École polytechnique de Louvain

Modelling of Low Carbon Energy Systems for 26 European Countries with EnergyScopeTD

Can European Energy Systems Reach Carbon Neutrality Independently?

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Abstract

To mitigate climate change, greenhouse gas emissions from the energy systems of countries should be reduced. In this study the goal was to evaluate if and how the energy systems of European countries could fulfill their whole energy demand in 2035 with only renewable resources on their territory. For this reason, a database for 26 European countries was created. It includes for each country an estimate of the total end use demand, the maximum installable renewable capacity, hourly profiles of renewables and the renewable energy potential. Dividing the renewable energy potential by the end use demand led to the creation of a new key performance indicator that maps which countries are in a favorable position to reach carbon neutrality by themselves. The energy systems for all countries were then modelled, optimised and analysed with EnergyScopeTD. Five countries were found unable to provide their demand entirely with renewables while the other 21 can. Overall there is enough renewable potential for the whole european energy demand but cooperation will be necessary as some countries lack the potential to provide their demand.

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Contents

Glossary

CAPEX stands for capital expenditure. It is the cost for installing or developing the product (*e.g.* the investment cost in the parts of a wind turbine).

CCGT A Combined Cycle Gas Turbine produces electricity by burning gas thanks to heat engines placed in series.

CHP Combined Heat and Power units are cogeneration plants producing heat and electricity.

Coal US Coal Ultra-Supercritical power plants are a new type of coal power plants. These plants are characterised by a higher efficiency and reduced GHG emissions compared to traditional coal power plants.

COP The Coefficient Of Performance of a heat pump is the ratio of useful heating provided to the work required. Higher COPs equate to lower operating costs. It usually exceeds 1.

CSP Concentrated Solar Power can produce electricity by converting the direct normal irradiance of the sun into heat. This heat can then be stored or used in a power block to produce electricity.

DHN District Heating Networks are systems that distribute through an adequate network the heat generated by centralized heat production units.

EUD The End-Use Demand is the energy demand in energy services. In EnergyScopeTD, there are 5 different EUDs : electricity, heating, cooling, mobility and non-energy use .

EUT The EUDs are split into more precise demands called End-Use Types, *e.g.*, heating EUD is split into water heating, space heating and high temperature heating in the industry.

FEC The Final Energy Consumption is defined as "the energy which reaches the final consumer's door" [28].

GWP The Global Warming Potential is used by EnergyScopeTD as the indicator to assess the global annual greenhouse gas emissions. The GWP is expressed in ktCO_2-eq./year.

HP Heat Pumps use electricity to transfer heat from one place to another. This is used in EnergyScopeTD for low temperature heating.

LCOE The Levelised Cost Of Energy is a measure of the average net present cost of electricity generation for a a generating plant over its lifetime [2].

Mpkm A passenger-kilometre, abbreviated as pkm, is the unit of measurement representing the transport of one passenger by a defined mode of transport (road, rail, air, sea, inland waterways etc.) over one kilometre[27].

Mtkm A tonne-kilometre, abbreviated as tkm, is a unit of measure of freight transport which represents the transport of one tonne of goods (including packaging and tare weights of intermodal transport units) by a given transport mode (road, rail, air, sea, inland waterways, pipeline etc.) over a distance of one kilometre. Only the distance on the national territory of the reporting country is taken into account for national, international and transit transport[26].

NG Natural Gas is a type of fossil fuel mainly used in heat engines or for non-energetic use as a raw material.

OPEX stands for operating expenditure. It is the ongoing cost for running the energy production units (*e.g.* the maintenance cost).

PHS Pumped Hydroelectric Storage can store electricity by pumping water into an upper reservoir, this storage can unload by releasing the water in turbines to produce electricity.

PV Photovoltaic panels are systems transforming solar power into electricity.

REP The Renewable Energy Potential is defined as the energy produced if all the renewables are installed or used to their maximum.

TD Typical Days are used by EnergyScopeTD to strongly decrease computational time. They are selected thanks to a clustering method that chooses a number, defined by the user, of TDs that can best represent the year.

TS A Time Serie is a normalised vector, put into EnergyScopeTD, representing the hourly profile of the year for a variable energy demand or a variable energy production source.

Introduction

The 2015 Paris agreement marked the moment when most countries decided to take global action to keep the increase of global temperature well under 2°C to mitigate climate change consequences. This implies reaching global carbon neutrality by 2050 [37]. The European Union (EU) aims to reach this goal which means implementing an economy with net-zero Greenhouse Gas(GHG) emissions [8]. In 2019, the production and use of energy across economic sectors accounted for more than 75% of the EU's GHG emissions[20]. Producing clean energy must then become one of the priorities that needs to be addressed rapidly to reach climate objectives.

However, European countries vary a lot in size, climate and energy demand. It is not clear if each European country could provide its energy needs by using only its own resources (*i.e*, independently) while being energetically carbon neutral. This leads to the following research question. **Can the energy systems of European countries reach carbon neutrality by 2035 independently?** The chosen target year for carbon neutrality of energy systems in this study is 2035 as the energy sector is the main GHG emitter and that the EU aims to be a global leader for climate policy. Therefore, a neutral energy system by 2035 would lead the way in that direction. This study assumes the demand will be the one following today's trends described by the European Commission Reference Scenario[12].

The tool used to answer that question is EnergyScopeTD, a novel open-source model for regional energy systems developed by Gauthier Limpens et al. by joint collaboration of UCLouvain and EPFL [48]. EnergyScopeTD was already used to model the energy systems of Belgium [49] and Switzerland [51]. This model is a linear programming model that optimises investment and operating strategy by performing an hourly resolution on a multi-sectoral energy system. This model not only studies the electrical sector but also heat, mobility and energy needs for the industry, therefore allowing interactions between those sectors. EnergyScopeTD model main principles are explained in Chapter 1.

The first and main contribution this paper provides is an expansion of the database for EnergyScopeTD to cover 26 European countries entirely. This database can be found on the EnergyScope Github repository [64]. The countries covered by the new database are all EU countries minus Cyprus and Malta for which too much data was missing. The United Kingdom, although not anymore in the EU, is also covered.

Additionally, EnergyScopeTD is also generalised to cover 10 more technologies and to include the cold demand in addition to the 4 sectors already covered. These modifications and the expansion of the database are described in Chapter 2. Methodology to evaluate the End Use Demand (EUD) in electricity and heat is also modified to better account for the heating and cooling produced by electricity. The computation of hourly profiles and the estimate of biomass resources are also modified.

With the newly established database, a new Key Performance Indicator R is also introduced to directly compare the renewable energy potential of a country to its EUD. This is done in Chapter 3 in parallel to a data analysis of EUD, renewable characteristics and renewable energy potential for European countries.

In addition, in Chapter 4, EnergyScopeTD is used to determine for which countries the energy system can reach, independently, carbon neutrality. The model predicts that 21 countries have enough renewable energy potential to provide their own needs and to be carbon neutral. It also predicts that 4 countries (Belgium, the Netherlands, Slovenia and Germany) can not meet their estimated demand in 2035 with only their renewable energy potential while being carbon neutral. It is still uncertain if Italy can reach carbon neutrality as the uncertainties of the model and data do not allow to clearly answer the question. Furthermore, most countries do not need to use their full renewable energy potential. This unused renewable energy is about 6 times the total energy deficit of Belgium, Germany, Slovenia and the Netherlands combined. France is also analysed more in-depth to better describe how fully renewable energy system can work and deal with renewable intermittency.

Finally, Chapter 5 serves as a discussion on the societal implications of the proposed solutions, the validity of cost parameters through a LCOE analysis and some of EnergyScopeTD limitations.

Chapter 1

Model Description

This Chapter aims at explaining the basic principles of the already existing EnergyScopeTD version used for this study. This enables a better understanding of the changes and improvements made to the model during this thesis which are then explained in Chapter 2. For a complete mathematical description, refer to EnergyScopeTD supplementary material [50]. EnergyScopeTD is a novel open-source model for regional energy systems [51]. It was developed by G. Limpens et al. and is the result of collaboration between UCLouvain and EPFL. This model is a linear programming model that optimises investment and operating strategy by performing an hourly resolution on a multi-sectoral energy system. The model has a constraint on the greenhouse gas emissions. The computational time is minimized by using Typical Days which will be explained later in this Chapter.

The working principles of EnergyScopeTD rely on 3 basic blocks: resources, energy conversion and demand. These 3 basic parts are illustrated in a conceptual example of an energy system in Figure 1.1. The task of EnergyScopeTD is to find the optimal energy conversion system under certain constraints. Therefore, the model uses layers that are defined as all the elements in the system that need to be balanced in each time period; they include resources and End Use Types (EUT: type of energy demand such as Space Heating, detailed later). These layers are linked to each other by technologies of EUTs, infrastructures and storage technologies. Technologies of EUTs transform the energy of one layer to a layer of EUT, *e.g.*, thermal solar panels that convert solar irradiance into heat. Storage technologies can take energy from a layer, at a certain time period, to deliver it back to the same layer when needed, *e.g.*, thermal storage that can store heat. Infrastructures gather the remaining technologies, including networks, such as the power grid and district heating networks (DHNs), but also technologies linking non end-use layers, such as methane production from wood gasification or hydrogen production from methane reforming [50].

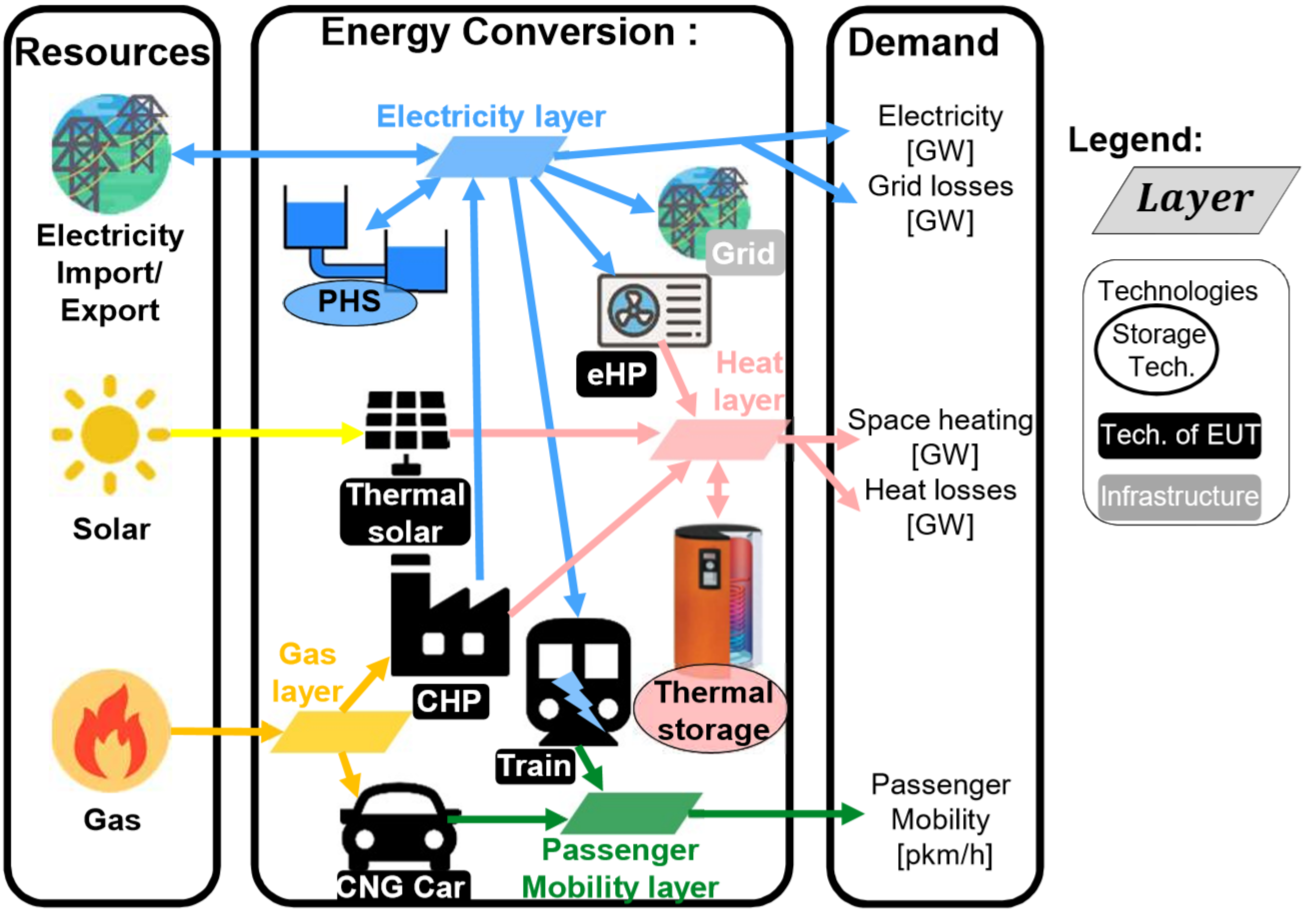


Figure 1.1: Example of an energy system done by Limpens [51]. Abbreviations: pumped hydro storage (PHS), electrical heat pump (eHP or HP), combined heat and power (CHP), compressed natural gas (CNG).Some icons are made by Freepik from www.flaticon.com.

The main objective of the model is to minimise the total cost of the energy system that meets an energy demand while not exceeding a Global Warming Potential (GWP) upper limit. The GWP is chosen by EnergyScopeTD [51] as the indicator to assess the global annual greenhouse gas emissions, the units of GWP are in ktCO_2-eq./year. In this model, the demand is expressed in terms of End-Use Demand (EUD), which is different from most energy models that often use the Final Energy Consumption (FEC). The EUD is the energy demand in energy services (*e.g.* electricity demand) and the FEC is defined as "the energy which reaches the final consumer's door" by the European Commission[28]. Basically, the FEC is the energy needed to satisfy the EUD. The two concepts are illustrated, by Limpens et al., as follows "in the case of decentralised heat production with a natural gas (NG) boiler, the FEC is the amount of NG consumed by the boiler; the EUD is the amount of heat produced by the boiler, *i.e.* the heating service needed by the final user". EnergyScopeTD implements 4 different EUDs : electricity, heating, mobility and non-energy demand. Non-energy demand is defined by the International Energy Agency [38] as "fuels that are used as raw materials in the different sectors and are not consumed as a fuel or transformed into another fuel". These EUDs are split in more precise demands which are called End-Use Types (EUTs). For example, heating is split in three EUTs: low temperature heat for hot water, low temperature heat for space heating and high temperature heat for industry.

To identify the optimal system, EnergyScopeTD works with an hourly resolution such that the hourly demand is met with the appropriate hourly production all year long. This sort of resolution is needed as the system has to take into account intermittent sources of power (*e.g.* photovoltaic panels) and time-dependent energy demands (*e.g.* heating). Thus, EnergyScopeTD uses Time Series (TSs) to describe the hourly production profile of intermittent sources and the hourly profile for time-dependent energy demands. In order to ease the use of these TSs for different scenarios, their profiles are normalised. For intermittent production technologies, the normalisation is done by dividing the hourly production [GW] by the installed capacity of the technology [GW] or, for time-dependent energy demands, by dividing the hourly energy demand [GWh] by the EUT [GWh]. This is shown for time-dependent energy demands in Equation 1.1 and for intermittent production technologies in Equation 1.2.

$$\text{TS of demand(h)} = \frac{\text{Energy demand(h)}}{\text{EUT of the demand}} \tag{1.1}$$

$$\text{TS of production(h)} = \frac{\text{Power of production(h)}}{\text{Total installed capacity of production}} \tag{1.2}$$

Once all the Time Series have been put into EnergyScopeTD, the model will compute a number of Typical Days (TDs) by using a clustering method [51]. This method selects TDs that best represent the whole year, *e.g.* if the chosen number of TDs is 4, there could be one TD representing hot sunny days, one representing cold sunny days, one representing hot cloudy days and, finally, one representing the cold cloudy days. For this study, the number of TDs is set to 12 as it reduces strongly the computational time of the model without affecting the validity of the results as explained by Limpens et al. [51]. This means that, in the model, each day of the year is represented by one of the 12 TDs. Thus, EnergyScope has to solve the optimisation problem for a year made of 12 TDs instead of solving it for a year made out of 365 different days.

Chapter 2

Methodology

EnergyScopeTD requires the user to adapt the input data depending on the scope of his analysis. This can go from just changing a few parameters, *e.g.* modifying the values of the End Use Demands (EUDs), to an expansion and generalisation of the program, *e.g.* by introducing a new EUD. One of the objectives of this thesis is to generalise EnergyScopeTD so that it encompasses all possible technologies and demands that could occur in the EU. Figure 2.1 summarizes the technological extensions made to the last version of EnergyScopeTD [51] by showing in black the technologies that were already implemented and in red the ones that are an addition from this thesis. Additionally, Table 2.1 summarizes all changes, including the non-technological ones, made to the original version of EnergyScopeTD [49][51]. Each of these changes is justified and described in this Chapter.

Most of the time, data is not available in the adequate form for the model. This section details how available data is processed to fit the model inputs and expanded to most of the EU countries[1]. First, Section 2.1 illustrates how EUDs are calculated for EU countries. Furthermore, it introduces the cooling demand which is a novelty to EnergyscopeTD. Secondly, Section 2.2 describes how time dependent parameters, *i.e.* TSs, are calculated. This includes new TSs like space cooling or tidal production but also modifications to pre-existing TS like solar thermal. Afterwards, Section 2.3 expands work previously done on biomass to better estimate available resources. Then, Section 2.4 details all the new technologies that this study introduces in EnergyScopeTD. Finally, Section 2.5 details how all the data is obtained and post-processed to include all EU countries. The generalised EnergyScopeTD version and the data used in this study are available on the EnergyScope Github repository [64].

[1] This thesis analyses 26 Countries. This includes 25 of the 27 EU countries (Cyprus and Malta are left out due to too missing data) and the United Kingdom. In this study, "EU countries" refers to these 26 countries.

Unification of previous works	Swiss and Belgium model are unified to include each of their implemented features.
EUD	Assumption that FEC = EUD is removed. Heating and Cooling previously included in Electricity are now accounted for in their respective Demand type.
Cooling	Space and Process Cooling Demand are added along with their TS and technologies.
Solar Thermal	Methodology to obtain Solar Thermal TS is changed.
Tidal	Tidal TS is added.
Biomass	A new methodology is implemented to estimate sustainable biomass potential and cost on a country basis.
Technologies	10 Technologies are added. 3 Marine technologies, 3 for concentrated solar, 2 for cooling, one for Cold storage and one for high temperature storage.

Table 2.1: Summary of changes between EnergyScopeTD Belgium/Switzerland [49][51] and generalised EnergyScopeTD used in this study.

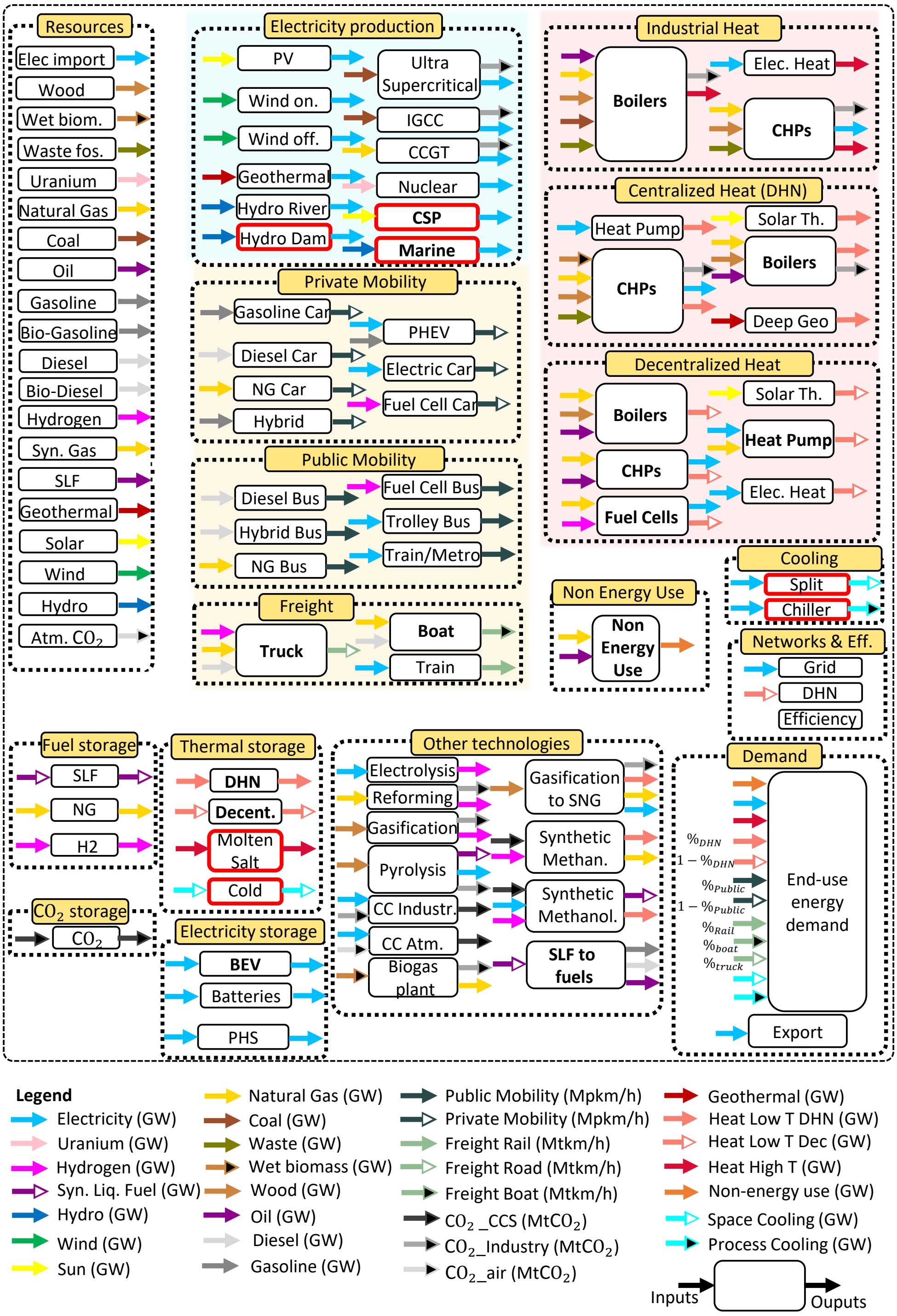


Figure 2.1: Summary of the data before [49] (in black boxes) and after (in red boxes) the generalisation of the EnergyScopeTD model. Technologies written in **Bold** represent groups of technologies with different energy inputs (e.g. **Boilers** include gas boilers, oil boilers, . . .). **Decent.** represents the group of thermal storage for each decentralised heat production technology. Abbreviations : photovoltaic (PV), integrated gasification combined cycle (IGCC), combined cycle gas turbine (CCGT), combined heat and power (CHP), heat pump (HP), natural gas (NG), synthetic natural gas (SNG), liquified natural gas (LNG), plug-in hybrid electric vehicle (PHEV), district heating network (DHN), battery electric vehicle (BEV), pumped hydro storage (PHS), concentrated solar power (CSP), synthetic liquified fuel (SLF).

2.1 End Use Demand

As explained in Chapter 1, the End Use Demand (EUD) is the demand in energy services such as electricity, heat, mobility or non-energy use. The EUD is to be distinguished from the Final Energy Consumption (FEC) which is, according to the European Commission definition, "the energy which reaches the final consumer's door" [28]. Basically, the FEC is the energy needed to satisfy the EUD. The goal of Energy system models such as EnergyscopeTD is to create a better understanding of possible conversion pathways between resources and human needs. Therefore, it is more interesting to use EUDs as they describe more accurately human needs than FECs. In addition to the three demand types already introduced (see Section 2.1.1), Section 2.1.2 introduces cooling demand as a new EUD to EnergyScopeTD. This new demand is implemented to better characterize southern European countries such as Spain.

2.1.1 Heat, Electricity and Mobility EUD

The different EUDs implemented in EnergyscopeTD are currently of four different types: electricity, heat, mobility and non-energy. The electricity is divided in two End Use Types (EUTs): a constant electricity demand, ELEC_{CST}, and a variable electricity demand, ELEC_{VAR}. These two combined constitute the EUD in electricity EUD_{Elec}. The EUD in heat EUD_{Heat} is divided in three different EUTs. Two of them are for low temperature heat and one for high temperature heat. The low temperature heat demand types are called Hot Water (HEAT_{HW}) and Space Heating(HEAT_{SH}) where HEAT_{HW} is constant over the year and HEAT_{SH} depends on the outside temperature. This dependence is further explained in Section 2.2.1. The last EUT is High Temperature (HEAT_{HT}) which appears only in the industry and is assumed constant over the year. HEAT_{HW} is typically domestic hot water used to take showers whereas HEAT_{SH} is the heating needed to keep a room warm. HEAT_{HT} is used only for industrial processes. Finally, mobility is simply divided between freight and passenger mobility. All these demands are divided by sector: a residential sector, a services sector (sometimes called tertiary), an industry sector and finally a mobility sector. All these EUTs are necessary because different types of demands can be fulfilled by different technologies. Furthermore, they enable better analysis of what actually happens in the system.

The aim of this section is to explain how these EUDs are obtained from available resources such as the European Commission Reference Scenario 2016 [12]. In this document, the FEC per sector for all EU countries is given for several years in the future including 2035. As mobility and non-energy are already characterised in terms of EUDs for non-energy, freight and passenger mobility needs in the EU reference scenario[12]. This means no further work is needed and non-energy nor mobility needs will be mentioned hereafter.

The methodology used to compute the different EUDs is illustrated by Figure 2.2. This figure shows how to transform the FEC obtained from the reference scenario[2] [12] into the EUTs mentioned here-above. This transformation process is done in 3 steps called A, B and C.

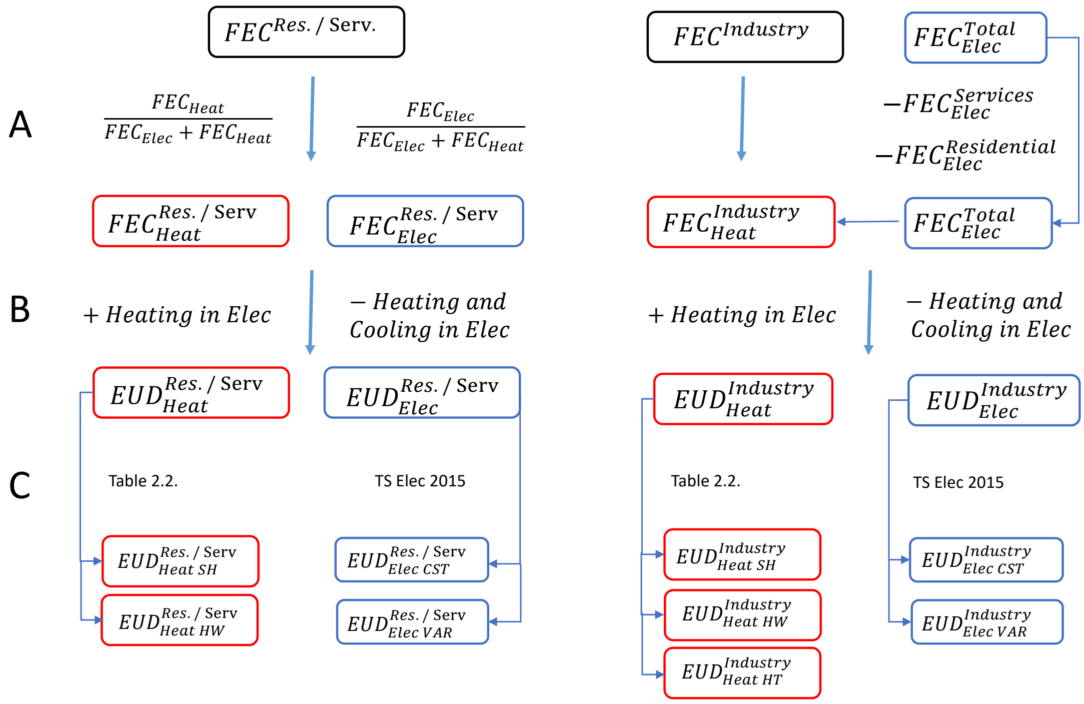


Figure 2.2: Summary of the process transforming EU data [12] into sectorial EUTs for heat and electricity. Res./Serv. represent either Residential or Services as the methodology is the same for both.

Step A was already implemented by Limpens [51] and consists in splitting the total FEC for each sector between Heat and Electricity. The original FEC from the Reference Scenario 2016 [12], in black, can be split between total electrical demand per sector and total heat demand per sector using EU Balance Sheets [21]. In this document, the ratio between electrical FEC and total FEC (heat + electricity) can be computed for both residential and services sector. By multiplying

[2]This reference scenario is based on a study made by the European Commission.

this ratio by the total 2035 FEC from the Reference Scenario [12], the total heat and the total FEC for residential and services sector are obtained. As the total electrical FEC is also known from the EU Reference Scenario [12], the industrial electrical FEC is simply obtained by subtracting both residential and services electrical demand to the total electricity. Total heating for industry is then obtained by subtracting the electrical FEC in industry from the total FEC of industry.

In Step B, FEC for heat and electricity are transformed in EUD. This is a novelty brought by this thesis to the original EnergyScopeTD methodology as before FEC and EUD were assumed equal. This was fine for countries like Belgium and Switzerland for which the heating demand is barely electrified but is not valid anymore for countries such as Sweden or France where the share of heating in residential electricity are 26 % and 13 % respectively[56]. This transformation is done using Equations 2.1 and 2.2. In short, these equations allow for heating and cooling previously accounted for in electricity to be accounted correctly. More precisely, in Equation 2.1, the EUD_{Elec} is obtained by subtracting the part of heating and cooling provided by electricity from the FEC in Electricity FEC_{Elec}. For heating, the share of electricity used for heating $\%_{\text{HeatByElec}}$ is obtained from Persson & Werner [56] for all EU countries. A limitation of this work is that only the share for residential heating was available, it was then assumed the same for the other sectors. This share takes into account the distribution and the efficiency of heat pumps and of electrical heating [3]. It is then multiplied by the FEC in Heating FEC_{Heat} to obtain for each country the demand in heating provided by electricity. In Equation 2.2, this heating energy is added to FEC_{Heat} to obtain EUD_{Heat}. The $\text{FEC}_{\text{Cooling}}$ is divided by the Seasonal Energy Efficiency Ratio (SEER) which is the ratio of output cooling energy to input electrical energy. Cooling demand is further discussed in Section 2.1.2.

$$\text{EUD}_{\text{Elec}} = \text{FEC}_{\text{Elec}} - \text{FEC}_{\text{Heat}}\%_{\text{HeatByElec}} - \frac{\text{FEC}_{\text{Cooling}}}{\text{SEER}} \tag{2.1}$$

$$\text{EUD}_{\text{Heat}} = \text{FEC}_{\text{Heat}} + \text{FEC}_{\text{Heat}}\%_{\text{HeatByElec}} \tag{2.2}$$

Finally, step C splits the EUDs for heat and electricity between different EUTs. As introduced earlier, electricity is made of ELEC_{CST} and ELEC_{VAR}. Heating is made of HEAT_{HT}, HEAT_{SH} and HEAT_{HW}. For heat EUTs, the same methodology as in Limpens 2019 [51] is applied using Swiss data [53] (see Table 2.2) by multiplying the total heating demand by the values in Table 2.2. The assumption is made that for all European countries the heat demand is distributed such as for Switzerland. However, the Swiss data was not used to split electricity into ELEC_{CST} and

[3] There is thus no need to process this share as it encompasses the efficiencies and shares of each technology transforming electricity into heat.

$ELEC_{VAR}$ like Limpens [51]. Indeed, this data seemed flawed as for instance in the residential sector the constant share of electricity was of 96.2% whereas our analysis of the electrical TS found that global constant share was only of 42.3% for France. Swiss data could be so high because what it measured was lighting appliances, whereas this study uses a base load $ELEC_{CST}$ over which a variable share $ELEC_{VAR}$ is added by multiplying $ELEC_{VAR}$ to its associated TS. This is illustrated by Figure 2.3. Hence, the TS of electricity in 2015 is used to split it between a variable and a constant demand. The constant demand is fixed by the minimal value of the TS. By dividing the constant demand over the total demand, the constant share in 2015 is obtained. It is assumed[4] that the share between variable and constant electricity stays the same between 2015 and 2035. The EUD_{Elec} found in step B is then multiplied by this share to finally obtain $ELEC_{CST}$ and $ELEC_{VAR}$ for Residential, Services and Industry.

	Households	Services	Industry
$HEAT_{HT}$	-	-	75.3 %
$HEAT_{SH}$	79.6 %	81.2 %	19.6 %
$HEAT_{HW}$	20.4 %	18.3 %	5.1 %

Table 2.2: Distribution of heating demand extrapolated from Swiss data from Stefano Moret[53].

2.1.2 Cooling EUD

Additionally to what was already implemented in EnergyScopeTD, this study also implements a cooling demand. This is done to include all European demand profiles. Indeed, southern countries have a non-negligible cooling demand. In this model, the cooling demand is divided into a process cooling demand, which is constant over time, and a varying space cooling demand. The latter demand is associated to a Time Serie which is further described in Section 2.2.1. Additionally, the technologies fulfilling this cooling demand are presented in Section 2.4.3.

In the Heat Roadmap [34], the total (residential, services and industry combined) as well as the individual industry EUD for space cooling and process cooling are available for the year 2035 for 14 countries. However, predictions for residential and services are not directly available for 2035. Figure 2.4 illustrates how these values are obtained. By subtracting industrial cooling demand from total cooling demand, only the cooling demand for residential and services combined remains.

[4] This is a strong assumption since an electrification of other energy sectors is likely to occur in the EU.

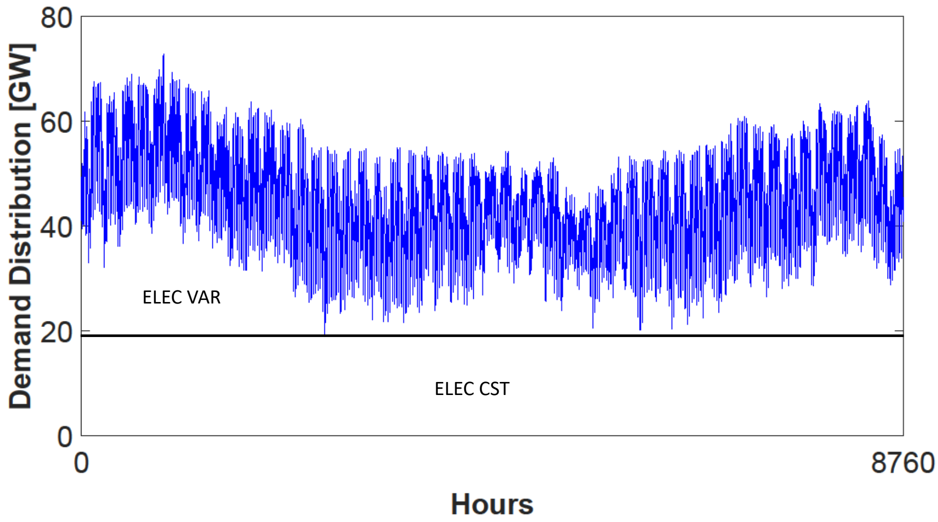


Figure 2.3: The constant and variable share of electricity are obtained using the TS of electricity.

Then, proportions between residential and services cooling demand are calculated from 2015 historical data [35]. Assuming both space cooling and process cooling keep the same proportion between 2015 and 2035, this ratio is used to finally compute cooling demand for residential and services in 2035.

As data for cooling is only available for 14 countries, the cooling demand for the remaining countries has been estimated by taking the cooling demand of a neighbouring country corrected by its population. The population data of 2035 comes from the European reference scenario [12]. For instance, the Space Cooling Demand for Portugal is taken by multiplying the space cooling demand for Spain multiplied by the ratio of Portuguese population over Spanish population. In the same manner, the cooling demand for Bulgaria has been extrapolated from Romania, Denmark from Germany, Estonia, Lithuania and Latvia from Finland, Slovenia, Greece and Croatia from Italy, Ireland from the United Kingdom and finally Slovakia from Hungary.

A limitation of this methodology is its restrained accuracy due to the resolution of the population that is given in millions of inhabitants. This may greatly reduce the accuracy of the cooling demand for countries like Estonia with population estimated at 1 Million in 2035 even though its population in 2020 is of 1.33 Million.

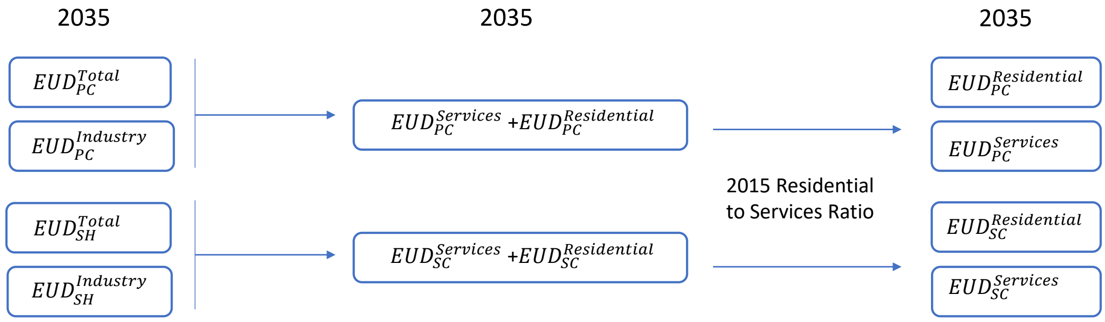


Figure 2.4: Process to obtain sectorial Cooling EUD for Process Cooling (PC) and Space Cooling (SC).

Clearly, this methodology is not ideal but is driven by the fact that there is a lack of data studying present and future cooling demand at the national level as Connolly points out in his report [15].

2.2 Time Series

When working with intermittent sources of power such as wind or photovoltaic panels (PV), it is important in an energy system to be able to characterize how energy is produced and consumed through time. Indeed, the varying demand in energy needs to be always fulfilled by a varying energy production. This is why Time Series (TS) are implemented. Depending on the production or demand side, they describe either, for production, the power produced at any time over installed capacity or, for demand, the hourly consumption over yearly End Use Demand. They are also used to define the Typical Days [51].

This Section describes the methodology for TSs that have been modified compared to previous work [51] and newly implemented ones. In Section 2.2.1, the hourly dependence between outside temperature and space heating and cooling is given. Section 2.2.2 describes how the electricity used for heating and cooling is removed from the consumed electricity to obtain the TS of specific electricity. Then, Section 2.2.3 explains how this study shifted to a new methodology to obtain solar thermal TS. Furthermore, Section 2.2.4 details the addition of a Tidal TS to the model. For other TSs, a quick methodology is given in Table 2.10 of Section 2.5. An important disclaimer is that as it is impossible to accurately predict the weather in 2035, historical hourly data is used as a model for 2035. All hourly data comes from the same year, 2015, as there are multiple links between TSs, *e.g.* people use space cooling when it is hot outside and this is reflected on the electrical grid where this electricity will be consumed.

2.2.1 Space Heating and Cooling

Space heating and Cooling are described by TSs to better reflect the daily and seasonal dependency linked to the outside temperature. Having this hourly distribution of the demand has direct interest in system modeling as synergies or anti-synergies can be seen between technologies and demand. For instance, solar thermal panels to provide space heating are a poor choice as the sun thermal energy is mostly available in warmer hours.

As explained in Section 2.1, the heating demand is described in EnergyScopeTD as the sum of three EUTs. High temperature heat and low temperature hot water demands are both considered constant. On the other hand, space heating is dependent on the outside temperature and is thus described by a TS. Similarly, the cooling demand is added to the existing model with two types of cooling: a process cooling which is a constant load and a space cooling which depends on the outside temperature. The aim of this section is to describe how space heating and space cooling TSs are obtained.

Space heating and cooling TSs are chosen to be described by Heating Degree Hours (HDH) and Cooling Degree Hours (CDH). They are described by Assawamartbunlue [9] as the sum of the differences between hourly average temperatures and the base temperature. At any given hour, a HDH and a CDH is given to reflect the need for heating or cooling. Therefore, it is the profile over the year of HDH and CDH which gives the profile for both space heating and cooling energy needs, *i.e.* HDH and CDH show how the annual EUD for space heating and cooling is spread. For any given hour i in a year, the number of HDH for that hour is described as

$$\mathrm{HDH}_i = (\mathrm{T}_{bh} - \mathrm{T}_i)^+ \tag{2.3}$$

where T_{bh} is the base temperature from which HDH are computed and T_i is the outside temperature observed for the hour i. The superscript "+" indicates that only positive values of the bracketed difference are taken into account. Similarly, Cooling Degree Hours are calculated as

$$\mathrm{CDH}_i = (\mathrm{T}_i - \mathrm{T}_{bc})^+ \tag{2.4}$$

where T_{bc} is the base temperature from which CDH are calculated. According to the European Environment Agency [22], the baseline temperatures in Europe for HDH and CDH are respectively $T_{bh} = 15.5\,°C$ and $T_{bc} = 22\,°C$. The profile for HDH and CDH is then calculated using these baseline temperatures.

In previous work using EnergyScopeTD [51], the temperature data used for the space heating profile was the one of a specific meteorological station in the country, *e.g.* for Belgium temperatures were measured in Uccle and it represented the whole country. Belgium is quite small so this does not cause much bias in the space heating demand. However, this method can not be extended to bigger European countries such as France or Italy without giving some significant bias in the heating and cooling profile. In this study, the temperature representing a whole country is the population weighted temperature such as calculated for all European countries by the model MERRA-2 [32]. As energy consumption is assumed to be linearly correlated with population density, the temperature of highly densely populated area will have more impact on the space heating and cooling demand than sparsely populated areas such as mountains.

2.2.2 Profile of EUD in Electricity

The EUD in electricity $\mathrm{EUD}_{\mathrm{Elec}}$ is, as described in Section 2.1, the demand for electricity services that can only be provided by electricity. This naturally excludes demand in heating and cooling provided by electricity. Section 2.1.1 discussed how $\mathrm{EUD}_{\mathrm{Elec}}$ is computed from $\mathrm{FEC}_{\mathrm{Elec}}$. This section focuses on how TS of $\mathrm{EUD}_{\mathrm{Elec}}$ is obtained. Indeed, $\mathrm{TS}_{\mathrm{Elec}}^{\mathrm{EUD}}$ is not directly accessible. Electrical data obtained on the ENTSOE website [24] describes the TS of electricity consumed $\mathrm{TS}_{\mathrm{Elec}}^{\mathrm{FEC}}$, *i.e.* the TS of $\mathrm{FEC}_{\mathrm{Elec}}$. This data must be post-processed to assess the part of electricity used for heating and cooling to obtain $\mathrm{TS}_{\mathrm{Elec}}^{\mathrm{EUD}}$. This is done using Equation 2.5 by subtracting, from $\mathrm{TS}_{\mathrm{Elec}}^{\mathrm{FEC}}$, the TS of heat and cooling provided by electricity, respectively $\mathrm{TS}_{\mathrm{Elec}}^{\mathrm{Heat}}$ and $\mathrm{TS}_{\mathrm{Elec}}^{\mathrm{Cooling}}$. This is best illustrated by Figure 2.5. In this Figure, $\mathrm{TS}_{\mathrm{Elec}}^{\mathrm{EUD}}$ is obtained by subtracting the part of heating produced by electricity and the part of cooling produced by electricity from $\mathrm{TS}_{\mathrm{Elec}}^{\mathrm{FEC}}$. The graph is displayed for France where the method produces good results as it allows to greatly reduce the seasonal dependence of electricity.

The rest of this section is used to describe how these last two terms are calculated.

$$\mathrm{TS}_{\mathrm{Elec}}^{\mathrm{EUD}} = \mathrm{TS}_{\mathrm{Elec}}^{\mathrm{FEC}} - \mathrm{TS}_{\mathrm{Elec}}^{\mathrm{Heating}} - \mathrm{TS}_{\mathrm{Elec}}^{\mathrm{Cooling}} \tag{2.5}$$

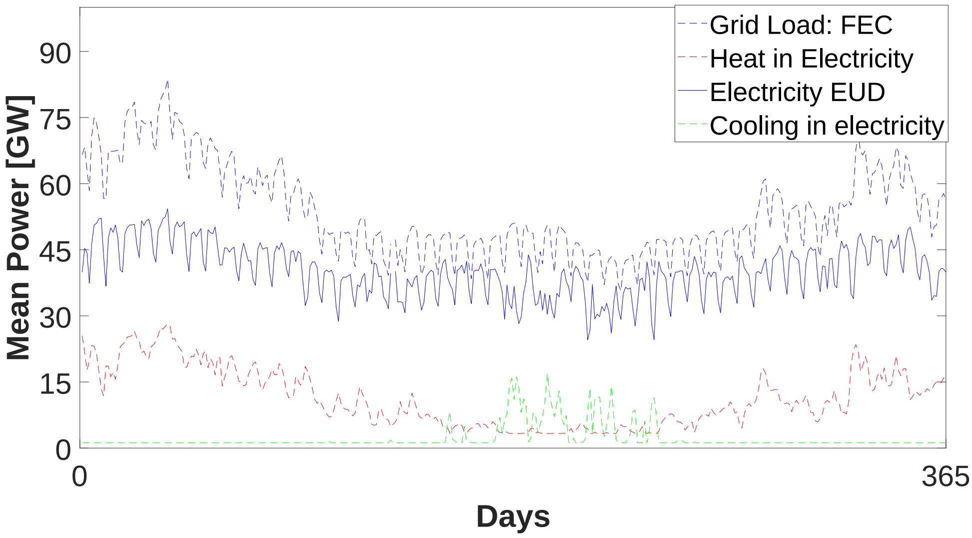


Figure 2.5: The Time Serie of Specific Electricity is obtained by subtracting from the TS of the grid load the part of heating and cooling provided by electricity. All data is averaged per day.

The Time Serie of heat produced by electricity is described by Equation 2.6 as

$$\mathrm{TS}_{\mathrm{Elec}}^{\mathrm{Heat}} = \%_{\mathrm{HeatByElec}}(\mathrm{HEAT}_{\mathrm{SH}}\mathrm{TS}_{\mathrm{SH}} + \frac{\mathrm{HEAT}_{\mathrm{HW}}}{8760} + \frac{\mathrm{HEAT}_{\mathrm{HT}}}{8760}) \tag{2.6}$$

Where $\mathrm{HEAT}_{\mathrm{HW}}$ and $\mathrm{HEAT}_{\mathrm{HT}}$ are the constant EUDs introduced in Section 2.1.1. As they are assumed constant over the year, their TS is uniform and obtained by dividing the EUD by the number of hours in a year. $\mathrm{HEAT}_{\mathrm{SH}}$ is the EUD of space heating discussed in Section 2.1.1. As the space heating needs vary over the year, $\mathrm{HEAT}_{\mathrm{SH}}$ is associated to the $\mathrm{TS}_{\mathrm{SH}}$ that was discussed in Section 2.2.1. Finally, $\%_{\mathrm{HeatByElec}}$ is the share of heat in electricity for residential that was discussed along Equation 2.1 in Section 2.1.1. Note that this ratio accounts for the proportions of heat pumps and electrical heating so there is no need for an efficiency term.

Similarly, the TS for cooling produced by electricity on the other hand is described by equation 2.7 as

$$\mathrm{TS}_{\mathrm{Elec}}^{\mathrm{Cooling}} = \%_{\mathrm{CoolingByElec}}\frac{1}{\mathrm{SEER}}(\mathrm{EUD}_{\mathrm{SC}}\mathrm{TS}_{\mathrm{SC}} + \frac{\mathrm{EUD}_{\mathrm{PC}}}{8760}) \tag{2.7}$$

Where the EUDs of Space Cooling and Process Cooling for 2035 are the ones previously discussed in Section 2.1. Space cooling is multiplied by its TS $\mathrm{TS}_{\mathrm{SC}}$

previously obtained in Section 2.2.1 and as process cooling is constant over the year, it is spread evenly. Do note that as the data provided only accounts for cooling from electric cooling and not natural cooling, $\%_{\text{CoolingByElec}}$ is one. This is finally divided by the seasonal energy efficiency ratio (SEER) which is the cooling output during a typical cooling-season divided by the total electric energy input during the same period [3]. The cooling output is calculated as the energy removed from a system. The reference cooling system used is a split system air conditioner with >5kW (big split). This is because this split system is the most widely spread cooling system for services and second most spread for residential sector [36]. SEER for big split is projected to be 7.3 in 2035 [36] and it is then the value used in our calculations.

Then, Equation 2.5 can be used to obtain $\text{TS}^{\text{EUD}}_{\text{Elec}}$. Finally, the TS input in EnergyScopeTD is obtained by subtracting from $\text{TS}^{\text{EUD}}_{\text{Elec}}$ its minimal value and by normalising the TS over the electricity EUD.

2.2.3 Solar Thermal

Nowadays, solar radiation can be directly transformed into electricity (photovoltaic panels) or into heat (solar thermal collectors). Nevertheless, the two types of technologies do not use the irrandiance of the sun in the same way. PV panels transform the global horizontal irradiance (GHI)[5] into electricity but solar thermal collectors can only transform the direct normal irradiance (DNI)[6] into heat. This justifies the need of two separated TSs linked to the sun, the PV TS and the solar thermal TS. This section aims at explaining the new computational method used to compute the solar thermal TS.

A solar thermal TS was already implemented into EnergyScopeTD[48] and was computed, as shown in Equation 2.8, using the hourly DNI, hourly GHI and the PV Time Serie.

$$\text{Solar thermal TS(h)} = \frac{\text{DNI(h)}}{\text{GHI(h)}}\text{PV TS(h)} \tag{2.8}$$

However, this method does not take into account the efficiency of the solar thermal collectors. Neither does it consider the thermal panel capacity that can be installed per unit area. In order to take these factors into consideration, the Equation 2.9 is applied which depends on the hourly DNI [42], the efficiency of the solar thermal collectors and the conversion factor. The conversion factor gives

[5]Global Horizontal Irradiance(GHI) is the total amount of solar irradiance received by an horizontal surface on Earth $\frac{\text{kW}_{\text{solar}}}{\text{m}^2}$.

[6]Direct Normal Irradiance(DNI) is the amount of perpendicular solar irradiance received per unit area $\frac{\text{kW}_{\text{solar}}}{\text{m}^2}$.

the installed capacity [kW_{th}] divided by the aperture area of the solar collector area[m^2] [39].

$$\text{Solar thermal TS(h)} = \eta_{\text{SolarCollector}} \frac{\text{DNI(h)}}{\text{Conversion factor}} \tag{2.9}$$

The values taken are $\eta_{\text{SolarCollector}} = 78\,\%$ and Conversion factor $= 0.7\,\frac{\text{kW}_{\text{th}}}{\text{m}^2}$ [39]. The DNI is obtained from the European Commission [42]. In this study, the $\eta_{\text{SolarCollector}}$ is assumed to be the same for every technology based on the solar thermal TS [39][30].

The difference in the daily averaged solar thermal TS between the two methods can be seen in Figure 2.6. The curves have the same behavior but with a different ratio. This is because the new method takes into account the efficiency of the solar panels and the original method takes the efficiency of PV panels (implicit in the PV TS).

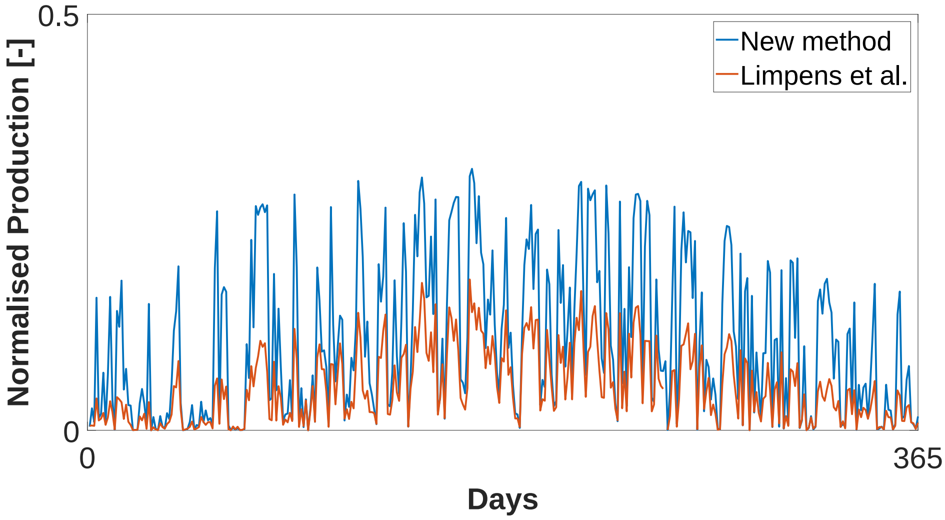


Figure 2.6: Comparison of the daily averaged solar thermal capacity factor of France 2015 computed with the original method [51] and with the new method.

For the solar thermal time serie, the expected capacity factor should have an order of magnitude of about 20 % (data for well located U.S. plants[11]). The original method and the new method give, respectively, a capacity factor of 5.2 % and 10.8 % for France. The difference between the capacity factor of France and the United States is due to the considered climate. The new method will be used in this study as it better represents the potential of the technologies linked to the solar thermal TS.

2.2.4 Tidal

As will be detailed in Section 2.4.1, tidal generators have been added to the model. These technologies produce electricity by collecting the kinetic (stream generators) or potential energy (range generators) from the tides. Since these tides are time-dependent, the addition of a tidal TS is required and has been done in the frame of this study. The TS implemented in this study is inspired by the computation (done and received by the ENS Rennes[7]) of tidal stream production in France. This normalised tidal stream production is shown in Figure 2.7. Note that the TS from the ENS only considers 8424 hours and not 8760 hours (number of hours in a year). The TS added to EnergyScopeTD has thus been filled by adding the first 336 hours of the year to the end of the TS from the ENS. Due to a lack of information, the same tidal stream production TS will be applied to each country with a coast on the Atlantic and with a non-negligible tidal potential (later detailed in Section 2.6). Note that the TS obtained thanks to ENS is for tidal stream generators, this TS will also be applied to tidal range generators since the hourly production of the two technologies behave in the same way[8] as demonstrated in [33]. This finally gives a tidal capacity factor (mean of the TS) of 9.5% for the TS implemented in this study. This is in line with the 9.3% obtained by the Energy Statistics Team of the UK [10] and validates the TS.

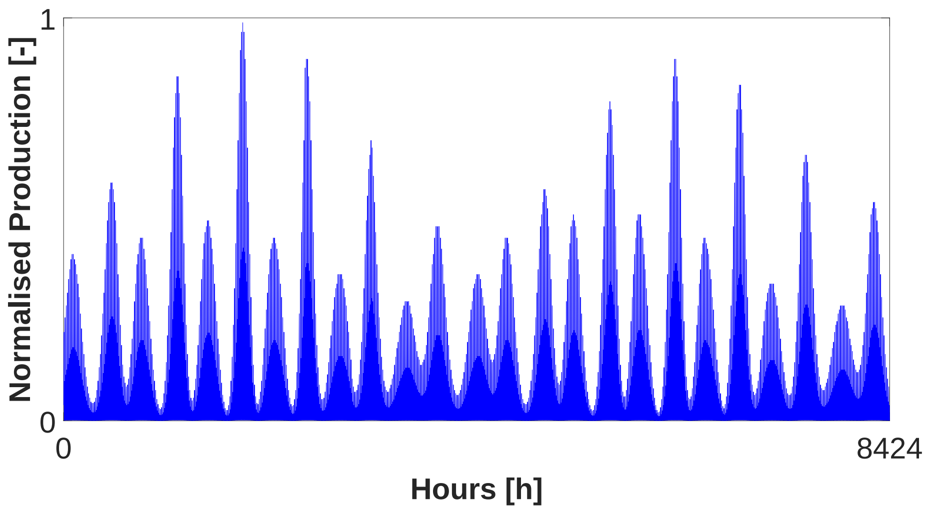


Figure 2.7: Tidal time serie from ENS.

[7]Ecole Normale Supérieure Rennes: French University.

[8]In reality, tidal range generators have a higher capacity factor than tidal stream generators.

2.3 Biomass Resources

Biomass is plant or animal material used for energy production. It can be used to produce heat through direct combustion or electricity if the heat is used in a thermal cycle. It can also be transformed to other forms of resources (biomethane, bioethanol, biodiesel, ...) through numerous conversion pathways. Although it releases CO_2 into the atmosphere, it is considered by legal framework as a renewable resource as the CO_2 released was initially captured by the plant. It is in fact the most used renewable energy in the EU [44] with the heating sector being the largest end-user, using about 75% of all bioenergy. It is with this information in mind that this work chooses to improve the way biomass resources are estimated.

In previous work [51] [53], biomass availability was evaluated on a country per country basis with local reports on biomass availability. As what can be considered as wood usable for energy can change drastically between two countries, a unifying framework was needed to work with all the EU member states. This study provides that unifying framework on the basis of Atlas of EU biomass potentials from Biomass Future [7], where all type of biomass resources and waste availability are evaluated per country. Two sets of data are available for the considered biomass resources. The first dataset considers a 50 % mitigation of GHG with respect to the fossil fuel mix of a country **excluding** indirect Land Use Change(iLUC) GHG (reference scenario). The second much stricter dataset considers 80 % mitigation of GHG with respect to the fossil fuel mix of a country **including** iLUC GHG (sustainable). iLUC takes place when existing agricultural land is diverted from production into land used for the production of biofuels (EC, 2011 [25]). As a consequence, the availability and the type of resources change between the two data sets. For instance, arable land is not used anymore for the production of biofuels with oleaginous or sugary biomass. Both of the data sets also exclude land use of rich bio diverse area such as NATURA 2000, which solidifies the trust in which the available biomass could reasonably be used. It has been chosen to work with the sustainable scenario data as it is assumed that arable land should not be used for energy purposes.

For instance, evaluated resources include black liquor, a wood residue from paper industry that can commonly be used as an energy resource to produce other byproducts by gasification or that can also be burned directly. They also include more traditional biomass such as roundwood and sugar-beet (commonly used to produce bioethanol). In total, 27 types of biomass or waste are evaluated per country both in cost and energy availability. As working with 27 different types of biomass is not practical, this study proposes to regroup these resources between 5

Wood	Additional roundwood, black liquor, landscape care wood, other industrial wood residues, perennials (woody), post consumer wood, saw-dust, sawmill by-products, primary forestry residues and roundwood
Wet Biomass	Verge gras, perennials (grassy), prunings, total manure, grass cutting, animal waste and forrage maize
Waster	Common sludges, MSW landfill, other MSW and paper cardboard
Oleaginous	Sunflower, used fats and oils rape
Sugary	Cereals, sugarbeet and corn/maize

Table 2.3: Classification of biomass resources by technical type of use.

categories according to the type of technologies that can use these resources. Three of them were already implemented to the model but are expanded to resources not yet considered: wood, wet biomass and waste. Wood is made of lignocellulosic biomass that can be used for direct combustion, gasification or pyrolysis. Wet biomass comprises of all biomass material wet enough that anaenorobic digestion is possible. Waste finally is all municipal landfill waste that can only be burned to produce heat. It is considered as renewable in this study. Two other resources are considered for this model thanks to this chemical characterisation. Oleaginous plants produce vegetable oil that can be transformed to biodiesel. Finally, sugary biomass uses alcoholic fermentation to produce bioethanol that is generally mixed with gasoline. The classification of the resources of the atlas of biomass [7] into these 5 categories is given in Table 2.3.

For the 5 biomass categories previously specified, the total energy available is then obtained by summing up the energy potential of each resource. As oleaginous and sugary biomass produce too much GWP in the sustainable data set, their energy potential is either negligible or 0 for all country studied. Therefore, it is not added in the model as a new resource. The cost per biomass type is obtained by making the average price weighted by energy potential. Table 2.4 gives the energy potential by biomass category and the associated price for France. Gasoline price is also given as a point of comparison. This shows that all biomass categories are significantly cheaper than gasoline but it has to be kept in mind that these resources still need to be transformed to usable fuel.

Resource Type	Energy Potential [GWh]	Price [$\frac{M€}{GWh}$]
Wood	324 686	0.016
Wet Biomass	162 075	0.007
Waste	57 777	0.0085
Oleaginous	3 012	0.022
Sugary	0	-
Gasoline	-	0.0823

Table 2.4: Biomass resource potential and averaged price for France in a reference scenario.

As a summary for biomass, the resource potential has been better estimated and priced for all European countries by taking more types of biomass into account. Wood, wet biomass and waste now include new resources which tend to increase the biomass potential and decrease the cost thanks to usable resources that could be overlooked as waste. This study also showed that oleaginous and sugary based biomass did not need to be added to the model as they have a too little sustainable energy potential. Nonetheless, work concerning new conversion pathways between biomass and synthetic fuels or useful reactants for chemistry could still be extended but this goes beyond the scope of this thesis.

2.4 Additional Technologies

In order to meet the EUDs, technologies are needed to transform a resource into layers that can supply this EUD. To generalize the model for this study, some technologies have been added to the original EnergyScopeTD [48] model. The generalized version takes marine technologies, concentrated solar power, cooling technologies and high temperature thermal storage into account. Figure 2.8 shows these technologies and their interactions with the adequate layers.

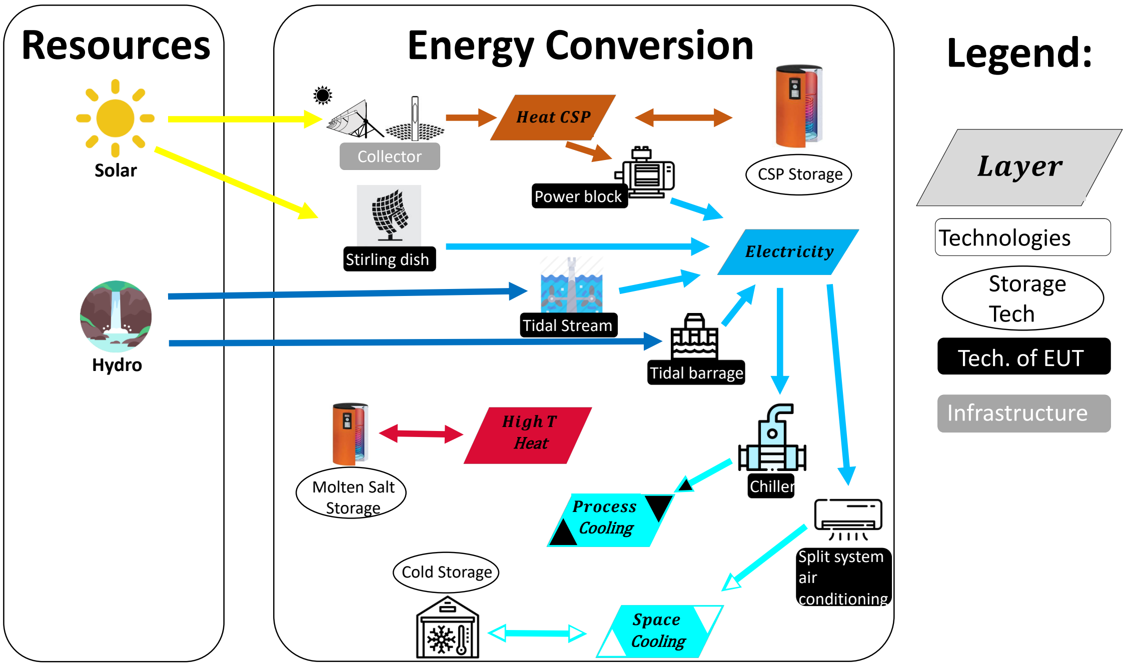


Figure 2.8: Technologies added to the model and their links to the different layers.Some icons are made by Freepik from www.flaticon.com.

2.4.1 Marine Power Technologies

Oceans and seas are within the largest untapped energy potentials and technologies aiming to collect their energy are not yet mature. This Section aims at adding the technologies that collect tidal stream energy, tidal range energy and wave energy. Tidal stream energy can transform the kinetic energy of marine streams into electricity by using tidal stream generators (also called marine turbines). Tidal range energy can convert the potential energy of tides into electricity by using tidal range generators (also called tidal barrage). Finally, wave energy can collect energy from the waves to transform it into electricity. Tidal stream generators and tidal range generators can be seen in Figure 2.8. Wave energy generator is missing in the Figure 2.8 since the potential and the wave TS are unknown. Therefore wave energy will not appear in the results studied in Section 4.

The motivation of the addition of marine power is the non-negligible technically available tidal energy resource in some EU countries. Note that tidal energy includes both tidal range energy and tidal stream energy. Table 2.5 shows the tidal potential for each country in Europe. These potentials are based on a parametric model of the European tides[33]. These results are the technically available tidal energy resource and not the sustainable available tidal energy resource. For example, Table 2.5 indicates a technical potential of 22.8 GW for France but studies made by RTE France show a maximum sustainable tidal potential of 5 GW [57].

Country	Technically available tidal energy resource	
	GW	TWh/year
United Kingdom	25.2	50.2
France	22.8	44.4
Ireland	4.3	8.0
Netherlands	1.0	1.8
Germany	0.4	0.8
Spain	0.07	0.13
Rest of Europe	0	0

Table 2.5: European countries with non-zero tidal energy potential [33].

The three technologies that are added in EnergyScopeTD for this study are shown in Table 2.6. This selection of technologies is based on their Technology Readiness Level, the market forecasts and their already installed technologies[14].

	$c_{inv}[\frac{€}{kW}]$	$c_{maint}[\frac{€}{kW*year}]$	lifetime [years]
Tidal stream generator	3752	165	20
Tidal range generator	2867	178	40[9]
Wave power generator	1909	42	20

Table 2.6: Data input for the EnergyScope TD model of marine power technologies [14][59].

2.4.2 Concentrated Solar Power Technologies

Concentrated Solar Power (CSP) technologies can produce electricity by converting direct normal irradiance of the sun into heat. This heat can then be stored or used in a power block to produce electricity. This study will implement three technologies: parabolic trough, solar tower and Stirling dish. Parabolic through and solar tower require the implementation of collectors, a power block and thermal storage. This latter is optional and not applicable to Stirling dish technology since it can not yet store thermal energy. These three technologies are illustrated in Figure 2.8. The two major reasons for implementing CSP are the competitive efficiencies with PV panels and their capacity to store heat (except for Stirling dishes). Storing heat allows flexibility for the energy systems. On the economical side, the CSP technologies are improving in competitiveness [63]. The solar energy converted into heat by the collector depends on the solar thermal TS as explained in section 2.2.3. This means that the technology can be of great use in regions with a lot of direct normal irradiance (i.e. south of Portugal). The data for the different technologies can be seen in Table 2.7.

Technology		$c_{inv}[\frac{€}{kW}]$	c_{maint} $[\frac{€}{kW*year}]$	Lifetime [years]	Total efficiency [%]
Parabolic trough	Collector	4504.71	62.65	25	16
	Steam turbine	1044.57	62.65	25	
	Storage(14h)	36.96	0.37	25	
Solar tower	Collector	5517.02	63.00	25	20
	Steam turbine	768.19	63.00	25	
	Storage(15h)	19.10	0.19	25	
Stirling Dish		6820	107.18	30	25

Table 2.7: Data input for the EnergyScope TD model of CSP technologies [30][40][45][52].

2.4.3 Cooling Technologies

In order to supply the newly introduced cooling demand (Section 2.1), new cooling technologies have to be added. Based on the market share and cost [36], the 2 technologies in Table 2.8 are implemented. Both technologies work with electricity as input as can be seen in Figure 2.8. The big split air conditioner and water-cooled chiller will be used, respectively, for the space cooling demand and the process cooling demand. The free cooling is not implemented in the technologies since the cooling demand introduced in the model is considered to be the cooling demand that needs to be supplied by electricity.

	$c_{inv}[\frac{€}{kW}]$	$c_{maint}[\frac{€}{kW*year}]$	Lifetime [years]
Split system air conditioning	232	9.333	15
Water-cooled chillers	119	4.76	20

Table 2.8: Data input for the EnergyScope TD model of cooling technologies [36].

2.4.4 Thermal Storage

The original EnergyScopeTD version does not contain any high temperature thermal storage or cold storage. The latter can be of great use due to the high variance of, both, the space cooling demand and the renewable power production. This intermittency of renewable energy could also require a high temperature thermal storage. In this study, the high temperature thermal storage is based on the molten salt technology. The data of the different storage technologies is shown in Table 2.9 and the way they interact with the layers is shown in Figure 2.8.

	$c_{inv}[\frac{€}{\text{kWh}}]$	$c_{maint}[\frac{€}{\text{kW}*\text{year}}]$	Lifetime [years]	Charge & discharge time [min]	Losses[-]
Molten salt	28.03	0.28	25	80	0.000355
Cold storage	25	0.3	20	240	0.00824

Table 2.9: Data input for the EnergyScope TD model of high temperature thermal storage [30][47] and cold storage [18].

2.5 Expansion of the Model to the EU

As already explained in this Chapter, modifications and extensions to EnergyScopeTD have been carried out in order to generalize the model so it could encompass all the EU countries. Once this is done, the model needs input data to run the model for all the EU countries. This leads to an expansion of the already available database from the Belgium case study, by Limpens et al. [49], to a database usable for the different EU countries. This Section aims at detailing the treatment of data performed in order to have the right input data for the model. In order to perform an accurate hourly resolution, all the demand TSs and production TSs had to be computed for each country in the EU. These TSs are based on historical data from the year 2015. This is detailed in Table 2.10. The other country-specific input parameters such as User Defined parameters, EUDs and miscellaneous parameters are detailed and explained, respectively, in Table 2.11, 2.12 and 2.13. The Tables mentioned here above show the sources of the data used and the methodology used to compute the input parameters of the model for each EU country. Some assumptions were made since some data was missing for a few countries, these assumptions for the expansion of data are also explained in the Tables. The input data can be found on the EnergyScope Github repository [64].

Time Serie	Methodology
Electricity [24]	The data used [24] gives the country-specific hourly electricity consumption, the electricity consumption for heating and cooling purposes have been substracted. Assumptions and complete methodology in Section 2.2.2.
Space heating [32]	Computation of the TS by using Heating Degree Hours based on country-specific data [32]. Assumptions and complete methodology in 2.2.1
Space cooling [32]	Computation of the TS by using Cooling Degree Hours based on country-specific data [32]. Assumptions and complete methodology in 2.2.1
Passenger mobility [50]	The TS of the Belgium study case by Limpens et al. [50] has been used for each country
Freight mobility [50]	The TS of the Belgium study case by Limpens et al. [50] has been used for each country
PV [24][42]	$\text{TS PV(h)} = \frac{\text{PV Production(h)}}{\text{Total PV capacity installed}}$ Due to missing data on ENTSO-E [24], the hourly production data has been taken from the Joint Research Center [42] for Estonia, Finland, Hungary, Ireland, Italy, Latvia, Poland and Sweden
Wind onshore [24][32]	$\text{TS Onshore(h)} = \frac{\text{Onshore Production(h)}}{\text{Total Onshore capacity installed}}$ Due to missing data on ENTSO-E[24] the hourly production data has been taken from MERRA-2 [32] for Slovenia, Luxembourg, Hungary, Ireland, Italy and Slovakia
Wind offshore [24][32][61]	$\text{TS Offshore(h)} = \frac{\text{Offshore Production(h)}}{\text{Total Offshore capacity installed}}$ The hourly production data has been taken from MERRA-2 [32][61] for Germany, Finland, France, the United Kingdom, Ireland, the Netherlands and Sweden as ENTSO-E [24] only had the hourly production for Belgium. Since data was missing, Estonia, Lithuania and Latvia use the TS from Finland, Spain and Portugal from France and Poland from Germany.
Hydro dam [24]	$\text{TS Hydro Dam(h)} = \frac{\text{Hydro Dam Production(h)}}{\text{Total Hydro Dam capacity installed}}$ has been applied to the data of ENTSO-E [24]. Since data was missing, Greece and Croatia use the TS from Bulgaria, Luxembourg from France and Italy uses the data from 2017.
Hydro river [24]	$\text{TS(h) Hydro River} = \frac{\text{HydroRiver Production(h)}}{\text{Total HydroRiver capacity installed}}$ has been applied to the data of ENTSO-E [24]. Since data was missing, Greece and Croatia use the TS from Slovenia, Luxembourg from Belgium and Italy uses the data from 2017.
Solar thermal [42]	Computation of the TS by using the country-specific hourly DNI [42], the conversion factor and the efficiency of solar thermal panels. Section 2.2.3 for complete methodology.
Tidal	Based on the TS received by the ENS, the same TS was used for all countries with a coast on the Atlantic. Section 2.2.4 for complete methodology

Table 2.10: Sources and methodology to obtain the country-specific production Time Series (TS) used in this study. All the data collected concerns the year 2015 (except detailed otherwise) and is specific to each country (except detailed otherwise).

User Defined	Methodology
Grid losses [21]	The total electricity distribution losses and the Final Energy Consumption of electricity can be found in the European Balance Sheet [21]. The grid losses are computed by using $\text{Losses} = \frac{\text{Distribution losses}}{\text{Final Energy Consumption}}$
Interest rate [51]	The same interest rate is used for each EU country and is based on the interest rate computed by Limpens et al. [51]
Heat Network losses [67]	According to Hai Wang et al. [67], District Heating Heat losses are between 4 and 8 %. 7% is chosen as a conservative value for all EU countries.
Maximum number of cars [12]	Maximum number of cars is assumed to be the half of the forecasted population in 2035 computed in the EU reference scenario [12]
Grid cost due to the integration of renewables [49]	The ratio between the total grid cost for integration of renewables and the capacity of renewables has been computed by taking the data from the Belgium case study by Limpens et al.[49]. This gave $\frac{208.926\text{ M€}}{\text{GW of renewable}}$. The original implementation (that was specific to Belgium) of this cost is changed to have a generalized model by having an integration cost that is defined as follows: $\frac{208.926\text{ M€}}{\text{[GW] of renewable}} \cdot \text{Capacity of renewable [GW]}$
Electricity import capacity [24]	The import capacity, for each country, has been computed by summing the capacities of the import grid lines forecasted for 2025 by ENTSO-E [24]. See Table A.5 for more details.

Table 2.11: Sources and methodology for country-specific data for User Defined parameters.

EUD	Methodology
Electricity [12][21][34][35]	The assumption of FEC = EUD has been removed. The electricity EUD, for each country, is obtained by substracting the parts of heating and cooling done by electricity [34][35] from the FEC [21][12]. Section 2.1 for methodology.
Heating [12][21][34][35]	Heating EUD has been computed based on the heating FEC and electricity FEC [21][12]. The part of the heating EUD [34][35] that was included in the electricity FEC has been accounted in the heating EUD for each country. Section 2.1 for methodology
Cooling [34][35]	Cooling EUD has been computed based on the Heat Roadmap cooling EUDs [34][35] for each country. Since data was given only for 14 countries of the EU, the cooling EUD of remaining countries has been based on neighbouring countries as explained in Section 2.1.
Mobility [12]	The same methodology as [51] has been applied to obtain the EUD for mobility for each country.
Non-energy [12]	The same methodology as [51] has been applied to obtain the EUD for non-energy use for each country.

Table 2.12: Sources and methodology for country-specific data for EUD parameters.

Miscellaneous	**Methodology**
Grid cost [12][21][51]	The grid cost from the Belgium analysis by Limpens et al. [51] has been taken and divided by its electric EUD [12][21]. This gives us a ratio of the grid cost compared to the electric EUD for Belgium. This ratio has been multiplied, for each EU country, by its electric EUD to obtain the country-specific grid cost.
PHS [43]	The already installed capacity is given, by Gimeno et al. [43], for each country in Europe. The potential capacity of PHS has been taken, for each country, from the same paper by considering all the realisable potential where the two reservoirs are separated by maximum 10 km and where at least one of two reservoirs is already existing. As for the charge and discharge time parameter for the storage, it has been computed by dividing the actual storage capacity [GWh] by the actual generation capacity [GW], if missing, the time parameters of France have been used
Dam storage [24][58]	The ratio between the dam storage capacity [GWh] and the dam generation capacity [GW] has been computed for France [58]. Since dam storage capacity data was missing for other countries, the ratio computed was multiplied by the country-specific dam generation capacity [24]. This gave us an estimate of the installed dam storage capacity for each country
PV, CSP, wind onshore and offshore [17][24]	The country-specific installed capacities have been found on ENTSO-e [24] and are used in the model as the minimum installed capacities. For the maximum installable capacities, values were taken from estimates done by Dupont et al. [17]. These estimates are based on technical and geographical constraints and are further detailed in Section 3.2.
Hydro dam and Hydro river [24]	The country-specific installed capacities have been found on ENTSO-e [24] and are used in the model as the minimum installed capacities. Since hydro is already well developed in the EU, as explained in Section 3.2, the assumption was made that there was no additional potential.
Geothermal [13][24]	The country-specific installed capacities have been found on ENTSO-e [24] and are used in the model as the minimum installed capacities. For the maximum installable capacities, values were taken from estimates done by Chamorro et al-2014 [13]. These estimates are based on sustainability and technical constraints and are further detailed in Section 3.2.
Tidal [33]	The minimum installed capacity is set to 0 for each country and the maximum installable capacity has been taken from Hammons(2011) [33] which computed technically feasible projects in the EU. This is detailed in Section 3.2.
Biomass [7]	A new methodology is implemented to estimate sustainable wet biomass potential and cost on a country basis [7]. Complete methodology explained in 2.3

Table 2.13: Sources and methodology for country-specific miscellaneous data.

Chapter 3

Case Study

Chapter 2 discussed the methodology used to obtain and process energy data without actually discussing the said data. By using this data, this Section gives an overview on the energy state of play in Europe and shows how it differs between countries.

First, Section 3.1 describes and compares the EUDs of European countries by looking at the absolute value and its distribution between the EUTs. Then, in Section 3.2, renewable characteristics are compared between countries to quantify how wind and solar production behave within the EU. That Section also details the potential capacity of the different renewables that could be installed in Europe. In Section 3.3, this potential capacity is then combined to the capacity factors of each renewable discussed in Section 3.2 to obtain the renewable energy potential in the EU. Finally, Section 3.4 compares EUD and renewable potential to give a first overlook of which countries could have enough renewable energy potential to supply their demand in 2035.

3.1 Quantitative Comparison of Energy Demand across Europe

This Section studies the End Use Demand (EUD) across Europe. Although its absolute value changes drastically between countries, the share of each EUD, *i.e.* electricity, heating, mobility, cooling and non-energy, stays similar across countries. Additionally, the yearly demand profile of the EUDs are also covered.

The different EUDs are not directly comparable, e.g. demand in electricity is expressed in GWh_{elec} while demand in mobility is expressed in millions of passengerkilometres (Mpkm). With this in mind, it is however of interest to be able to classify the countries by total EUD and to compare the different EUDs to be able to put an order of magnitude on each of them[1]. This is why all EUDs are compared in GWh in the Figures of this Section. For electricity, heating and non-energy, the conversion is direct as we assume electrical or thermal GWh are directly transformed in GWh. A GWh of cooling, defined as the removal of 1 GWh of heat, is also directly converted in 1 GWh. Mobility EUD whose data is expressed in Mpkm and Mtkm in EnergyScopeTD are converted to GWh using a conversion factor detailed in Annex A.2.

Now that all EUDs are put into the same unit, comparison of data across Europe can be done. Figure 3.1 shows the agglomerated EUD for all countries studied sorted by size in 2035. It shows how much countries differ in absolute EUD. Massive countries such as Germany (DE), France (FR) or Italy (IT) clearly take the biggest share of Demand in Europe while most countries have an EUD between 50 and 500 TWh. This also shows a limitation of this work as countries like France are studied as a single block in the same way smaller countries like Luxembourg or Belgium are.

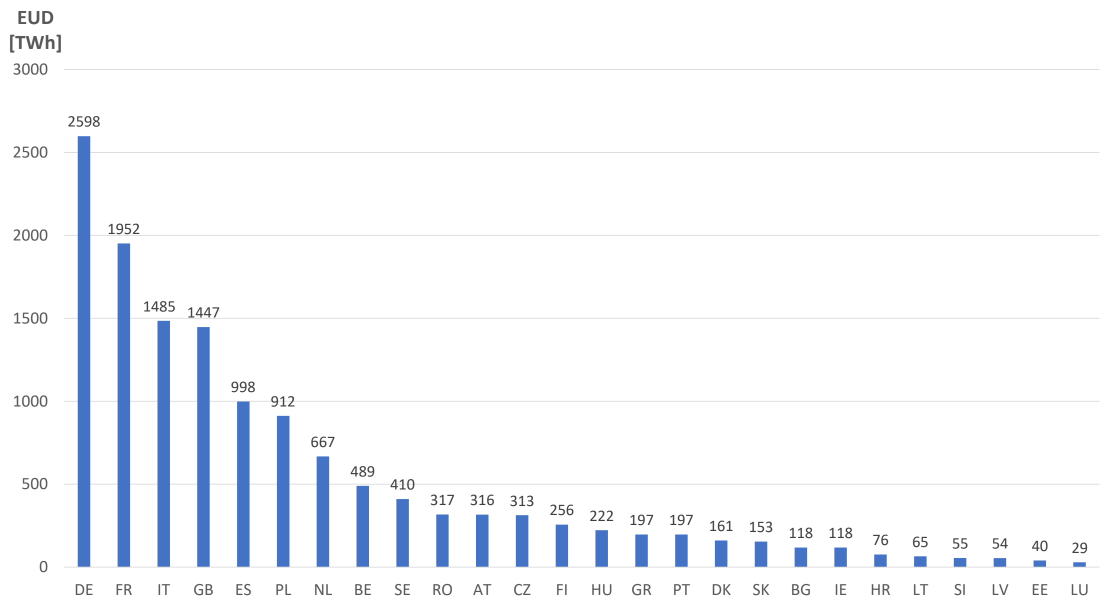


Figure 3.1: Sorted absolute EUD in Europe 2035. This EUD aggregates EUDs in electricity, heating, cooling, mobility and non-energy uses. See Table A.2 for numerical data.

[1]Note that the conversions to GWh are arbitrarly and are only used to compare the EUDs.

This paper also compares the different EUDs across the 26 studied countries. The respective share of each EUD, *i.e* electricity, heating, cooling, mobility and non-energy, is illustrated by Figure 3.2. In this comparison between EUDs, heating and cooling provided by electricity have been subtracted from electricity to be accounted for in heating and cooling as presented in Section 2.1. Doing that allows us to compare EUDs and not FECs. This is in line with previous studies like Connolly [15] where electricity, heating and cooling were also compared in Europe by EUD. Our study also includes process cooling which is a step up. Additionally, mobility and non-energy needs are also included to give a complete overview of EU demand in Energy.

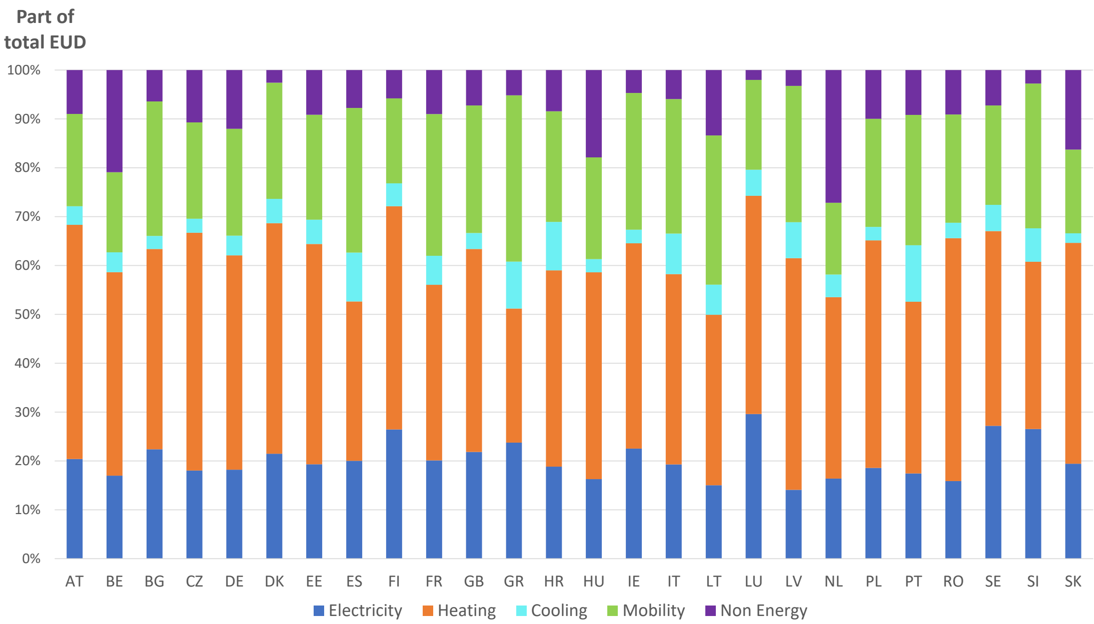


Figure 3.2: Relative representation of each EUT for European countries. Heating is the biggest demand in 25 out of 26 countries. Heating and cooling provided by electricity have been subtracted to the electricity part to be counted in heating and cooling such as presented in Section 2.1.

The results suggest that the heat demand (including space heating, hot water and process heating) is the largest of all demands for 25 out of the 26 studied countries. Greece is an exception since its demand in mobility is larger than its demand in heating. Surprisingly, cooling demand is never greater than heating demand. This goes against the common assumption that warmer countries like Spain, Portugal or Greece have a lower heat demand than cooling demand. Overall, heating represents 27% (Greece) to 50 % (Romania) of the total demand with 41%

of the total EUD on average. In comparison, cooling ranges from 2 % (Slovakia) to 12 % for Portugal with 5 % on average. This low value of cooling suggests that people are willing to live with the discomfort of an overheated house during the warmer months of the year as Werner suggests [68]. This demand may increase in the future as people seek higher levels of comfort. Conversely, heating is expected to keep decreasing as insulating improves.

Mobility is second in size in the EU with an average of 24 % for all countries combined. The highest share is Lithuania at 31 % while the Netherlands have the lowest at only 15 %. This low share for the Netherlands can be explained by its high non-energy demand therefore decreasing all other shares. Furthermore, mobility data [12] does not encompasses bikes although in countries like the Netherlands they provide a high share of the mobility.

Electricity is only the third highest EUD with 20 % on average in the EU ranging from 14% for Latvia to 30 % for Luxembourg. It is historically the most studied sector for an Energy transition but this data shows that enough attention should be put on the heating and the transport sector. In Chapter 4, we will see that a high electrification of both the heating and transport sector is foreseen as renewable electricity can be produced by a large variety of technologies. This will however lead to an extremely large increase of the FEC of electricity and could especially stress the electricity sector during winter period where heat demand is at its highest.

The non-energy EUD, which is all the energy being transformed in products (*e.g.* petroleum used for plastic bottles), is the most uneven sector among studied countries. With on average 10 % of the EUD in Europe, it ranges from 2% in Luxembourg to 27 % in the Netherlands and 21 % in Belgium. This high share for few countries can be explained by geographical and historical reasons.

To better illustrate how this demand is spread over the year, France EUD in 2035 is showed as an example in Figure 3.3. This Figure shows a high seasonality for both heating and cooling demands. At its peak during February, the heating demand is 3.1 times the electrical demand. As it is the peak demand that dictates the capacity that needs to be installed, an electrification with inefficient technologies like electrical heating could drastically increase the stress on the electrical grid. That is why more efficient technologies like heat pumps should be preferred instead.

Electrical EUD is rather constant over the year and is decreasing slightly during week-ends. Note that this lack of seasonality is only possible thanks to the methodology applied in Section 2.2.2 which removed the part of heating and cooling from the FEC of electricity to obtain the specific electricity TS.

Finally, although the mobility and non-energy EUDs appear constant over the year, only non-energy is really constant. Mobility only appears constant as this graph shows the daily averaged EUDs. Since it is assumed that each day of the year has the same mobility demand profile, the daily average will always be constant.

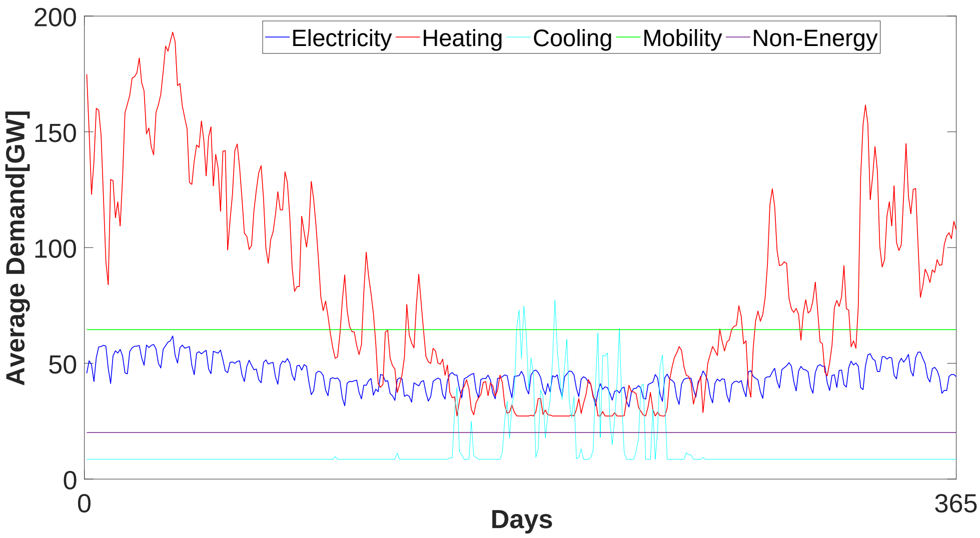


Figure 3.3: France EUD over the 365 days of the year in 2035. The EUD is averaged per day for reading purposes.

3.2 Renewable Energy Characteristics in the EU

This section aims at exploring the characteristics of the different renewables across the EU. It is for instance well known that Spain is sunnier than Finland but this section gives a quantitative answer to how much sunnier Spain is and with which yearly profile. The following renewable energies will be detailed : solar, wind, geothermal, tidal and hydro. For each intermittent (wind and solar related) technology, the profile of the capacity factor and the capacity factors across the EU will be shown. As a reminder, the capacity factor is the ratio between the actual production of the technology and the total installed capacity. These characteristics will be used by EnergyScopeTD to assess which technologies will be implemented into the energy system solutions.

3.2.1 Wind energy

Wind energy is one of the most well-known sources of renewable energy. This energy can be harvested both onshore and offshore. As the two categories have different characteristics, they are both described separately in EnergyScopeTD by a country specific TS (concept explained in Chapter 1). For wind, these TSs are based on real-time wind electricity production data for 2015 from ENTSO-E [24]. For the TSs that were not available on ENTSO-E, the data was taken from the MERRA-2 database [32] (Section 2.5).

Onshore wind production can be described by a monthly averaged capacity factor as shown in Figure 3.4. This Figure highlights the monthly capacity factor for 6 different countries across EU. It shows a strong seasonality for the production with a higher production towards the winter periods and a lower production towards the summer. This seasonality could be an advantage for systems with high energy demands (*e.g.* space heating) during the winter. Even though there is a seasonality, the production is almost never at zero as can be seen on the duration curve in Figure 3.5. A duration curve shows the variation of a load/production capacity in a downward way, the greatest production capacity is plotted at the left and the smallest production capacity is plotted at the right. Since the duration curve for onshore wind is always above 0, it means that there is always wind energy produced somewhere in the country. It can also be seen that the production is rarely very high or very low. The duration curves are different between the EU countries due to their various characteristics. They thus have different onshore wind TSs, this results in a difference of yearly averaged capacity factors for each EU country. This can be seen in Figure 3.6 which shows that the yearly averaged capacity factor, in 2015, ranges from 7 % to 35%. The nordic and the atlantic countries show the highest capacity factors thanks to their beneficial geography. When comparing the average capacity for whole Europe with a report from Wind Europe [69], the difference is very small, our average is at 23.5% against 24% for Wind Europe. This gives a high level of confidence with regards to the quality of onshore wind data.

Offshore wind features similar characteristics as onshore wind, however, it has a greater capacity factor than onshore wind. But even though offshore wind is a source with very good capacity factors for an intermittent renewable, not every EU country has the opportunity to harvest it. Since time series for Mediterranean countries were not found, only Nordic countries or countries with an Atlantic coast can implement offshore wind turbines as detailed in Section 2.5. For countries able to install offshore wind turbines, this gives monthly offshore capacity factors above 50% for the winter and above 20% for the summer (detailed in Annex A.1.3). On a yearly scale, their annual capacity factor, in 2015, ranges from 33% to 53%. This

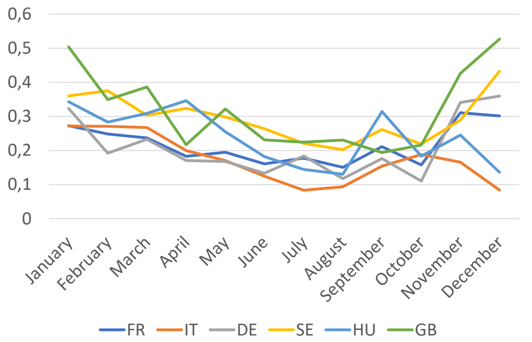


Figure 3.4: Monthly capacity factor for onshore wind production based on data for the year 2015 [24] [32].

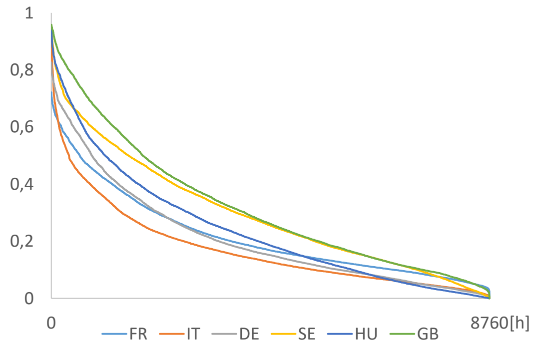


Figure 3.5: Duration curve of the onshore wind production based on data for the year 2015 [24] [32].

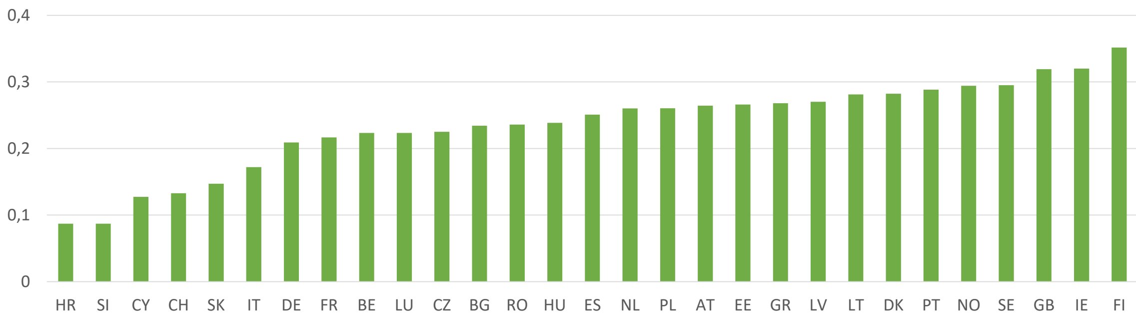


Figure 3.6: Yearly averaged onshore wind capacity factor for each EU country based on data for the year 2015 [24] [32].

gives us an averaged capacity factor of offshore wind production equal to 41.2% compared to a value of 38% from Wind Europe [69]. This leads to a moderate level of confidence concerning offshore wind data, as it might be slightly over-evaluated. This can be explained since most of the TSs for offshore wind production are based on the MERRA-2 database that uses a model to compute the theoretical TSs.

3.2.2 Solar Energy

Solar energy is a very abundant energy source in Europe as will be seen later in this chapter. This solar energy can be harvested thanks to its irradiance in two different ways. The GHI can be collected to produce electricity by PV panels or the DNI can be collected to produce heat, this heat can then be used to produce electricity thanks to CSP (as explained in Section 2.4.2) or to meet the heating demand thanks to solar thermal panels. Respectively, the production of the PV

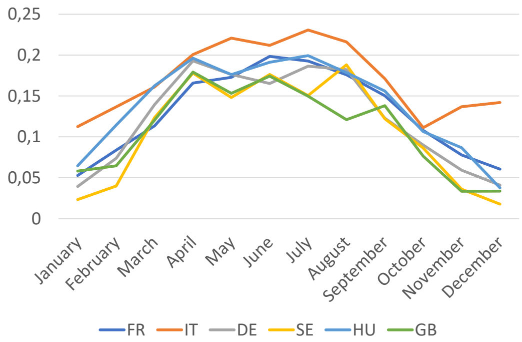


Figure 3.7: Monthly capacity factor for PV production based on data for the year 2015 [24] [42].

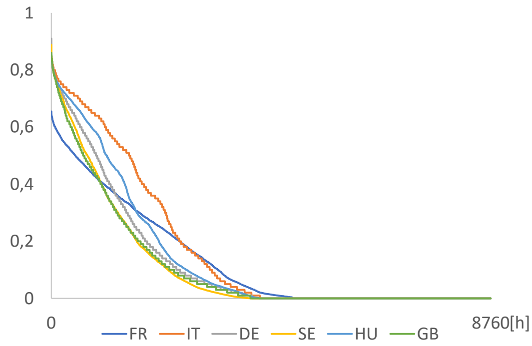


Figure 3.8: Duration curve of the PV production based on data for the year 2015 [24] [42].

panels is characterized, in the model, by a PV TS and the production of energy via solar thermal panels or CSP is characterized by a Solar thermal TS. The TSs are country specific and are based on ENTSO-E [24] data for PV or Joint Research Centre data [42] for both PV (when missing on ENTSO-E) and solar thermal.

Photovoltaic depends on the global irradiance of the sun, in other words, it means that when there is light thanks to the sun on the surface of the earth, PV panels will produce electricity. In Europe, summer days are characteristed by higher and longer irradiation than during the winter period. This can be seen in Figure 3.7 which shows the monthly averaged capacity factor for 6 different countries. This shows the strong seasonality of PV, for example, PV in France can have a capacity factor of 20% in the summer contrary to only 5% during the winter. Since PV depends on the irradiance of the sun, electricity can not be produced during the night. This explains the plateau observed in Figure 3.8 and explains why the PV panels do not produce any electricity during at least 50% of the year. The irradiance depends on the day/night cycle, the weather, but it depends also on the regions in Europe. Figure 3.9 illustrates this dependence by showing the yearly averaged capacity factor of PV. It varies from 9%, for northern countries as Finland and Estonia, to 21%, for southern countries as Portugal and Spain.

Solar thermal features the same characteristics as PV except that the solar thermal time serie is based on the DNI component of the irradiance instead of the GHI for PV (as explained in Section 2.2.3). This means that for very cloudy days, there is no solar thermal energy production, and for very sunny days, the production is at its highest. Solar thermal has the same seasonality as PV, but since very cloudy hours do not result in energy production, the averaged capacity

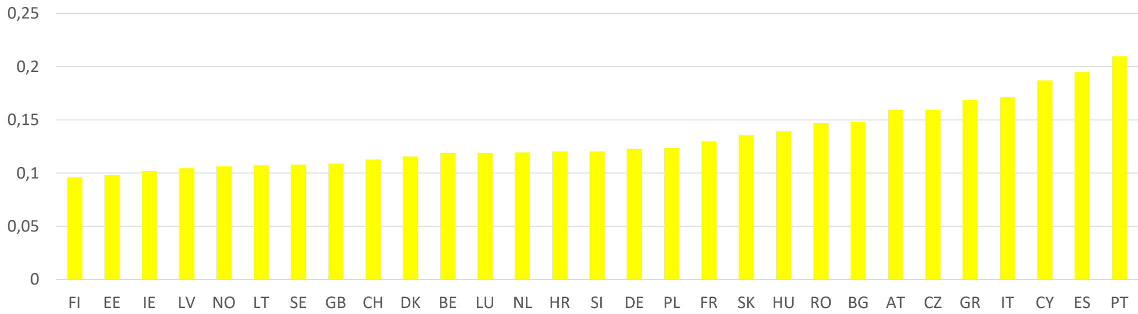


Figure 3.9: Yearly averaged PV capacity factor for each EU country based on data for the year 2015 [24] [42].

factor should be lower than for PV (detailed in Annex A.1.3). This results in a yearly averaged capacity factor that ranges from 6.3% to 19.3% in the EU.

3.2.3 Maximum Installable Capacity of Renewables in Europe

EnergyScopeTD takes a whole set of technologies into account and part of them are renewable technologies. Of course these renewable technologies have an upper limit of installable capacity, *e.g.*, it is not realistic to cover the whole area of a country with PV panels, neither it is to put wind turbines where there is very little wind. This is why EnergyScopeTD needs an upper limit for the capacity it can install. This upper limit on the capacity does not apply to biomass since biomass is not restricted by the installable capacity of the power plants but is limited by its primary sustainable resource availability, already discussed in Section 2.3. This Section aims at explaining the origin of the installable capacities. In this study, there is a limit to the maximum capacity for the following technologies : PV, CSP, onshore wind, offshore wind, hydroelectric plants, tidal generators and geothermal electricity generators. Note that this study does not put an upper limit on the solar thermal panels [2] capacity due to a lack of solid data. This same reason enforces the upper limit for the geothermal heating capacity installable to 0 in our model. The maximum installable capacity for each technology will then be used as an upper bound in the model.

PV, CSP, onshore and offshore wind installable capacities have been computed by Dupont et al. [17] by applying constraints in order to obtain a realistic upper bound. This has been done for wind (onshore and offshore) and solar (PV

[2] As a reminder, this technology transforms irradiance of the sun into low temperature heat.

and CSP) power capacities in the EU. Dupont et al. splitted the countries of the EU in cells and each cell is assessed by a geographical suitability factor. This factor depends on energy return on investment(EROI) and geographical constraints, and determines the fraction of each cell that is best suited for each renewable technology. From this methodology, maximum installable capacities can be obtained for each technologies and are used as upper limit for this study. Since this study does not take into account that CSP and PV can not be installed at the same place, and that the requirements to install CSP are way stricter than the requirements to install PV, the upper limit of CSP is subtracted from the upper limit of PV to obtain a new PV limit. This means that the areas where both PV and CSP capacities could be installed will only be available for CSP in this study. In that way the upper limit for both technologies will not overlap. Later in Section 4.2, the results show that this methodology is coherent with the results since the majority of the systems rather install CSP before installing PV.

Geothermal electricity installable capacities are based on the values from Chamorro et al. [13], this article estimates the technical and sustainable capacity potentials in Europe for the Enhanced Geothermal Systems[3] (EGS). This technology is projected to be the most installed geothermal system in 2050 [13]. The sustainable capacity potential, in this article, is defined as "the fraction that can be used under sustainable production criteria" and will be used as upper limit for the geothermal electricity production in this study.

Tidal installable capacities implemented in the model are the results of a study made by Hammons 2011 [33]. These results are based on a parametric approach that assesses all reasonably exploitable sites within the EU with a mean range above three meters. Thus this gives the technically available tidal energy potential and the installed capacity needed to harvest this energy. The technical installable capacity from Hammons 2011 is taken as the upper limit for tidal generators in this thesis.

Hydroelectric installable capacities are taken from the ENTSO-E database [24]. The maximum installable capacity has been limited to the actual installed capacity for each hydroelectric technology. This is done because the majority of favourable large hydropower sites are already being exploited in the EU as explained by the European Commission [62].

[3] "Enhanced geothermal systems aim to exploit the widely available hot rock resources, where insufficient water exists and/or permeability is low. The process implies enhancing permeability by opening pre-existing fractures in the rock or creating new ones." [13].

Resulting from all these papers, the total installable renewable capacity is obtained and shown in Figure 3.10. Since this does not take into account solar heating panels and geothermal heating systems, all the renewable shown produce electricity. The two main capacity potentials in the EU are the solar related and wind related technologies. However this does not mean that these technologies will be the most used in the systems, it simply shows the capacity that could be installed. It is also important to remember that renewable technologies like hydro, tidal and geothermal have important advantages compared to intermittent sources like solar and wind energy. Hydroelectricity made by the rivers can easily be forecasted and is generally not considered to be an intermittent source of power thanks to its dependence on the water flows. Hydro dams feature the same advantages as the hydro river technologies, except that it also has the ability to store water in its reservoir and to release it whenever energy is needed. Geothermal energy production has also the great advantage of being a constant source of power as shown in Section A.1.2. For tidal energy production, this can easily be forecasted by looking at the tides.

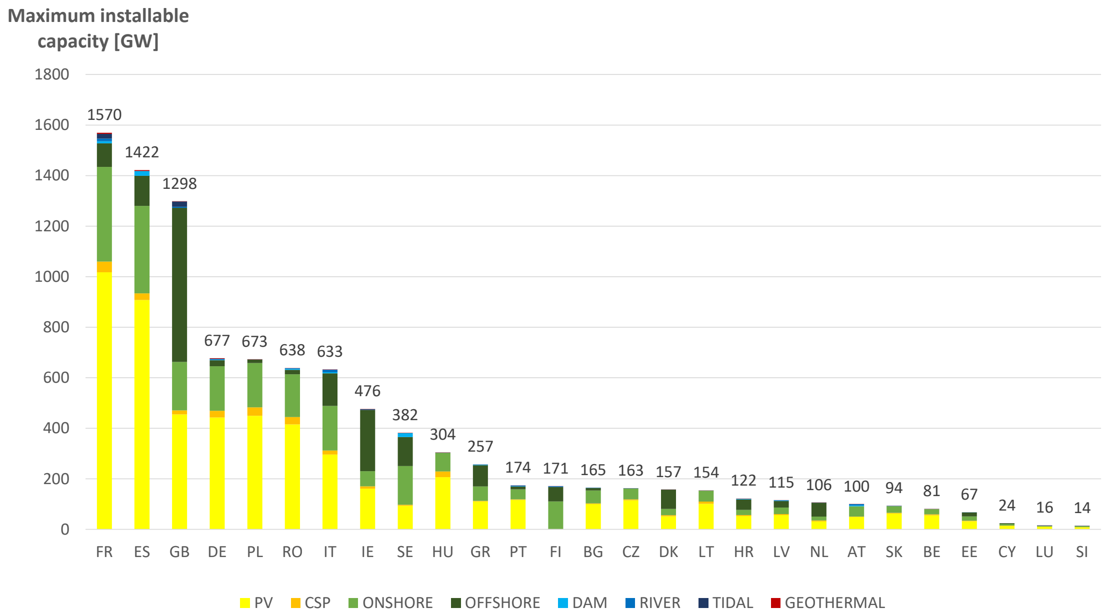


Figure 3.10: Maximum installable capacity for renewable energy across Europe [17] [24] [13] [33]. See Table A.3 for numerical values.

3.3 Quantitative Estimate of Renewable Energy Potential in Europe

In order to evolve to sustainable energy systems that are based on renewable energy, it is important to assess the Renewable Energy Potential (REP). In the scope of this study, this has been evaluated for each country in Europe. The renewables that are taken into account here are the same as in Section 3.2 with the addition of biomass resources.

The different REPs, except biomass, are computed thanks to the country specific characteristics detailed in Section 3.2. This is done, for each renewable except biomass, by multiplying the maximum hourly production by the sum of the hourly capacity factors (also known as the TS) over the whole year. This is shown in Equation 3.1. For biomass, the sustainable energy potential is not estimated in the same way since the limiting factor is the primary biomass energy available and not the installable capacity. This sustainable biomass energy potential has already been discussed and detailed in Section 2.3. Note, and this is important, that the biomass energy potential is expressed in terms of primary energy, this means that if 1 TWh of biomass energy potential is used in a power plant with a 40% efficiency, the output will be 0.4 TWh. The reason behind this is the flexibility of the biomass resources which can be used for different purposes (heating, gasification, etc..) that all have different efficiencies. This is not the case for the other renewables taken into account in this study, they all produce electricity. Their potential is thus measured in terms of output energy meaning that the efficiency of the technology is already taken into account.

$$\text{REP [TWh]} = \text{Maximum hourly production [TWh]} \cdot \sum_{h=1}^{8760} \text{capacity factor} \quad (3.1)$$

By summing all those potentials, the total renewable energy potential is obtained for each country as shown in Figure 3.11. It can be seen that solar (PV and CSP) and wind (onshore and offshore) potentials are the two biggest energy potentials amongst renewables in Europe. However these are also the two most intermittent sources of energy with the exception of CSP. Indeed, CSP plants are implemented with a storage unit (see Section 2.4.2) and can thus decide when to release the energy to the grid. It can be seen in Figure 3.11 that northern countries and countries at the Atlantic have a great wind potential, and that southern countries have a high share of solar potential. Of course, the renewable energy potential increases with the size of the country.

The third biggest energy potential in Europe comes from biomass (wood + waste + wet biomass) which has a big advantage over the intermittent sources by offering flexibility to the system. The system can choose when to use the biomass energy. As for the other renewables, they also have the advantages detailed in Section 3.2. Finally, it is important to remember that Figure 3.11 shows the total potential per country for each renewable. It is not because the share of a renewable is small in a country that it is negligible or useless, *e.g.*, the relative share of hydro in France is pretty small but it will play a big role in the energy transition of France as will be seen later in Section 4.3.3.

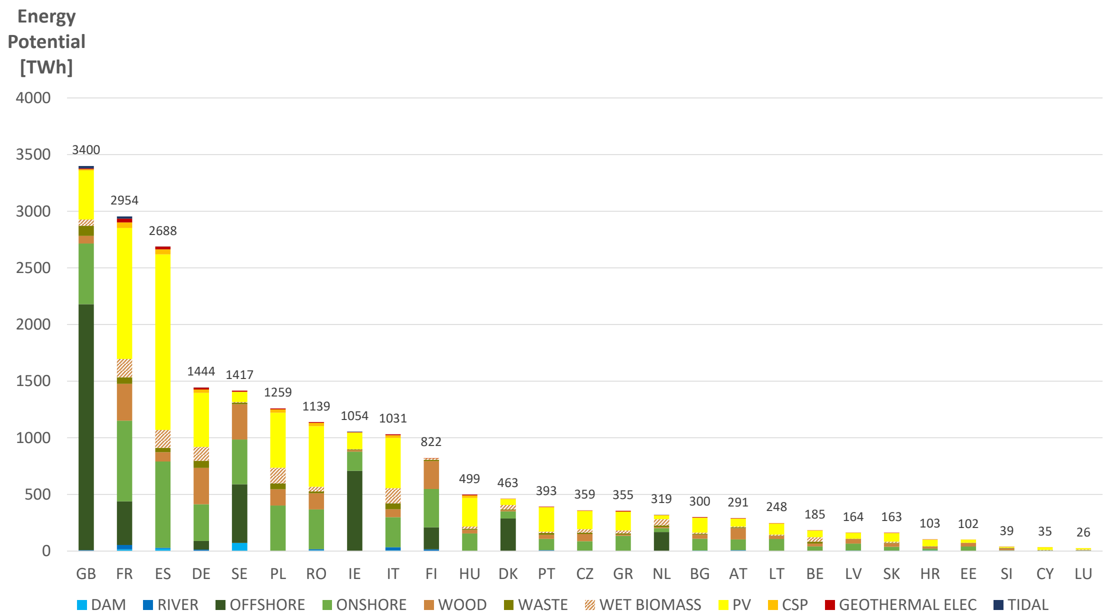


Figure 3.11: Renewable energy potential [TWh] in Europe based on the values of Section 3.2. See Table A.4 for numerical values.

3.4 Quantitative Comparison between Potential and Demand

For European countries to be autonomous, they need to be able to provide their demand with the REP available within their borders. One first step to comprehend which countries will be able to be fully renewable is to compare directly their energy demand and their REP without looking the system that links the energy resources to the EUD. To do that, a new key performance indicator R is introduced which is the ratio between all the renewable energy potential of a country divided by the total EUD of a country. This ratio is described by Equation 3.2. The REP is expressed in TWh and its calculation is explained in Section 3.3. The total EUD is also expressed in TWh and its calculation is explained in Section 3.1.

$$R = \frac{\mathrm{REP}}{\mathrm{EUD}} \tag{3.2}$$

Note that R inferior to one does not necessarily mean that the country can not reach energy autonomy as a few technologies, like Heat Pumps with its COP > 1, can increase the efficiency of the energy system and therefore allow a system with less resources than demand to still provide that demand. Similarly, a R superior to one does not imply that an energy system will be able to provide its demand as there are technologies with efficiencies below 1, *e.g.* biomass technologies and losses in the system, *e.g.* grid losses or heat losses in a district heating network. With this in mind, R still allows us to understand which countries could be energetically independent and which ones can definitely not. Note that these results for R are obtained under the assumptions made in Section 3.1 and Section 3.3. For a few countries R does not allow to assess if they can be energetically independent and an energy system study is required. Chapter 4 will detail this energy system study.

Figure 3.12 highlights the availability of renewable energy compared to the EUD. It shows R sorted from countries with most relative renewable potential to countries with the least relative amount. They are categorised in 3 sets. A first one for countries with $R > 1.2$ which are assumed to be able to fulfill their energy needs with their energy potential and probably even export. A second one with for countries $R < 0.8$ that will probably not be able to fulfill their EUD[4]. And finally a last category for countries with $0.8 < R < 1.2$ for which energy independence might be possible but challenging. Note that the limit between the categories is rather arbitrary and is only a tool to get a clearer idea of the overall situation in Europe.

An encouraging result is that 15 countries in Europe out of the 26 studied (58 %) belong to the first category and have significantly more REP than total EUD. Moreover, taking the combined REP and combined EUD of all countries for an agglomerated EU, R= 1.56 is obtained. This means that overall the EU has significantly more renewable resources than the total energy demand in 2035. However, the energy demand should remain under control for energetic independence to remain possible.

[4]Further analysis shows that indeed those 5 countries are the only ones that can not reach independently carbon neutrality.

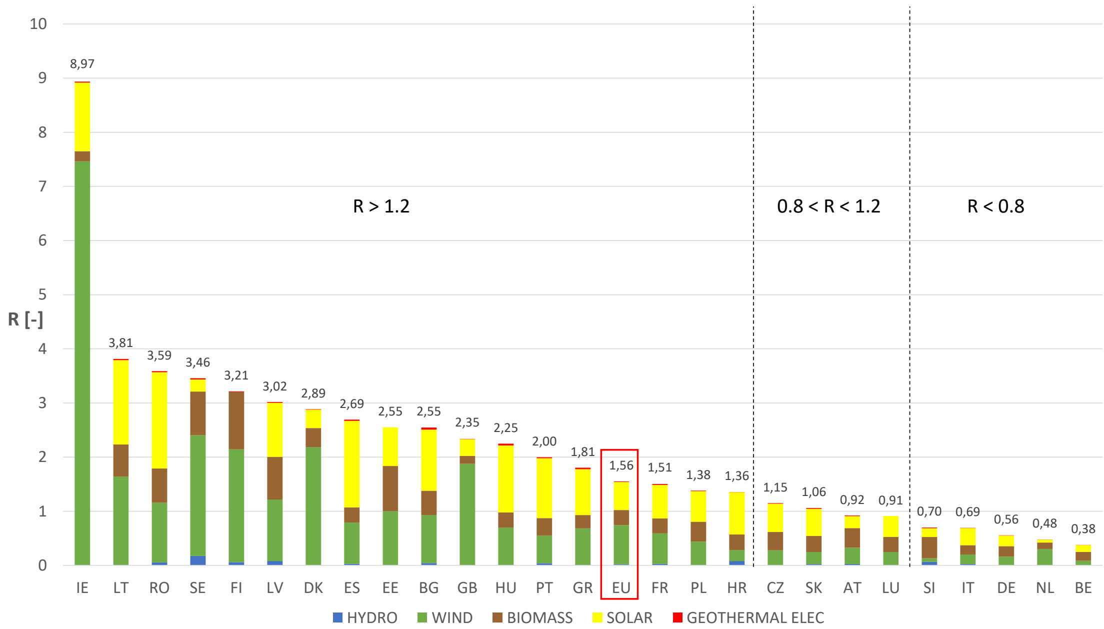


Figure 3.12: Renewable Potential to Total EUD Ratio R. Most European Countries have enough renewable potential to be fully renewable but for some countries energy independence is not possible. Overall, the EU has 1.56 times more renewable potential than EUD.

A less encouraging result is that 5 countries have significantly more demand than energy potential. These countries are Slovenia, Italy, Germany, the Netherlands and Belgium. These countries will most likely not be able to fulfill their total EUD with the energy potential on their territory. These 5 countries combined represent 38 % of the total demand for 34 % of the total population. Their demand is therefore not disproportionately high. However, the high share of non-energy for the Netherlands and Belgium discussed in Section 3.1 does not make sense from an energy point of view since there is a lack of REP in these countries.

Moreover, countries with poor R are located close to each other as illustrated on Figure 3.13. For these countries, this means that not only they lack resources, but most of their neighbouring countries do too. A fully renewable Europe will have to find clever ways to bring renewable energy from the periphery of Europe to its core. This may prove challenging as grid losses increase with distance and as biomass resources have a low energy density which makes them poorly suited for transportation. Possible solutions may come from Synthetic Liquid Fuels (SLF, still underdeveloped in EnergyScopeTD) or better inter-connectivity between countries but this is beyond the scope of this thesis.

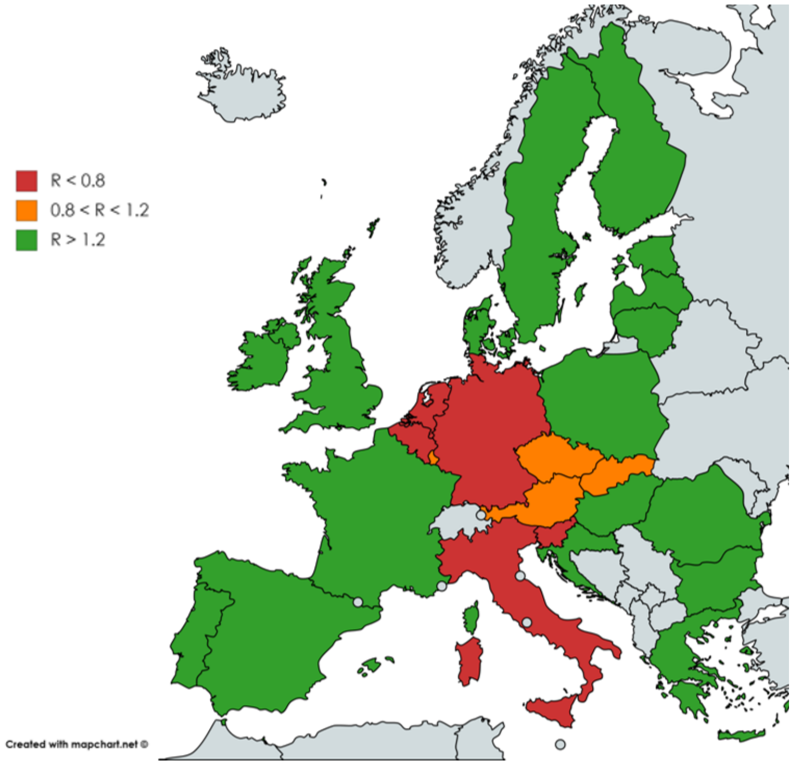


Figure 3.13: Geographical mapping of the R ratio in Europe. A fully renewable EU will need energy exchanges from its periphery to its core.

Chapter 4

Results

This Chapter show how the expansion and generalisation of EnergyScopeTD to the whole EU are utilised. EnergyScopeTD is used to determine for each country if the Renewable Energy Potential described in Section 3.3 is sufficient to meet the country EUD described in Section 3.1. First, in Section 4.1, the energy system for each country is optimised in cost without any constraint on Global Warming Potential (GWP). The goal is to observe which energy systems countries naturally tend to with only a cost-incentive. It also gives a benchmark to compare it with the minimal GWP solution. Then, in Section 4.2, EnergyScopeTD is used to determine which countries can reach null net emissions independently. Primary Energy Mix, cost and renewable energy potential still available after cost-optimisation at minimal GWP are also discussed. Finally, Section 4.3 illustrates a more in depth study of France to illustrate how a fully renewable system behaves and how it could deal with renewable intermittency.

4.1 Cost-Optimised Solution

The first main results the newly built database can give are the energy systems in cost optimised condition. This section will present the set of results obtained when optimising the cost of an energy system directly from the database without any constraint on the GWP. This solution is useful to understand which solutions are the most competitive but also proves itself useful as a point of comparison for the minimum GWP scenario presented in Section 4.2.

The energy mix of the cost-optimised solution is shown in Figure 4.1 for each country. It illustrates the share of each primary resource used in the different systems. These systems are categorised using the ratio R introduced in Section 3.4 and the renewables used to their maximum potential are striped. The first encouraging sign is that renewables are used in each country for cost optimal solutions. In fact, the major part of the energetic mix of the EU[1] comes from renewables, covering 55% of the primary resources used. The second encouraging sign is that the cost optimised EU only contains a 14.7% share of emission intensive resources (natural gas, coal and imported electricity[2]) in their energetic mix.

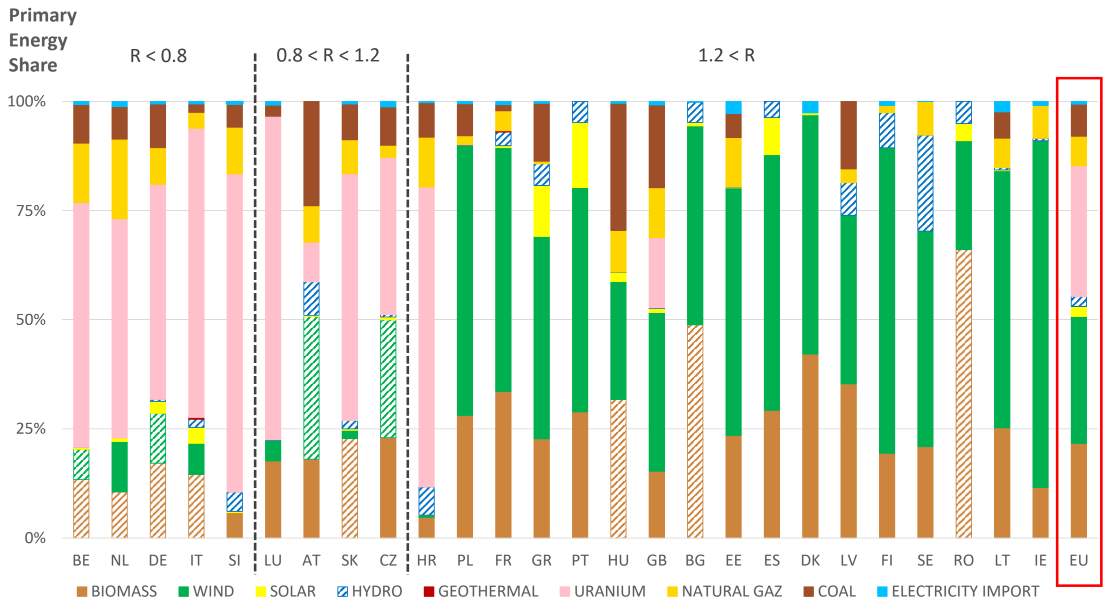


Figure 4.1: Energetic mix of the primary energy resources used for the cost-optimised solution for each EU country. The bar of a renewable is striped when the country uses the maximum potential of the resource. Countries have been categorised by their R ratio as defined in Section 3.4.

Figure 4.1 also shows that some countries already use the maximum energy potential of some of their renewables. This is the case for biomass, wind and hydro energy. The saturation of the hydro potential for each country can be explained by the inputs of the model since it is assumed that EU is already exploiting all the hydro potential [62]. Wind and biomass are the most competitive resources and are therefore implemented for the great majority of the countries. It is important to stress that the competitiveness of renewables is dependent on the country as capacity factors and TSs vary between countries as discussed in

[1]Remember that Cyprus and Malta are not taken into account since too much data was missing.

[2]As implemented in the model, import of electricity has an emission of 0.48 $ktCO_2/GWh$ compared to an emission of 0.266 $ktCO_2/GWh$ for natural gas.

Section 3.2 and that the biomass prices change between countries as seen in Section 2.3. As for solar energy[3], it proves to be only competitive for countries with a lower latitude, *e.g.* Spain or Greece. Note that it is imposed that each country implements at least the same capacity of renewables (for PV, CSP, geothermal electricity, onshore and offshore wind turbines) as already installed in 2020 even though these technologies may not be competitive in some countries. This can explain why countries like Belgium or the Netherlands have such a small share of solar energy, and why countries like Slovakia contain a very small share of wind energy.

By categorizing the countries based on their R ratio (defined in Section 3.4), trends can be outlined. All the countries with a R smaller than 1.2 use uranium in their energy mix as nuclear is a cost-competitive solution for countries with a low R. These systems also use fossil fuels as they have to counterbalance the intermittency of energy production (solar and wind). As discussed later in Section 5.2, fossil fuels are less competitive than wind but more than solar in most countries. Their main use is for flexibility in production. For the 17 countries with a R above 1.2, it can be seen that the majority greatly benefits from their renewable potential (mainly wind and biomass energy). For four of them, the cost-optimised solution is even made out of 100% renewable. Only 2 of these 17 countries implement nuclear for the cost-optimised solution, but nearly all of the 17 countries have to use fossil fuels in order to counterbalance the intermittency. This is done by burning these fuels when the energy demand can not be met with renewables. Note that the solar energy shares have some flexibility when CSP are installed as high temperature storage is included in them (see Section 2.4.2). To summarize, cost-optimised systems prove that, with a good hourly strategy, renewables can be cost competitive and provide a high share in the energetic mix of most countries.

As seen in Figure 4.1, the primary resources used in the energy systems vary a lot for the cost optimised solution. As a consequence of this, the Global Warming Potential (GWP) varies in different countries accordingly. This is illustrated in Figure 4.2 where yearly GWP of each country is associated to their yearly EUD. Each point represents the cost-optimised energy system for the country studied. There is naturally a trend linking increase in EUD and increase in country emissions as some part of the total EUD is met by fossil fuels utilisation. However, higher EUD does not necessarily mean higher GWP. Spain is the best example of this as while having the 5$^{\text{th}}$ largest EUD, it has emissions similar to much smaller countries like Croatia. Similarly, although Belgium has only a quarter of France EUD, Belgium has the same GWP as France. Consequently, CO_2 emissions are not directly correlated to EUD. This was expected since the main driver of CO_2

[3]Composed not only of PV but also of CSP.

emissions is the utilisation of fossil fuels which differs significantly between countries in a cost-optimised solution.

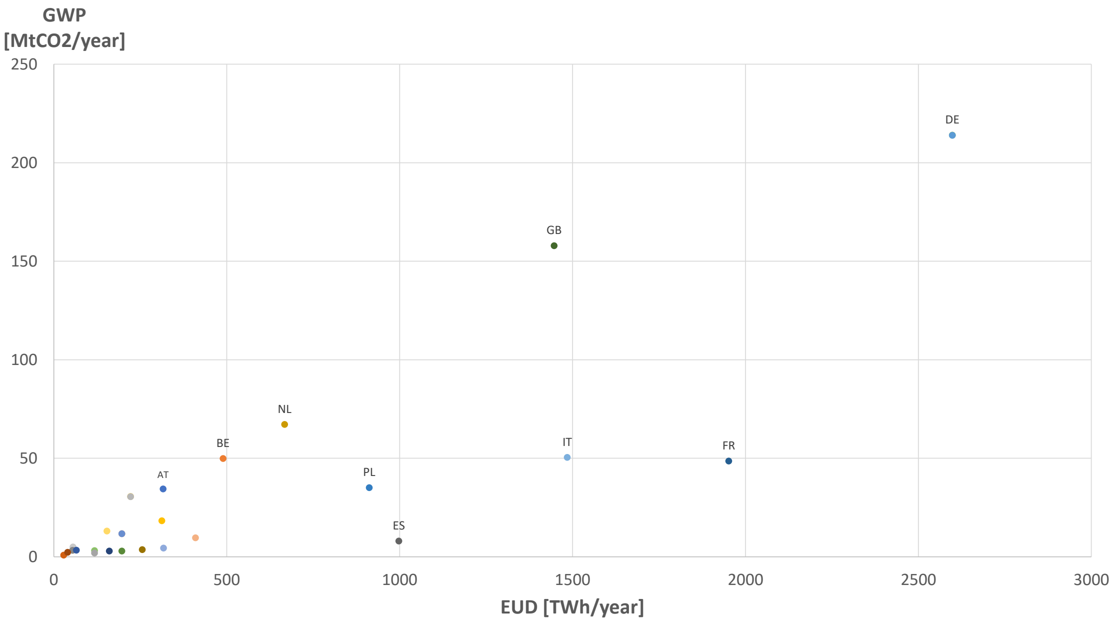


Figure 4.2: Cost-optimised solution in 2035. CO_2 Emissions are not directly correlated to a country EUD.

Conversely, cost and EUD are nearly linearly correlated as Figure 4.3 illustrates. Although resources and technologies used change abundantly between countries, the overall cost per EUD remains extremely stable across all countries. In fact, the correlation found is linear and one can directly predict the cost of an optimised system regardless of the composition of its demand or its resources by using Equation 4.1. Furthermore, a major conclusion from this graph is that there is not a specific set of technologies that gives the best price but rather a range of different solutions that give similar overall price. For some countries, a 100% renewable solution is already the cheapest option. Moreover, countries should consider reducing their demand as this mechanically reduces the price of their energy system.

$$\text{Cost [B€]} = 0.03518[\frac{\text{B€}}{\text{TWh}}] \cdot \text{EUD [TWh]} \tag{4.1}$$

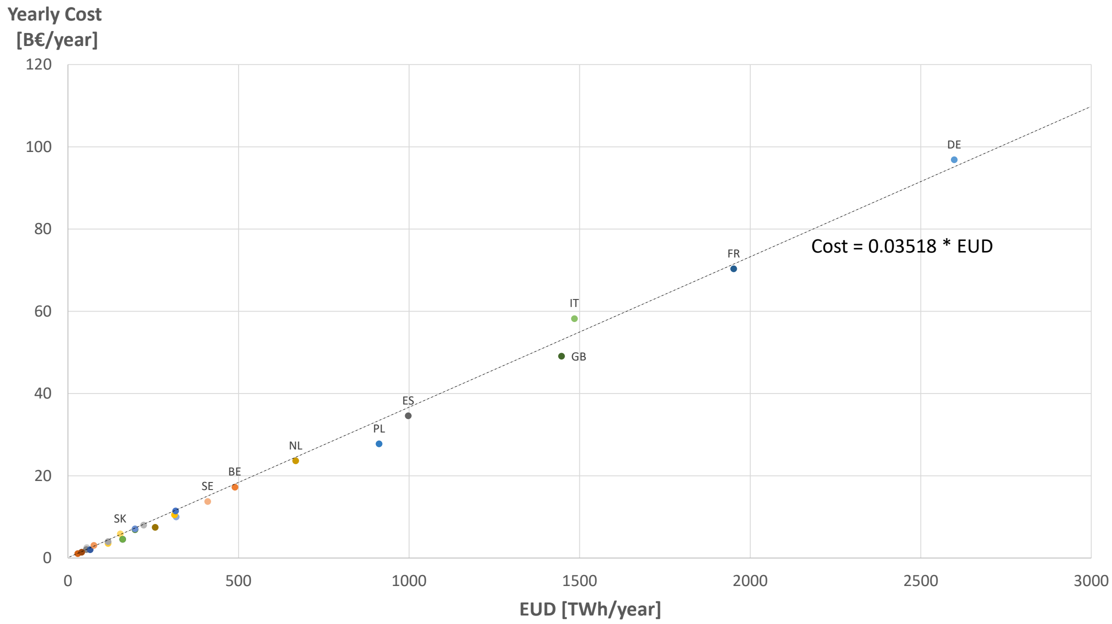


Figure 4.3: Cost-optimised solution in 2035. There is a strong correlation between a country optimal cost and its EUD.

4.2 Minimum GWP Solution

In this paper, one of the main objectives is to determine which countries can reach carbon neutrality whilst only using the resources available on their territory. To achieve this objective, cost is optimised with a constraint of null net yearly GWP. Biomass and waste emissions are set to 0 as the potential considered is sustainable and therefore the few GHG it emits during its life cycle can be neglected. As both nuclear and electrical imports are allocated emissions, they are absent in the solutions. This is also due to the scope of this study focusing on countries taken individually and to the fact that the uranium production and reserves in Europe are extremely low [55][1]. For Belgium, the Netherlands, Germany and Slovenia, this problem is not solvable. This means that no matter the cost, they can not reach energy independence.

For these countries an other methodology is used which is to impose maximum utilisation of their renewable potential. That is imposing maximum capacity of PV, solar towers[4], wind turbines and geothermal while imposing maximum utilisation of biomass potential. Additionally, coal utilisation is forbidden as it is the fossil causing the most GWP. Nevertheless, electrical imports, natural gas and nuclear

[4] Solar towers are implemented in EnergyScopeTD as the most cost-competitive CSP technology.

are allowed for these 4 countries. The cost-optimised energy systems for countries with null net emissions and the four others with highest possible share of renewables are later referred to as minimum GWP solutions.

To assess if the EU countries can rely entirely on their renewable energy potential, the resources used for the minimum GWP solution are analysed. This can be seen in Figure 4.4 for the 26 countries studied. As in Section 4.1, the countries have been categorised based on their ratio R detailed in Section 3.4. The resources being used to their maximum potential have been striped in order to evaluate which resources are seen as most optimal by the model for the different countries. Remember that the hydro potential is considered to be fully used due to its implementation in the model explained in Section 3.2. Figure 4.4 is pretty encouraging since 22 out of the 26 countries succeed in implementing a 100% renewable system.

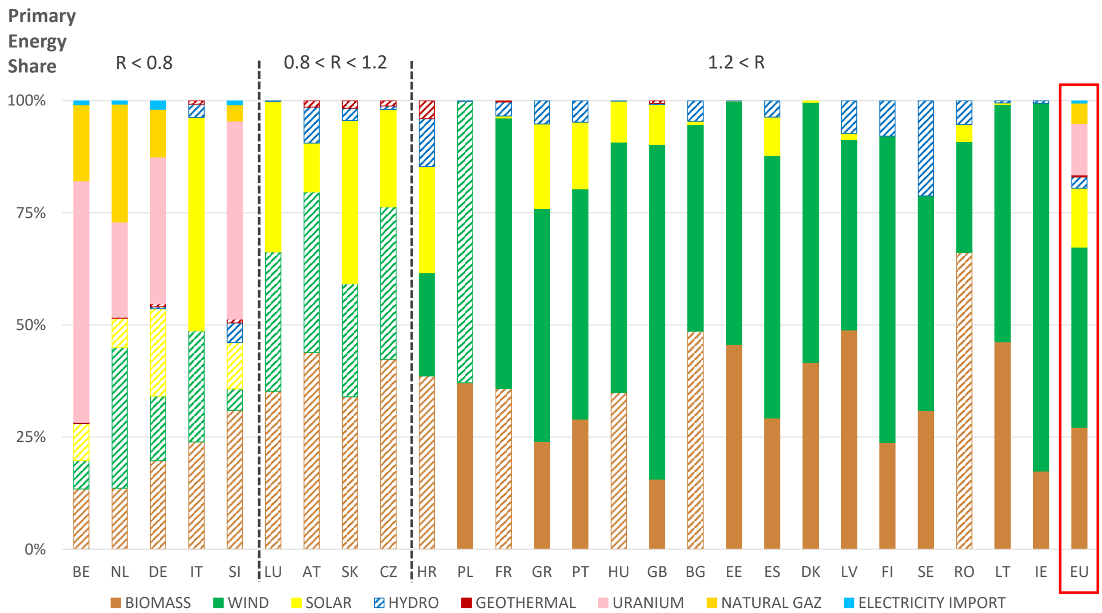


Figure 4.4: Energetic mix of the primary energy resources used for the minimum GWP solution for each EU country. The bar of a renewable is striped when the country uses the maximum potential of the resource. Countries have been categorised by their R ratio as defined in Section 3.4.

Only four countries (Belgium, the Netherlands, Germany and Slovenia) are not able to reach the 100% renewable scenario by only utilising their own renewable energy potential. It can be seen that by pushing the renewables to their maximum for these four countries, the share of renewable in the primary energy mix ranges from 28% for Belgium to 54.7% for Germany. These systems supply the remaining part of their energy by using nuclear energy, natural gas and electricity imports. Since nuclear energy is a low-carbon technology, the GHG emissions in the minimum GWP scenario should mainly come from the natural gas used in the four countries mentioned before. All of this results in a total share of renewable of about 82% for the EU, and only 5% of the mix coming from emission intensive resources (natural gas and import electricity[5]). This is of course an improvement from the 55% renewable share and the 15% emission intensive resource share for the cost-optimised EU.

As seen in Section 3.3, the major part of the renewable potential in Europe comes from wind and solar energy, however, this does not mean that they will be the most competitive or the most used in the solutions. Figure 4.4 shows that the biggest primary energy share in the EU comes from wind energy (39.3%), the second and third biggest are coming from biomass (27%) and solar energy (13%). Hydro and geothermal account for, respectively, 2.5% and 0.5% of the primary energy mix. These shares can partially be explained by looking at the trends resulting from the categorisation of the countries in function of their ratio R. A complete explanation would require a more in depth study for each country which is beyond the scope of this thesis. It can be seen that each country with a R below 0.8 pushes all the renewable potential to their upper limit, except for solar energy in Italy. Italy is particular as it is able to achieve a 100% renewable energy system with a $R < 0.8$. This is resulting from the use of 12 TDs to represent the year as it will be explained later in this Section.

For the countries with a $R > 0.8$, it seems always possible to have a fully renewable scenario by mixing a diversity of renewable technologies. Countries with a R around 1 usually take profit of their maximum potential of biomass, wind, hydro[6] and geothermal energy. If these renewables can not deliver enough energy, the system will turn to solar energy for the remaining energy demand. For the remaining systems with a R ratio above 1.2, the main resources used are biomass and wind as they prove to be the most competitive. Note that solar energy can still be part of the optimal system as some countries have great sun irradiance and are installing the upper limit of the CSP technology, *e.g.* Greece. This is due to the storage CSP can provide thus making the solar production more flexible than for PV panels. As for geothermal energy, it is most of the time not competitive

[5]As implemented in the model, import electricity has an emission of 0.48 $ktCO_2/GWh$ compared to an emission of 0.266 $ktCO_2/GWh$ for natural gas.

[6]In this study, Hydro is considered to already use its maximum potential in 2020 (see Section 3.2 for more details).

compared to the other renewables.

To summarize, wind energy and biomass are the most used resources and they are used at their maximum potential: 14 out of the 26 countries use all their sustainable biomass potential and 10 out of the 26 countries use all their wind energy potential. The maximum hydro potential is used for each country as it is assumed that the EU is already exploiting its maximum potential in 2020. Finally, the minimum GWP solution for the EU uses each renewable[7] as they all have advantages but for four countries, the total renewable potential is not big enough to supply the whole energetic demand. These countries will have to seek help from other countries in order to make a 100% renewable EU.

As the minimum GWP solution adds a GWP constraint over the cost-optimised solution, the price increases mechanically but remains under control. Figure 4.5 illustrates the cost of energy systems with minimal GHG emissions. Although the linearity is less apparent than in Figure 4.3, the correlation between cost and EUD remains strong. The slope of the line is obtained by computing the average of the specific price of energy over the EU countries without considering the size of each country. This slope is now of 0.03853 B€/TWh which is only a 9.5 % increase compared to the optimal cost solution. Note that this increase means that, on average, the price of energy (B€/TWh) for a specific country in a minimum GWP scenario will cost 9.5% more than the price of energy for that country in a cost-optimised scenario.

This leads to the computation of the relative additional cost for each country of implementing the minimum GWP solution compared to the cost-optimised solution. Obviously, the additional cost for each EU country will be different due to their different characteristics (detailed in Section 3.2). This additional cost is shown in Figure 4.6. The minimum GWP scenario would lead to a 8.6 % total overcost for the EU compared to the cost-optimised solution. This is well to be distinguished from the 9.5% country averaged cost increase obtained earlier since the total relative additional cost (8.6%) was computed by taking the size of the systems into account. By agglomerating all the countries, the total cost goes from 483.2 B€/year , for the cost-optimised solution, to 524.8 B€/year, for the minimum GWP solution[8]. This results in a total additional cost of 41.5 B€/year. This represents only 0.19% of the 2035 forecasted GDP for the agglomerated EU [12].

[7] Except tidal which is never used.

[8] To put into perspective, 483.2 B€/year and 524.8 B€/year represent, respectively, 2.3% and 2.5% of the 2035 forecasted GDP for the agglomerated EU [12].

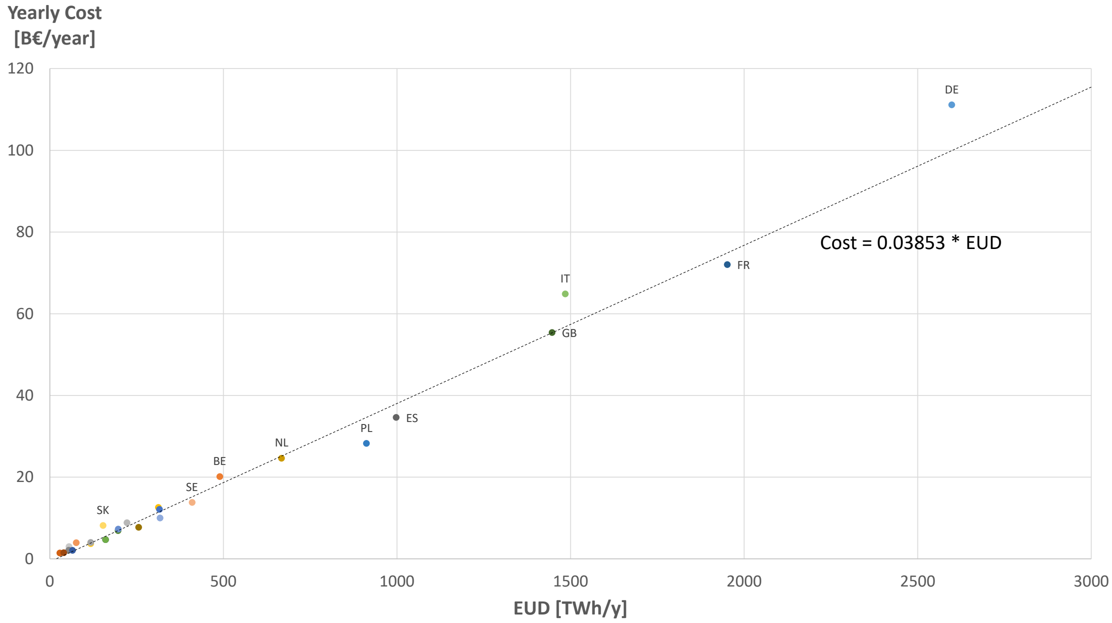


Figure 4.5: 2035 Cost-optimised solution for countries with minimal GWP. The yearly cost increases only by 9.5 % compared to cost-optimised solution.

Figure 4.6 also shows that countries with a low R ratio (as seen in Section 3.4) have, on average, a higher additional cost than the ones with higher R ratio. Note that for countries with a R lower than 0.8, the overcost is not the highest in the EU since these countries can implement cheap non-renewable technologies. The variation in additional cost mainly depends on the quality of the renewables that the systems have to install. This quality is determined by the country's specific characteristics of each renewable described in Section 3.2, *e.g.* the capacity factor. Furthermore, this capacity factor used by EnergyScopeTD can be biased due to the use of Typical Days as will be detailed later in this Section. Finally, the fully renewable scenario of the EU results in a global GWP of 175 $MtCO_2$/year compared to a global GWP of 806 $MtCO_2$/year obtained for the cost optimised solution (as seen in Section 4.1) and this GWP reduction would only cost 8.6% more than the cost optimised scenario at the EU scale. For comparison, in 2017, the EU emitted 4483 $MtCO_2$/year [23], including non-energy related emissions not accounted for in this study.

It has been seen that even while using the maximum of their renewable energy potential, it is impossible for 4 countries to reach energetic independence and null net emissions. However, the 22 others countries can reach that state and even have a surplus of energy. Figure 4.7 illustrates the remaining renewable energy potential that has not been used by countries to fulfil their own needs. It is computed by

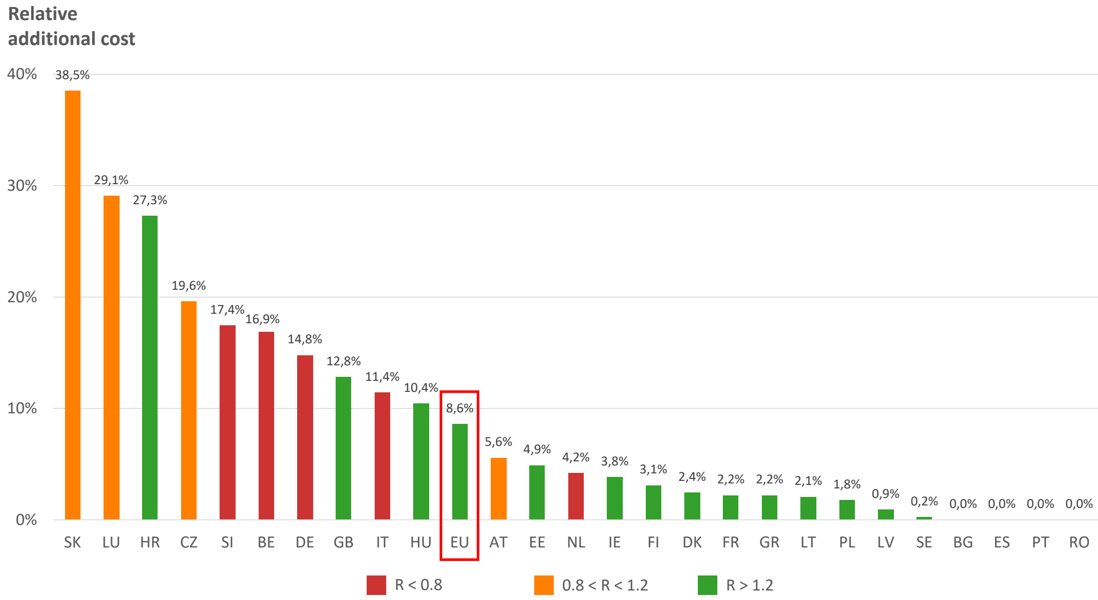


Figure 4.6: Additional cost [%] of the systems in the minimum GWP scenario compared to the cost-optimised scenario.

subtracting the energy actually provided by renewable resources with the solved problem from the renewable potential evaluated in Section 3.3. This remaining energy potential is later called energy surplus. The four countries unable to reach energetic independence had to fulfil some of their needs with non-renewable energy sources. This is called energy deficit and is calculated by subtracting the energy produced by renewables from the EUD. Overall, the energy surplus is about 6 times the energy deficit. This means that there is a high probability that Europe can reach energetic independence and null net emissions. Nevertheless, further study is needed to access that statement as transport of energy across long distances implies losses and the moment when energy is needed may not correspond to when energy is available.

Indeed, Figure 4.7 also illustrates the share of each renewable that can still be utilised. The remaining share is mostly composed of Solar Energy as its high intermittency makes it less competitive than other renewable resources. Note that the cost of additional renewables is likely to increase as best energy spots are already taken but this phenomena is not captured by EnergyScopeTD. There is still a significant wind potential in Europe mostly in Great Britain, Sweden and Ireland. Unused sustainable biomass potential will probably prove to be essential as it provides flexibility, through SLF and SNG, to compensate for the intermittency

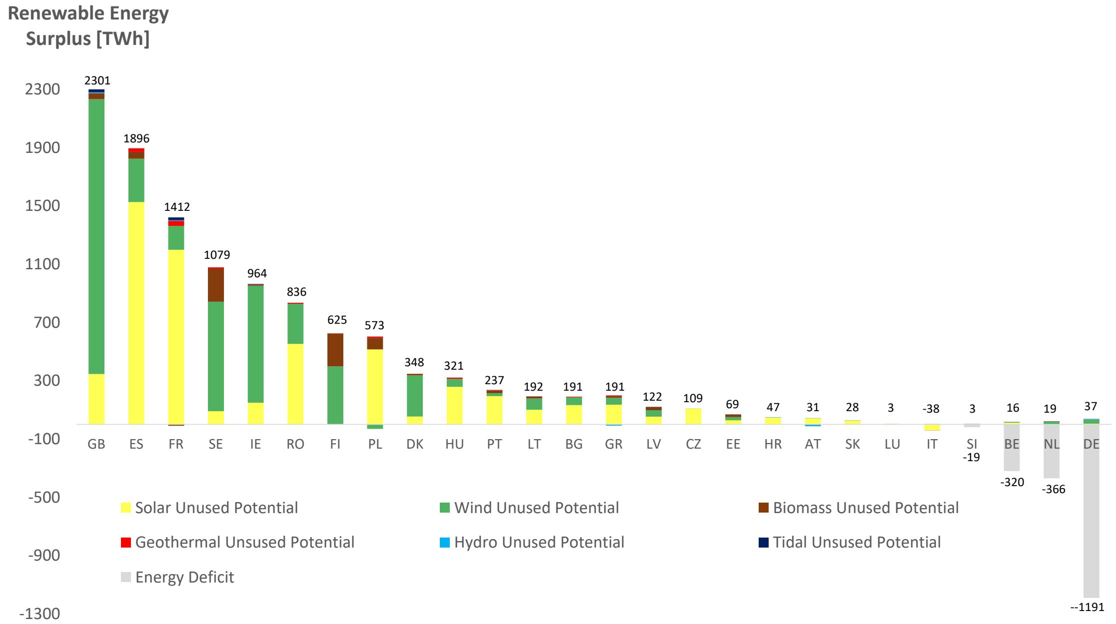


Figure 4.7: The potential renewable energy surplus is about 6 times the energy deficit in countries that can not reach energetic independence. High probability that Europe can reach energetic independence and null net emissions.

of some renewables. Finally, tidal and geothermal potential stay mostly untouched as they are not cost-competitive for the minimum GWP solution.

Looking at Figure 4.7, one might notice that some energy surplus are actually negative. This is most notably the case for Italy where the energy surplus is of -38 TWh. Moreover, countries with energy deficit still have some energy surplus. This strange phenomena can be explained by the use of Typical Days (TDs) in EnergyScopeTD. To obtain this minimum GWP solution, EnergyScopeTD has been used with 12 TDs because this offers a good trade-off between accuracy and computational time [51]. However, accuracy is still lost in the process compared to the yearly data. As the renewable energy potential of Section 3.3 is based on the yearly TS and the used renewable energy presented above is based on a representation of the year based on 12 TDs, there is a difference in the capacity factors and, therefore, a difference in total production between what would really be produced and what the model assumes is produced based on 12 TDs. For instance in Italy, the year represented by the 12 TDs shows a PV capacity factor equal to 18.14% instead of the 17.13% obtained by the 2015 input data. Solar Thermal is also overevaluated by 13.17%. This translates to an overevaluation of 40.5 TWh of the solar potential[9] and is the reason why our results find a fully renewable solution for Italy even though it has a small renewable potential compared to its demand. The remaining potential for Slovenia, Belgium, the Netherlands and Germany are also explained this way. Note that this only affects energy sources represented by TSs and that biomass is correctly evaluated. Overall, this does not change drastically the results but the limitation of the TDs should be kept in mind as the evaluated Italy as being able to fulfil its needs even though Italy is highly unlikely to do so.

To conclude, 21 countries within the 26 studied could reach independently carbon neutrality. For Belgium[10], Germany[11], the Netherlands and Slovenia it is impossible to reach carbon neutrality independently but there is enough remaining renewable energy in other countries to provide that demand. For Italy, a solution is found by EnergyScopeTD but it is highly probable that in reality Italy can not reach independently carbon neutrality and that the difference is due to TDs utilisation. The minimum GWP solution for the countries is only 8.6 % more expensive than the cost-optimised solution which suggests an affordable energy transition.

[9]-38 TWh in the graph is obtained by adding to the -40.5 TWh of solar the hydro potential underevaluated by 14.2 %.

[10]This is acknowledged in Belgium 2050 plan for carbon neutrality where carbon neutral electrical imports are expected[66].

[11]One of Germany carbon neutrality plan for 2050 main focuses is energy efficiency which means decrease in demand[29]. This is not in line with demand forecast of the European Commission[12] on which these results are based on.

4.3 France

Even though the scope of this study is to have a global view on the European energetic systems, studying a country more in depth allows to better understand how a 100 % renewable energy system behaves. This section serves as an example with the case study of France. It will detail the management of the intermittent energy production in France, the Pareto front of the evolution of the price of the system in function of its CO_2 emissions and also the primary resources used in function of the CO_2 emissions. However, a more in-depth analysis could be done for France and for all other EU countries taking, for instance, political strategies and political choices into account, but this goes beyond the scope of this thesis.

4.3.1 Evolution of France Energetic System over Varying GWP

The GWP of a country is a constraint in EnergyScopeTD defined by the user. This parameter could reflect the policies that a country would want to make. By changing the GWP constraint and optimising the cost, one can observe the multiplicity of energy systems that vary in price, resources and overall set of technologies used. This Section focuses on resources and overall system cost as GWP varies while Section 4.3.2 and Section 4.3.3 will describe the energy system at null net emissions. Note that the set of energy systems as a function of GWP does not represent the transition from today's energy system but rather a mapping of energy system solutions for different GWP constraints.

Figure 4.8 illustrates the primary resources utilised for all energy systems between 200 $MtCO_2$/year and null net emissions with a resolution of one energy system every 10 $MtCO_2$/year. Note that for the energy systems emitting 10 and 0 $MtCO_2$/year, biomass emissions are not accounted for. The biggest tendency in the graph is that as GHG emission decreases, fossil fuel utilisation decreases to be replaced by renewable resources. Coal is the resource diminishing the most rapidly as its high CO_2 emissions power plants are gradually replaced by wind turbines. Meanwhile, Natural Gas(NG) utilisation, mainly for non-energy purposes, remains quite stable until 30 $MtCO_2$/year. After that, NG is still used in the Non-Energy sector and by CCGTs for flexibility but is now obtained through biomethanation of wet biomass. Thus, the systems emitting less than 30 $MtCO_2$/year use synthetic natural gas instead of the imported natural gas used before. As wet biomass is already fully utilised across all GWP constraints, the non-energy demand is more and more satisfied by synthetic liquid fuels produced by pyrolysis of wood. The potential in wood becomes fully utilised at 30 $MtCO_2$/year. Other resources like hydro dam and river always remain saturated as its capacity are already saturated in Europe. Meanwhile, the solar resource is barely utilised in France across all GWPs and only remains at 2020 installed capacity. Finally, electrical imports allow flexibility for the days with less wind across all GWPs except null net emissions where their associated emissions disqualifies them.

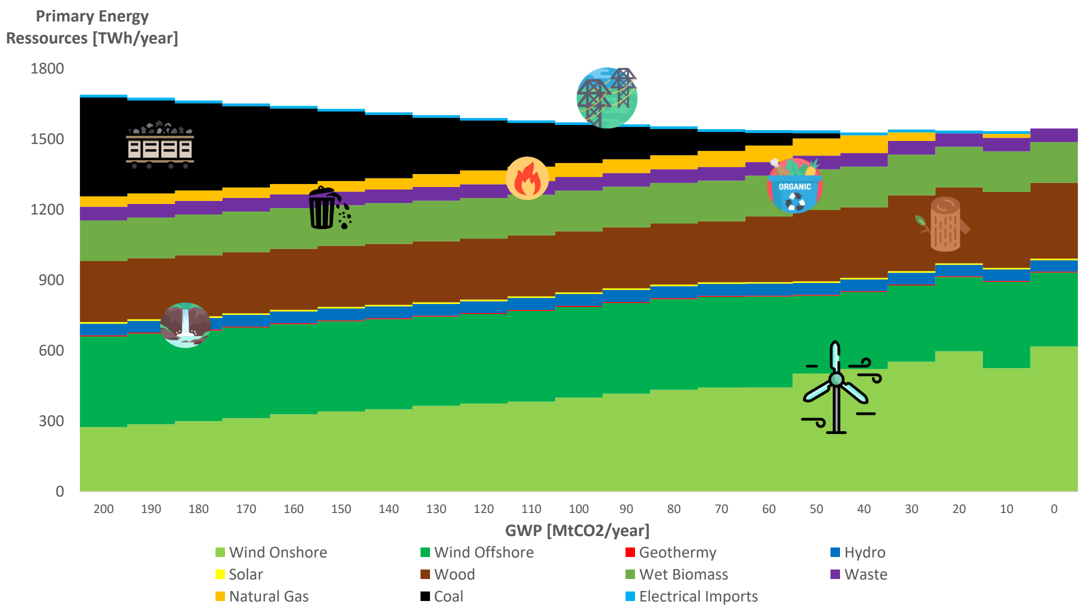


Figure 4.8: Primary Resource utilisation by GWP emissions for France in 2035.Some icons are made by Freepik from www.flaticon.com.

For France, cost remains steady across all GWP. This can be seen in Figure 4.9 where the yearly system cost is plotted for different GWP. Note that the y-axis starts at 70 B€/year so the variations seen are quite small. When the GWP decreases, the cost also decreases slightly from 74.88 to 73.64 B€/year at 50 $MtCO_2$/year. This is due to the use of more efficient technologies and the shift from coal power plants to wind turbines that are even cheaper. After the cost optimum, the cost increases but only slightly to reach null net emissions at 75.33 B€/year. This increase in cost is mainly due to stopping of electrical imports. Not allowing electrical imports for a carbon-free France is mainly motivated by France's geography as Section 3.4 highlighted. Indeed, most of France's neighbours would likely partially rely on France for their renewable energy. Moreover, although 75 B€ per year may seem expensive, it is only 2.3% of the predicted 2816 B€ Gross Domestic Product of France in 2035 [12]. The increase in price to reach carbon neutrality from the cost optimised solution illustrates clearly that, for France, carbon neutrality and energetic independence is economically achievable.

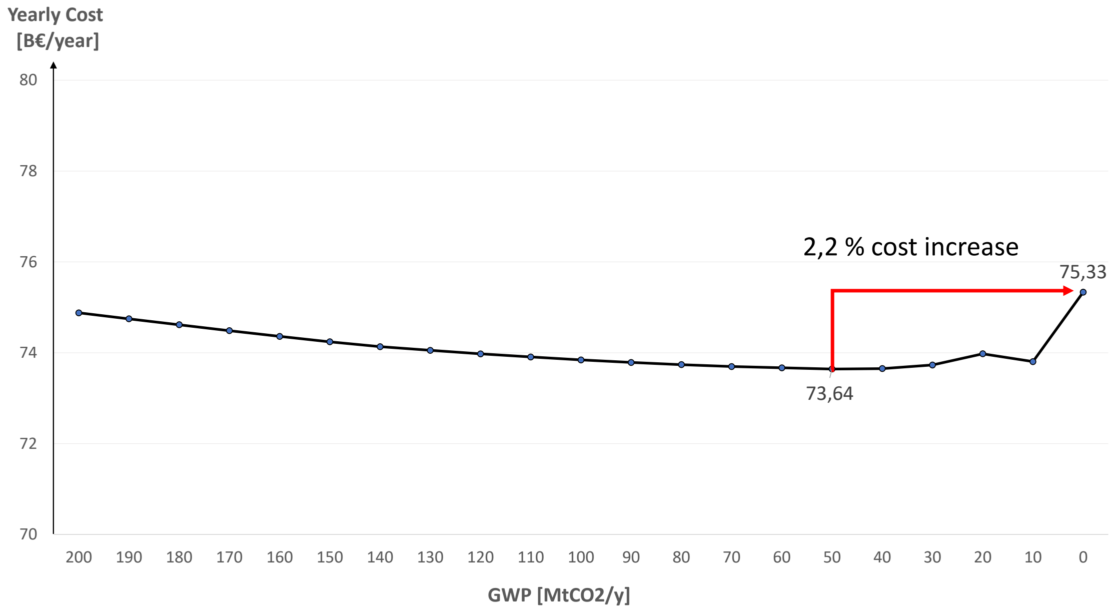


Figure 4.9: Yearly Energy System Cost by GWP for France in 2035. The cost is really stable across all GWPs and only increases slightly between the cost optimised point and a system with null net emissions.

4.3.2 Minimal GWP Energy System

As seen in Section 3, France has enough renewable potential to fulfill its demand entirely. This section aims at describing how France could build its energetic system to achieve zero net emissions. Note that in reality emissions could be slightly higher as biomass emissions are set to 0 for this Section. Furthermore, remember that emissions from non-energy sectors are not accounted for, as this feature is not yet implemented in EnergyScopeTD. Still, the system proposed for France highlights key features of decarbonated energy systems for countries with enough renewable resources.

Figure 4.10 presents the cost-optimised solution for a decarbonated France in 2035. The resources used in the system are on the left side of 4.10. They are all renewable energy sources. Biomass and waste resources are used at their maximum sustainable potential. Similarly, offshore wind is also saturated at 93 GW of installed capacity on the windy Atlantic coast. Onshore wind is the most prominent energy with a yearly production of 617 TWh provided out to the 1952 TWh of yearly EUD for France. This energy comes from the 334 GW of onshore capacity installed but the onshore wind capacity is not yet saturated as it could still install 40 additional GW. Onshore and offshore wind combined constitute about 60% of the primary energy mix for 31% of the total cost. Assuming turbines of 3 MW and 6 MW for onshore and offshore respectively, this would represent 127 700 wind turbines within the territory of France, the vast majority of which inland. This will of course lead to questions of social acceptance that will need to be addressed for energetic independence to be possible. Other renewable resources used are hydro dam and river which are also already saturated. On the other hand, PV remains only at its installed capacity from 2020. PV's poor success can be attributed to its seasonal capacity factor which is really poor in winter while the overall demand is at its highest during that time period. The opposite phenomena appears with wind whose production is at its best in winter as seen in Section 3.2.1.

On the right side of Figure 4.10 appear the different EUDs for France in 2035. It can be seen that although the electrical layer covers about 1015 TWh, the EUD of electricity only constitutes 380 TWh. This is because most of the heat and mobility demands are now electrified. Low temperature heat is now nearly entirely provided by efficient technologies like heat pumps. Although their CAPEX (also known as capital investment) is more expensive than alternatives, they remain overall cheaper due to their high efficiency. District heating network should also be implemented massively as it is overall cheaper than decentralised heating. High temperature heat is either provided directly trough electrical resistances or by incinerating waste or wood when wind is not available therefore releasing stress on the system. Mobility benefits from a variety of different energy sources. Public mobility is mainly provided by electricity by the means of trains or tramways while private mobility is provided entirely by hydrogen. Freight also uses hydrogen but at a lesser extent as its main source of energy is diesel produced by pyrolysis. Biomass also covers the entire non-energy demand via pyrolysis and biomethanation. It also produces the gas used by CCGT during the harshest days of the years.

Storage also plays a major role to provide stability of the system and is used abundantly in most layers. Storage layers are highlighted in red in Figure 4.10. Note that although the majority of energy is produced by electricity, only a minor part of the storage is actually electric, with only Dam Storage and PHS being used. Instead cheaper storage like low temperature heat storage or gas storage are preferred due to their lower cost. Storage and flexibility in demand and production are key to a renewable energy system and are more thoroughly discussed in Section 4.3.3.

In summary, France is a country of wind and biomass and is able to become affordably independent energetically and at 0 net emissions. This is possible with a high electrification of heat with efficient technologies like Heat Pumps. Mobility will also be highly electrified but not directly with electric cars but rather with synthetic liquid fuels produced from either electricity or biomass.

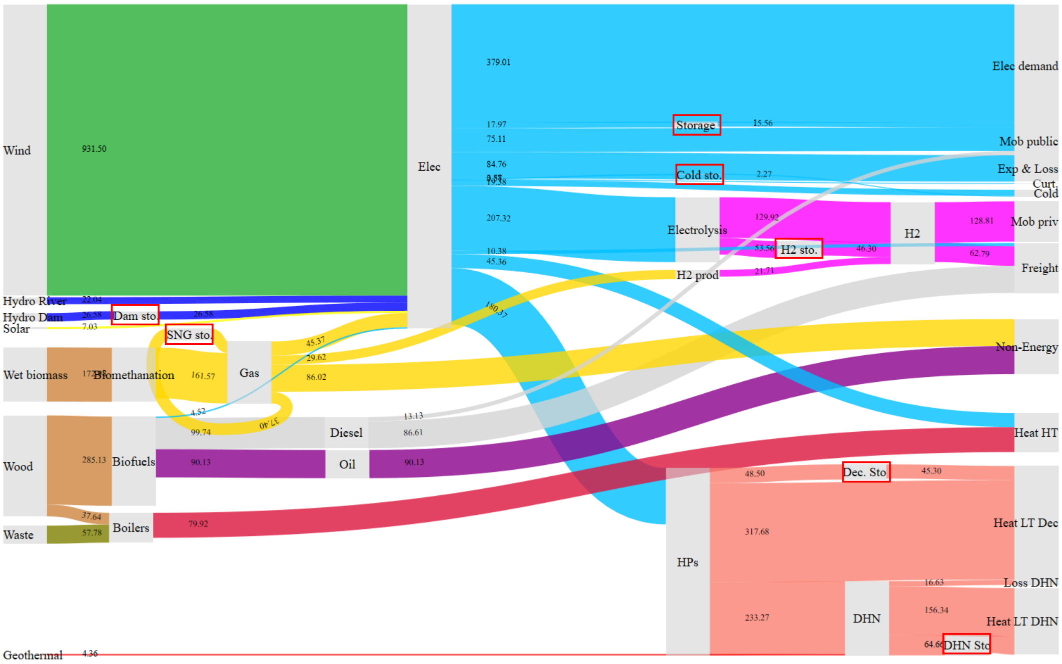


Figure 4.10: Sankey diagram of a decarbonated France. Wind is the prominent energy source. Heat is electrified through efficient technologies like Heat Pumps. District Heating Network are largely implemented. Mobility is partially electrified through hydrogen production. Biomass also plays a major role to provide synthetic liquid fuels. Its potential is used at its maximum sustainable limit.

4.3.3 Management of the Intermittency

Until now, the results shown were only in terms of totals on a year (*e.g.* the energy mix for minimum GWP scenario) and, by showing the results this way, the hourly strategy of the system can not be seen. But this hourly strategy is important for energetic systems and becomes even more important when the systems deal with a high share of intermittent renewables. As explained in Section 1, EnergyScopeTD optimises the hourly strategy of the system over the whole year by using Typical Days (TDs). This enables us to look at the different solutions used by the system in order to deal with the intermittent production.

This Section focuses on the hourly strategy of the system of minimal GWP for France presented in Section 4.3.2. The primary energy mix of this system contains a 60% wind energy share, this means that more than half of the energy comes from an intermittent source. In order to deal with this intermittency, the system has to adapt when the wind production is too high or too low since most of the energy comes from the wind. This section will detail the management of the intermittency on the electricity layer while the heat layer is covered in the Annex A.3.1. The electrical layer is described for 4 different TDs out of the 12 used for the resolution representing different scenarios : a cold unwindy day, a hot unwindy day, a cold windy day and a hot windy day. This analysis is done for France and only explains how the intermittent production is managed for the minimal GWP France case, other systems in Europe are, of course, different and some of them will use different strategies.

The electrical layer is illustrated in Figure 4.11 for the 4 TDs mentioned before. As a reminder, layers are defined as elements in the system that need to be balanced in each time period. Thus, the electricity supply needs to be balanced with the electricity demand at all times. An important characteristic in Figure 4.11 is that some production technologies are not flexible *e.g.* wind, PV and hydro river[12]. These energy productions depend on factors that can not be controlled (*e.g.* wind speed). The same is also true for the demand side, and more precisely for $\mathrm{TS}_{\mathrm{Elec}}^{\mathrm{EUD}}$ that can not be modified.

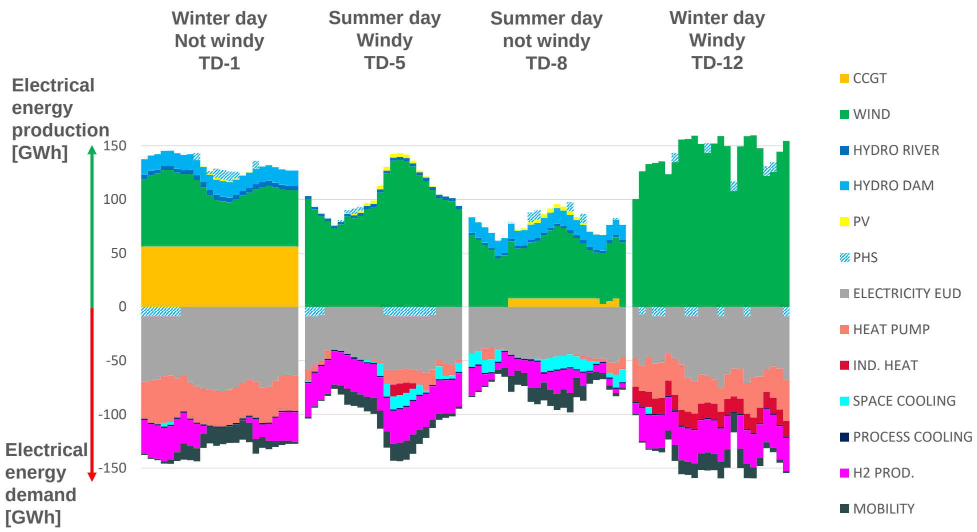


Figure 4.11: Energy production and demand for the electricity layer for 4 different TDs.

[12]In reality, Hydro Run-of-river and poundage can, sometimes, have some flexibility in production using small reservoirs but data is lacking to implement these reservoirs in the model.

Fortunately, aside from the uncontrollable parts of the layer, there are lot of controllable and adaptable features. For production, there is the possibility of burning Synthetic Natural Gas (SNG) in CCGTs to produce electricity as can be seen in Figure 4.11. This SNG can be obtained through biomethanation of wet biomass, wood gasification or even methanation of H_2. Biomass allows to drastically increase the flexibility of the system since it can choose how to spread its biomass potential throughout the hours of the year. This CCGT is used only for 2 TDs out of the 12 TDs, these 2 days represent the roughest periods during the year when the wind production is at its lowest. The system for France has also flexibility through hydro dams[13]. This technology can collect water in huge reservoirs and release this water through turbines to produce electricity when needed. Note that the water flow into the reservoirs can not be controlled. It can be seen in Figure 4.11 that the hydro dams are most used during the unwindy days : TD-1 and TD-2. In fact, the dams are working at maximum capacity during those days in order to supply the maximum support to the system. Finally, when the production of renewables is too high, the system can resort to curtailement which enables to cut a part of the production by shutting it off.

Another strong asset is the flexibility the system has on the demand side. As shown in Section 4.3.2, electricity is both used directly for electrical EUD but also for heating (low and high temperature), cooling (space cooling and process cooling), hydrogen production (for private mobility and freight) and public mobility. For all these uses (except for cooling due to its basic implementation), the system could determine to use another resource than electricity to provide the energy, *e.g.*, high temperature heat can also be supplied through wood boilers.

Furthermore for the electricity layer, there is a great axis of liberty provided by the storages. The most direct storage related to the electricity layer is, of course, the electrical storage. In addition to the hydro dams, the system implements Pumped Hydroelectric Storage (PHS) as fully controllable electric storage. But PHS and hydro dams are not the only storages supporting the electricity layer for the minimal GWP system of France. There are several kind of storages that can indirectly help the electricity layer. Thanks to these storages, the system can transform electricity into another layer when production is high and then store the energy in the adequate layer, *e.g*, electricity can be used in heat pumps to produce low temperature heat that can be stored into the DHN storage[14].

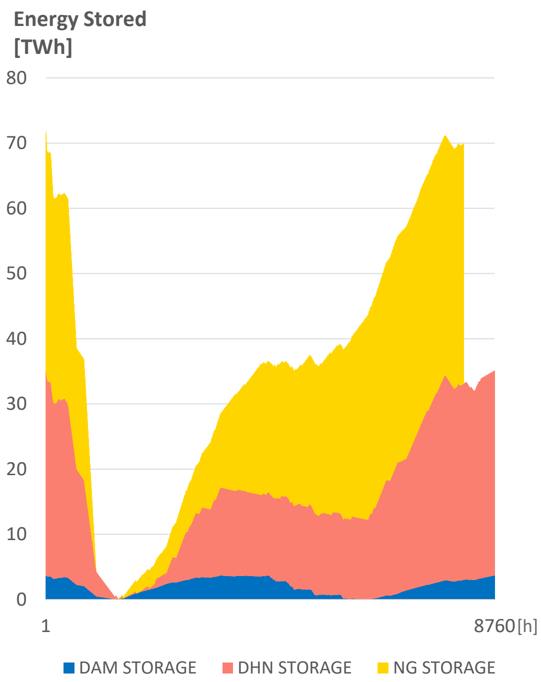
[13]Hydro dam is not the only renewable technology offering flexibility. For instance, CSP can also have flexible production as explained in Section 2.4.2.

[14]This is detailed and illustrated in Annex A.3.1.

Finally, it is not surprising that storage plays a huge role in the minimal GWP energetic system of France as it uses a lot of intermittent renewable energy. Storage enables to adapt the system to this kind of production. A distinction can still be made between the storage units by looking at their scale and their use. It can be seen in Figure 4.12 that the system for France implements three big storage units, each with a different purpose. They are characterized by a big scale and by a seasonal use, these two characteristics are correlated. The system stores for periods when the production of renewables is high compared to the demand and releases it when the production decreases or the demand increases. In function of the storage, it features only one or two cycles (the two cycles are briefly explained later in Chapter 5).

On the other hand, the system also implements smaller storage units as PHS, decentralised storage, H2 storage, cold storage and SLF storage. This can be seen in Figure 4.13. Small storage units are characterized by small scale storage capacity and by a daily or weekly use of the storage. These enable the system to be flexible on a daily/weekly basis, *e.g.*, load during the night to release energy during the day. As one might have noticed, some layers use one big and one small storage unit : electricity uses dam storage and PHS, and low temperature heat uses DHN and decentralised storage. For electricity, dam storage and PHS are used since the storage capacity is already installed and used in France[15]. For low temperature heat, DHN and decentralised storage are installed because constraints have been set to split the low temperature production between DHN and decentralised production [51]. Note that decentralised storage capacity is way smaller than DHN storage since it is less cost-effective for seasonal storage, but still proves to be useful for daily storage. For H_2, rather than installing costly seasonal H_2 storage, it is preferred to use cheap NG seasonal storage and to transform that NG into H_2 when H_2 production is cut off as it is overall less costly. This SNG storage is also useful for electrical production through CCGTs and directly used for non-energy uses.

[15]It was considered that France would continue to use them in 2035.



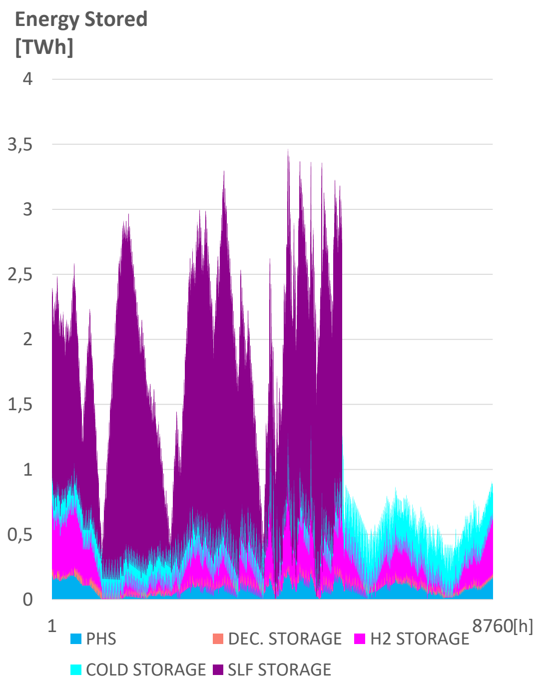


Figure 4.12: Seasonal storage used in the case of a minimal GWP system for France.

Figure 4.13: Small scale storage used in the case of a minimal GWP system for France.

Chapter 5

Discussion

In Chapter 4, a minimal GWP solution was proposed for European Countries. This Chapter discusses more thoroughly these results and proposes to take a step back on them. First, Section 5.1 gives an analysis on what are some of the implications of our technical solution on society but more importantly what impact society could have on our solution. Then, Section 5.2 discusses the influence of price on our solution and the bias it could have in EnergyScopeTD. Finally, Section 5.3 discusses how Time Series and Typical Days choices can affect the solution.

5.1 Societal Impacts

Traditionally, electrical systems were built on a top to bottom approach where a few power plants managed by a single or few entities would meet the electrical demand. Other needs in energy like heat or mobility would generally be met locally directly by fossil fuels that are easily storable and there would be little interaction between all these systems.

With the solution proposed in this thesis, the energy system structure changes completely. Most of the energy system is now electrified and this electricity is supplied by intermittent renewables, mostly wind. The flexibility provided by CCGT (based on gas produced by biomass), by PHS and by dams is limited. As a consequence, most of the time there is an overabundance of energy while some days the available energy is restrained. For these few days the demands usually provided by electricity has to temporally switch to the energy previously stored or other sources of energy. The responsibility on the stability of the grid is now shared as the energy demands and the energy production have to collaborate to optimise the energy system.

This implies that most of the SLF industries using usually overabundant electricity and some of the heat demand need to stop using electricity when there is few wind or sun. Communication between production and demand will have to improve drastically for this to be possible. For big and moderate size actors like SLF producers from electricity or DHN provided by HP, this communication seems feasible. However, it will prove difficult to convince small consumers using HP that they should store heat when it is windy and use that stored heat when the stability of the grid is at risk. A conceivable solution includes the use of control and automation for the efficient use of energy. This would manage the consumption of the end-users but there is no warranty that end users wish to use that solution at home.

Additionally, renewables are considerably less dense energetically than traditional energy production plants. For the fully renewable solution, a total of 566 500 onshore wind turbines, 63 500 offshore wind turbines and 305 millions PV would have to be installed across Europe[1]. What is the degree of acceptance of the population to this renewable expansion? Will French people accept to have additional wind turbines in their backyard to provide electricity to countries like Germany that can not provide their own needs? If the population realises the extent of this expansion, will they reconsider traditional options like fossil fuels or nuclear with their own sets of drawbacks? Energy demand decrease would also help attenuating this problem, but forecasts like the one of European Commission[12] used in this study indicate that all demands but heat are expected to increase. Are people willing to reconsider their consumption when they realise no energy production technology is without flaws? All these are questions that are yet to be answered.

In conclusion, the solution proposed in this paper for a mostly renewable Europe seems technically feasible and affordable but this solution implies consequent changes from the population, the industry and the political world as responsibility on the grid stability becomes shared. Furthermore, it implies massive implementation of renewables that the population may reject.

5.2 Influence of Price

In Chapter 4 the main way to use EnergyScopeTD was to optimise the cost of the energy system while putting some constraints over the GWP. This was not only done in Section 4.1 where the cost-optimised European energy system was

[1] 1700 GW of onshore across the EU assuming 3 MW wind turbine, 381 GW offshore wind turbine assuming 6 MW wind turbine and 1066 GW of PV assuming 3.5 kW PV. That is 4500 km^2 or 0.01% of Europe Surface for PV with 0.2367 $\frac{GW}{km^2}$[48].

presented but also in Section 4.2 for null net emissions. Although availability of resources and composition of the demand play a major role in the system proposed, the actual main parameter when optimising over cost is the Levelised Cost of Energy (LCOE) which is a measure of the average net present cost of electricity generation for a generating plant over its lifetime[2]. When agglomerated over the overall energy system, this parameter is also the objective function that EnergyScopeTD minimises. Hence, technologies with a lower LCOE are favorised by EnergyScopeTD as long as it is possible to respect the other constraints all year long. LCOE is computed by dividing the sum of costs over the plant lifetime over the energy the plant produces over its lifetime as described by Equation 5.1.

$$\text{LCOE} = \frac{\text{Sum of costs over lifetime}}{\text{Sum of produced energy over lifetime}}[\frac{€}{\text{MWh}}] \tag{5.1}$$

This tool allows to compare technologies on a consistent basis. The calculation of the LCOE is based on equations (1) to (5) of the Supplementary Material [48] and is further described in Annex A.4. The cost includes the investment cost which is annualised with the interest rate. The maintenance costs are also taken into account. The cost also includes the price of the resources used when relevant, the efficiency to convert them into electricity and the charge factor as there is some downtime for maintenance. Plants are assumed to produce energy continually when not under maintenance. The energy produced for a plant depends on either the charge factor for non-renewables or the capacity factor for renewables. As the capacity factor changes between countries, Figure 5.1 illustrates the data of renewables with a box-and-whisker plot (boxplot).

Figure 5.1 displays the LCOE of electricity producing technologies for EnergyScopeTD and 3 sources of literature: Energy Information Administration (EIA) for prices in 2040 [65], Lazard [46] for prices in 2018 and the European Commission for prices in 2013 [19]. Technologies in EnergyScopeTD are evaluated for different future years ranging from 2025 for coal to 2035 for CCGT [48]. Figure 5.1 illustrates that the LCOE can change significantly for the same technology between sources. There is no clear consensus on electricity producing technologies prices. For instance, CCGT highest price estimate is 3.8 times more than its lowest estimate. As a consequence, there is no right price for technologies but only estimates that are more or less accurate with regards to literature. This has to be kept in mind when analysing the results. For instance, nuclear price estimate is quite low in EnergyScopeTD and as a consequence is a favored solution in most results. It can be explained by the interest rate which is shared among technologies in EnergyScopeTD but is in reality generally higher for nuclear[2]. The LCOE of CCGT is mainly influenced by the gas price which is illustrated by the OPEX. However, forecasts of natural gas price often fail to capture gas increases or decreases as S. Moret [54] points out. The PV price seems to be relatively high compared to evaluated sources especially when considering that PV prices are expected to keep decreasing [6]. Moreover, the capacity factor of solar makes the LCOE change significantly between countries, ranging from 29 $\frac{€_{2015}}{MWh}$ for Portugal to 63 $\frac{€_{2015}}{MWh}$ for Finland. For most countries the LCOE of PV is worth more than 40 $\frac{€_{2015}}{MWh}$ which makes it quite expensive, especially when taking into account backup technologies and grid integration cost needed to implement PV. Solar Tower are less studied in the literature as it is a less mature technology. As capacity factors vary more for Solar Tower, its LCOE can nearly triple between countries and this solution only makes sense for southernmost countries.

For onshore wind, the LCOE is a low price estimate as most countries have similar cost as the lower estimates. The onshore wind price is quite consistent among countries and only Croatia and Slovenia suffer from particularly poor wind exposure which explains why these countries used little wind in the cost optimised solution of Section 4.1. Offshore Wind is the only source for which literature data is consistent and EnergyScopeTD estimates are really low. As seen in Section 3.2, offshore TS is likely slightly over-evaluated (3 % more than other sources) but this does not explain the doubling in price between EnergyScopeTD data and the literature. It could be explained by the expected high decrease in cost for offshore wind turbines between 2019 and 2030 (4 % yearly according to IFRI[3] [16]). Hydro dam and river LCOE are high compared to the European Commission estimate but as all European hydro potential is already utilised this does not play a role in EnergyScopeTD planning.

Prices in EnergyScopeTD can also be compared between themselves. Onshore and offshore wind are by far the cheapest energy sources for most European countries and this explains their prevalence in our results. Afterwards, nuclear is the cheapest option for most countries other than some southern countries for which PV and solar thermal are more advantageous. Note that energy systems rarely only work with these technologies as renewables are intermittent and nuclear is mostly used as baseload. This is why most solutions use CCGT or/and Coal[4] to provide some flexibility. When CO_2 emissions are not taken into account, the choice between those 2 depends on the total energy that has to be provided. Indeed, CAPEX needs

[2]Investors can add a risk premium to the interest charges applied to nuclear plants[70].

[3]Institut Français des Relations Internationales: French Research Center.

[4]Coal only when no restriction on GWP.

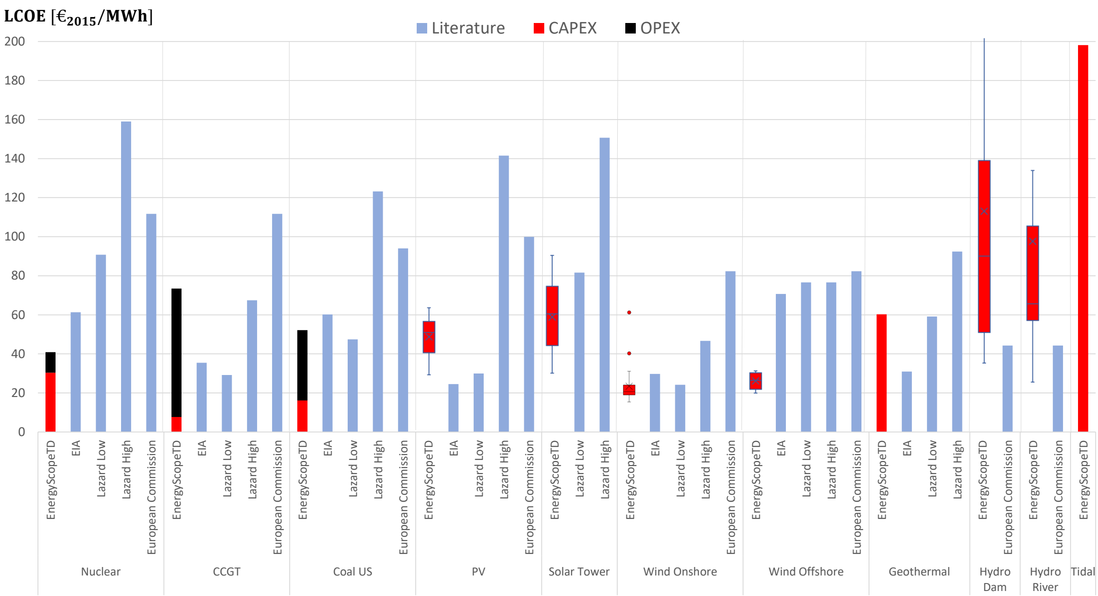


Figure 5.1: LCOE of electricity producing technologies:comparison between EnergyScopeTD data and EIA[65], Lazard[46] and European Commission data[19]. LCOE calculated using equations (1) to (5) of EnergyScopeTD supplementary material [48]. In blue are displayed LCOE issued from different sources of literature. Nuclear, CCGT, Coal US, Geothermal and Tidal are displayed using CAPEX and OPEX. CAPEX includes investment and maintenance cost while OPEX includes fuel cost. Renewable resources are displayed using boxplots to display the variability of LCOE between countries. The cross is the mean LCOE. The middle bar is the median LCOE. In red are the LCOE points between first and third quartile. Conversion to €$_{2015}$ is done using Equation A.8. CEPCI from [4][5][48] and changes rate between currencies of 1st January 2015 from [31].

to be paid for the full year for the total capacity while the power plant for some part of the year. Due to this difference between CAPEX and OPEX, a 1 GW coal power plants becomes more interesting than CCGT of the same capacity after 2205 GWh yearly[5]. In the cost-optimised solution for countries with few renewables, nuclear, coal and CCGT were implemented. Nuclear provides the cheapest baseload while Coal and CCGT build up together the peak load. This peak load is preferably met by coal over the year but the few hours where the coal installed capacity is insufficient for peak load CCGT is used additionally. Additionally, geothermal seems more expensive than renewable alternatives and is only considered as a last resource to be exploited in the fully renewable scenario. Finally, tidal technology is found to be extremely expensive and this explains why it is never considered in the used resources.

In conclusion, wind is the most cost-competitive technology but its price is lower than in the literature. Nuclear technology also benefits from its low implemented price and is the second most favoured technology. Coal is more economical than CCGT but only if it can produce enough energy all year long. PV and Solar suffer from high prices added to their intermittency which explains their low use in our results. Geothermal, hydro and tidal have high prices and are not favoured by the model. Finally, EnergyScopeTD could benefit from a sensitivity analysis on price.

5.3 Influence of the Time Series on the Solutions

In this thesis, the Time Series used were computed based on data taken from the year 2015 for each country as detailed in Section 2.5. Nevertheless, the year 2015 was chosen arbitrarily and is not the result of a study. This can thus lead to input TSs described by capacity factors that are overestimated or underestimated since they are subject to yearly variance, *e.g.*, Belgium could be pretty sunny one year and cloudy the year after. This variability is shown for the 30 past years in the MERRA-2 [32] database for each country and each renewable. As an example, the yearly capacity factor for Belgium in the past 30 years ranges from 20.9% to 27.4% for onshore wind, from 26.9% to 35.8% for offshore wind and from 11.1% to 13.3% for PV. Since the computation of the renewable energy potential in Section 3.3 is based on the capacity factors of 2015, the potentials shown in that Section can only be considered as valid for 2015. In order to assess the right average yearly potential, data should be averaged based on all the years available.

Furthermore, as explained above, the capacity factor of a renewable has an impact on its LCOE and thus also has an impact on its cost-competitiveness in

[5]See Annex A.4.1.

the model. For example, Croatia had a bad wind capacity factor for 2015, Figure 4.4 highlighted that it did not have a wind energy share as high as in other countries. This share could have been much higher if another year was chosen with a better wind capacity factor. Moreover, the hourly profiles, of both production and demand Time Series, have also an important impact on the solution of the system as EnergyScope optimises the hourly strategy of the system. For example, for most countries, the dam storage only features one cycle on the year, but as seen in Section 4.3.3 the dam storage in France has 2 cycles (Figure 4.12). This is the consequence of the space heating demand profile and wind production profile in 2015: the first discharge of the dam storage is due to a very high demand in heating, and the second discharge is due to a weak production of wind energy.

The solutions obtained thanks to EnergyScopeTD do not only depend on the input TSs but also on the TD chosen by EnergyScopeTD. As a reminder, the input data represents the whole year on an hourly scale (2015 in our case). Based on this data, EnergyScopeTD choses a certain number of TDs defined by the user. All optimisations were done with 12 TDs as it is the best trade-off between computational time and accuracy according to Limpens et al. [49]. To choose the 12 TDs, the user can define a weight for each Time Serie that will define the importance of the Time Serie. The weights used for each country of this study are shown in Table 5.1 and are the same as the ones used by Limpens et al. [49]. Since some weights are smaller than others, the year represented by the TDs can bias the capacity factors of the TSs and can result in inaccurate solutions. The smaller the weight of the TS, the higher the probability that the capacity factor is erroneous. This error has been defined as shown in Equation 5.2 by subtracting the capacity factor of the year represented by 12 TDs from the capacity factor of the TS put into the model. A positive error (resp. negative) is thus meaning that the capacity factor has been overestimated (resp. underestimated).

$$\text{Error} = \frac{\text{C}_p \text{ of the input data} - \text{C}_p \text{ of the year based on TDs}}{\text{C}_p \text{ of the input data}} \tag{5.2}$$

This error is shown for the set of countries studied in Section 3.2 in Table 5.2. Since the weight is pretty high for the demand TSs, their errors are pretty small. The most problematic errors are for the production TSs as they are way higher than for the demand side. Note that the results obtained for the minimum GWP scenario can be considered as conservative since they achieve to implement 100% renewable systems by mostly underestimating their renewable production. This is of course not always true as has been explained in Section 4.2, for example in the case of Italy that largely overestimates the solar thermal production. So due to the errors linked to the TDs, the model solves the different systems with a majority of underestimated renewable potentials but this also affects the cost-competitiveness of renewables, seen in Section 5.2, since the LCOE depends on the capacity factor.

Time Serie	**Weight**
Electricity	3
Space Heating	3
Space Cooling	1
PV	1.5
Onshore Wind	0.75
Offshore Wind	0.75

Table 5.1: Weight of the different Time Series used to compute the TDs. The weight for space cooling was added during this study as cooling was not included previously.

	FR	IT	DE	SE	HU	GB
Electricity	-0.8%	0.9%	7.3%	2.6%	5.6%	3.0%
Space Heating	1.4%	-1.7%	1.5%	-3.5%	4.0%	-1.7%
Space Cooling	-2.4%	-3.6%	-3.9%	-0.9%	-69.9%	0.0%
PV	-2%	5.9%	5.1%	-7.1%	-34.2%	-4.1%
Solar Thermal	-1.9%	13.7%	14.6%	-18.9%	-73.3%	-8.7%
Onshore Wind	-2.2%	-11.2%	-20.3%	-8.3%	19.5%	-10.5%
Offshore Wind	5.9%	-	-20.3%	6.8%	-	-15.0%
Hydro River	-15.8%	-3.0%	-5.6%	-	-17.0%	-3.6%
Hydro Dam	-10%	-14.2%	-10.6%	-1.1%	-24.8%	-
Tidal	-28.8%	-	-31.6%	-%	-	-27.8%

Table 5.2: Error for capacity factors represented by the year made of 12 TDs compared to capacity factors of the real-time year.

To summarize, the choice of the year and the computation of the TDs can have a significant impact on the solution of the various systems. Care should be taken when choosing the year depending on the aim of the study since it can affect the capacity factor of the different renewables. For the computation of the TDs, the approach taken by this study is rather conservative as most of the renewable capacity factors are underestimated compared to the real capacity factors of 2015. On the other hand, the demand TSs are only slightly biased. However, the results obtained can serve as benchmark for future studies to be able to tune the weights and the number of TDs used since they affect the estimation of the capacity factors.

As there are 2 additional TSs has since the study of the influence of the number of TDs on the accuracy and the computational time by Limpens et al. [51], 12 TDs may no longer provide enough accuracy. Additionally, the systems presented in this study differ significantly from the Swiss test case as they are 100 % renewable and not rather than still with 50 % of fossil fuels unimpacted by TD choice. For certain studies, it may also be interesting to compare different years to assess which one is most adequate for the study or even to validate the solution based on a year data by testing it on other years to see if the system is resilient enough. This can be done as Chapter 2 mentions all the sources used that usually encompass several years and that this Chapter also shows all the methodology needed to rebuild the different input data to the model.

Conclusion

Europe aims at becoming carbon neutral by 2050 to mitigate climate change consequences. Today, production and consumption of energy account for more than 75% of Europe's greenhouse gas emissions [20]. This makes the energy sector and the energy systems as a whole one of the main focuses of this transition towards a carbon neutral Europe. However, European countries vary significantly in size and demand, and it is not clear if each EU country could provide its energy demand with only resources on its territory while being carbon neutral. Hence, the following research question: **Can the energy systems of European countries reach carbon neutrality by 2035 independently?**

This question motivated the creation of a new database to cover most European countries. It also led to an improvement of EnergyScopeTD that now covers 10 additional technologies and the cooling demand. Among others, the methodology to evaluate the profile of electrical needs, the solar thermal Time Serie and the sustainable potential of biomass were also improved. The database and the generalised EnergyScopeTD version can be found on the EnergyScope Github repository [64].

With the newly established database, future European energy demand, renewables characteristics within the EU and installable renewable capacity were also analysed. It also led to an evaluation of the renewable energy potential for EU countries. A new key performance indicator R was introduced to compare the renewable energy potential of a country to its EUD. On the European level this indicator was found to be 1.56. This means that there is enough renewable potential in Europe for its whole demand. However, this indicator also highlights that demand and renewable energy potential are not located in the same countries. Some countries have largely enough resources for their own needs while for others the demand largely exceeds the renewable potential.

Optimising the energy systems of European countries with EnergyScopeTD confirmed there is indeed a disparity between energy demand and renewable energy potential. The model predicts that Belgium, the Netherlands, Slovenia and Germany can simply not provide their energy needs entirely with only their renewable potential. This result was expected since they all had less renewable potential than energy demand. The model also suggested that Italy could provide its own needs but a further analysis showed that this country was within the uncertainties of the model. The model also predicted that the 21 remaining countries could provide their energy demand independently while having a carbon neutral energy system. While some can barely be energetically independent, other countries like the United Kingdom or Spain have consequent energy surplus and could still use more of their renewable potential. Overall for the 26 countries, there is 6 times more energy surplus than energy that is not yet provided by renewables. This means that it is likely that Europe could entirely fulfill its own needs but this should be verified by an analysis where countries could interact.

The minimal GWP solutions proposed by EnergyScopeTD seem technically possible. The main characteristics across countries are a high electrification of the heat and the mobility demand through the use of heat pumps and hydrogen and a production of electricity based on intermittent renewable (mostly wind). It is made possible not by massive electrical storage but rather by storage in other sectors like heat and mobility. Although heat is now produced mostly by electricity with heat pumps, daily and seasonal heat storage allow to greatly reduce the consumption of electricity for heat when needed. Similarly, synthetic fuel production from biomass or by electrolysis adds great flexibility to the energetic system. The model shows that biomass and waste should constitute the second most used energy source in the EU behind wind but before solar resources.

The solution also seems to be economically affordable. Compared to the energy system that would be the cheapest possible without any constraint on electrical imports or in carbon neutrality, the proposed solution would only be 8.6 % more expensive for the EU. The total additional cost is only of 41.5 B€/year which represents only 0.2 % of EU GDP. This increase in cost varies significantly between countries as for some countries the cheapest solution is already to be 100 % renewable while others can have a relative overcost of up to 38.5 %.

Of course, this study has limitations. First, it relies on the energy demand forecast of the European Commission [12] but the uncertainties are high and these demands could change drastically if societal changes were to occur. The model is also highly sensitive to price and there is no consensus on the price of technologies in the future. Additionally, all time dependent data are based on 2015 historical data. There is no evidence that 2035 would be like 2015 or any other year that could have been chosen. The use of Typical Days also has its drawbacks as it decreases the accuracy of the production and demand. Mobility costs are not yet fully accounted for and synthetic liquid fuels could benefit from a more advanced implementation, especially since they seem to be a key component of future energy systems. This work also focused on countries taken individually although countries are of course not isolated in reality and can exchange energy. Finally, the results show a snapshot of what would be an ideal energy system in 2035 but do not study what would be the transition pathway between today's infrastructure and the one of 2035.

This study opens the path to further work as the possibilities for further studies seem endless. The newly created database allows to study each country in the EU individually, similarly to what this paper presented for France. This data can also be used to represent the EU as a whole based on a multi-cell model where the interactions between countries could be further studied. This could verify that the countries in peripheral Europe with enough energy could provide the countries that lack renewable energy potential. A parametric study on cost and demand would also be of great interest. The robustness of the proposed energy system could also be improved by challenging an energy system with the data of multiple past years. Work on social acceptance of the massive deployment of renewables is also fundamental as such a massive change can not be done without the support of the people. Finally, pathways between today and 2035 could be studied to optimise the transition between today's infrastructure and a carbon neutral EU in 2035.

To conclude, although most European countries can provide entirely their own needs and can be carbon neutral, some can simply not. Cooperation between countries will be essential to overcome those barriers and massive changes will have to be done to reach carbon neutrality. There is still a lot of work but also a lot of hope as this proposed system is both technically achievable and economically affordable.

Appendix A

Annex

A.1 Time Series and Capacity Factors

A.1.1 Validity of Considering Countries as one Cell

The version of Energyscope used is a single node version, this means that each country is averaged to one value for the various demands and renewable energy production. This Annex explores succinctly the validity of this assumption for the renewable energy production of France (as it is a big country). It is known that weather varies in function of the region. This small analysis looks if the ratio of the energy produced in one year on the capacity installed is about the same everywhere in France. Also it is interesting to look at the distribution of the capacity across France. For example, if a technology is installed in the South of France, it could be hard to supply the North by using that technology.

Wind Production The distribution of the 2015 installed capacity of wind power in France [57] is shown in Figure A.1. First of all, there was a total of 10.3 GW installed in France in 2015. It is then interesting to assess if it can be assumed that 1 MW installed would produce the same energy on a year wherever the wind farm is installed. This study compares the south (Aquitaine Limousin Poitou-Charentes, Languedoc-Roussillon, Midi-Pyrénées, Auvergne Rhône-Alpes, Provence-Alpes-Côtes d'Azur, Corse) to the north (the rest). Equation A.1 shows that there is four times more wind farms installed in the north than in the south in 2015. Approximately the same ratio is found in Equation A.2 when comparing the yearly produced electricity between the north and south. Since the ratio for energy production and the ratio for the installed capacity are really close, the assumption of using one cell seems valid for wind power in France

$$\frac{\text{Installed Capacity North}}{\text{Installed Capacity South}} = \frac{8251\,\text{MW}}{2061\,\text{MW}} = 4 \tag{A.1}$$

$$\frac{\text{Produced electricity North}}{\text{Produced electricity South}} = \frac{16\,905\,\text{GWh}}{4166\,\text{GWh}} = 4.05 \tag{A.2}$$

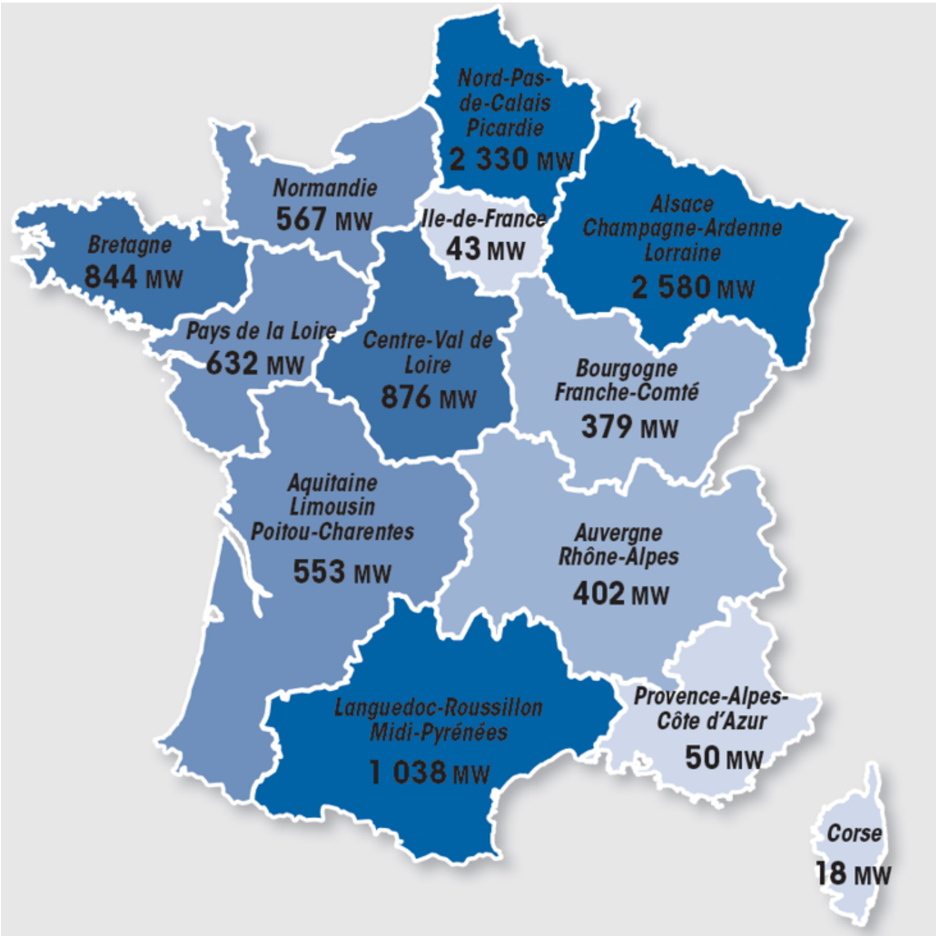


Figure A.1: Geographic distribution of the installed wind power capacity in France in 2015 [57]

Photovoltaic power The PV energy production depends on the irradiance reaching the panels. This irradiance of the sun on the surface of the earth is a strongly weather-dependent power resource. Also there is a certain variance in irradiance between the different regions of France as can be seen in Figure A.2

(expressed in $\frac{\text{kWh}}{\text{kWp}}$). It can be seen that the specific PV power potential can vary, approximately, between 1000 $\frac{\text{kWh}}{\text{kWp}}$ in the North and 1600 $\frac{\text{kWh}}{\text{kWp}}$ in the South. Since more than 72.5% of the territory of France has an irradiance of [3.3 $\frac{\text{kWh}}{\text{kWp}}$ $\pm$ 10%] [60], it can be considered that the yearly variance of the production between the different regions remains under control. Nevertheless, it is important when using EnergyScopeTD to model the sun irradiance by taking a Time Serie that best represents France has a whole.

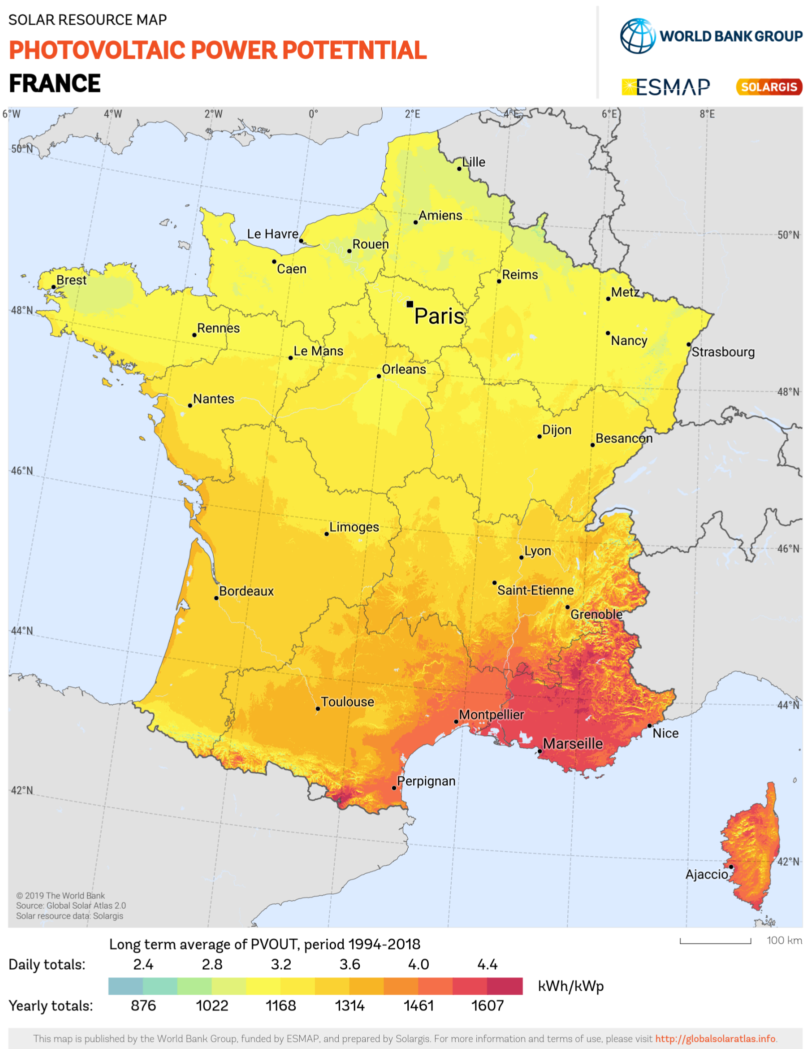


Figure A.2: Specific photovoltaic power potential across France [60]

A.1.2 Geothermal Time Serie

Geothermal energy can collect heat from the sub-surface of the earth. This energy can then be used as heat or can be converted to electricity. As this heat source does not depend on important time-dependent factors, geothermal energy is considered to be constant. It was thus implemented with a constant capacity factor in EnergyScopeTD. This Annex aims at verifying the time-independency of geothermal energy. This will be done by comparing the hourly geothermal electricity production in Italy[24] to a typical nuclear time serie (Germany 2015[24]). The choice of comparing the geothermal TS to a typical nuclear TS is made because, in this study, the nuclear production is considered to be constant eventhough it might vary slightly in reality. The daily averaged time serie of geothermal energy and nuclear can be seen in Figure A.3. The Italian capacity factor of geothermal energy is 0.84 which is a classic order of magnitude for geothermal plants[41]. The results of the variance computation of each time serie is shown in Equation A.3.

$$\text{Var}(\text{Geothermal Time Serie}) = 0.042\,\% \ll 0.48\,\% = \text{Var}(\text{Nuclear Time Serie}) \tag{A.3}$$

Since the variance of the geothermal time serie is much smaller than the variance of the nuclear time serie, this study will thus consider a constant capacity for geothermal energy as was done in previous works[50].

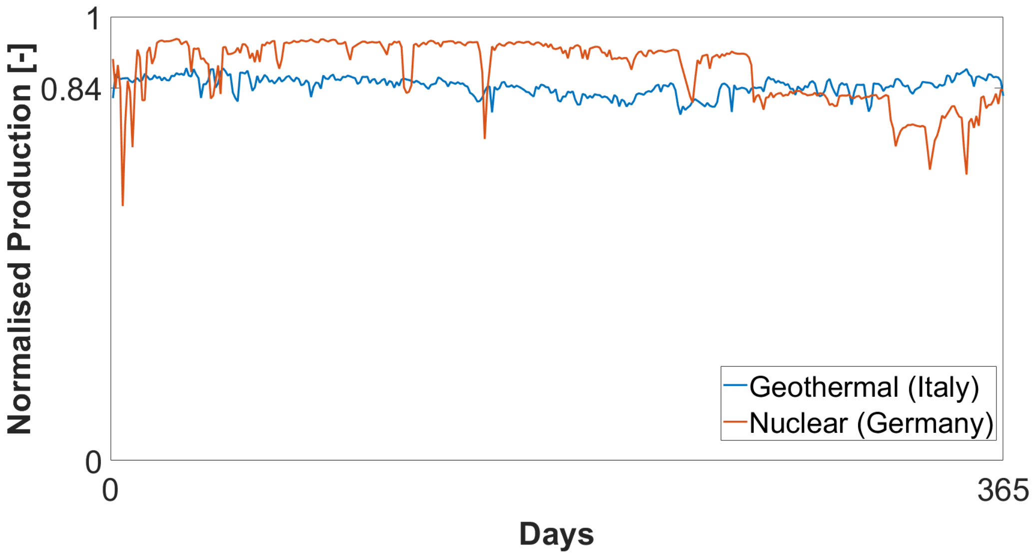


Figure A.3: Normalised production in 2015 of geothermal electricity in Italy compared to nuclear electricity production in Germany[24]

A.1.3 Capacity factors for Offshore wind and Solar Thermal

Offshore wind

Offshore wind is known to have a greater capacity factor than onshore wind. The monthly averaged capacity factor of offshore production can be seen in Figure A.4. Similarly to onshore wind, there is a seasonality with higher capacity factors during the winter. Note that for the winter, all capacity factors for the shown countries are above 50%. During the summer, the monthly averaged capacity factor is lower than during the winter but still remains above the 20%. The duration curve in Figure A.5 shows the sorted hourly capacity factor during the year. This shows that the hourly offshore wind capacity factor is rarely low. Even though offshore wind is a source with very good capacity factors for an intermittent renewable, not every EU country has the opportunity to harvest it. Figure A.6 shows the yearly averaged capacity factor for the EU countries that can benefit from offshore winds. This study does not take into account the offshore winds in the Mediterranean sea since time series were not found. Thus the model we propose does not have offshore wind time series for countries with only a Mediterranean coast or no coast at all. The averaged capacity factor of offshore wind production (by taking only the countries shown in Figure A.6) in our model is equal to 41.2% compared to a value of 38% from Wind Europe [69]. This gives us a moderate level of confidence concerning offshore wind data, as it might be over-evaluated. This can be explained since most of the TS for offshore wind production are based on the MERRA-2 database that uses a model to compute the TS.

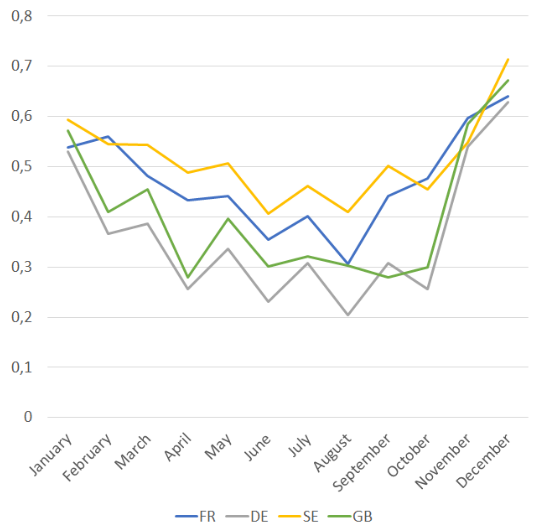


Figure A.4: Monthly capacity factor for offshore wind production based on data for the year 2015 [24] [32].

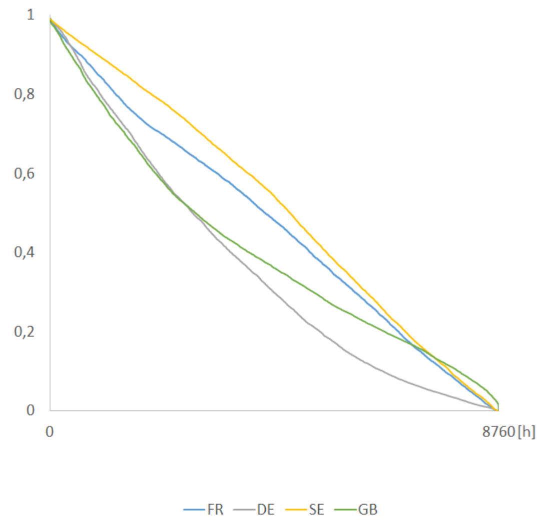


Figure A.5: Duration curve of the offshore wind production based on data for the year 2015 [24] [32].

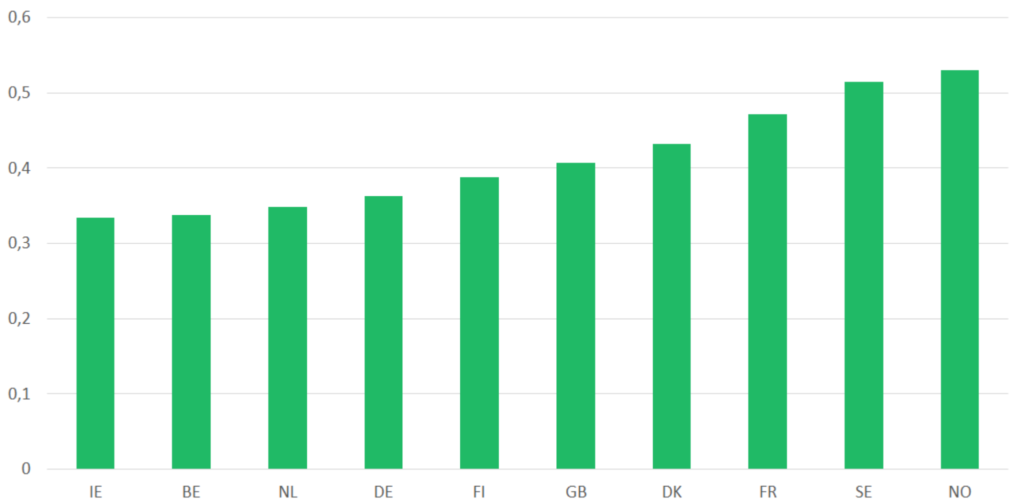


Figure A.6: Yearly averaged offshore wind capacity factor for each EU country based on data for the year 2015 [24] [32]

Solar thermal

As explained in Section 2.2.3, the solar thermal time serie is based on the DNI component of the irradiance. This means that for very cloudy days, there is no energy production, and for very sunny days, the production is at its highest. Thus the periods when we have the sunniest days and longest days will have the highest capacity factors. This is shown in Figure A.7, as PV, solar thermal capacity factor is seasonal and can drop to very low values for countries with very short days during the winter. Added to the seasonality of the time serie, there are the day/night cycles and very cloudy days that reduce the monthly averaged capacity factor. These two characteristics put the production to 0 for most hours of the year as can be seen in Figure A.8. As PV, the solar thermal is dependent on the latitude of the country. This is shown in Figure A.9.

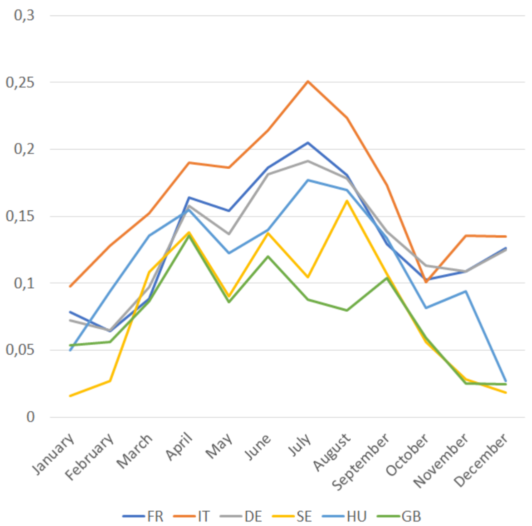


Figure A.7: Monthly capacity factor for Solar thermal production based on data for the year 2015 [42]

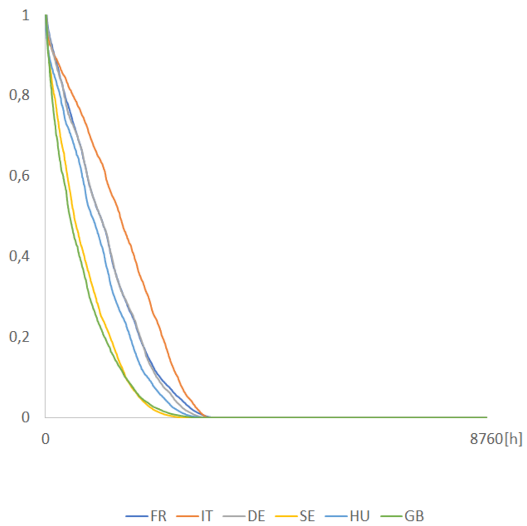


Figure A.8: Duration curve of the Solar thermal production based on data for the year 2015 [42]

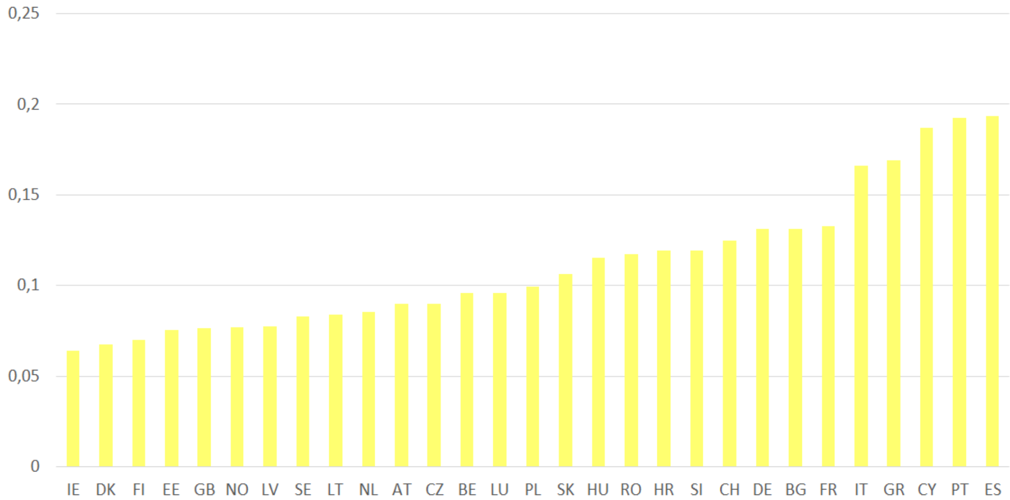


Figure A.9: Yearly averaged PV capacity factor for each EU country based on data for the year 2015 [42]

A.2 Conversion Mobility units into GWh

Mobility EUD, expressed in Mpkm for passenger mobility and in Mtkm for freight, is transformed in GWh using ratios calculated from the EU reference scenario [12]. In this report, EUD for mobility is expressed in both ktoe and Gpkm/Gtkm for passenger and freight mobility. For every country, we use the same ratio based on France Data in 2035. The ratios are calculated using eq. A.4 and A.5 where 11.63 is the conversion between ktoe and GWh, the numerators are the passenger and freight demand expressed in ktoe and the denominators are the passenger and freight demand expressed in Mpkm or Mtkm. After these ratios are obtained, we multiply for each country the demand expressed in Mpkm/Mtkm by these ratios to finally be able to compare the mobility demand to other demands.

$$Ratio_{Mpkm=>GWh} = \frac{11.63[ktoe_{2035}]}{[Mpkm_{2035}]} = 0.320[\frac{GWh}{Mpkm}] \tag{A.4}$$

$$Ratio_{Mtkm=>GWh} = \frac{11.63[ktoe_{2035}]}{[Mtkm_{2035}]} = 0.240[\frac{GWh}{Mtkm}] \tag{A.5}$$

A.3 Further Results

A.3.1 Operating strategy for the Heat Layer of France

The same kind of analysis (as seen in Section 4.3.3) can be done for the heat layer shown in Figure A.10. This Figure shows the great asset of using storage. For example, and as seen before, heat pumps produce low temperature heat when the electricity production is high in order to store it. This storage can then release the low temperature heat when needed as is done for DHN storage during TD-1. Note that for the heat layer, there is no flexible demand as each demand is an EUD type. Also, the heat layer only uses industrial boilers as flexible type of production when high temperature heat can not be supplied through electricity due to a small electricity production of renewables. So almost the entire heat layer is supported with thermal storage.

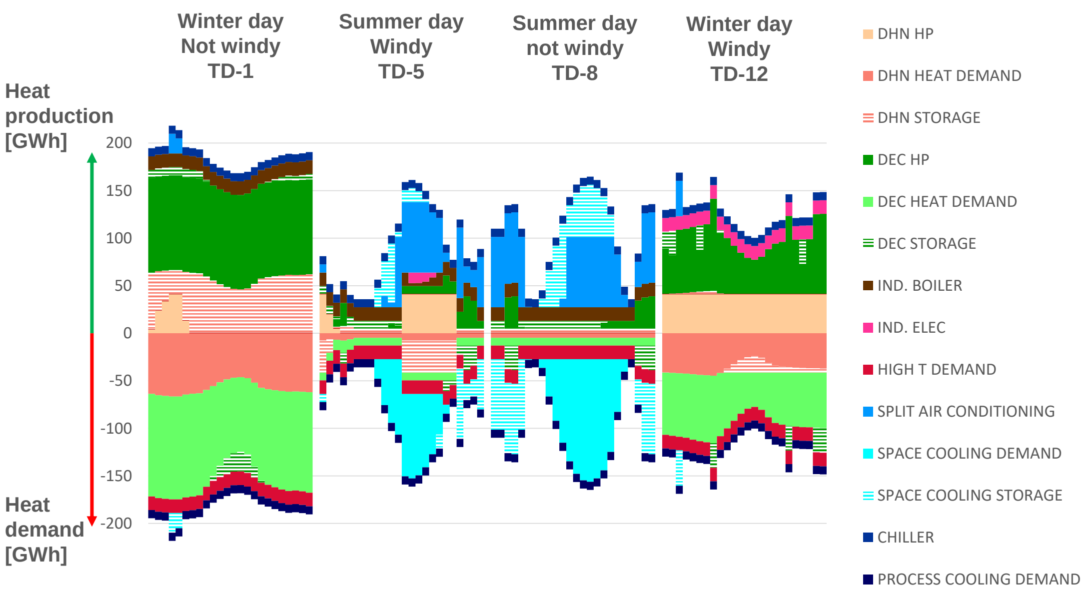


Figure A.10: Energy production and demand for the electricity layer for 4 different TDs

A.3.2 Primary Energy Used for the Minimised GWP Solution

	Biomass	Wind	Solar	Hydro	Geo-thermal	Imported Electricity	Uranium	Natural gas
AT	114.07	92.97	28.24	20.83	3.75	0	0	0
BE	80.14	38.08	49.38	0.12	1.42	5.46	321.98	101.59
BG	53.02	50.26	0.81	5.03	0	0	0	0
CZ	106	85.16	54.35	1.9	3.01	0	0	0
DE	507.56	370	500.61	11.53	17.33	49.97	841.21	272.62
DK	48.03	66.88	0.46	0	0	0	0	0
EE	15.44	18.35	0.03	0.02	0	0	0	0
ES	231.64	463.54	67.64	29.14	0	0	0	0
FI	46.71	134.14	0	15.52	0	0	0	0
FR	553.53	932.76	6.38	48.64	4.36	0	0	0
GB	171.67	820.07	97.77	3.08	6.63	0	0	0
GR	39.5	85.45	31.02	8.52	0	0	0	0
HR	21.74	12.95	13.31	6.01	2.26	0	0	0
HU	62.24	99.57	16.3	0.18	0	0	0	0
IE	15.73	74.06	0	0.5	0	0	0	0
IT	255.43	264.78	508.32	31.61	8.29	0	0	0
LT	25.72	29.43	0.21	0.28	0	0	0	0
LU	8.01	7.07	7.63	0.04	0	0	0	0
LV	20.29	17.61	0.57	3.03	0	0	0	0
NL	78.91	182.13	38.05	0	1.42	4.5	123.32	152.59
PL	254.78	430.64	0.01	1.23	0	0	0	0
PT	45.12	80	23.1	7.49	0	0	0	0
RO	199.97	74.87	11.54	16.02	0	0	0	0
SE	104.47	161.74	0	71.76	0	0	0	0
SI	21.74	3.37	7.24	3.08	0.59	0.65	31.01	2.54
SK	45.66	33.91	48.88	3.71	2.26	0	0	0
EU	3127.1	4629.78	1511.86	289.27	51.32	60.58	1317.51	529.34

Table A.1: Primary energy used [TWh] for the minimised GWP solution shown in Section 4.2

A.4 LCOE Calculations

This annex describes how is calculated the Levelised Cost of Energy (LCOE) discussed in Section 5.2. Equation A.6 is an adaption of equation (1) to (4) of EnergyScopeTD supplementary material [48]. This equation is simply the ratio between total annualised cost and total annualised energy produced. All costs are in €2015.C_{inv} is the total investment cost in $\frac{M€}{GW}$. The total investment cost is covered over the lifetime of the power plant through the Capital Recovery Factor (CRF) described in Equation A.7 where i is the interest rate and y is the lifetime of the power plant. C_{maint} is the annual maintenance cost in $\frac{M€}{GW}$. C_{op} is the cost of the resource used in $\frac{M€}{GWh}$. τ is the inverse of the efficiency to convert the resource into electricity. C_p is for technologies that use resources the charge factor that accounts for maintenance time where no electricity is produced. For renewables however, C_p is the annual capacity factor described in Section 3.2. This last value change for every renewable and every country. 8760 are simply the number of hours in a year. By multiplying it to C_p the energy produced by 1 GW of installed capacity is obtained.

$$\text{LCOE} = \frac{CRF.C_{inv} + C_{maint} + C_{op}.\tau.C_p.8760}{C_p.8760} \tag{A.6}$$

$$\text{CRF} = \frac{i.(i+1)^y}{(i+1)^y - 1} \tag{A.7}$$

To adapt prices from the literature where prices can be expressed in other currencies than € and that price can refer to prices of other years than 2015 which is the reference year. Equation A.8, from EnergyScopeTD supplementary material [48], does that conversion. As described in the supplementary material, C and y are the currency and the year in which the original cost data are expressed, respectively, is the symbol of American Dollars and the Chemical Engineering's Plant Cost Index (CEPCI) is an index taking into account the evolution of the equipment cost. The CEPCI are issued from [48] for dates prior to 2015 and [4][5] for later dates. Conversion between USD and € is done using exchanges rates from 1$^{\text{st}}$ January 2015 found on [31].

$$\text{LCOE}[€_{2015}] = \text{LCOE}[\text{C}_\text{y}].\frac{\text{USD}_y}{\text{C}_y}.\frac{\text{CEPCI}_{2015}[\text{USD}_{2015}]}{\text{CEPCI}_\text{y}[\text{USD}_\text{y}]}.\frac{€_{2015}}{\text{USD}_{2015}} \tag{A.8}$$

A.4.1 Fossil Fuel Choice by EnergyScopeTD

This annex does a quick review on why EnergyScopeTD chooses to implements nuclear power plants, coal power plants and CCGTs in the cost-optimised solution even though nuclear has the lowest LCOE followed by coal and then only CCGTs (See Section 5.2). However, their CAPEX and OPEX differs significantly between each others with nuclear having the highest CAPEX followed by coal and then gas which is the cheapest. For OPEX, nuclear has by far the lowest operating cost followed by coal and then gas.

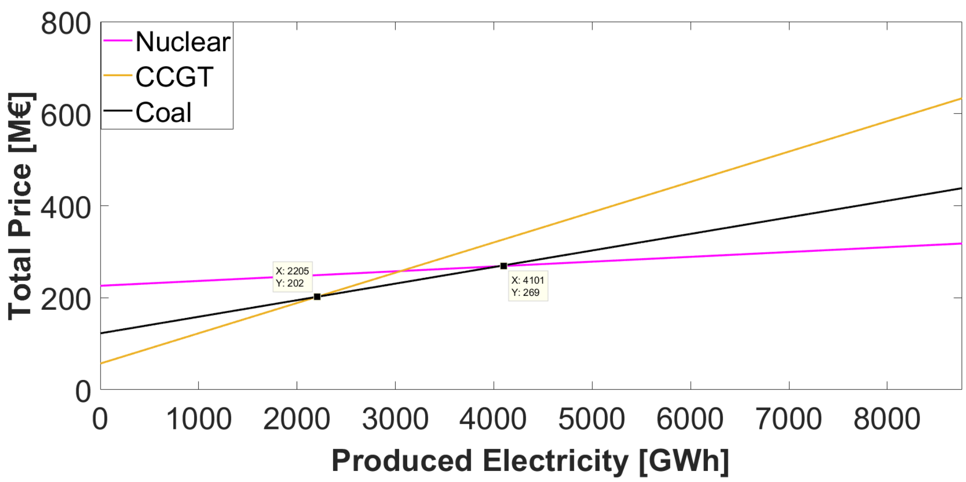


Figure A.11: Comparison of nuclear, CCGTs and coal power plants for 1 GW of installed capacity based on OPEX and CAPEX.

Figure A.11 illustrates that disparity for 1 GW power plants. The intercept is the CAPEX for nuclear, coal and NG. It includes maintenance cost and total investment cost over the lifetime including capital cost which is then divided by the lifetime of the plant to get the yearly cost for a 1 GW power plant. The x axis is the energy produced by the power plant. Note that none of the plants can produce 8760 GWh over the year as they all have a charge factor. The slope of the lines is the operating cost is calculated as $\frac{C_{op}.\tau.C_p.8760}{C_p.8760}$. However, installed power plant capacity can not always produce electricity as some other source of energy may be cheaper at a time. However, those renewables sources may not be available all the time and in these times power plants start functioning as peak load[1]. Note that the CAPEX of those power plants still needs to be paid even though they can

[1] Nuclear is coded in EnergyScopeTD such as it always function as base load similarly as what is done in reality.

produce only during a small portion of the year, increasing the effective LCOE. EnergyScopeTD chooses either coal or CCGT to do the peak load and this choice is motivated by the total energy needed in peak load. If up to one GW is needed in peak load, EnergyScopeTD installs preferably CCGTs if less than 2205 GWh are needed yearly in peak load and coal otherwise. Note that in case of more capacity needed EnergyScopeTD may result in choosing a clever mix of both to pay the less overall.

A.5 Data Tables

	Electricity [TWh]	Heating [TWh]	Cooling [TWh]	Mobility [TWh]	Non-Energy [TWh]	Population [M inhabitants]
AT	64.44	151.39	12	63.34	28.41	9
BE	83.22	203.71	20	85.56	102.33	13
BG	26.4	48.29	3.16	34.86	7.58	6
CZ	56.38	152.03	9	65.89	33.48	11
DE	472.81	1139.88	105	603.81	312.27	79
DK	34.48	75.72	7.97	41.02	4.15	6
EE	7.76	18.1	2	9.12	3.68	1
ES	199.95	325.11	100	316.47	77.35	44
FI	67.66	116.79	12	47.42	14.85	6
FR	392.49	701.44	116	565.5	176.15	68
GB	316.05	601.03	47	407.08	104.77	72
GR	46.76	53.95	18.92	72.27	10.21	10
HR	14.34	30.6	7.57	18.47	6.44	4
HU	36.14	94.03	6	49.57	39.68	10
IE	26.48	49.41	3.26	35.57	5.51	5
IT	286.21	578.33	123	439.95	88.14	65
LT	9.77	22.7	4	21.11	8.7	2
LU	8.52	12.85	1.54	5.68	0.58	1
LV	7.65	25.71	4	15.76	1.77	2
NL	109.48	247.75	31	104.13	181.25	18
PL	169.45	424.69	25	214.03	90.99	37
PT	34.3	69.1	22.73	56.6	18.04	10
RO	50.38	157.74	10	75.01	28.9	19
SE	111.4	163.33	22	88.69	29.68	11
SI	14.67	18.92	3.78	17.43	1.52	2
SK	29.8	69.33	3	27.99	24.96	5
EU	2676.97	5551.92	719.94	3482.31	1401.42	516

Table A.2: End Use Demands and population forecasted for 2035 shown in Section 3.1 and used to compute the R ratio in Section 3.4.

	PV	CSP	Onshore	Offshore	Dam	River	Tidal	Geothermal
AT	49.51	0.94	40.86	0	2.97	5.54	0	0.5
BE	55.39	3.84	20.38	0.71	0	0.17	0	0.2
BG	100.16	2.71	50.94	9.43	1.57	0	0	0.6
CY	13.48	1.39	5.97	3.36	0	0	0	0
CZ	114.53	3.96	43.17	0	0.65	0.44	0	0.4
DE	442.98	25.85	176.4	23.85	1.52	3.99	0.33	2.3
DK	51.37	4.52	24.9	76.28	0	0.01	0	0.2
EE	31.58	2.36	17.24	15.96	0	0.01	0	0
ES	907.67	26.04	346.09	119.4	18.19	1.09	0.08	3.2
FI	0.24	0.01	109.83	57.19	0	3.26	0	0.3
FR	1017.51	41.97	375.07	93.16	8.21	10.31	19.01	4.5
GB	454.8	16.06	191.85	609.56	0	4.16	21.02	1
GR	110.36	2.29	57.23	83.95	2.46	0	0	0.8
HR	52.52	4.08	20.34	41.32	1.44	0.42	1	0.8
HU	206.44	22.41	74.12	0	0.03	0.03	0	1
IE	161.02	9.26	60.09	241.67	0	0.22	3.59	0.3
IT	295.81	16.27	176.41	128.72	4.38	10.39	0	1.1
LT	100.99	8.66	43.18	0.49	0	0.13	0	0.2
LU	10.55	0.11	3.64	0	0.01	0.03	1	0.2
LV	56.42	3.71	26.08	25.82	1.54	1.54	0	0.1
NL	31.17	3.96	15.16	54.98	0	0.04	0.83	0.2
PL	449.19	33.67	175.34	13.38	0.16	0.38	0	1.2
PT	116.65	1.71	39.69	10.98	1.44	2.98	0	0.5
RO	415.05	29.04	169.6	17.34	3.8	2.67	0	0.9
SE	93.24	4.14	153.04	114.82	15.96	0	0	1.3
SI	8.18	0.3	4.75	0	0	1.05	0	0.1
SK	62.32	2.96	26.49	0	0.42	1.2	0	0.3

Table A.3: Maximum installable capacity [GW] for renewables across the EU shown in Section 3.2.

	Dam	River	On-shore	Off-shore	Wood	Wet Biomass	Waste	PV	CSP	Geo-thermal	Tidal
AT	3.02	5.65	94.61	0	98.47	6.07	9.52	69.14	0.74	3.72	0
BE	0	0.12	39.89	2.10	23.43	38.88	17.83	57.71	3.22	1.49	0
BG	5.03	0	104.5	0	34.65	9.83	8.55	130.01	3.12	4.47	0
CY	0	0	6.66	0	0.49	3.2	0.44	22.1	2.27	0	0
CZ	1.17	0.73	85.17	0	63.07	30.45	12.48	159.96	3.12	2.98	0
DE	0.61	13.11	323.03	75.82	321.64	123.72	62.2	476.44	29.68	17.13	0.33
DK	0	0	61.57	288.58	11.37	39.3	6.18	52	2.67	1.49	0
EE	0	0.03	40.18	0	32.41	0.28	0.76	27.16	1.56	0	0
ES	22.17	7.65	760.71	0	81.9	158.7	38.2	1550.22	44.12	23.83	0.08
FI	0	15.52	338.26	194.28	246.57	13.51	11.1	0.21	0.01	2.23	0
FR	15.58	38.76	712.1	385.12	324.69	162.08	57.78	1156.19	48.89	33.51	19.01
GB	0	8.95	536.5	2170.14	66.4	55.31	89.97	433.4	10.8	7.45	21.02
GR	0	0	134.33	0	12	26.74	9.93	163.03	3.39	5.96	0
HR	4.63	1.46	15.52	0	17.56	0.92	3.26	55.36	4.26	0.3	0
HU	0.11	0.09	154.88	0	32.38	19.53	10.34	251.94	22.6	7.45	0
IE	0	0.75	168.47	708.19	13.4	2.08	6.54	143.75	5.18	2.23	3.59
IT	6.03	27.71	265.81	0	69.3	133.43	52.7	444.06	23.67	8.19	0
LT	0	0.31	106.4	0	28.21	7.59	2.71	94.94	6.37	1.49	0
LU	0.02	0	7.12	0	2.34	3.89	1.78	11	0.09	0	0
LV	2.89	1.46	61.73	0	41.62	0.48	0.57	51.71	2.52	0.74	0
NL	0	0	34.55	168.02	9.78	56.38	12.75	32.61	2.97	1.49	0.83
PL	0.12	1.35	400.05	0	143.94	138.37	51.24	486.12	29.34	8.94	0
PT	1.62	6.19	100.26	0	35.18	11.16	17.39	214.38	2.88	3.72	0
RO	6.69	10.49	350.54	0	142.48	42.33	15.15	534.37	29.81	6.7	0
SE	71.77	0	395.77	517.6	310.5	4.87	15.31	88.16	3.02	9.68	0
SI	0	3.66	3.63	0	17.56	0.92	3.26	8.62	0.32	0.74	0
SK	0.17	3.58	34.15	0	30.33	9.99	5.34	74.08	2.76	2.23	0
EU	141	147	5336	4509	2211	1100	523	6788	289	158	44

Table A.4: Renewable energy potential [TWh] shown in Section 3.3 and used in Section 3.4 to compute the R ratio.

Country	Net Transport Capacity [MW]
AT	12560
BE	8880
BG	4500
CH	13100
CY	0
CZ	5300
DE	33515
DK	10165
EE	2366
ES	9200
FI	4200
FR	24480
GB	12250
GR	4510
HR	5850
HU	7900
IE	1600
IT	8340
LT	2900
LU	2480
LV	2750
NL	10800
NO	8835
PL	6190
PT	3500
RO	3800
SE	11090
SI	5750
SK	4090

Table A.5: Grid Import Capacity 2025 projection for European countries[24]. Country grid divided in multiple local grids are aggregated together

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