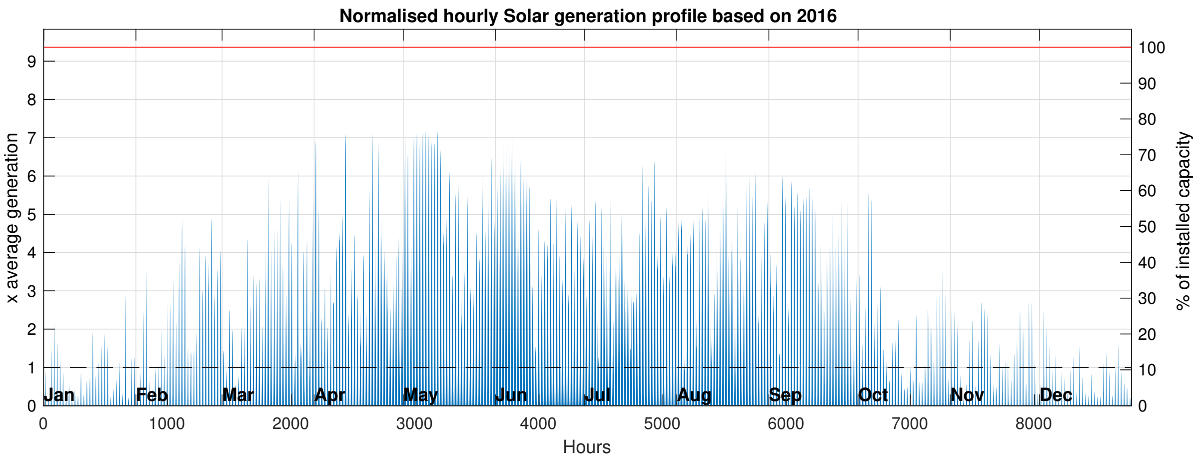


Figure E.7: Normalised hourly Solar electricity generation profile Denmark, 2016 base year

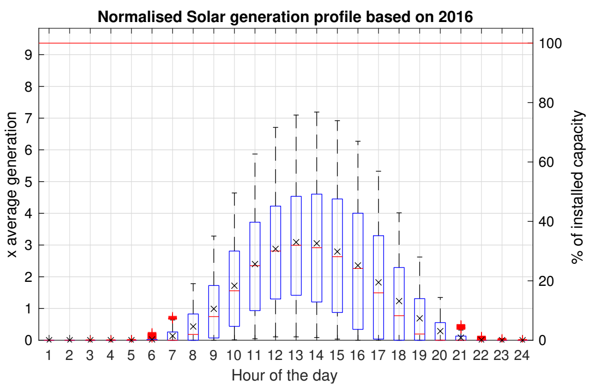


Figure E.8: Hourly boxplot normalised Solar electricity generation profile Denmark, 2016 base year

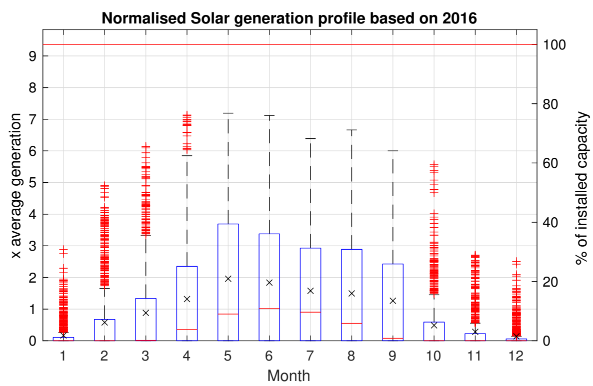


Figure E.9: Monthly boxplot normalised Solar electricity generation profile Denmark, 2016 base year

E.1.2. Onshore wind electricity generation

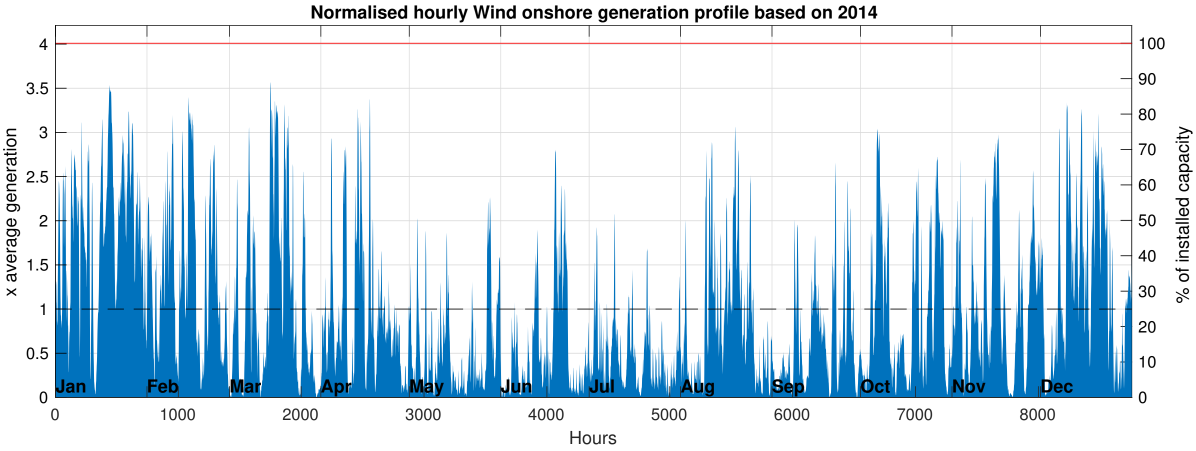


Figure E.10: Normalised hourly onshore wind electricity generation profile Denmark, 2014 base year

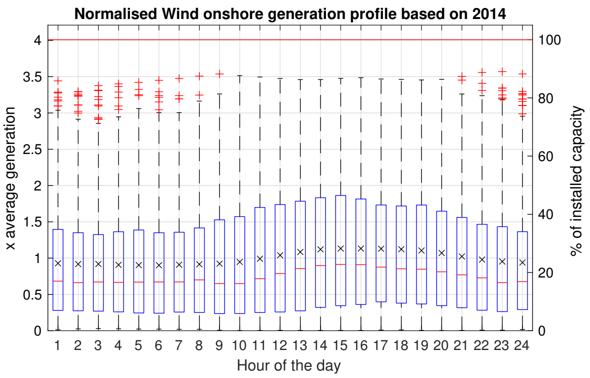


Figure E.11: Hourly boxplot normalised onshore wind electricity generation profile Denmark, 2014 base year

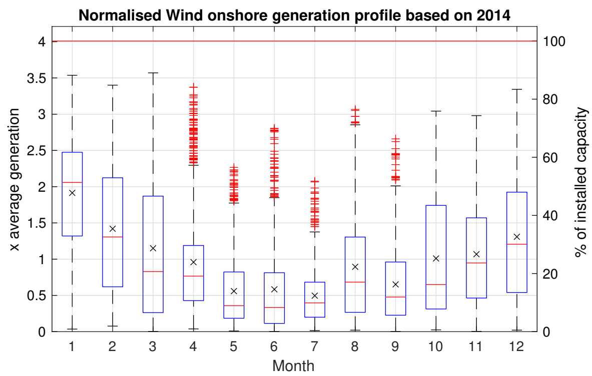


Figure E.12: Monthly boxplot normalised onshore wind electricity generation profile Denmark, 2014 base year

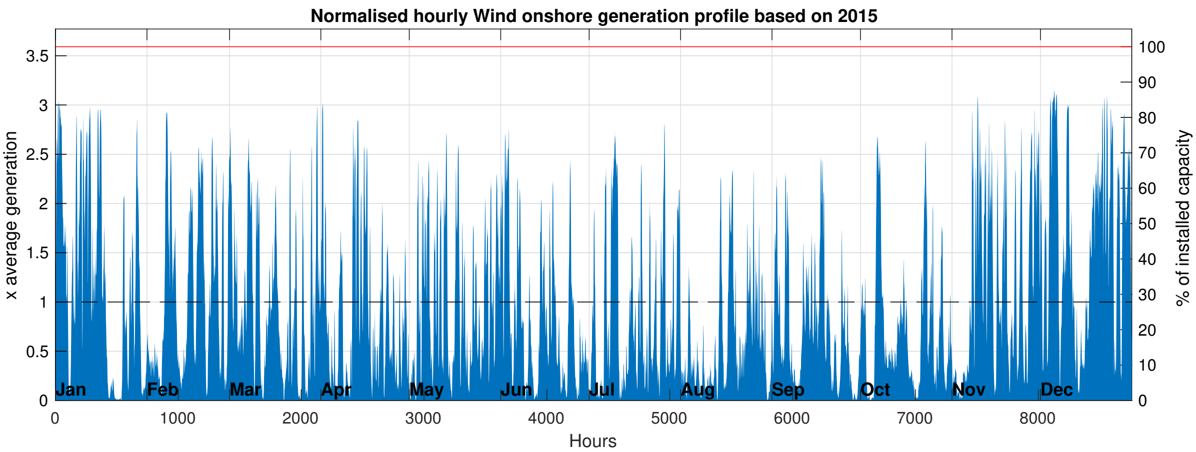


Figure E.13: Normalised hourly onshore wind electricity generation profile Denmark, 2015 base year

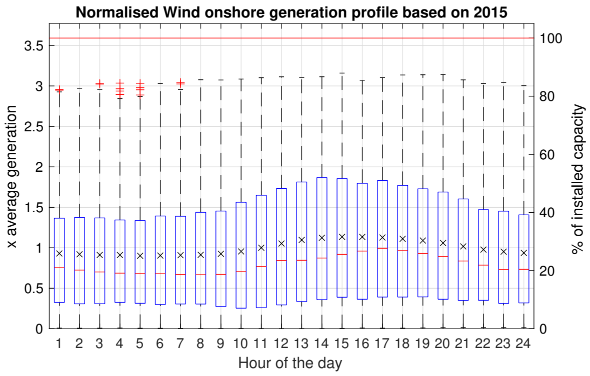


Figure E.14: Hourly boxplot normalised onshore wind electricity generation profile Denmark, 2015 base year

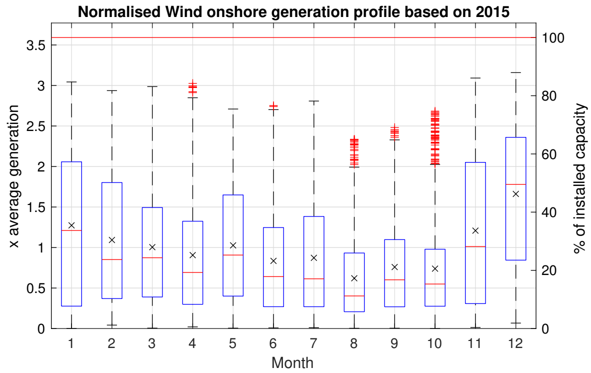


Figure E.15: Monthly boxplot normalised onshore wind electricity generation profile Denmark, 2015 base year

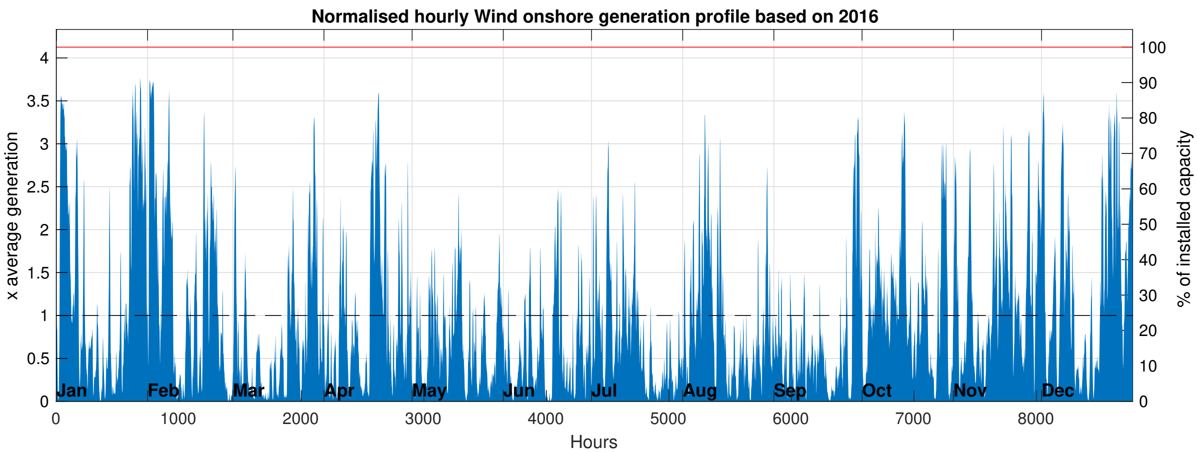


Figure E.16: Normalised hourly onshore wind electricity generation profile Denmark, 2016 base year

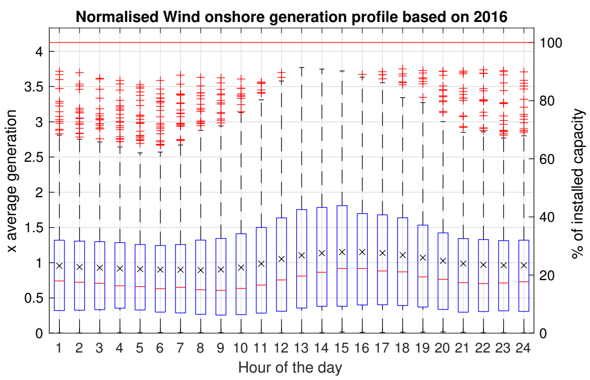


Figure E.17: Hourly boxplot normalised onshore wind electricity generation profile Denmark, 2016 base year

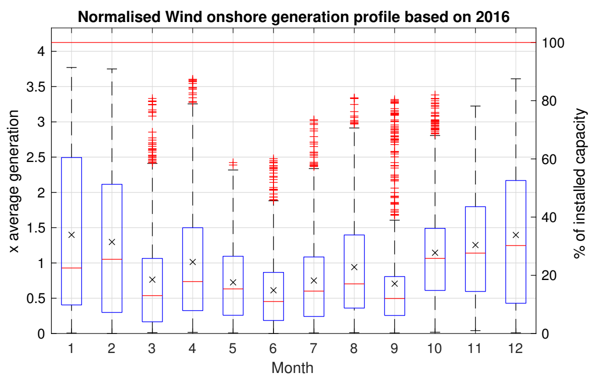


Figure E.18: Monthly boxplot normalised onshore wind electricity generation profile Denmark, 2016 base year

E.1.3. Offshore wind electricity generation

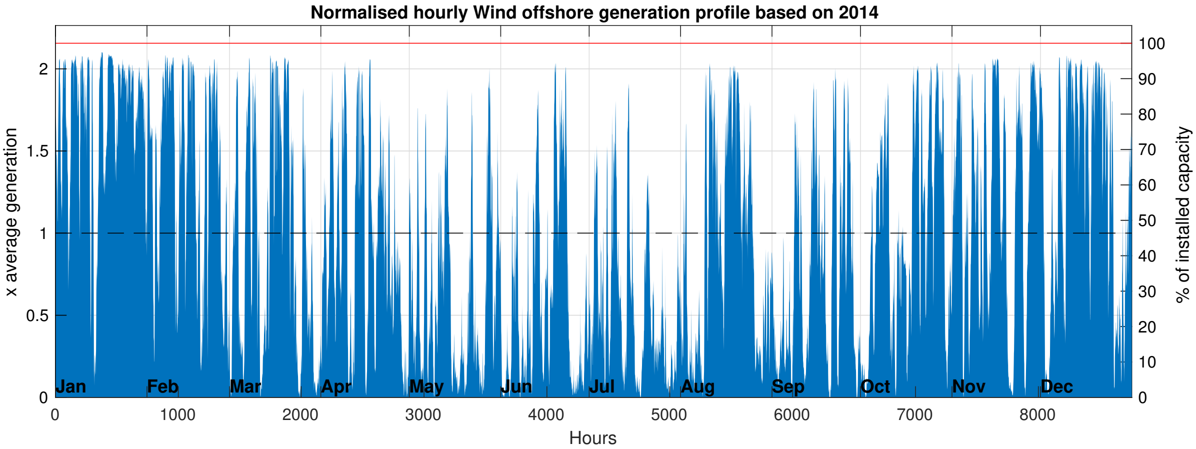


Figure E.19: Normalised hourly offshore wind electricity generation profile Denmark, 2014 base year

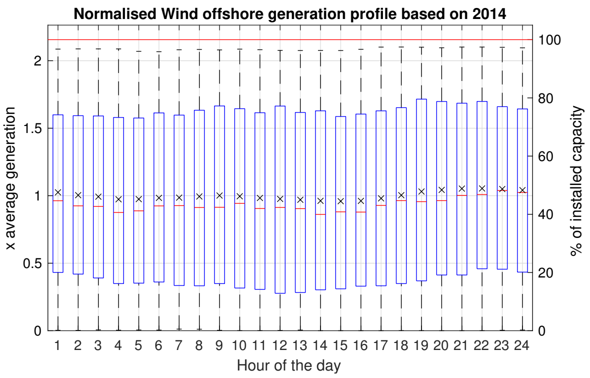


Figure E.20: Hourly boxplot normalised offshore wind electricity generation profile Denmark, 2014 base year

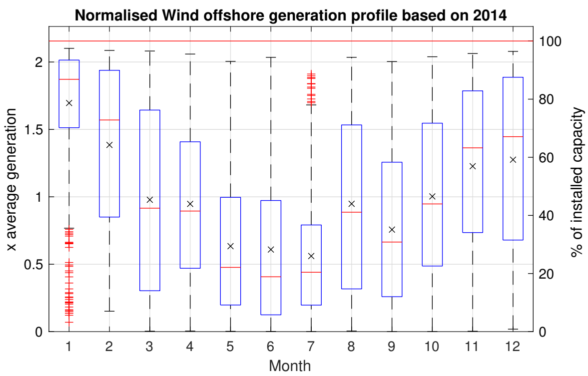


Figure E.21: Monthly boxplot normalised offshore wind electricity generation profile Denmark, 2014 base year

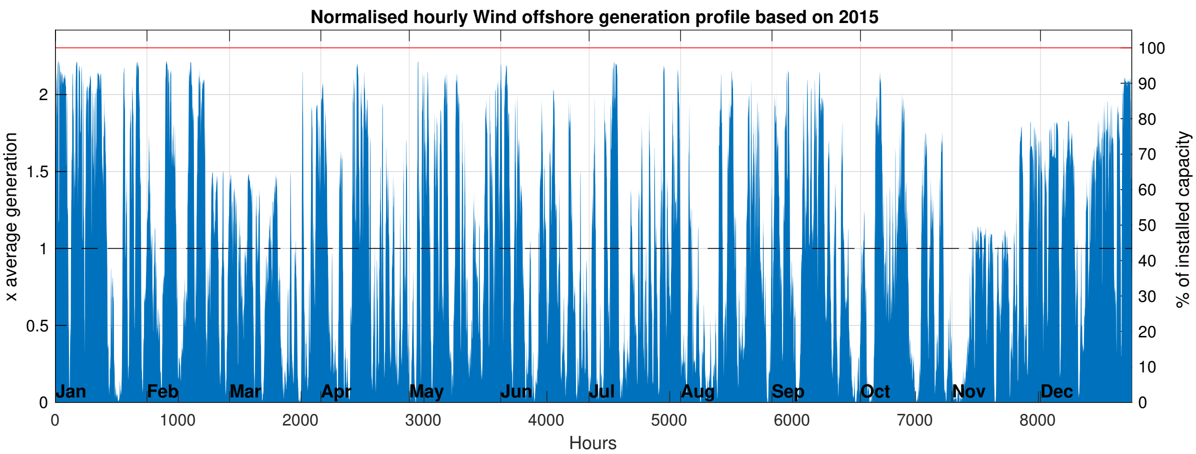


Figure E.22: Normalised hourly offshore wind electricity generation profile Denmark, 2015 base year

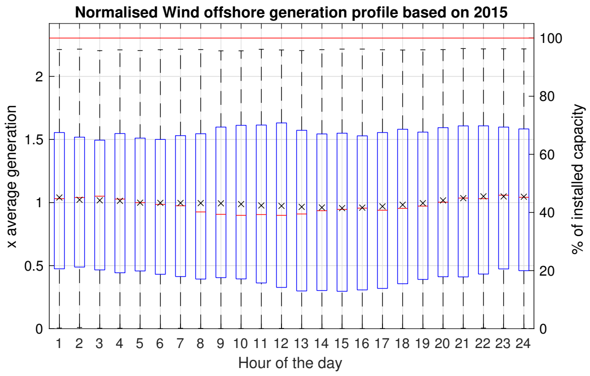


Figure E.23: Hourly boxplot normalised offshore wind electricity generation profile Denmark, 2015 base year

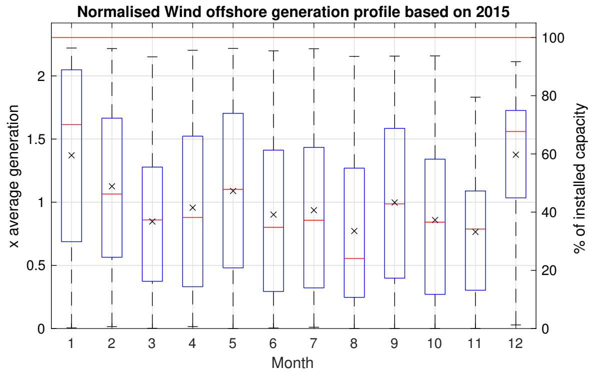


Figure E.24: Monthly boxplot normalised offshore wind electricity generation profile Denmark, 2015 base year

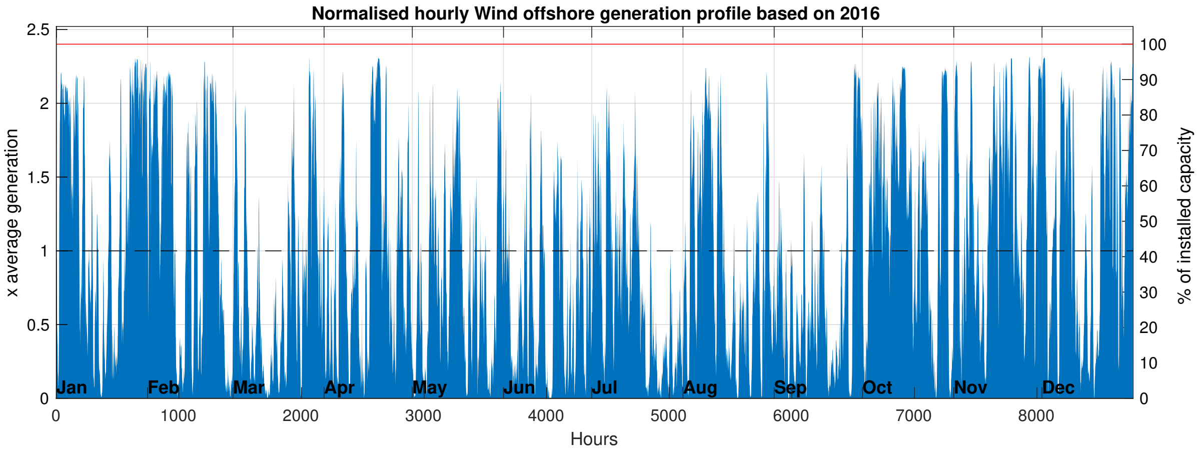


Figure E.25: Normalised hourly offshore wind electricity generation profile Denmark, 2016 base year

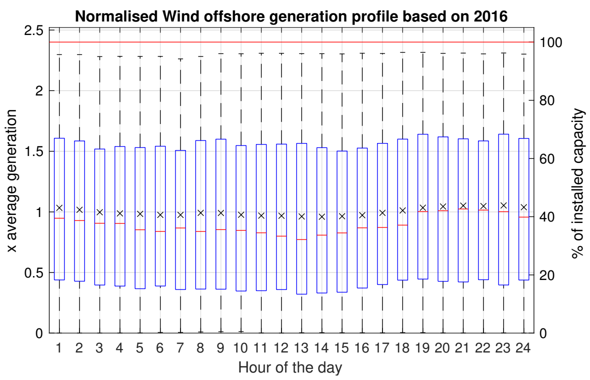


Figure E.26: Hourly boxplot normalised offshore wind electricity generation profile Denmark, 2016 base year

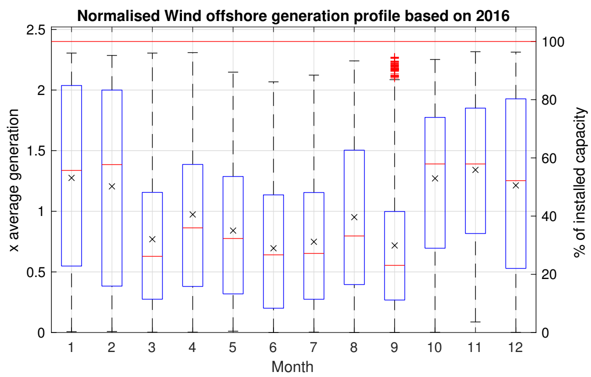


Figure E.27: Monthly boxplot normalised offshore wind electricity generation profile Denmark, 2016 base year

E.1.4. Local CHP & waste

E.1.5. Classic electricity consumption

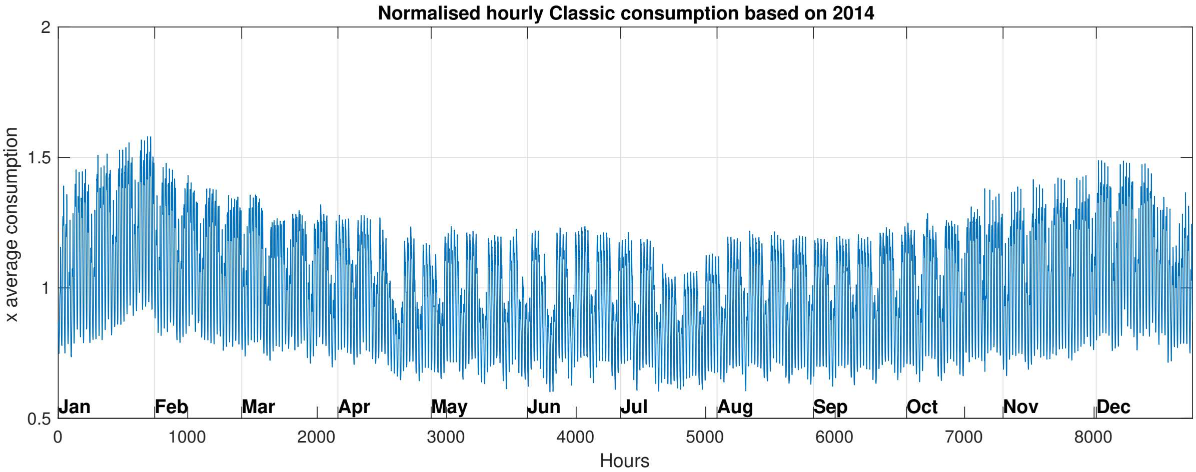


Figure E.28: Normalised hourly classic electricity consumption profile Denmark, 2014 base year

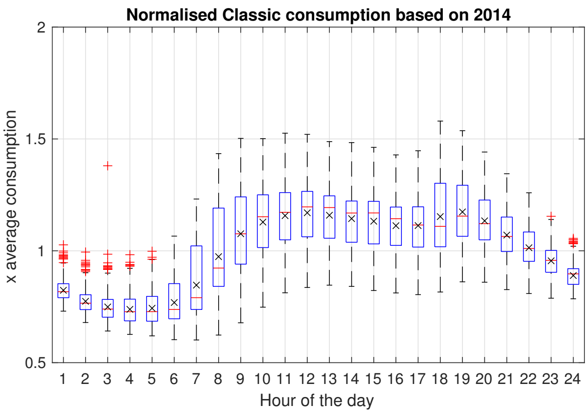


Figure E.29: Hourly boxplot normalised classic electricity consumption profile Denmark, 2014 base year

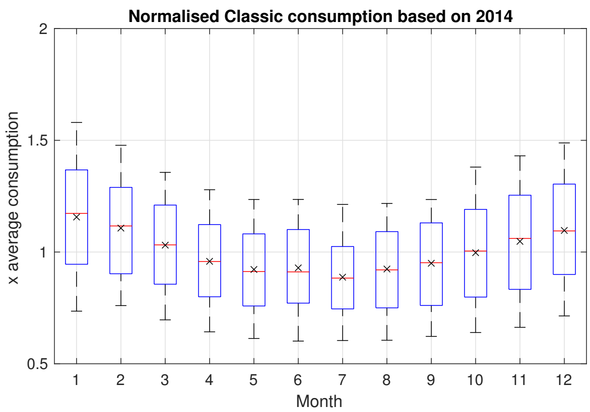


Figure E.30: Monthly boxplot normalised classic electricity consumption profile Denmark, 2014 base year

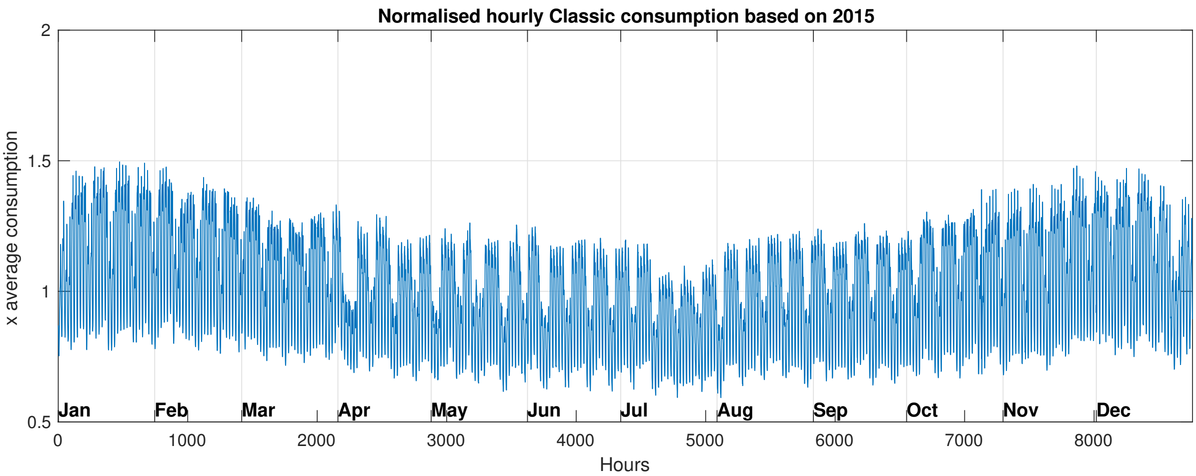


Figure E.31: Normalised hourly classic electricity consumption profile Denmark, 2015 base year

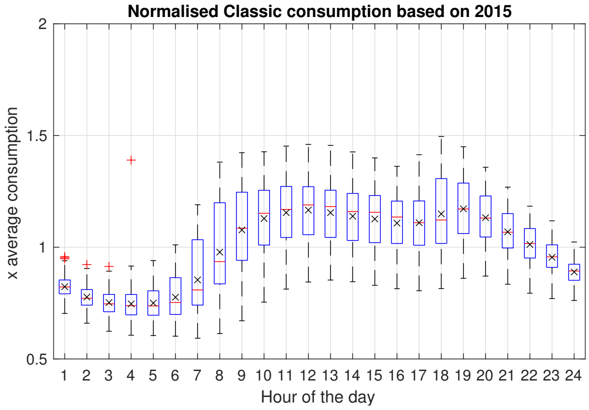


Figure E.32: Hourly boxplot normalised classic electricity consumption profile Denmark, 2015 base year

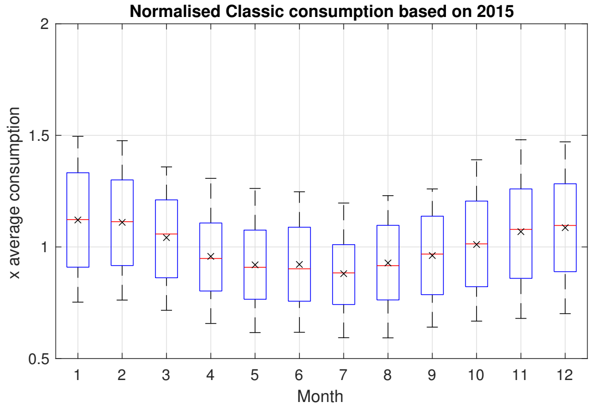


Figure E.33: Monthly boxplot normalised classic electricity consumption profile Denmark, 2015 base year

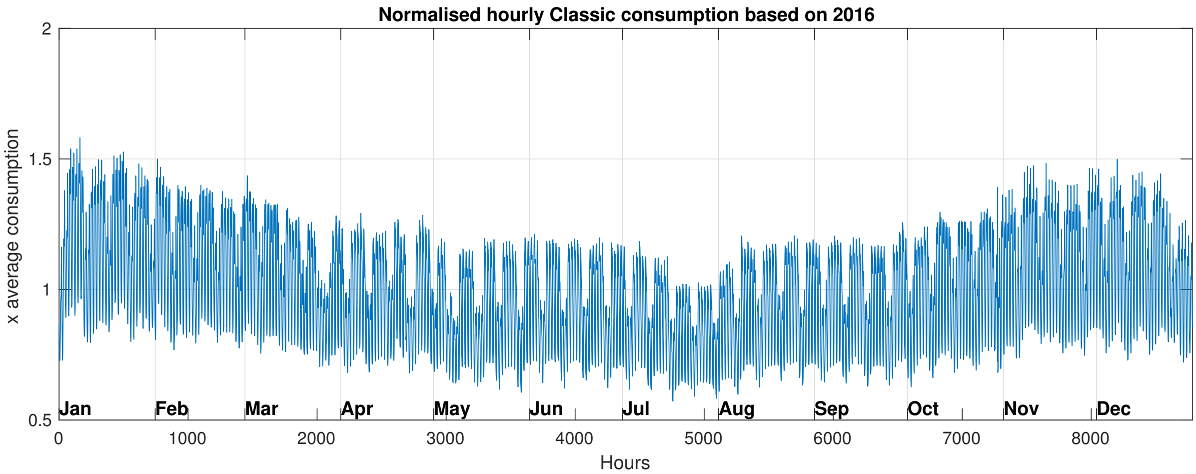


Figure E.34: Normalised hourly classic electricity consumption profile Denmark, 2016 base year

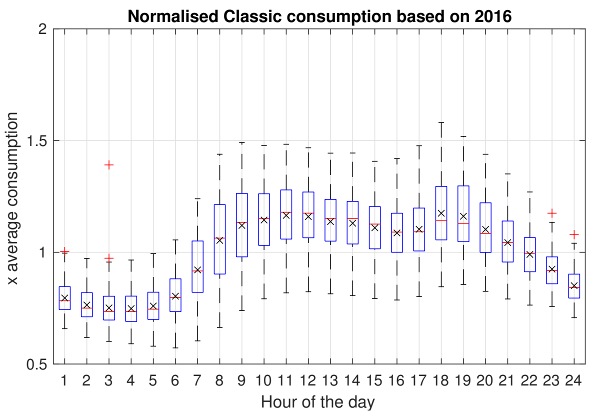


Figure E.35: Hourly boxplot normalised classic electricity consumption profile Denmark, 2016 base year

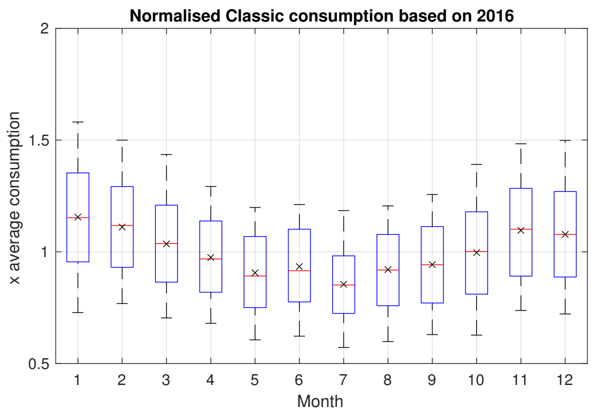


Figure E.36: Monthly boxplot normalised classic electricity consumption profile Denmark, 2016 base year

E.1.6. Electric heating demand & average outside temperature

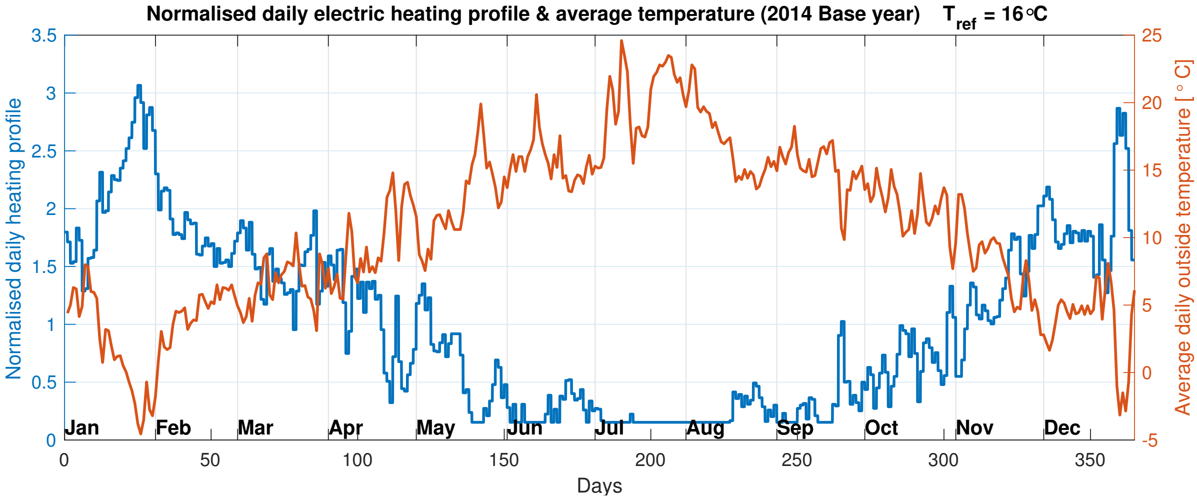


Figure E.37: Normalised daily electric heating demand, 2014 base year

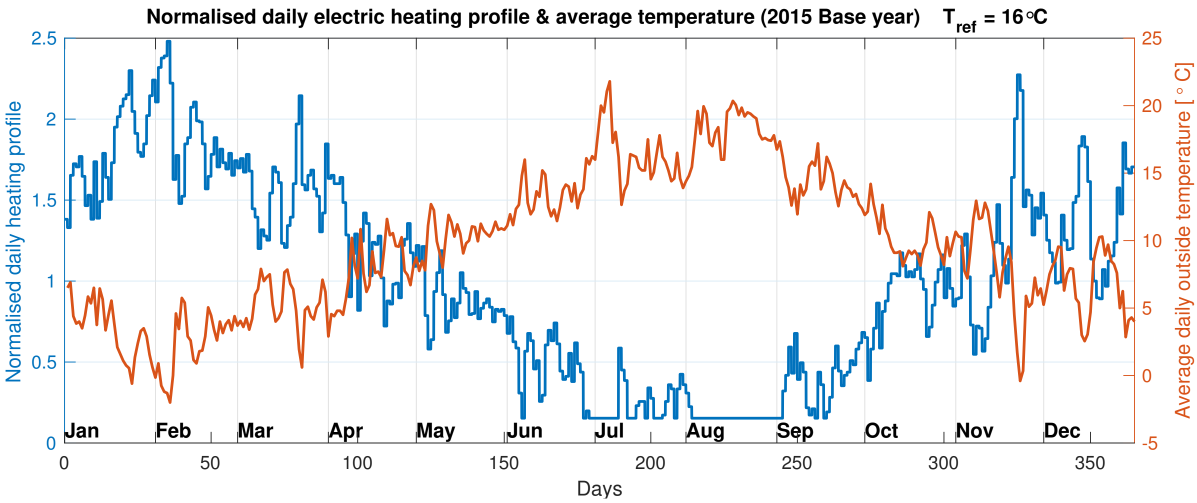


Figure E.38: Normalised daily electric heating demand, 2015 base year

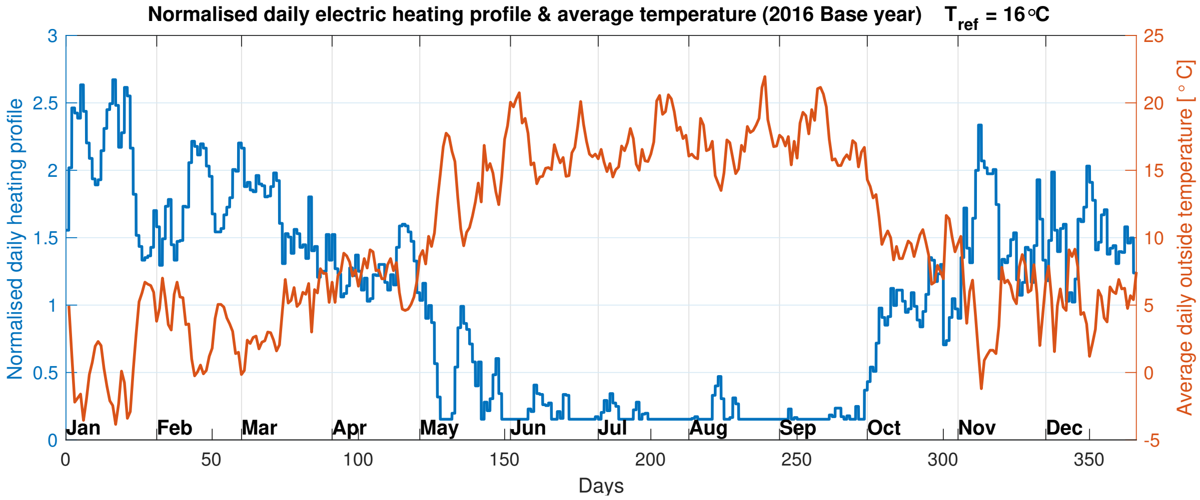


Figure E.39: Normalised daily electric heating demand, 2016 base year

E.2. Model output

Table E.2: Model outputs Denmark

	2014	2015	2016		2014	2015	2016
Electricity generation (TWh)				Direct electricity consumption (TWh)	35.98	35.77	35.57
Solar	1.30	1.08	1.38	% of total electricity consumption	87.19	86.69	85.98
Onshore wind	5.08	5.99	5.50	Electrolyser consumption (TWh)	24.34	24.74	25.31
Offshore wind	47.22	46.71	47.26	Electrolyser capacity (GW)	9.58	10.57	11.04
CHP	3.75	3.75	3.76	Electrolyser capacity factor (%)	28.99	26.71	26.10
Waste	2.97	2.97	2.98	FCEV V2G demand (TWh)	5.29	5.49	5.80
Total	60.32	60.51	60.88	FCEV V2G peak demand (GW)	4.40	4.78	4.39
Installed capacity (GW)				million vehicles	0.44	0.48	0.44
Solar	1.33	1.40	1.48	% of passenger FCEVs	38.72	42.09	38.66
Onshore wind	2.32	2.46	2.58	Peak storage capacity (million kg)	116.22	74.86	103.83
Offshore wind	11.62	12.29	12.92	BEV charging load (GW)	0.51	0.51	0.51
CHP	1.23	1.23	1.23				
Waste	0.37	0.37	0.37				
Total	16.86	17.74	18.57				
Electricity consumption (TWh)							
Classic	30.36	30.36	30.44				
Electricity for heating	6.74	6.74	6.76				
BEV charging	4.16	4.16	4.17				
Total	41.26	41.26	41.37				
Road transport cons. (TWh)	10.39	10.39	10.42				
Final energy cons. (TWh)	79.06	79.06	79.17				
Hydrogen cons. (million kg)							
Road transport	272.32	272.32	273.07				
V2G	223.61	232.27	245.28				
Residual storage	2.97	2.34	0.32				
Total production	498.98	507.11	518.69				

E.2.1. Sankey diagrams

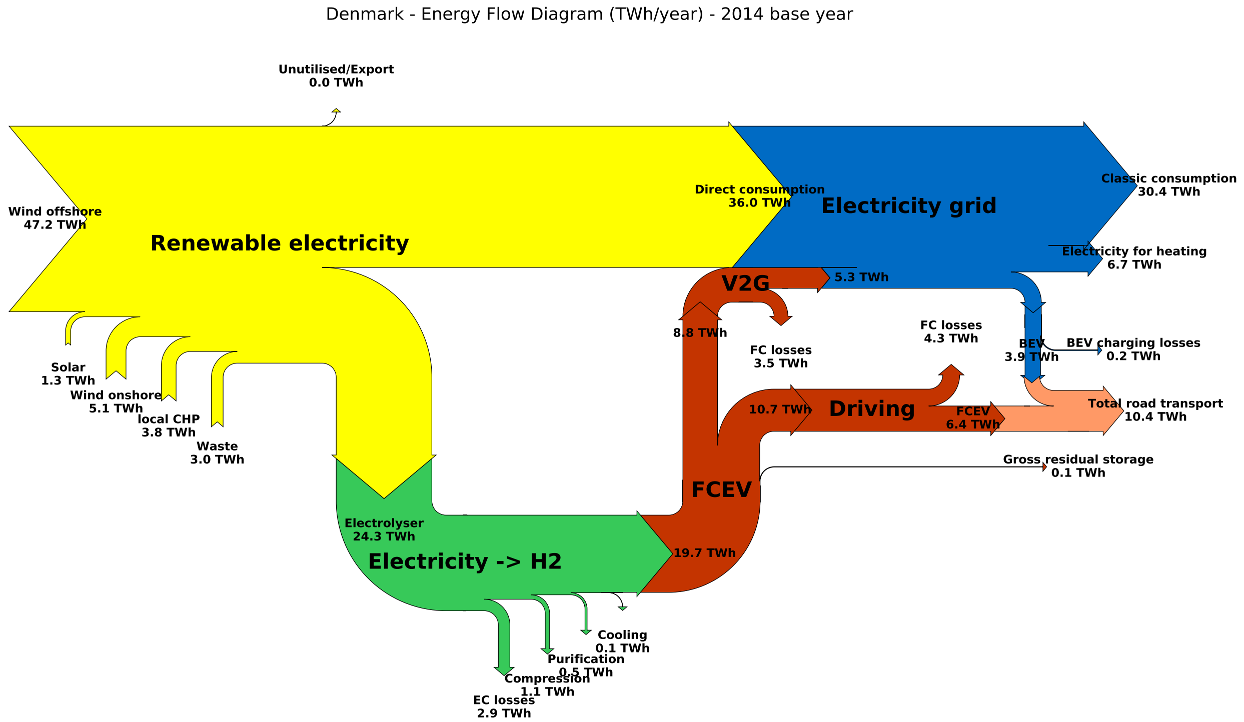


Figure E.40: Energy flow diagram for Denmark with 2014 as base year

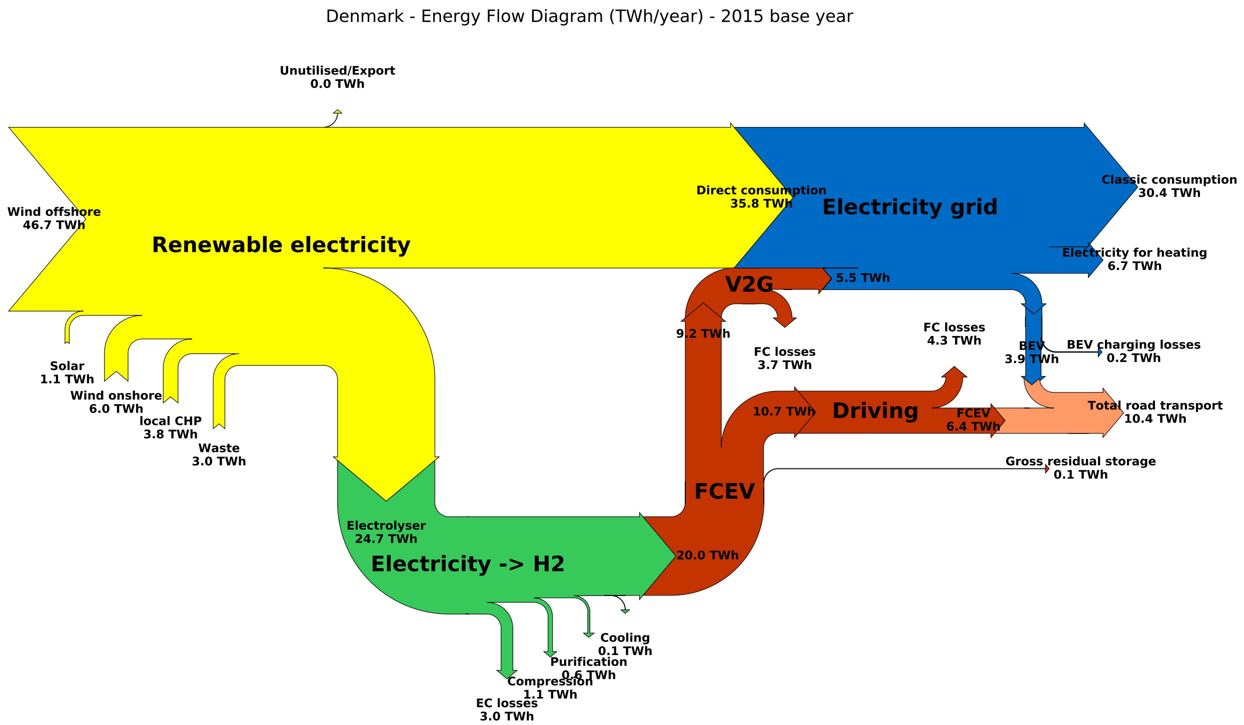


Figure E.41: Energy flow diagram for Denmark with 2015 as base year

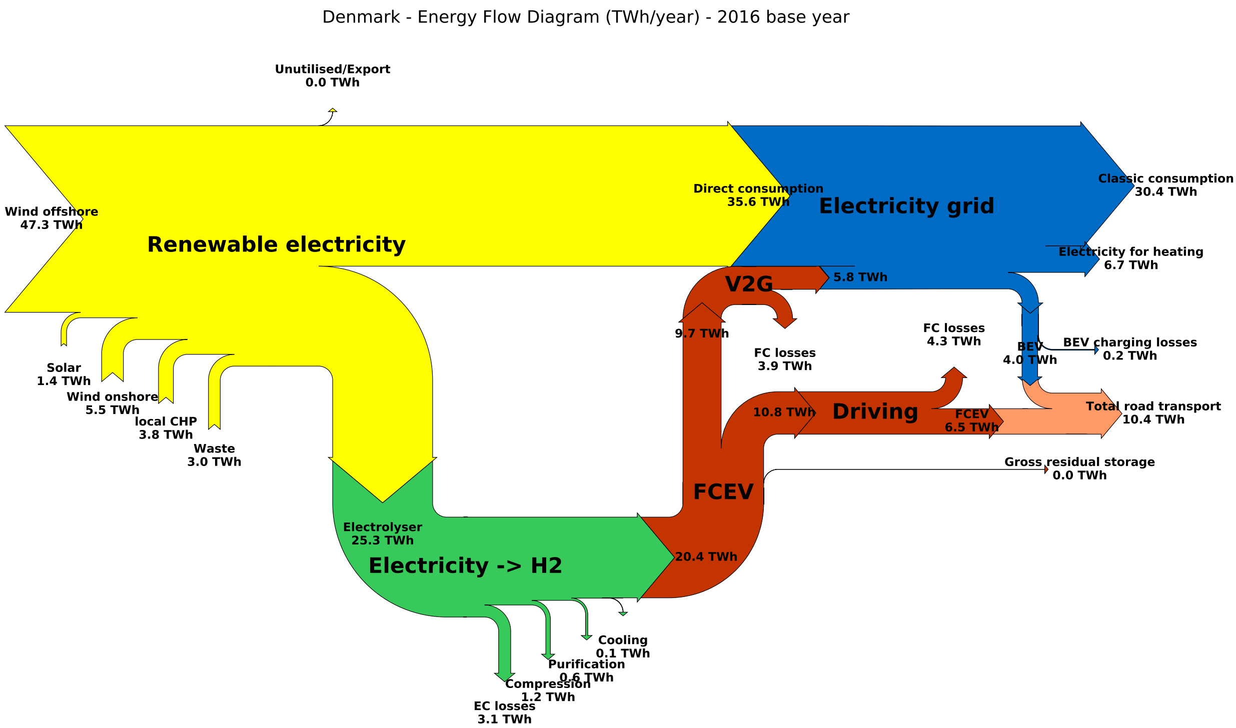


Figure E.42: Energy flow diagram for Denmark with 2016 as base year

E.2.2. Generation & Consumption profiles (2016 base year)

Only the scaled generation and consumption profiles for base year 2016 are shown to the generation and consumption in terms of GW's. The shape of the profiles are the same as the normalised profile.

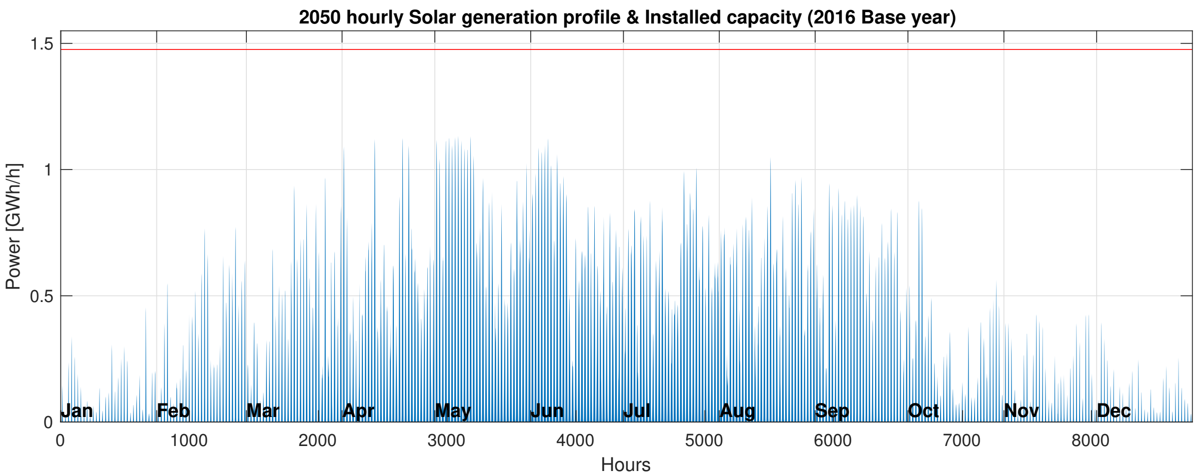


Figure E.43: Solar electricity generation in Denmark in 2050 (2016 base year)

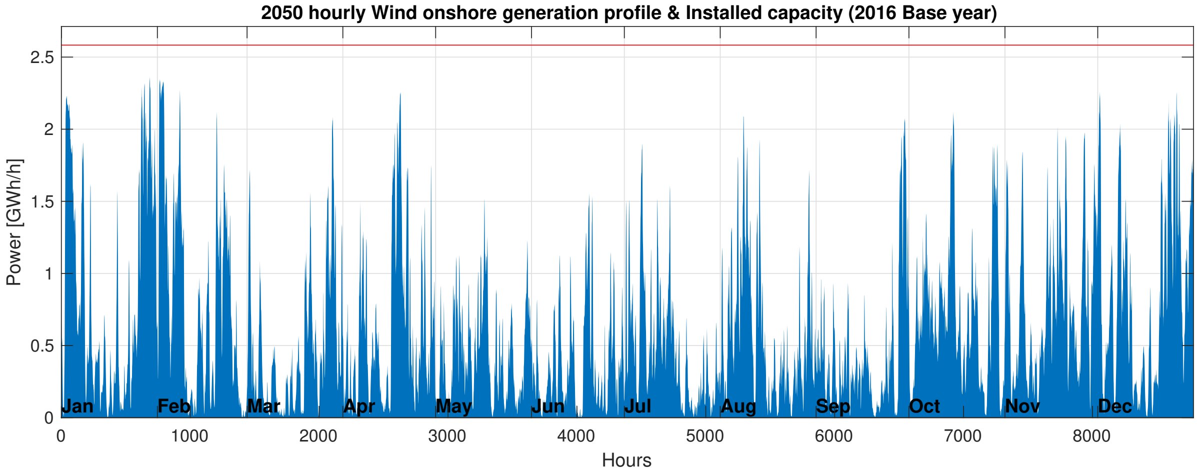


Figure E.44: Onshore wind electricity generation in Denmark in 2050 (2016 base year)

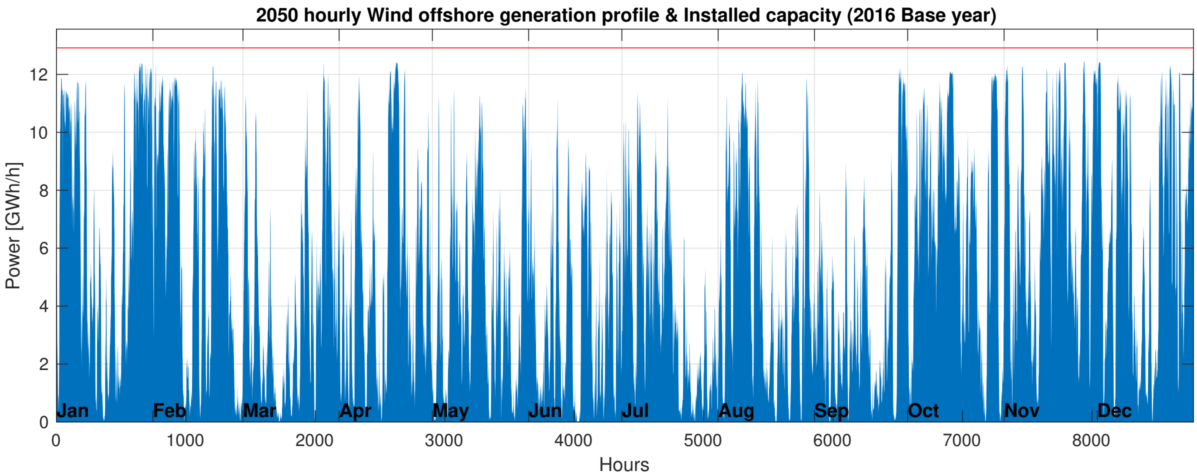


Figure E.45: Offshore wind electricity generation in Denmark in 2050 (2016 base year)

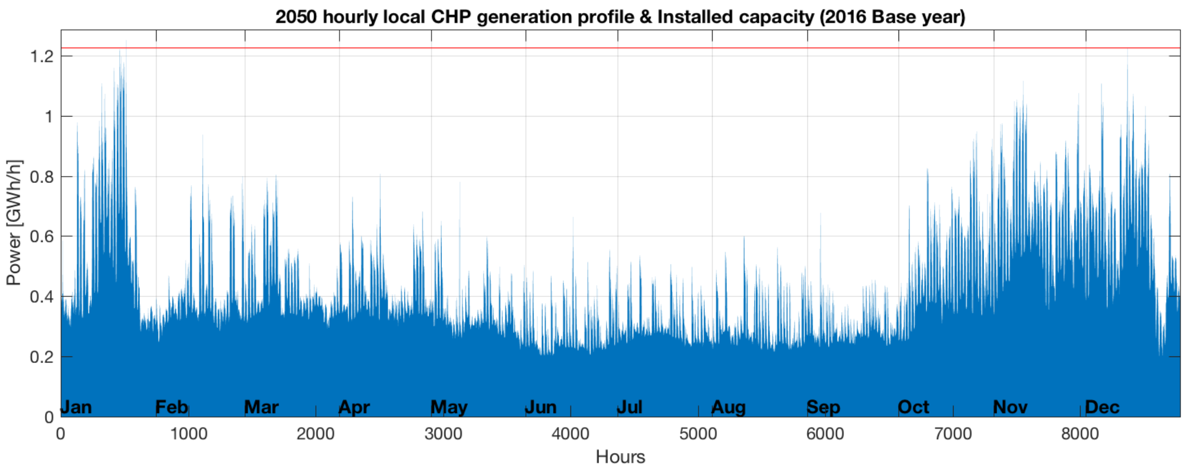


Figure E.46: Local CHP electricity generation in Denmark in 2050 (2016 base year)

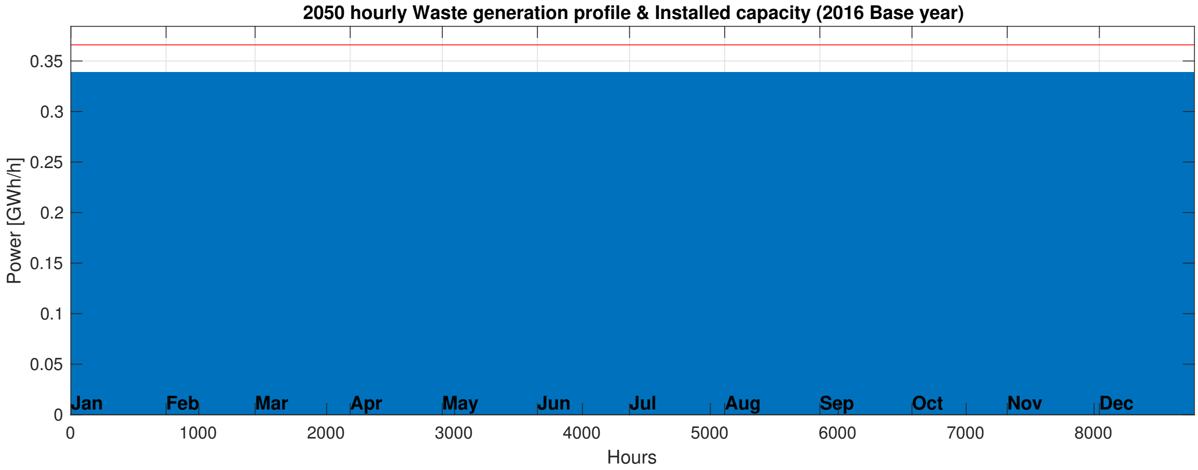


Figure E.47: Electricity generation from waste in Denmark in 2050 (2016 base year)

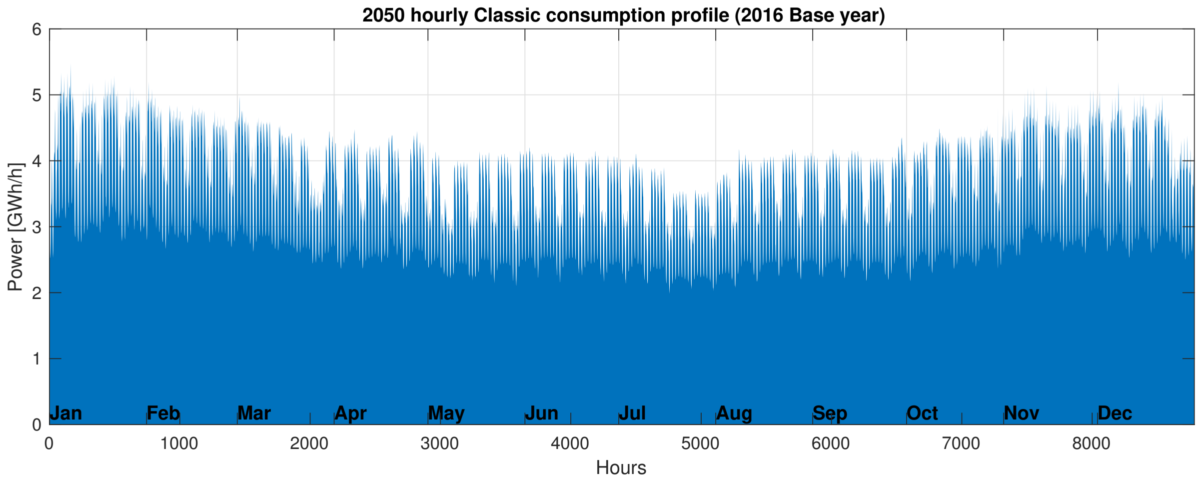


Figure E.48: Classic electricity consumption in Denmark in 2050 (2016 base year)

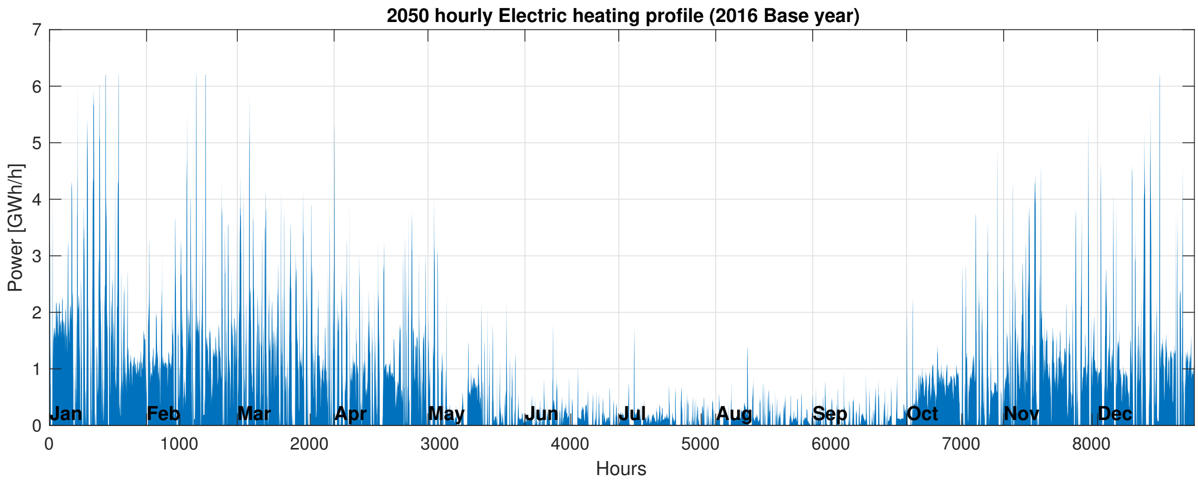


Figure E.49: Electric heating consumption in Denmark in 2050 (2016 base year)

E.2.3. Imbalance

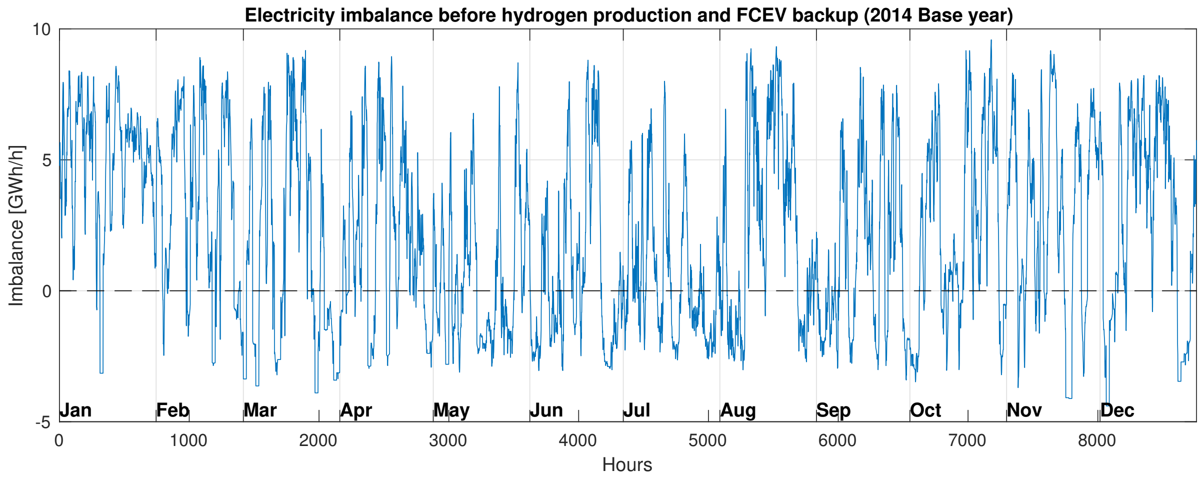


Figure E.50: Electric imbalance in Denmark in 2050 (2014 base year)

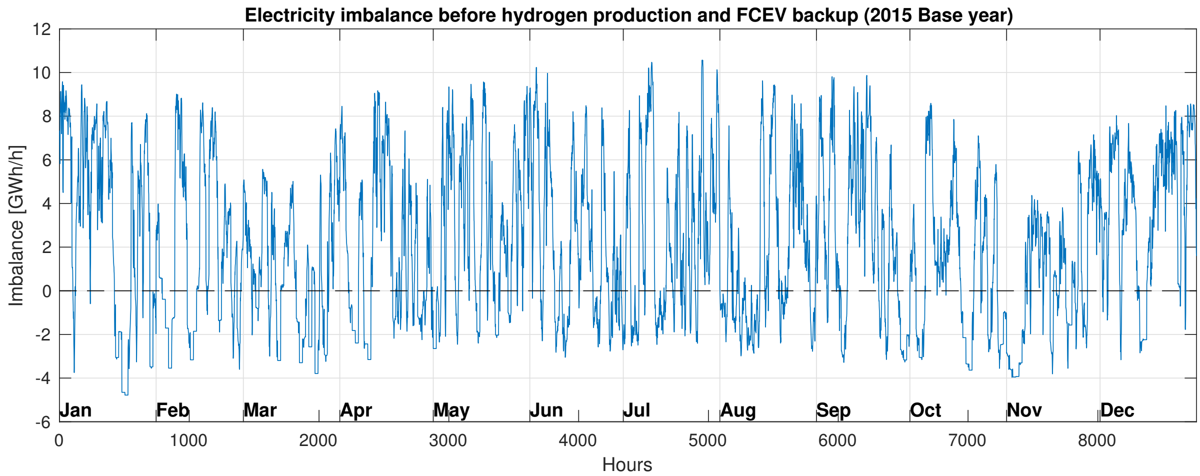


Figure E.51: Electric imbalance in Denmark in 2050 (2015 base year)

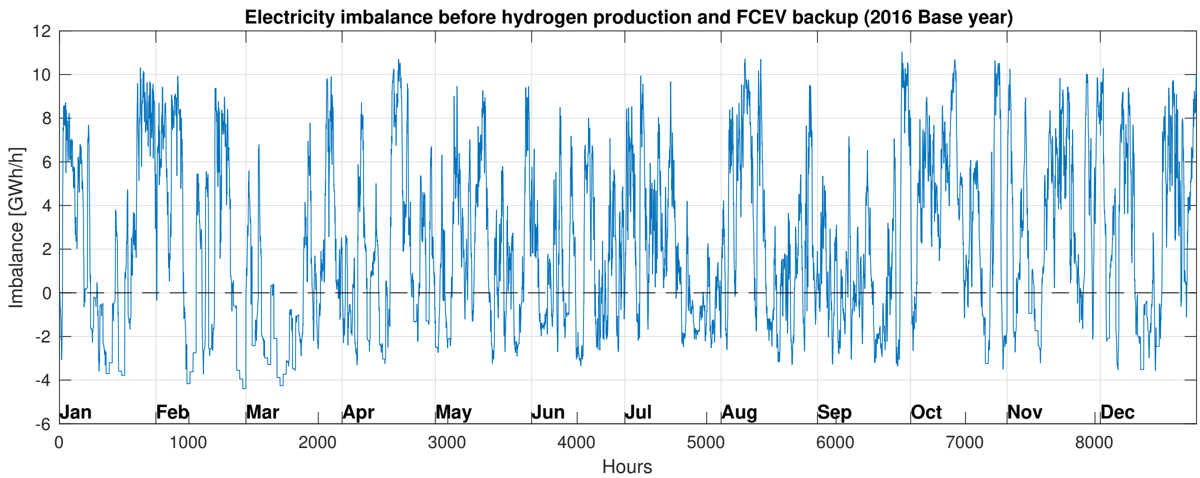


Figure E.52: Electric imbalance in Denmark in 2050 (2016 base year)

E.2.4. Electrolyser

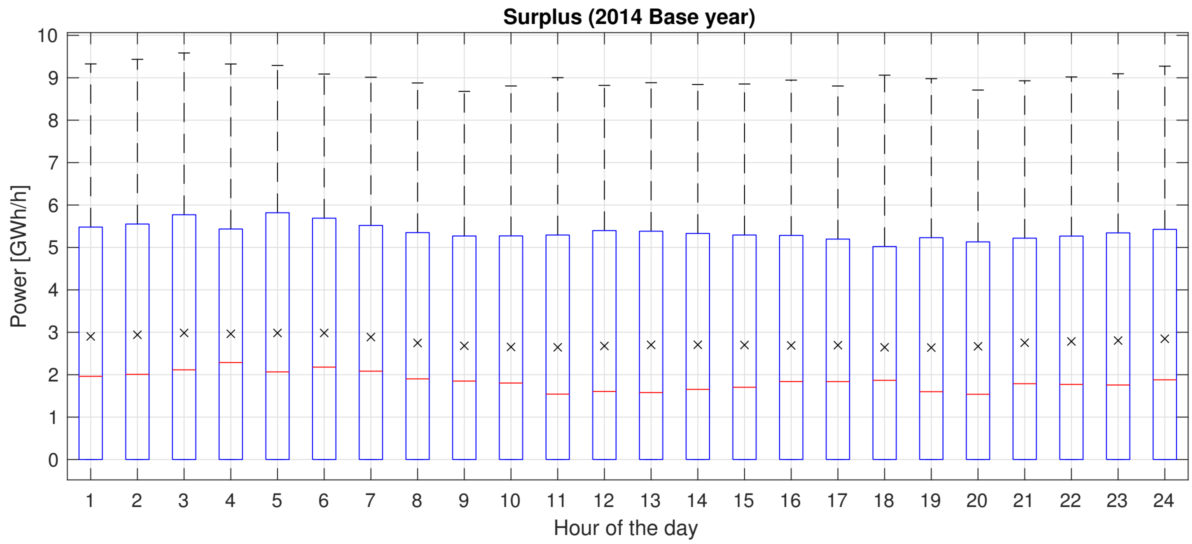


Figure E.53: Hourly boxplot electrolyser consumption in Denmark in 2050 (2014 base year)

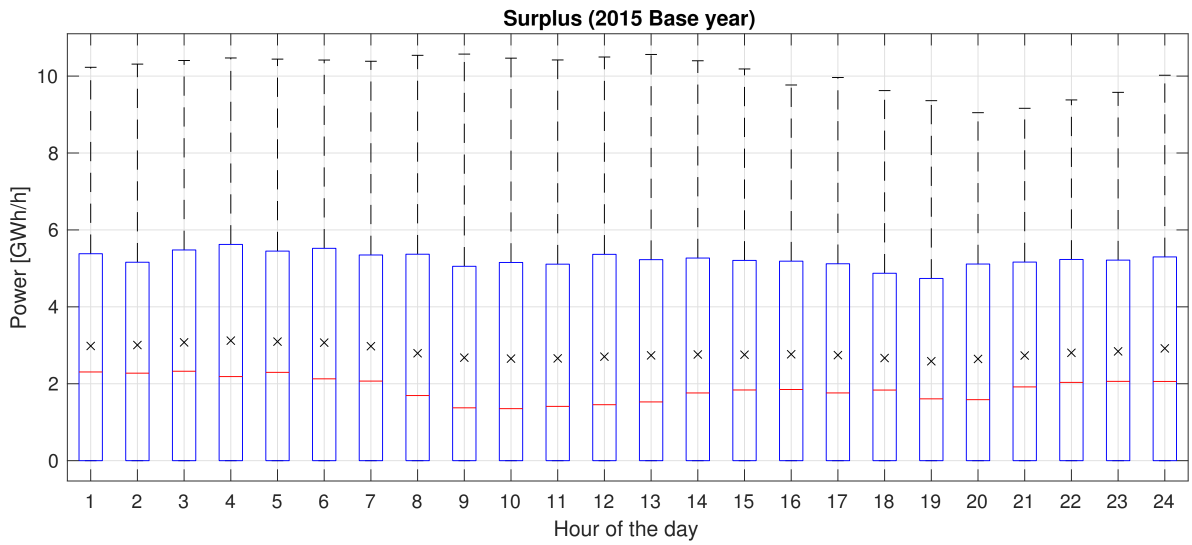


Figure E.54: Hourly boxplot electrolyser consumption in Denmark in 2050 (2015 base year)

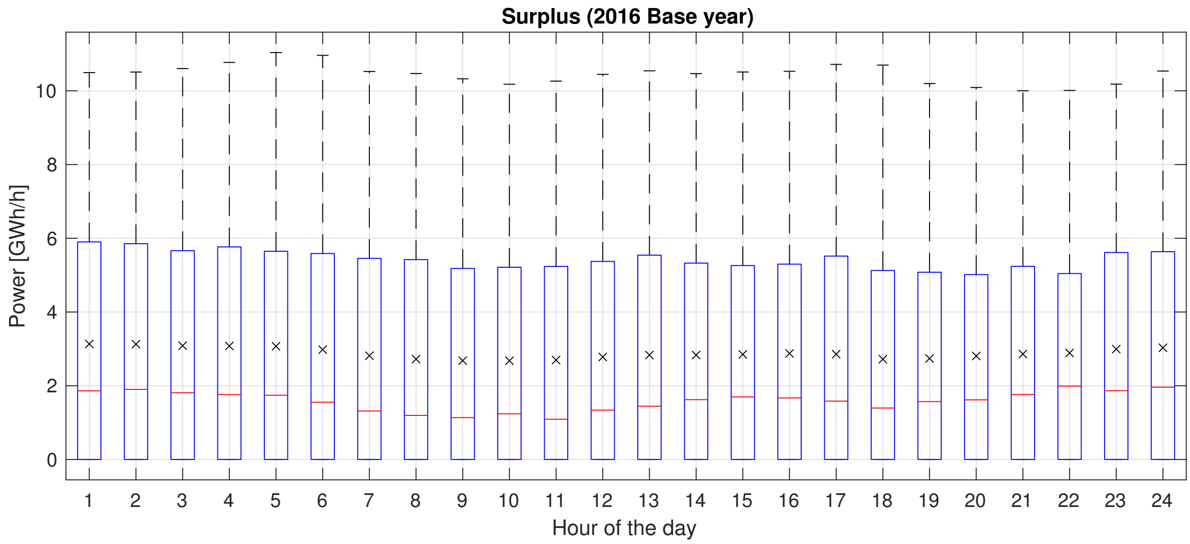


Figure E.55: Hourly boxplot electrolyser consumption in Denmark in 2050 (2016 base year)

E.2.5. FCEV backup

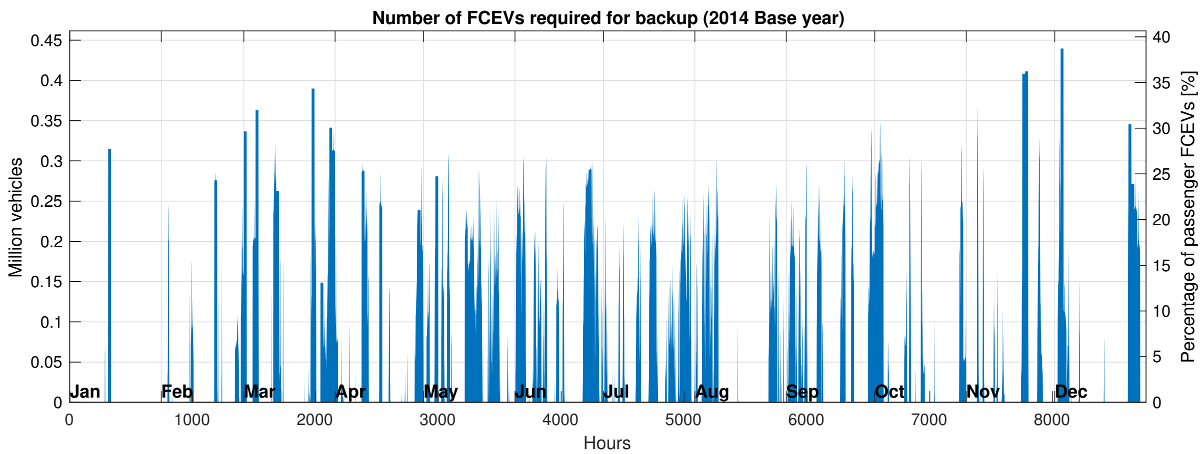


Figure E.56: FCEV backup in Denmark in 2050 (2014 base year)

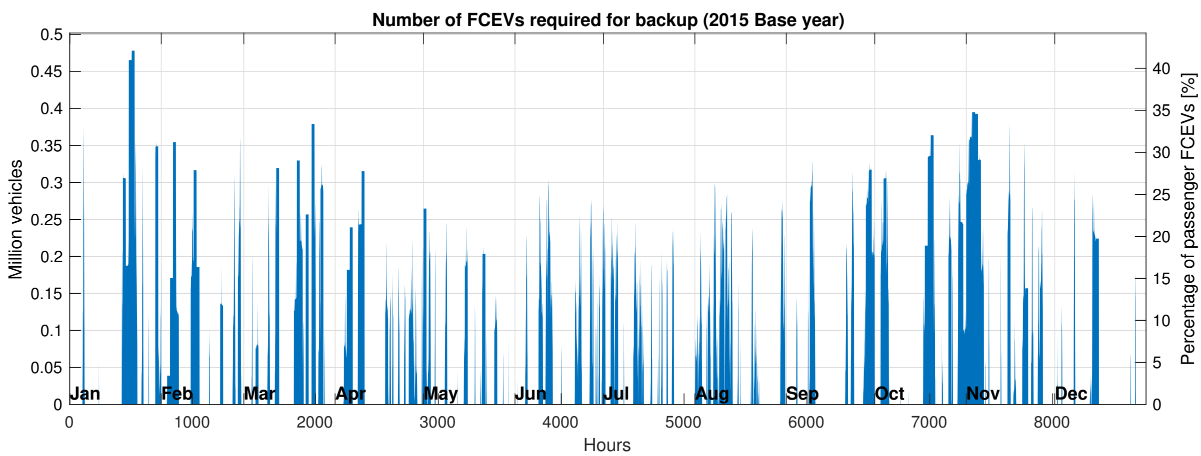


Figure E.57: FCEV backup in Denmark in 2050 (2015 base year)

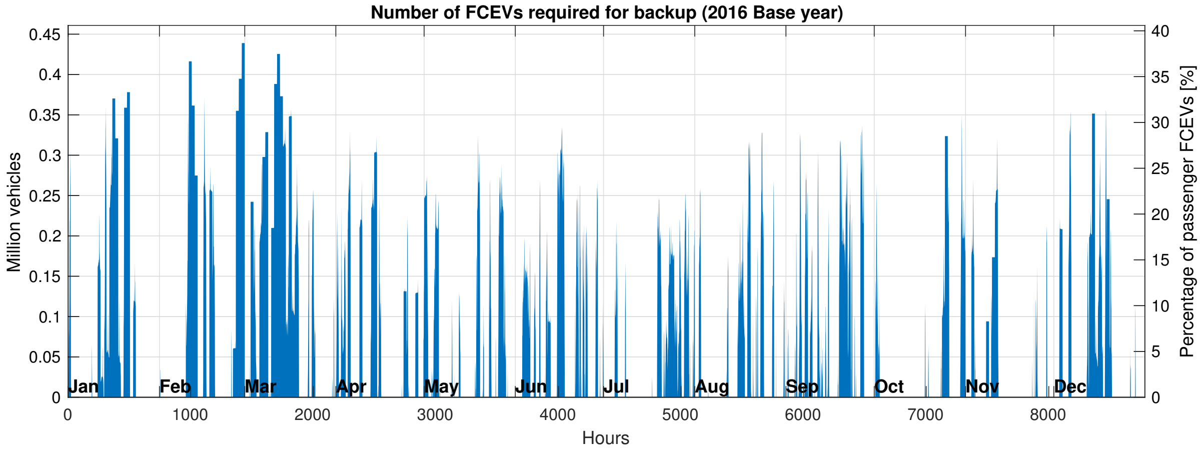


Figure E.58: FCEV backup in Denmark in 2050 (2016 base year)

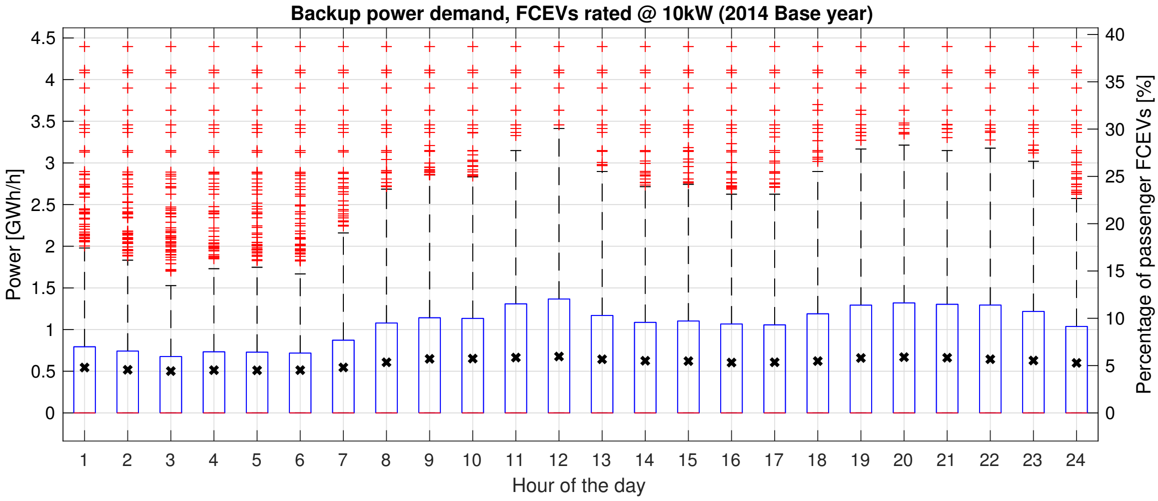


Figure E.59: Hourly boxplot FCEV backup in Denmark in 2050 (2014 base year)

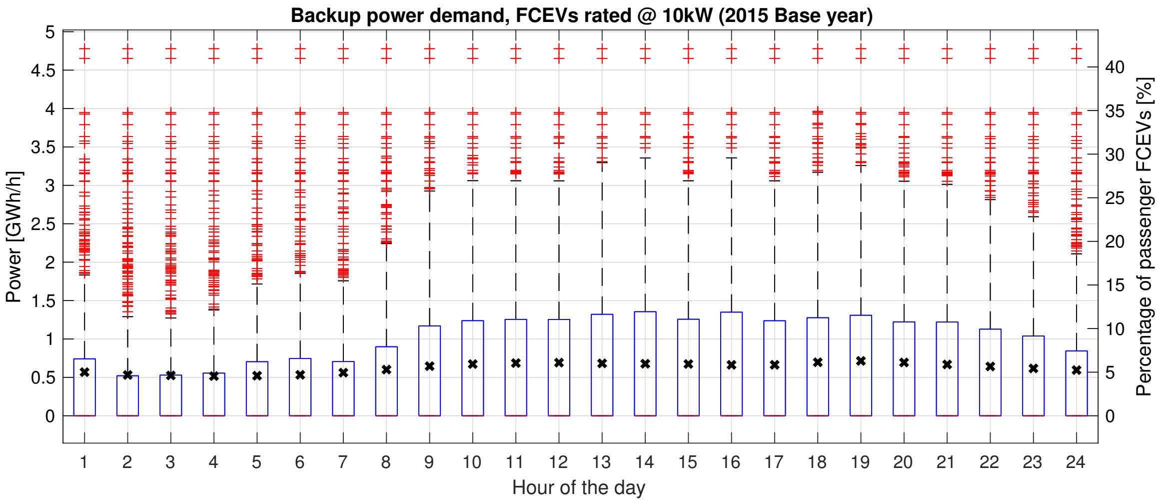


Figure E.60: Hourly boxplot FCEV backup in Denmark in 2050 (2015 base year)

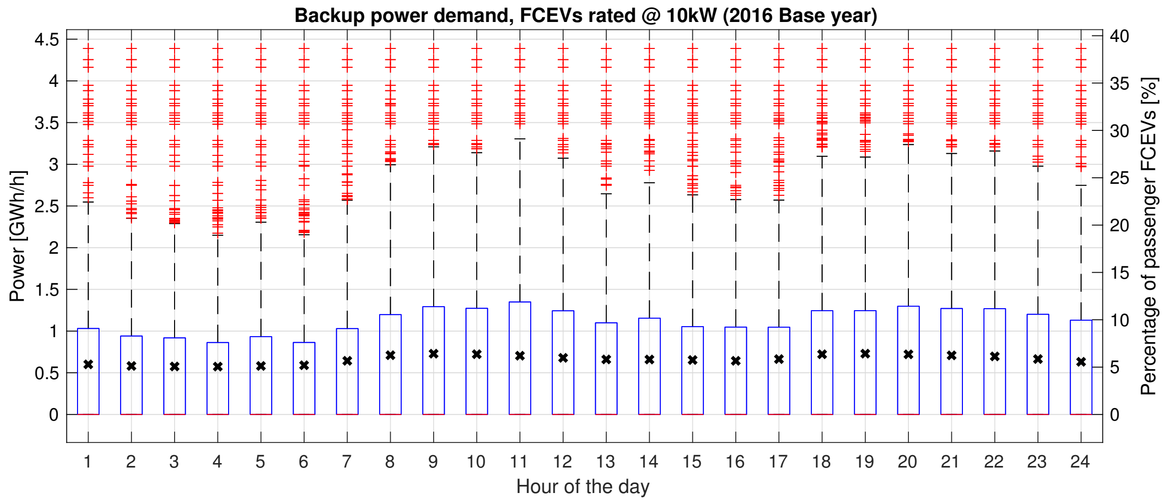


Figure E.61: Hourly boxplot FCEV backup in Denmark in 2050 (2016 base year)

E.2.6. Weekly charge & discharge rates of hydrogen

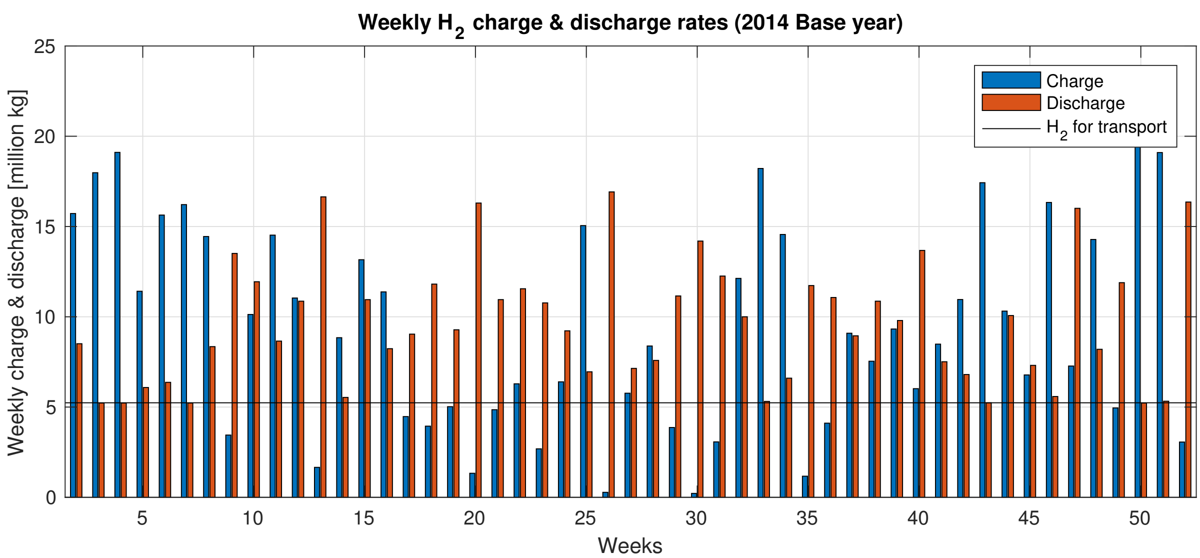


Figure E.62: Hydrogen weekly charge and discharge rates in Denmark in 2050 (2014 base year)

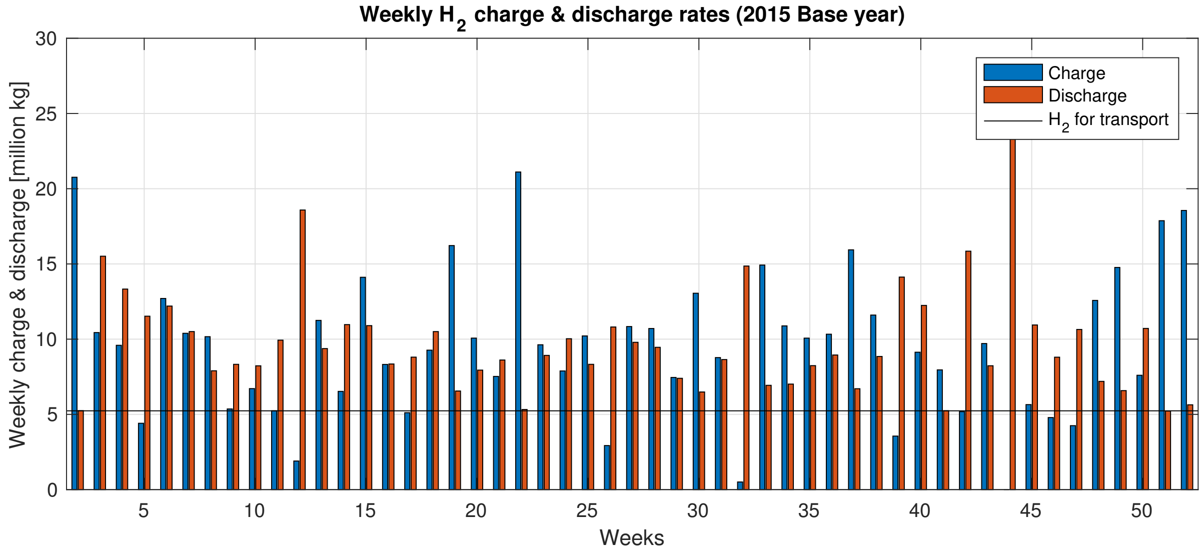


Figure E.63: Hydrogen weekly charge and discharge rates in Denmark in 2050 (2015 base year)

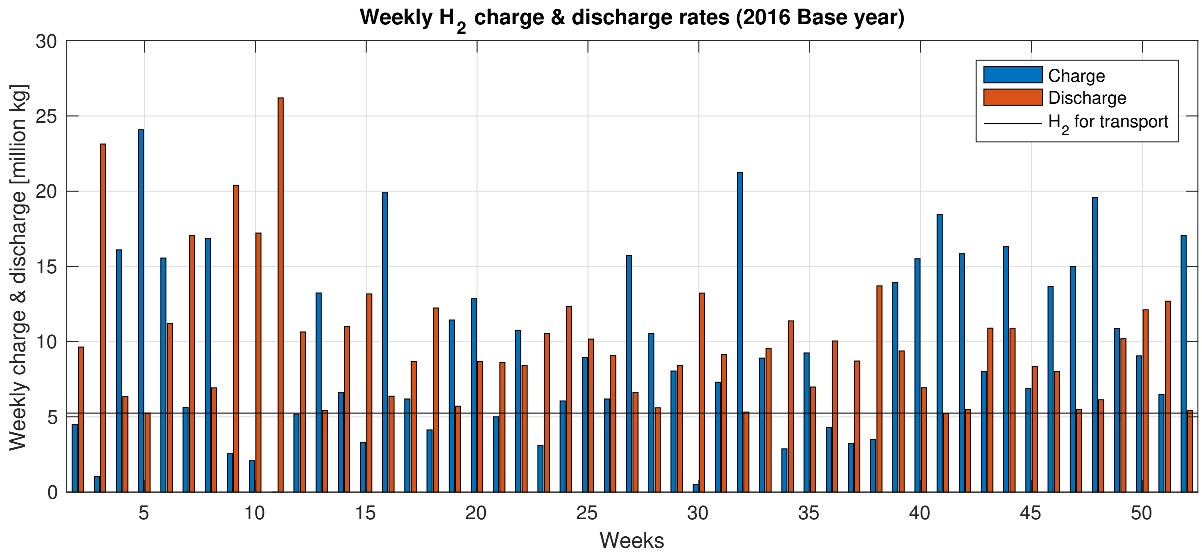


Figure E.64: Hydrogen weekly charge and discharge rates in Denmark in 2050 (2016 base year)

E.2.7. Fuelling

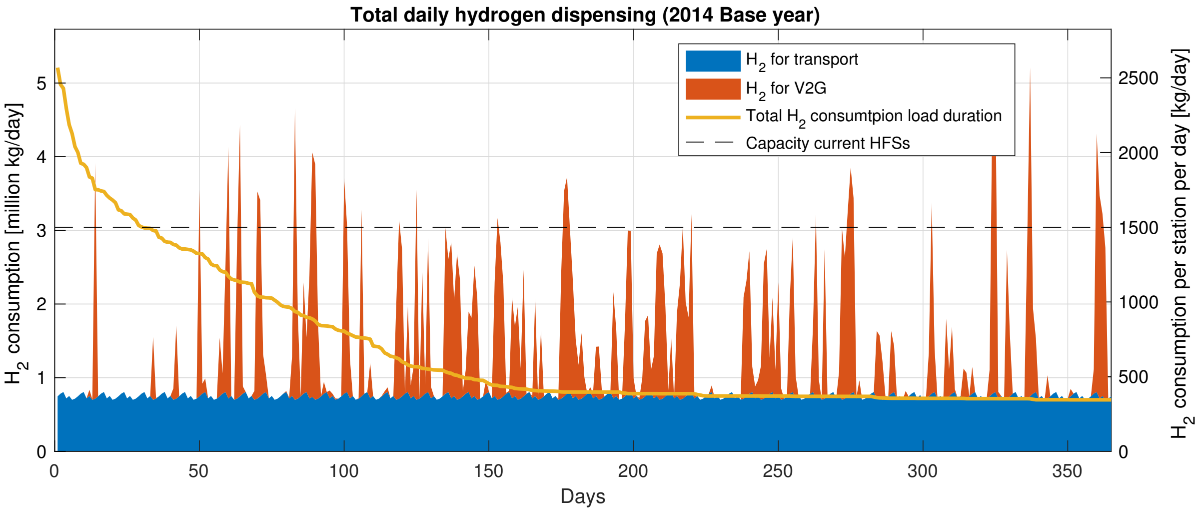


Figure E.65: Total daily hydrogen dispensing and dispension per HFS in Denmark in 2050 (2014 base year)

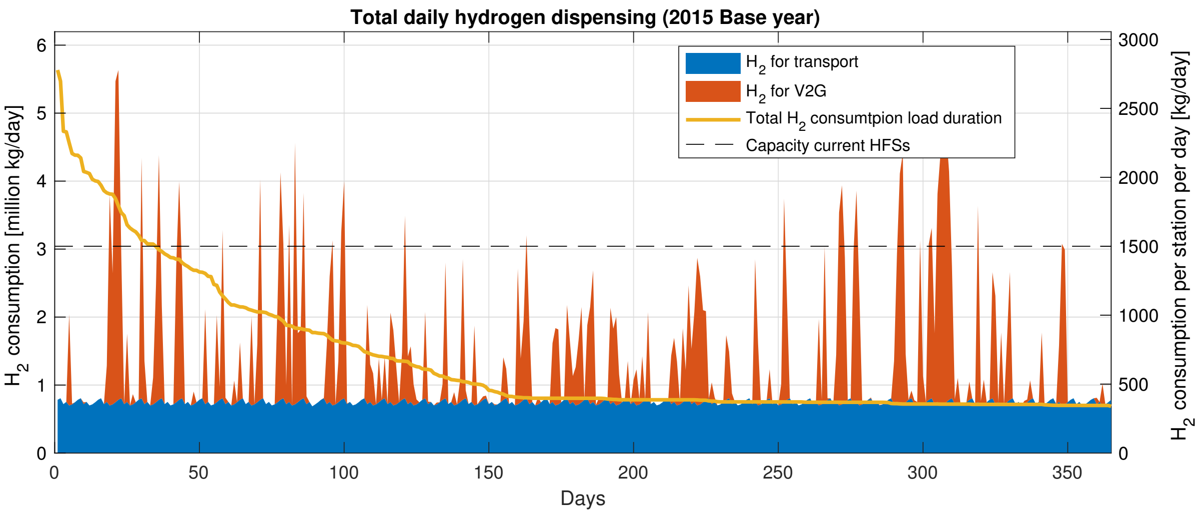


Figure E.66: Total daily hydrogen dispensing and dispension per HFS in Denmark in 2050 (2015 base year)

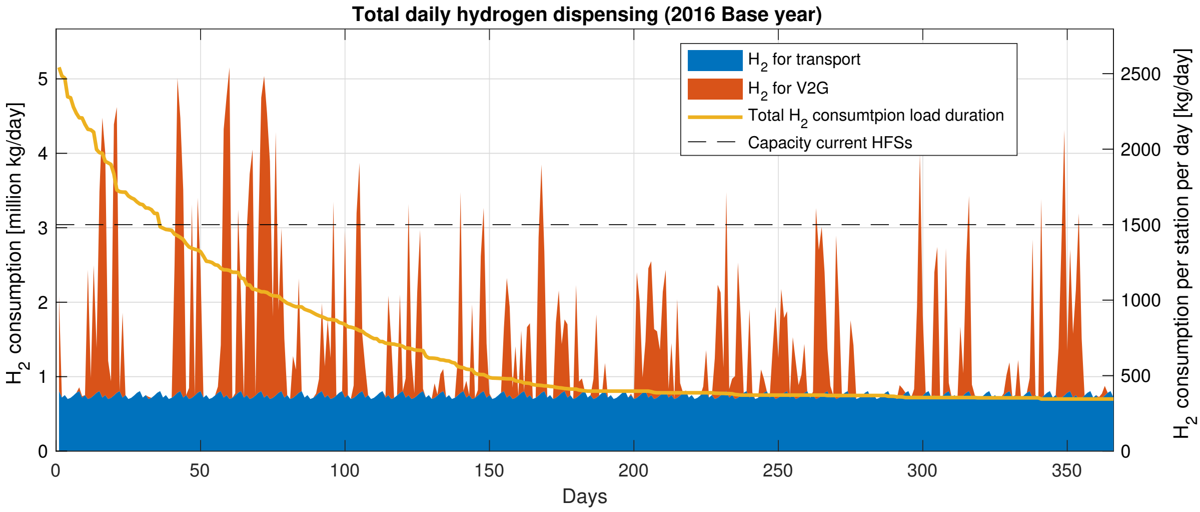


Figure E.67: Total daily hydrogen dispensing and dispension per HFS in Denmark in 2050 (2016 base year)

F

Inputs, results & additional data Germany

F.1. Normalised generation & consumption profiles

F.1.1. Solar PV electricity generation

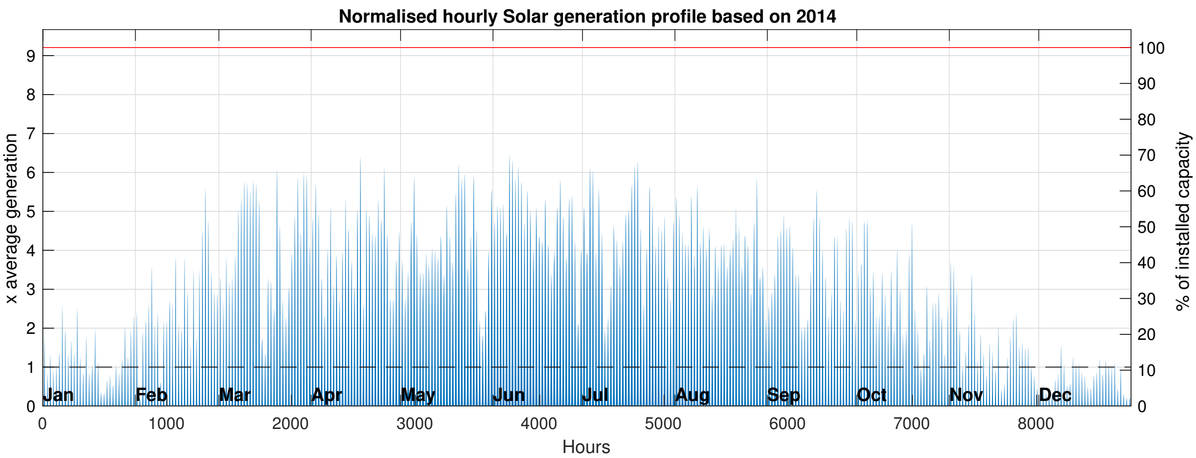


Figure F.1: Normalised hourly Solar electricity generation profile Germany, 2014 base year

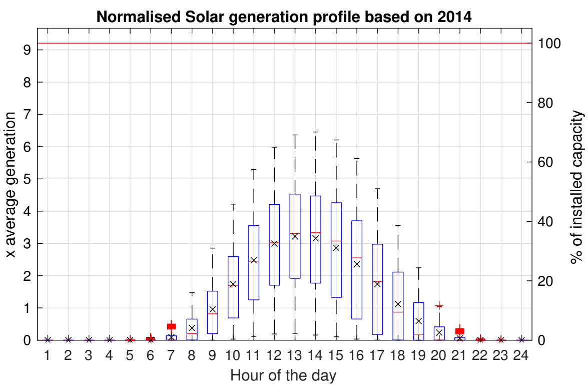


Figure F.2: Hourly boxplot normalised Solar electricity generation profile Germany, 2014 base year

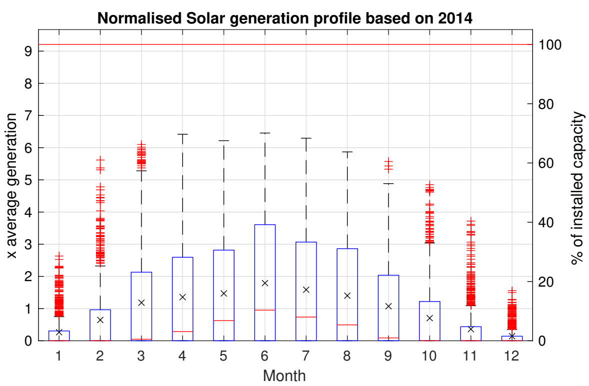


Figure F.3: Monthly boxplot normalised Solar electricity generation profile Germany, 2014 base year

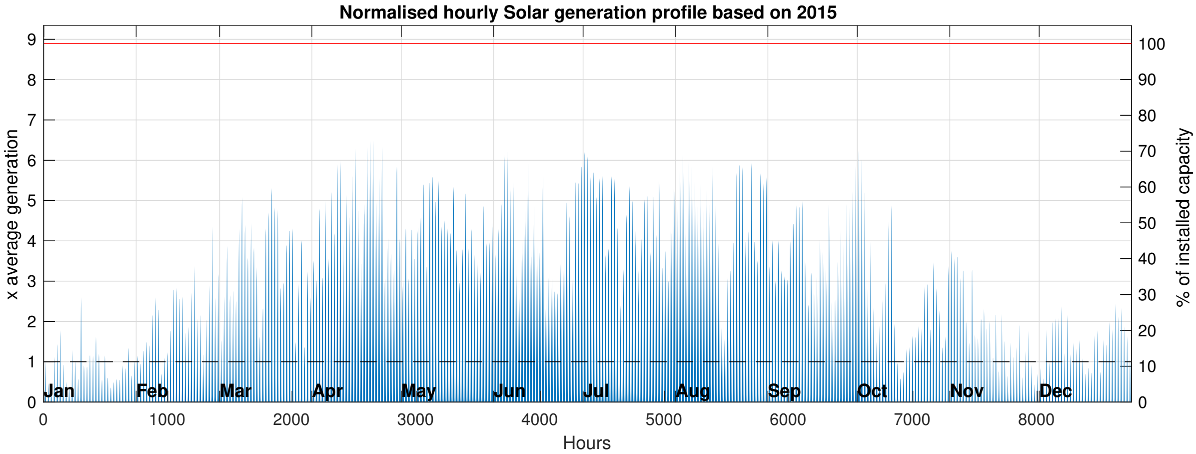


Figure F.4: Normalised hourly Solar electricity generation profile Germany, 2015 base year

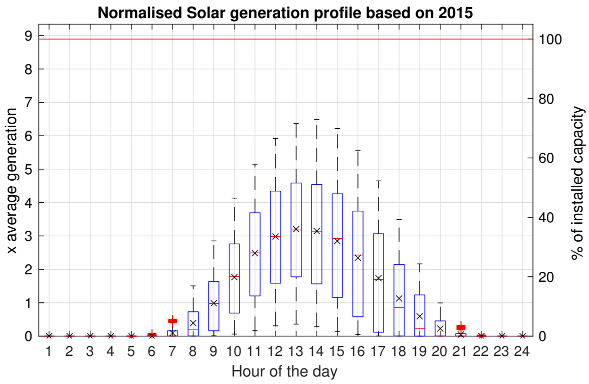


Figure F.5: Hourly boxplot normalised Solar electricity generation profile Germany, 2015 base year

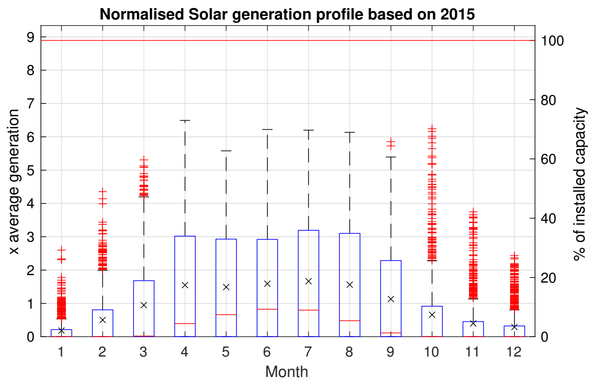


Figure F.6: Monthly boxplot normalised Solar electricity generation profile Germany, 2015 base year

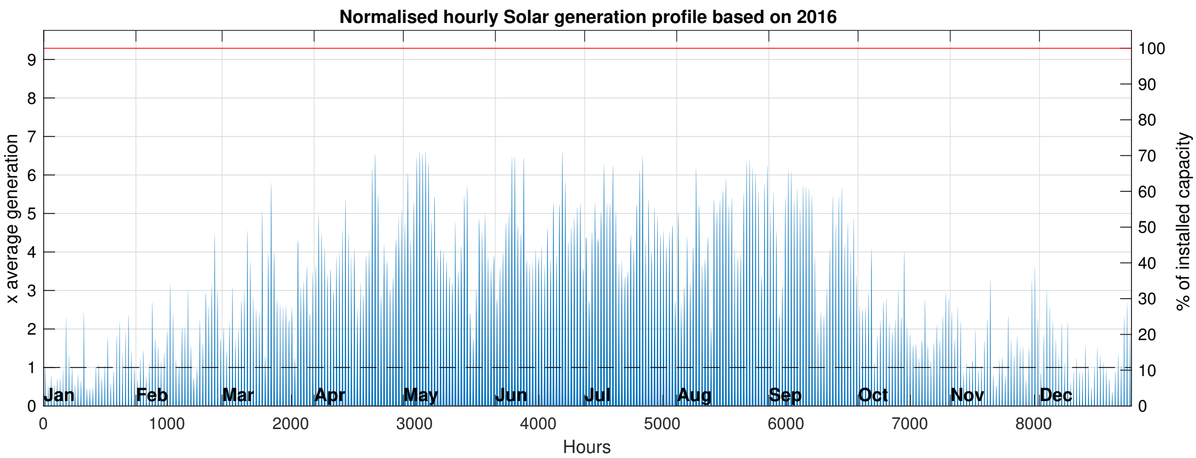


Figure F.7: Normalised hourly Solar electricity generation profile Germany, 2016 base year

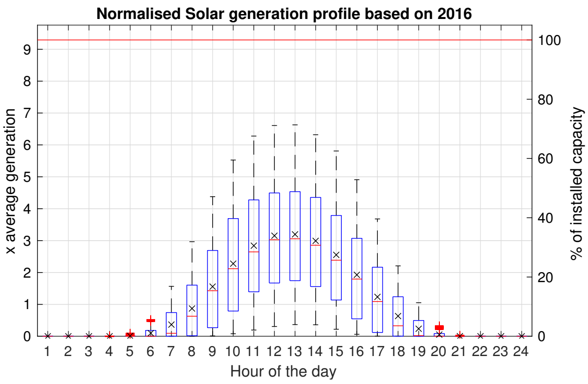


Figure F.8: Hourly boxplot normalised Solar electricity generation profile Germany, 2016 base year

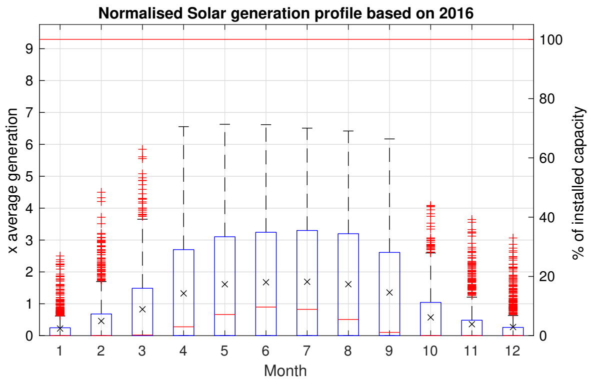


Figure F.9: Monthly boxplot normalised Solar electricity generation profile Germany, 2016 base year

F.1.2. Onshore wind electricity generation

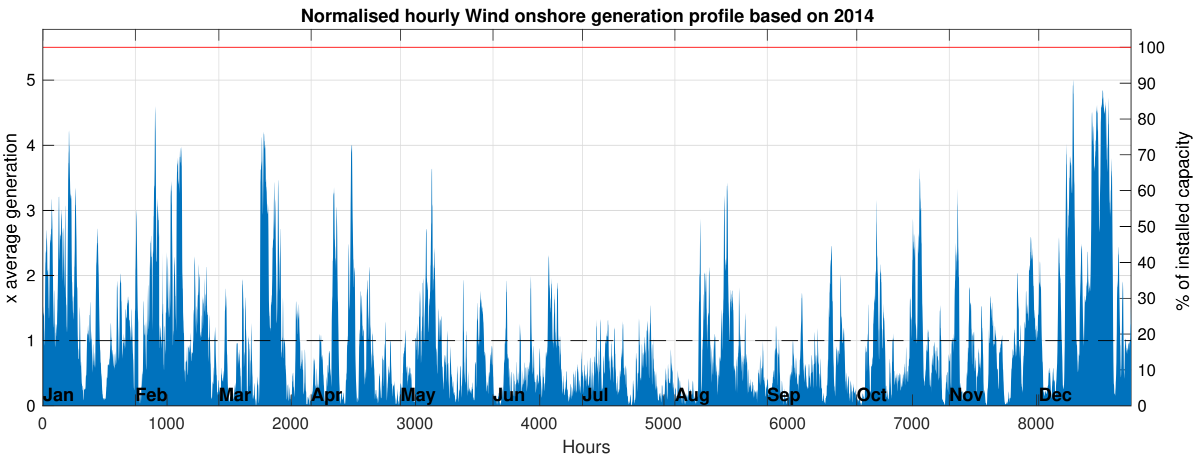


Figure F.10: Normalised hourly onshore wind electricity generation profile Germany, 2014 base year

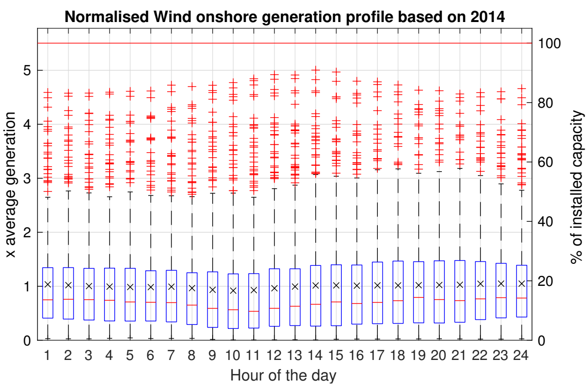


Figure F.11: Hourly boxplot normalised onshore wind electricity generation profile Germany, 2014 base year

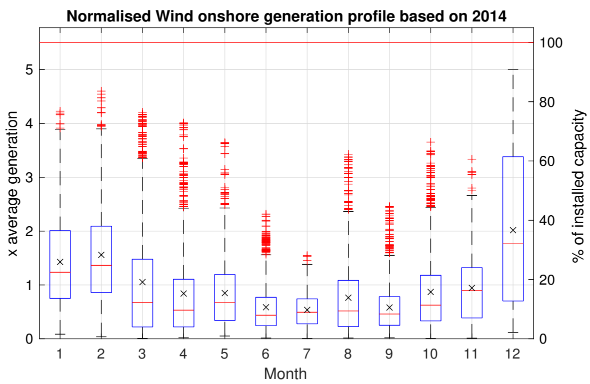


Figure F.12: Monthly boxplot normalised onshore wind electricity generation profile Germany, 2014 base year

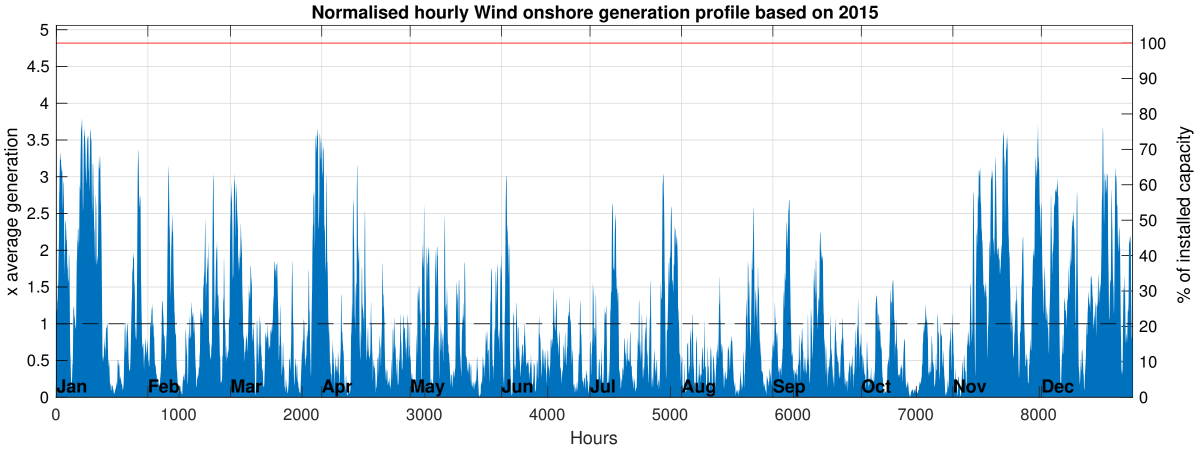


Figure F.13: Normalised hourly onshore wind electricity generation profile Germany, 2015 base year

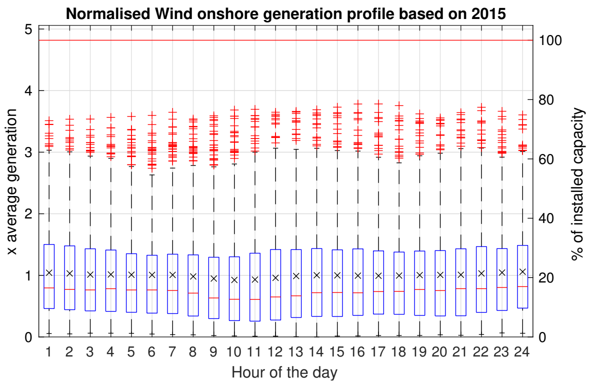


Figure F.14: Hourly boxplot normalised onshore wind electricity generation profile Germany, 2015 base year

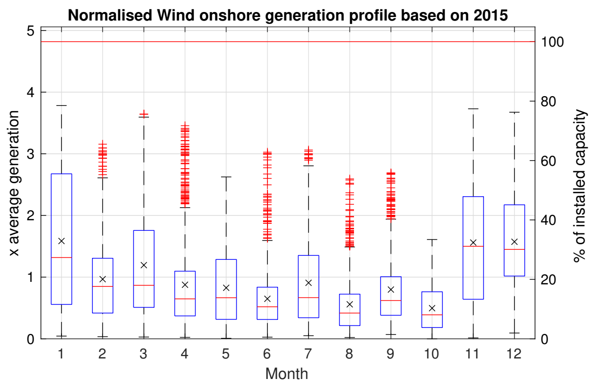


Figure F.15: Monthly boxplot normalised onshore wind electricity generation profile Germany, 2015 base year

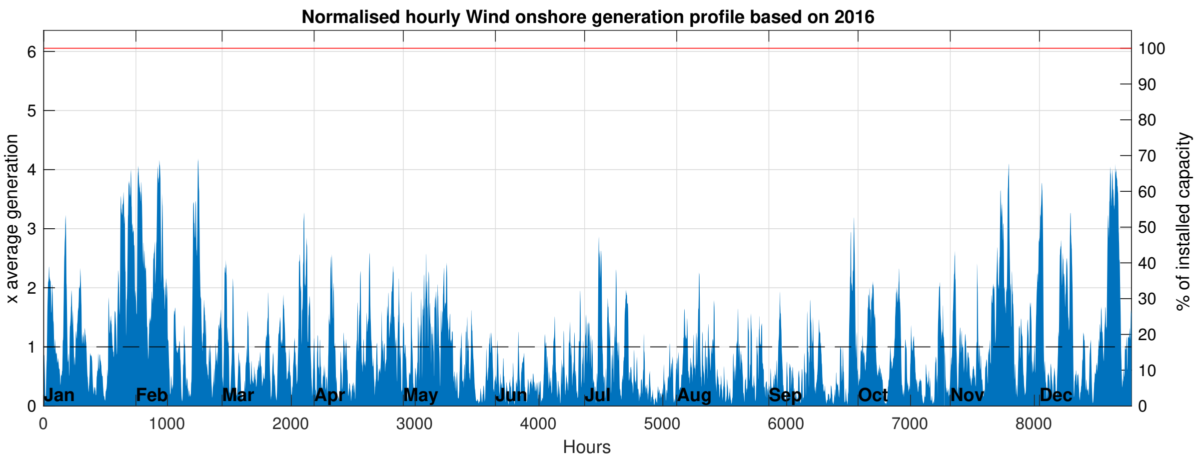


Figure F.16: Normalised hourly onshore wind electricity generation profile Germany, 2016 base year

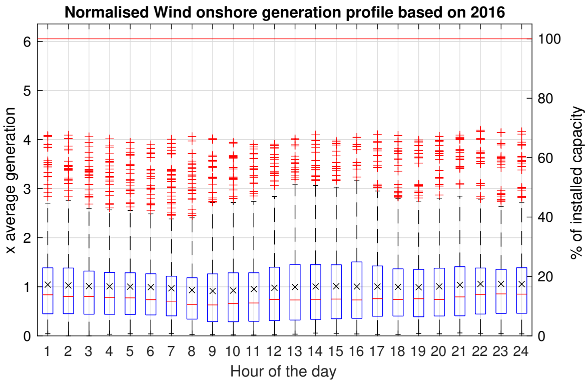


Figure F.17: Hourly boxplot normalised onshore wind electricity generation profile Germany, 2016 base year

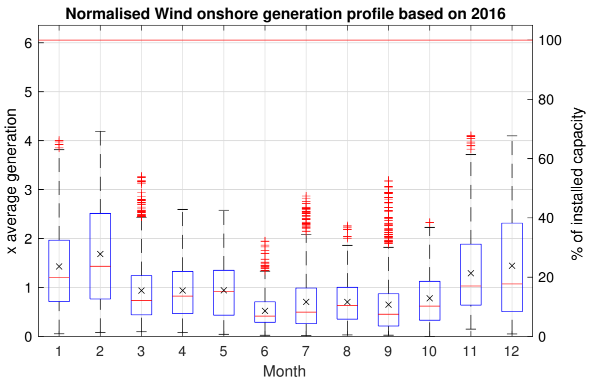


Figure F.18: Monthly boxplot normalised onshore wind electricity generation profile Germany, 2016 base year

F.1.3. Offshore wind electricity generation

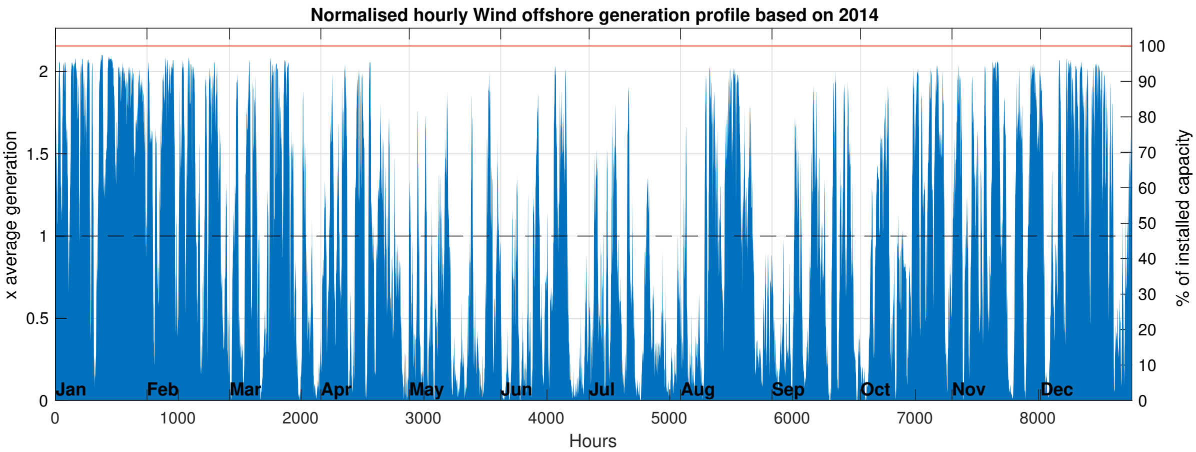


Figure F.19: Normalised hourly offshore wind electricity generation profile Germany, 2014 base year

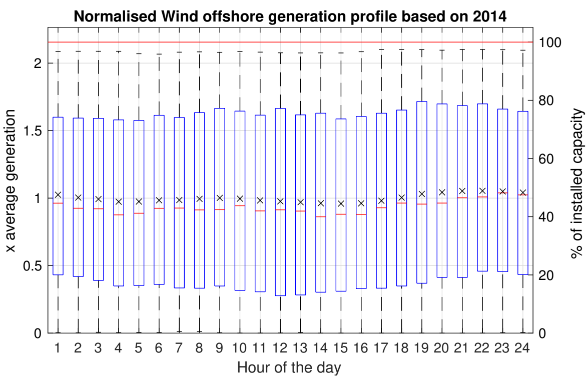


Figure F.20: Hourly boxplot normalised offshore wind electricity generation profile Germany, 2014 base year

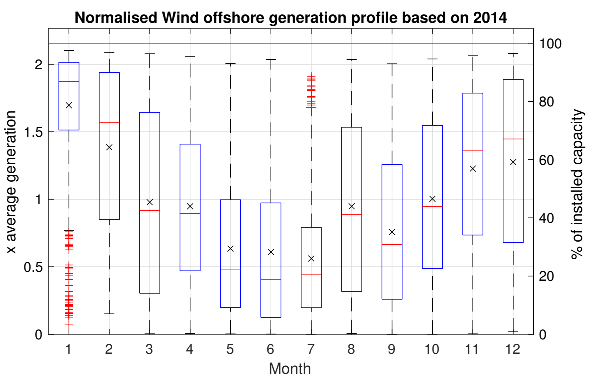


Figure F.21: Monthly boxplot normalised offshore wind electricity generation profile Germany, 2014 base year

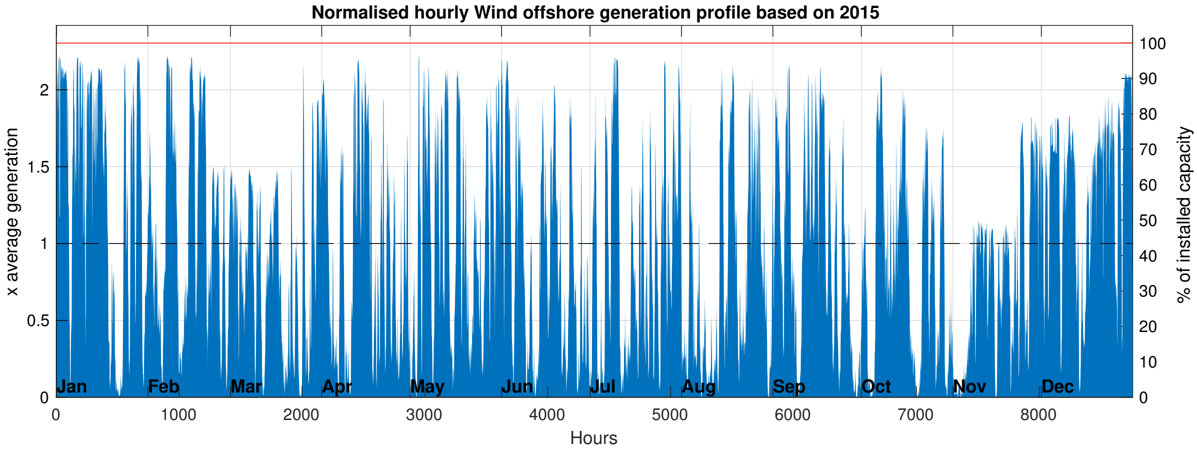


Figure F.22: Normalised hourly offshore wind electricity generation profile Germany, 2015 base year

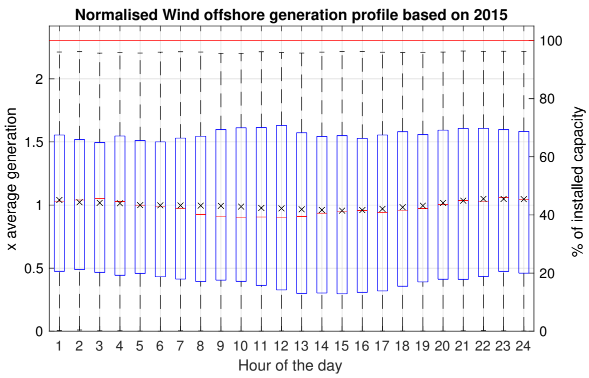


Figure F.23: Hourly boxplot normalised offshore wind electricity generation profile Germany, 2015 base year

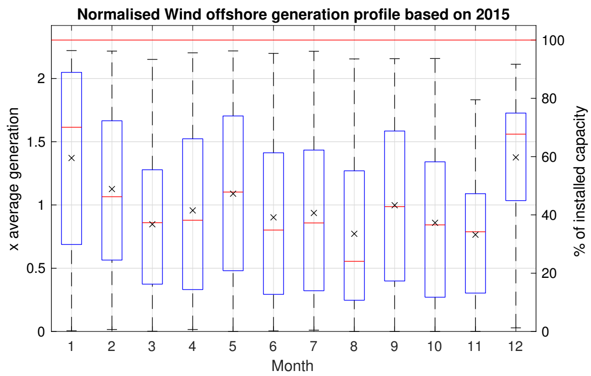


Figure F.24: Monthly boxplot normalised offshore wind electricity generation profile Germany, 2015 base year

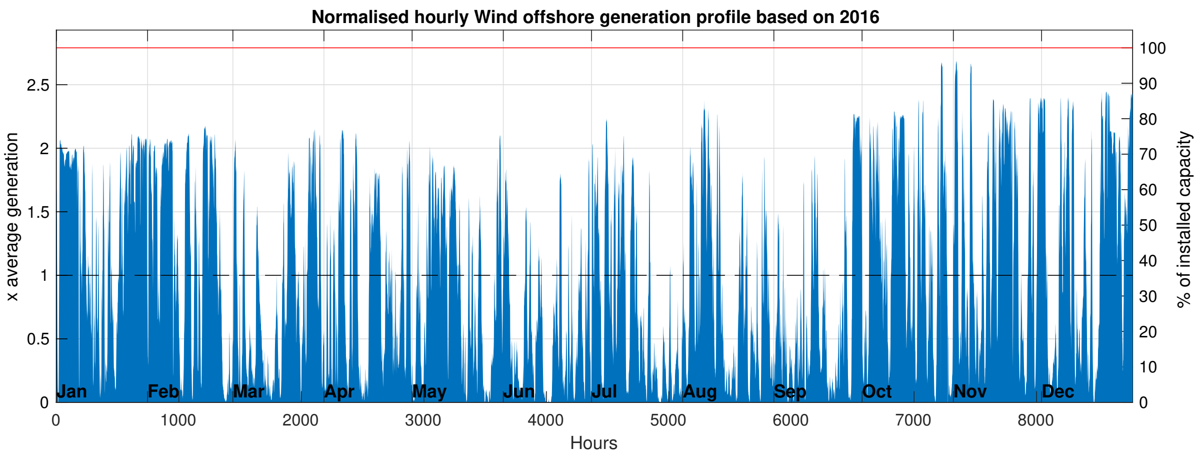


Figure F.25: Normalised hourly offshore wind electricity generation profile Germany, 2016 base year

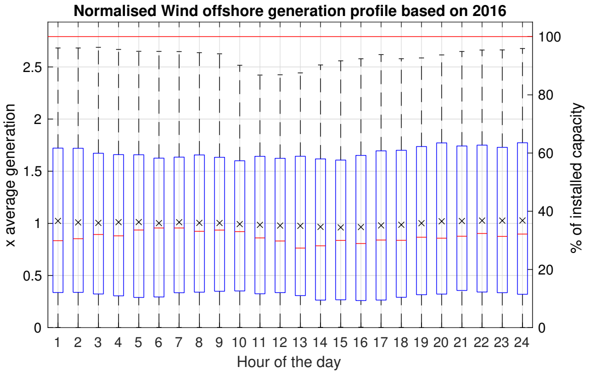


Figure F.26: Hourly boxplot normalised offshore wind electricity generation profile Germany, 2016 base year

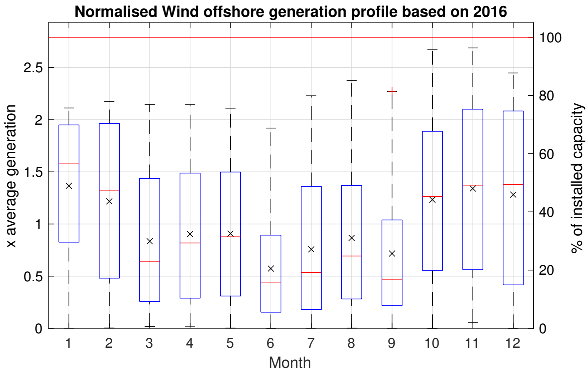


Figure F.27: Monthly boxplot normalised offshore wind electricity generation profile Germany, 2016 base year

F.1.4. Hydro

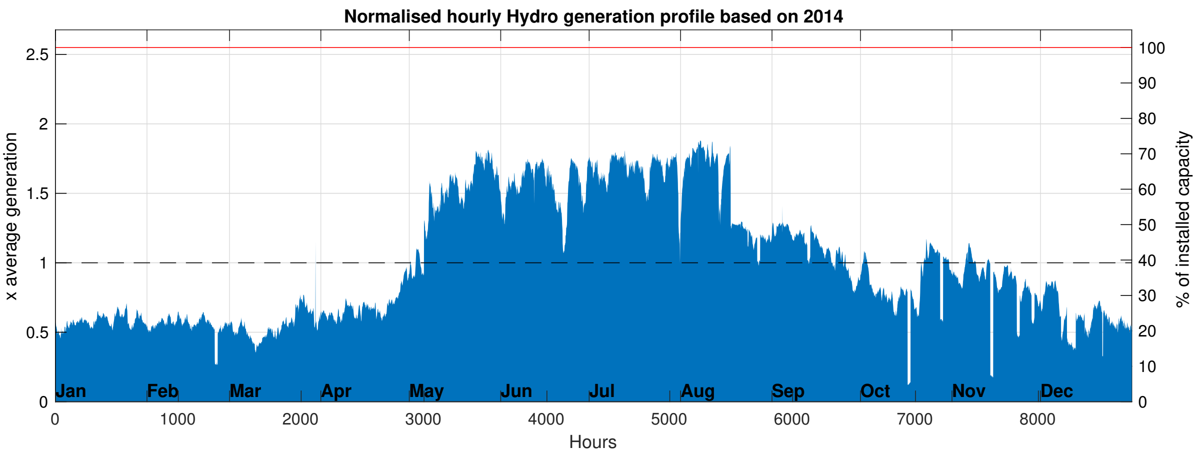


Figure F.28: Normalised hourly hydro electricity generation profile Germany, 2014 base year

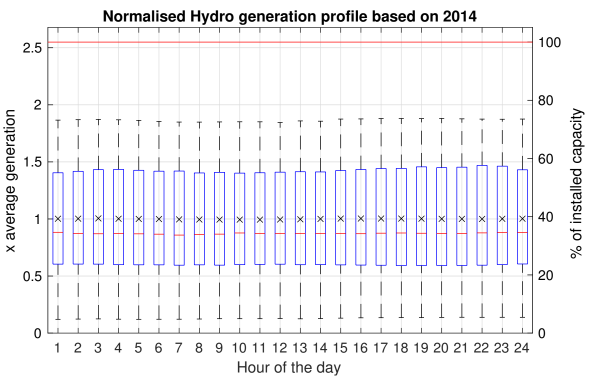


Figure F.29: Hourly boxplot normalised hydro electricity generation profile Germany, 2014 base year

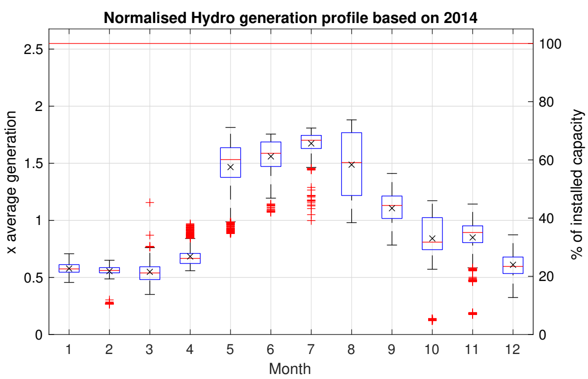


Figure F.30: Monthly boxplot normalised hydro electricity generation profile Germany, 2014 base year

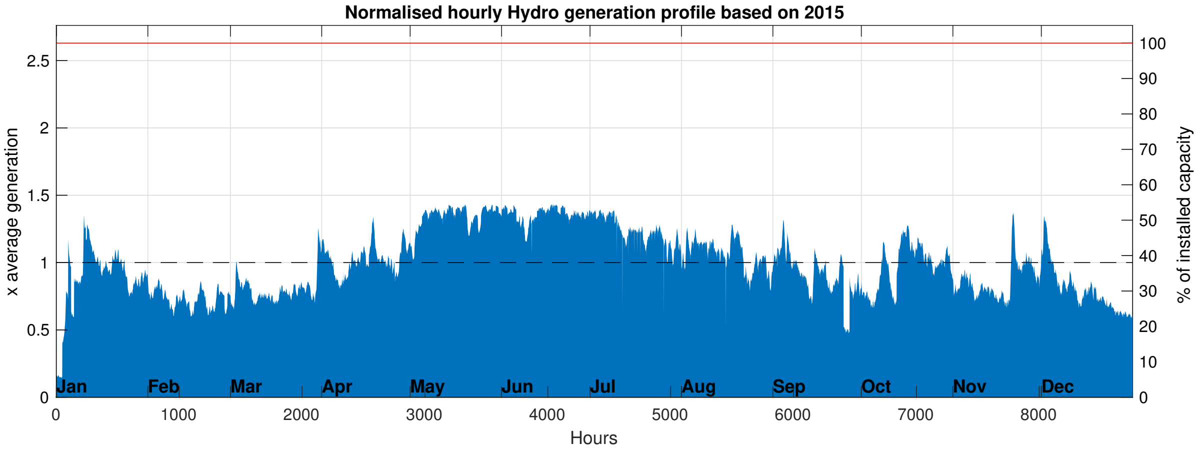


Figure F.31: Normalised hourly hydro electricity generation profile Germany, 2015 base year

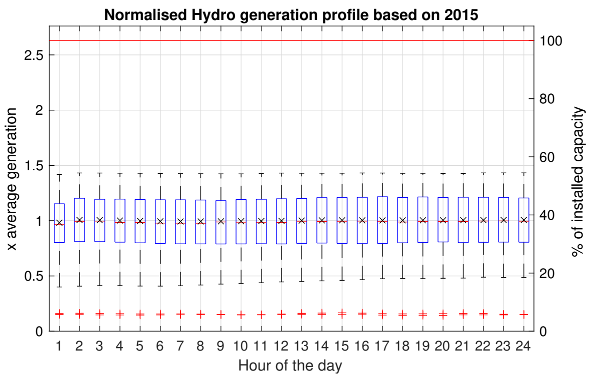


Figure F.32: Hourly boxplot normalised hydro electricity generation profile Germany, 2015 base year

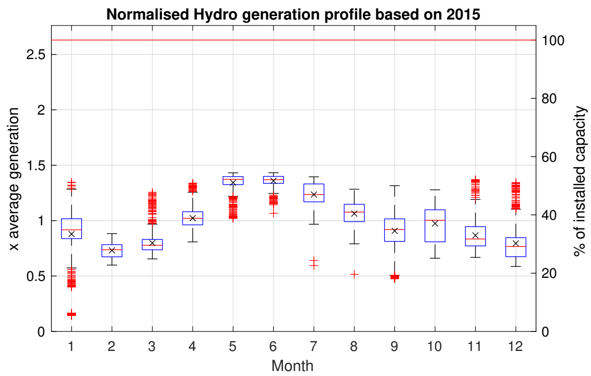


Figure F.33: Monthly boxplot normalised hydro electricity generation profile Germany, 2015 base year

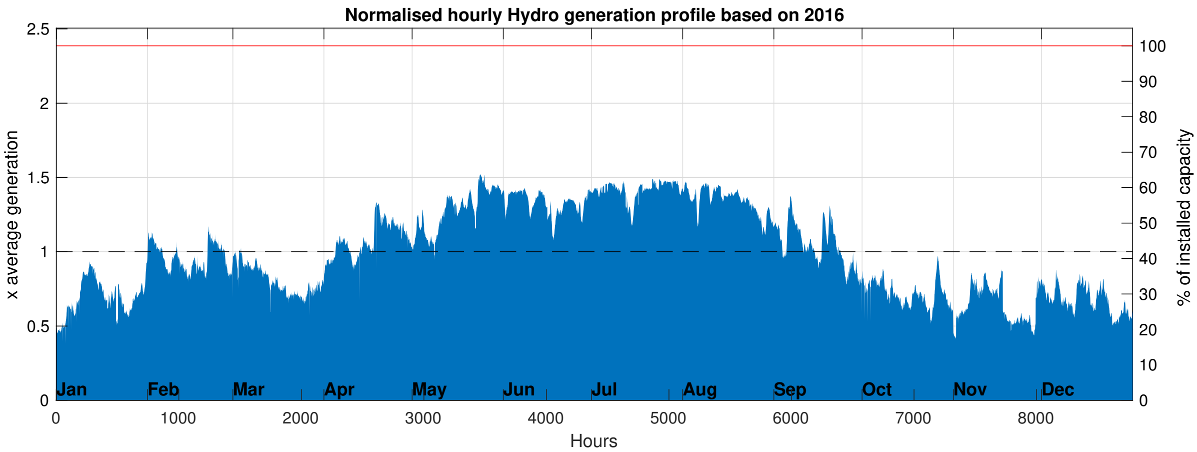


Figure F.34: Normalised hourly hydro electricity generation profile Germany, 2016 base year

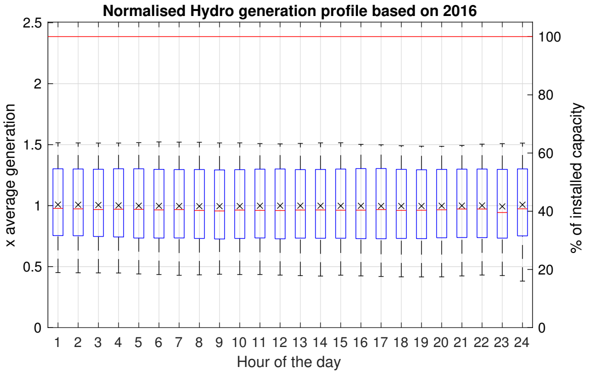


Figure F.35: Hourly boxplot normalised hydro electricity generation profile Germany, 2016 base year

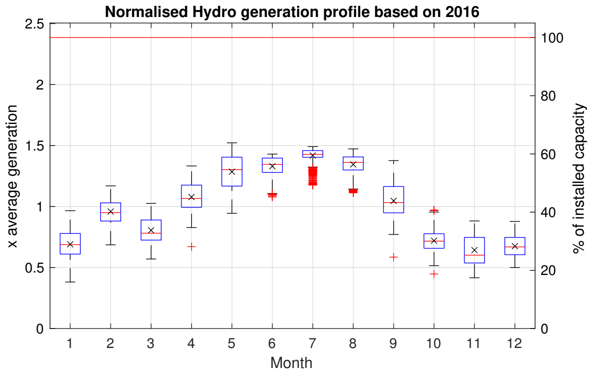


Figure F.36: Monthly boxplot normalised hydro electricity generation profile Germany, 2016 base year

F.1.5. Classic electricity consumption

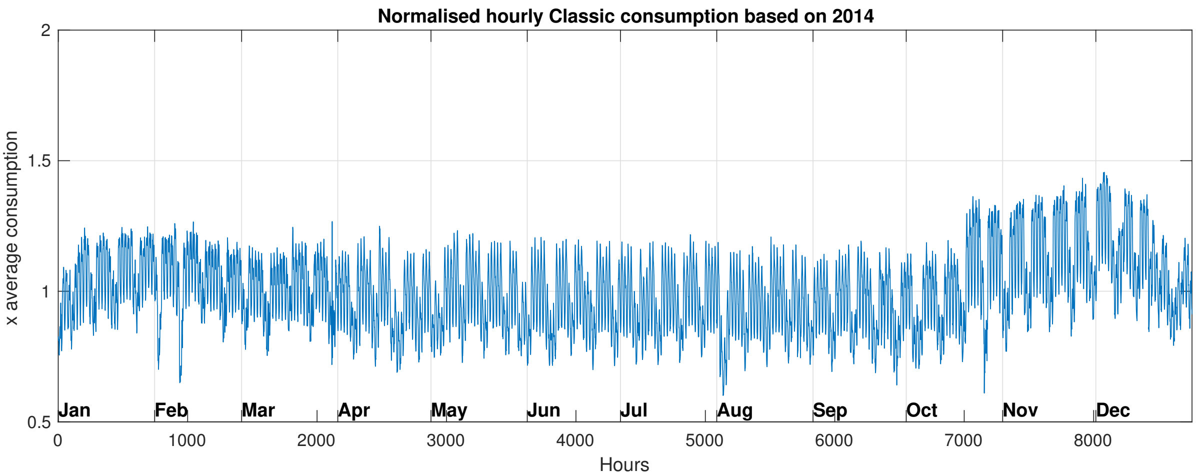


Figure F.37: Normalised hourly classic electricity consumption profile Germany, 2014 base year

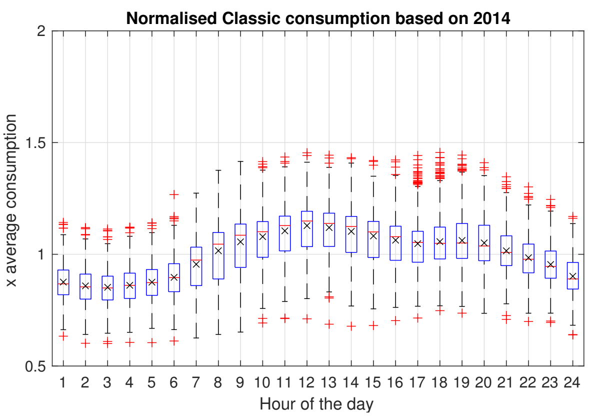


Figure F.38: Hourly boxplot normalised classic electricity consumption profile Germany, 2014 base year

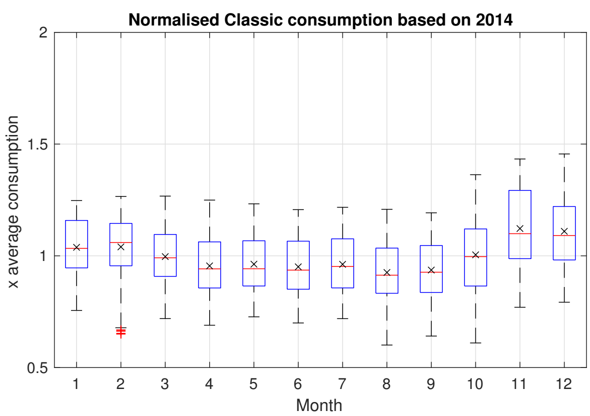


Figure F.39: Monthly boxplot normalised classic electricity consumption profile Germany, 2014 base year

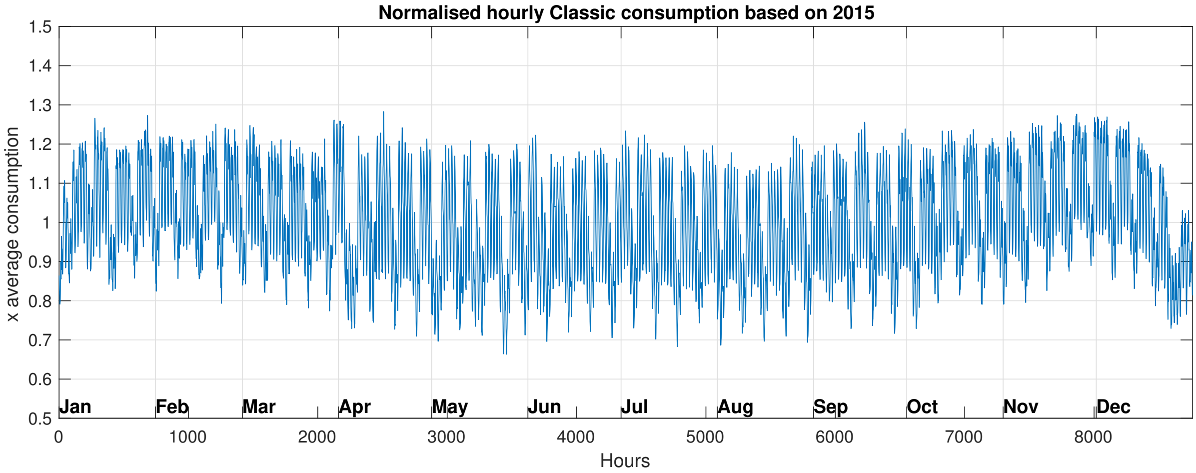


Figure F.40: Normalised hourly classic electricity consumption profile Germany, 2015 base year

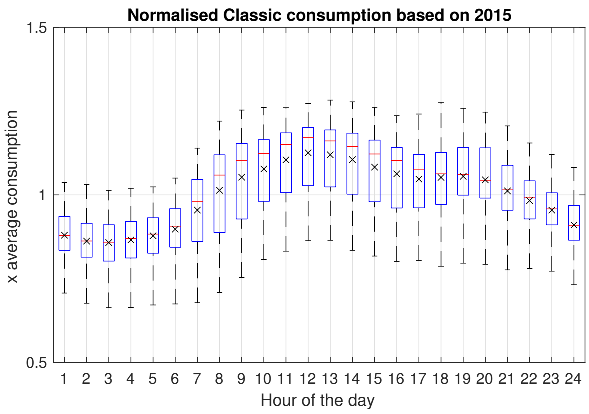


Figure F.41: Hourly boxplot normalised classic electricity consumption profile Germany, 2015 base year

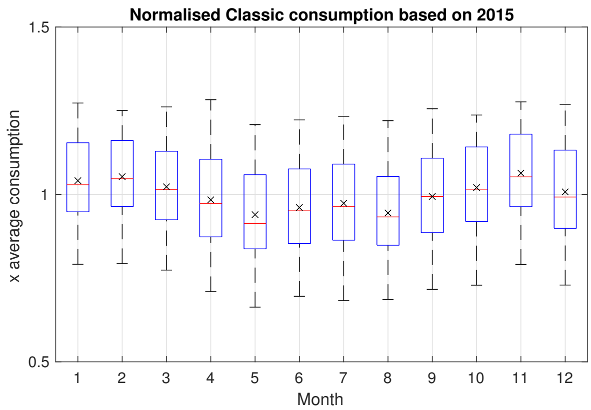


Figure F.42: Monthly boxplot normalised classic electricity consumption profile Germany, 2015 base year

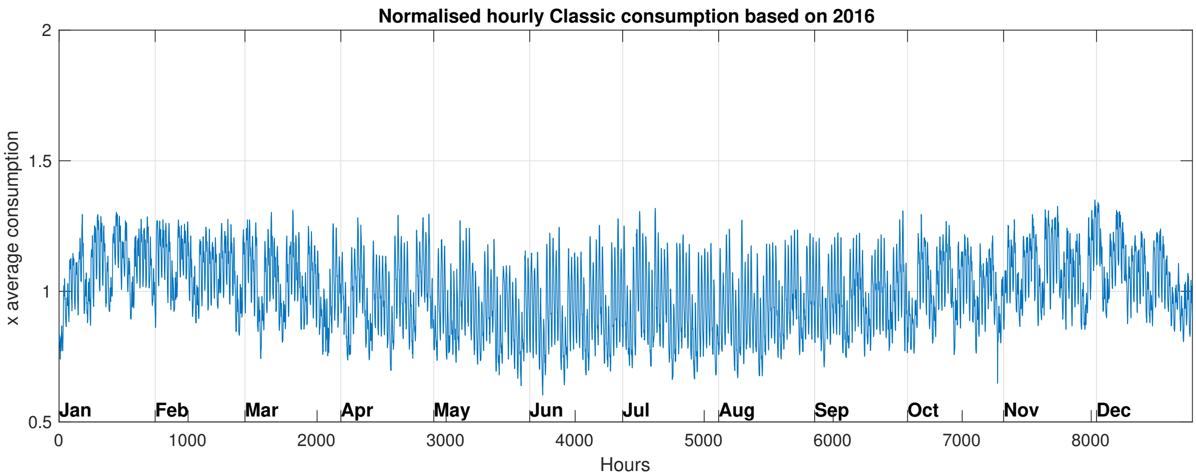


Figure F.43: Normalised hourly classic electricity consumption profile Germany, 2016 base year

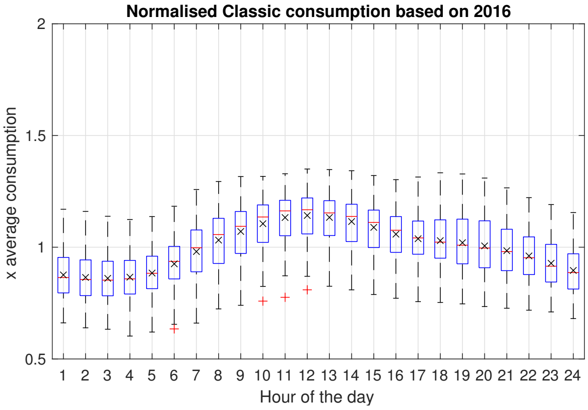


Figure F.44: Hourly boxplot normalised classic electricity consumption profile Germany, 2016 base year

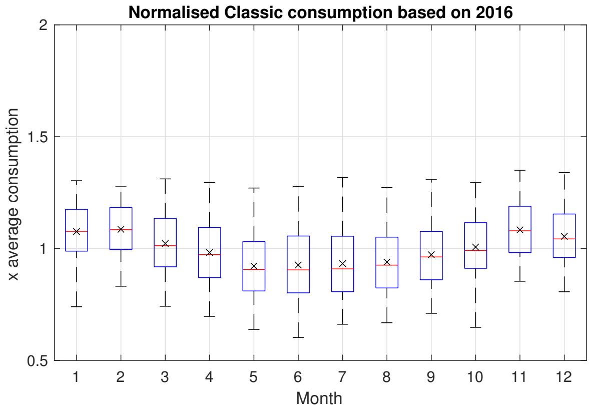


Figure F.45: Monthly boxplot normalised classic electricity consumption profile Germany, 2016 base year

F.1.6. Electric heating demand & average outside temperature

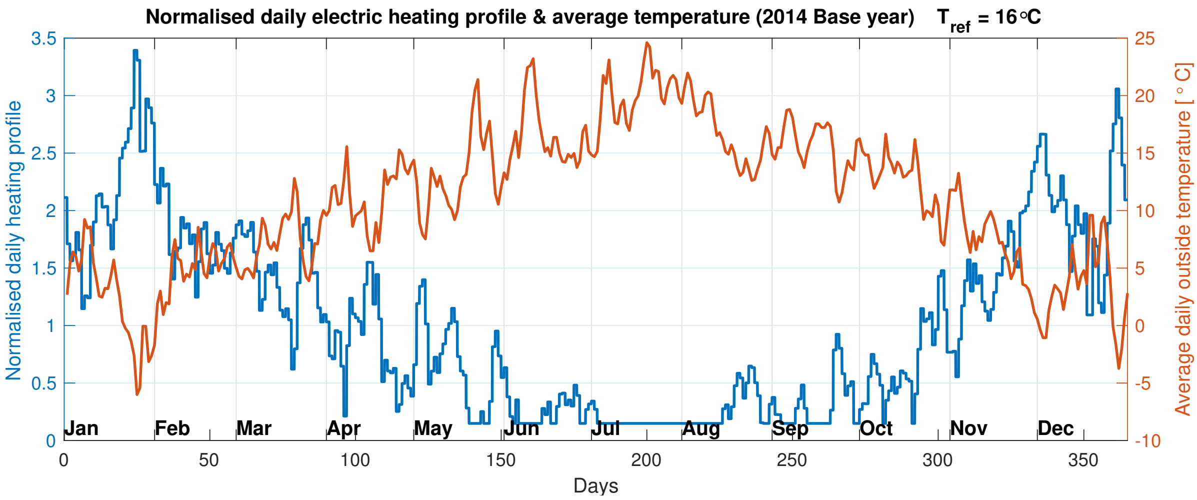


Figure F.46: Normalised daily electric heating demand, 2014 base year

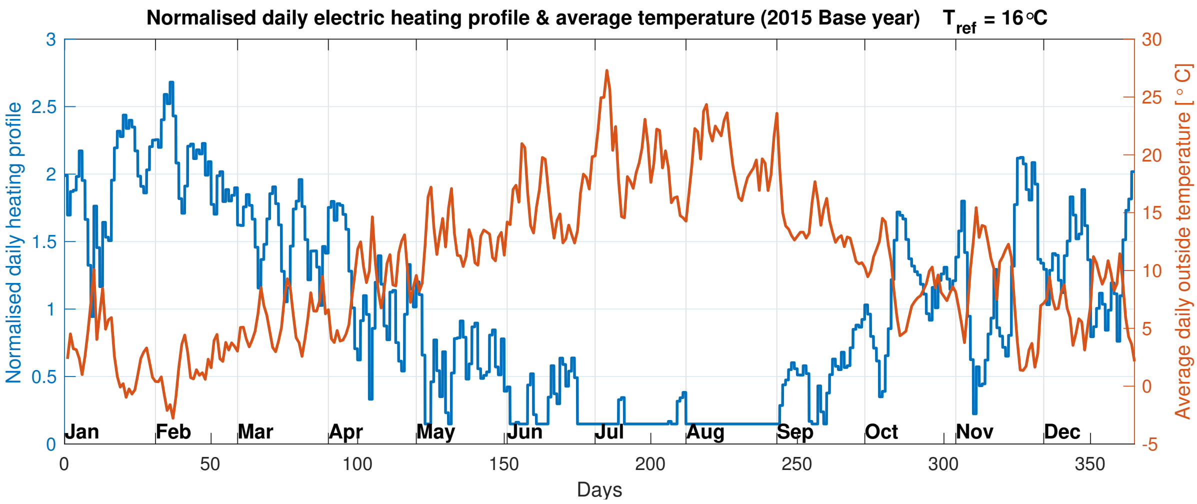


Figure F.47: Normalised daily electric heating demand, 2015 base year

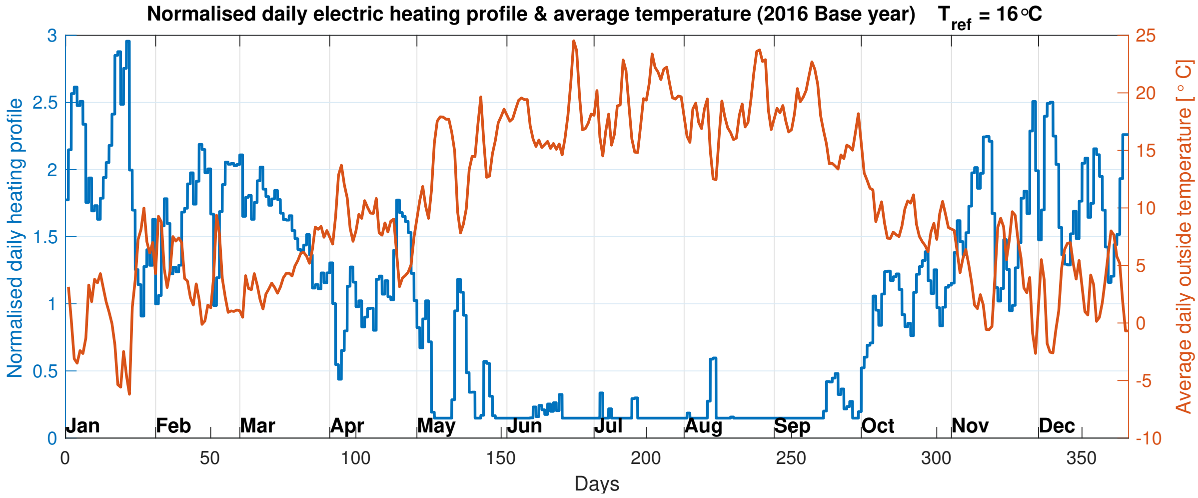


Figure F.48: Normalised daily electric heating demand, 2016 base year

F.2. Model output

Table F.1: Model outputs Germany

	2014	2015	2016		2014	2015	2016
Electricity generation (TWh)				Direct electricity consumption (TWh)	486.10	486.69	485.26
Solar	273.69	267.93	299.36	% of total electricity consumption	88.53	88.63	88.13
Onshore wind	322.15	347.91	323.21	Electrolyser consumption (TWh)	318.08	316.56	322.15
Offshore wind	169.30	149.80	144.37	Electrolyser capacity (GW)	223.86	241.60	270.23
Hydro	17.04	15.62	18.41	Electrolyser capacity factor (%)	16.22	14.96	13.57
CHP	22.00	22.00	22.06	FCEV V2G demand (TWh)	63.00	62.41	65.34
Total	804.18	803.26	807.41	FCEV V2G peak demand (GW)	79.97	61.59	64.71
Installed capacity (GW)				million vehicles	8.00	6.16	6.47
Solar	287.68	272.02	316.68	% of passenger FCEVs	36.38	28.02	29.44
Onshore wind	202.37	191.35	222.77	Peak storage capacity (million kg)	1251.09	1780.74	1938.20
Offshore wind	41.66	39.40	45.86	BEV charging load (GW)	7.13	7.13	7.13
Hydro	4.96	4.69	5.00				
CHP	14.00	14.00	14.00				
Total	550.67	521.46	604.31				
Electricity consumption (TWh)							
Classic	375.00	375.00	376.03				
Electricity for heating	116.22	116.22	116.54				
BEV charging	57.88	57.88	58.03				
Total	549.10	549.10	550.60				
Road transport cons. (TWh)	145.39	145.39	145.79				
Final energy cons. (TWh)	997.39	997.39	998.82				
Hydrogen cons. (million kg)							
Road transport	3824.00	3824.00	3834.48				
V2G	2664.46	2639.47	2763.25				
Residual storage	30.87	24.41	6.12				
Total production	6519.69	6488.71	6603.12				

F.2.1. Sankey diagrams

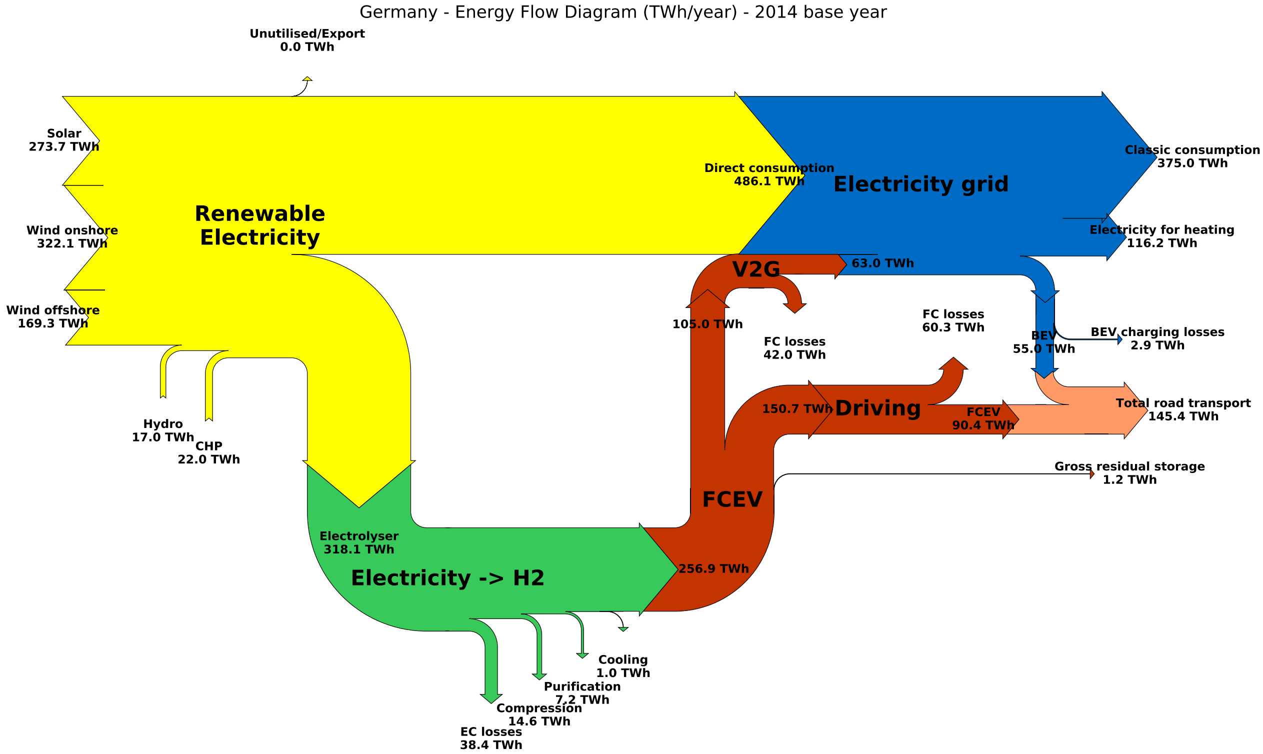


Figure F.49: Energy flow diagram for Germany with 2014 as base year

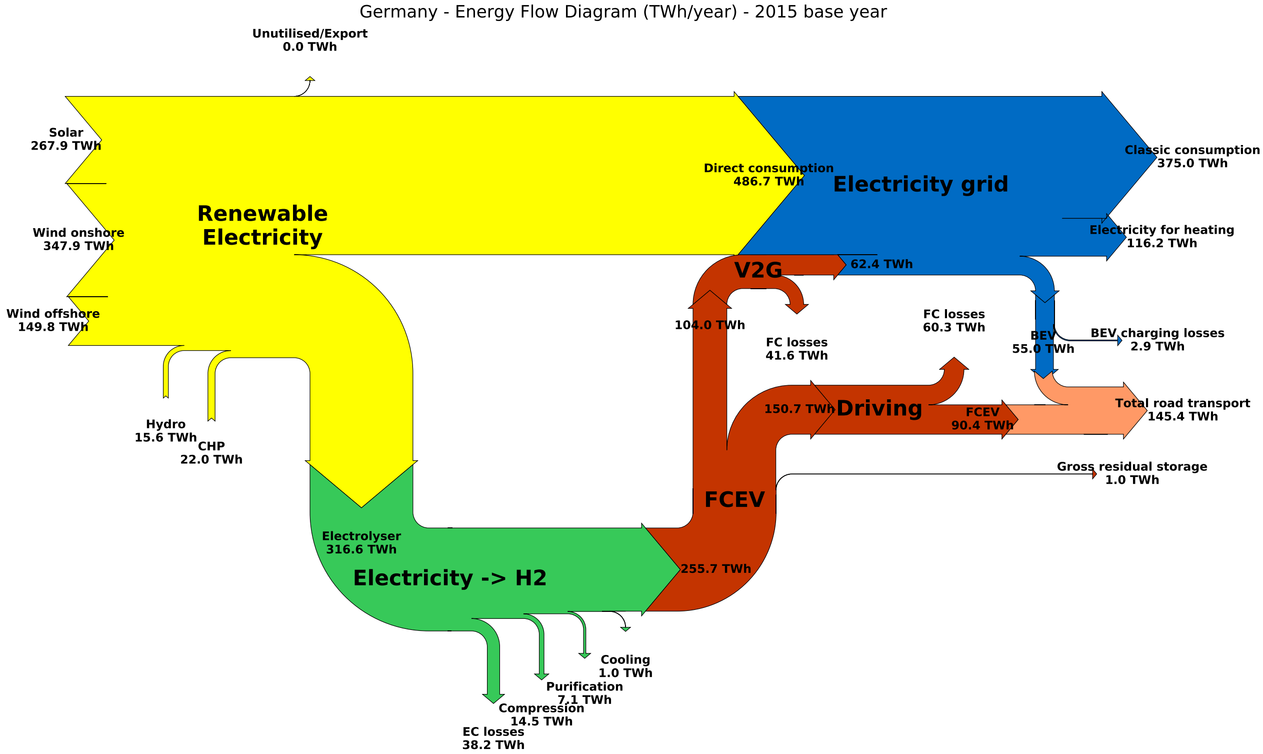


Figure F.50: Energy flow diagram for Germany with 2015 as base year

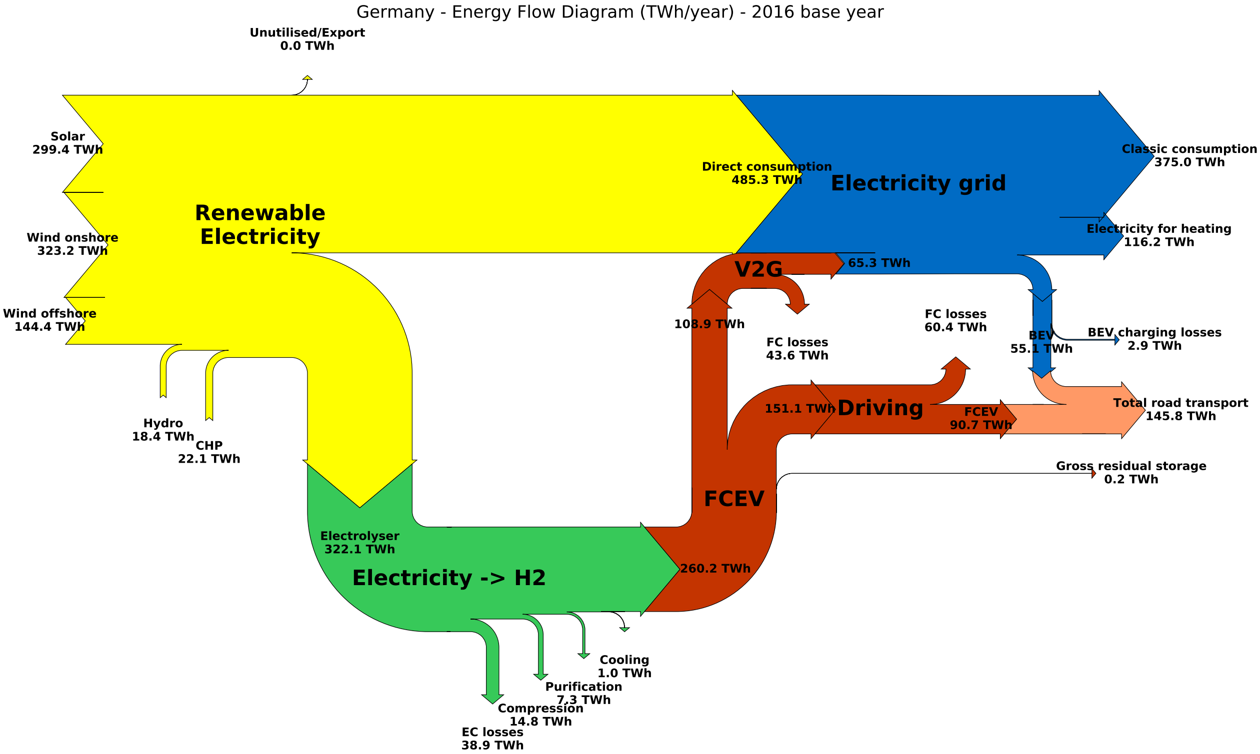


Figure F.51: Energy flow diagram for Germany with 2016 as base year

F.2.2. Generation & Consumption profiles (2016 base year)

Only the scaled generation and consumption profiles for base year 2016 are shown to the generation and consumption in terms of GW's. The shape of the profiles are the same as the normalised profile.

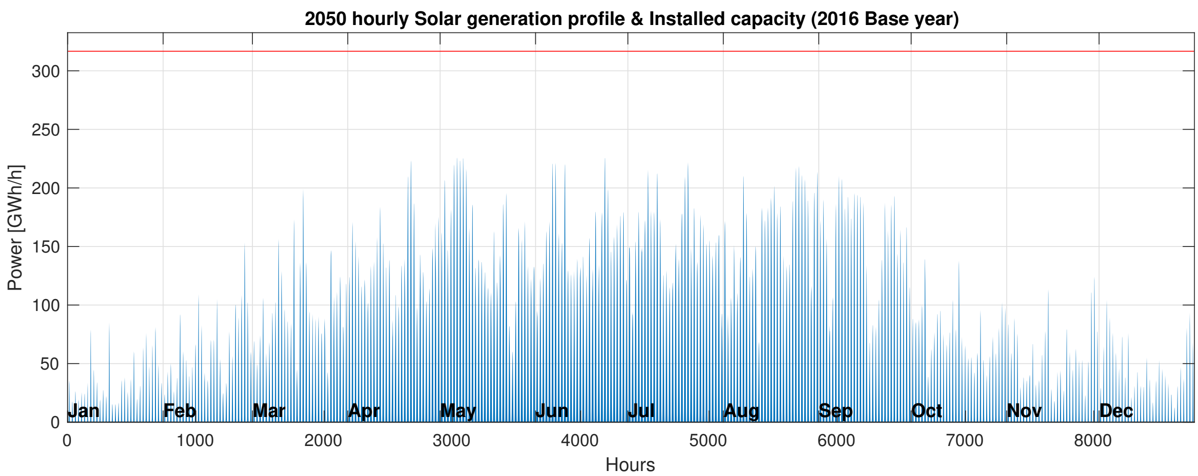


Figure F.52: Solar electricity generation in Germany in 2050 (2016 base year)

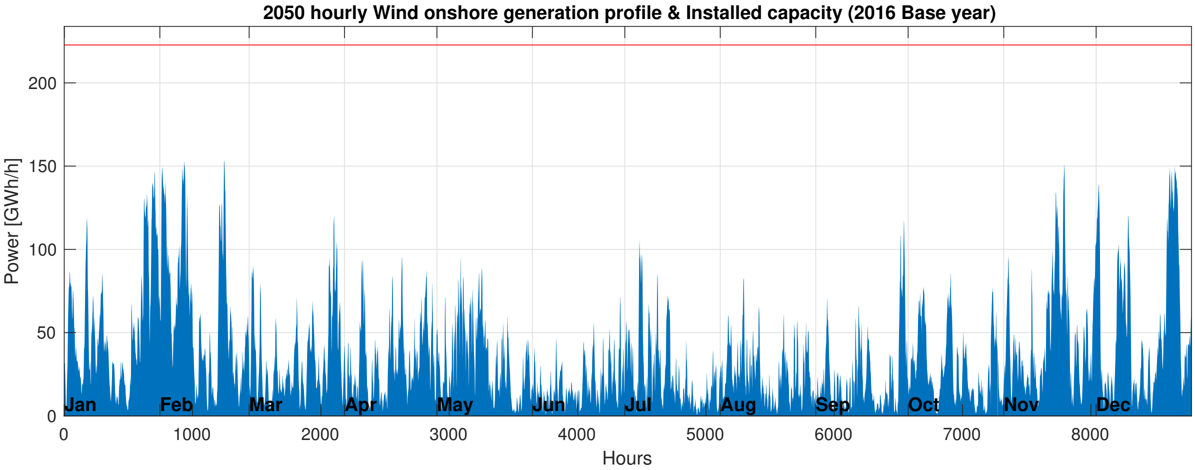


Figure F.53: Onshore wind electricity generation in Germany in 2050 (2016 base year)

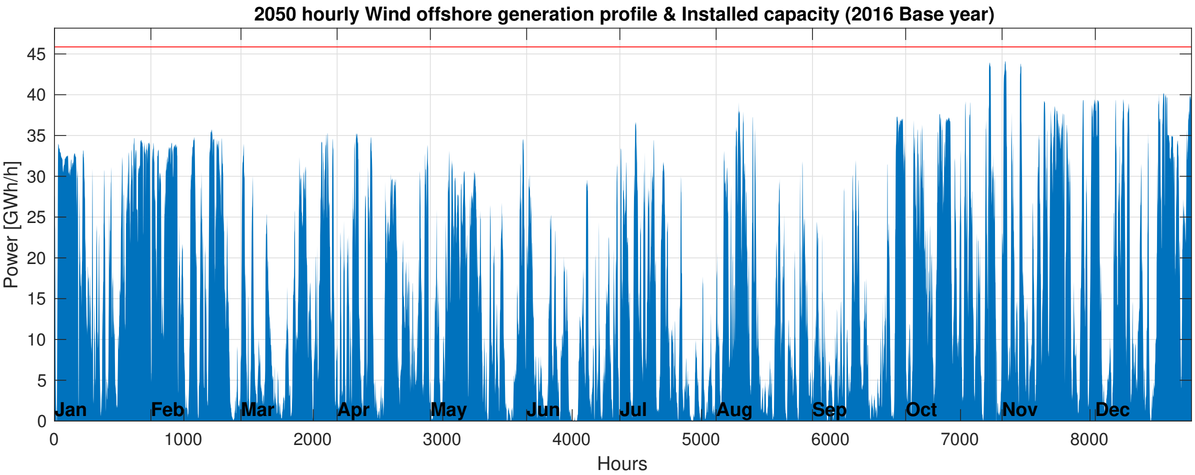


Figure F.54: Offshore wind electricity generation in Germany in 2050 (2016 base year)

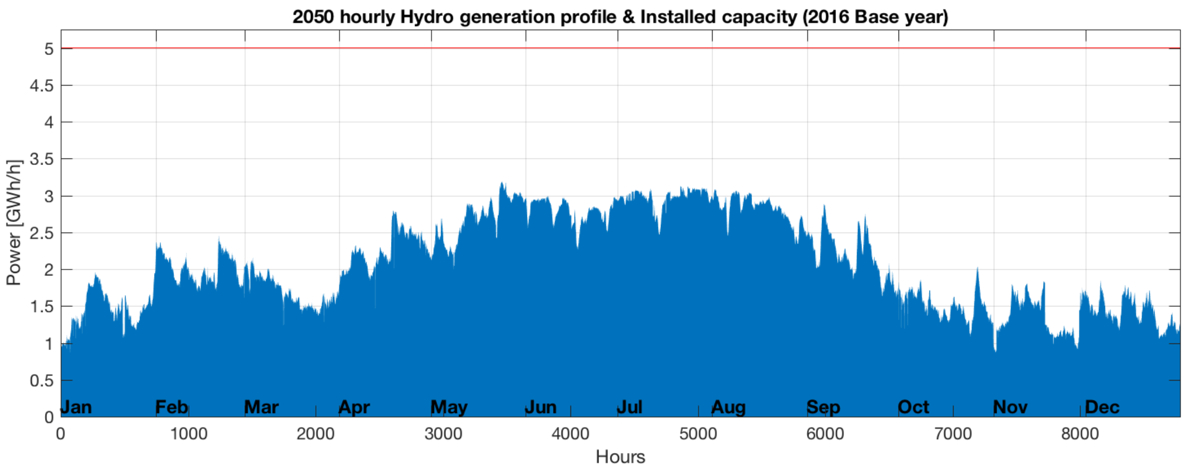


Figure F.55: Hydro electricity generation in Germany in 2050 (2016 base year)

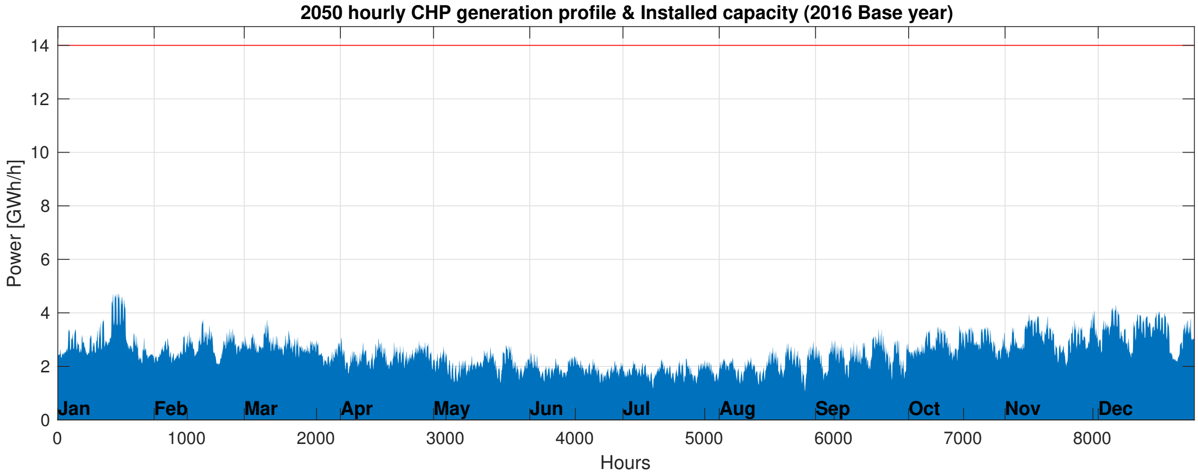


Figure F.56: CHP electricity generation in Germany in 2050 (2016 base year)

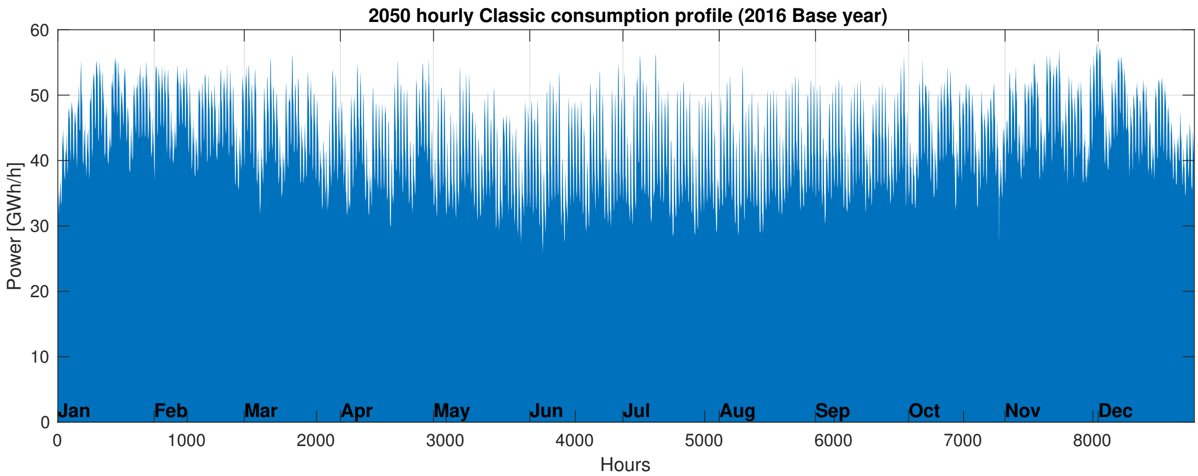


Figure F.57: Classic electricity consumption in Germany in 2050 (2016 base year)

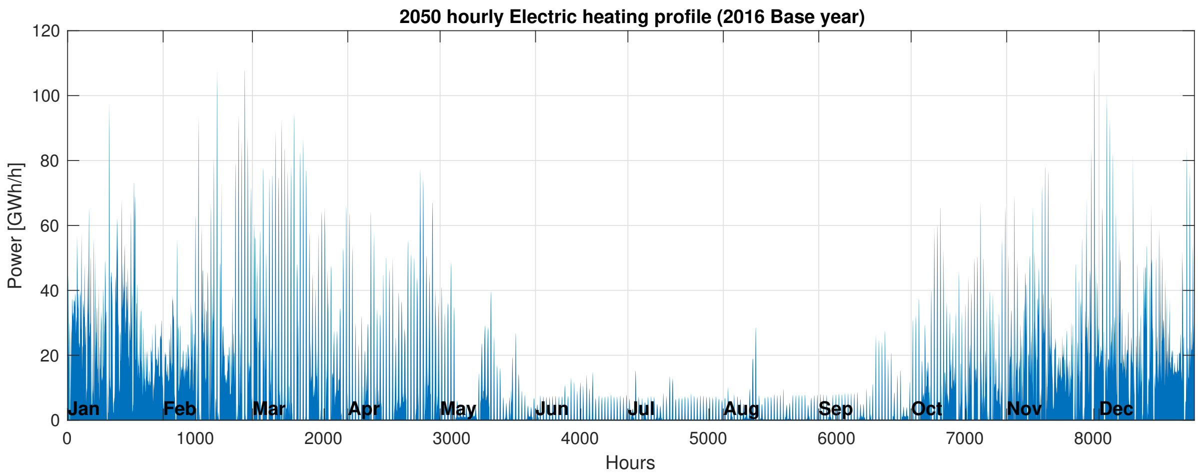


Figure F.58: Electric heating consumption in Germany in 2050 (2016 base year)

F.2.3. Imbalance

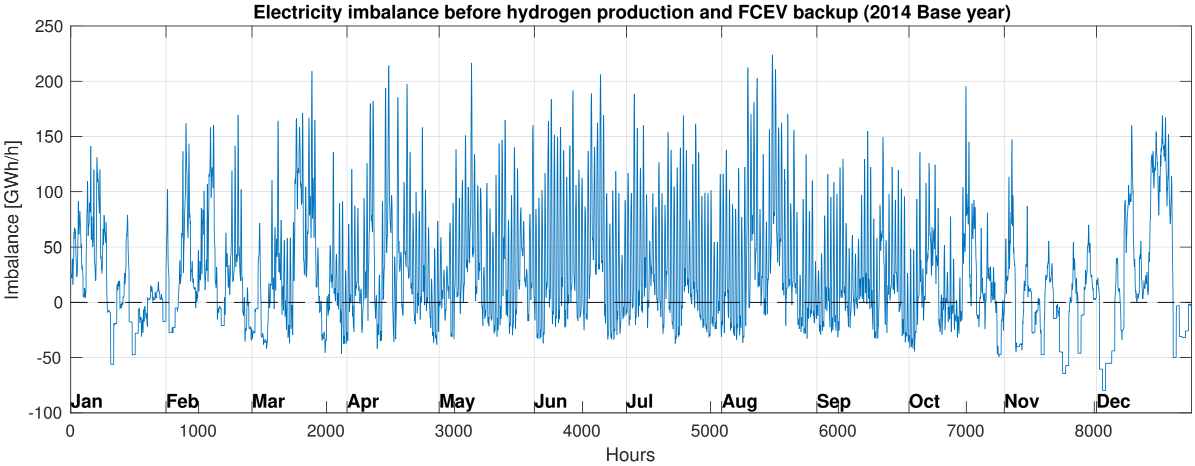


Figure F.59: Electric imbalance in Germany in 2050 (2014 base year)

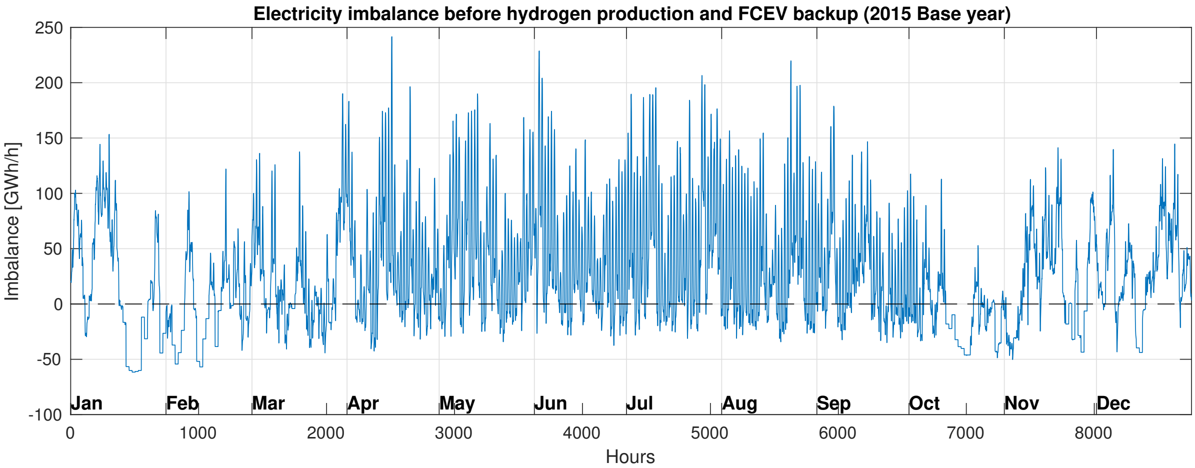


Figure F.60: Electric imbalance in Germany in 2050 (2015 base year)

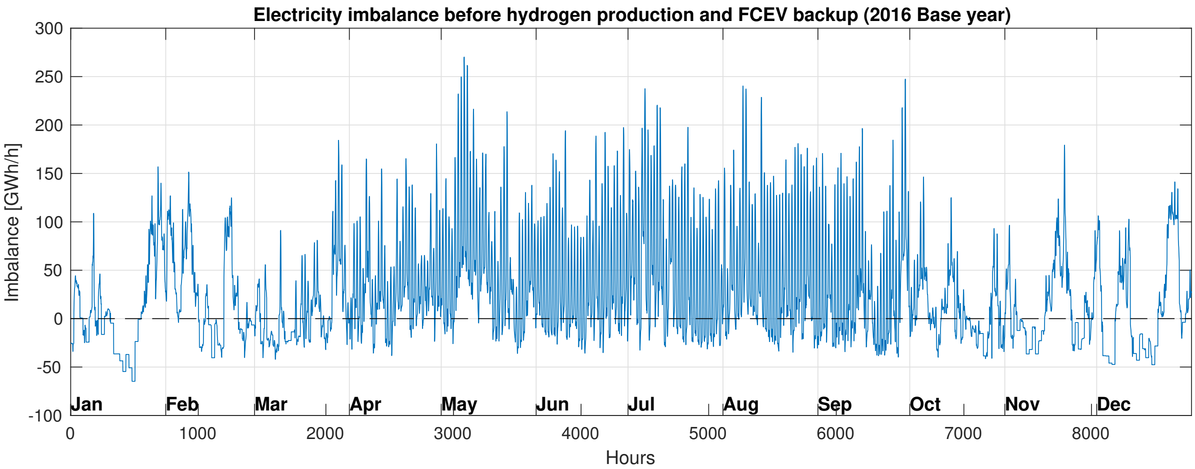


Figure F.61: Electric imbalance in Germany in 2050 (2016 base year)

Electrolyser

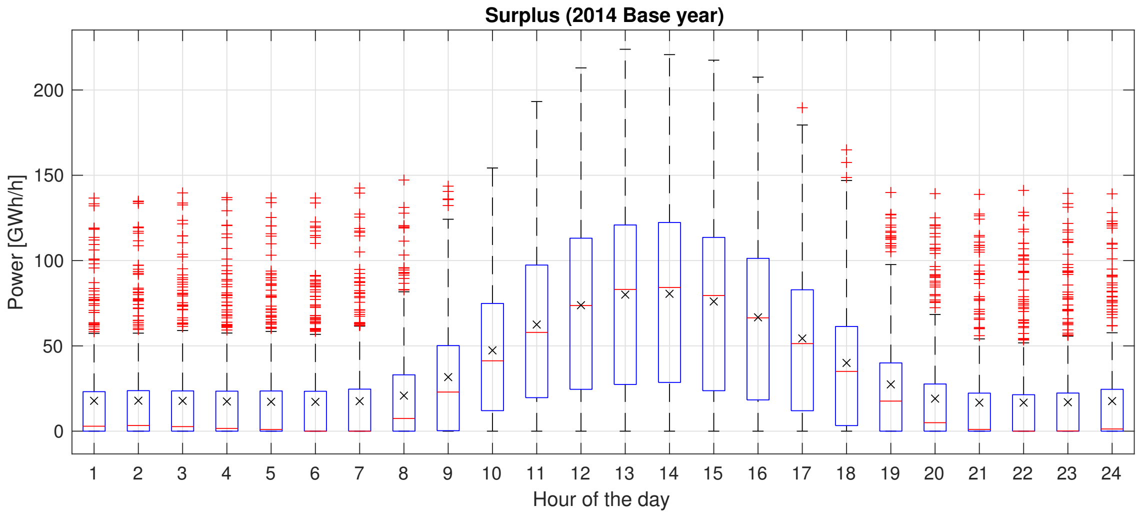


Figure F.62: Hourly boxplot electrolyser consumption in Germany in 2050 (2014 base year)

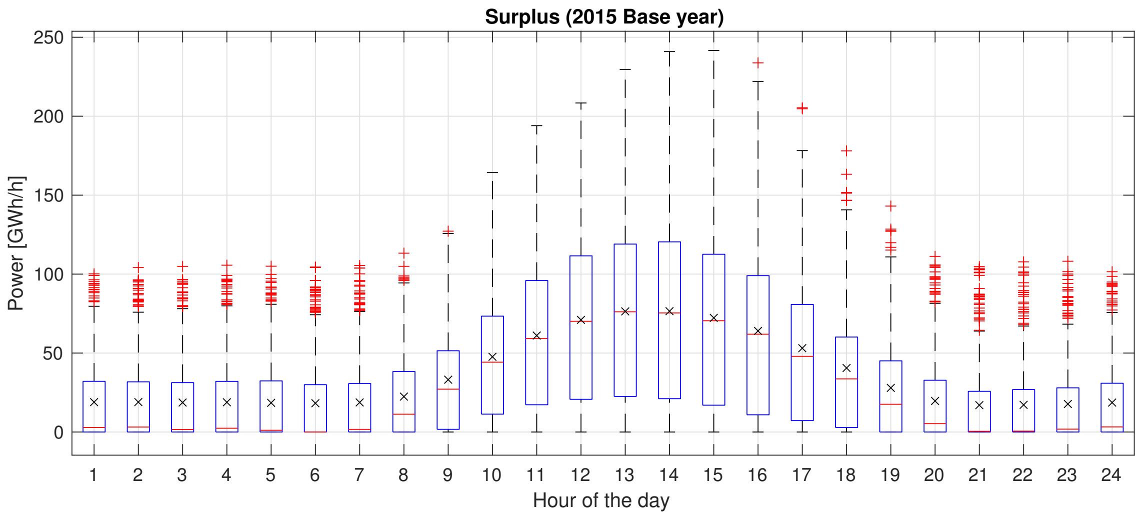


Figure F.63: Hourly boxplot electrolyser consumption in Germany in 2050 (2015 base year)

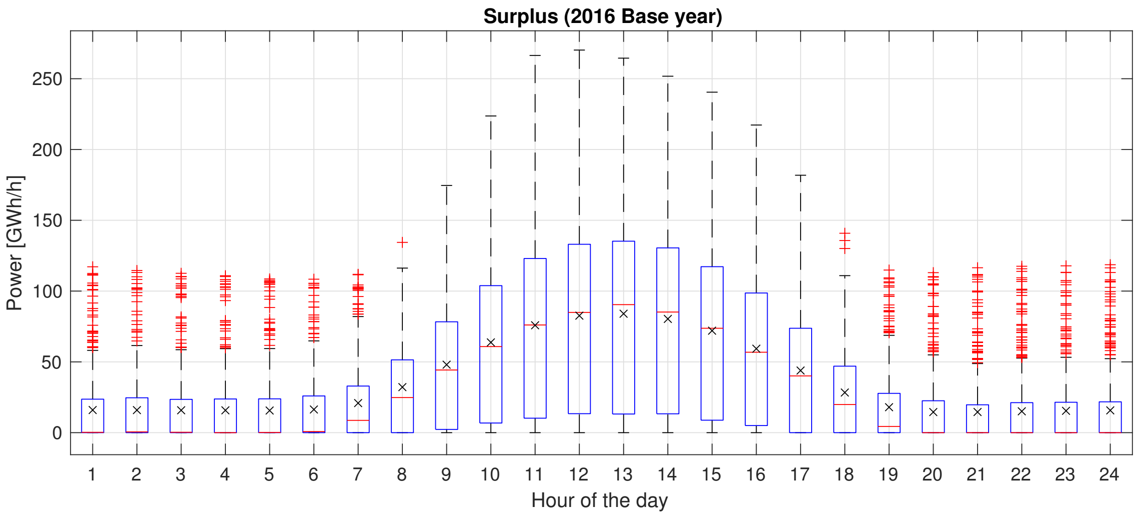


Figure F.64: Hourly boxplot electrolyser consumption in Germany in 2050 (2016 base year)

F.2.4. FCEV backup

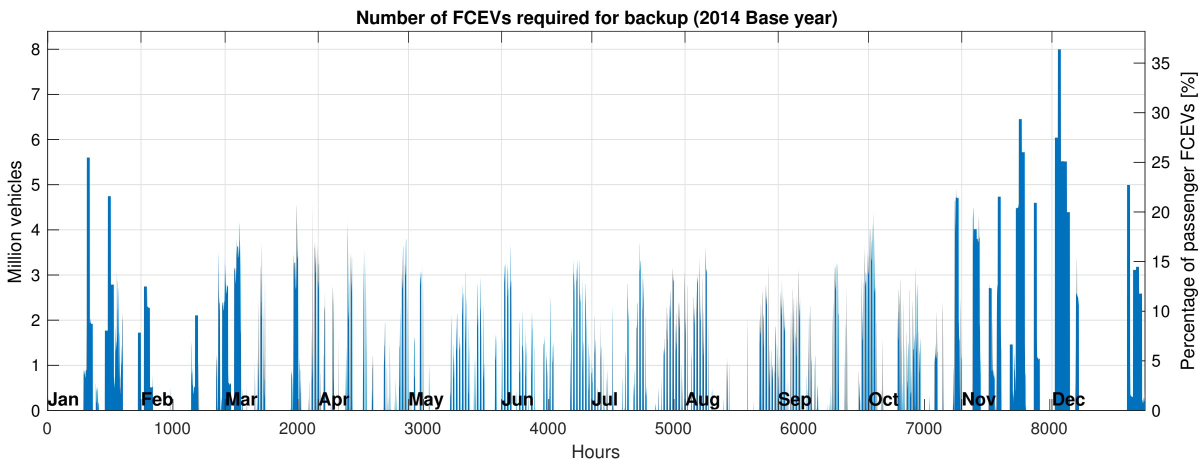


Figure F.65: FCEV backup in Germany in 2050 (2014 base year)

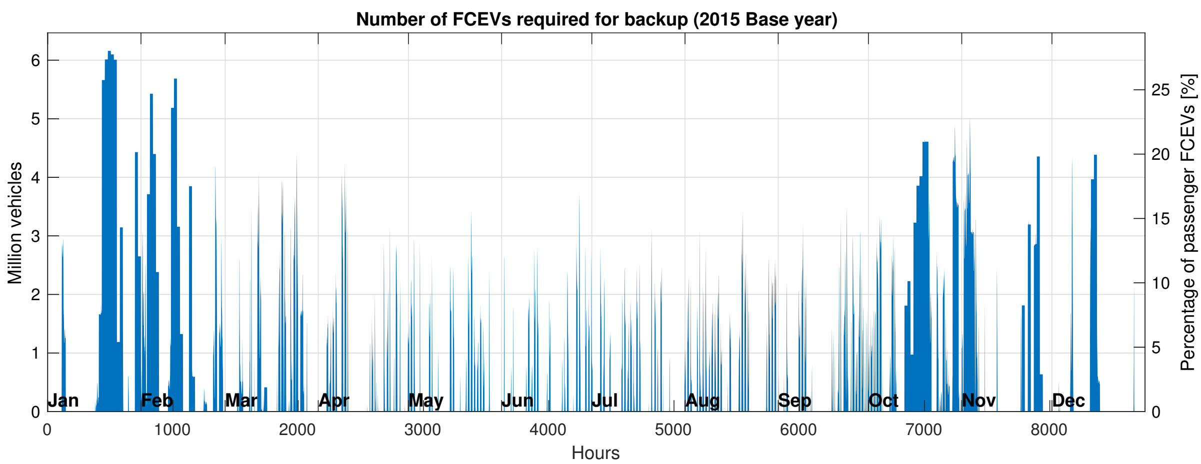


Figure F.66: FCEV backup in Germany in 2050 (2015 base year)

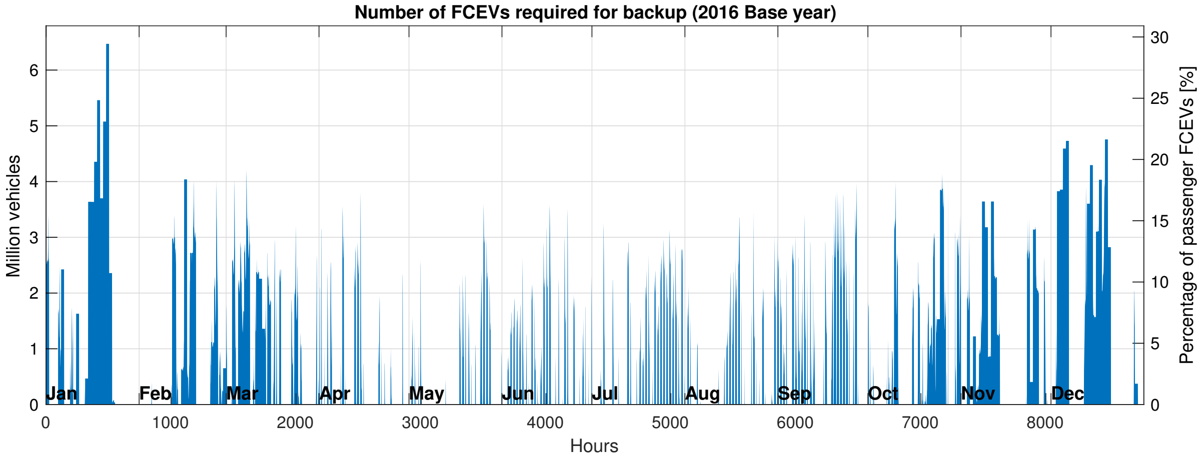


Figure F.67: FCEV backup in Germany in 2050 (2016 base year)

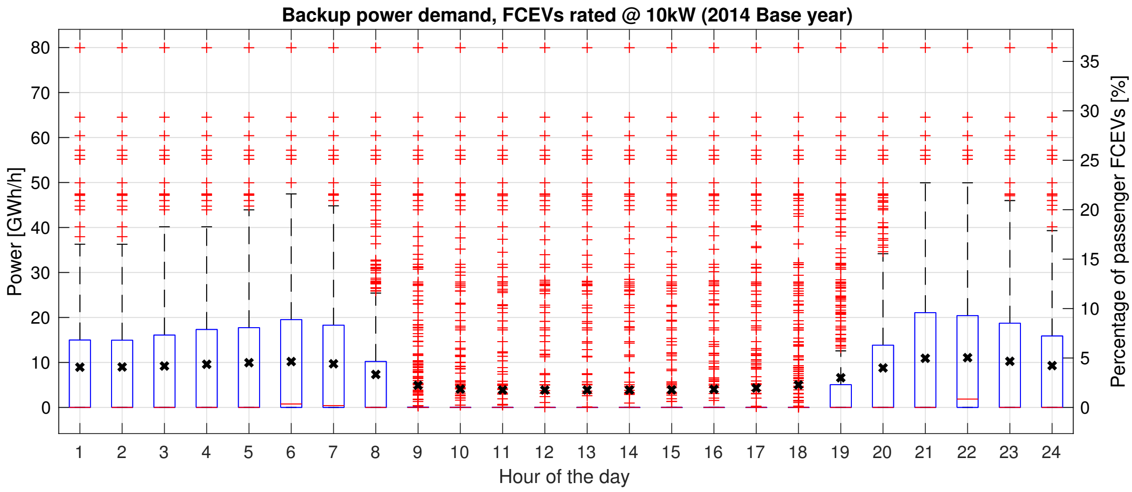


Figure F.68: Hourly boxplot FCEV backup in Germany in 2050 (2014 base year)

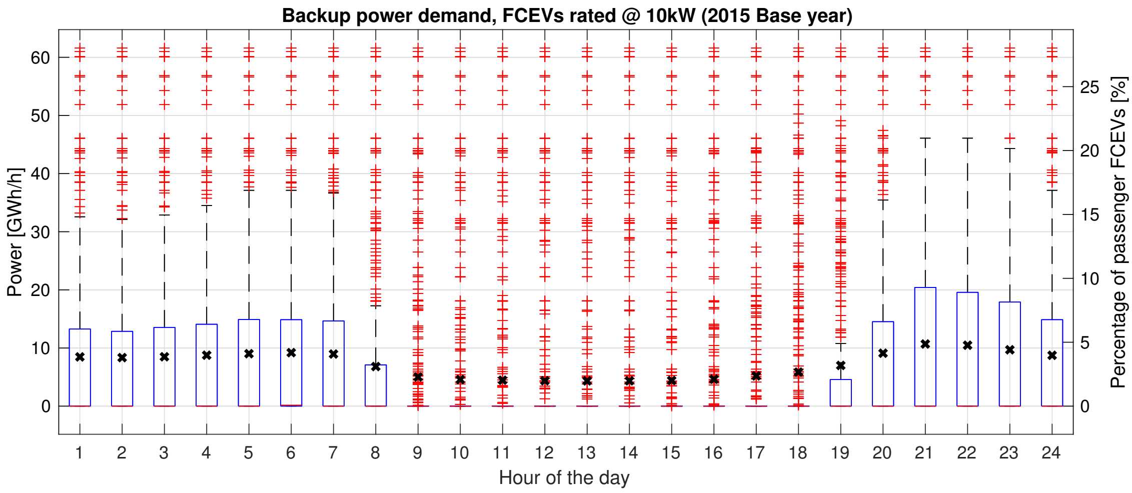


Figure F.69: Hourly boxplot FCEV backup in Germany in 2050 (2015 base year)

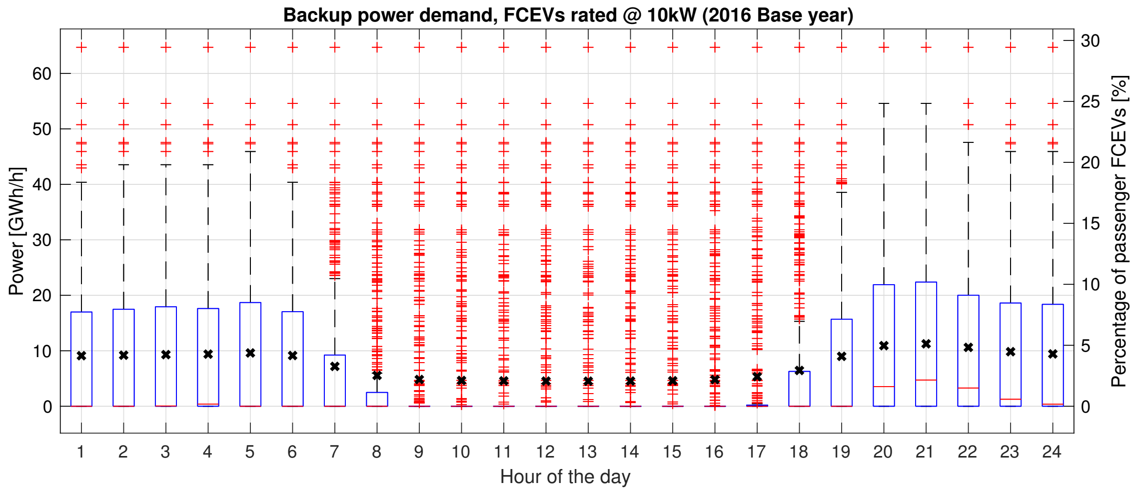


Figure F.70: Hourly boxplot FCEV backup in Germany in 2050 (2016 base year)

F.2.5. Weekly charge & discharge rates of hydrogen

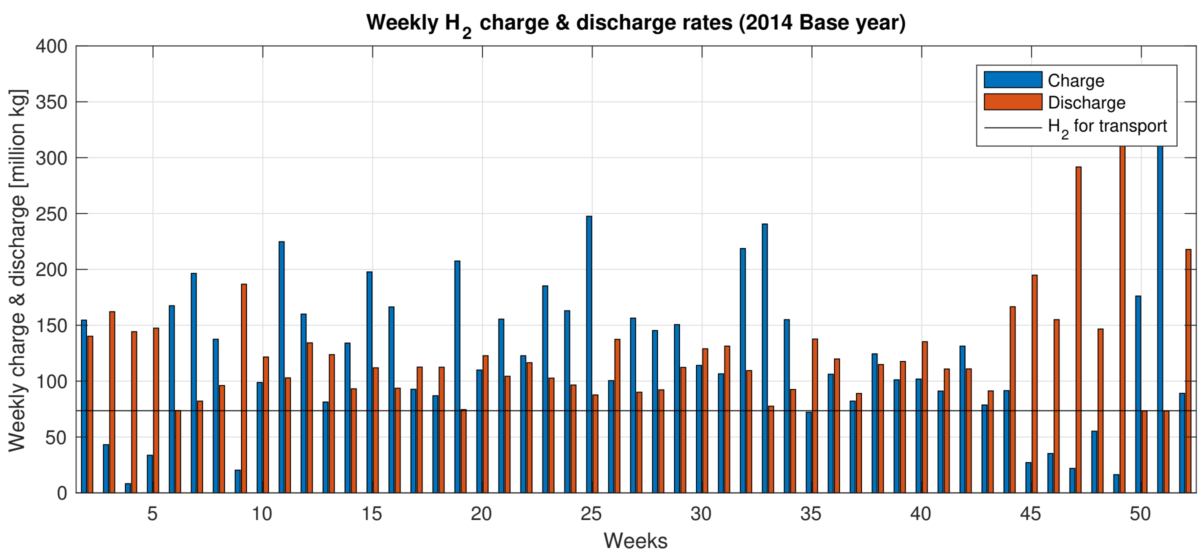


Figure F.71: Hydrogen weekly charge and discharge rates in Germany in 2050 (2014 base year)

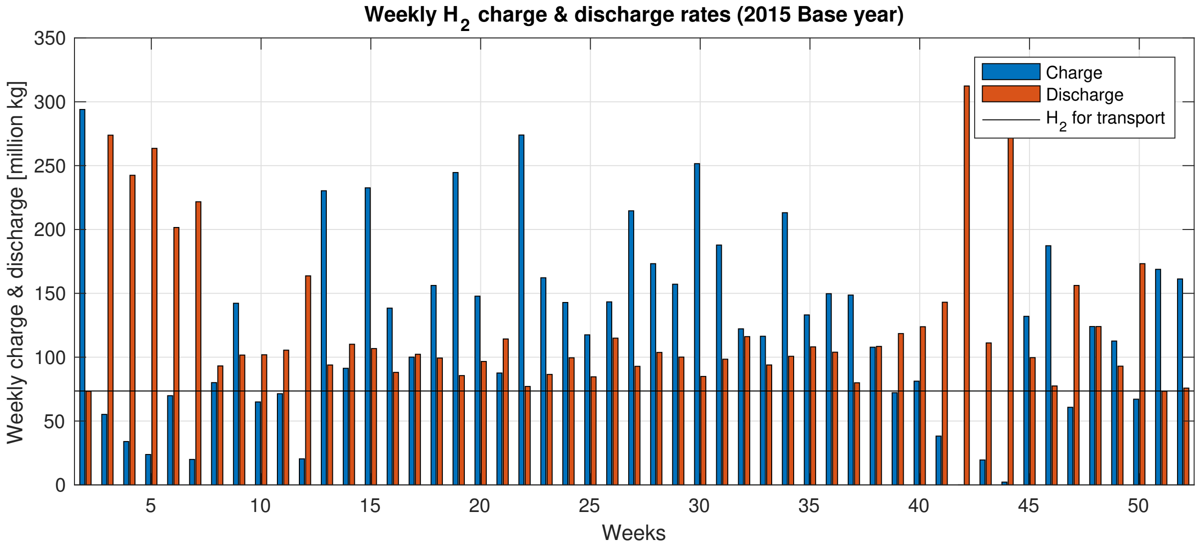


Figure F.72: Hydrogen weekly charge and discharge rates in Germany in 2050 (2015 base year)

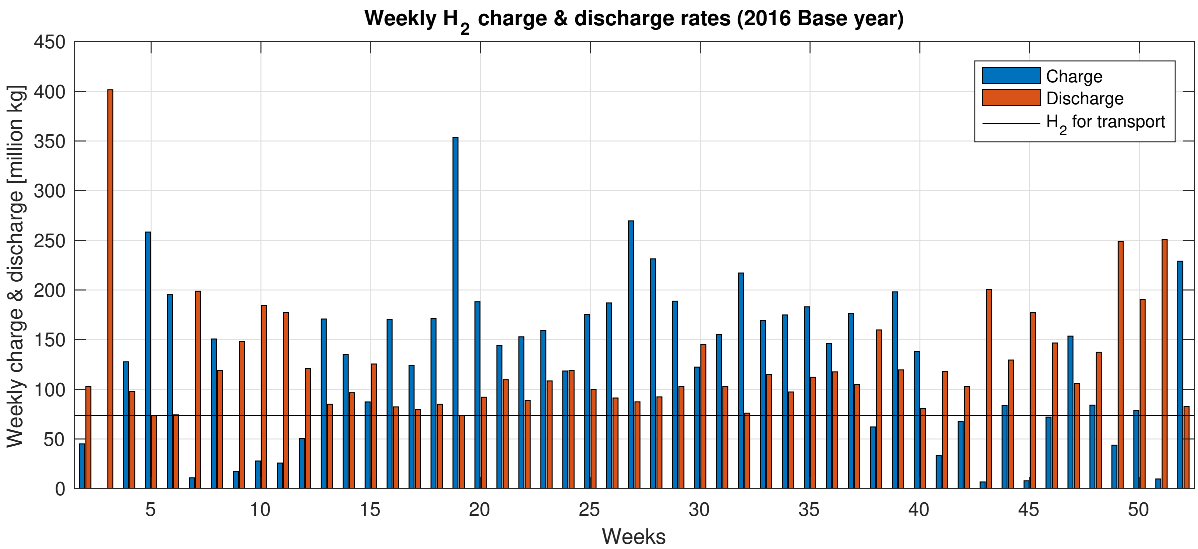


Figure F.73: Hydrogen weekly charge and discharge rates in Germany in 2050 (2016 base year)

F.2.6. Fuelling

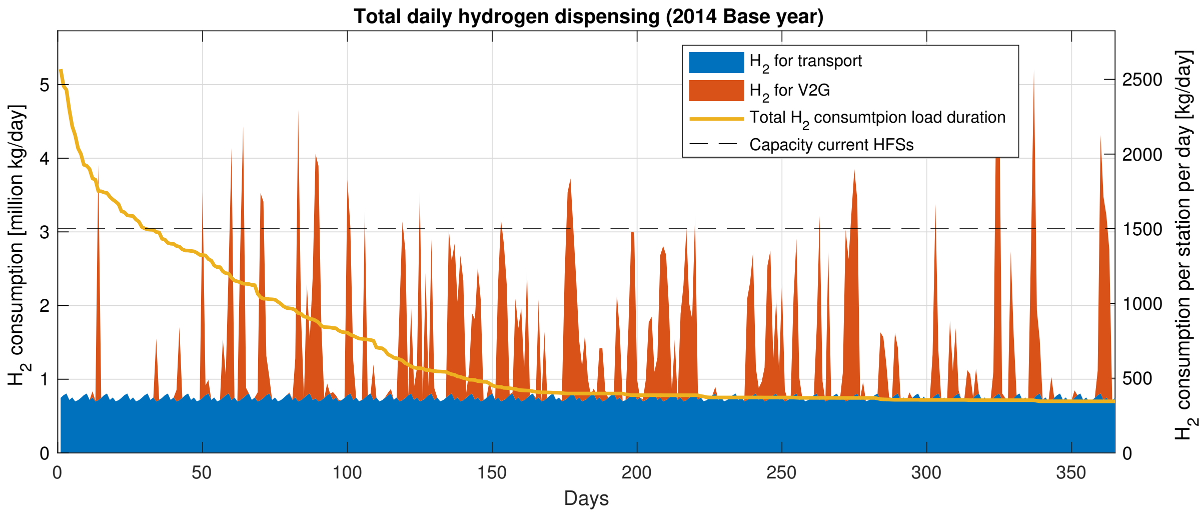


Figure F.74: Total daily hydrogen dispensing and dispension per HFS in Denmark in 2050 (2014 base year)

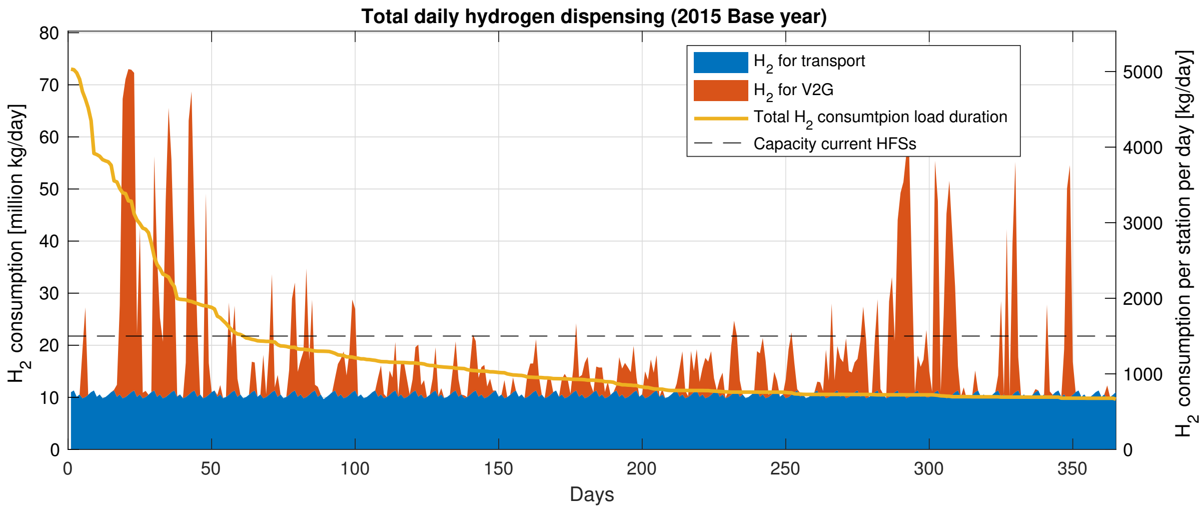


Figure F.75: Total daily hydrogen dispensing and dispension per HFS in Germany in 2050 (2015 base year)

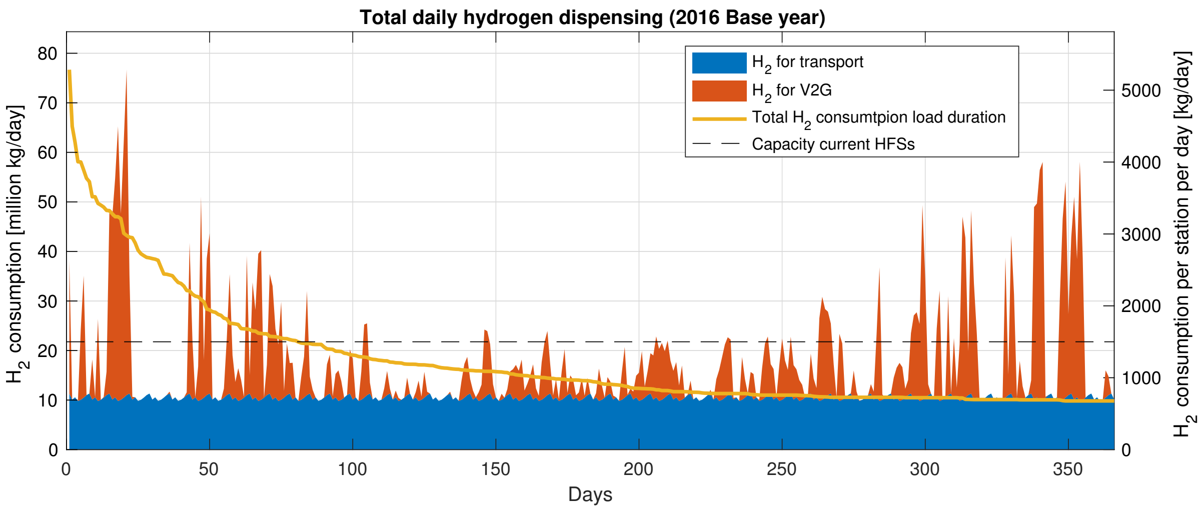


Figure F.76: Total daily hydrogen dispensing and dispension per HFS in Germany in 2050 (2016 base year)

G

Inputs, results & additional data Belgium

G.1. Normalised generation & consumption profiles

G.1.1. Solar PV electricity generation

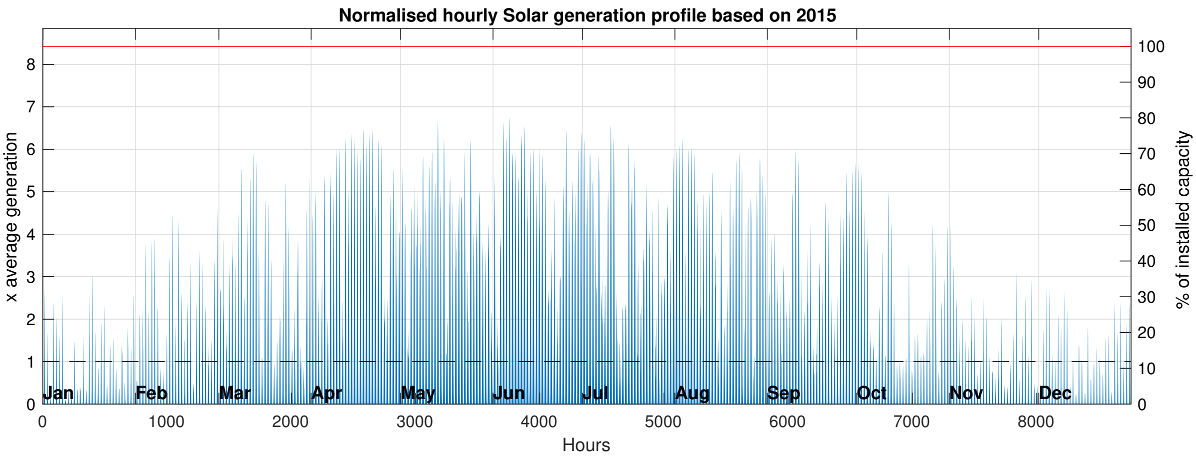


Figure G.1: Normalised hourly Solar electricity generation profile Belgium, 2015 base year

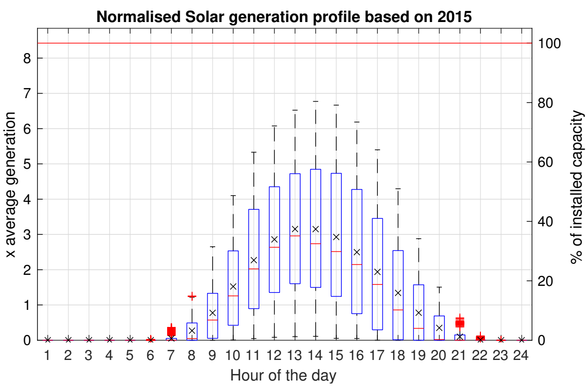


Figure G.2: Hourly boxplot normalised Solar electricity generation profile Belgium, 2015 base year

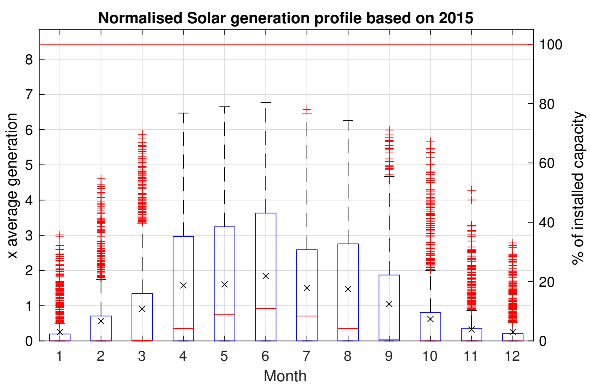


Figure G.3: Monthly boxplot normalised Solar electricity generation profile Belgium, 2015 base year

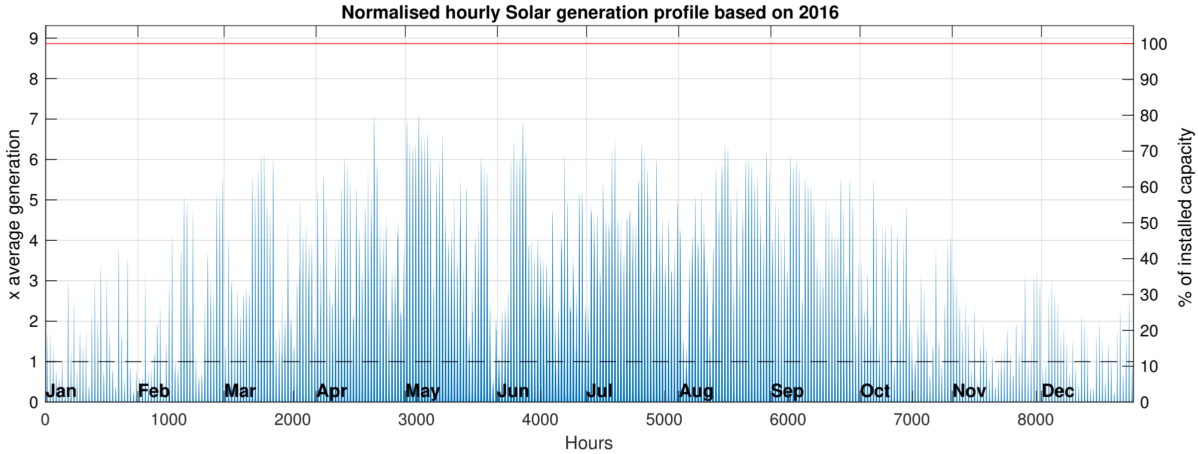


Figure G.4: Normalised hourly Solar electricity generation profile Belgium, 2016 base year

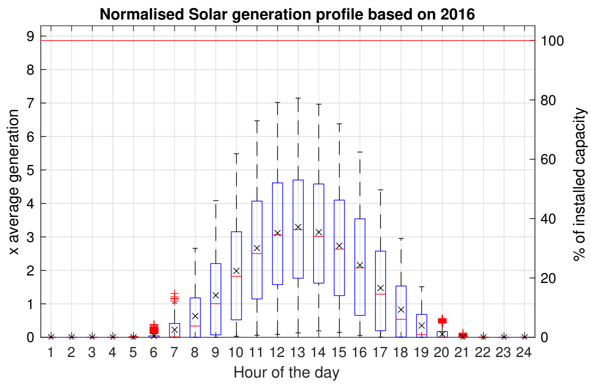


Figure G.5: Hourly boxplot normalised Solar electricity generation profile Belgium, 2016 base year

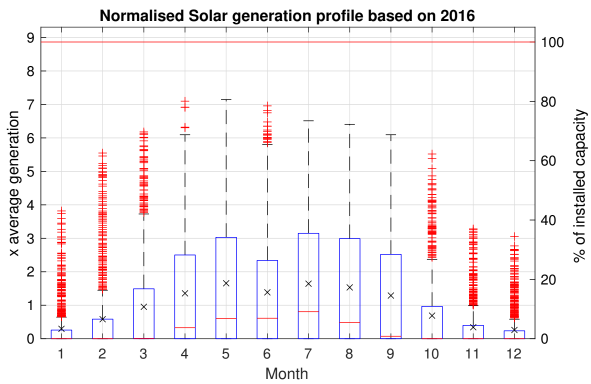


Figure G.6: Monthly boxplot normalised Solar electricity generation profile Belgium, 2016 base year

G.1.2. Onshore wind electricity generation

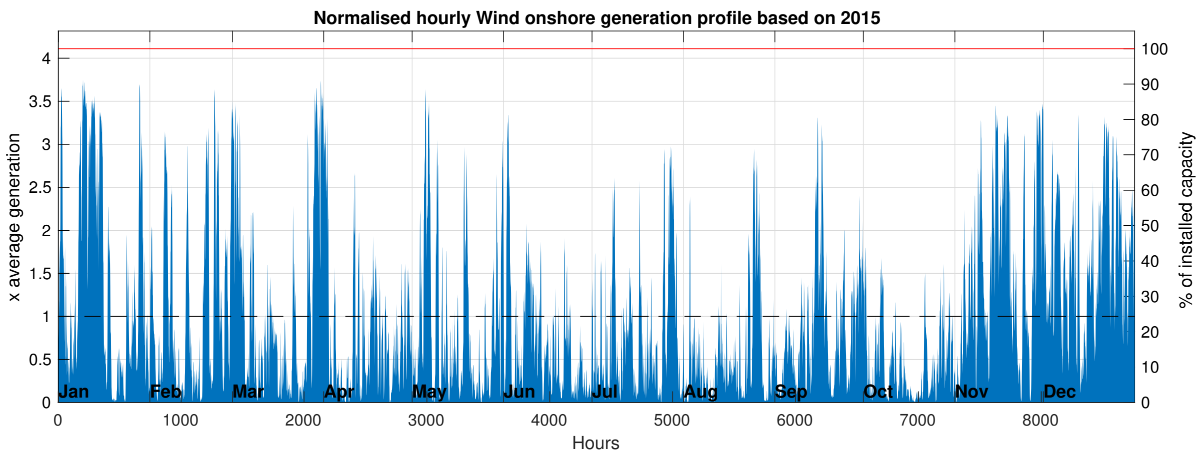


Figure G.7: Normalised hourly onshore wind electricity generation profile Belgium, 2015 base year

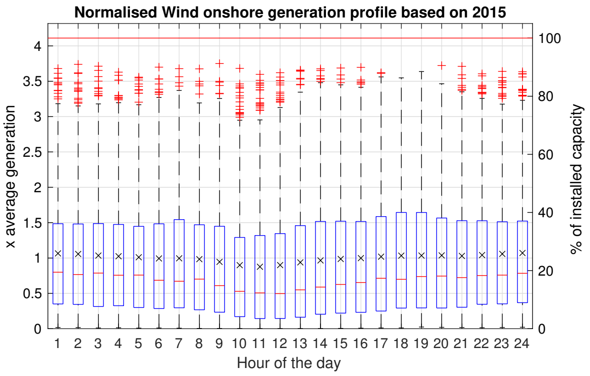


Figure G.8: Hourly boxplot normalised onshore wind electricity generation profile Belgium, 2015 base year

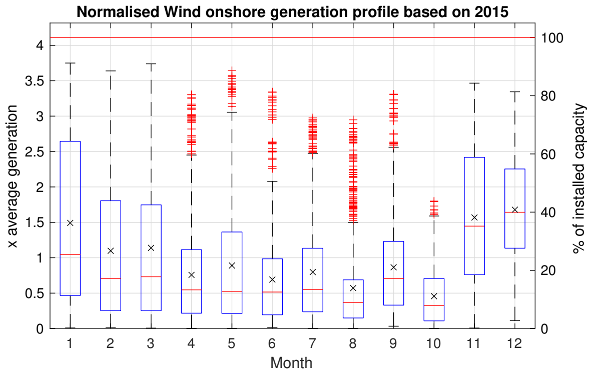


Figure G.9: Monthly boxplot normalised onshore wind electricity generation profile Belgium, 2015 base year

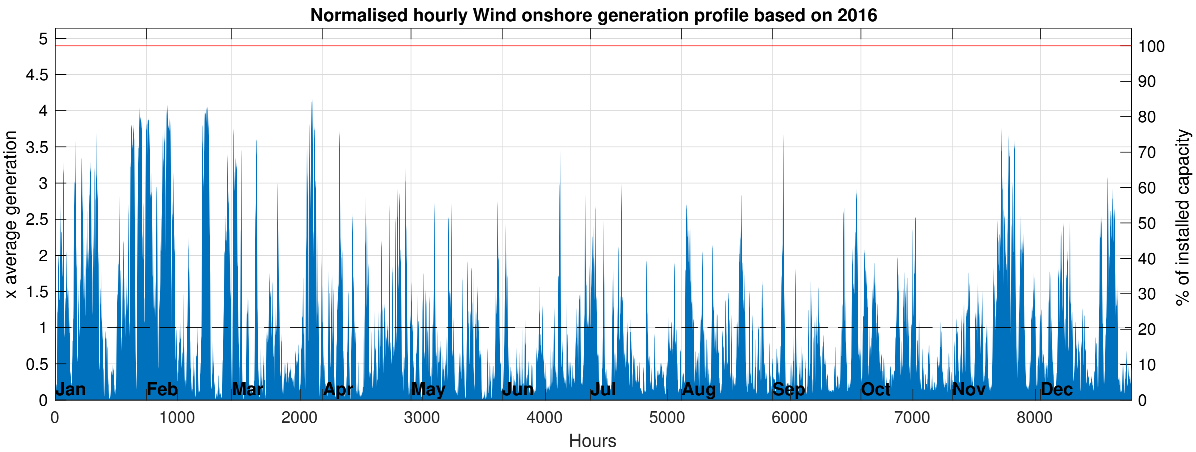


Figure G.10: Normalised hourly onshore wind electricity generation profile Belgium, 2016 base year

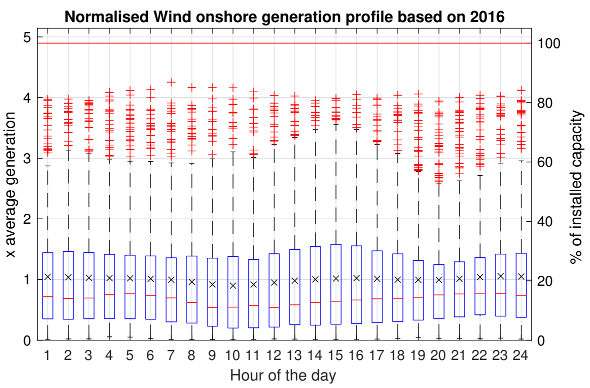


Figure G.11: Hourly boxplot normalised onshore wind electricity generation profile Belgium, 2016 base year

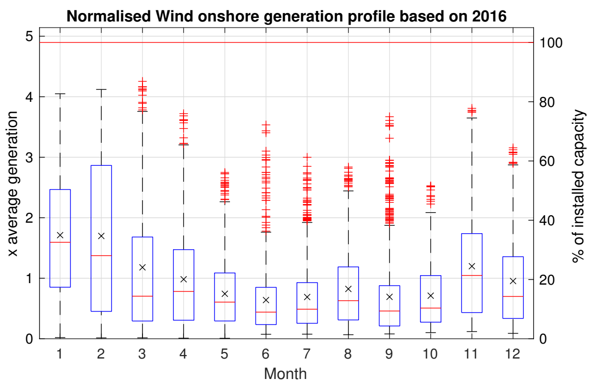


Figure G.12: Monthly boxplot normalised onshore wind electricity generation profile Belgium, 2016 base year

G.1.3. Offshore wind electricity generation

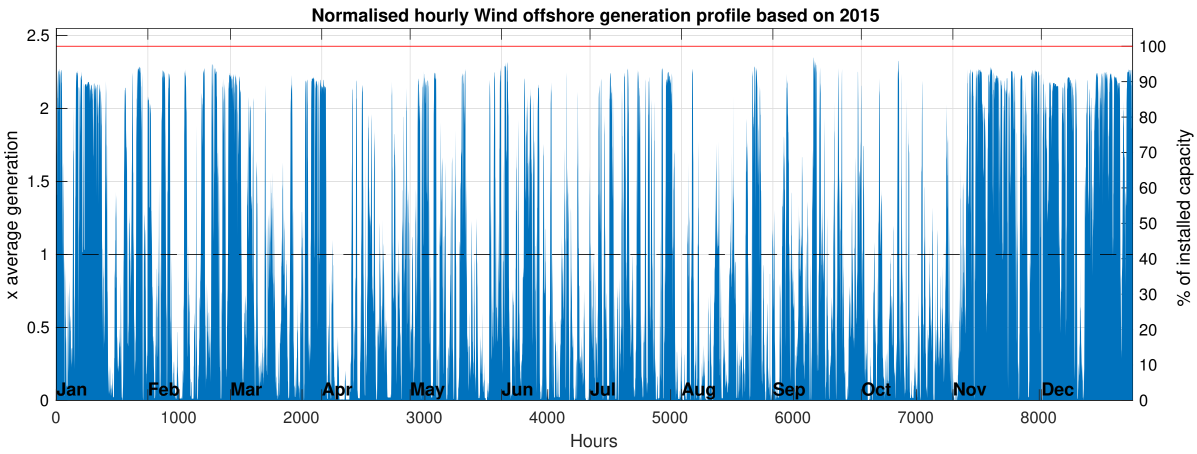


Figure G.13: Normalised hourly offshore wind electricity generation profile Belgium, 2015 base year

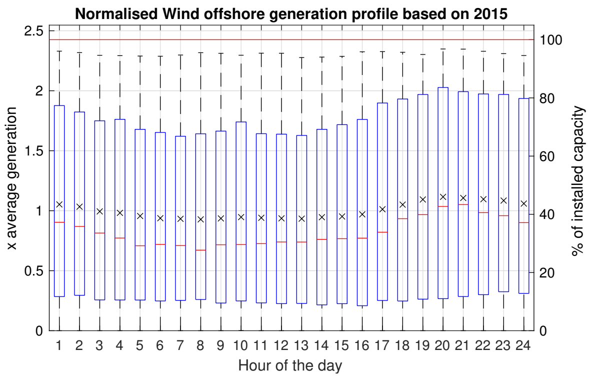


Figure G.14: Hourly boxplot normalised offshore wind electricity generation profile Belgium, 2015 base year

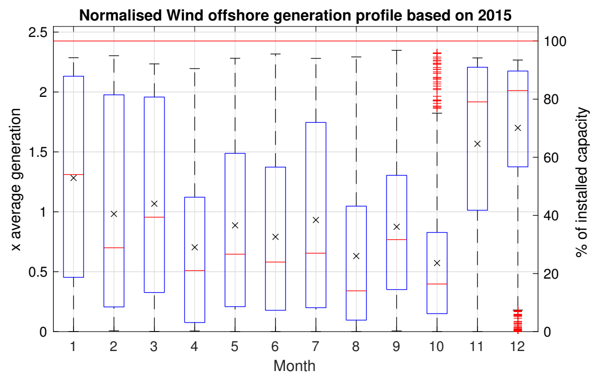


Figure G.15: Monthly boxplot normalised offshore wind electricity generation profile Belgium, 2015 base year

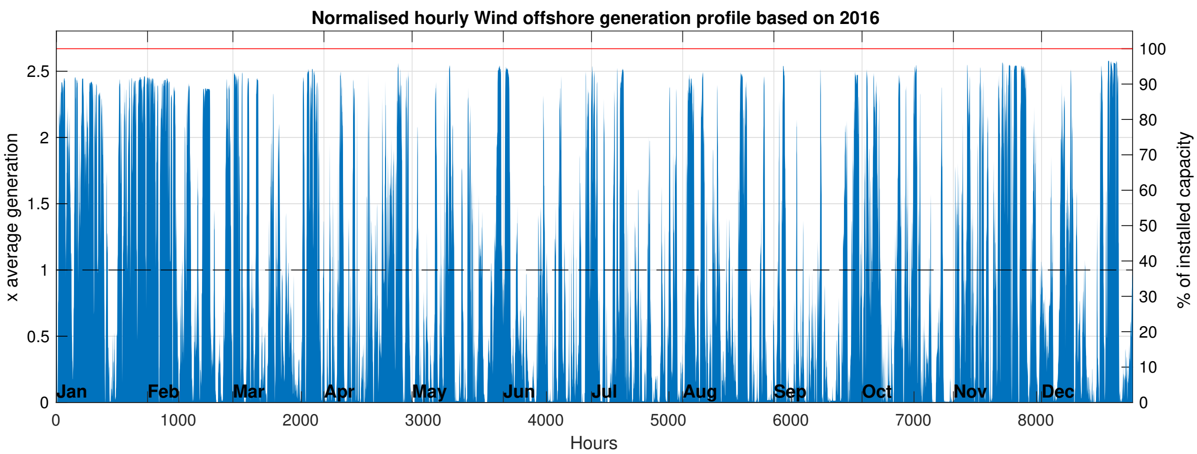


Figure G.16: Normalised hourly offshore wind electricity generation profile Belgium, 2016 base year

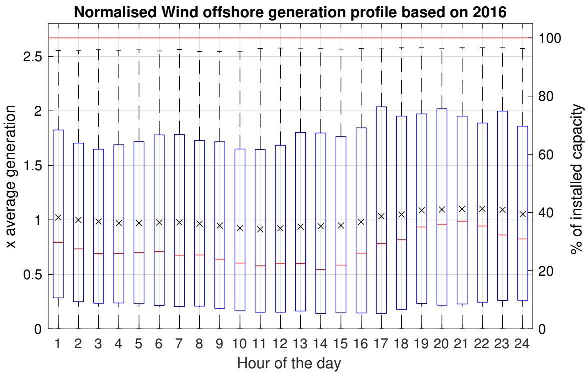


Figure G.17: Hourly boxplot normalised offshore wind electricity generation profile Belgium, 2016 base year

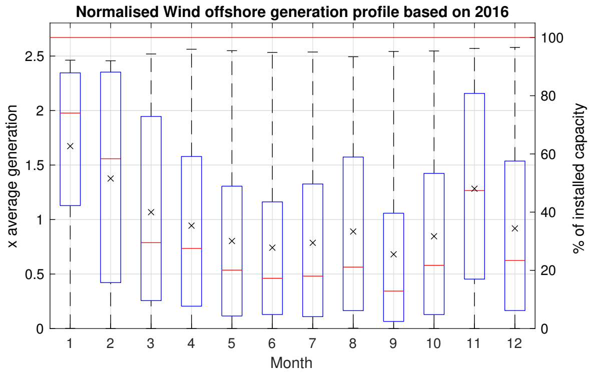


Figure G.18: Monthly boxplot normalised offshore wind electricity generation profile Belgium, 2016 base year

G.1.4. Geothermal

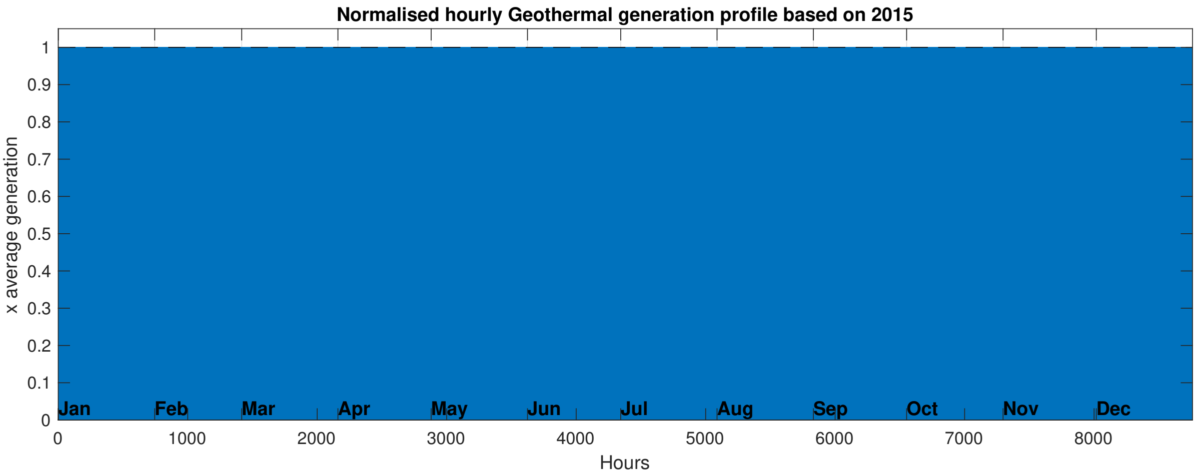


Figure G.19: Normalised hourly Geothermal electricity generation profile Belgium, 2015 base year

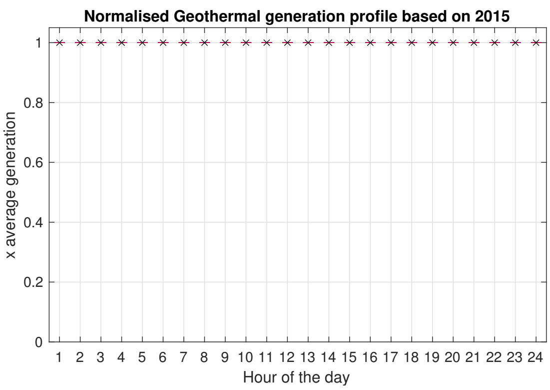


Figure G.20: Hourly boxplot normalised Geothermal electricity generation profile Belgium, 2015 base year

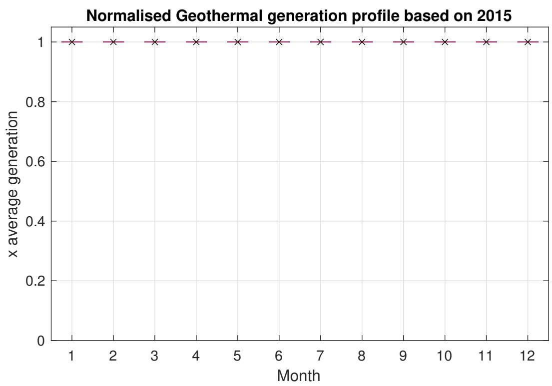


Figure G.21: Monthly boxplot normalised Geothermal electricity generation profile Belgium, 2015 base year

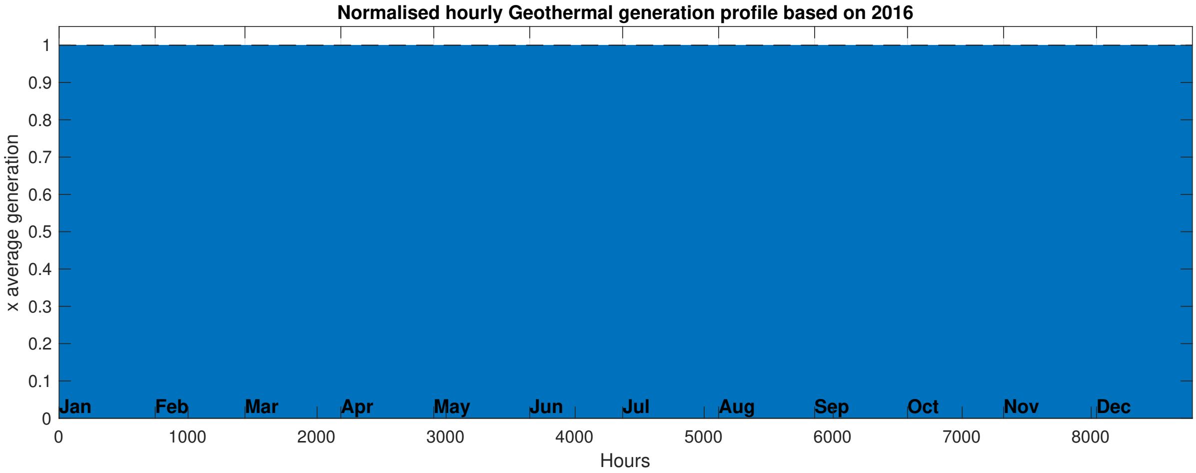


Figure G.22: Normalised hourly Geothermal electricity generation profile Belgium, 2016 base year

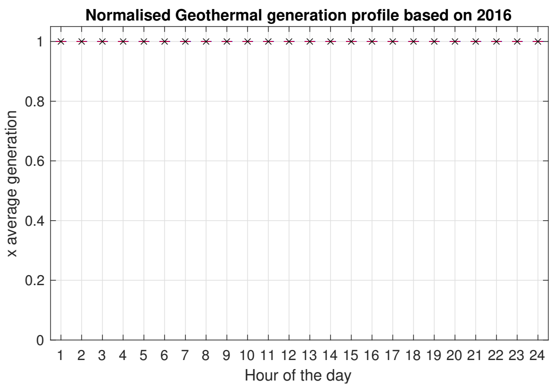


Figure G.23: Hourly boxplot normalised Geothermal electricity generation profile Belgium, 2016 base year

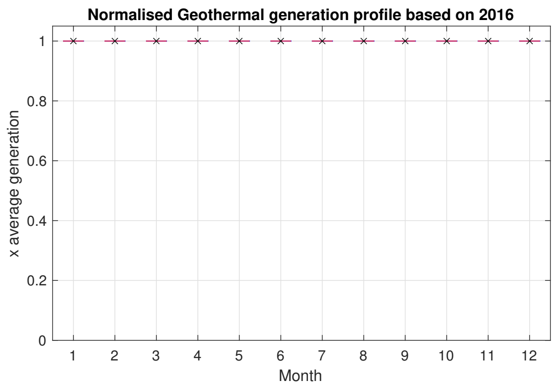


Figure G.24: Monthly boxplot normalised Geothermal electricity generation profile Belgium, 2016 base year

G.1.5. Classic electricity consumption

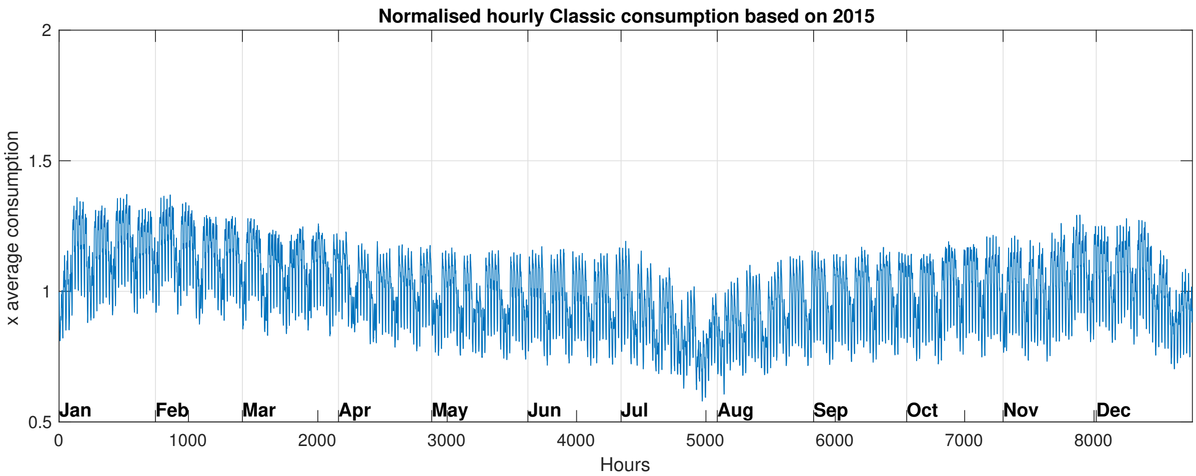


Figure G.25: Normalised hourly classic electricity consumption profile Belgium, 2015 base year

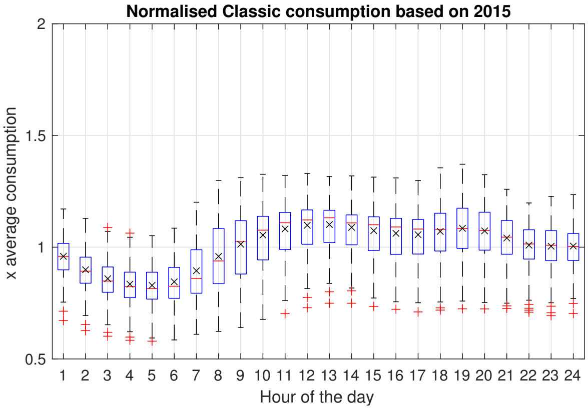


Figure G.26: Hourly boxplot normalised classic electricity consumption profile Belgium, 2015 base year

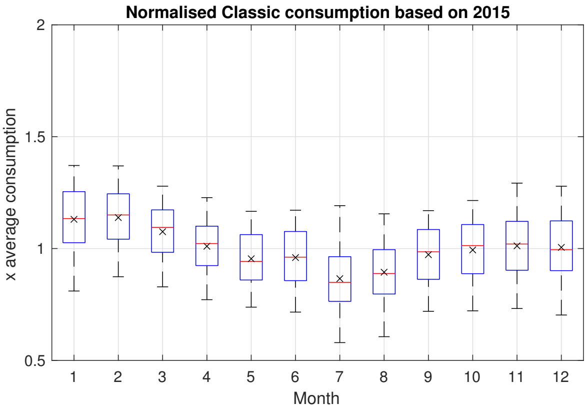


Figure G.27: Monthly boxplot normalised classic electricity consumption profile Belgium, 2015 base year

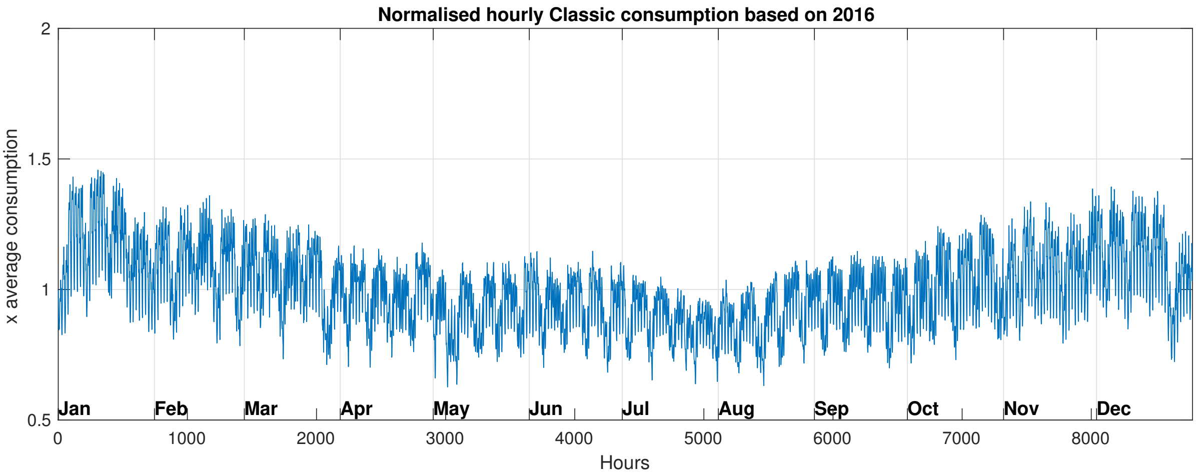


Figure G.28: Normalised hourly classic electricity consumption profile Belgium, 2016 base year

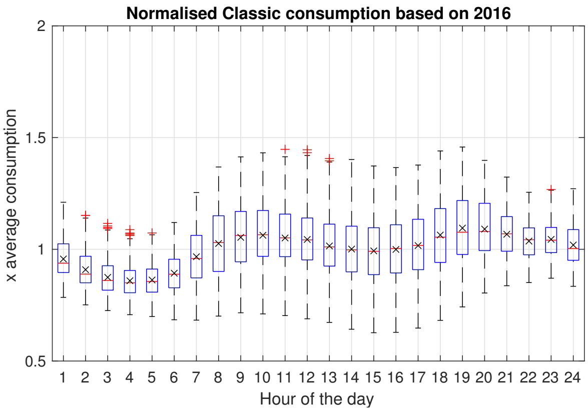


Figure G.29: Hourly boxplot normalised classic electricity consumption profile Belgium, 2016 base year

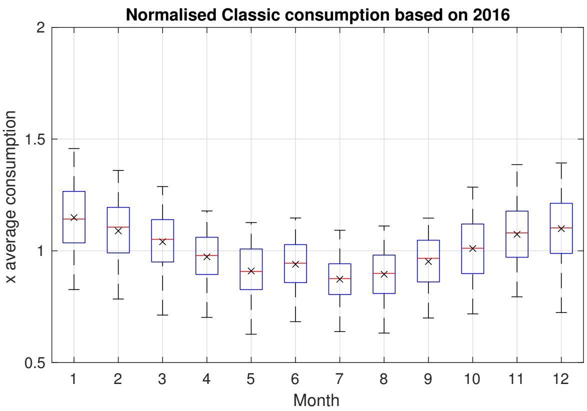


Figure G.30: Monthly boxplot normalised classic electricity consumption profile Belgium, 2016 base year

G.1.6. Electric heating demand & average outside temperature

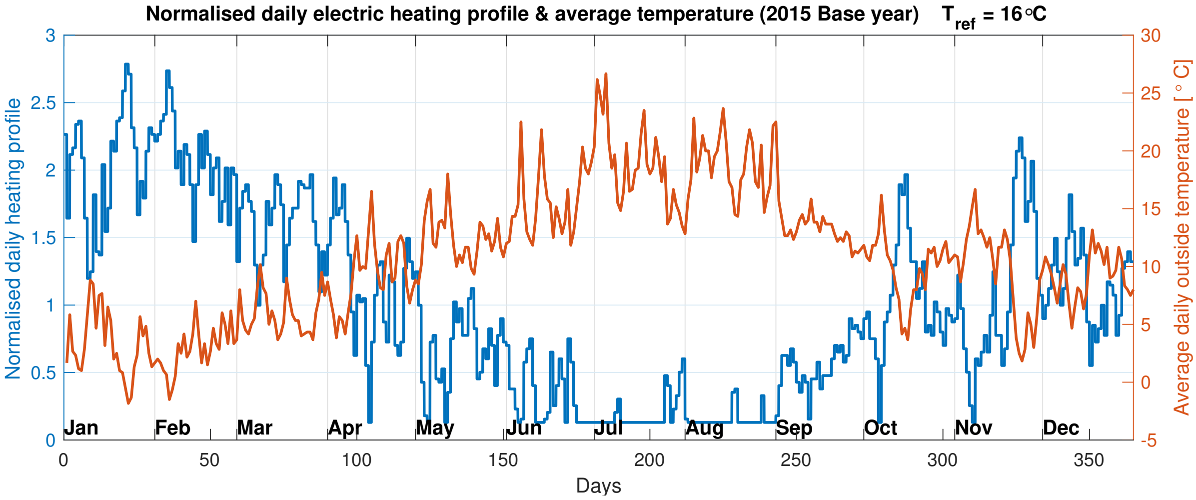


Figure G.31: Normalised daily electric heating demand, 2015 base year

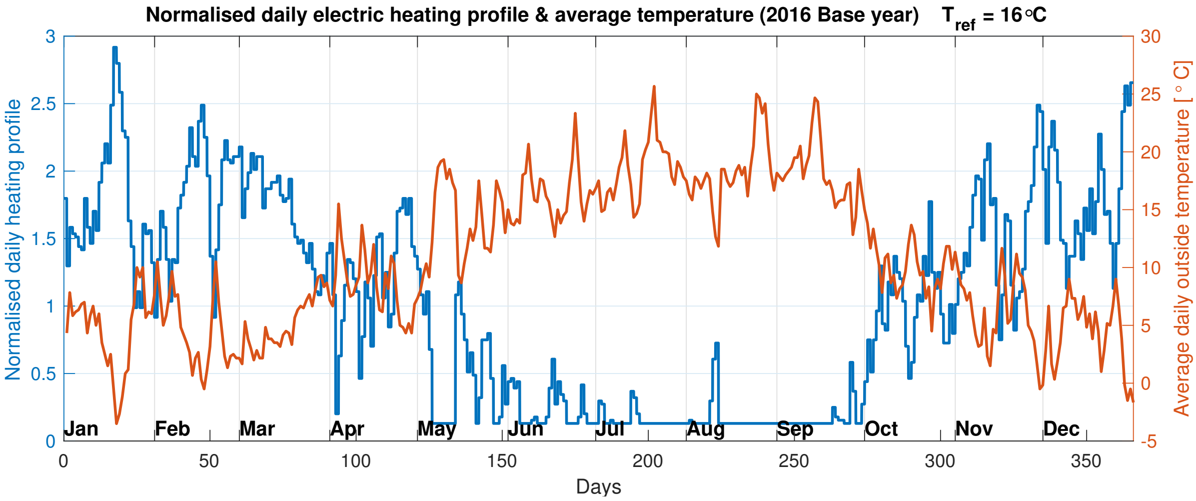


Figure G.32: Normalised daily electric heating demand, 2016 base year

G.2. Model output

Table G.1: Model outputs Belgium

	2015	2016		2015	2016
Electricity generation (TWh)			Direct electricity consumption (TWh)	114.32	111.75
Solar	50.02	57.07	% of total electricity consumption	87.82	85.61
Onshore wind	18.45	18.60	Electrolyser consumption (TWh)	62.11	68.10
Offshore wind	72.96	69.09	Electrolyser capacity (GW)	46.26	53.10
Geothermal	35.00	35.10	Electrolyser capacity factor (%)	15.33	14.60
Total	176.43	179.85	FCEV V2G demand (TWh)	15.86	18.79
Installed capacity (GW)			FCEV V2G peak demand (GW)	13.85	13.96
Solar	48.10	57.60	million vehicles	1.39	1.40
Onshore wind	8.66	10.37	% of passenger FCEVs	48.94	49.32
Offshore wind	20.20	21.00	Peak storage capacity (million kg)	319.10	419.41
Geothermal	4.00	4.00	BEV charging load (GW)	1.04	1.04
Total	80.96	92.97			
Electricity consumption (TWh)					
Classic	104.17	104.45			
Electricity for heating	17.61	17.66			
BEV charging	8.40	8.42			
Total	130.18	130.54			
Road transport cons. (TWh)	22.10	22.16			
Final energy cons. (TWh)	194.78	195.12			
Hydrogen cons. (million kg)					
Road transport	597.25	598.89			
V2G	670.85	794.64			
Residual storage	4.78	2.33			
Total production	1273.05	1395.93			

G.2.1. Sankey diagrams

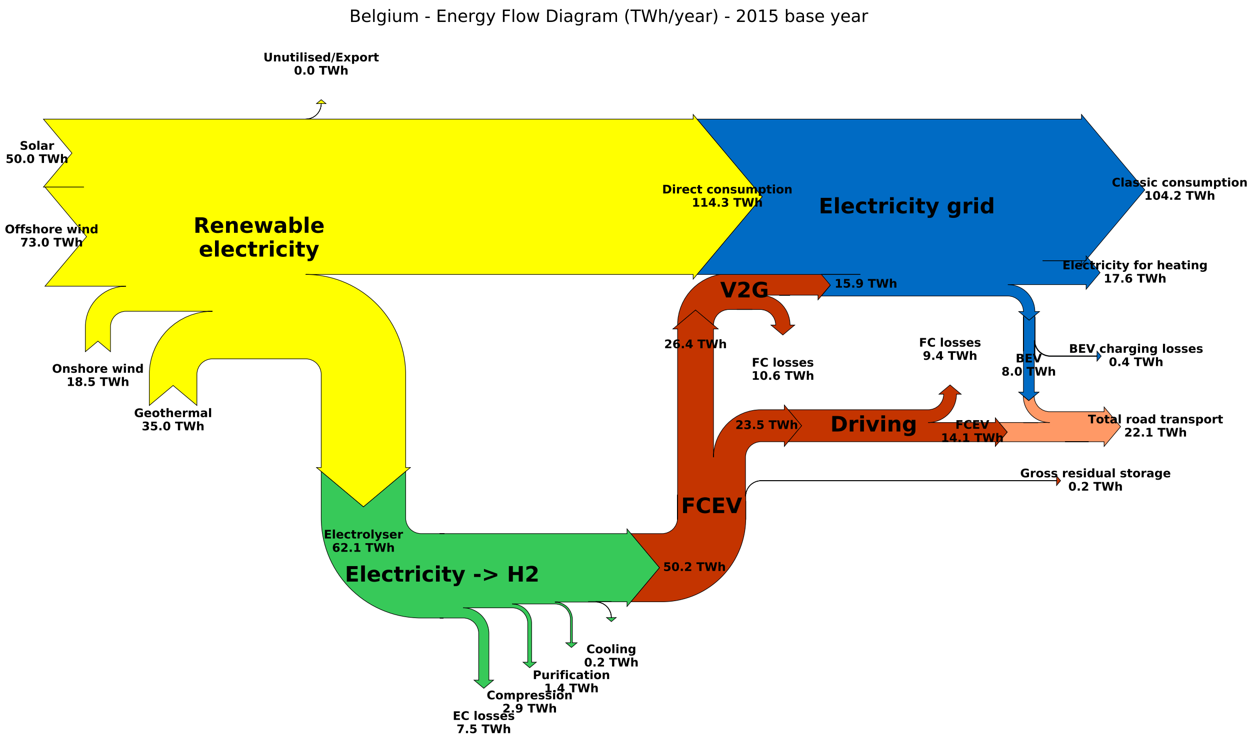


Figure G.33: Energy flow diagram for Belgium with 2015 as base year

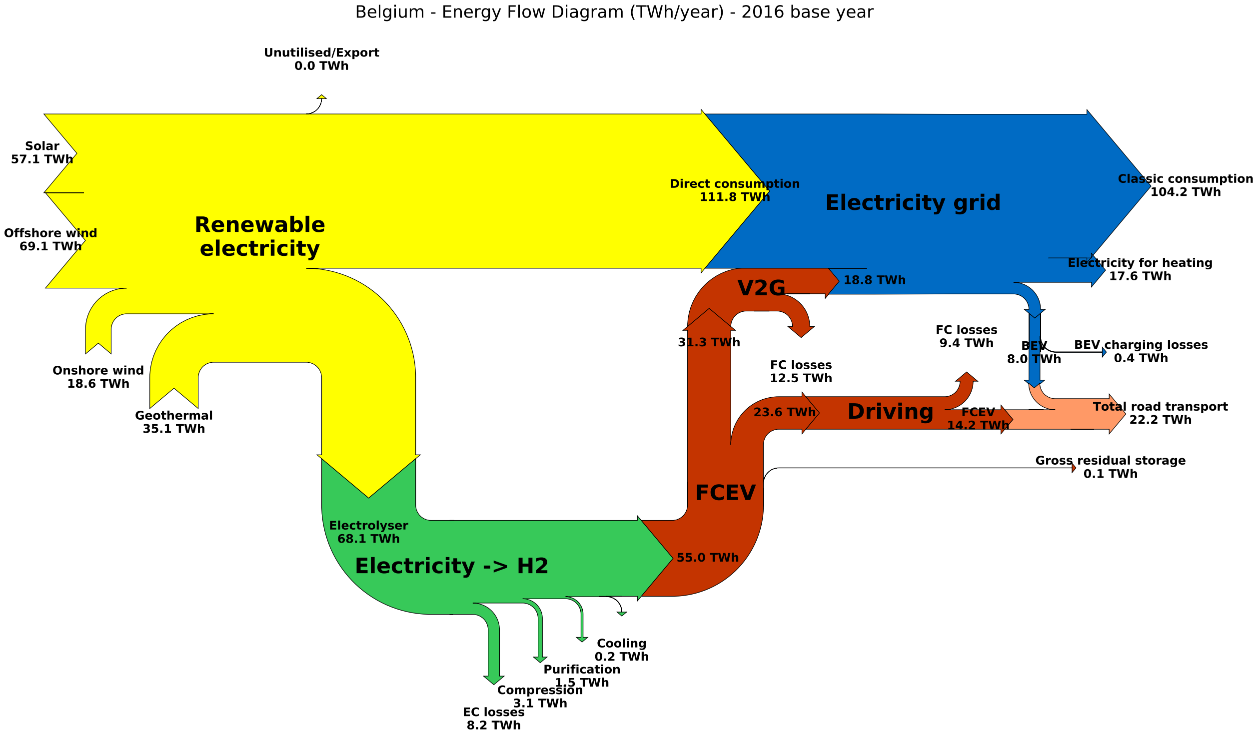


Figure G.34: Energy flow diagram for Belgium with 2016 as base year

G.2.2. Generation & Consumption profiles (2016 base year)

Only the scaled generation and consumption profiles for base year 2016 are shown to the generation and consumption in terms of GW's. The shape of the profiles are the same as the normalised profile.

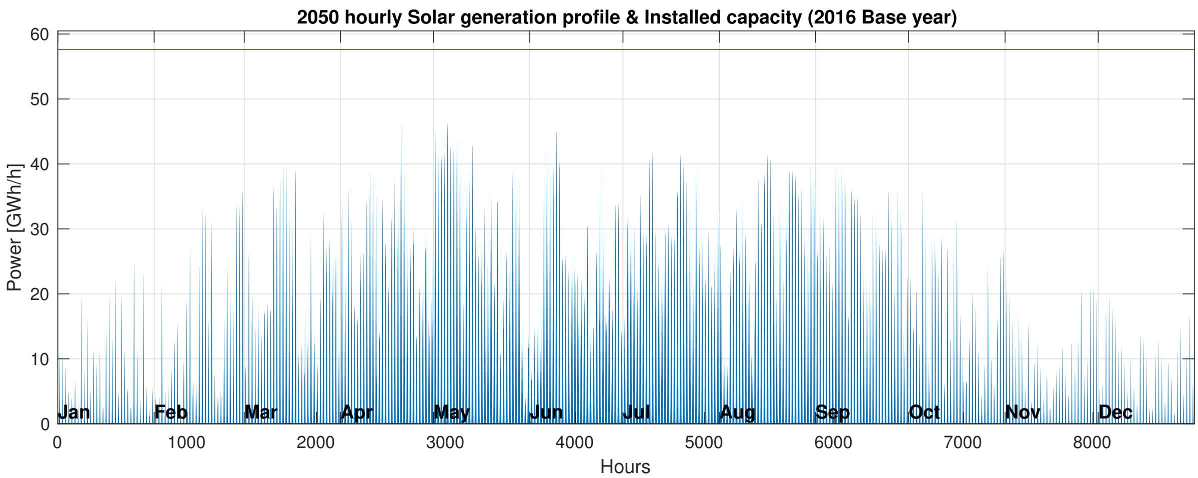


Figure G.35: Solar electricity generation in Belgium in 2050 (2016 base year)

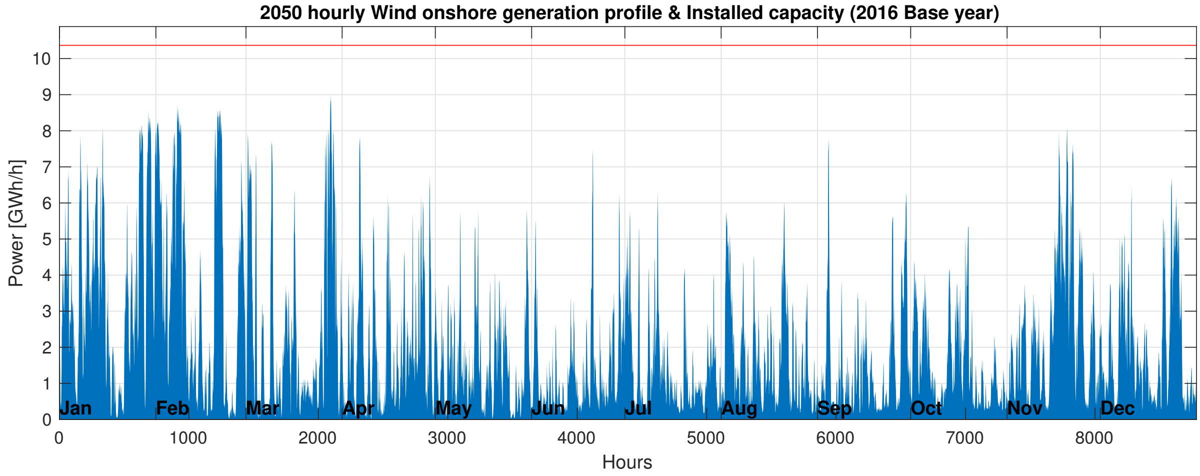


Figure G.36: Onshore wind electricity generation in Belgium in 2050 (2016 base year)

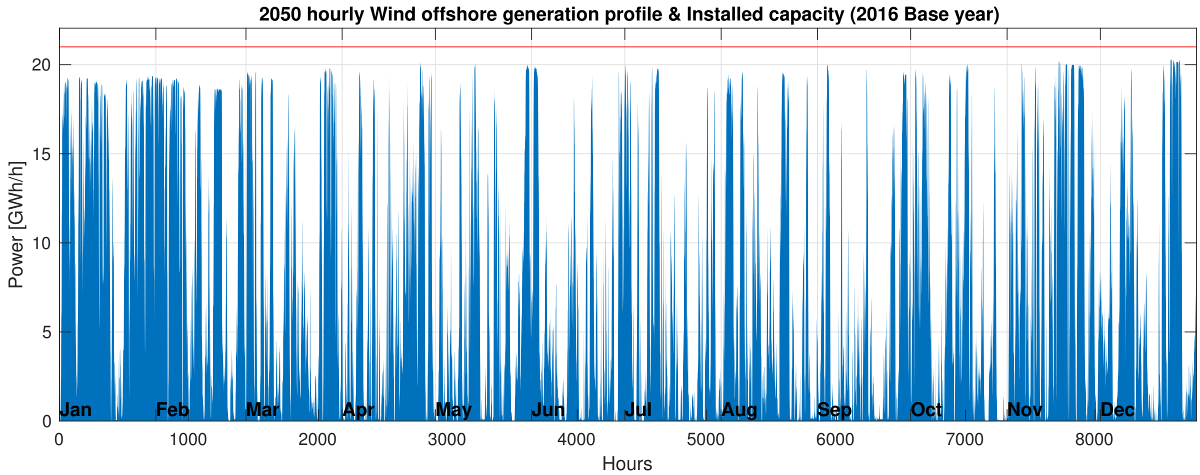


Figure G.37: Offshore wind electricity generation in Belgium in 2050 (2016 base year)

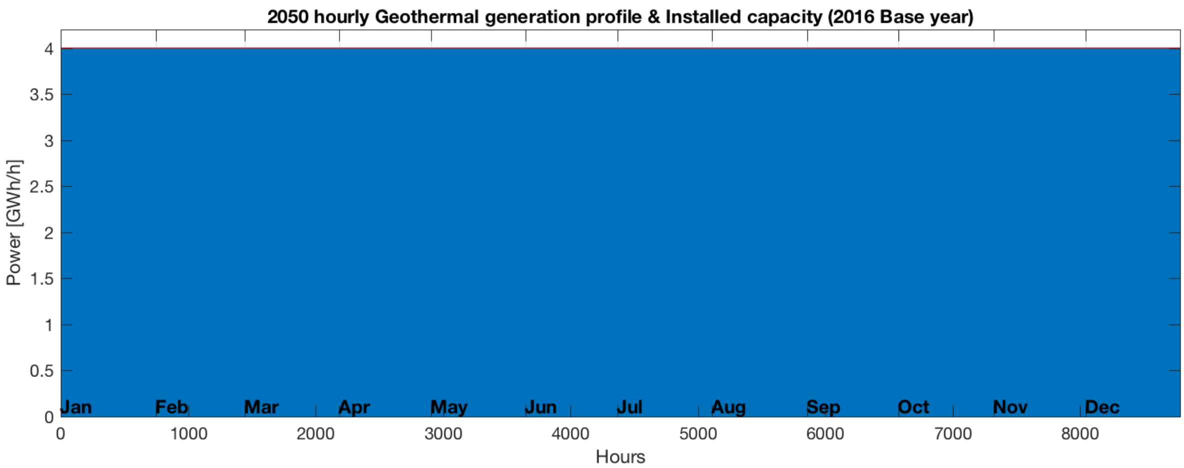


Figure G.38: Geothermal electricity generation in Belgium in 2050 (2016 base year)

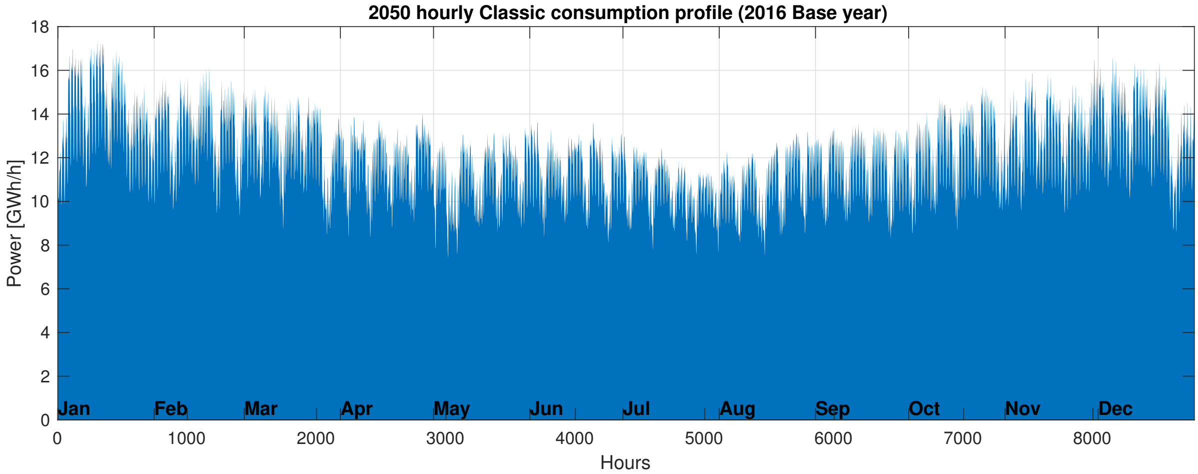


Figure G.39: Classic electricity consumption in Belgium in 2050 (2016 base year)

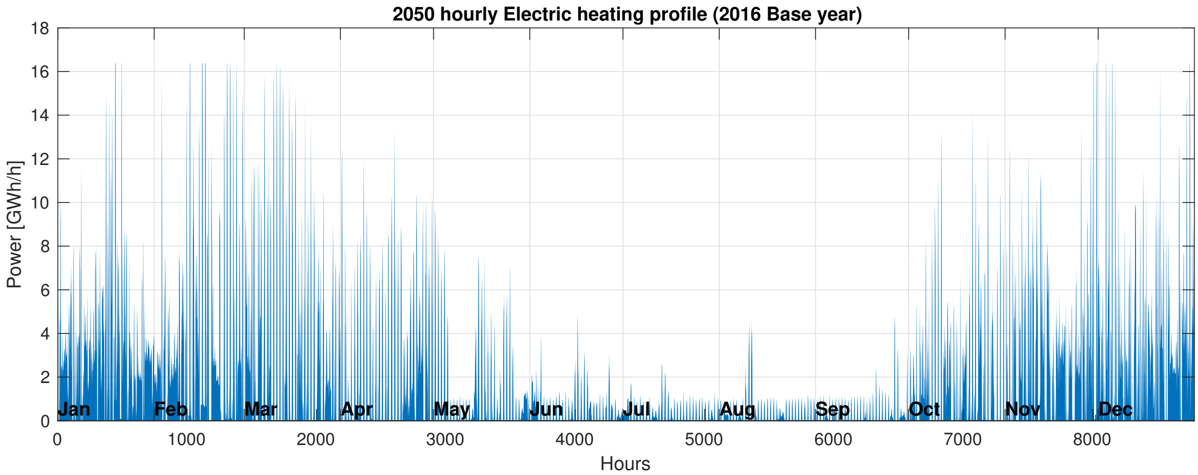


Figure G.40: Electric heating consumption in Belgium in 2050 (2016 base year)

G.2.3. Imbalance

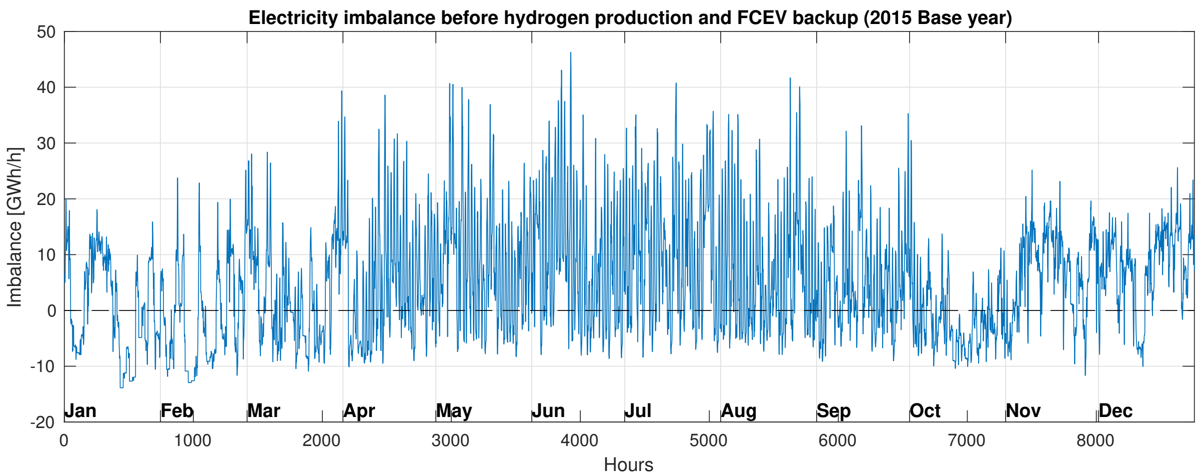


Figure G.41: Electric imbalance in Belgium in 2050 (2015 base year)

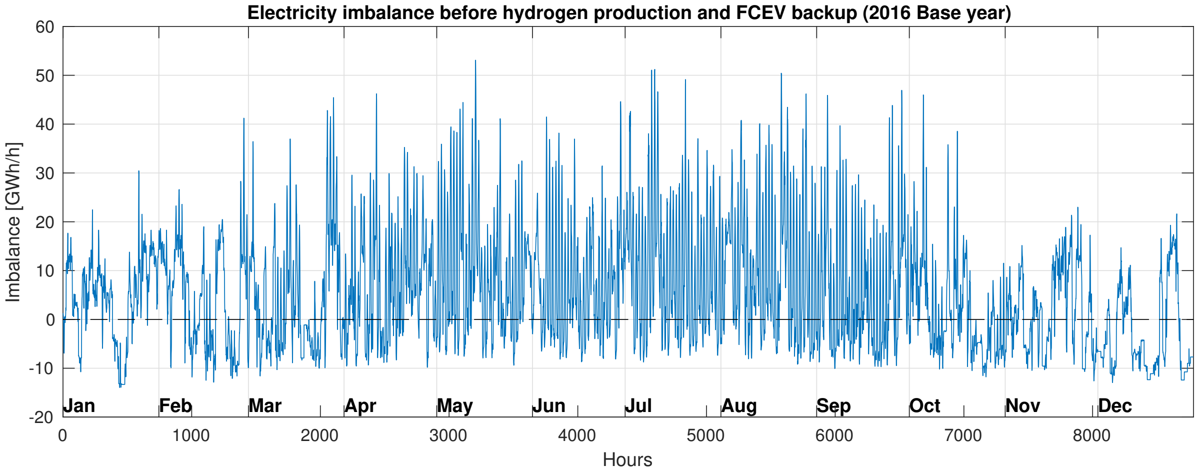


Figure G.42: Electric imbalance in Belgium in 2050 (2016 base year)

G.2.4. Electrolyser

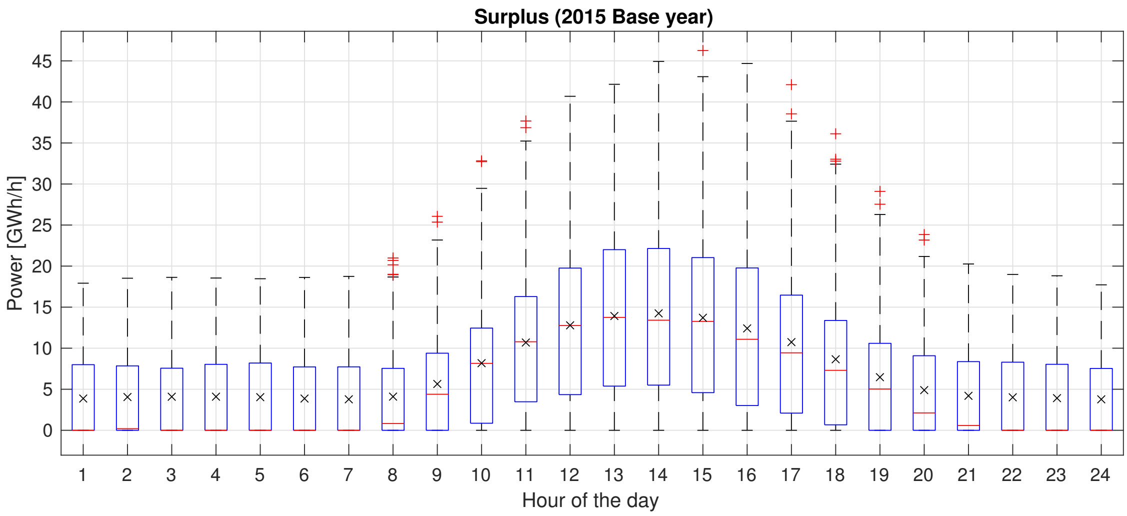


Figure G.43: Hourly boxplot electrolyser consumption in Belgium in 2050 (2015 base year)

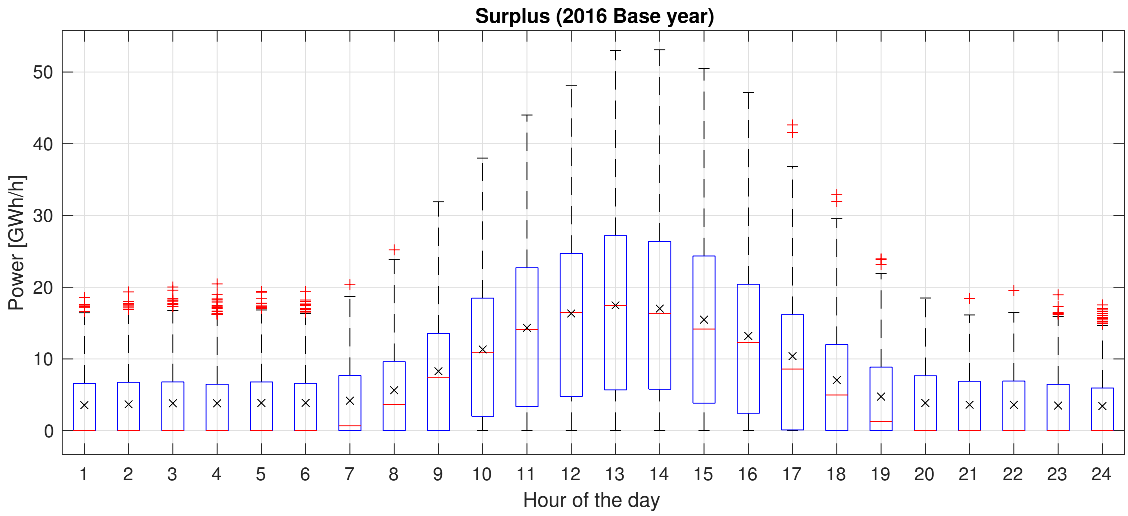


Figure G.44: Hourly boxplot electrolyser consumption in Belgium in 2050 (2016 base year)

G.2.5. FCEV backup

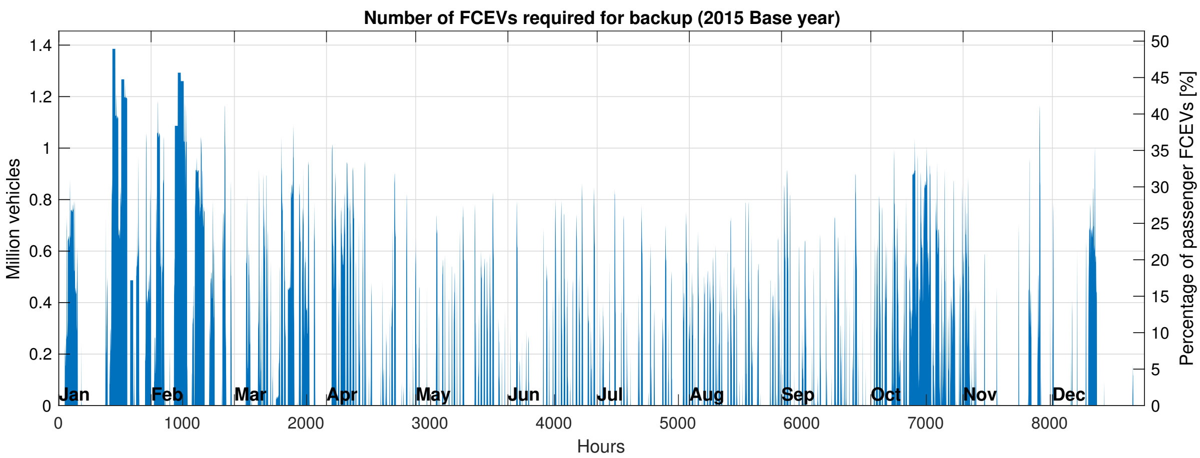


Figure G.45: FCEV backup in Belgium in 2050 (2015 base year)

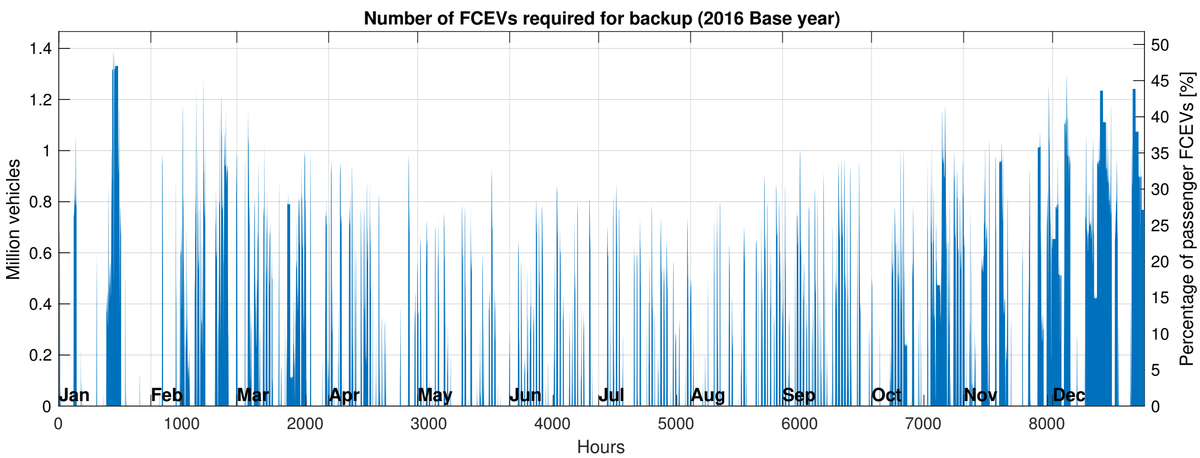


Figure G.46: FCEV backup in Belgium in 2050 (2016 base year)

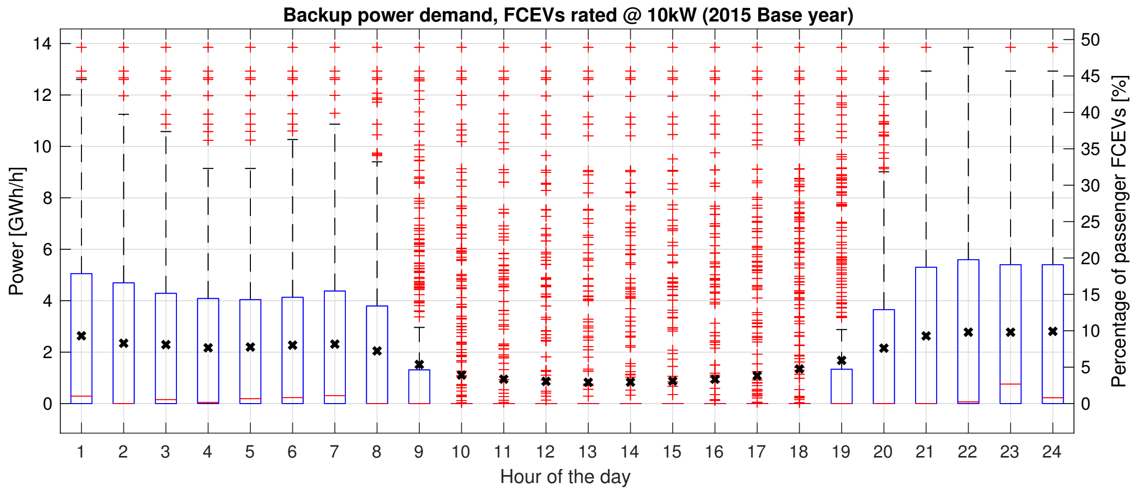


Figure G.47: Hourly boxplot FCEV backup in Belgium in 2050 (2015 base year)

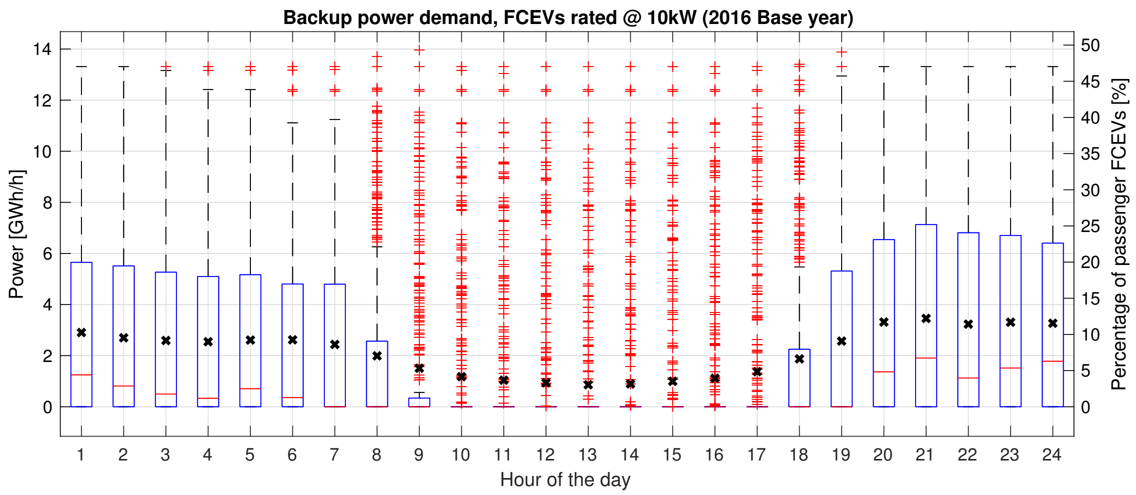


Figure G.48: Hourly boxplot FCEV backup in Belgium in 2050 (2016 base year)

G.2.6. Weekly charge & discharge rates of hydrogen

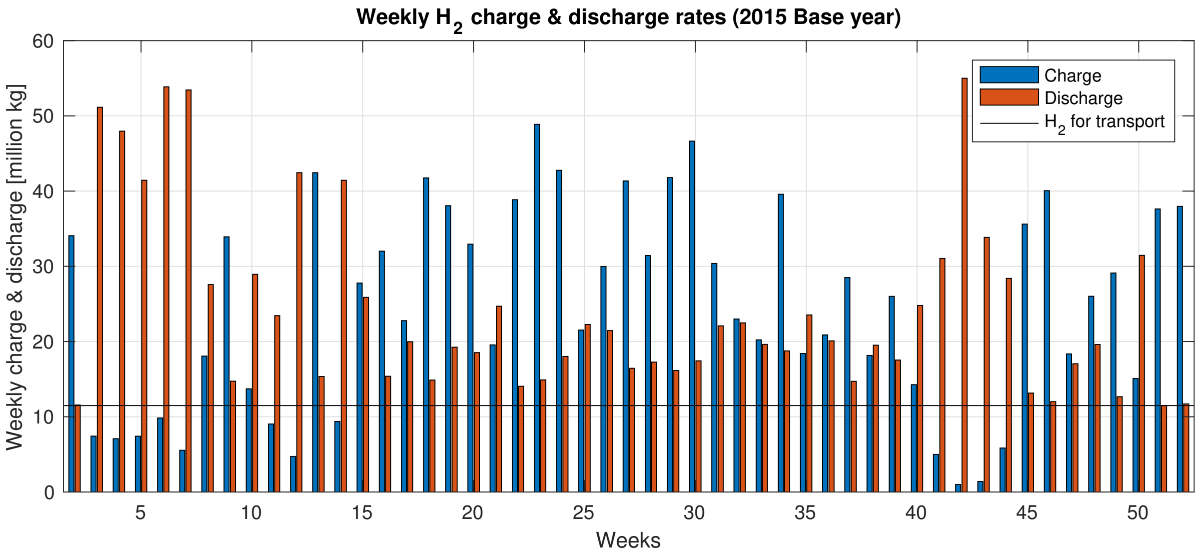


Figure G.49: Hydrogen weekly charge and discharge rates in Belgium in 2050 (2015 base year)

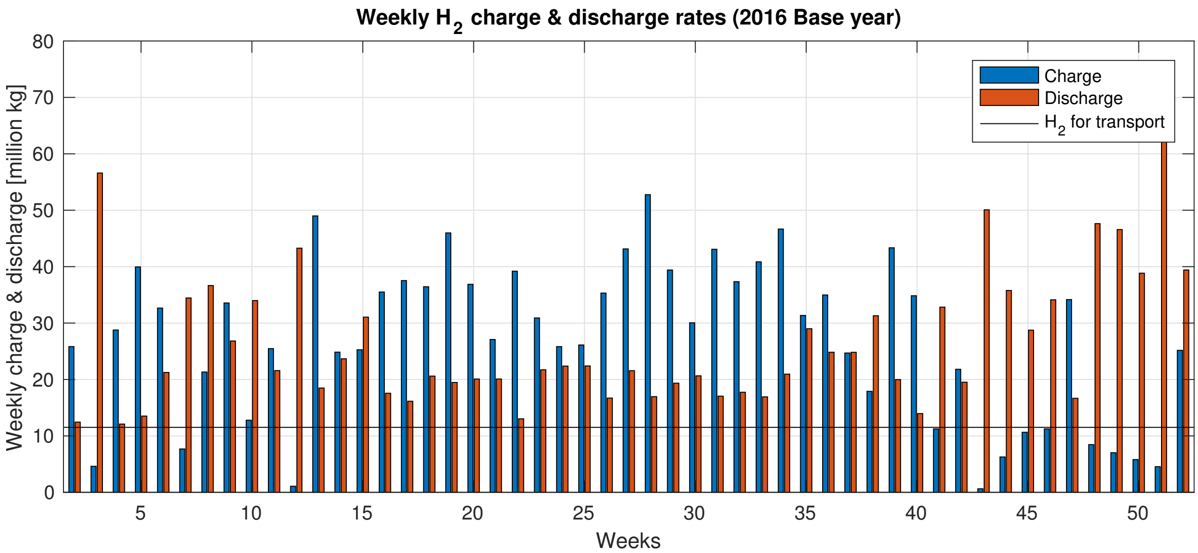


Figure G.50: Hydrogen weekly charge and discharge rates in Belgium in 2050 (2016 base year)

G.2.7. Fuelling

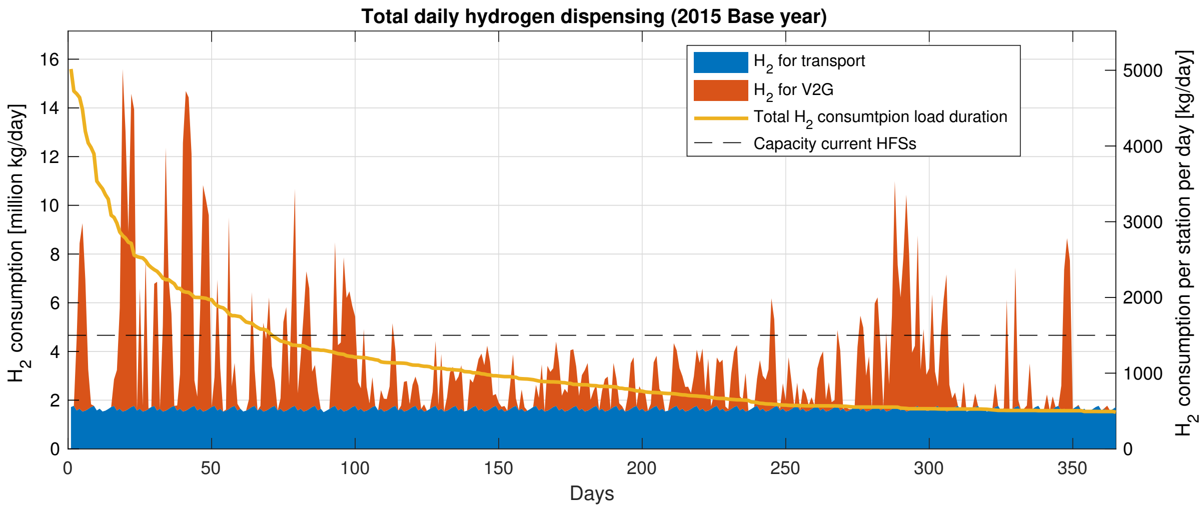


Figure G.51: Total daily hydrogen dispensing and dispension per HFS in Belgium in 2050 (2015 base year)

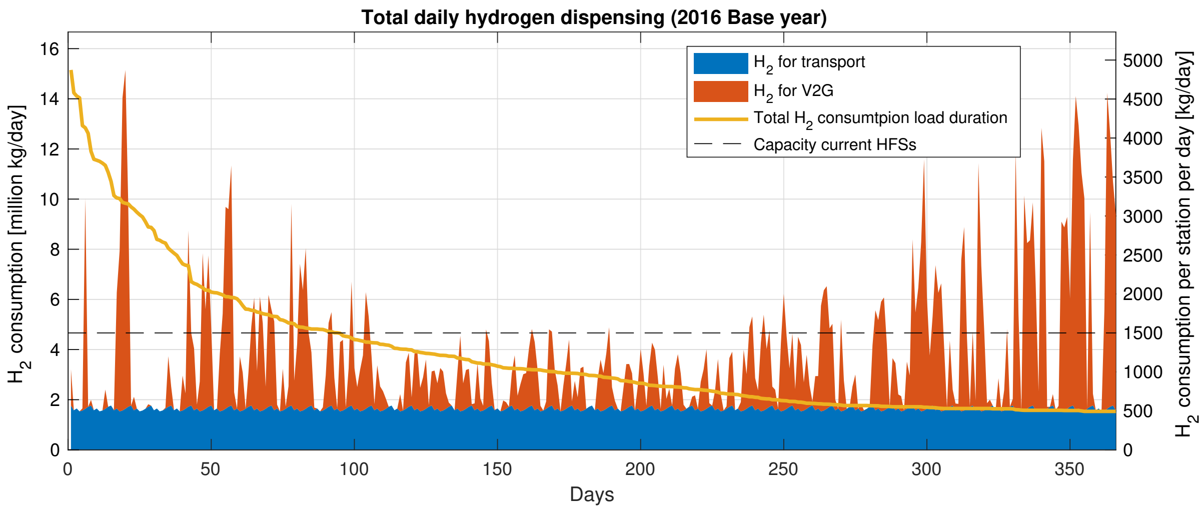


Figure G.52: Total daily hydrogen dispensing and dispension per HFS in Belgium in 2050 (2016 base year)

H

Inputs, results & additional data Great Britain

H.1. Normalised generation & consumption profiles

H.1.1. Solar PV electricity generation

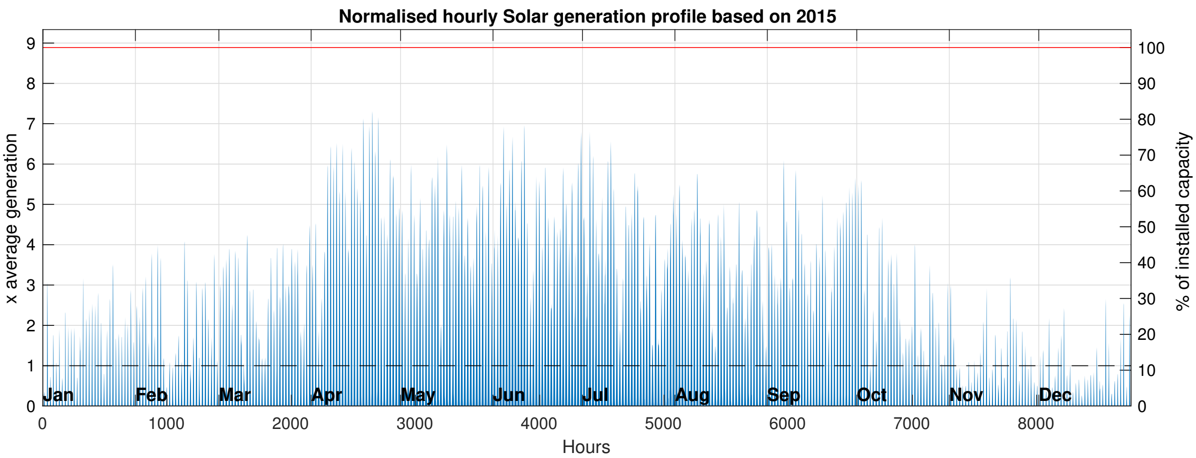


Figure H.1: Normalised hourly Solar electricity generation profile GB, 2015 base year

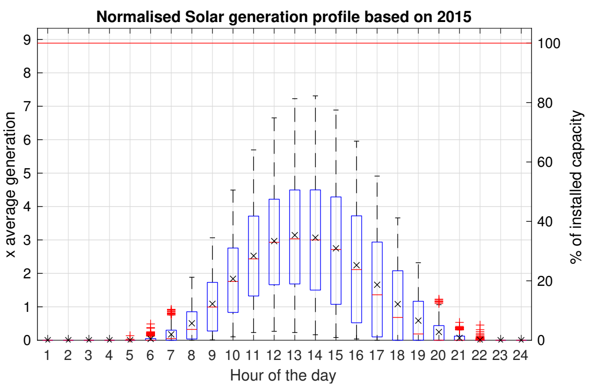


Figure H.2: Hourly boxplot normalised Solar electricity generation profile GB, 2015 base year

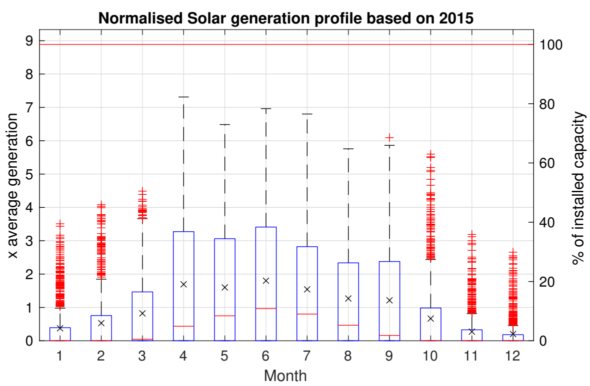


Figure H.3: Monthly boxplot normalised Solar electricity generation profile GB, 2015 base year

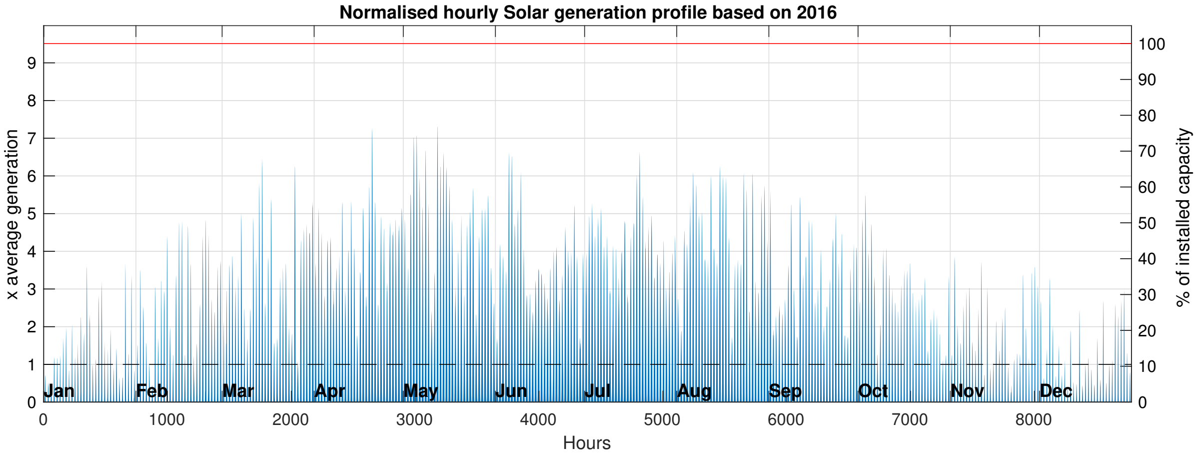


Figure H.4: Normalised hourly Solar electricity generation profile GB, 2016 base year

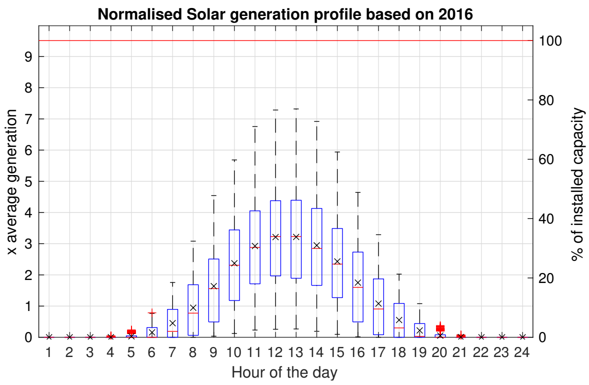


Figure H.5: Hourly boxplot normalised Solar electricity generation profile GB, 2016 base year

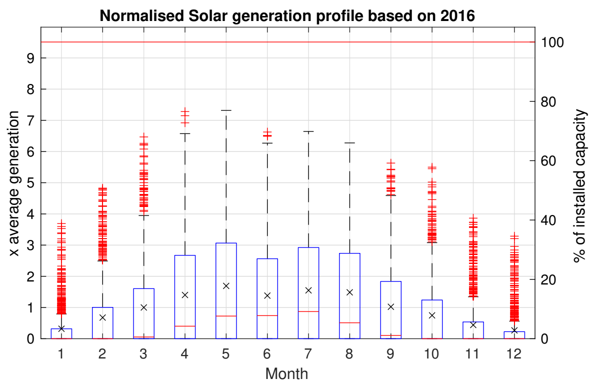


Figure H.6: Monthly boxplot normalised Solar electricity generation profile GB, 2016 base year

H.1.2. Onshore wind electricity generation

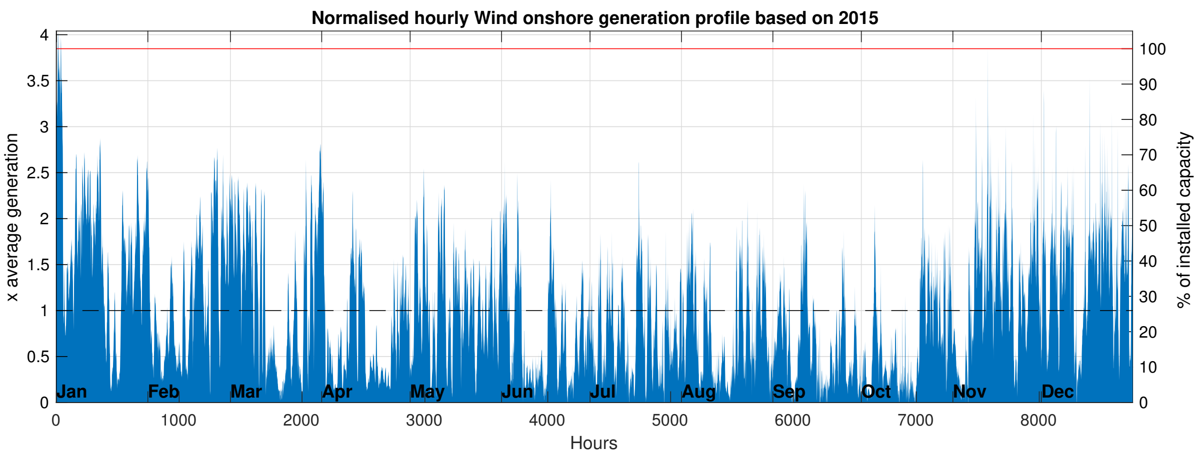


Figure H.7: Normalised hourly onshore wind electricity generation profile GB, 2015 base year

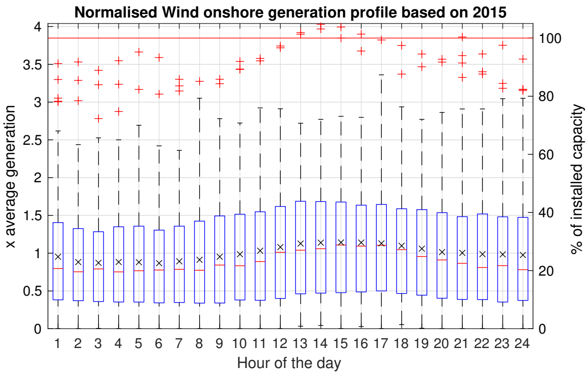


Figure H.8: Hourly boxplot normalised onshore wind electricity generation profile GB, 2015 base year

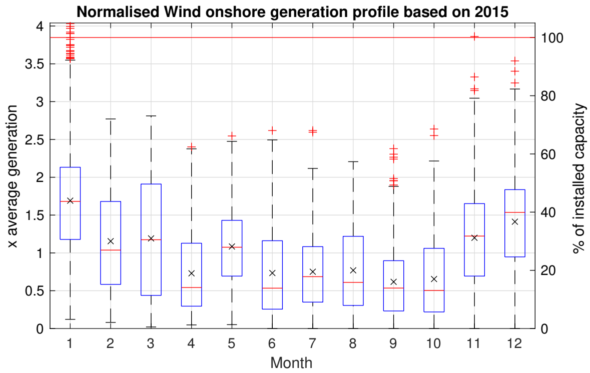


Figure H.9: Monthly boxplot normalised onshore wind electricity generation profile GB, 2015 base year

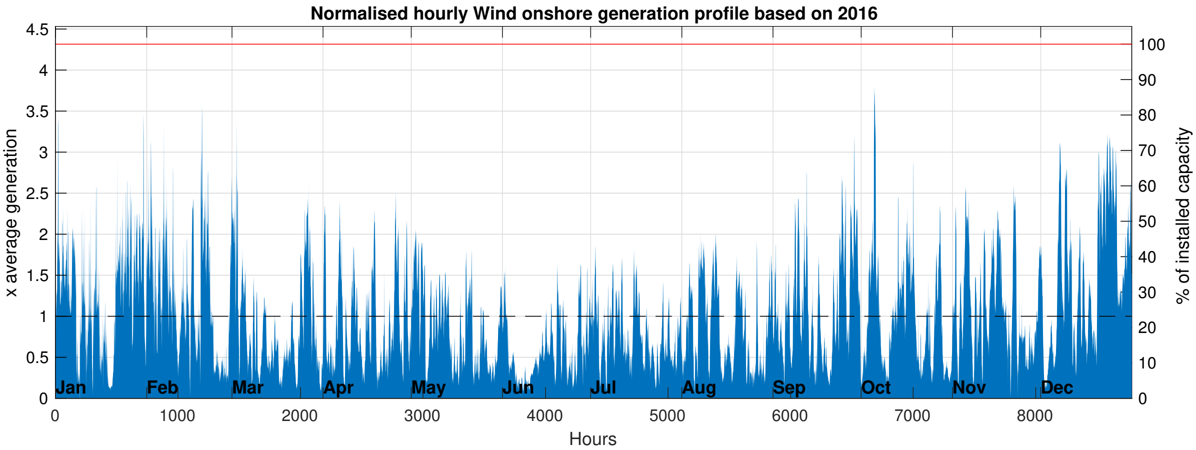


Figure H.10: Normalised hourly onshore wind electricity generation profile GB, 2016 base year

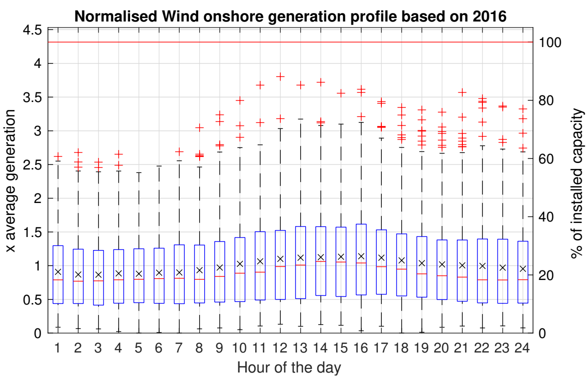


Figure H.11: Hourly boxplot normalised onshore wind electricity generation profile GB, 2016 base year

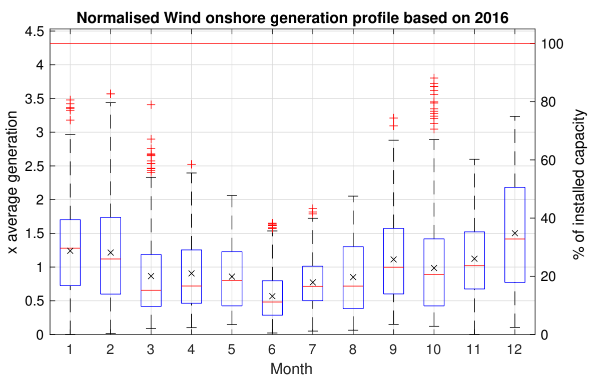


Figure H.12: Monthly boxplot normalised onshore wind electricity generation profile GB, 2016 base year

H.1.3. Offshore wind electricity generation

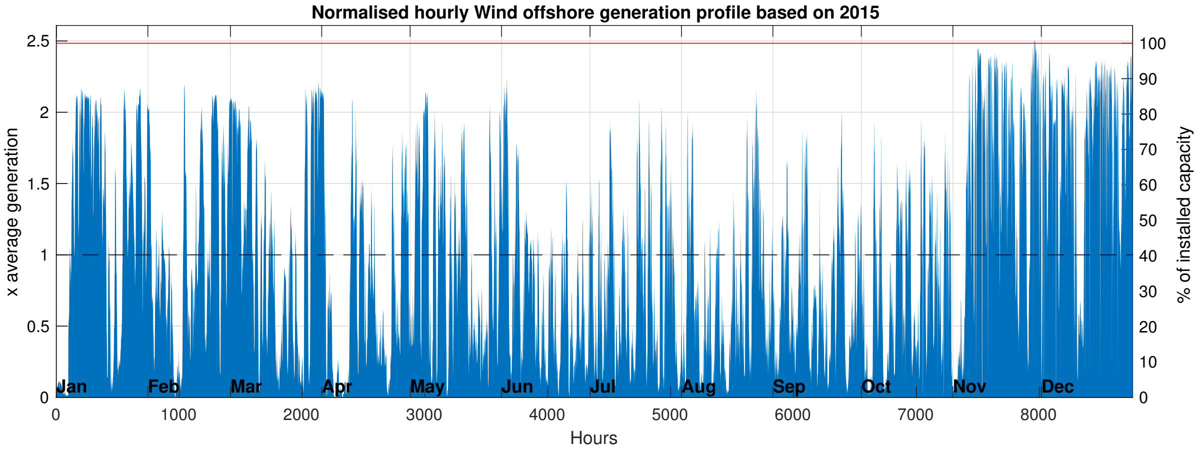


Figure H.13: Normalised hourly offshore wind electricity generation profile GB, 2015 base year

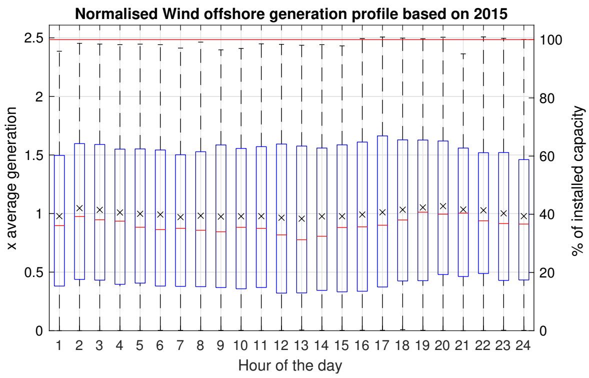


Figure H.14: Hourly boxplot normalised offshore wind electricity generation profile GB, 2015 base year

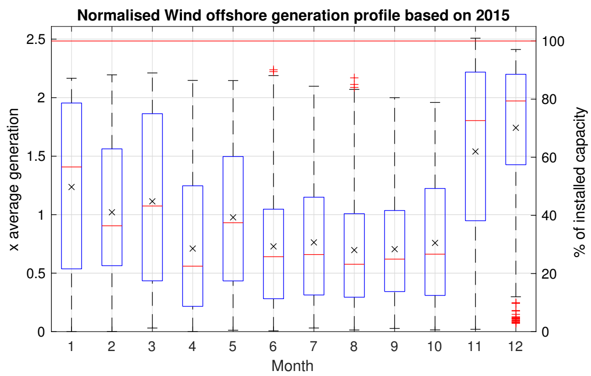


Figure H.15: Monthly boxplot normalised offshore wind electricity generation profile GB, 2015 base year

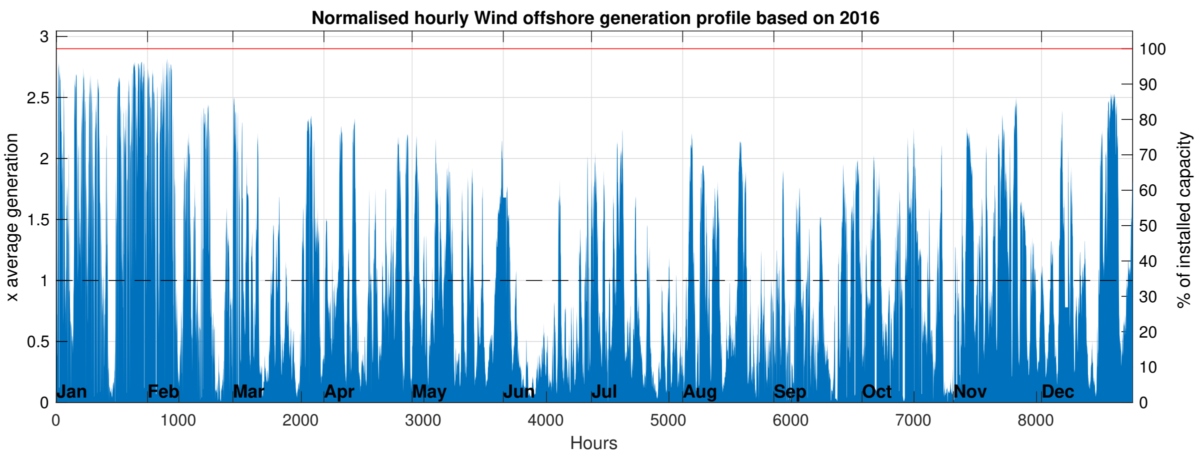


Figure H.16: Normalised hourly offshore wind electricity generation profile GB, 2016 base year

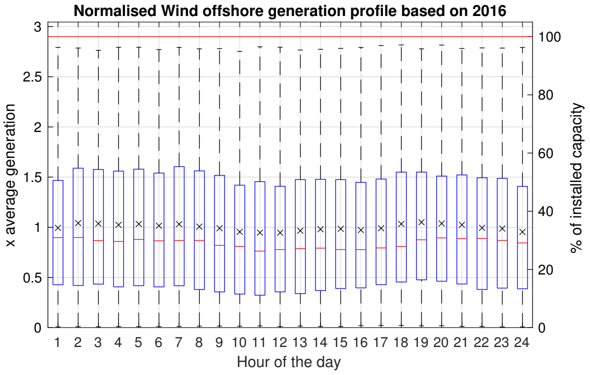


Figure H.17: Hourly boxplot normalised offshore wind electricity generation profile GB, 2016 base year

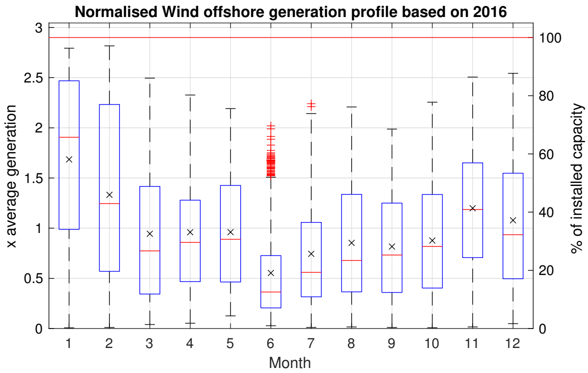


Figure H.18: Monthly boxplot normalised offshore wind electricity generation profile GB, 2016 base year

H.1.4. Hydro

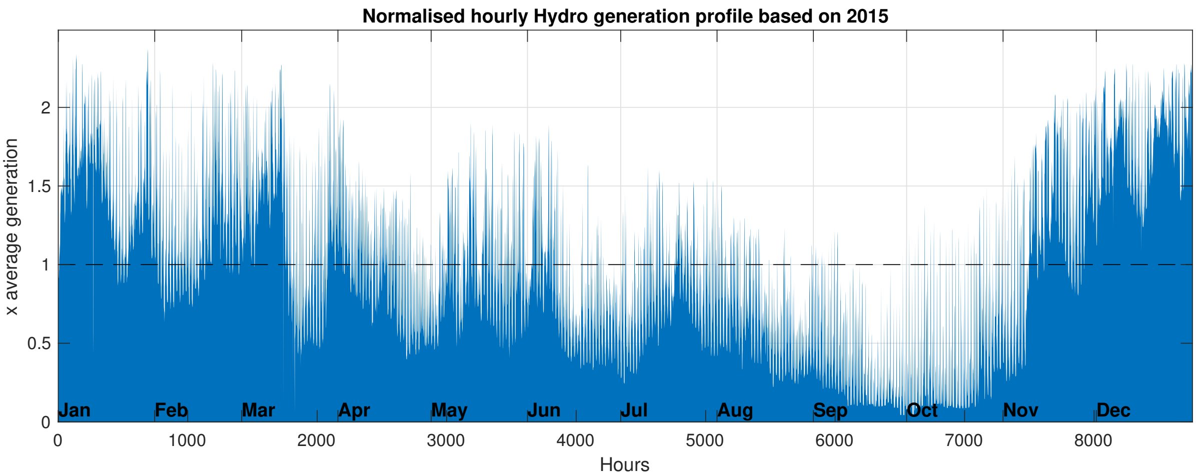


Figure H.19: Normalised hourly Hydro electricity generation profile GB, 2015 base year

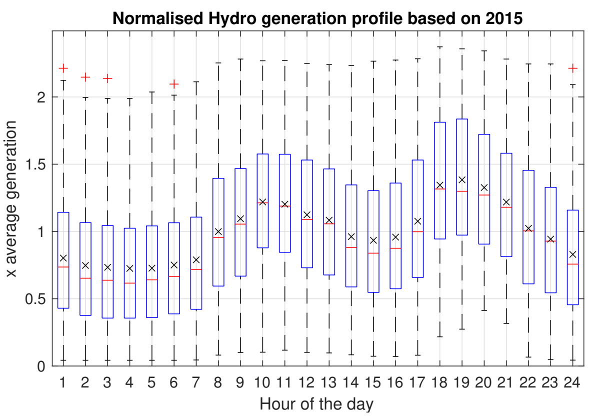


Figure H.20: Hourly boxplot normalised Hydro electricity generation profile GB, 2015 base year

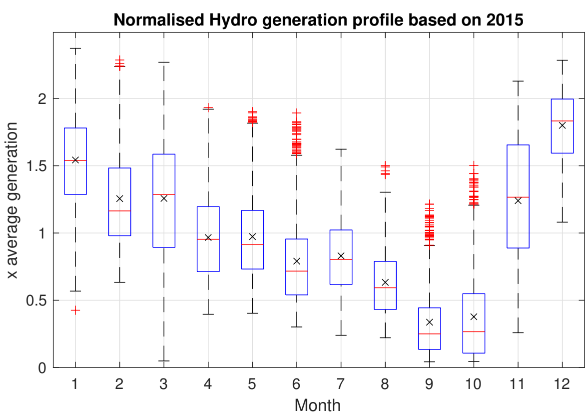


Figure H.21: Monthly boxplot normalised Hydro electricity generation profile GB, 2015 base year

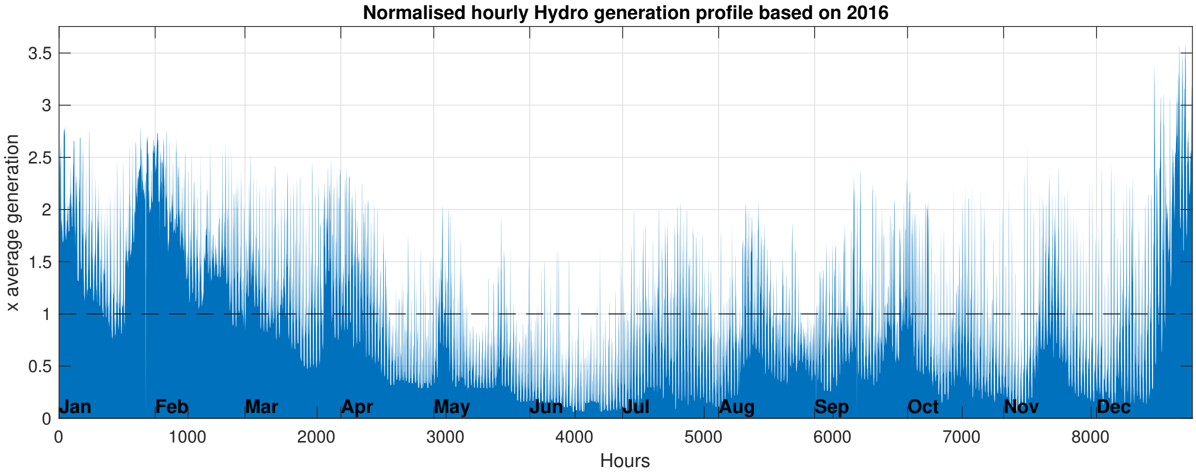


Figure H.22: Normalised hourly Hydro electricity generation profile GB, 2016 base year

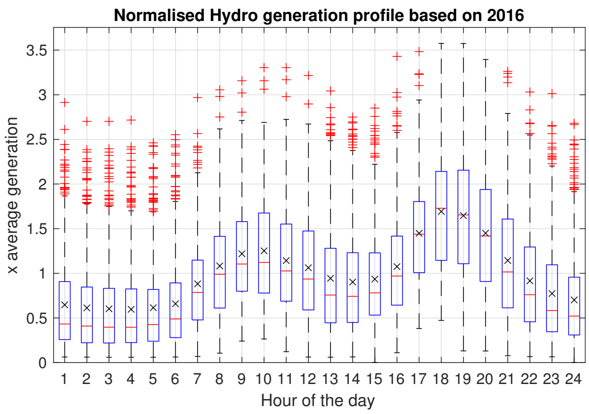


Figure H.23: Hourly boxplot normalised Hydro electricity generation profile GB, 2016 base year

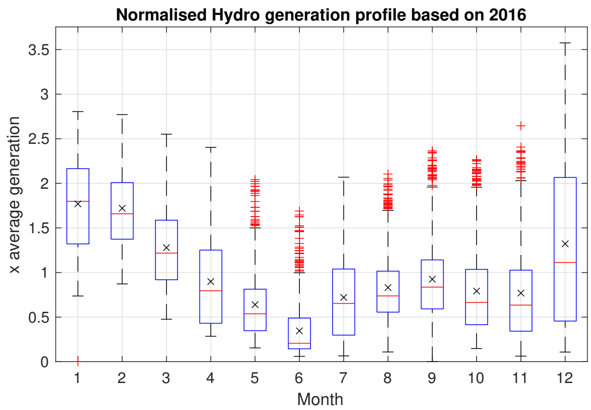


Figure H.24: Monthly boxplot normalised Hydro electricity generation profile GB, 2016 base year

H.1.5. Classic electricity consumption

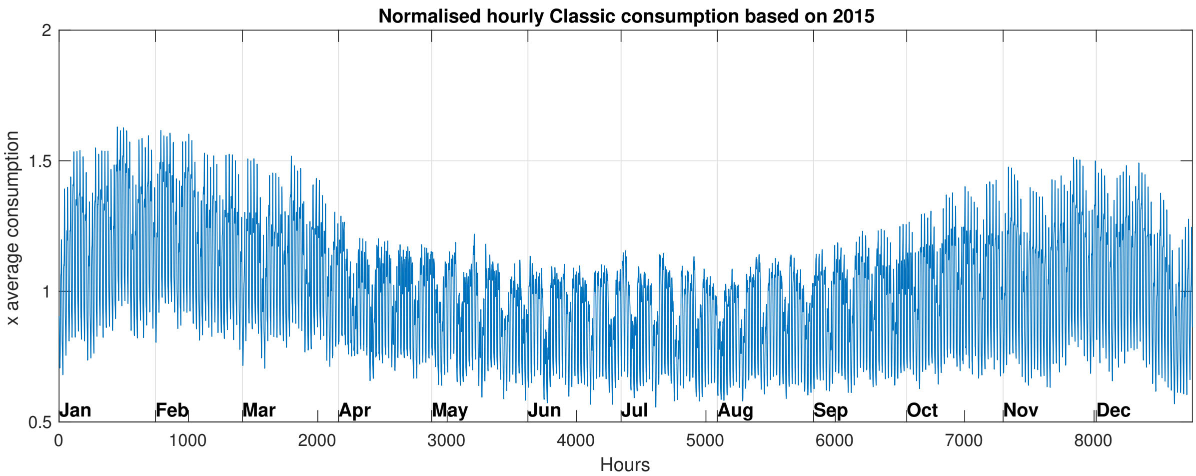


Figure H.25: Normalised hourly classic electricity consumption profile GB, 2015 base year

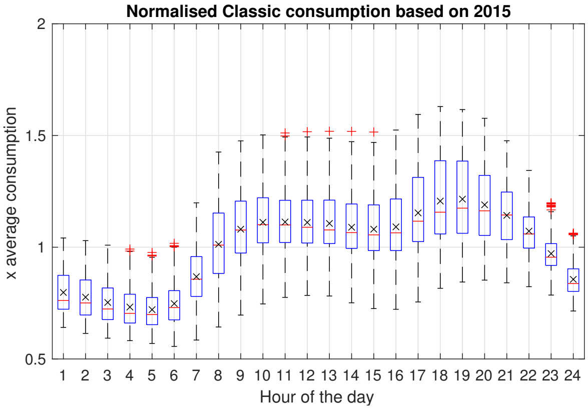


Figure H.26: Hourly boxplot normalised classic electricity consumption profile GB, 2015 base year

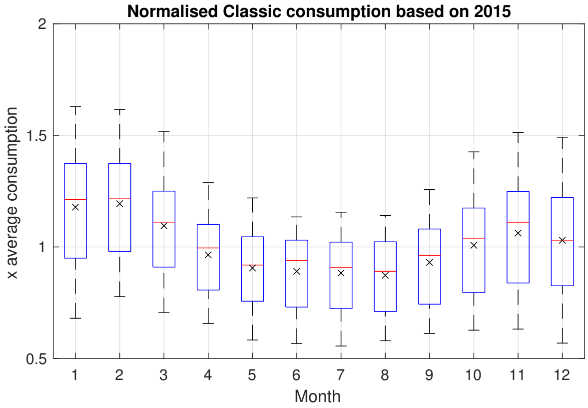


Figure H.27: Monthly boxplot normalised classic electricity consumption profile GB, 2015 base year

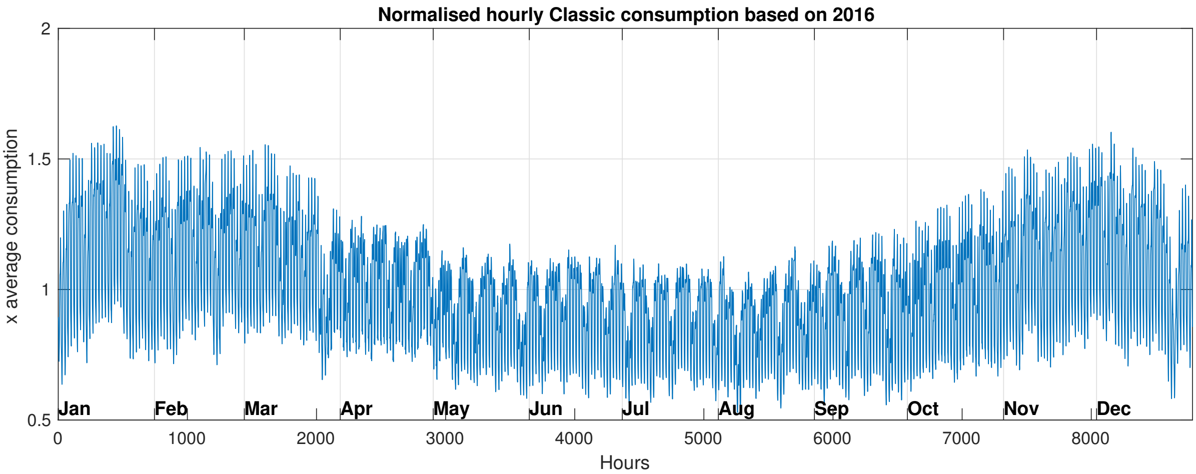


Figure H.28: Normalised hourly classic electricity consumption profile GB, 2016 base year

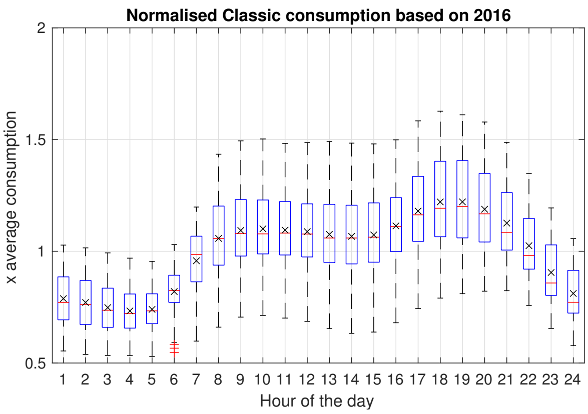


Figure H.29: Hourly boxplot normalised classic electricity consumption profile GB, 2016 base year

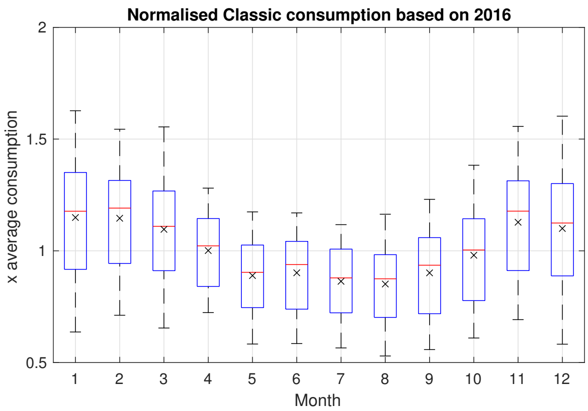


Figure H.30: Monthly boxplot normalised classic electricity consumption profile GB, 2016 base year

H.1.6. Electric heating demand & average outside temperature

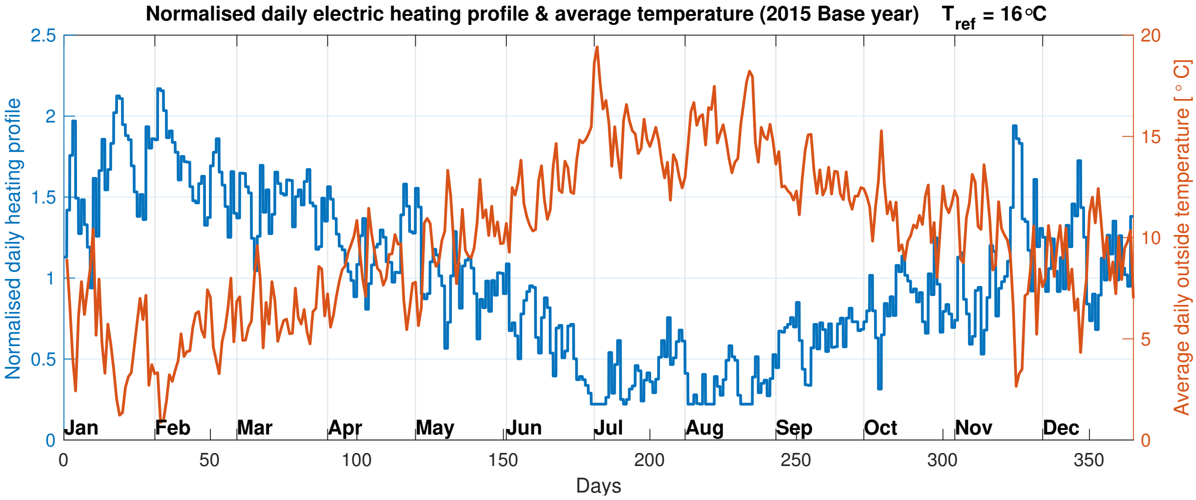


Figure H.31: Normalised daily electric heating demand, 2015 base year

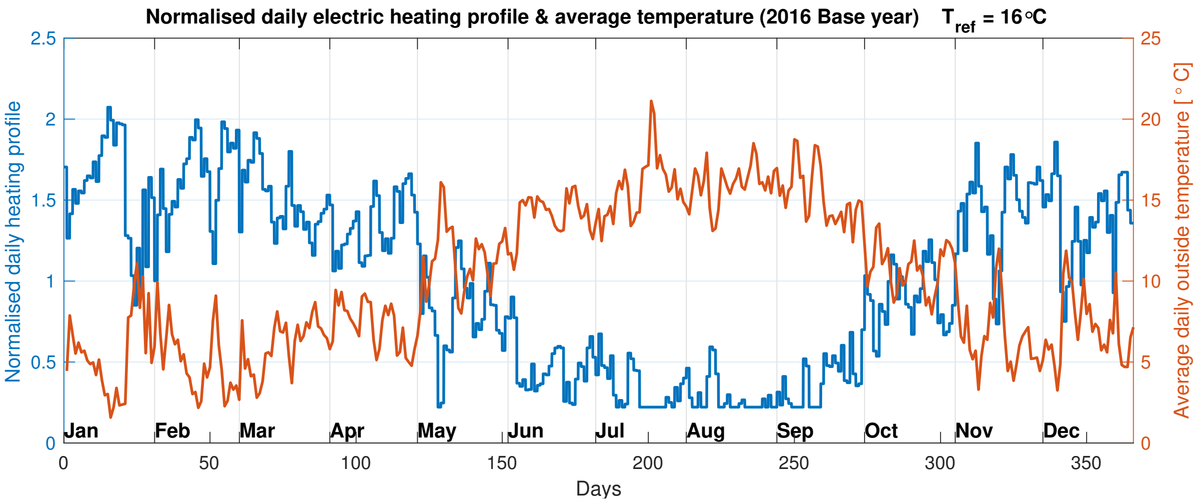


Figure H.32: Normalised daily electric heating demand, 2016 base year

H.2. Model output

Table H.1: Model outputs Great Britain

-	2015	2016		2015	2016
Electricity generation (TWh)			Direct electricity consumption (TWh)	326.78	329.69
Solar	115.40	122.01	% of total electricity consumption	90.94	91.50
Onshore wind	130.44	131.57	Electrolyser consumption (TWh)	213.11	209.37
Offshore wind	278.59	269.98	Electrolyser capacity (GW)	128.51	131.07
Hydro	6.85	6.87	Electrolyser capacity factor (%)	18.93	18.19
CHP	8.61	8.64	FCEV V2G demand (TWh)	32.55	30.62
Total	539.89	539.05	FCEV V2G peak demand (GW)	40.86	44.10
Installed capacity (GW)			million vehicles	4.09	4.41
Solar	117.09	132.10	% of passenger FCEVs	27.02	29.16
Onshore wind	57.29	64.64	Peak storage capacity (million kg)	625.31	673.60
Offshore wind	79.00	89.13	BEV charging load (GW)	5.23	5.23
Hydro	3.04	3.04			
CHP	7.50	7.50			
Total	263.93	296.41			
Electricity consumption (TWh)					
Classic	226.00	226.62			
Electricity for heating	90.90	91.15			
BEV charging	42.42	42.53			
Total	359.32	360.30			
Road transport cons. (TWh)	110.88	111.18			
Final energy cons. (TWh)	689.03 67 89.95				
Hydrogen cons. (million kg)					
Road transport	2985.17	2993.34			
V2G	1376.41	1294.88			
Residual storage	6.03	2.23			
Total production	4368.18	4291.48			

H.2.1. Sankey diagrams

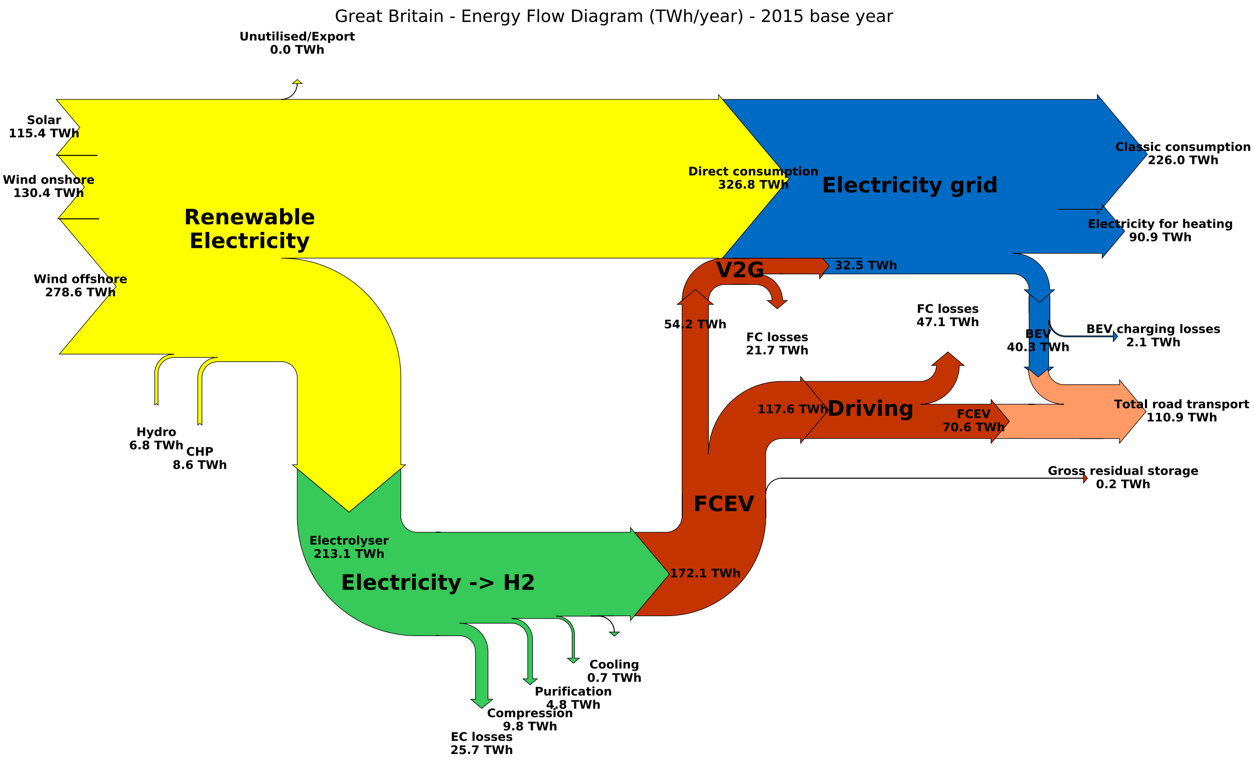


Figure H.33: Energy flow diagram for GB with 2015 as base year

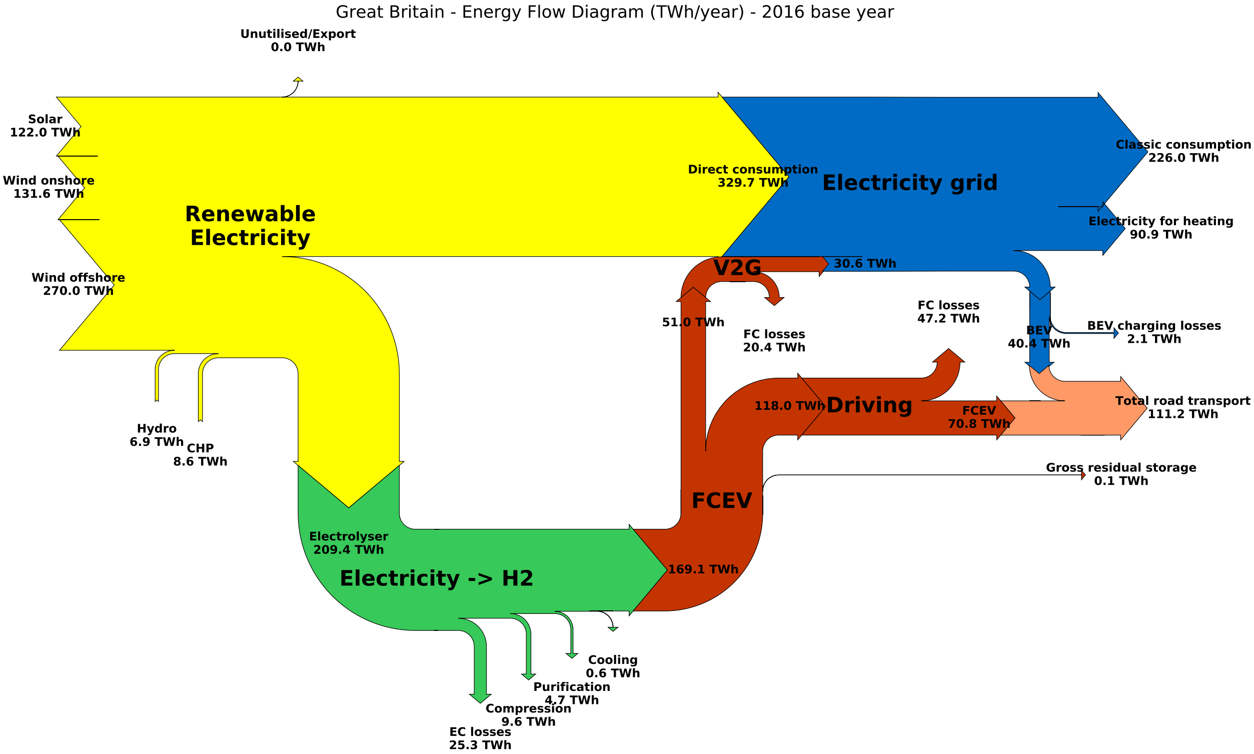


Figure H.34: Energy flow diagram for GB with 2016 as base year

H.2.2. Generation & Consumption profiles (2016 base year)

Only the scaled generation and consumption profiles for base year 2016 are shown to the generation and consumption in terms of GW's. The shape of the profiles are the same as the normalised profile.

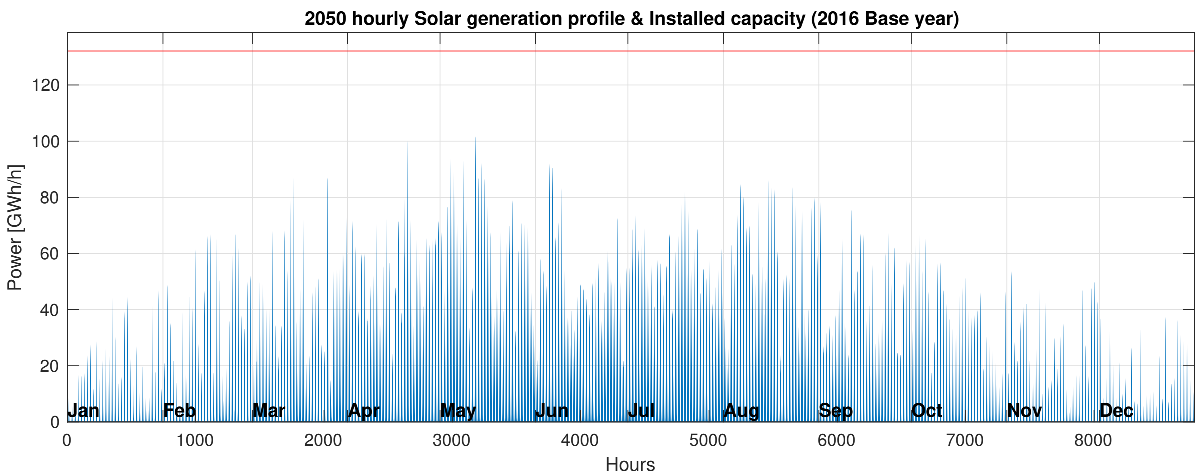


Figure H.35: Solar electricity generation in GB in 2050 (2016 base year)

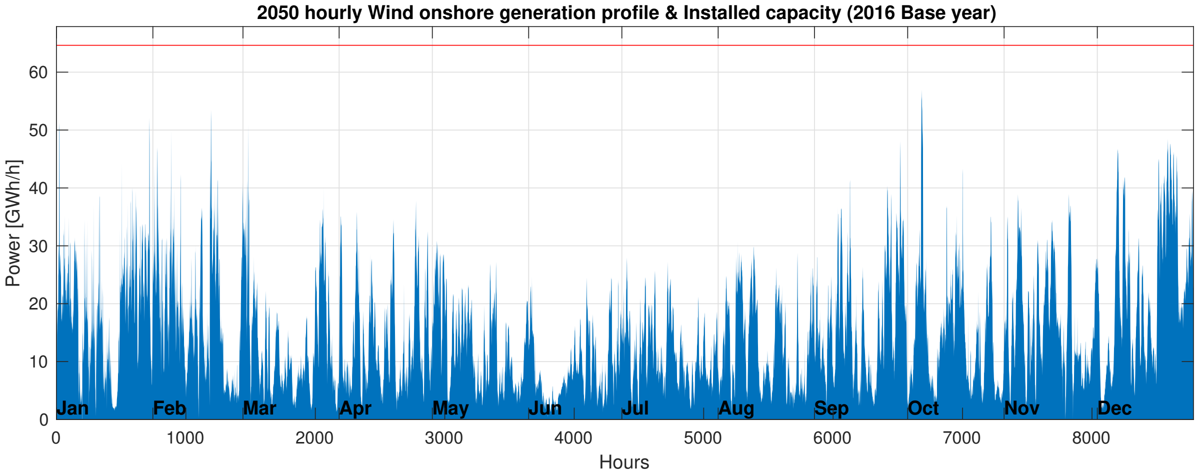


Figure H.36: Onshore wind electricity generation in GB in 2050 (2016 base year)

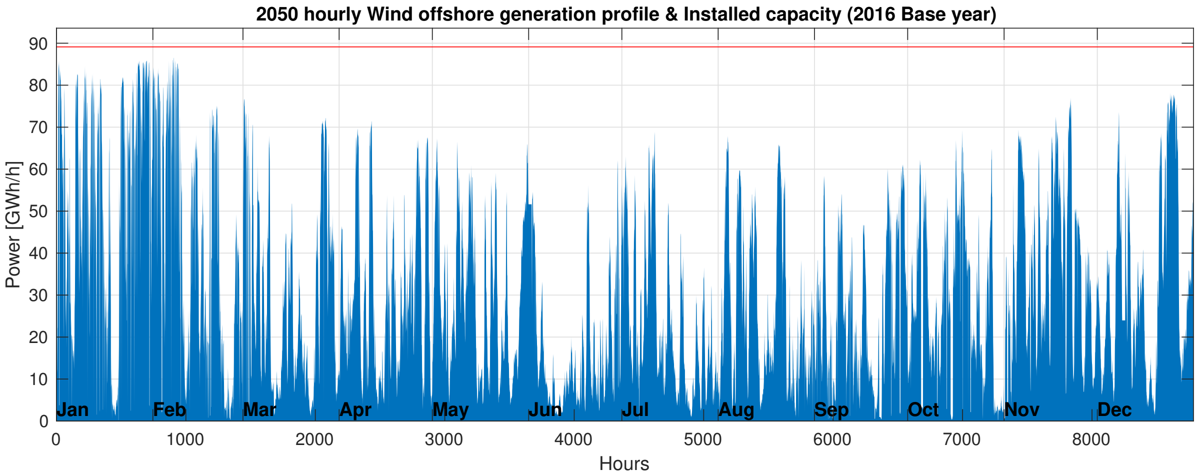


Figure H.37: Offshore wind electricity generation in GB in 2050 (2016 base year)

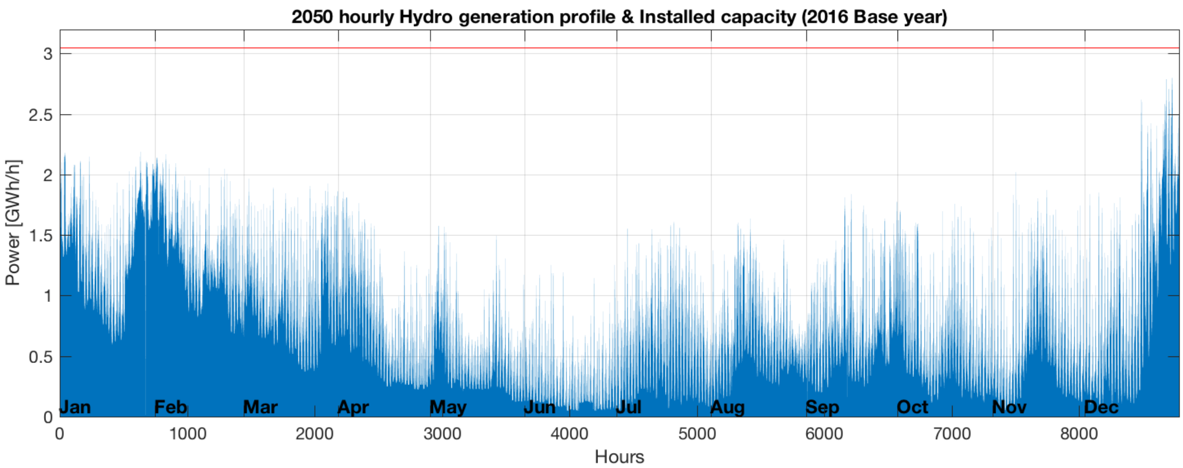


Figure H.38: Hydro electricity generation in GB in 2050 (2016 base year)

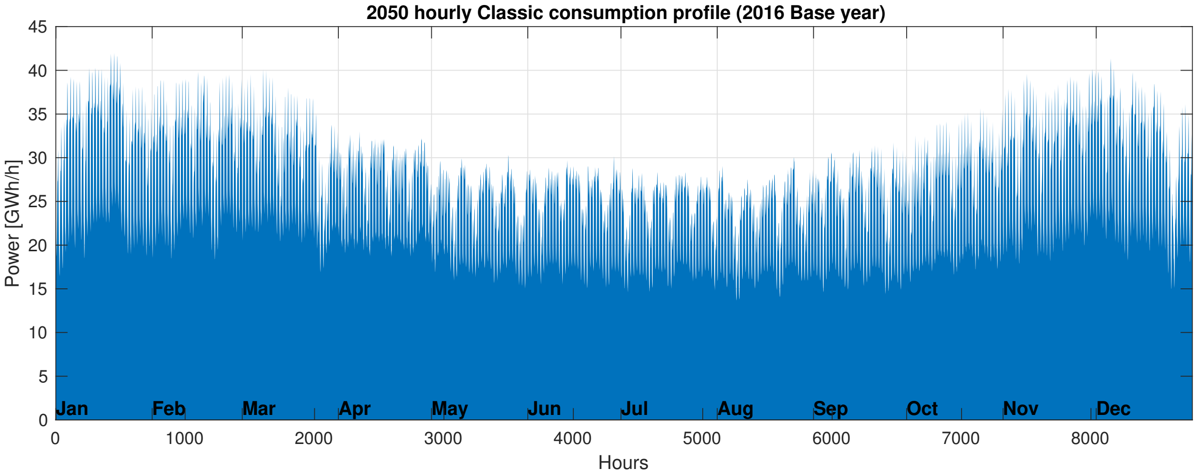


Figure H.39: Classic electricity consumption in GB in 2050 (2016 base year)

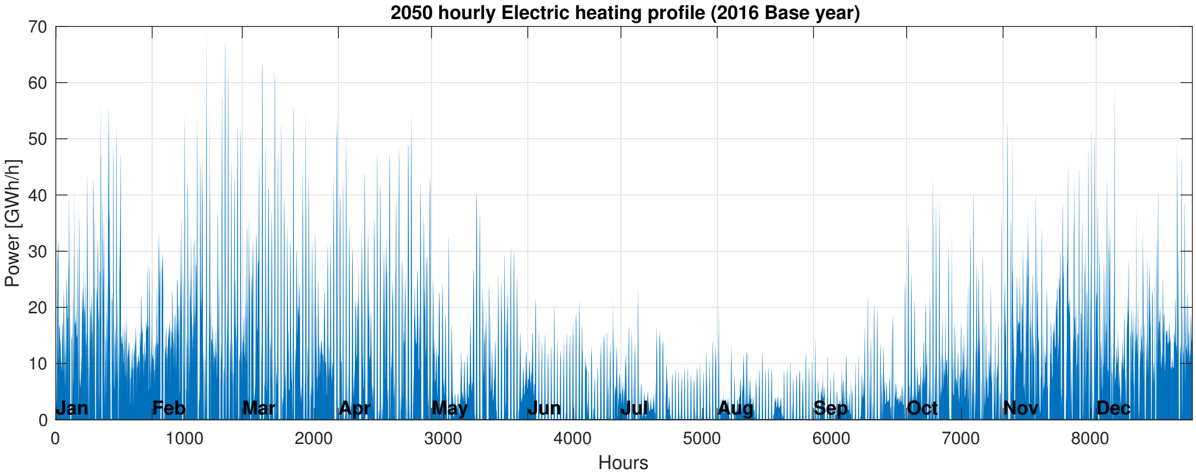


Figure H.40: Electric heating consumption in GB in 2050 (2016 base year)

H.2.3. Imbalance

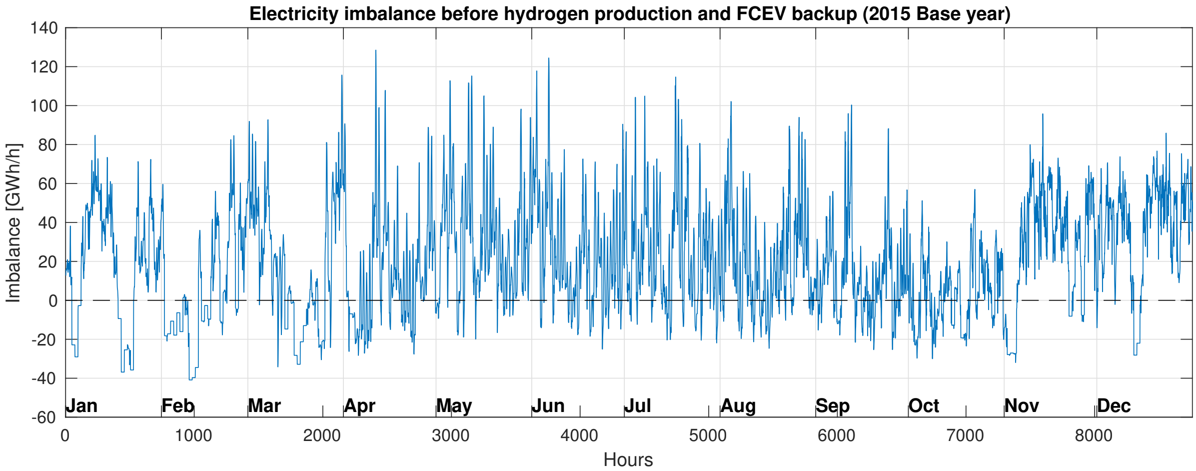


Figure H.41: Electric imbalance in GB in 2050 (2015 base year)

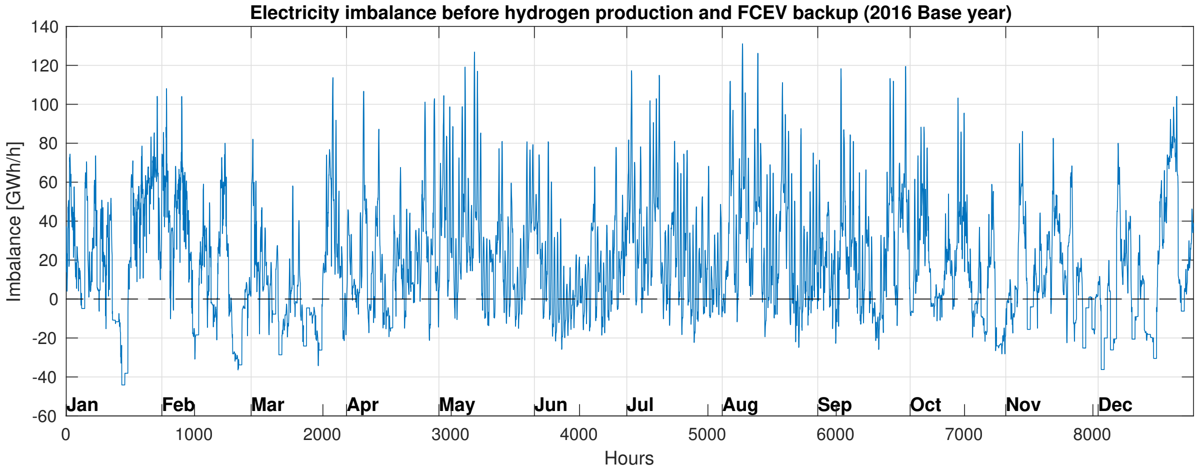


Figure H.42: Electric imbalance in GB in 2050 (2016 base year)

Electrolyser

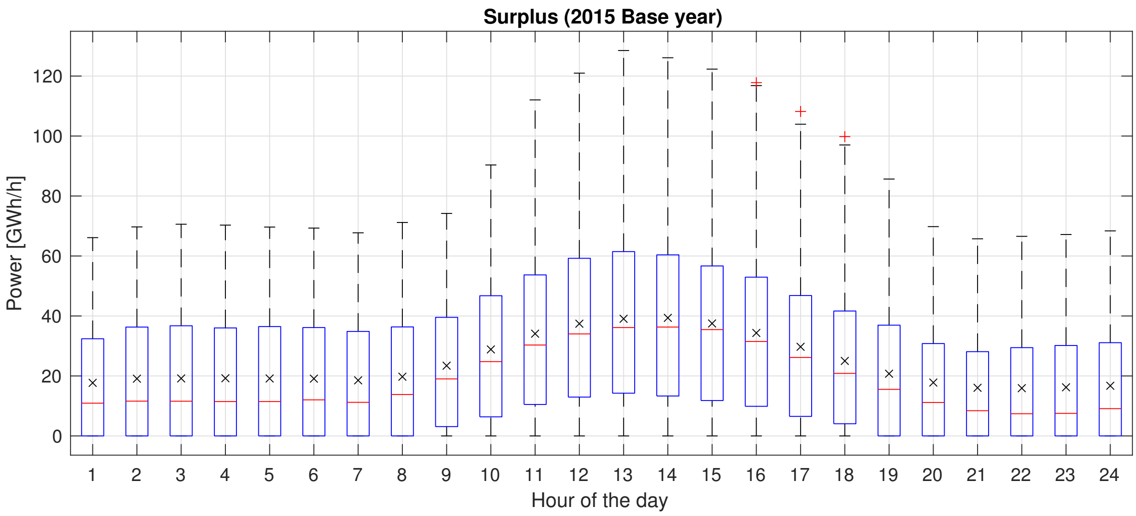


Figure H.43: Hourly boxplot electrolyser consumption in GB in 2050 (2015 base year)

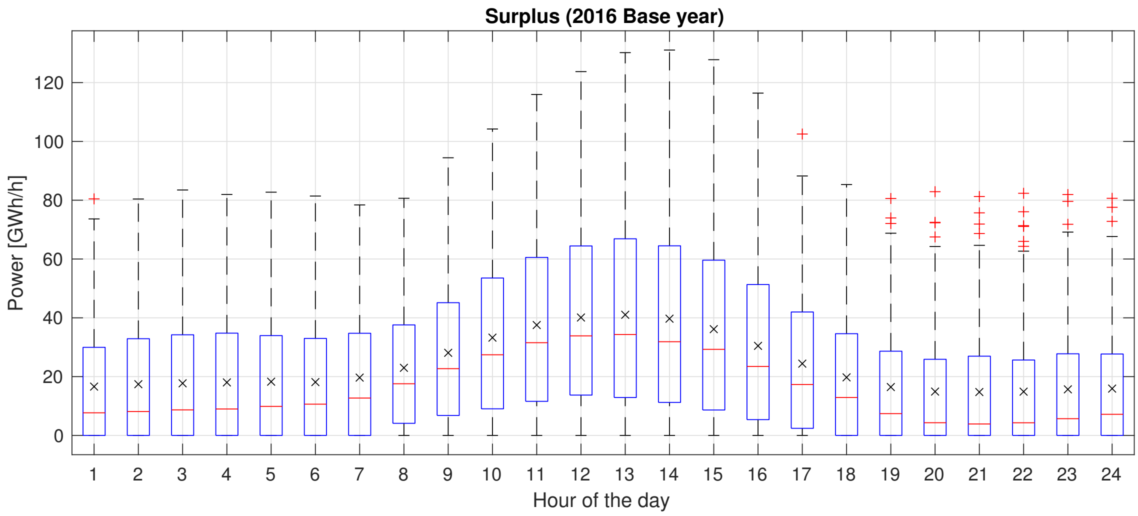


Figure H.44: Hourly boxplot electrolyser consumption in GB in 2050 (2016 base year)

H.2.4. FCEV backup

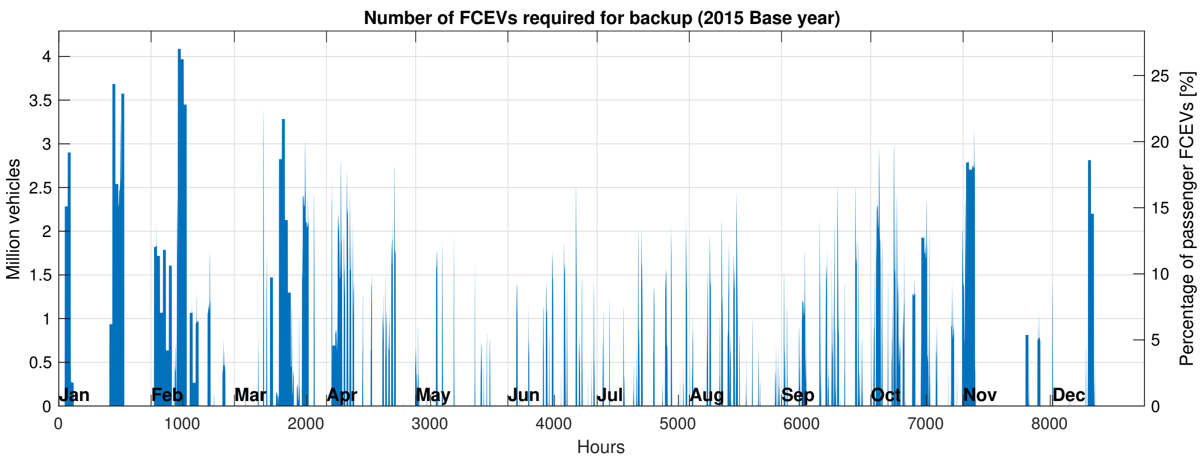


Figure H.45: FCEV backup in GB in 2050 (2015 base year)

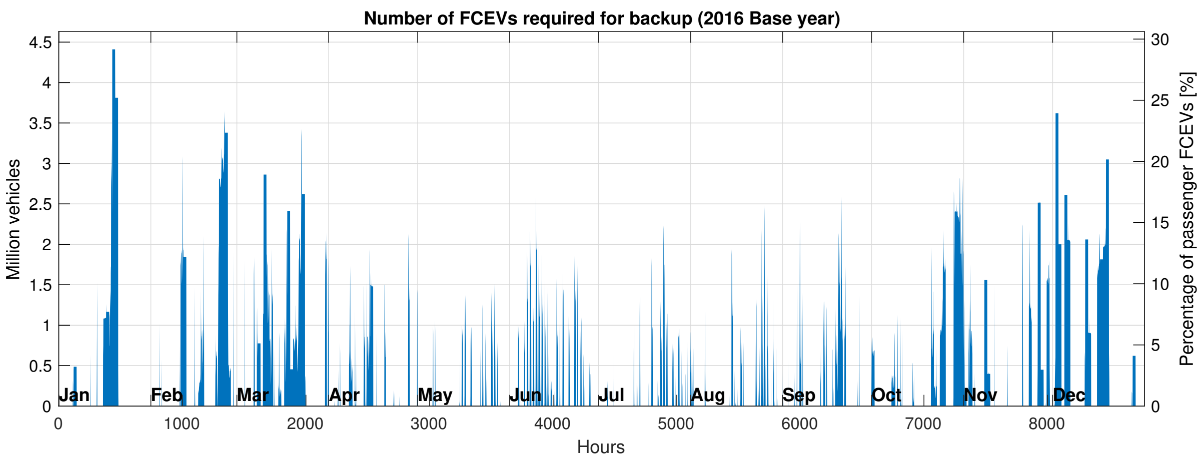


Figure H.46: FCEV backup in GB in 2050 (2016 base year)

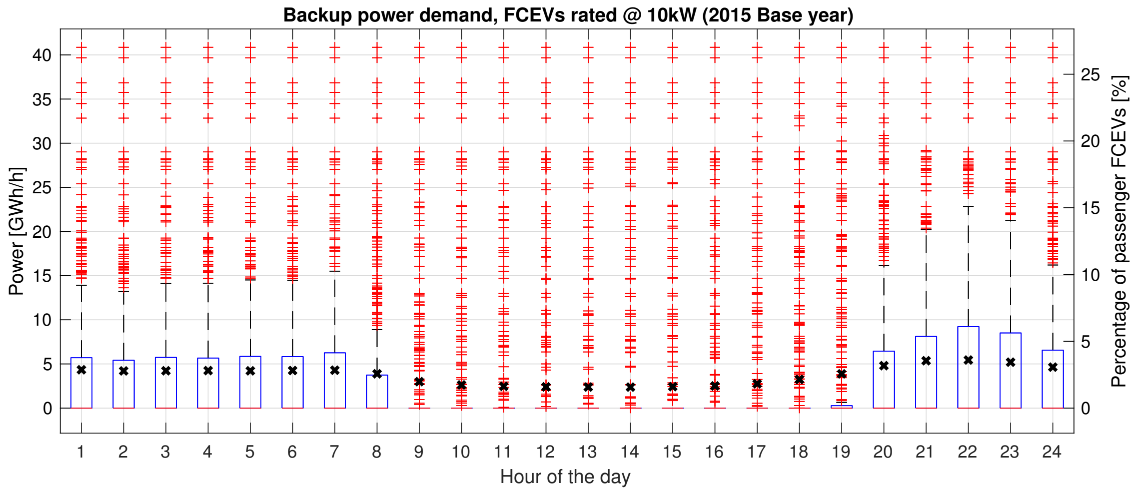


Figure H.47: Hourly boxplot FCEV backup in GB in 2050 (2015 base year)

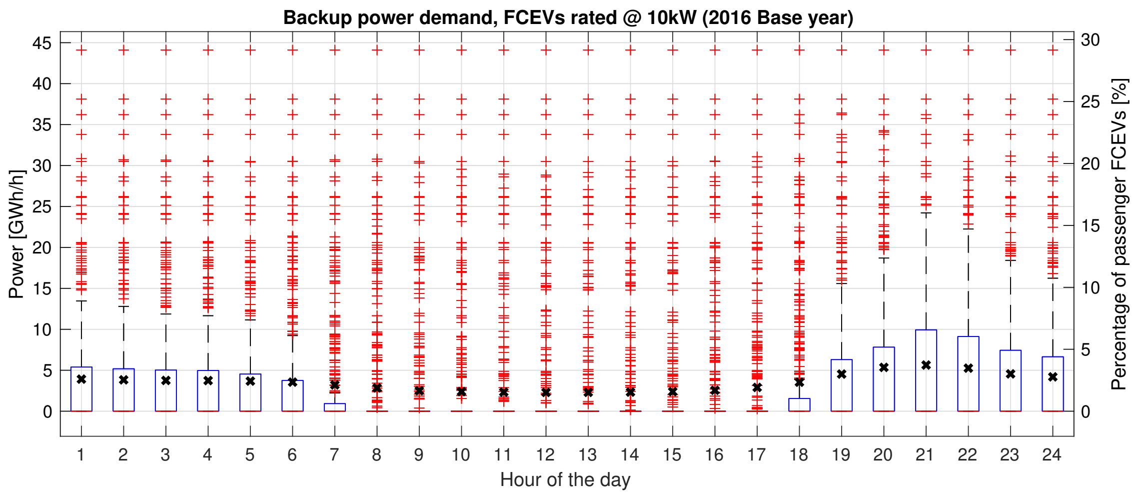


Figure H.48: Hourly boxplot FCEV backup in GB in 2050 (2016 base year)

H.2.5. Weekly charge & discharge rates of hydrogen

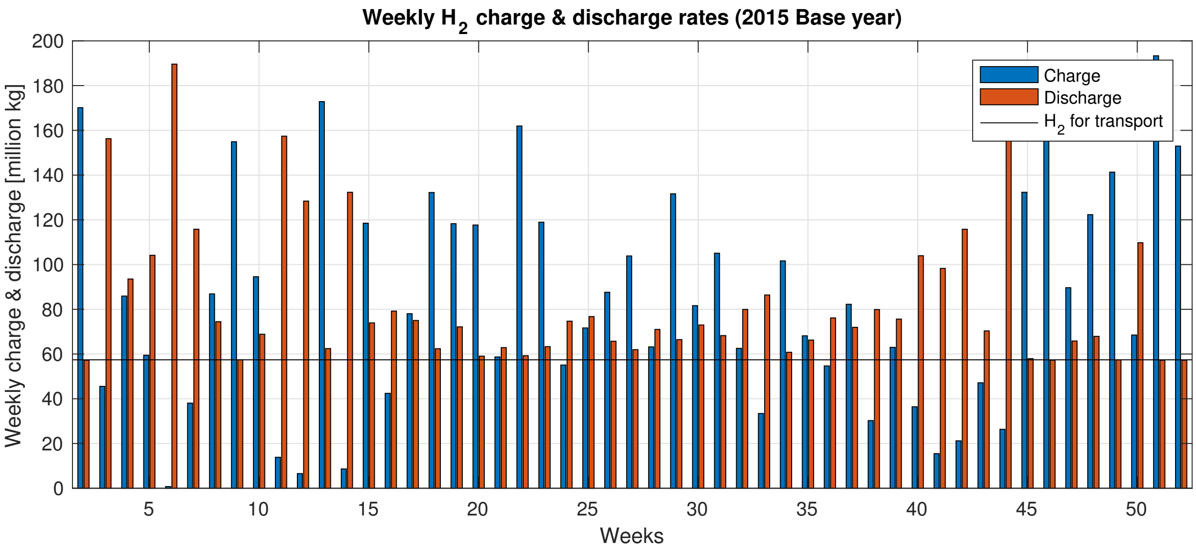


Figure H.49: Hydrogen weekly charge and discharge rates in GB in 2050 (2015 base year)

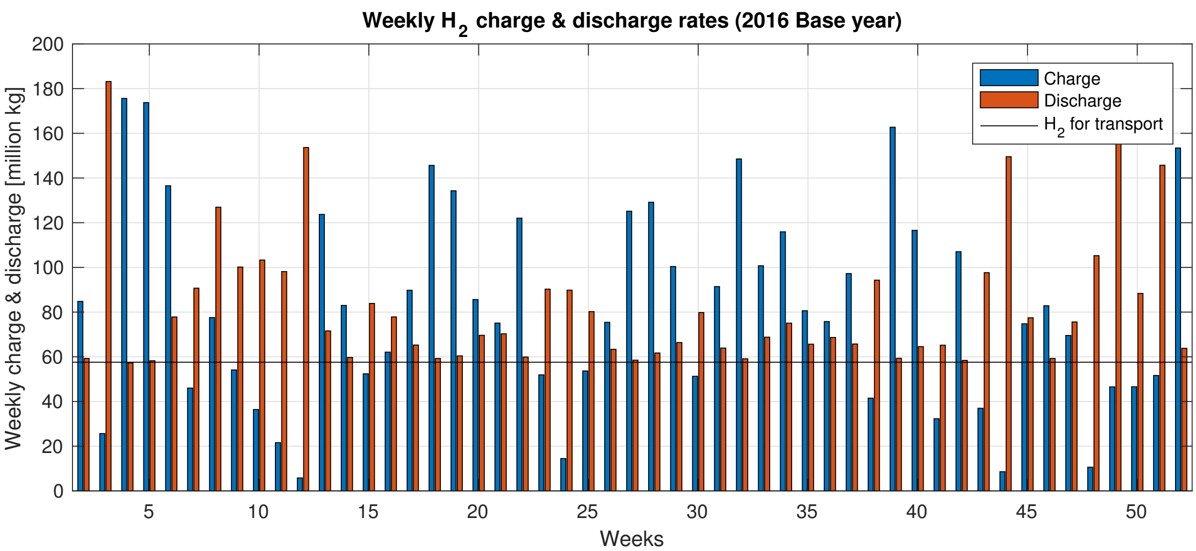


Figure H.50: Hydrogen weekly charge and discharge rates in GB in 2050 (2016 base year)

H.2.6. Fuelling

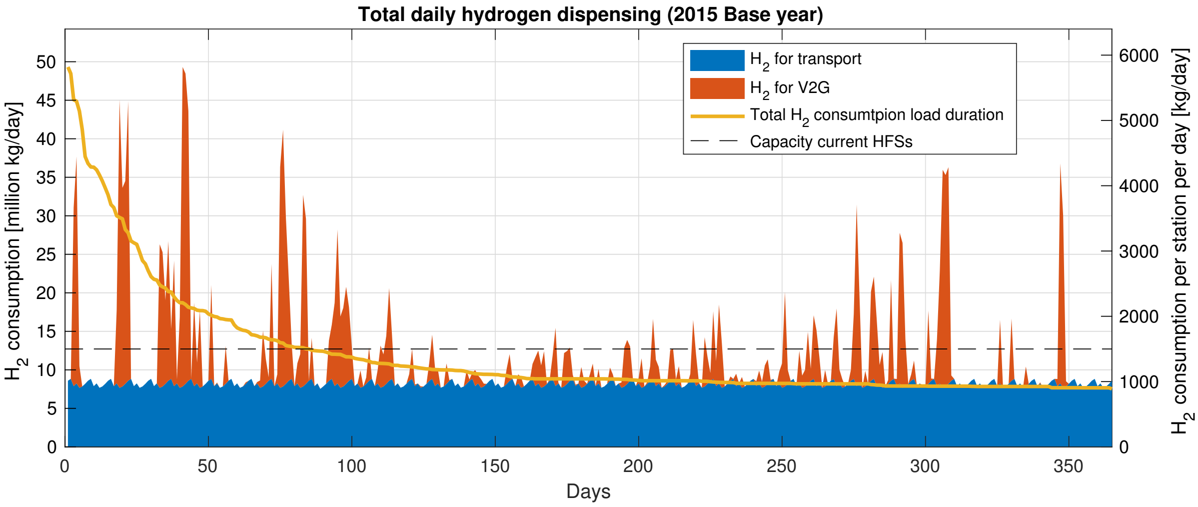


Figure H.51: Total daily hydrogen dispensing and dispension per HFS in GB in 2050 (2015 base year)

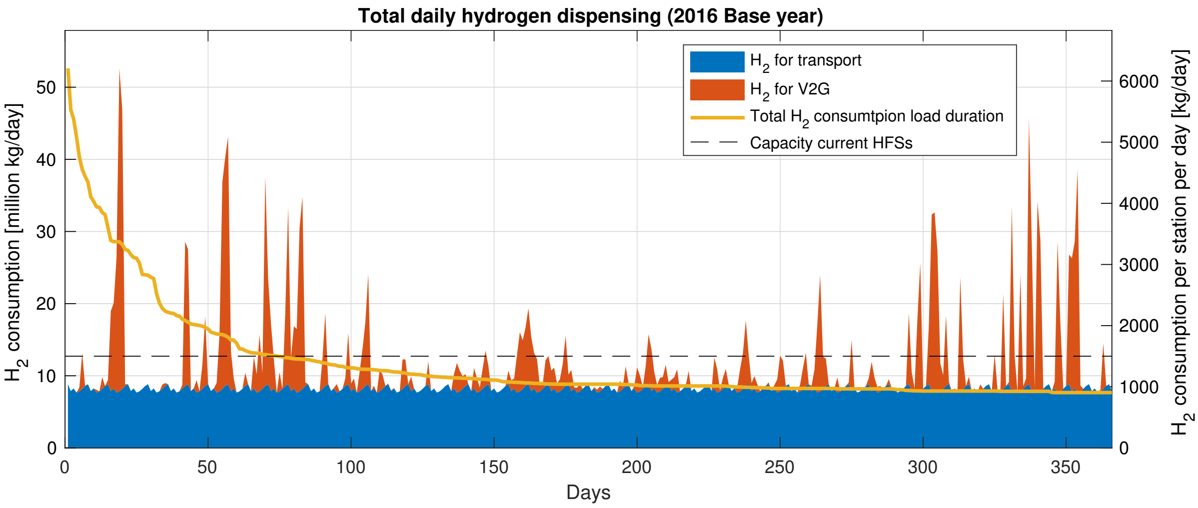


Figure H.52: Total daily hydrogen dispensing and dispension per HFS in GB in 2050 (2016 base year)

Inputs, results & additional data France

I.1. Normalised generation & consumption profiles

I.1.1. Solar PV electricity generation

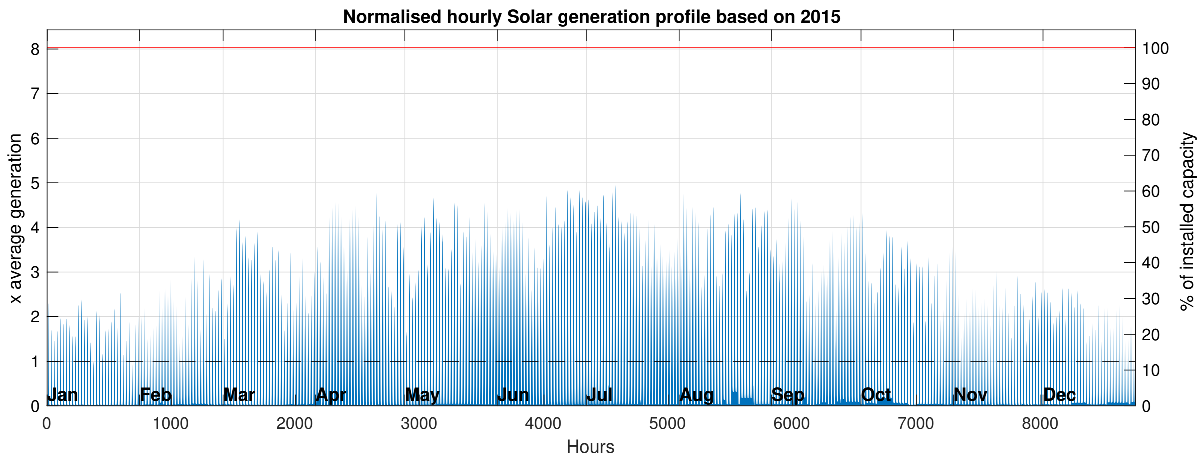


Figure I.1: Normalised hourly Solar electricity generation profile France, 2015 base year

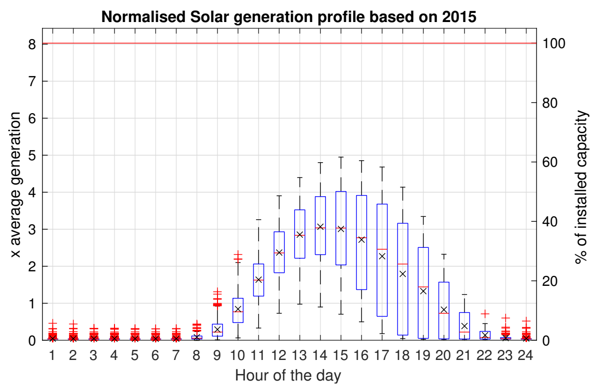


Figure I.2: Hourly boxplot normalised Solar electricity generation profile France, 2015 base year

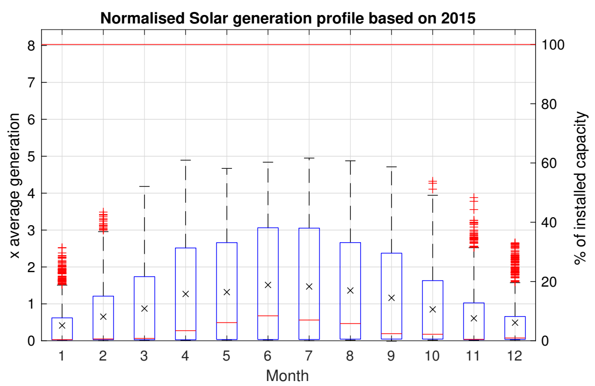


Figure I.3: Monthly boxplot normalised Solar electricity generation profile France, 2015 base year

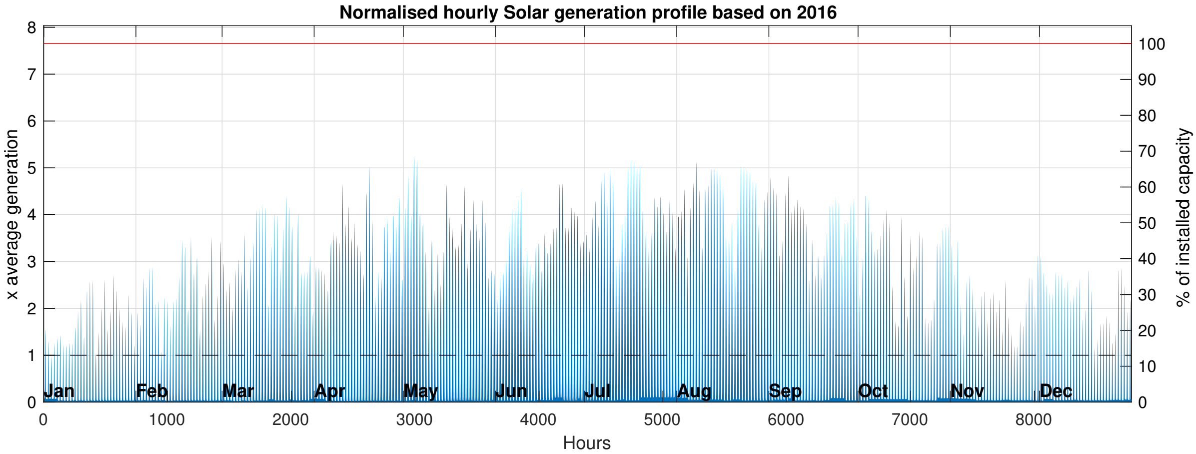


Figure I.4: Normalised hourly Solar electricity generation profile France, 2016 base year

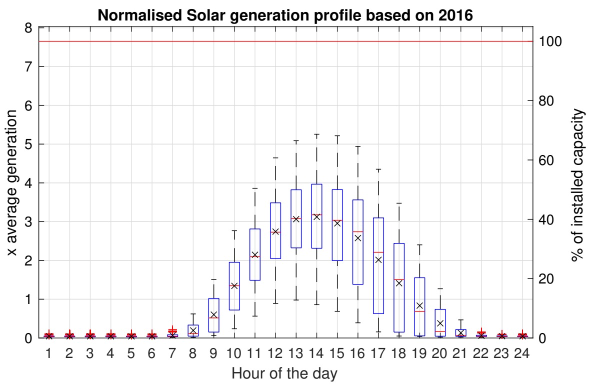


Figure I.5: Hourly boxplot normalised Solar electricity generation profile France, 2016 base year

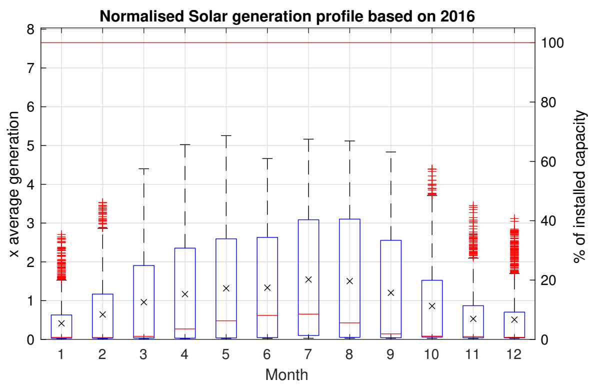


Figure I.6: Monthly boxplot normalised Solar electricity generation profile France, 2016 base year

I.1.2. Onshore wind electricity generation

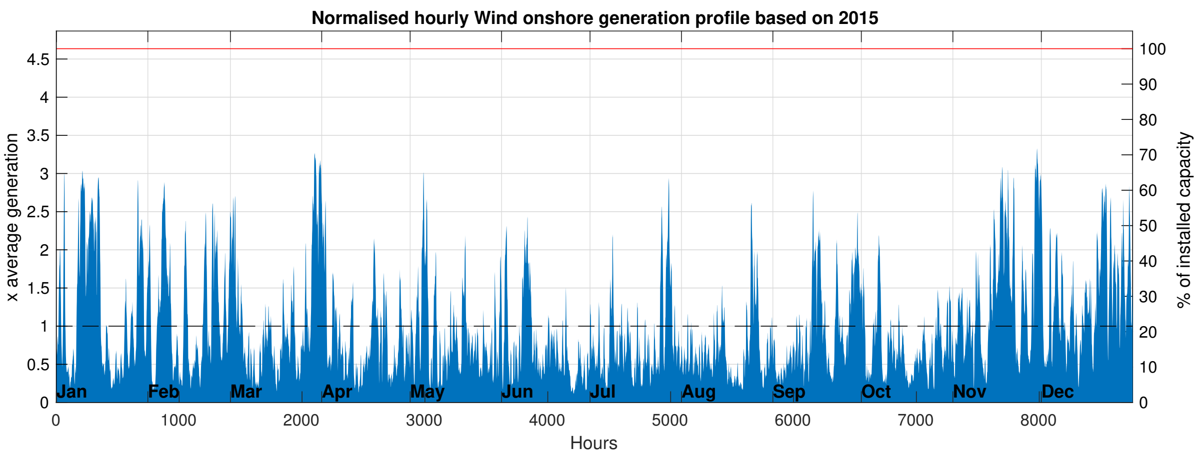


Figure I.7: Normalised hourly onshore wind electricity generation profile France, 2015 base year

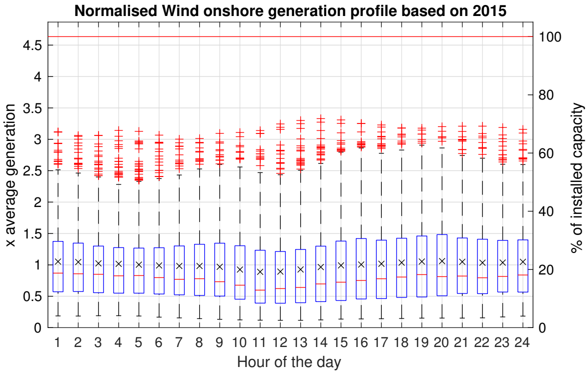


Figure I.8: Hourly boxplot normalised onshore wind electricity generation profile France, 2015 base year

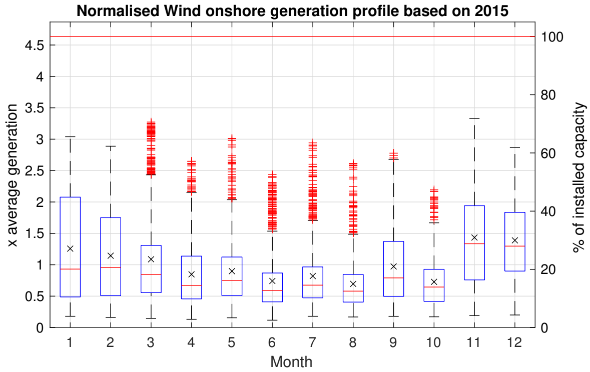


Figure I.9: Monthly boxplot normalised onshore wind electricity generation profile France, 2015 base year

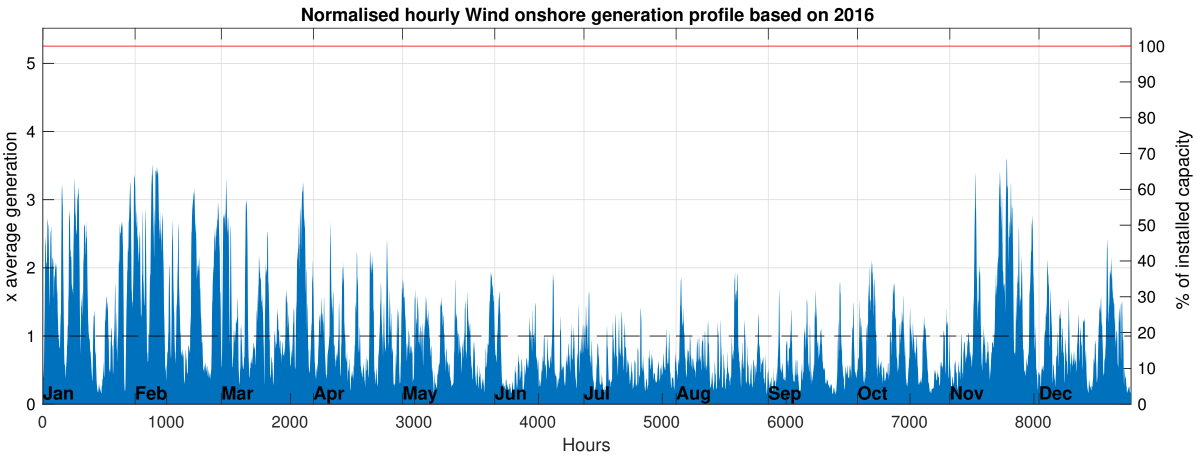


Figure I.10: Normalised hourly onshore wind electricity generation profile France, 2016 base year

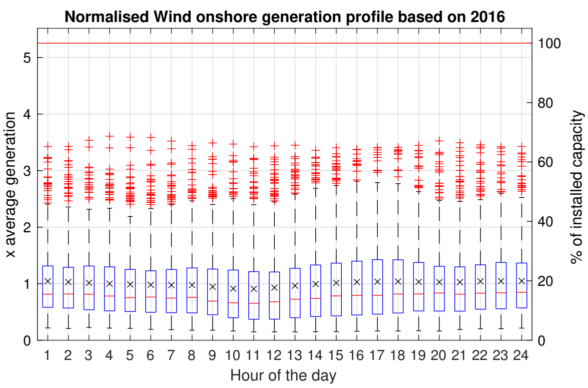


Figure I.11: Hourly boxplot normalised onshore wind electricity generation profile France, 2016 base year

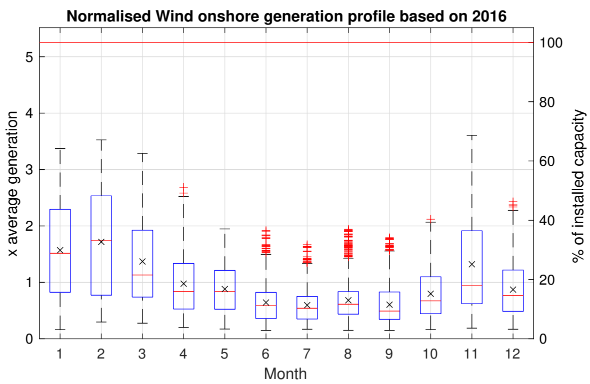


Figure I.12: Monthly boxplot normalised onshore wind electricity generation profile France, 2016 base year

I.1.3. Offshore wind electricity generation

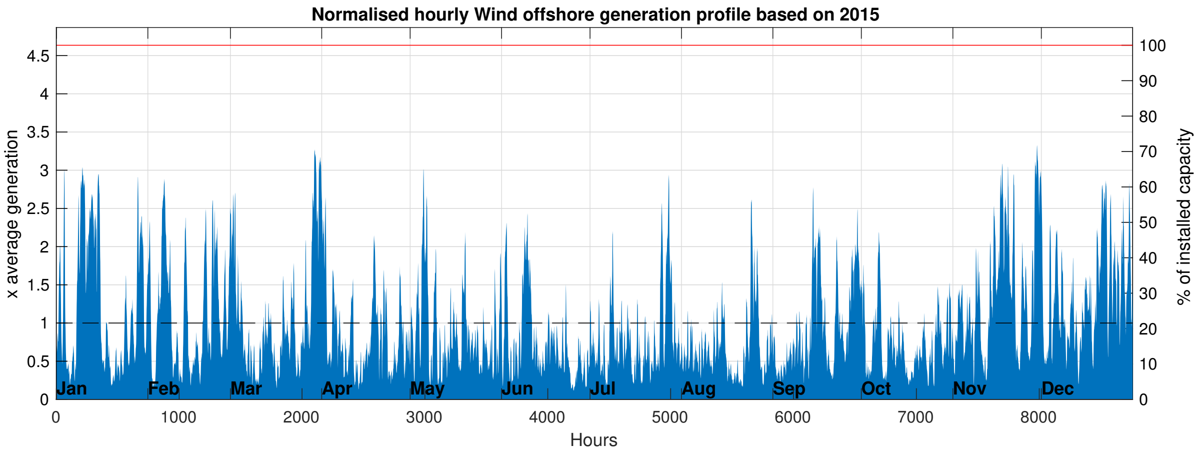


Figure I.13: Normalised hourly offshore wind electricity generation profile France, 2015 base year

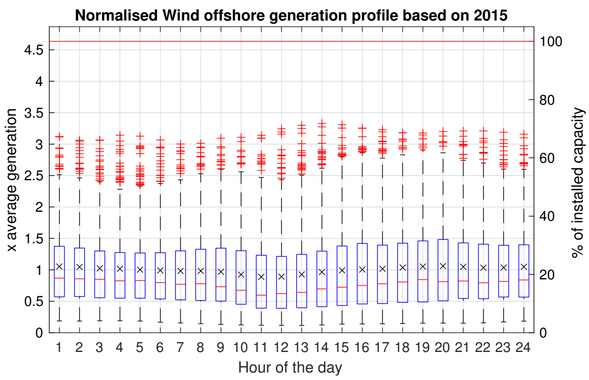


Figure I.14: Hourly boxplot normalised offshore wind electricity generation profile France, 2015 base year

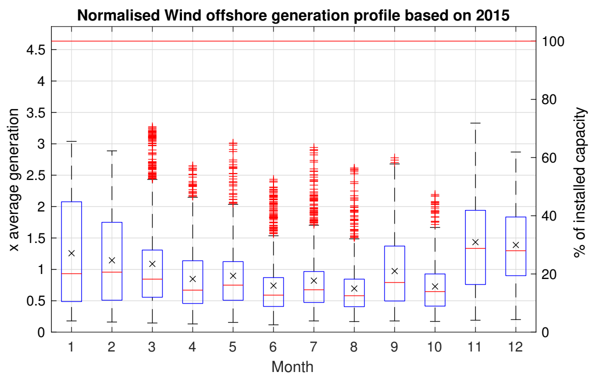


Figure I.15: Monthly boxplot normalised offshore wind electricity generation profile France, 2015 base year

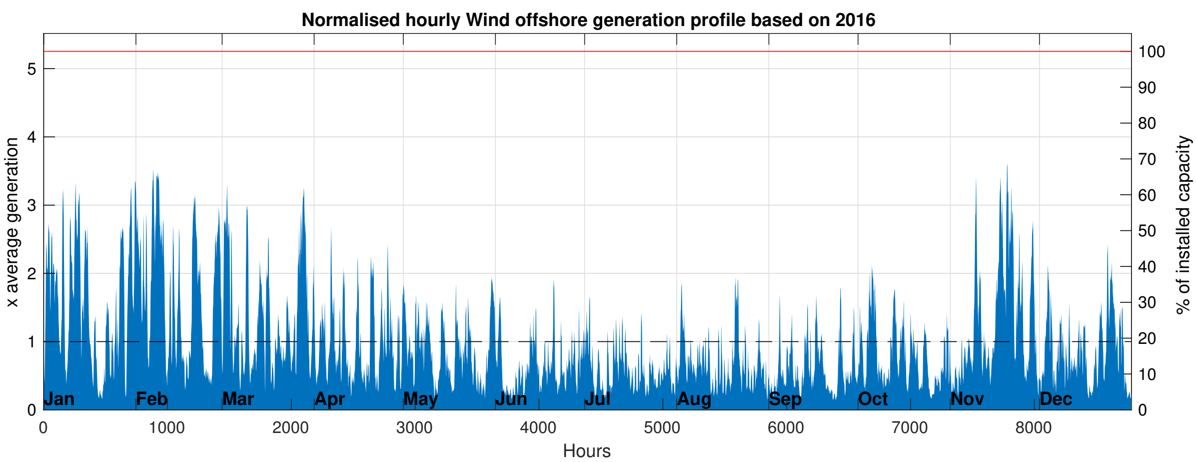


Figure I.16: Normalised hourly offshore wind electricity generation profile France, 2016 base year

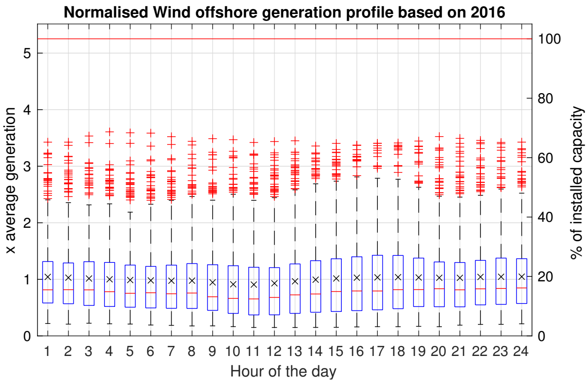


Figure I.17: Hourly boxplot normalised offshore wind electricity generation profile France, 2016 base year

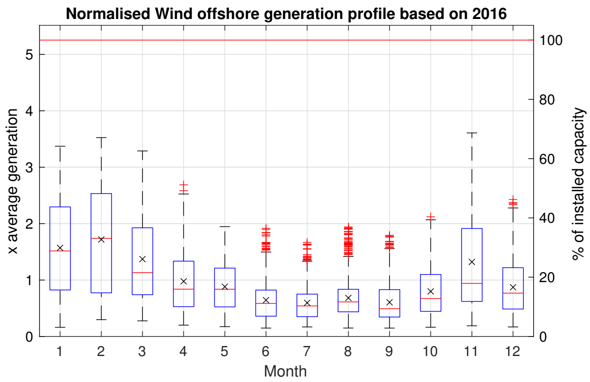


Figure I.18: Monthly boxplot normalised offshore wind electricity generation profile France, 2016 base year

I.1.4. Hydro

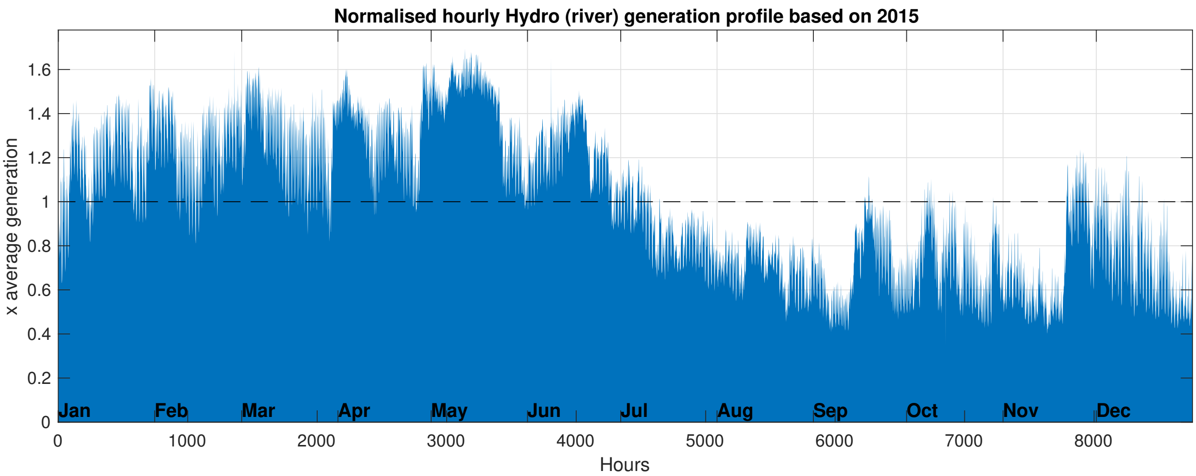


Figure I.19: Normalised hourly Hydro (river) electricity generation profile France, 2015 base year

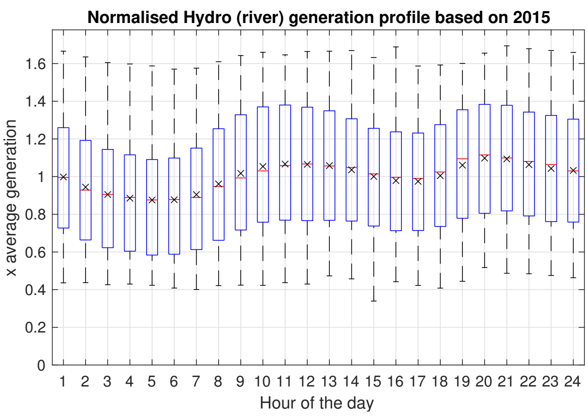


Figure I.20: Hourly boxplot normalised Hydro (river) electricity generation profile France, 2015 base year

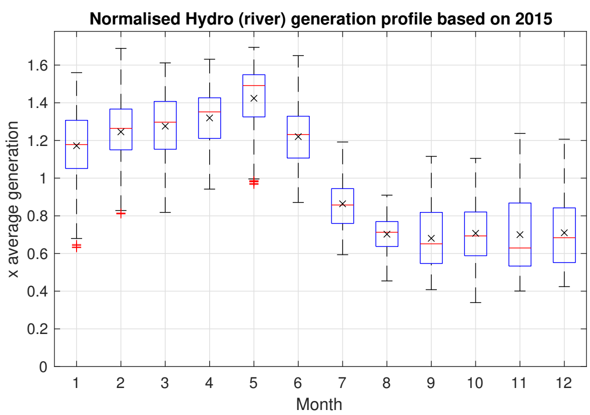


Figure I.21: Monthly boxplot normalised Hydro (river) electricity generation profile France, 2015 base year

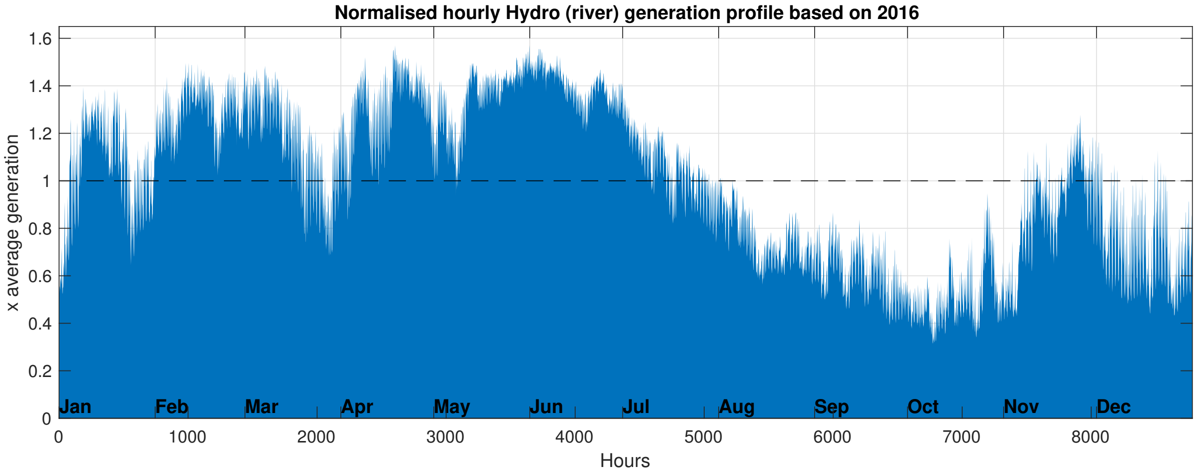


Figure I.22: Normalised hourly Hydro (river) electricity generation profile France, 2016 base year

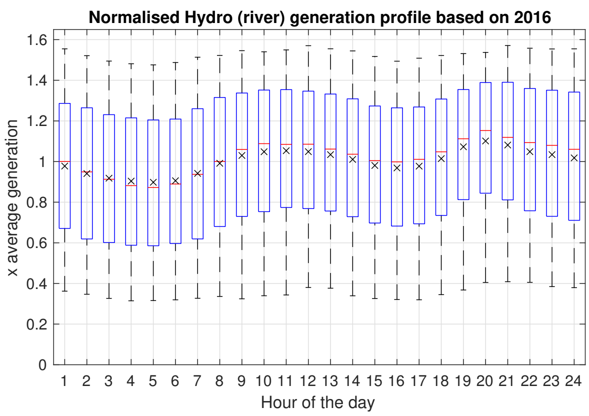


Figure I.23: Hourly boxplot normalised Hydro (river) electricity generation profile France, 2016 base year

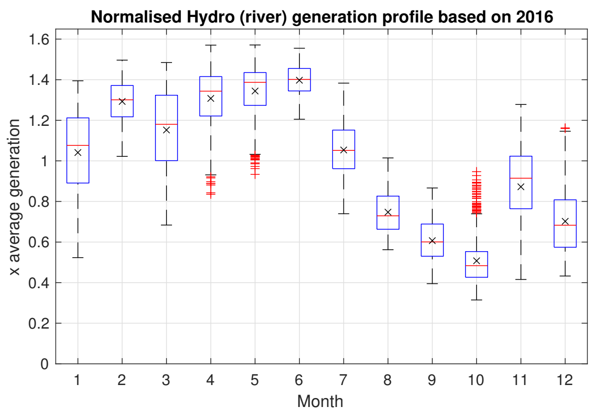


Figure I.24: Monthly boxplot normalised Hydro (river) electricity generation profile France, 2016 base year

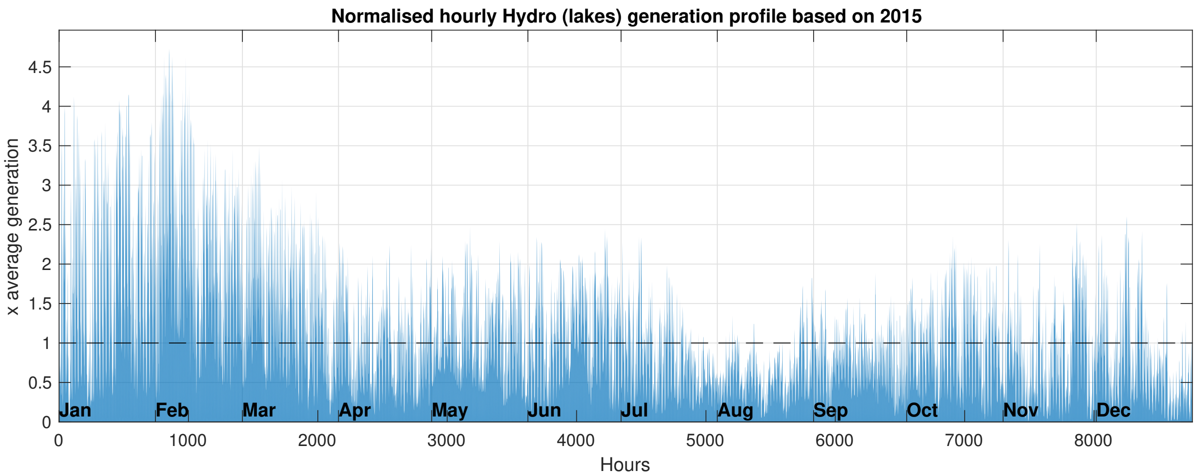


Figure I.25: Normalised hourly Hydro (lakes) electricity generation profile France, 2015 base year

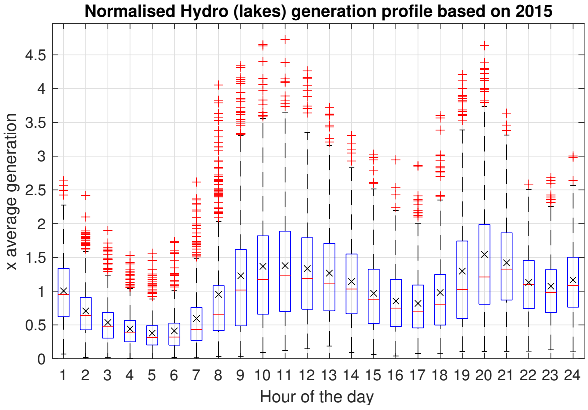


Figure I.26: Hourly boxplot normalised Hydro (lakes) electricity generation profile France, 2015 base year

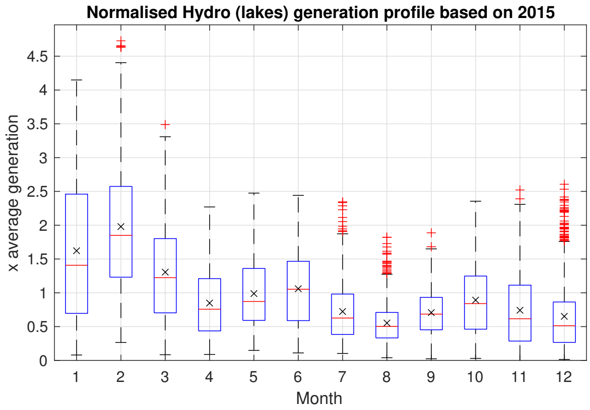


Figure I.27: Monthly boxplot normalised Hydro (lakes) electricity generation profile France, 2015 base year

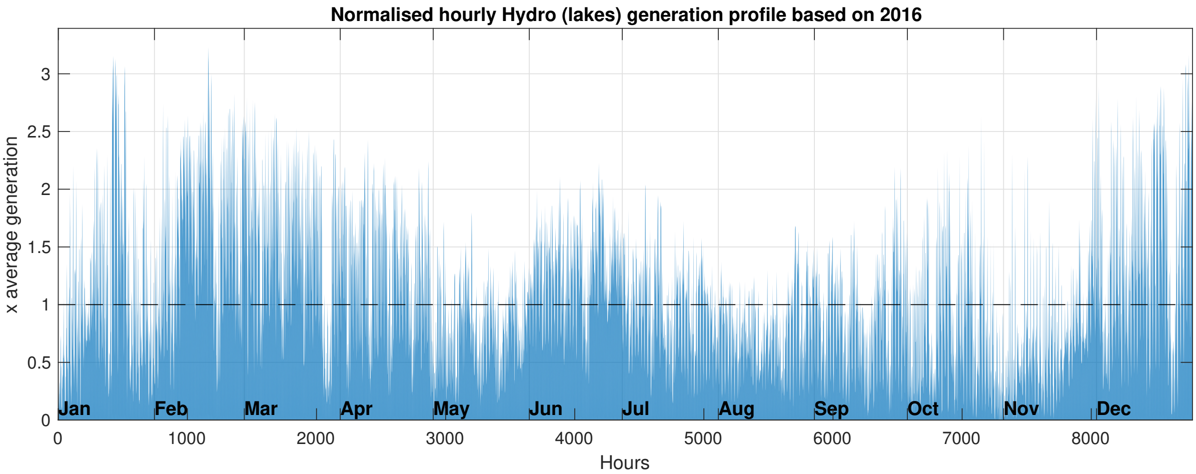


Figure I.28: Normalised hourly Hydro (lakes) electricity generation profile France, 2016 base year

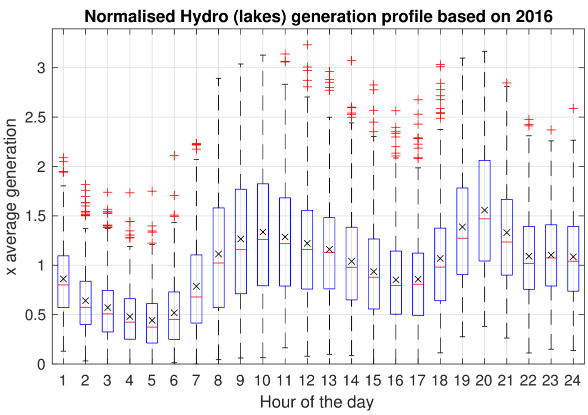


Figure I.29: Hourly boxplot normalised Hydro (lakes) electricity generation profile France, 2016 base year

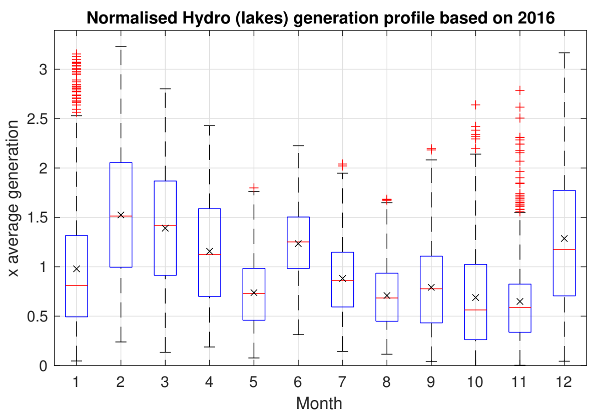


Figure I.30: Monthly boxplot normalised Hydro (lakes) electricity generation profile France, 2016 base year

I.1.5. Classic electricity consumption

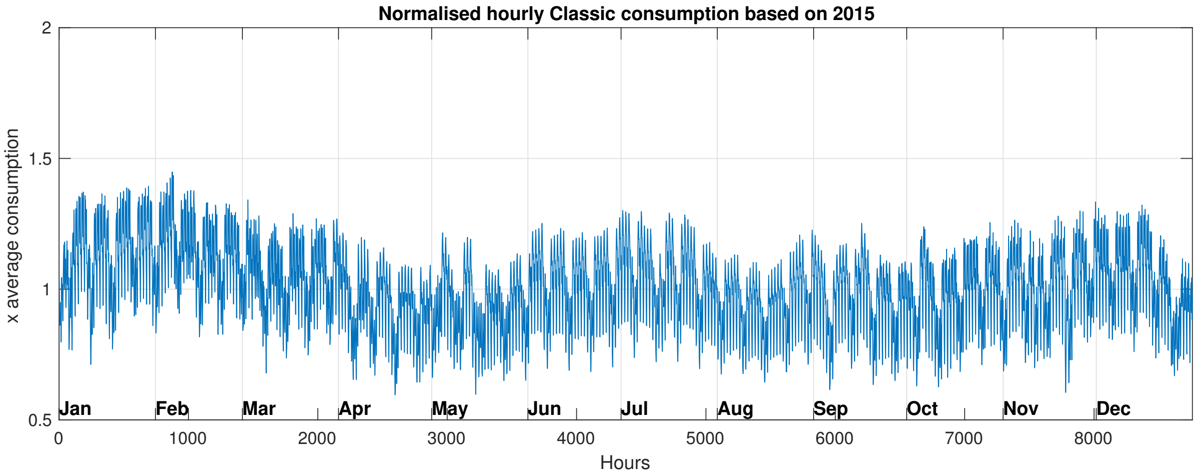


Figure I.31: Normalised hourly classic electricity consumption profile France, 2015 base year

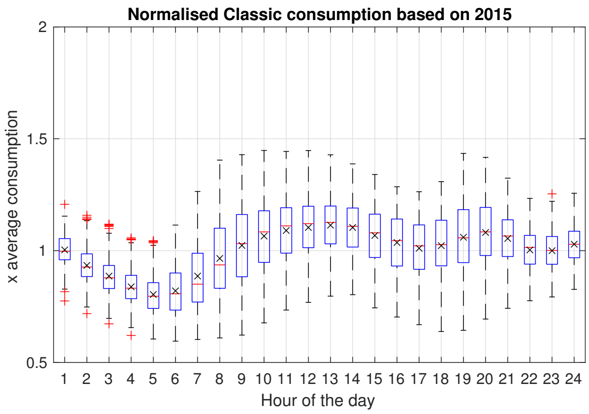


Figure I.32: Hourly boxplot normalised classic electricity consumption profile France, 2015 base year

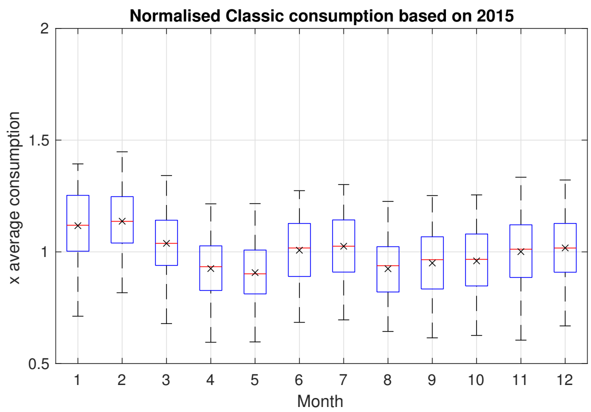


Figure I.33: Monthly boxplot normalised classic electricity consumption profile France, 2015 base year

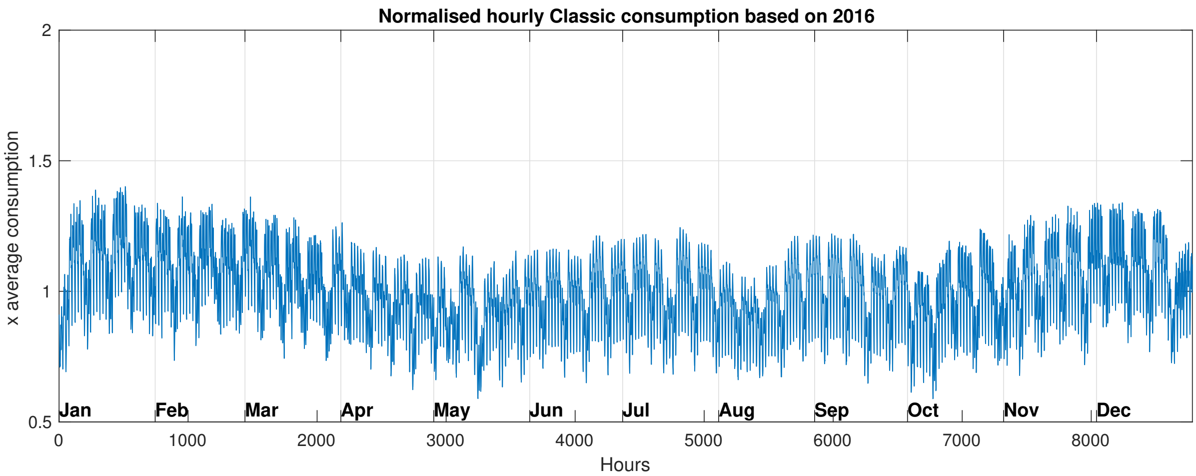


Figure I.34: Normalised hourly classic electricity consumption profile France, 2016 base year

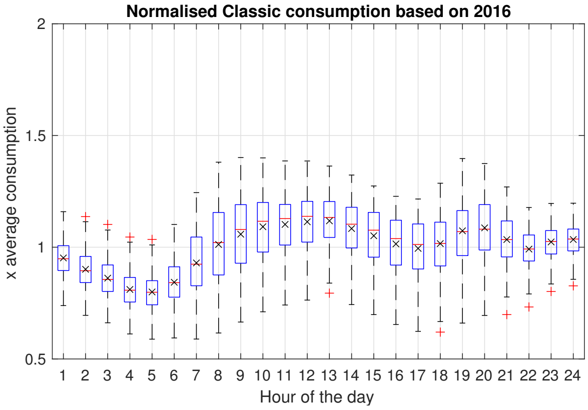


Figure I.35: Hourly boxplot normalised classic electricity consumption profile France, 2016 base year

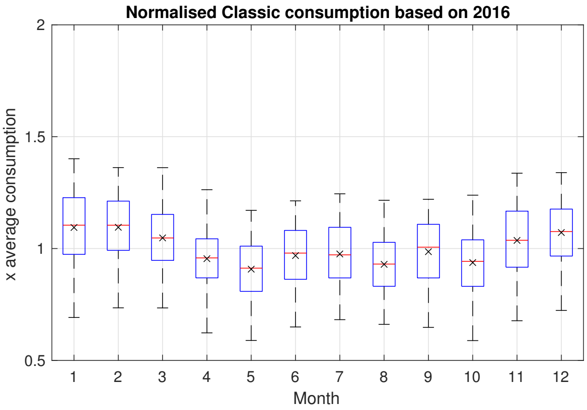


Figure I.36: Monthly boxplot normalised classic electricity consumption profile France, 2016 base year

I.1.6. Electric heating demand & average outside temperature

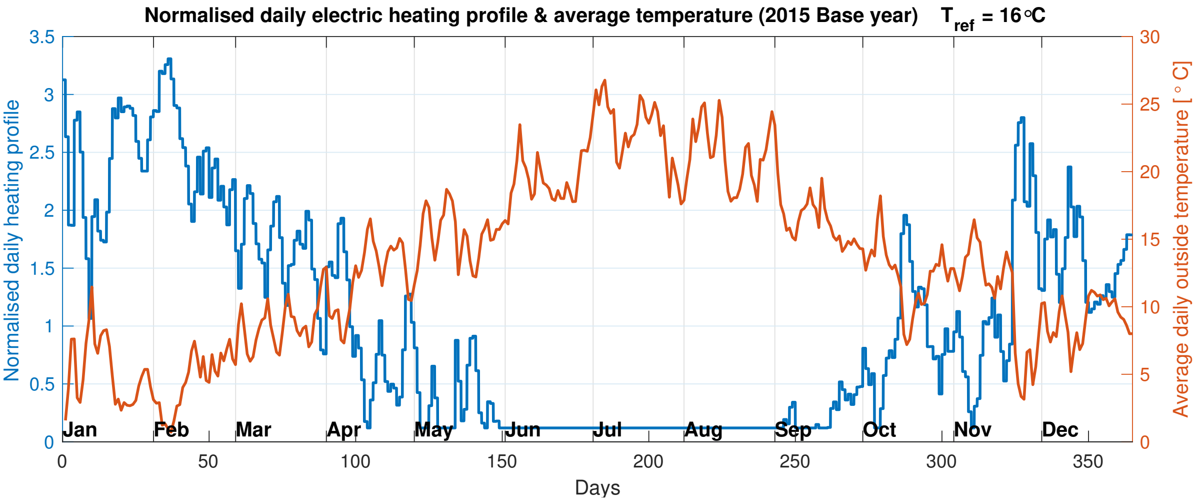


Figure I.37: Normalised daily electric heating demand, 2015 base year

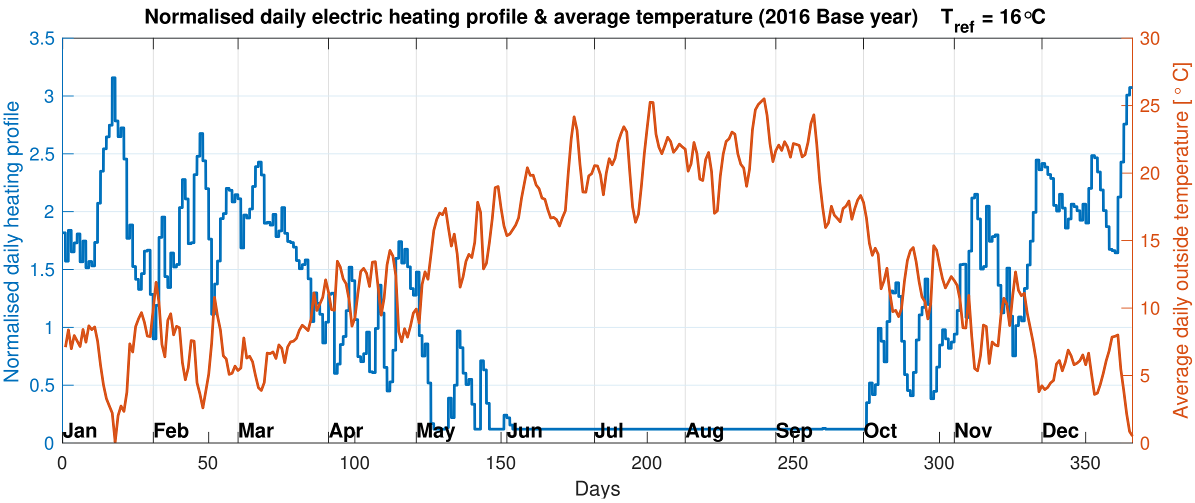


Figure I.38: Normalised daily electric heating demand, 2016 base year

I.2. Model output

Table I.1: Model outputs France

-	2015	2016		2015	2016
Electricity generation (TWh)			Direct electricity consumption (TWh)	405.98	404.07
Solar	139.05	161.43	% of total electricity consumption	92.02	91.50
Onshore wind	366.56	349.16	Electrolyser consumption (TWh)	203.78	209.24
Offshore wind	37.99	37.09	Electrolyser capacity (GW)	146.27	145.31
Hydro	38.75	38.86	Electrolyser capacity factor (%)	15.90	16.39
CHP	27.40	27.48	FCEV V2G demand (TWh)	35.19	37.60
Total	609.76	614.02	FCEV V2G peak demand (GW)	37.85	42.37
Installed capacity (GW)			million vehicles	3.79	4.24
Solar	127.43	140.62	% of passenger FCEVs	23.73	26.56
Onshore wind	193.97	208.80	Peak storage capacity (million kg)	717.25	1004.97
Offshore wind	20.10	22.18	BEV charging load (GW)	5.52	5.52
Hydro	10.33	10.33			
CHP	13.20	13.20			
Total	365.03	395.13			
Electricity consumption (TWh)					
Classic	332.10	333.01			
Electricity for heating	64.28	64.46			
BEV charging	44.79	44.91			
Total	441.17	442.37			
Road transport cons. (TWh)	106.08	106.37			
Final energy cons. (TWh)	719.41	720.61			
Hydrogen cons. (million kg)					
Road transport	2687.48	2694.84			
V2G	1488.47	1590.11			
Residual storage	0.98	3.58			
Total production	4176.99	4288.93			

I.2.1. Sankey diagrams

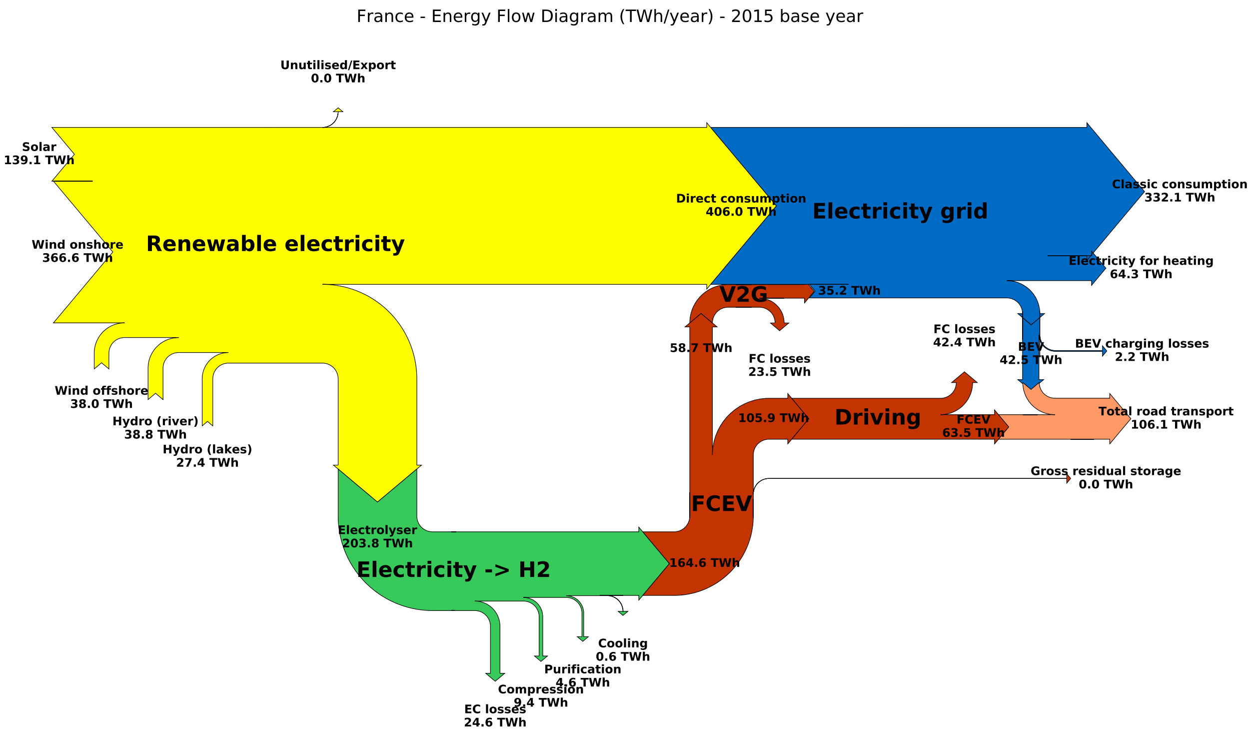


Figure I.39: Energy flow diagram for France with 2015 as base year

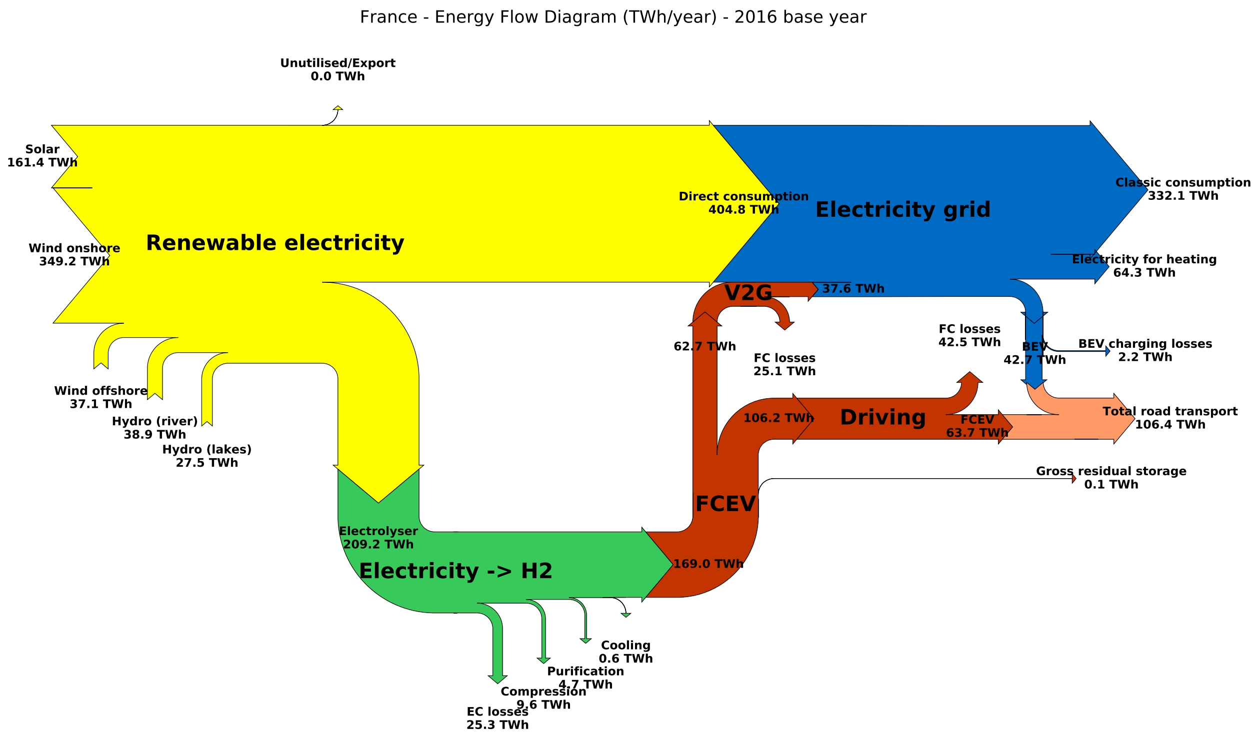


Figure I.40: Energy flow diagram for France with 2016 as base year

I.2.2. Generation & Consumption profiles (2016 base year)

Only the scaled generation and consumption profiles for base year 2016 are shown to the generation and consumption in terms of GW's. The shape of the profiles are the same as the normalised profile.

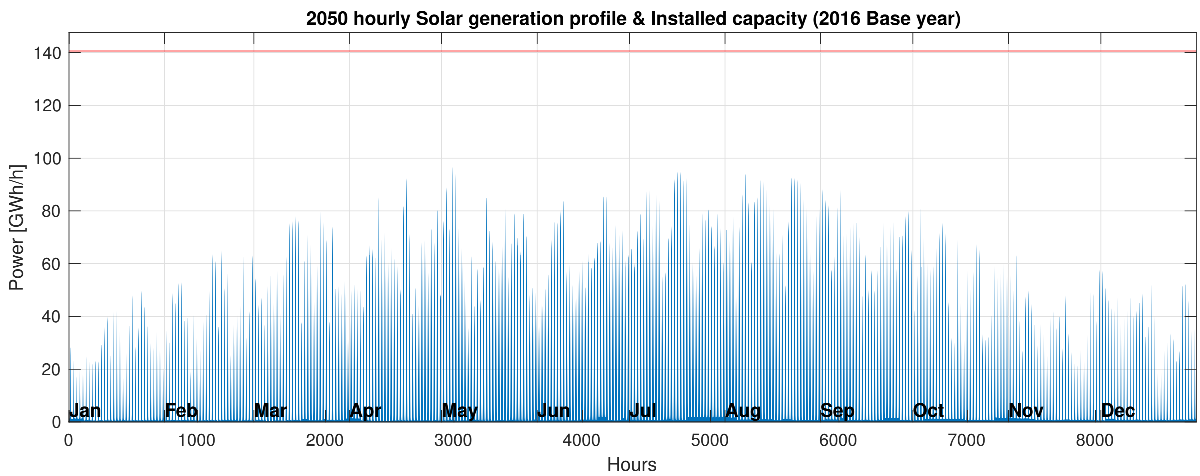


Figure I.41: Solar electricity generation in France in 2050 (2016 base year)

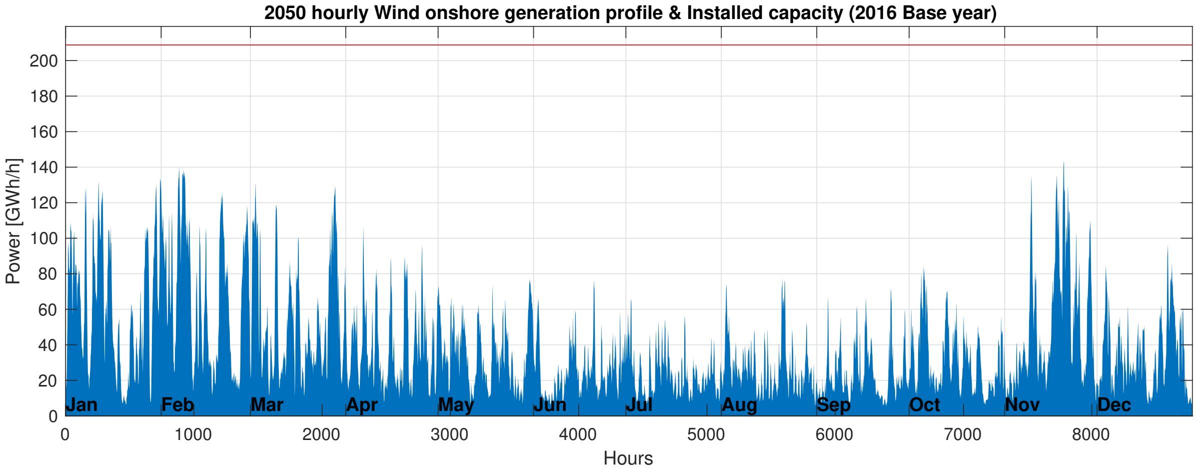


Figure I.42: Onshore wind electricity generation in France in 2050 (2016 base year)

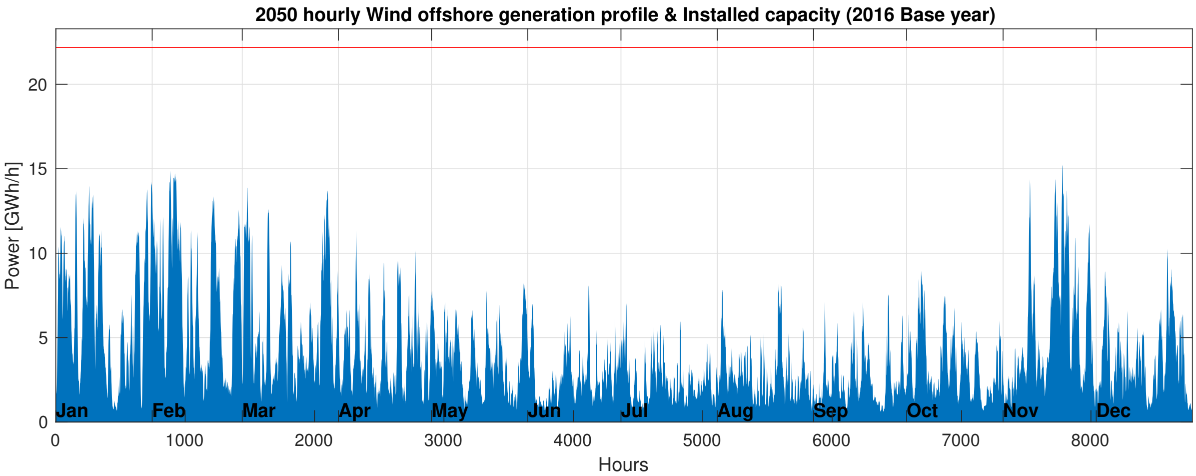


Figure I.43: Offshore wind electricity generation in France in 2050 (2016 base year)

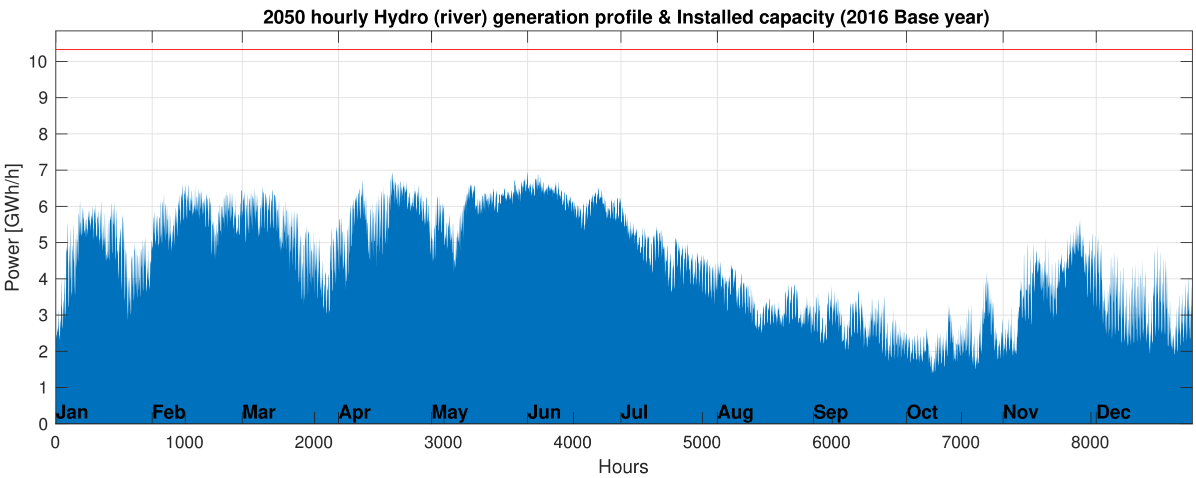


Figure I.44: Hydro (river) electricity generation in France in 2050 (2016 base year)

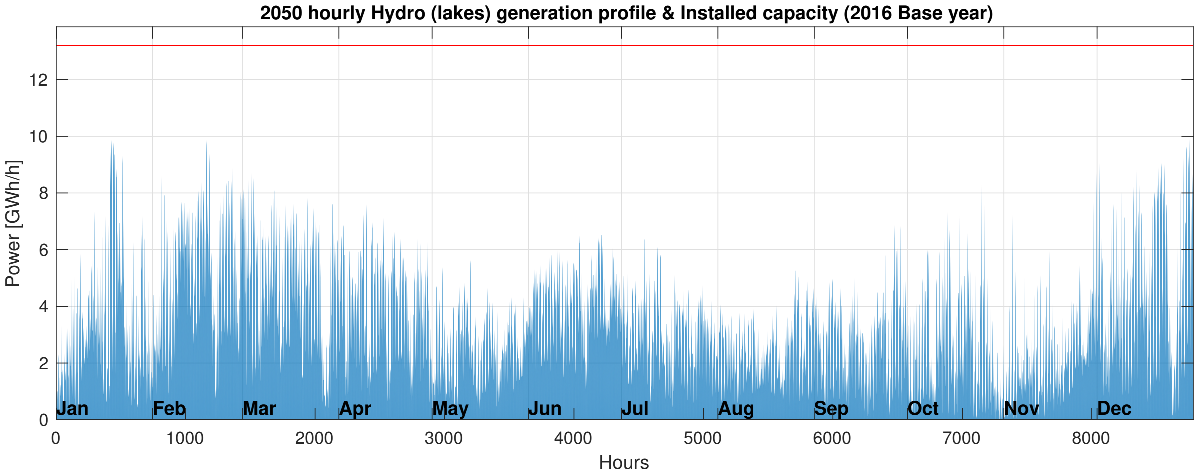


Figure I.45: Hydro (lakes) electricity generation in France in 2050 (2016 base year)

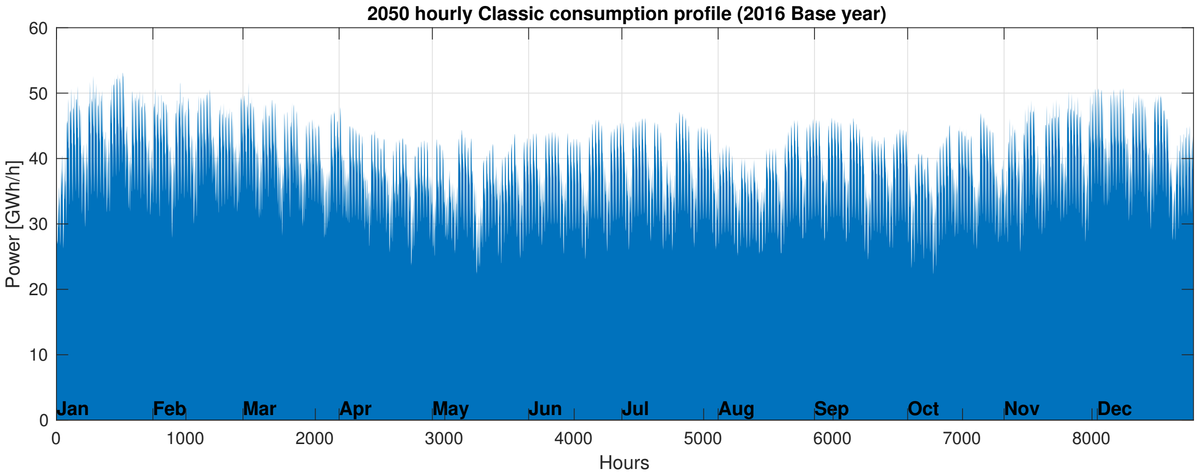


Figure I.46: Classic electricity consumption in France in 2050 (2016 base year)

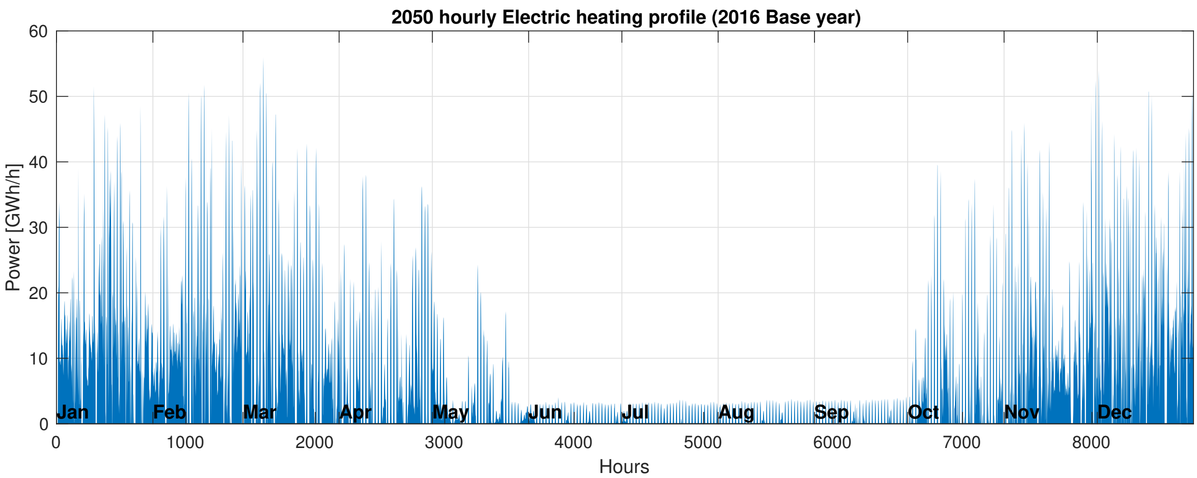


Figure I.47: Electric heating consumption in France in 2050 (2016 base year)

I.2.3. Imbalance

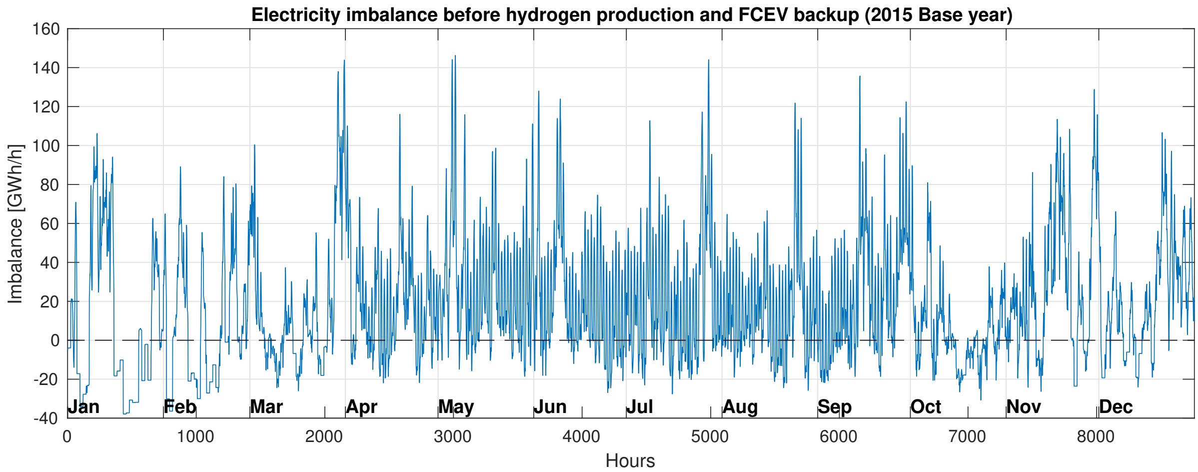


Figure I.48: Electric imbalance in France in 2050 (2015 base year)

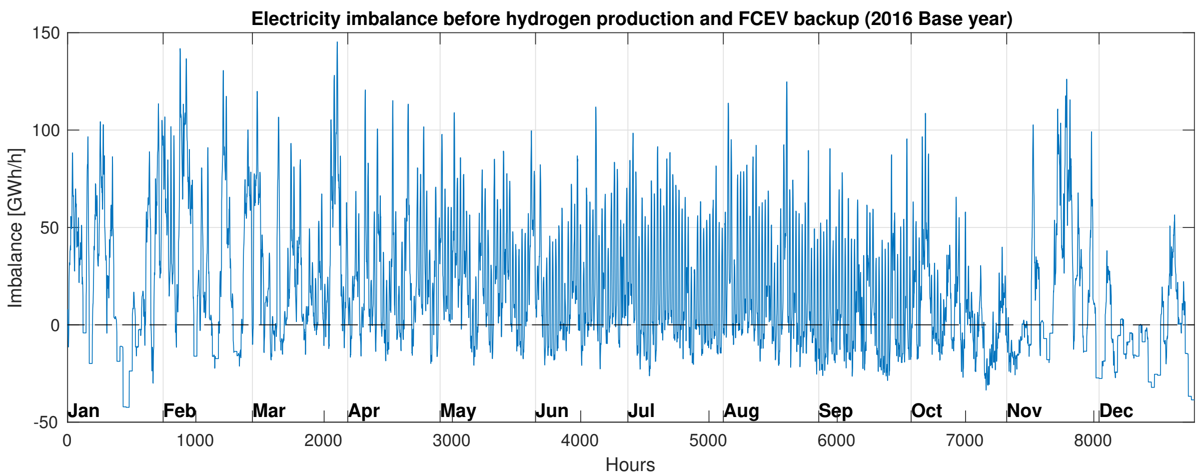


Figure I.49: Electric imbalance in France in 2050 (2016 base year)

I.2.4. Electrolyser

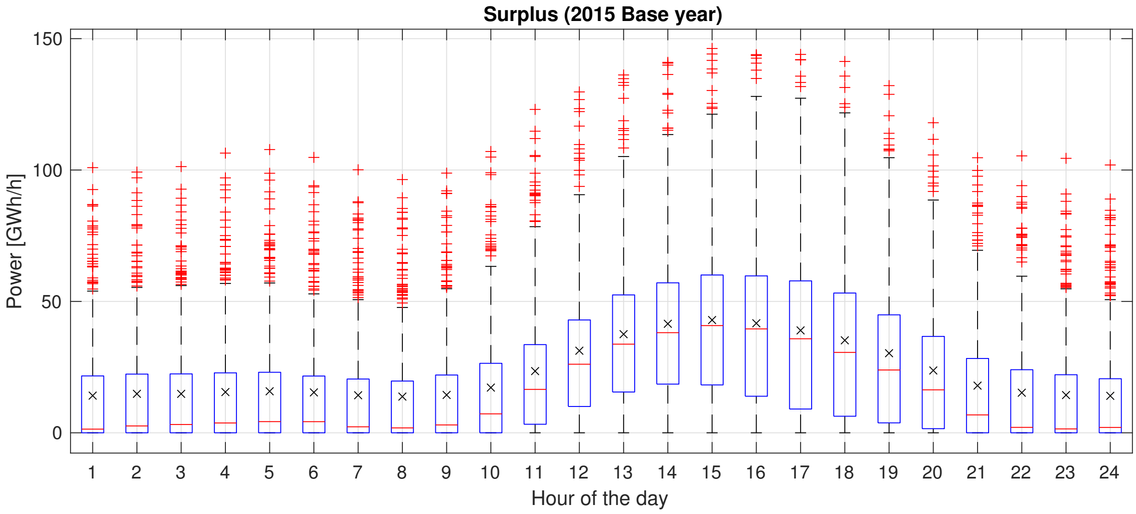


Figure I.50: Hourly boxplot electrolyser consumption in France in 2050 (2015 base year)

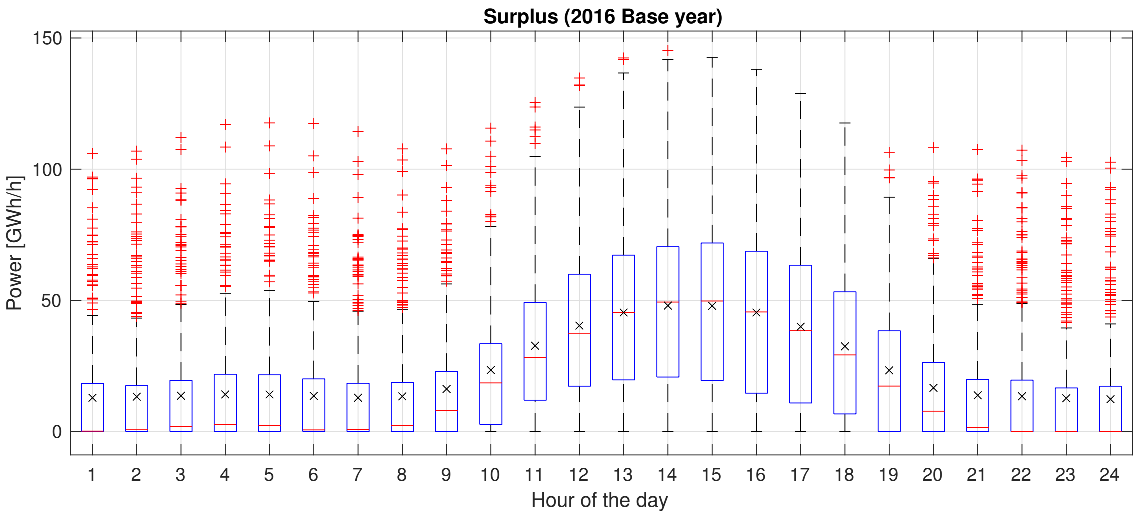


Figure I.51: Hourly boxplot electrolyser consumption in France in 2050 (2016 base year)

I.2.5. FCEV backup

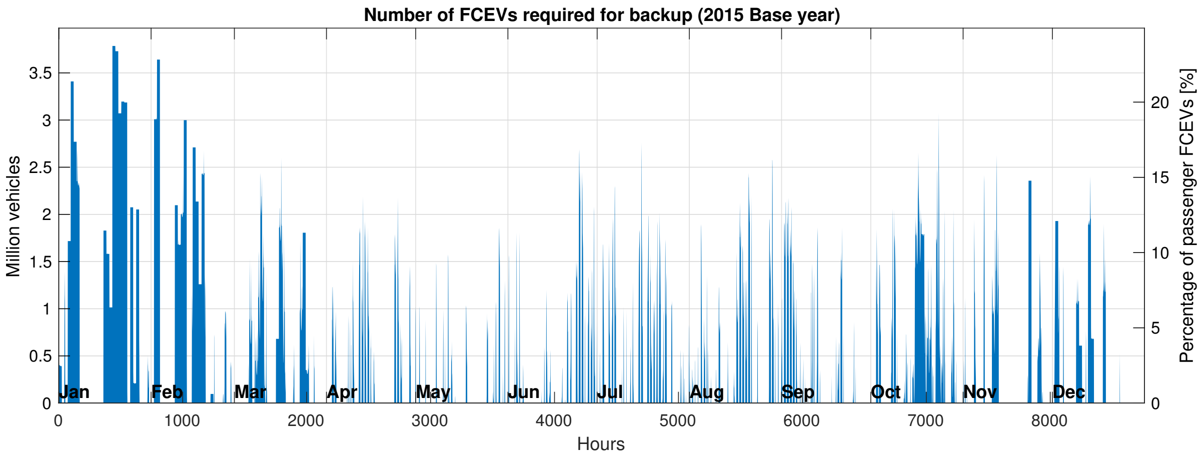


Figure I.52: FCEV backup in France in 2050 (2015 base year)

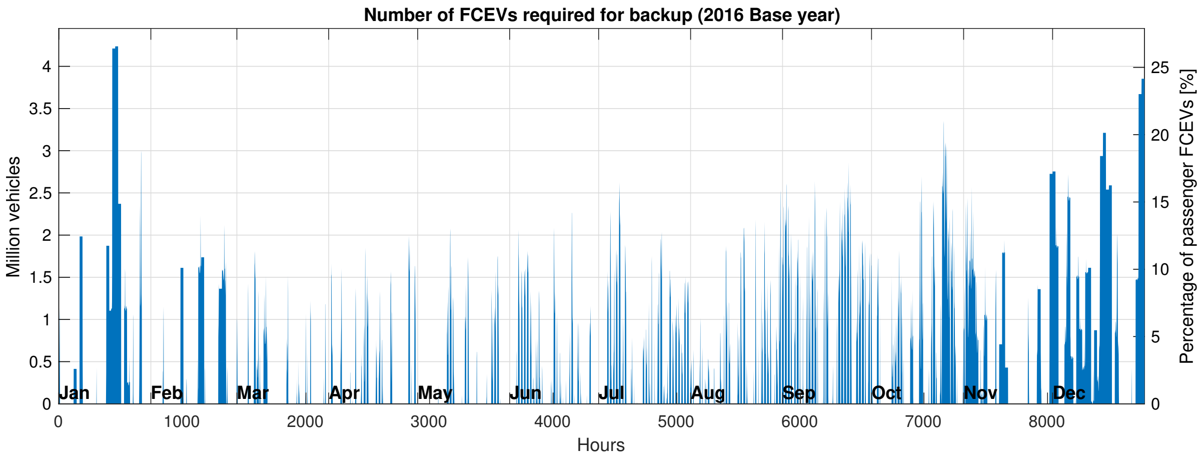


Figure I.53: FCEV backup in France in 2050 (2016 base year)

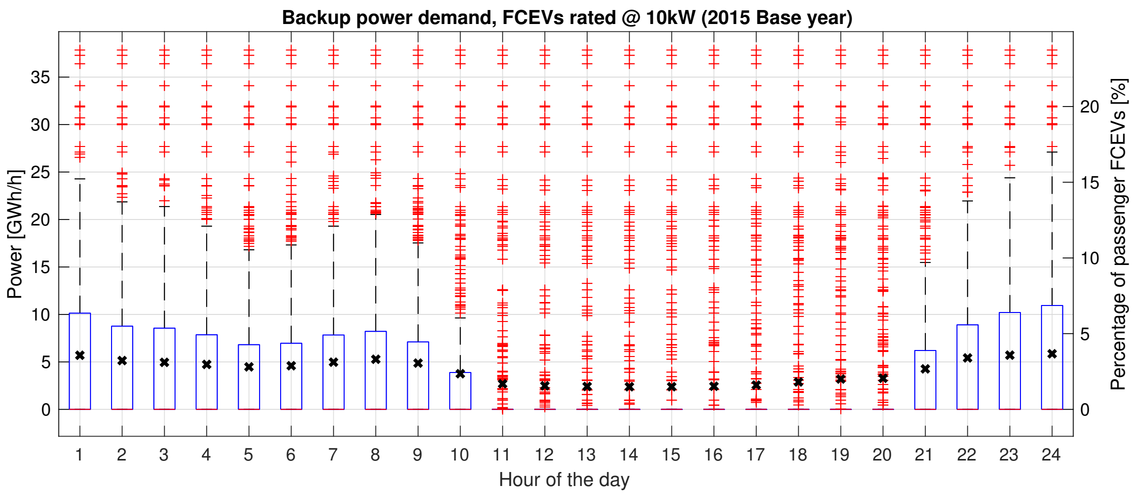


Figure I.54: Hourly boxplot FCEV backup in France in 2050 (2015 base year)

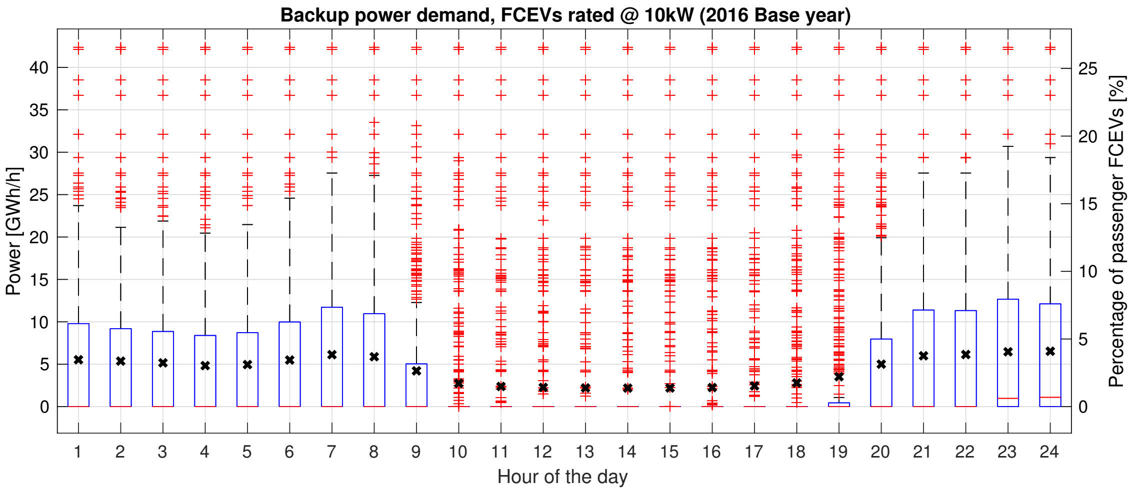


Figure I.55: Hourly boxplot FCEV backup in France in 2050 (2016 base year)

I.2.6. Weekly charge & discharge rates of hydrogen

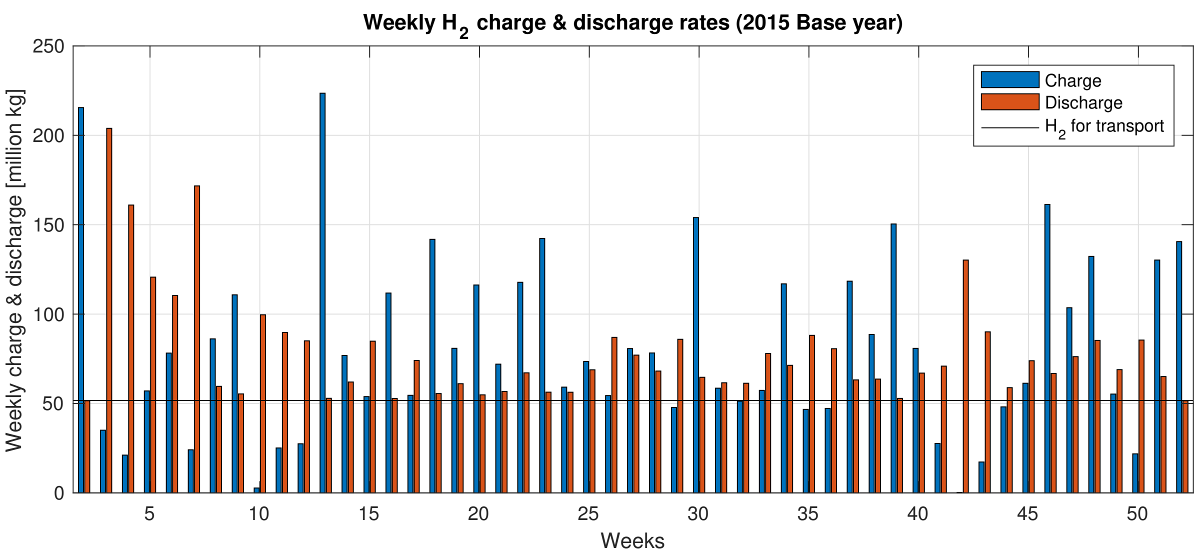


Figure I.56: Hydrogen weekly charge and discharge rates in France in 2050 (2015 base year)

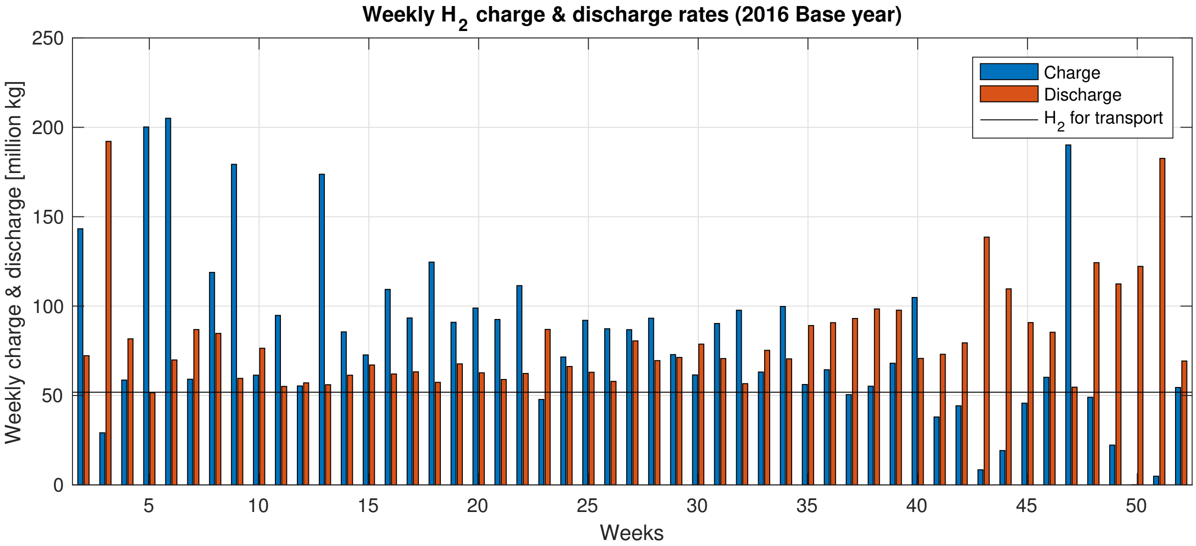


Figure I.57: Hydrogen weekly charge and discharge rates in France in 2050 (2016 base year)

I.2.7. Fuelling

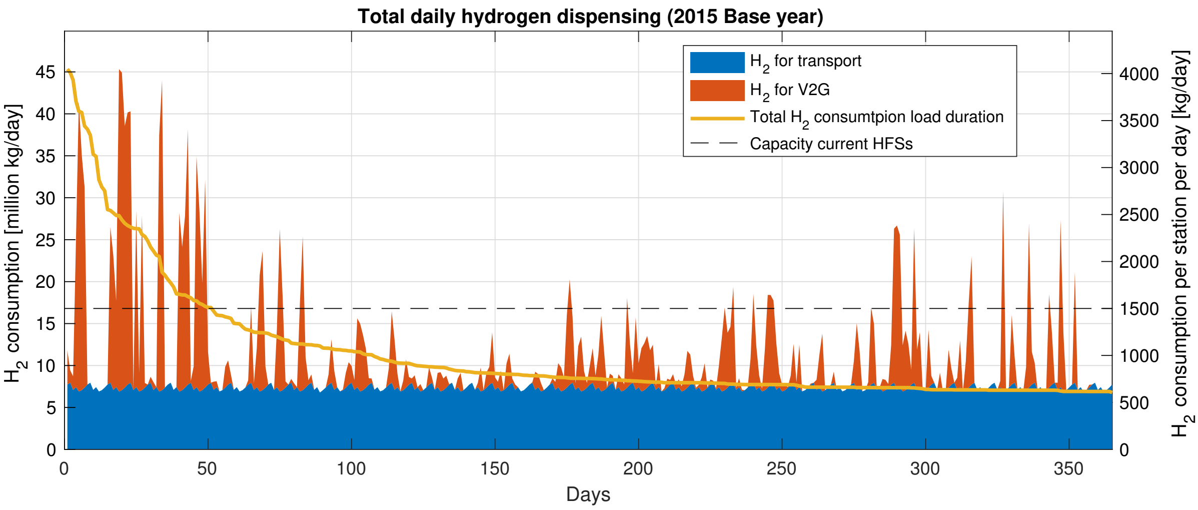


Figure I.58: Total daily hydrogen dispensing and dispension per HFS in France in 2050 (2015 base year)

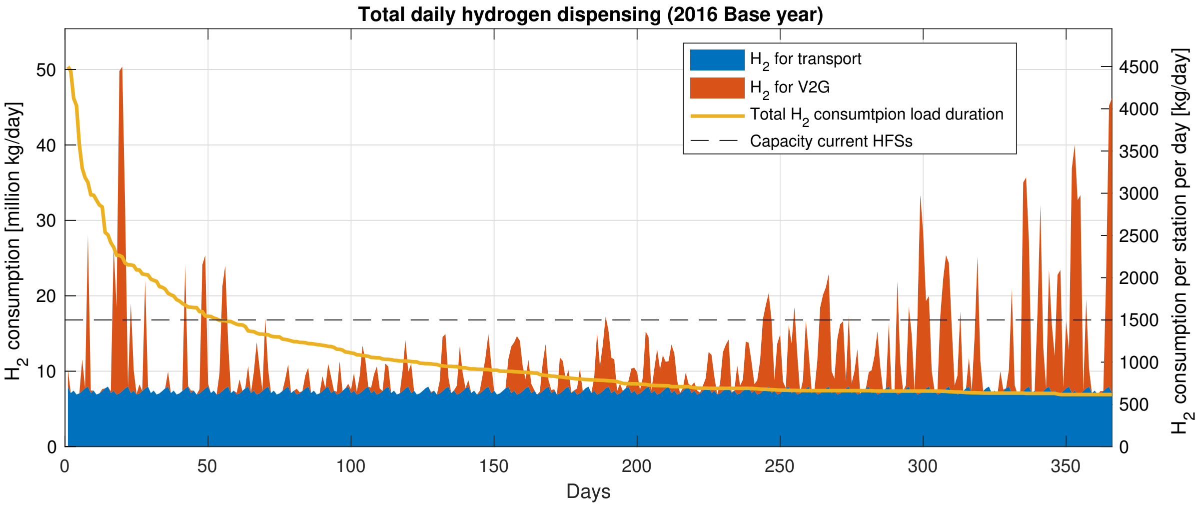


Figure I.59: Total daily hydrogen dispensing and dispension per HFS in France in 2050 (2016 base year)

J

Inputs, results & additional data Spain

J.1. Normalised generation & consumption profiles

J.1.1. CSP electricity generation

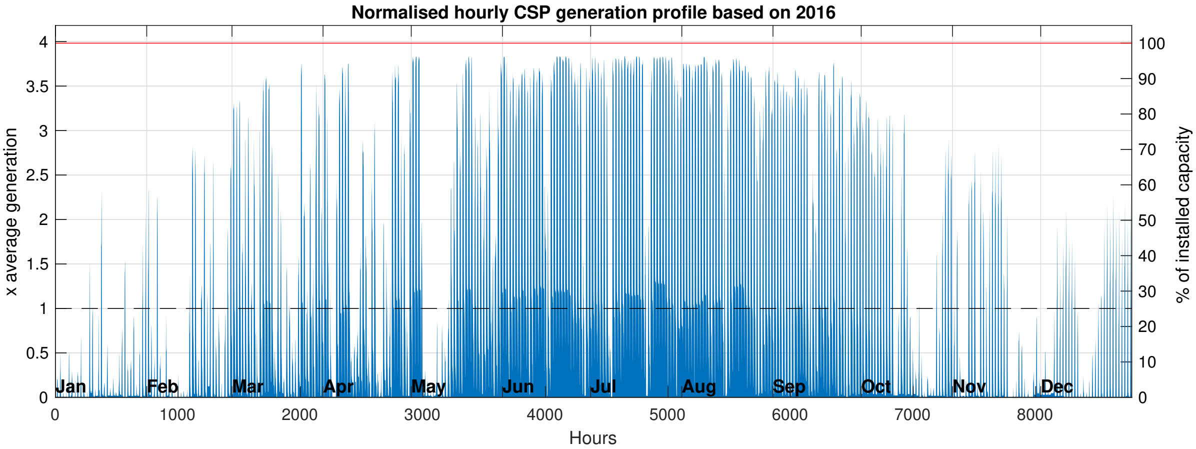


Figure J.1: Normalised hourly CSP electricity generation profile Spain, 2016 base year

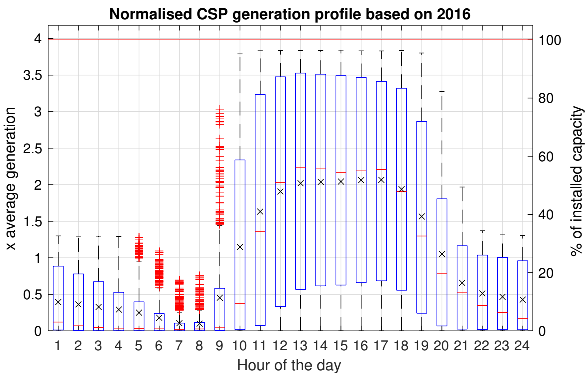


Figure J.2: Hourly boxplot normalised CSP electricity generation profile Spain, 2016 base year

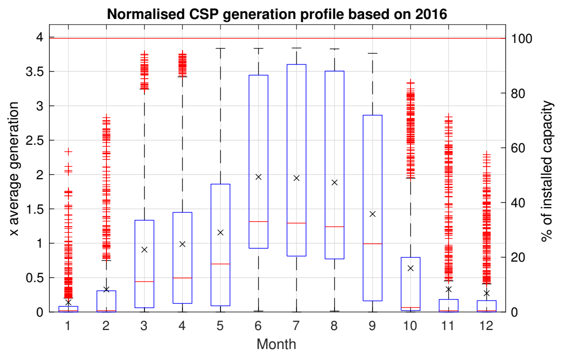


Figure J.3: Monthly boxplot normalised CSP electricity generation profile Spain, 2016 base year

J.1.2. Solar PV electricity generation

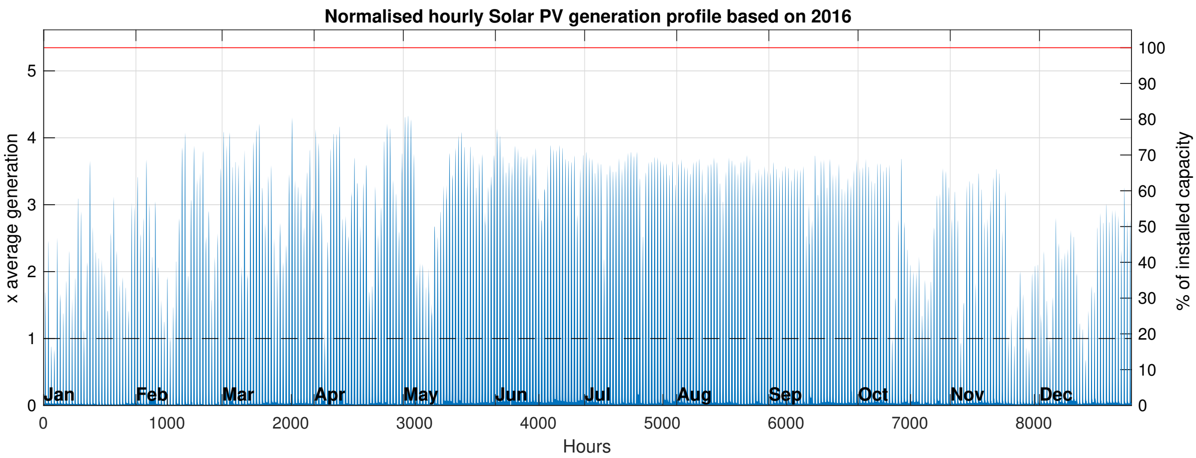


Figure J.4: Normalised hourly Solar electricity generation profile Spain, 2016 base year

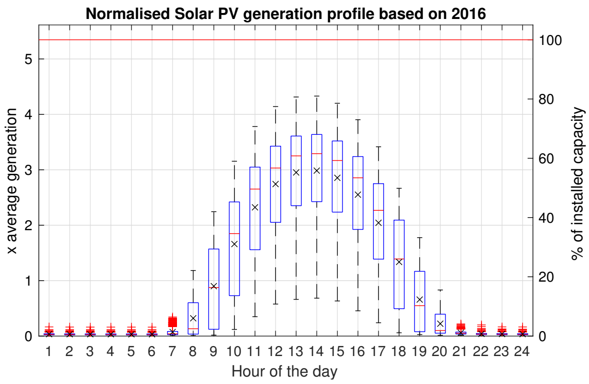


Figure J.5: Hourly boxplot normalised Solar electricity generation profile Spain, 2016 base year

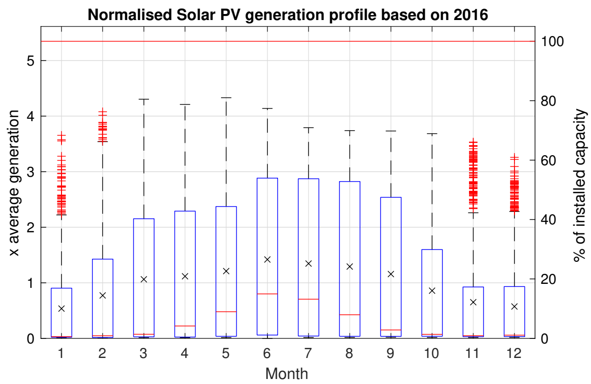


Figure J.6: Monthly boxplot normalised Solar electricity generation profile Spain, 2016 base year

J.1.3. Onshore wind electricity generation

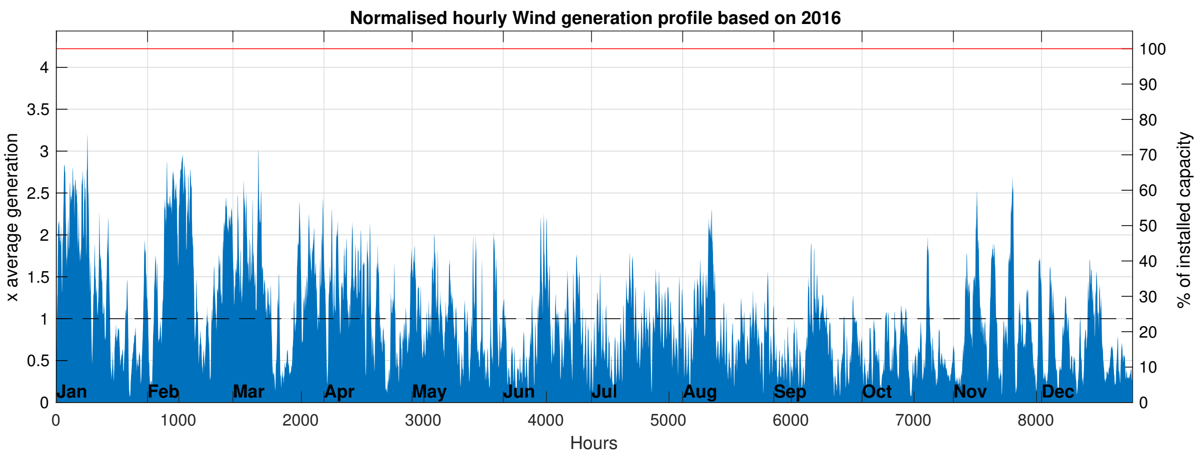


Figure J.7: Normalised hourly wind electricity generation profile Spain, 2016 base year

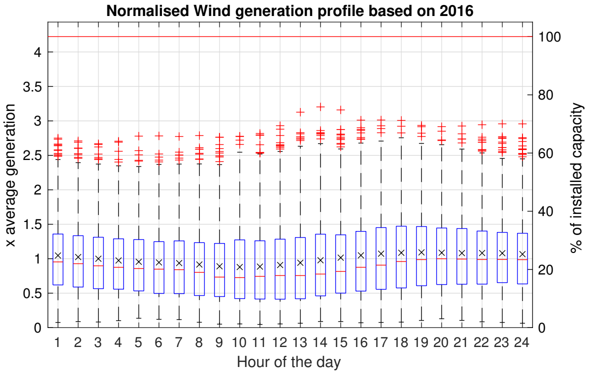


Figure J.8: Hourly boxplot normalised wind electricity generation profile Spain, 2016 base year

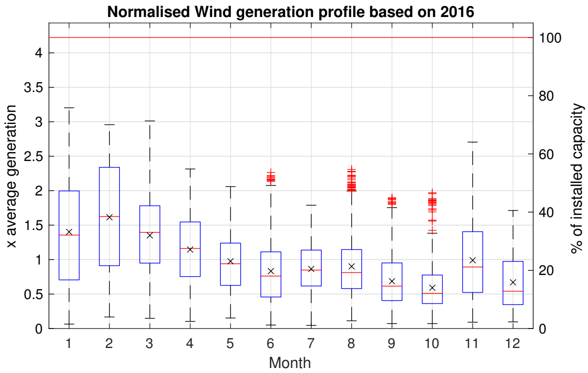


Figure J.9: Monthly boxplot normalisednwind electricity generation profile Spain, 2016 base year

J.1.4. Hydro

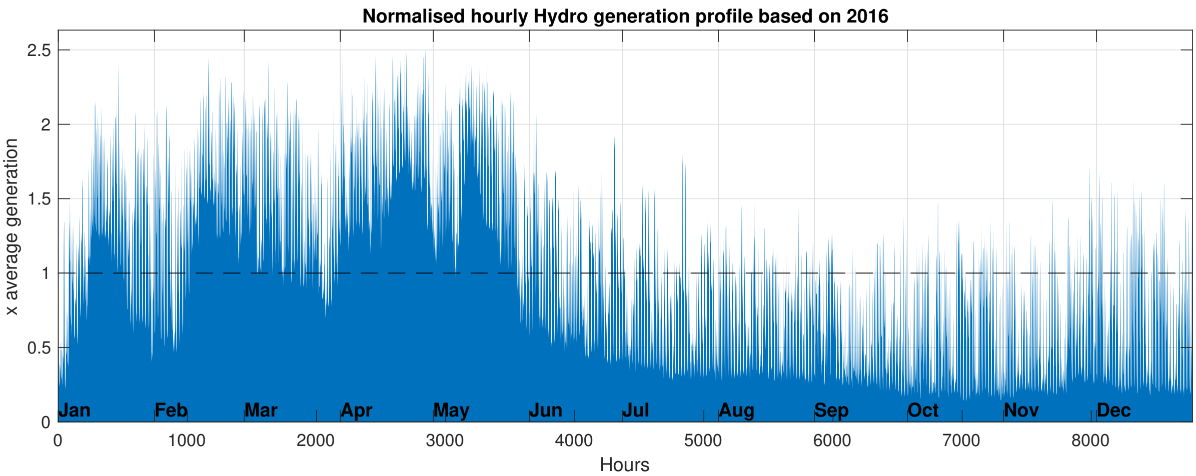


Figure J.10: Normalised hourly Hydro electricity generation profile Spain, 2016 base year

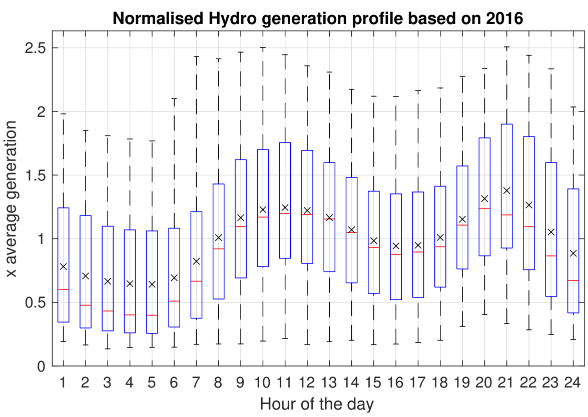


Figure J.11: Hourly boxplot normalised Hydro electricity generation profile Spain, 2016 base year

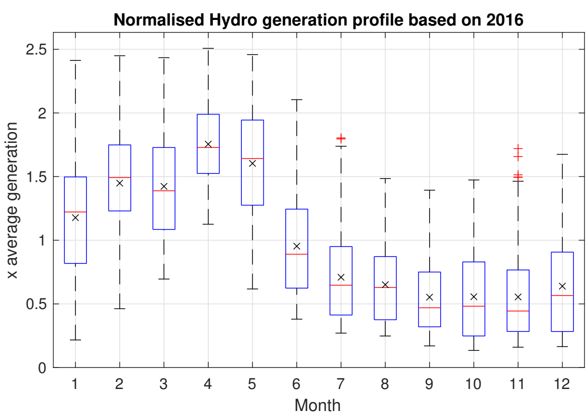


Figure J.12: Monthly boxplot normalised Hydro electricity generation profile Spain, 2016 base year

J.1.5. Classic electricity consumption

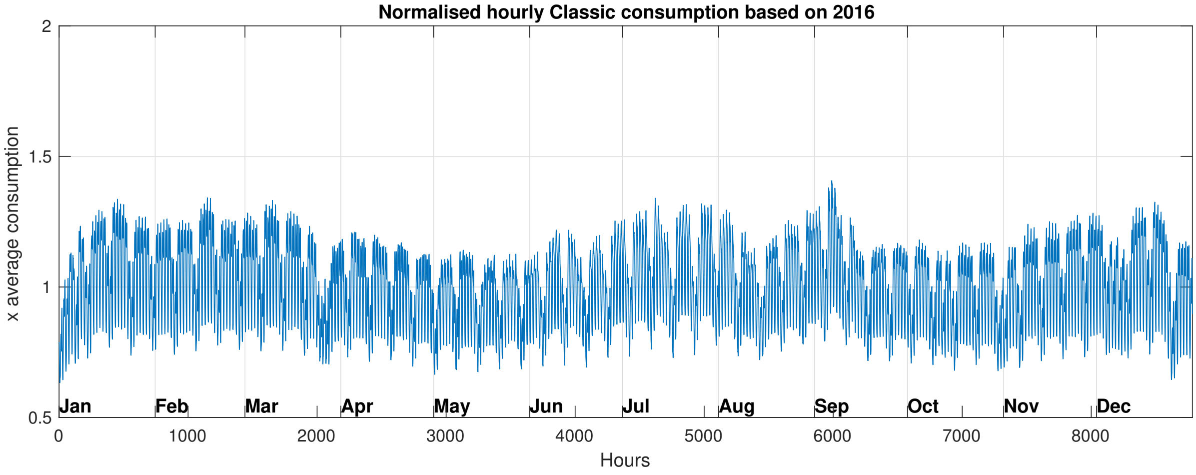


Figure J.13: Normalised hourly classic electricity consumption profile Spain, 2016 base year

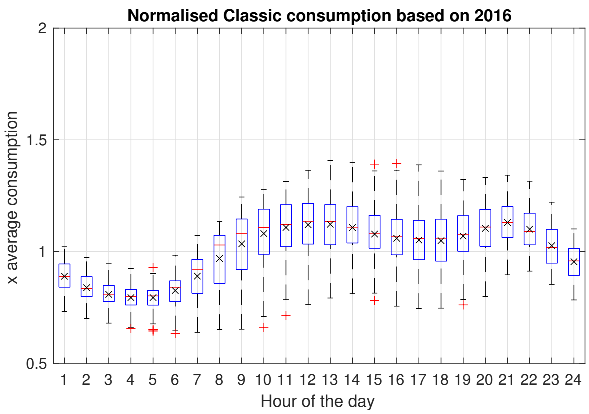


Figure J.14: Hourly boxplot normalised classic electricity consumption profile Spain, 2016 base year

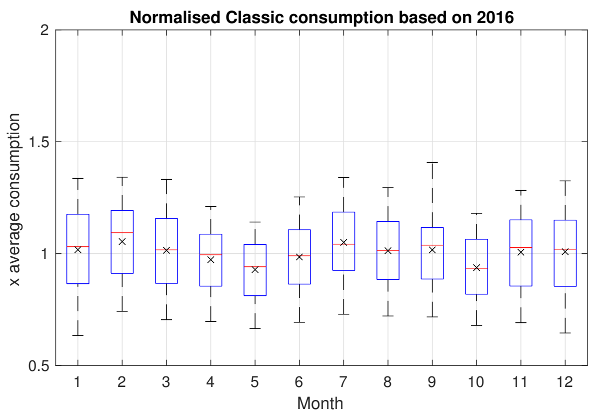


Figure J.15: Monthly boxplot normalised classic electricity consumption profile Spain, 2016 base year

J.1.6. Electric heating demand & average outside temperature

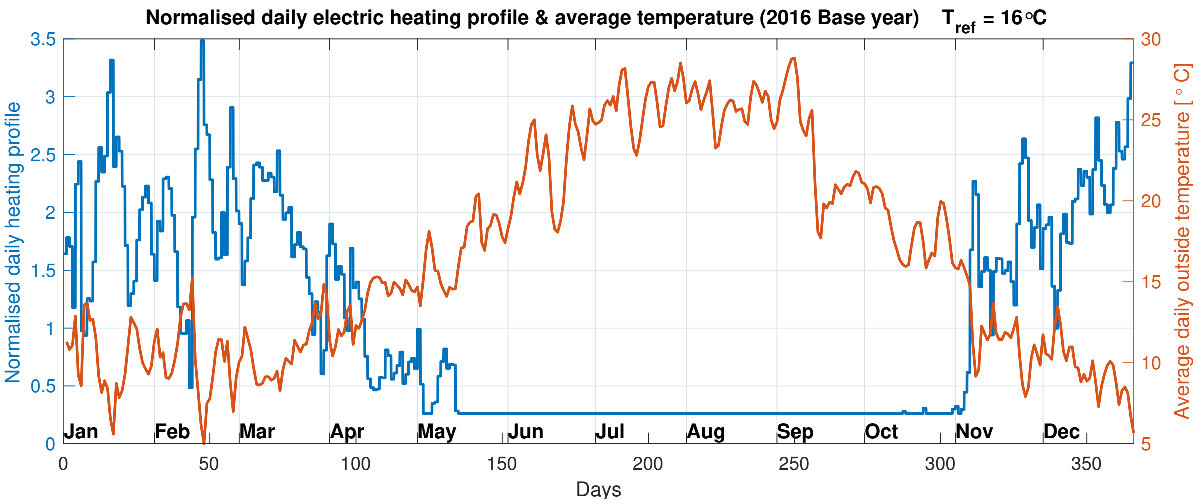


Figure J.16: Normalised daily electric heating demand, 2016 base year

J.2. Model output

Table J.1: Model outputs Spain

	2016		2016
Electricity generation (TWh)		Direct electricity consumption (TWh)	235.99
CSP	34.20	% of total electricity consumption	92.93
Solar PV	214.63	Electrolyser consumption (TWh)	236.54
Wind	189.40	Electrolyser capacity (GW)	133.23
Hydro	34.30	Electrolyser capacity factor (%)	20.21
Total	472.52	FCEV V2G demand (TWh)	17.97
Installed capacity (GW)		FCEV V2G peak demand (GW)	21.27
CSP	15.51	million vehicles	2.13
Solar PV	130.63	% of passenger FCEVs	25.13
Wind	91.04	Peak storage capacity (million kg)	1134.83
Hydro	17.03	BEV charging load (GW)	4.44
Total	254.21		
Electricity consumption (TWh)			
Classic	186.65		
Electricity for heating	31.19		
BEV charging	36.12		
Total	253.95		
Road transport cons. (TWh)	130.66		
Final energy cons. (TWh)	458.48		
Hydrogen cons. (million kg)			
Road transport	4074.98		
V2G	759.78		
Residual storage	13.49		
Total production	4848.34		

J.2.1. Generation & Consumption profiles

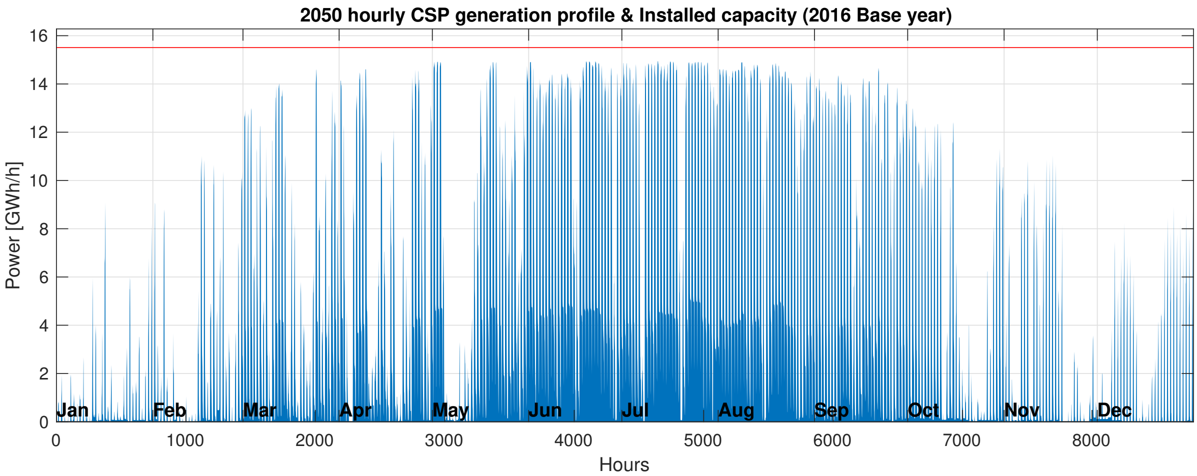


Figure J.17: CSP electricity generation in Spain in 2050 (2016 base year)

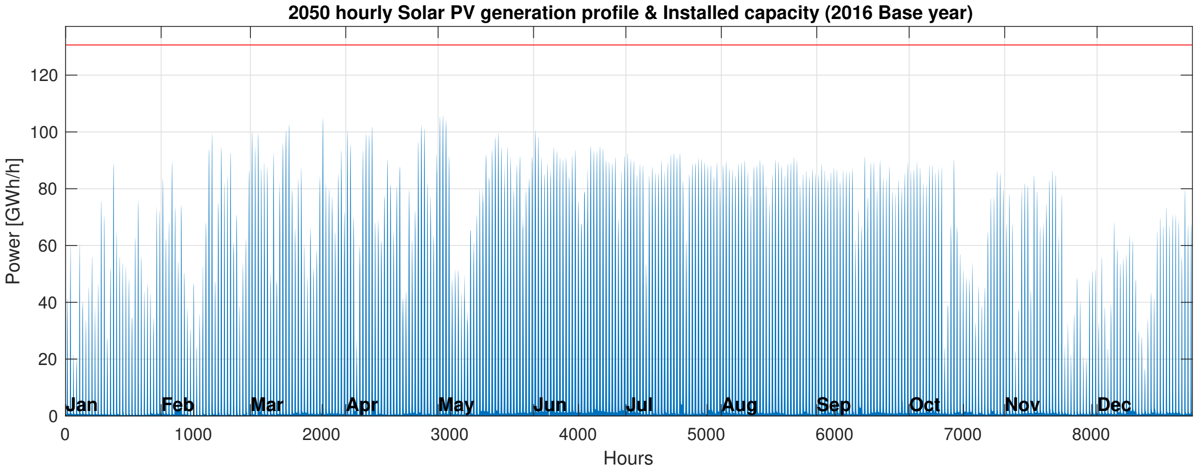


Figure J.18: Solar electricity generation in Spain in 2050 (2016 base year)

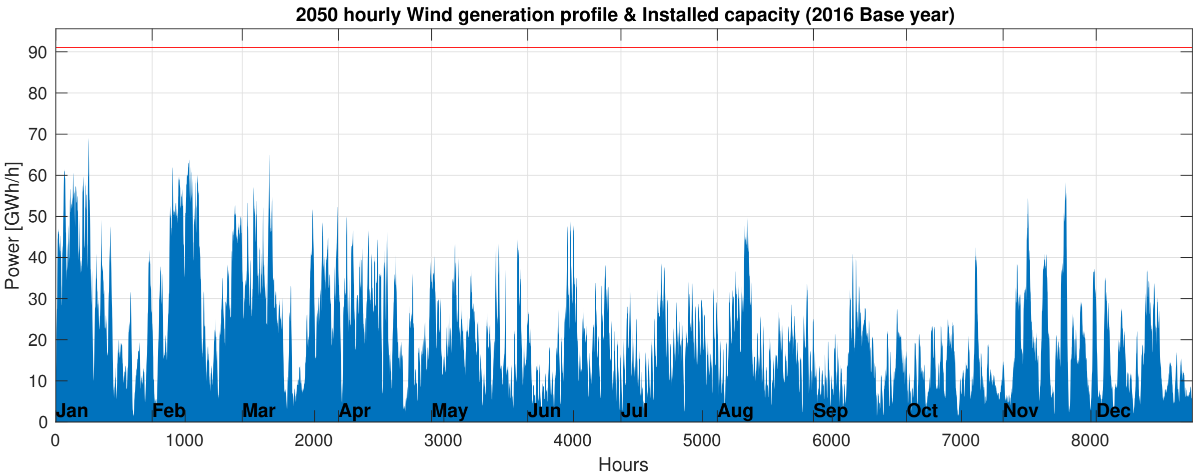


Figure J.19: OWind electricity generation in Spain in 2050 (2016 base year)

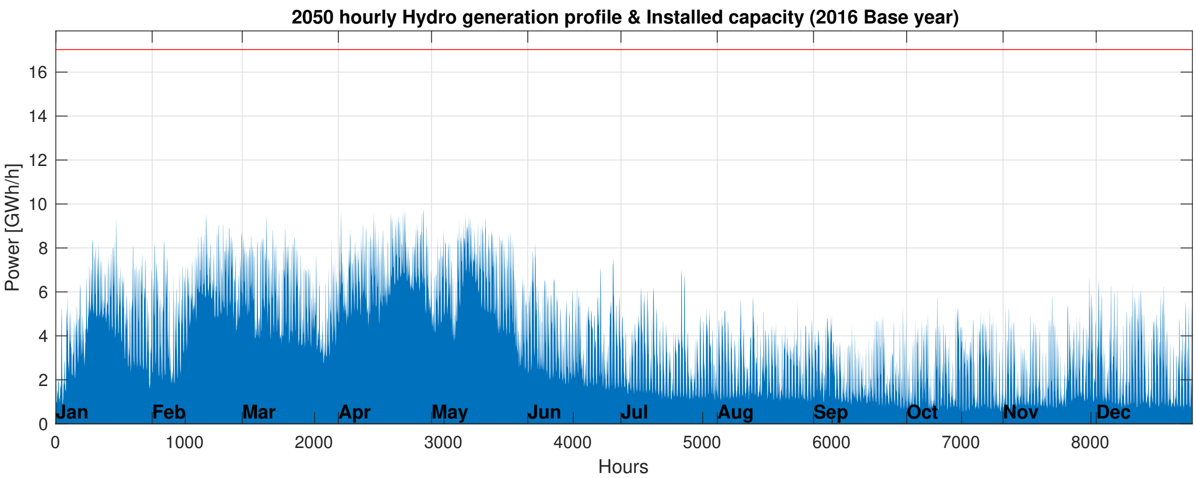


Figure J.20: Hydro electricity generation in Spain in 2050 (2016 base year)

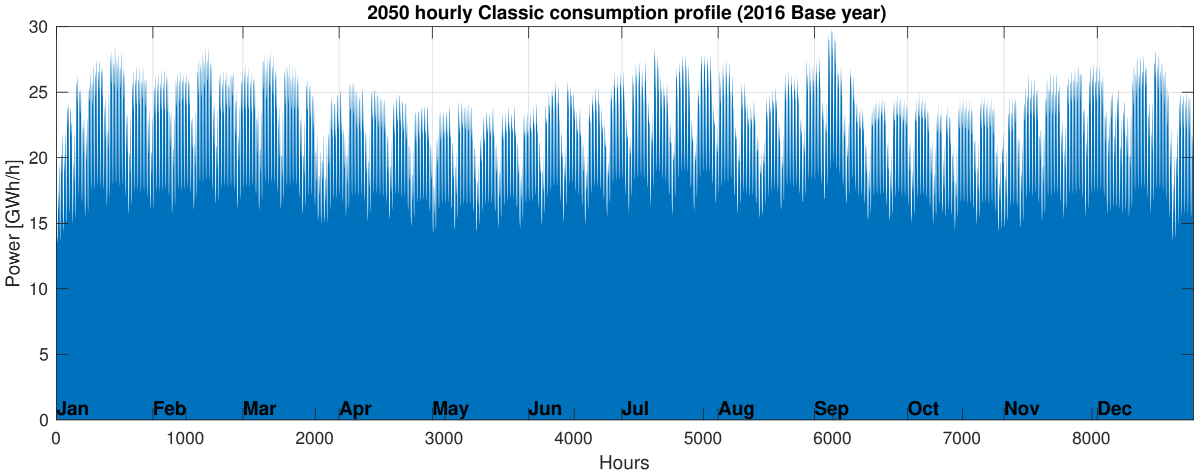


Figure J.21: Classic electricity consumption in Spain in 2050 (2016 base year)

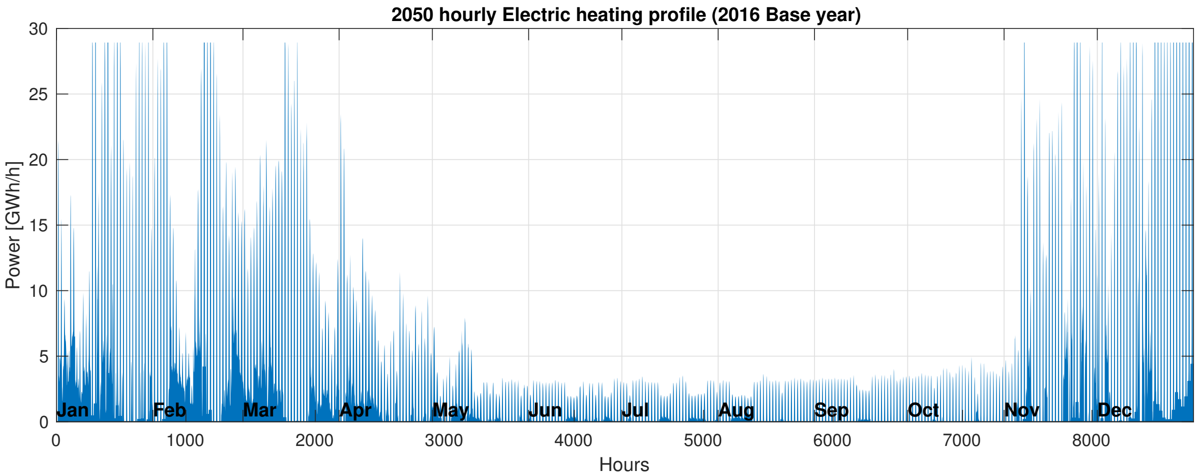


Figure J.22: Electric heating consumption in Spain in 2050 (2016 base year)

J.2.2. Imbalance

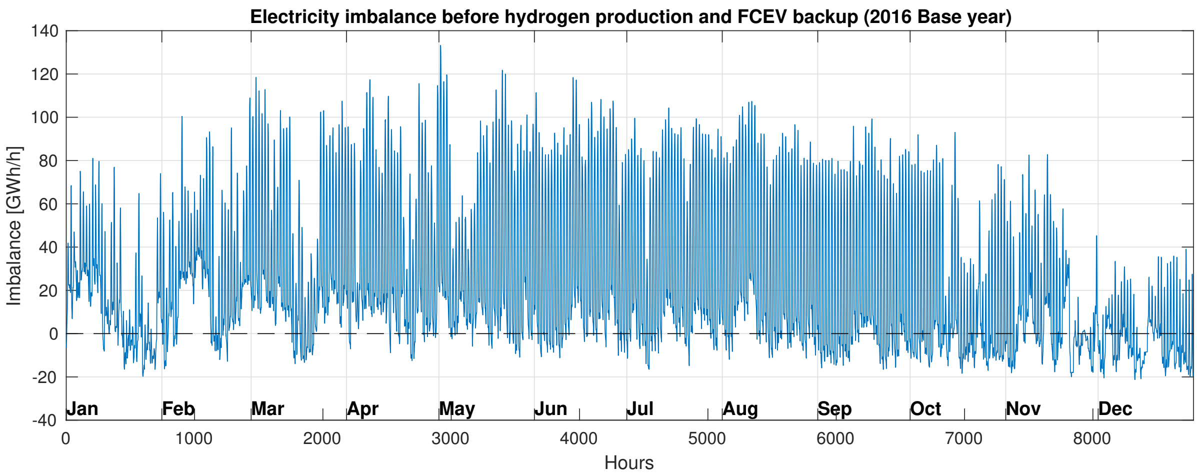


Figure J.23: Electric imbalance in Spain in 2050 (2016 base year)

J.2.3. Electrolyser

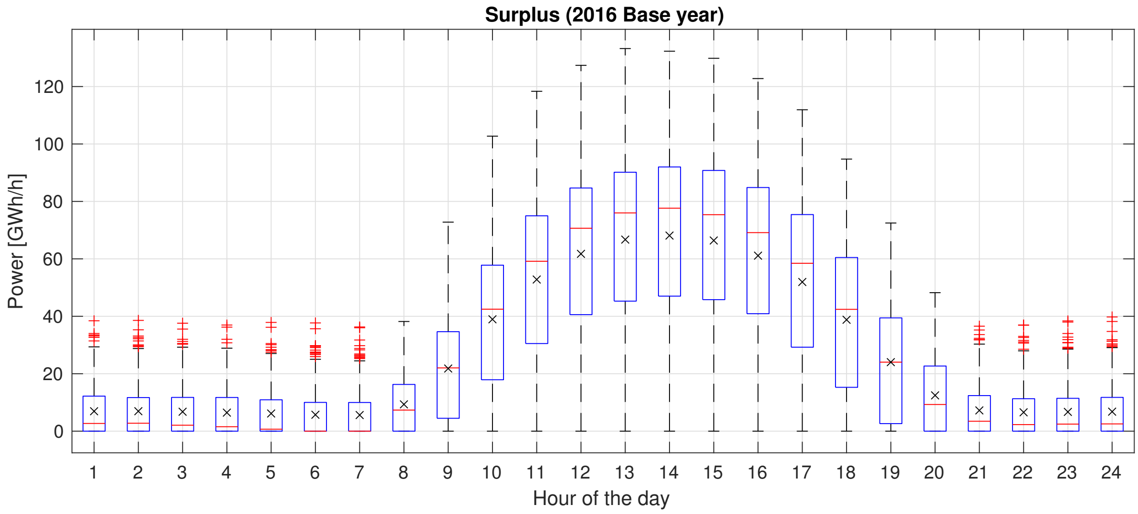


Figure J.24: Hourly boxplot electrolyser consumption in Spain in 2050 (2016 base year)

J.2.4. FCEV backup

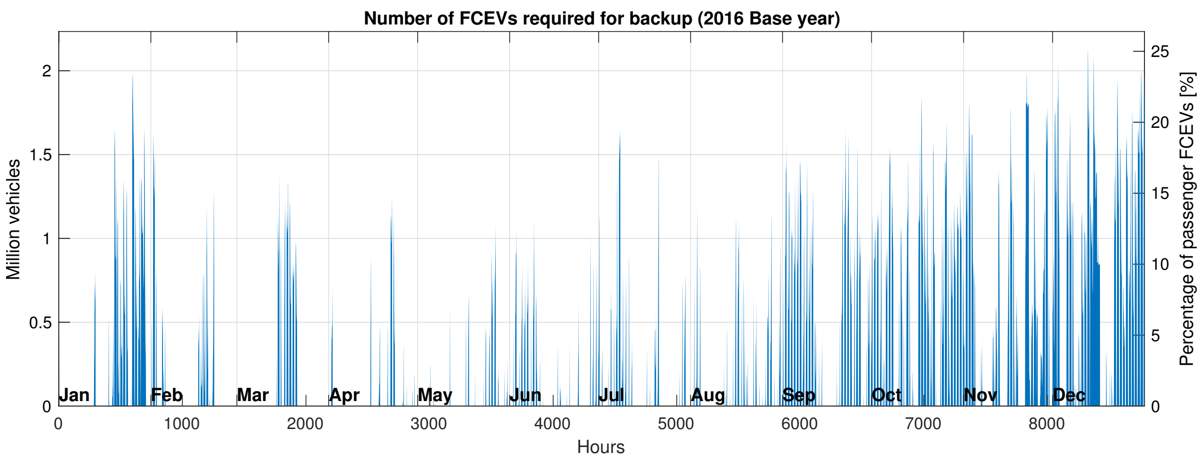


Figure J.25: FCEV backup in Spain in 2050 (2016 base year)

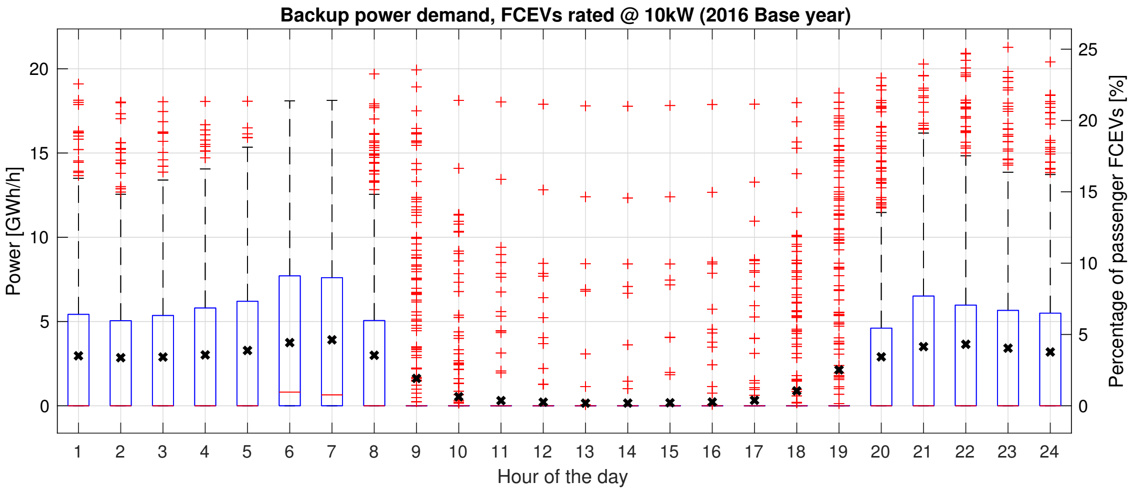


Figure J.26: Hourly boxplot FCEV backup in Spain in 2050 (2016 base year)

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