Electricity Without Borders

The need for cross-border transmission investment in Europe

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PROEFSCHRIFT

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Carlo Brancucci Martínez-Anido – September 2013

1. Introduction

Parts of this chapter are based on the following book chapter:

- Zeniewski, P., Brancucci Martínez-Anido, C., Pearson, I.,**Framing new threats and securing networks: the case of gas and electricity in the EU**, in *International Handbook of Energy Security* (eds. Hugh Dyer & Julia Trombetta), Edward Elgar Publishing, July 2013.

1.1. Background and motivation

In the coming decades, several trends driven by different policy goals may lead to an increase in cross-border electricity flows in Europe. First of all, the penetration of variable renewable energy sources (RES) is expected to increase substantially. A related trend that will impact cross-border electricity flows is the potential RES development in the Middle East and North Africa (MENA) region and the electrical integration of the Euro-Mediterranean region. Other trends that will impact electricity flows across borders are the electrification of transport, the potential charging strategies of electric vehicles (EVs) and possible shifts in electricity generation dispatch due to the evolution of CO_2 prices.

1.1.1. Decarbonisation of the power sector

In order to keep the overall global annual mean surface temperature increase below 2° Celsius above pre-industrial levels, the European Council concluded on 4 February 2011 (EUCO, 2011) that "reaching the EU objective [. . .] of reducing greenhouse gas emissions by 80-95% by 2050 compared to 1990", in the context of necessary reductions according to the Intergovernmental Panel on Climate Change (IPCC) by developed countries as a group, "[. . .] will require a revolution in energy systems, which must start now". In order to achieve a low-carbon economy, electricity will have to play a central role. As stated in a communication from the European Commission (EC, 2011a), the electricity sector "can almost totally eliminate CO_2 emissions

by 2050, and offers the prospect of partially replacing fossil fuels in transport and heating". Consequently, the European Commission has called for a decarbonised European power sector (EC, 2011a). Almost totally eliminating CO_2 emissions from electricity generation is technically feasible but will require substantial investments in every segment of the power sector, from generation to transmission and distribution as well as consumption.

The European Commission (as stated in its "Energy Roadmap 2050" communication to the European Parliament, the Council, the European Economic and Social Committee, and the Committee of the Regions) expects RES share to reach at least 55% in gross final energy consumption in 2050 in all its scenarios (EC, 2011b). Together with hydro, wind and solar energy are the two main renewable sources of energy. The primary challenge arising from the expected large penetration of RES is how to cope with the variability and unpredictability of wind speed and solar radiation.

1.1.2. Challenges from the integration of renewable energy

RES integration brings several challenges to electricity networks. First of all, the structural characteristics of the electricity system must undergo fundamental changes in order to accommodate the large-scale deployment of RES. The traditional structure of the power system is evolving by introducing electricity generators at lower voltage levels and at widely distributed locations. In this evolution, electricity consumers can become producers as well (also known as prosumers), depending on their RES electricity output at a given moment in time. In addition, RES integration affects generation adequacy and back-up needs. Traditional electricity generation technologies are characterised by specific availability factors which may depend on several aspects, such as maintenance time, overhaul, reserves and potential unplanned interruptions. For RES, however, availability factors depend on the wind and solar radiation resources in the geographical location of the wind turbines or the PV panels. In the case of hydro energy sources, their availability depends on the characteristics of the power plant, if it is driven by run of river, its power output is partly controllable and can be quite accurately predicted; in the case of storage and/or pumping facilities, the power output can be fully controlled and its management depends on seasonal hydro inflows.

The European Commission defines security of electricity supply as the "ability of an electricity system to supply customers with electricity" (EC, 2005). However, the simplicity of this definition belies the complexity of electricity generation and transport. Indeed, unlike primary fossil fuels such as gas, oil and coal, electricity is

a transformed form of energy that cannot be easily stored. Because of this unique attribute, most electricity must be consumed whenever it is produced. This intrinsic characteristic challenges the integration of renewables into the electricity generation portfolio due to their variability and their partial unpredictability.

An important measure that is used by the European Network of Transmission System Operators for Electricity (ENTSO-E) for the analysis of the generation adequacy in a specified country or region is the Reliable Available Capacity (RAC), which is equal to Net Generating Capacity (NGC) minus the Unavailable Capacity. The latter consists of Non Usable Capacity, maintenance, overhauls, outages and system reserves. The Unavailable Capacity is an important tool for estimating the additional investments necessary for ensuring security of supply, particularly in cases where a large amount of electricity is generated by RES. However, European TSOs account for the unavailability or the Non Usable Capacity of wind and solar energy sources in very different and conflicting ways (ENTSO-E, 2012a). According to some TSOs, wind generation capacity must be considered totally (100%) or almost totally (94-96%) as Non Usable generation when assessing generation adequacy due to the variable and uncertain characteristics of wind power generation. Other TSOs only consider the average unavailability factor (70-75%) of wind power generation. In order to efficiently plan the future European electricity infrastructure, it is necessary that common definitions are used by all stakeholders. As the Agency for the Cooperation of Energy Regulators (ACER) stated, "it is important that ENTSO-E promotes new methodological approaches to estimate reliable capacity of wind and solar power plants" (ACER, 2012).

The RAC of RES depends on the size of the region that is considered and on the location and distribution of the wind turbines and the solar panels. Several studies (Li et al., 2009; Hoicka & Rowlands, 2011; Widén, 2011) have analysed the correlation and potential complementarity of wind and solar energy sources. In some cases, these correlations increase the RES contribution in the RAC estimates. A recent study (Grave et al., 2012) defines the concept of "secure capacity", which results from a combination of several probabilistic distributions on the availability of each type of generation capacity. The increase in secure generation capacity provided by wind or solar energy generation is defined as their "capacity credit". The study focuses on Germany and assumes that the secure capacity for solar energy generation is 0%, since the annual peak demand occurs during hours of relative darkness, between 6 and 7 p.m. in a winter evening. However, this result will probably not be applicable to Southern European countries which observe annual peak load demand in the middle of a summer day due to the high air conditioning demand. In this

case the "secure capacity" or "capacity credit" of solar energy generation would be higher. The same study (Grave et al., 2012) calculates that the capacity credit for wind lies between 5.2% and 6.2% of total installed wind generation capacity. The capacity credit depends on the distances between wind parks. When they increase, the correlation between the wind resources decreases and therefore the distribution function of wind energy generation flattens and the capacity credit grows.

The calculation of the capacity credit of wind or solar energy generators is based on meteorological statistical databases. The longer the period under analysis, the more accurate the capacity credit values are. Intuitively, and due to the previously mentioned geographical correlation of natural wind resources, considering an interconnected larger area provides a higher RES capacity credit, which means that secured capacity needs from other energy sources (such as gas-fired power plants) will be lower. The challenges that RES pose to security of supply, mainly in terms of "secure capacity", can be balanced by technological means such as the development of cross-border electricity transmission capacity, electricity storage and demand response.

A large share of variable RES does not challenge security of supply only in terms of generation adequacy. The increase in cross-border electricity flows triggered by RES impacts network reliability and, therefore, security of electricity supply. For instance, "the 6 blackouts that occurred in 2003 within 6 weeks impacting upon 112 million people in the US, UK, Denmark, Sweden and Italy demonstrate that increased cross-border trade of electricity resulting from the liberalisation of the electricity supply industry was not accounted for in the assessment of system security" (SESAME, 2012). The increase in cross-border electricity flows may also lead to network congestion which, in turn, increases transmission losses.

In the coming decades, European electricity networks will be facing several challenges (SESAME, 2012). These include economic risks (e.g. under-investment and rising electricity demand) and external events (e.g. natural calamities, severe weather conditions, nuclear accidents, terrorist attacks and cyber attacks). Moreover, "the high penetration of renewables in the grid will require detailed system planning coupled with accurate resource and load forecasting across Europe".

1.1.3. The demand for transmission network capacity

Electricity transmission is an enabling technology that can be used to alleviate, to a certain extent, the challenges that variable RES pose to the security of electricity

supply in Europe. Several studies state that electricity transmission development, including cross-border interconnections, is essential in order to cope with the variability of RES and to reach the almost total decarbonisation of the European power system by 2050 (EC, 2011a; Jaureguy-Naudin, 2012). A recent study (Haller et al., 2012) states that "if transmission and storage capacities are expanded well above their current levels, a near complete decarbonisation of the power sector can be achieved". For instance, ENTSO-E's latest TYNDP (ENTSO-E, 2012b) claims that 80% of the planned electricity transmission projects for the next decade will bring high benefits for the expected RES integration; half will directly connect RES and the other half will accommodate inter-area imbalances triggered by RES.

Electricity transmission development is not only beneficial for integrating RES and for increasing and ensuring security of supply. From the overall welfare point of view, research has shown that the European transmission network is experiencing serious underinvestment (Supponen, 2012). The benefits and needs of further expanding the European electricity transmission network have been frequently discussed in the literature. For example, "cooperative behaviour in developing renewable energy technologies across borders and/or cross-border transmission capacity investment can reduce the cost of achieving a renewable energy target" (Saguan & Meeus, 2011). A study stating that "a large-scale wind, water, and solar energy system can reliably supply all of the world's energy needs [. . .] at reasonable cost" highlights the need to expand the electricity transmission network considerably in order to accommodate the new sources of power (Delucchi & Jacobson, 2011).

1.1.4. Problem statement

Ideally, the best way of assessing the adequacy of the European transmission network would be to compare the present or the expected future infrastructure with the optimal level. However, "optimality" depends on how public values are interpreted, and since there are conflicting values (and interpretations) involved, it is bound to be politically contested. Furthermore, the assumptions considered in the model and in the analysis will always lead to uncertainties in the optimal transmission investment level. Given the difficulties in calculating the optimal level of cross-border electricity transmission investment, it is important to first understand and explore if and why there is a need for such investment in Europe in the coming decades.

In order to investigate the need for cross-border electricity transmission investment in Europe, it is necessary to model the impacts of cross-border transmission capacity expansion on the European interconnected power system. These impacts should be

analysed not only in terms of electricity dispatch costs but also in terms of renewable energy curtailment, security of supply and CO_2 emissions.

Energy storage and demand response can have similar impacts as cross-border transmission on the power system. Therefore, a study is needed about the way in which investments in cross-border electricity transmission impact the need for energy storage and demand response investments.

1.2. Modelling the European electricity system

Several dispatch and investment models have been developed in recent years in order to answer different questions about the European electricity transmission system. For example, ELMOD (Leuthold et al., 2008; Weigt et al., 2010), a non-linear optimisation model maximising welfare under perfect competition, includes a very detailed representation of the transmission grid of a European region, mainly Germany, but does not model every hour of a year. In contrast, COMPETES (Lise & Hobbs, 2005) covers 20 European countries with a detailed representation of every single power plant (in order to observe differences between perfect and strategic competition), but the representation of the electricity network is aggregated to one node per country and the year is divided into 12 demand periods. LIMES (Haller et al., 2010; Haller et al., 2012), a multi-scale power system model that integrates optimal investment allocation in grid and generation capacities into a single optimisation framework, represents 20 geographical regions connected by 32 transmission corridors. Long-term investment decisions are modelled with time steps of 5 years, while short-term fluctuations are represented by 49 different periods. MTSIM (Zani et al., 2011) is a zonal electricity market simulator that determines hourly market clearing prices for a whole year. The power system is modelled by an equivalent representation with one node per country.

The European Climate Foundation (Hewicker et al., 2011) uses an electricity generation dispatch model within the study of potential decarbonisation pathways for Europe. Some of its key features are its hourly resolution, hydro optimisation, storage utilisation and the flexibility of demand. However, the model divides Europe into nine regions in order to reduce complexity. The authors of a recent publication (Lynch et al., 2012) use a model to determine the optimal amount of investment in new generation capacity as well as optimal investment in cross-border transmission for a test system of eight Northern European countries from 2011 until 2030.

The model has an hourly resolution but it does not consider the start-up costs of conventional power plants.

Both URBS-EU (Schaber et al., 2012) and PowerACE-Europe (Pfluger & Wietschel, 2012) include several nodes representing European regions or countries and simulate investment in power generation, network extensions and storage in order to obtain the least-cost solution for meeting demand in each hour of the year and in each hour of six representative weeks, respectively. IPM, an investment planning model (Neuhoff et al., 2008), is used to analyse the cost savings from transmission expansion. It captures the variability of wind but it only considers 20 load segments per week. MESEDES, a multi-objective model, identifies optimal generation and cross-border transmission investments (Unsihuay-Vila et al., 2011). The model only considers three load segments corresponding to low, medium and peak demand.

To my knowledge, a single model with high geographic and temporal resolutions that represents every node of the European electricity transmission network for every hour of a given year does not exist. Moreover, it would be difficult to populate such a model with equally accurate supply and demand data for each node, as much of this data is not available. Therefore, depending on the scope of the research undertaken, each dispatch or investment model focuses on different aspects, looks at different elements, has different temporal and spatial resolutions and sets different geographical boundaries. However, none of the models that have been introduced simulate the entire interconnected European power system with one-hour time steps for an entire year in order to account for the hourly and seasonal variability of renewable energy sources as well as to represent the short- and long-term management of energy storage and the short-term scheduling of demand response.

1.3. Modelling approach

As part of the research presented in this thesis, EUPowerDispatch was developed. This model, which is described in Chapter 2, is a minimum-cost dispatch model of the European electricity system which is used to investigate the need for cross-border electricity transmission investment in Europe. EUPowerDispatch represents 32 interconnected European countries and is designed to study an interconnected multi-national power system with high renewable energy sources penetration. Due to the variable nature of RES, a high time resolution is of paramount importance for analysing their impacts on network planning and operation. Therefore, the time step of EUPowerDispatch is set to one hour. The model simulates the European trans-

mission network for an entire year in order to account for RES variability in terms of seasonality and possible long periods (weeks/fortnights) of low or high wind. EUPowerDispatch uses actual weather data concerning wind speed, solar radiation and precipitation. The available data for wind speed and solar radiation have different temporal and spatial resolutions, but each data set covers the same entire year. This feature ensures that potential correlations (between wind speed, solar radiation, hydro precipitation and electricity consumption) that may affect the management and operation of the European electricity transmission network are taken into consideration.

The distinctive feature of EUPowerDispatch compared with the other tools described in the previous section is the annual management of energy storage. The energy storage elements represented in the model are hydro reservoirs, which, depending on the country, may have natural inflows and/or pumping capacity. The detailed modelling of hydro energy sources in the model provides support for the annual management of hydro reservoirs, which can be very valuable for managing a network with a very high RES penetration for balancing purposes as well as for reducing overall annual electricity generation costs. In addition, for some specific applications, EUPowerDispatch is expanded by including demand response in the form of controlled electric vehicle (EV) charging.

Given the detailed modelling of energy storage and demand response within EUPowerDipatch, the model can be used to investigate the impact of cross-border transmission capacity expansion on energy storage and demand response investments, and vice versa.

1.4. Research questions

The main research question of this thesis is:

What is the impact of possible changes in generation and demand patterns on the adequacy of cross-border transmission capacity in Europe?

EUPowerDispatch is applied to four independent studies, each of which answers a sub-research question. First of all, the impacts of different generation and demand patterns, partly driven by renewable and carbon policies, are explored with respect to the need for cross-border electricity transmission investment in Europe. The results are analysed in view of the EU's main policy objectives of economic efficiency,

security of supply and environmental sustainability. The effects on economic efficiency are measured in terms of the impact on dispatch cost and curtailment of RES (the latter is not always caused by the lack of cross-border transmission capacity, it may also be driven by costly and inefficient start-ups of conventional power plants). Security of supply is operationalised as the expected volume of unserved energy demand per year, while CO_2 emissions are used as an indicator for environmental sustainability. On this subject, Chapter 3 answers the following research question:

What are the impacts of the expected cross-border electricity transmission capacity expansion in Europe by 2025 on dispatch costs, RES curtailment needs, CO_2 emissions and unserved load for different scenarios in terms of electricity demand growth, RES penetration and CO_2 price?

The challenges that arise from RES volatility could be decreased not only by the increase of cross-border electricity transmission capacity but also by investments in energy storage and demand response mechanisms. Therefore, Chapters 4 and 5 answer the following two research questions:

To what extent do cross-border transmission and energy storage substitute and/or complement one another?

To what extent do cross-border transmission and demand response substitute and/or complement one another?

Several European initiatives promote the development of renewable energy sources in North Africa as well as the electrical integration of the two shores of the Mediterranean Sea. The success of such initiatives will depend, among other obstacles, on the ability of the European electricity network to suitably accommodate electricity imports from North Africa. In this respect, Chapter 6 presents a study which answers the following research question:

What are the impacts of North-African electricity imports on the European power system?

Cross-border electricity transmission investment plans are expected to positively impact the security of electricity supply. Therefore, two additional studies, which are presented in Chapter 7, independently analyse the impacts of network topology and of cross-border transmission capacity on network reliability by analysing monthly

statistics of major fault events in several European electricity transmission networks in order to answer the following sub-research questions:

What are the impacts of national (internal) network interconnectivity on the occurrence of major fault events and on Energy Not Supplied (ENS), Total Loss of Power (TLP) and Restoration Time (RT)?

What are the impacts of cross-border electricity transmission capacity on the occurrence of major fault events?

1.5. Thesis structure and reading guide

Chapter 2

Chapter 2 presents and describes EUPowerDispatch providing a detailed model description, including its mathematical formulation. EUPowerDispatch has been used to conduct four different studies presented in chapters 3, 4, 5 and 6. The essence of the model is the same for the four studies, however, some features were modified or added to adapt the model for the specific goals of each study. The model features that are specific to one of the four studies are described in the corresponding chapters.

In addition, Chapter 2 provides an overview of the common scenario data used in the three studies presented in chapters 3, 4 and 5. These compare different model runs which correspond to different scenarios with varying electricity demand, generation capacities, CO_2 price and cross-border transmission capacities.

The scenario data for the study in chapter 6 is described in that chapter, because the study was done before updating the scenario data used for the other studies. In addition, the study presented in chapter 6 looks at a different time horizon, 2030. Chapter 3 considers 2010 and 2025. Chapters 4 and 5, instead, only consider 2025 (but they also include scenarios representing no investment in cross-border electricity transmission in Europe between 2010 and 2025, and therefore also use 2010 data for cross-border transmission).

Finally, this chapter concludes with a study used to validate EUPowerDispatch.

Chapter 3

Chapter 3 presents a study which discusses the evolution of the European electricity transmission network between 2010 and 2025. It assesses the impacts of the expected investments in cross-border transmission capacity in Europe by 2025 on dispatch costs, on RES curtailment needs, on CO_2 emissions, on hydro pumping utilisation and on unserved load. In addition, a sensitivity analysis is performed by assessing the latter's impact on different levels of electricity consumption, RES penetration and CO_2 price.

Chapters 4 & 5

Chapters 4 and 5 independently analyse the extent to which investments in energy storage and demand response can either substitute or complement the need for cross-border transmission investment in Europe. Complementarity is defined as the reciprocal relation whereby an increase in one variable increases the demand for another. Substitution, on the other hand, refers to the capacity of one variable to replace demand for the other. The impacts of investments in hydro pumping capacity and in controlled electric vehicle (EV) charging are compared with the impacts of cross-border transmission investment on dispatch costs, on RES curtailment needs, on CO_2 emissions, on unserved load, and on one another for high RES scenarios.

Chapter 6

Chapter 6 presents a study in which EUPowerDispatch investigates the effects of North-African imports on the European power system. The analysis is performed in combination with a detailed analysis of the impacts on the Italian transmission grid. Within a common set of assumptions, the two interrelated studies analyse the North-African import impact in terms of marginal prices in the European countries and the Italian market zones as well as cross-border electricity flows for the different scenarios.

Chapter 7

Chapter 7 includes two studies which independently analyse the impacts of network topology and of cross-border transmission capacity on network reliability. In the two studies, network reliability is assessed using monthly statistics of major fault events

on electricity transmission networks. The first study analyses the impact of national (internal) network interconnectivity on the occurrence of major fault events and on three reliability indicators: Energy Not Supplied (ENS), Total Loss of Power (TLP) and Restoration Time (RT). The second study, by contrast, analyses the impact of remaining margin and import capacity on the occurrence of major fault events.

Chapter 8

Finally, Chapter 8 presents the conclusions and discusses the policy implications derived from the results presented in this thesis. In addition, it gives scientific recommendations and reflects on the methodology used in the thesis with respect to the results presented.

Appendices

Appendix A provides the GAMS code for EUPowerDispatch's weekly model. Appendix B provides the installed electricity generation capacities for each energy source for the 32 countries included in EUPowerDispatch for 2010 and 2025. Appendix C provides the cross-border electricity transmission capacities assumed in EUPowerDispatch for 2010 and 2025.

2. EUPowerDispatch

This chapter is based on the methodology, validation and scenario sections of the following peer-reviewed journal article:

- Brancucci Martínez-Anido, C., Vandenbergh, M., de Vries, L.J., Alecu, C., Purvins, A., Fulli, G., Huld, T., **Medium-term demand for European cross-border electricity transmission capacity**, *Energy Policy* 61 (2013) 207-222.

2.1. Introduction

This chapter presents and describes EUPowerDispatch, a minimum-cost dispatch model for the European electricity system. EUPowerDispatch was developed for analysing the need for cross-border electricity transmission investment in Europe. It has been used to conduct four different studies presented in chapters 3, 4, 5 and 6.

This chapter is structured as follows. First, a detailed model description is provided, including its mathematical formulation. The next section provides an overview of the common scenario data used in the three studies presented in chapters 3, 4 and 5. Finally, this chapter concludes with a study used to validate EUPowerDispatch.

2.2. Model description

EUPowerDispatch was developed in order to estimate the impact of changes in the electricity generation portfolio and in demand upon cross-border electricity flows and consequently the need for cross-border transmission investment.

EUPowerDispatch is a minimum-cost dispatch model of the European electricity transmission network. The model's optimisation is coded in the General Algebraic Modelling System (GAMS, 2010) using CPLEX, a high-performance mathematical

programming solver from IBM (IBM Corp., 2012). Off-line input/output data processing is performed using a commercial software package, Matlab (The Mathworks Inc., 2011).

EUPowerDispatch is solved as a mixed-integer linear problem and the core of the model can be described as a Minimum Cost Flow Problem (MCFP), taking into account generation and transmission constraints. EUPowerDispatch is used to compare different electricity generation and cross-border transmission scenarios with respect to their impacts on the need for cross-border transmission investment; it is not used to estimate optimal cross-border transmission investments.

The objective function is social welfare maximisation, or, in other words, the minimisation of annual variable electricity dispatch costs in the interconnected European countries considered in the model. Annual variable electricity dispatch costs are defined as the sum of variable generation costs and variable network costs.

Variable electricity generation costs vary for each generation source and are defined as the sum of the variable operation and maintenance costs and the fuel costs. In addition, CO_2 emission costs are included. Depending on the time horizon of the scenario to be modelled and the scope of the analysis, variable electricity generation costs can be very different because fuel prices, power plant efficiencies and the CO_2 price may vary significantly. Neither green certificates nor feed-in tariffs are considered for variable RES (wind and solar); variable electricity generation costs dictate the generation dispatch regardless of the support scheme. Section 2.3 provides the variable generation costs for each energy source used for different scenarios.

Variable network costs are assumed to be proportional to the surface areas of the two countries. Consequently, transmission costs between two small countries (e.g. Belgium and the Netherlands) are smaller than between two large countries (e.g. Spain and France). This assumption is considered in order to represent, in a model with one node per country, the fact that transmission costs increase with distance. Otherwise, cross-border flows over very long distances across Europe would appear unrealistically attractive.

Electricity generation and transmission investment costs are not considered in the model. Electricity generation capacities and cross-border transmission capacities are exogenous variables which vary depending on the modelled scenarios. EUPowerDispatch is used to compare the impacts of different cross-border transmission scenarios on the European power system, but it does not calculate the optimal level of cross-border transmission capacity for a given scenario.

EUPowerDispatch simulates cross-border electricity flows by modelling a single European electricity dispatch according to variable generation and network costs, and assuming perfect knowledge of one-year hydro inflow forecasts and of one-week wind speed and solar radiation forecasts. In reality, weather forecasts are much shorter and forecast errors vary. In addition, every country manages its electricity dispatch and in several European countries renewables are always dispatched first.In the model, electricity flows across-borders result from the differences in variable electricity generation costs between countries, and not from differences in electricity prices between countries.

Countries are each represented as a single node, meaning that internal network constraints are not included in the model. The reasons are computational capacity limits and the unavailability of data on electricity consumption and generation distribution throughout the countries considered in the model. Instead, EUPowerDispatch focuses on cross-border interconnections, for which the EU has specific policy objectives.

I would have liked to model the electricity flows in the European transmission network for each node. However, I would need to know the capacity of all the links in the network, as well as the electricity consumption time series for each node and the position, type and generation capacity of each electricity generator with respect to the network. I do not have access to such detailed data for the 32 countries represented in the model. Because demand and generation data are not available at a higher geographic resolution than per country, I also do not divide large European countries (e.g. Germany, France, Italy) into multiple regions.

In addition, even if the data described above would be accessible, the available computational capacity would limit the representation of the model. I am not able to model the overall European electricity transmission network for a whole year with weekly simulations with a one-hour time step considering the internal electricity flows as well as the hourly dispatch of each electricity generator.

The major limitation of simplifying the network to cross-border interconnectors is that internal network congestion is not considered, which in some cases is more critical than congestion at the borders (e.g. for Germany). Results from EUPowerDispatch should be considered in the light of the fact that network flows and internal network congestion are not considered.

However, for the purposes of the studies presented in this thesis, the electricity transmission assumptions considered in EUPowerDispatch do not affect the meaning and validity of the results. The goal of EUPowerDispatch is to model the interconnections

within the region of ENTSO-E. Within this scope, the future needs for cross-border transmission capacity are analysed by modelling the evolution of the system and by comparing different transmission development scenarios with each other.

A modelling option for improving the accuracy of the transmission network representation would consider Power Transfer Distribution Factors (PTDF). A representative PTDF matrix translates the transaction between two nodes into the power flow distribution in the available interconnections. In other words, the PTDF matrix allows the model to determine the fraction of the flow between two nodes that is transferred through a given interconnector. The main reason why EUPowerDispatch does not consider PTDF matrices is that the representative matrix for the European transmission network depends on the electricity flows and therefore on the load and generation situation at a certain moment in time. In order to be accurate, one should use a different PTDF matrix for each time reference. As EUPowerDispatch models every hour in a whole year, it is unrealistic to have a PTDF matrix for each hour. Using different PTDF matrices that depend on the time of the year, the day of week and the time of the day would still imply a rough assumption. Furthermore, data for representative PTDF matrices for the European transmission network is not publicly available. For instance, ENTSO-E is currently working on this issue but the data is not published.

The model includes 32 interconnected nodes, each representing a European country[1]. The number of cross-border interconnectors varies depending on the time horizon of the scenario under consideration. Because power flows are determined by the specific volume of demand and dispatch of generation at each moment, the dispatch of generation in the 32 European countries is modelled for every hour of a given year under perfect competition conditions (optimal dispatch according to variable generation cost). Demand is modelled as being perfectly price-inelastic.

Due to computational capacity limits, the model is unable to run a whole year with a one-hour time step. Therefore, a preliminary yearly run with weekly time steps is used to set the hydro seasonal reservoir levels at the start and end of each week in each node. These constraints are used as inputs for 52 weekly runs with one-hour time steps. Within each week, generation dispatch is optimised, assuming full knowledge about generator cost and availability, including renewables. Hydro seasonal reservoirs are the only storage element with annual management, so it is assumed that all other variables can be analysed within a weekly time-frame for

[1] Austria, Belgium, Bosnia-Herzegovina, Bulgaria, Croatia, the Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Macedonia, Montenegro, Norway, Poland, Portugal, Romania, Serbia, Slovakia, Slovenia, Spain, Sweden, Switzerland, The Netherlands, United Kingdom.

each of the 52 weeks in the year. For simplicity, the model represents 364 days in the year, equal to 7 days times 52 weeks.

The inputs of EUPowerDispatch are:

- net generation capacities for each energy source at each node;
- load time series at each node;
- cross-border transmission limits;
- weather data at each node;
  - wind speed time series;
  - solar radiation time series;
  - run-of-river flow time series;
  - inflow to hydro reservoirs time series;
- variable electricity production costs per energy source.

Time series for electricity consumption and weather information are based on 2010 real data. Detailed descriptions are provided in the next sub-sections. The main model outputs are:

- generation of each energy source at each node;
- electricity dispatch costs;
- cross-border electricity flows;
- CO_2 emissions;
- variable RES (wind and solar) curtailment needs;
- unserved load.

These variables are calculated for every hour of the year. The need to curtail RES is determined by the model as the amount of electrical energy which is potentially generated from wind turbines and PV panels at a moment in time and that is not consumed due to lack of electricity consumption or because it is economically more feasible to curtail the RES available power rather than to ramp-down or turn off a conventional power plant. Unserved load, instead, is mathematically modelled as a very expensive generation unit (10000 €/MWh) which is only used when the model does not find a feasible solution within the defined constraints. Unserved load represents the energy demand that is not supplied by the network due to lack of available

local generation and electricity imports. However, given that EUPowerDispatch does not model electricity prices, it can not provide insight on the value of lost load.

2.2.1. Generation

Generation is represented by different energy sources, including nuclear, fossil fuels, hydro and renewable energy sources. For most energy sources (nuclear, oil, mixed oil & gas, solar, wind, biomass, run-of-river hydro, seasonal hydro and pure pumping hydro) a virtual power plant represents the total net installed generation capacity for each source in each country. For coal, lignite and gas, however, the model divides the total installed capacity of each energy source in a country into single units with a maximum rated capacity of 1 GW. For example, the generation of a country with an electricity generation mix which includes 3 GW of nuclear, 5.2 GW of coal, 3.8 GW of gas, 2 GW of oil and 2.3 GW of wind will be modelled by 1 unit of nuclear, 6 units of coal, 4 units of gas, 1 unit of oil and 1 unit of wind.

Different operational constraints are defined for each energy source. Reserves are not modelled separately, but are assumed to be included within the availability factors and are partly considered in fixing minimum operational power plant output levels. Installed generation capacities per energy source depend on the modelled scenario. Details on generation capacity data are given in section 2.3. The next four subsections provide details about the modelling of conventional, variables RES, biomass and hydro generation, respectively.

Conventional generation

Nuclear energy availability during each time step is assumed to be equal to 84.5%, the global median capacity factor of nuclear reactors in 2008 (World Nuclear Association, 2011). This assumption takes the planned and unplanned unavailability of nuclear power plants into account. In order to restrict the ramping rates of nuclear energy sources, the virtual power plant in a country is assumed to be able to vary its power output between 70 and 100% of available power. The ramp-up (RU) and ramp-down (RD) rates for the virtual nuclear power plant in a country is 20% of available power per hour.

Fossil-fired power plants are assumed to have an average availability factor of 90% (VGB PowerTech, 2011), which allows, as for nuclear, planned and unplanned unavailability to be taken into account. In order to consider start-up costs, the model divides the total installed capacity of lignite, hard-coal and gas power plants in a

country into single units with a maximum rated capacity of 1 GW. Lignite and hard-coal power plants, like nuclear, are considered to be base-load power plants due to their high capital cost and low variable operational costs (mainly fuel costs) (Blok, 2007). In addition, they are characterised by a slow and costly start-up time and ramp-up rate (Bruynooghe et al., 2010). Therefore, the model assumes that lignite and hard-coal power plants have a 6-hour start-up time. For gas power plants instead, the start-up time is assumed to be 1 hour, which therefore corresponds to a much lower start-up cost.

Each unit is represented by a binary variable allowing for the power plant to be on or off and for the model to consider start-up and shut-down costs. Start-up costs are calculated as the costs of running the power plant at minimum allowed power output for the number of hours corresponding to the start-up time (in other words, the variable generation cost times the minimum power output times the start-up time). Shut-down costs are not considered but still included in the mathematical formulation in order to allow the inclusion in future simulations. The power output of each lignite and hard-coal power plant unit is limited to between 70 and 100% of rated capacity, already corrected by an availability factor. For gas power plants, instead, the power output is limited between 40 and 100%. The ramp-up (RU) and ramp-down (RD) rates for coal and lignite power plants are equal to their minimum power output per hour (e.g. for a 1 GW lignite power plant, its minimum power output is 700 MW and its ramp-up and ramp-down rates are 700 MW/h). For gas power plants, instead, ramp-up and ramp-down rates are not constrained.

Oil and mixed-fuel (oil and gas) power plants are modelled as one virtual power plant per energy source at each node. Because of the averaging effect of having one virtual power plant per node and the fast-reacting characteristics of such power plants, power output is limited only by available capacity. Minimum power output constraints, as well as ramp-up and ramp-down rates, are not considered.

Variable renewable energy generation

Some of the input data for modelling solar and wind energy are meteorological data. Meteorological data are important parameters in the modelling of renewable energy sources. In order to use these data in EUPowerDispatch, they (and their spatial distribution) need to be processed.

The model represents each country as one node, therefore it assigns average values for wind speed and for solar radiation for each hour and each country in Europe.

The data used are 2010 wind speed and solar radiation time series, together with background (or reference) spatial data. The wind speed data (Kalnay et al., 1996) is provided in the form of surface flux data composed of two vector components at 10 m altitude, 4 times per day (0h, 6h, 12h, 18h), in a regularly spaced grid with a 2.5° latitude-longitude resolution. Solar radiation data are based on the satellite retrieval scheme of CM-SAF (Mueller et al., 2009). The calculation of PV energy production is based on the PVGIS methodology (Huld et al., 2012), and represents hourly energy output delivered to the grid (kWh/MW installed) at each grid point. Hourly data (02:45 – 20:45) is provided for each point of the regularly spaced grid with a 1.51° latitude-longitude resolution.

Concerning data access, many research teams make much data available in the public domain. Most of the data are processed before being published in different formats. Two steps are followed here in order to obtain the required data: first, preliminary processing of the meteorological data and then spatial data processing. The spatial data processing is performed using a DEM (Digital Elevation Model) with NUTS (Nomenclature of Units for Territorial Statistics) administrative units: NUTS1, NUTS2, NUTS3 from GISCO (Geographical Information System at the European Commission). The administrative units are supplemented by non-EU spatial data from DIVA-GIS (DIVA-GIS, 2011).

Since the model has a one-hour time step, the hourly wind inputs are estimated by a linear relationship between the source data. Furthermore, it is assumed that the wind turbine height in our scenarios is 100 m. Equation 2.1 is used for wind speed calculation at the new height (Gipe, 2004):

$$V = V_0 \frac{\ln \frac{H}{k}}{\ln \frac{H_0}{k}} \tag{2.1}$$

where V is wind speed at height H, V_0 is wind speed at height H_0 and k is the roughness length constant (it expresses the roughness of the terrain). The roughness constant for the water surface in the case of offshore farms is 0.0002 and for onshore wind farms 0.1, which is the value applied to agricultural land with some houses and similar obstacles with a distance of around 500 m between them.

In order to obtain wind generation it is necessary to determine the installed wind farm capacity and its power characteristics. The European countries considered in EUPowerDispatch are divided into regions at NUTS1 and/or NUTS2 level. Each region has its own wind generation capacity, obtained from ENTSO-E's Scenario Outlook & Adequacy Forecast (ENTSO-E, 2011e) (priority) and a TradeWind study

(Toorn, 2007). Furthermore, regions are divided into three categories according to altitude above sea level — offshore, lowland (<400 m) and highland (>400 m). This division is obtained from another TradeWind study (McLean, 2008). The latter provides aggregated wind farm power characteristics for each of the categories, including curves for several time horizons ranging from 2005 until 2025.

The wind speed data points are linked to different regions defined with the help of NUTS administrative units. They are used to delineate regions of approximately the same size in order to have a homogeneous distribution of wind grid points. For onshore wind farms, the onshore wind speed point closest to the centre of gravity of the region is applied. For offshore farms, the offshore wind speed point closest to the mid-point of the offshore line of the region is applied. For islands, in both offshore and onshore cases, the wind speed point closest to the region's centre of gravity is applied. Fig. 2.1 shows the land, coast and island centres with respect to the wind speed data points.

To obtain an attribute to distinguish between low regions (below 400 m) and high regions (above 400 m), the DEM is used. Each defined region is overlain by a DEM layer and the percentages of the surface below and above 400 m determine whether it is low or high. Thus, if a region contains less than 50% of its surface below 400 m it is considered low, otherwise it is considered high. In this way, each region incorporates altitude information. Finally, the resulting wind power for each hour in each country is the sum of lowland, highland (if any) and offshore (if any) values in each region.

A similar adjustment of attributes is performed for the solar radiation information. Fig. 2.2 shows the solar radiation data points. In this case, an average value is calculated for the energy output delivered to the grid for each country, in hourly values. The final result is a time series for average energy output delivered to the grid (kWh/MW installed) for each of the 32 European countries.

Biomass generation

Electricity generation from biomass is modelled with a single virtual power plant per country, covering total net installed generation capacity from solid, gaseous and liquid biomass. The power output is constrained only by the maximum installed power capacity. The average load factor of biomass virtual power plant is set at 50% for each week in order to reflect the scarcity of available bio-fuel source. The reason is that we did not consider it realistic that biomass would run as base load

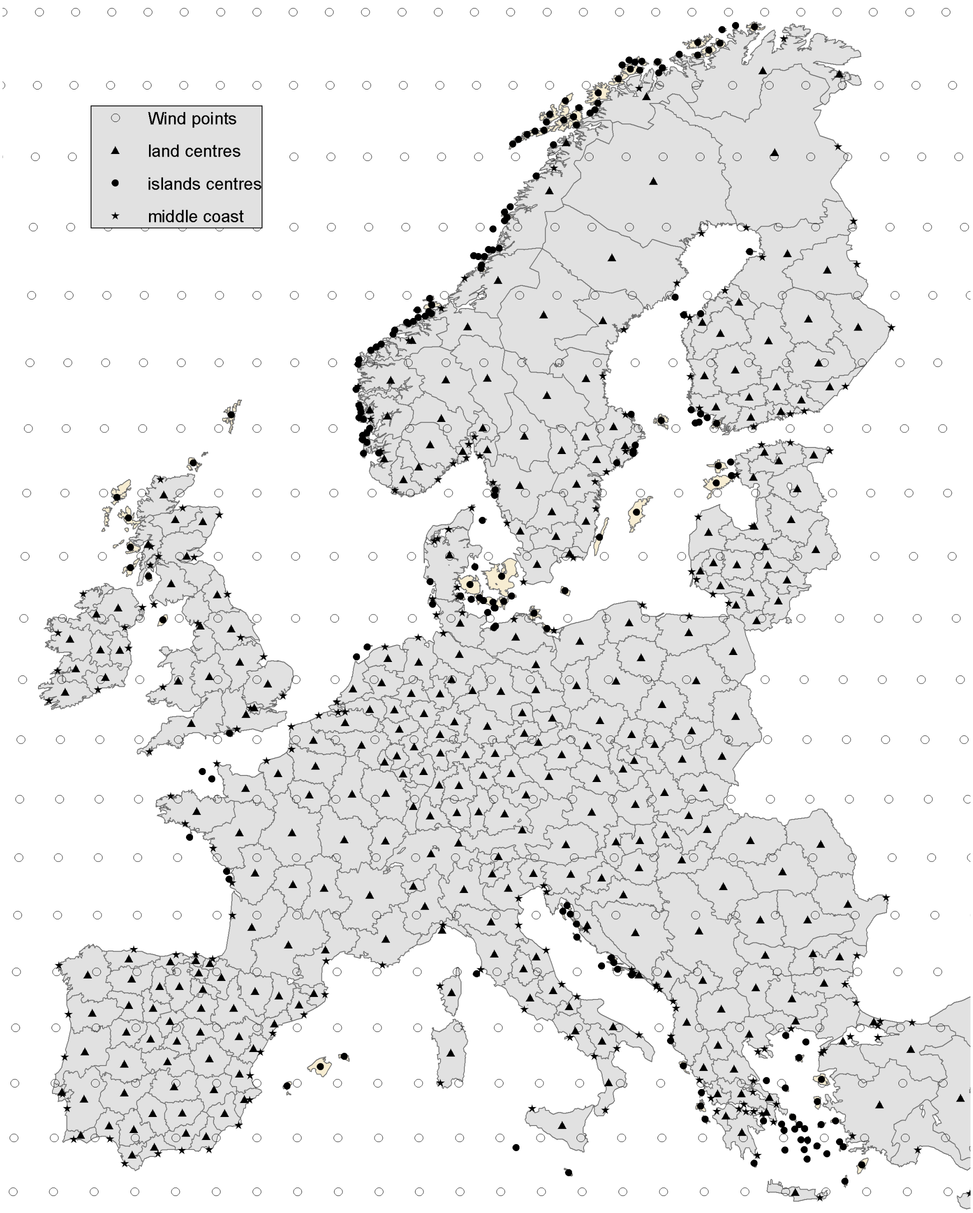


Fig. 2.1.: Wind speed data points and land, mid-coast and island centres

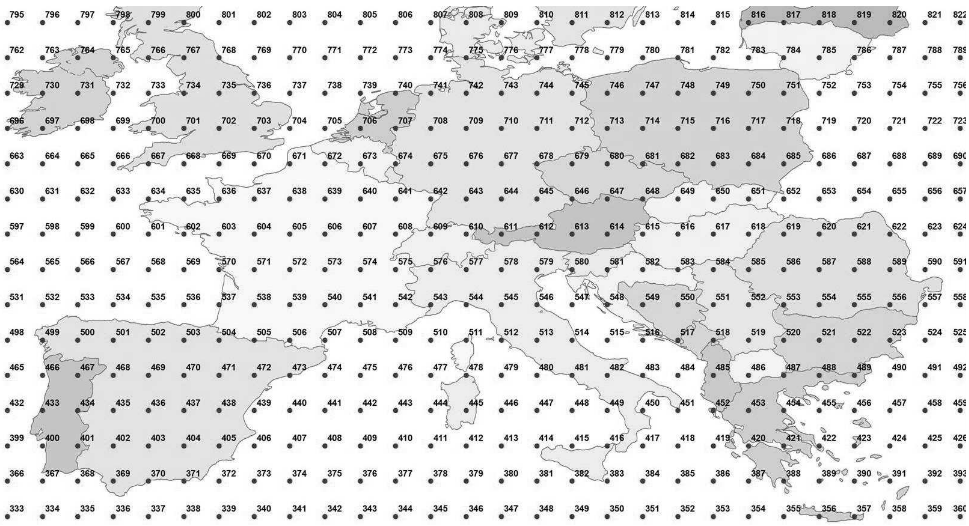


Fig. 2.2.: Solar radiation data points

in scenarios where it is cheaper than natural gas due to physical restrictions in the biomass supply chain.

Hydro generation

Hydro power plants are usually classified into three main categories: run-of-river, storage and pumping plants. The production of run-of-river plants is not controlled as it depends on a natural inflow not stored behind a dam. Storage plants, where water is stored in an upper reservoir fed by a natural inflow, are operated according to seasonal and daily dispatch strategies. Finally, in a pure pumping plant, water is pumped from a lower reservoir into an upper reservoir with no natural inflow. Pumping plants usually have a few hours of full power equivalent and are used with a daily dispatch strategy. In reality, in mountainous countries, hydro power systems can be much more complex, including several interconnected water reservoirs with several dispatchable parameters (generation and pumping powers and reservoir levels) to be optimised.

In order to simplify the modelling task, several assumptions are made. Hydro plant dynamics are simulated in the following simplified way. An ideal flexibility is assumed with negligible start-up, shut-down, ramp-up or ramp-down costs. A single model per European country aggregates all the parameters of all national hydro plants. Reservoir levels are optimised for overall variable electricity production costs only

and the lower limits are set at 30% of seasonal reservoir levels in order to partially consider environmental and landscape constraints. Round-trip pumping efficiency is assumed to be 75%. The hydro storage model for a specific country can be of two types. Fig. 2.3 illustrates the two types of models.

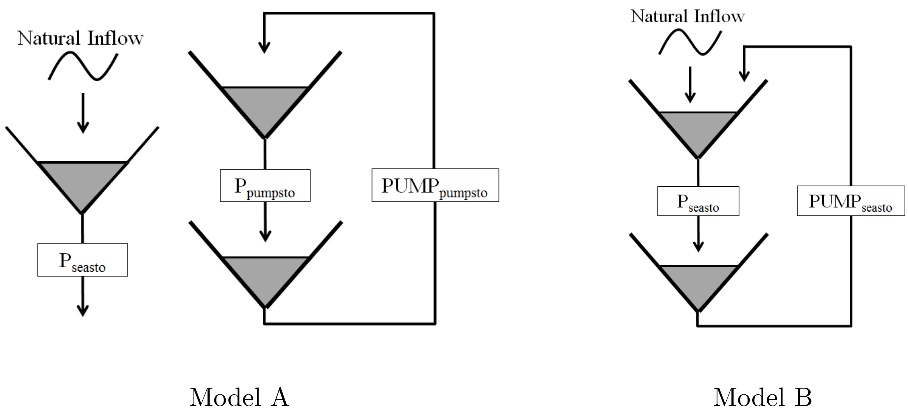


Fig. 2.3.: Hydro storage models

In the general model (A), there are three dispatchable parameters: power generation from the natural inflow reservoir (P_{seasto}), power generation from the pumped hydro reservoir ($P_{pumpsto}$) and pumping power into the pumped hydro reservoir ($PUMP_{pumpsto}$), which are assumed to be controllable continuously between zero and the rated power. Two natural water inflows provide renewable power with a seasonal profile depending on the meteorology. In mountainous countries like Austria, Norway, Switzerland or Sweden, water can be pumped into existing reservoirs that are also fed by natural inflows. Therefore, a second model (B) is used with only two dispatchable parameters: power generation from the reservoir (P_{seasto}), and pumping power feeding the same reservoir ($PUMP_{seasto}$).

The main source of information for defining the appropriate model for each country and for the the time series for run-of-river flows and for hydro reservoir inflows is 2010 data collected by Michel Vandenbergh (Brancucci Martínez-Anido et al., 2013b) from ENTSO-E's statistics (ENTSO-E, 2011f), complemented by research projects (SUPWIND, 2011; EWIS, 2011; SUSPLAN, 2011; Sintef, 2011; Nowitech, 2011), national Transmission System Operator (TSO) websites (Statnett, 2011; FINGRID, 2011; TERNA, 2011a; REE, 2011; RTE, 2011; SVK, 2011) and other stakeholders (EURELECTRIC, 2011; Nord Pool Spot, 2011; SFOE, 2011; Ministerio Español

de Medio Ambiente y Medio Rural y Marino, 2011; E-Control, 2011; German Federal Ministry of Economics and Technology, 2011; German Federal Statistical Office, 2011; BfG, 2011; EDP, 2011; DECC, 2011). If hydro plant parameters are not available from these sources, data is taken from the TradeWind project (TRADEWIND, 2011). The reservoir, generation and pumping capacities are calculated considering the generation capacity scenarios provided in section 2.3.

2.2.2. Cross-border transmission

In EUPowerDispatch, each of the 32 countries is represented by a single node. They are interconnected by links with transmission capacity values that correspond to the physical cross-border interconnectors. Each interconnector is defined by its maximum transfer capacity, which may have two different values corresponding to the direction of electricity flow. The transfer capacity of each interconnector is defined as the current Net Transfer Capacity (NTC) or as the expected future NTC when a future scenario is considered.

Network losses, comprising distribution and national transmission losses, are included in the load time series. However, cross-border transmission is also subject to relatively small costs.

2.2.3. Mathematical formulation

In this subsection the mathematical formulation of EUPowerDispatch is presented. First of all, a preliminary run with weekly time steps provides the hydro reservoir levels at the start and end of each week in the year that is being modelled for each country. These are then used as inputs for 52 different weekly simulations with a time step of one hour (Appendix A provides the GAMS code for the weekly model).

Eq. 2.2 shows the objective function of the optimisation problem for each weekly simulation. It corresponds to the minimisation of total dispatch costs, defined as the

sum of variable generation costs (including start-up and shut-down costs of coal, lignite and gas power plants) and cross-border transmission costs.

minimise

$$\sum_{t=1}^{T}\left(\sum_{n=1}^{N}\left(\sum_{g=1}^{G}(P_g \cdot VC_g + su_g \cdot SUC_g + sd_g \cdot SDC_g) + \sum_{h=1}^{H}(P_h \cdot VC_h)\right)\right)$$
$$+\sum_{t=1}^{T}\left(\sum_{i=1}^{I}|F_i| \cdot TC_i\right) \tag{2.2}$$

Eqs. 2.3, 2.4, 2.5, 2.6 and 2.7 define the different sets of variables and their components.

$$t = \{t_1, t_2, t_3, ...t_{168}\} \tag{2.3}$$
$$n = \{AT, BE, BA, BG, HR, CZ, DK, EE, FI, FR, DE, ...$$
$$GR, HU, IE, IT, LV, LT, LU, MK, ME, NO, PL, PT, RO, ...$$
$$RS, SK, SI, ES, SE, CH, NL, GB\} \tag{2.4}$$
$$g = \{nuc, lig, coal, gas, oil, mixed, sol, won, woff, bio\} \tag{2.5}$$
$$h = \{ror, sto_{seas}, sto_{pump}\} \tag{2.6}$$
$$i = \{i_1, i_2, i_3, ...I\} \tag{2.7}$$

t represents the simulation time steps within a week: 168 hours. n represents the nodes considered in the model: 32 interconnected European countries. g represents the different types of electricity generation sources: nuc stands for nuclear, lig stands for lignite, $coal$ stands for hard coal, gas stands for gas, oil stands for oil, $mixed$ stands for mixed oil & gas, sol stands for solar, won stands for onshore wind, $woff$ stands for offshore wind, and bio stands for biomass. h represents the different types of hydro power plants: ror stands for run-of-river, sto_{seas} stands for seasonal storage, and sto_{pump} stands for pumped storage. i represents the cross-border interconnectors considered in the model.

The objective function (Eq. 2.2) is subject to several constraints, provided in the following equations. First of all, energy balance must be maintained at each node at every moment in time, as detailed in the equilibrium equation (2.8). At each node and at each moment in time, the sum of electricity generation (P) of all energy sources

and electricity imports (IMP) must be equal to the sum of electricity demand (D), hydro pumping ($PUMP$) and electricity exports (EXP).

$$\sum_{g=1}^{G}(P_g) + \sum_{h=1}^{H}(P_h) + IMP = D + \sum_{h=1}^{H} PUMP_h + EXP \qquad \forall n, t \tag{2.8}$$

Electricity flows must respect the transmission capacity limits considered in the modelled scenario in both flow directions (Eq. 2.9).

$$Fmaxneg_i \leq F_i \leq Fmaxpos_i \qquad \forall i, t \tag{2.9}$$

Eqs. 2.10 and 2.11 denote the power limits of the power plants. The start-up and shut-down logic for coal, lignite and gas power plants is given in Eq. 2.12. The ramping limits of the nuclear, lignite, coal and gas power plants are denoted in Eqs. 2.14 and 2.16. Eqs. 2.13, 2.15 and 2.17 only refer to the first hour of the week, which needs the information of the last hour of the previous week.

$$on_g \cdot PMIN_g \leq P_g \leq on_g \cdot PMAX_g \qquad \forall n, (lig, coal, gas), t \tag{2.10}$$

$$PMIN_g \leq P_g \leq PMAX_g \qquad \forall n, (nuc, oil, mixed, sol, won, woff, bio), t \tag{2.11}$$

$$su_{g_t} - sd_{g_t} = on_{g_t} - on_{g_{t-1}} \qquad \forall n, (lig, coal, gas), t > 1 \tag{2.12}$$

$$su_{g_{t_1}} - sd_{g_{t_1}} = on_{g_{t_1}} - on_{g_{t_0}} \qquad \forall n, (lig, coal, gas) \tag{2.13}$$

$$P_{g_{t-1}} - P_{g_t} \leq RD_g \qquad \forall n, (nuc, lig, coal, gas), t > 1 \tag{2.14}$$

$$P_{g_{t_0}} - P_{g_{t_1}} \leq RD_g \qquad \forall n, (lig, coal, gas) \tag{2.15}$$

$$P_{g_t} - P_{g_{t-1}} \leq RU_g \qquad \forall n, (nuc, lig, coal, gas), t > 1 \tag{2.16}$$

$$P_{g_{t_1}} - P_{g_{t_0}} \leq RU_g \qquad \forall n, (lig, coal, gas) \tag{2.17}$$

As previously explained, electricity generation from biomass is limited to a 50% weekly load factor, as denoted in Eq. 2.18.

$$\sum_{t=1}^{T} (P_{bio_t}) \leq \frac{8736}{2} \cdot PMAX_{bio} \qquad \forall n, (bio) \tag{2.18}$$

Run of river hydro generation is modelled as non-dispatchable, as denoted in Eq. 2.19.

$$P_{ror} = ROR \qquad \forall n, t \tag{2.19}$$

The electricity generation limits for both seasonal storage and pure pumping hydro power plants are expressed in Eq. 2.20. The hydro pumping power limits are given in Eq. 2.21 and the limits for the hydro reservoir levels are provided in Eq. 2.22.

$$PMIN_h \leq P_h \leq PMAX_h \qquad \forall n, (seasto, pumpsto), t \tag{2.20}$$

$$PUMPMIN_h \leq PUMP_h \leq PUMPMAX_h \qquad \forall n, (seasto, pumpsto), t \tag{2.21}$$

$$LMIN_h \leq L_h \leq LMAX_h \qquad \forall n, (seasto, pumpsto), t \tag{2.22}$$

Finally, Eq. 2.23 expresses the inter-temporal relationship between hydro electricity generation, pumping and the reservoir level. If hydro electricity generation in a country is modelled as in model A (see Section 2.2.1), Eq. 2.23 is used twice, in one case with no pumping ($PUMP = 0$) and in the second case with no natural inflow ($INF = 0$). Instead, if hydro electricity generation in a country is modelled as in model B, only one Eq. 2.23 is necessary. Eq. 2.24 only refers to the last hour of the year in order to meet the hydro reservoir level at the end of the week, as established by the preliminary yearly simulation.

$$L_{h_t} = L_{h_{t-1}} + 0.75 \cdot PUMP_{h_{t-1}} + INF_{h_{t-1}} - Pumph_{t-1}$$
$$\forall n, (seasto, pumpsto), t < 168 \tag{2.23}$$

$$L_{h_{t_{168}}} + 0.75 \cdot PUMP_{h_{t_{168}}} + INF_{h_{t_{168}}} - Pumph_{t_{168}} = L_{h_{t_{168+1}}}$$
$$\forall n, (seasto, pumpsto) \tag{2.24}$$

2.3. Scenario data

This section provides information about the data sources and values for the considered electricity demand, generation capacities for each energy source modelled in EUPowerDispatch, and cross-border transmission capacities for 2010 and 2025. In addition, variable generation costs are provided for 2010 and for 2025 for different assumed CO_2 prices. Generally, scenario data is taken from ENTSO-E for consistency reasons.

2.3.1. Demand

The electricity demand for each hour of the year at each node is based on ENTSO-E's national electricity load time series (ENTSO-E, 2011b) for the year 2010 (this year was chosen to be consistent with the 2010 hydro inflow, wind speed, and solar radiation time series data). The time series provided by ENTSO-E include transmission and distribution losses. For a few countries (e.g. Austria), the load time series do not represent total electricity consumption (ENTSO-E, 2011c), so these values are corrected by a factor so the annual national demand used in the model corresponds to the total national electricity consumption. For 2025, electricity demand time series are scaled by shifting the load curve considering the growth rates per country (ENTSO-E, 2012a). The main change from 2010 to 2025 in the scenario is a 15% increase in electricity demand (ENTSO-E, 2012a). This moderate increase is estimated due to the expected gradual recovery of the economy after the financial crisis.

2.3.2. Generation

The electricity generation capacities for 2010 are based on the January 2011 values of the Best Estimate Scenario (scenario B) of ENTSO-E's SO&AF 2011 - 2025 (ENTSO-E, 2011e). For 2025, instead, they are based on the July 2025 values of the Best Estimate Scenario (scenario B) of ENTSO-E's SO&AF 2012 - 2030 (ENTSO-E, 2012a). The main features of the two scenarios with respect to changes between 2010 and 2025 in Europe are a large increase in installed renewable energy sources and an increase in fossil fuel generation up to 2015, followed by a decrease until 2025. These scenarios have been chosen because they include consistent electricity generation data for the 32 interconnected European countries considered in EUPowerDispatch. Fig. 2.4 shows the total installed generation capacities per energy source in the 32

European countries for 2010 and 2025. Appendix B provides the installed electricity generation capacities for each energy source for the each of the 32 countries included in EUPowerDispatch for 2010 and 2025.

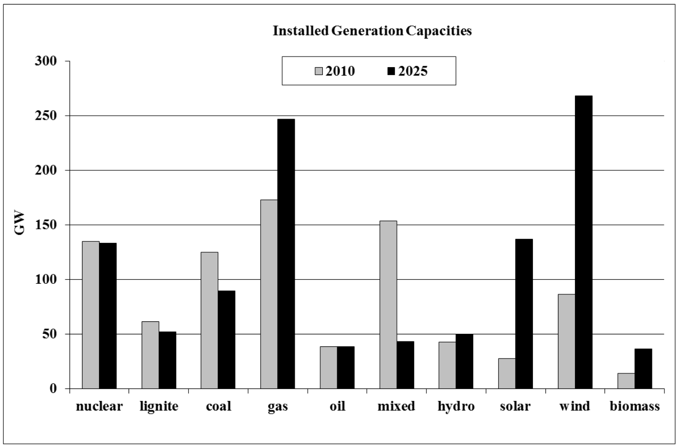


Fig. 2.4.: Installed generation capacity per energy source in 2010 (ENTSO-E, 2011e) and 2025 (ENTSO-E, 2012a)

2.3.3. Variable Generation Costs

The variable electricity generation costs of each energy source are assumed to be the same in every country and are calculated on the basis of a deliverable of the TradeWind project (Korpas et al., 2007). Variable costs are calculated as the sum of variable operation and maintenance costs, fuel costs and CO_2 costs. Depending on the energy source, the fuel efficiencies of new plants and fuel costs may vary over time. Table 2.1 shows the variable electricity generation costs assumed in the study. If not specified for 2025, the default CO_2 price considered is 22.5 €/tonne.

Lignite, coal and gas fired power plants are modelled as single units with a maximum rated capacity of 1 GW, rather than as one single virtual power plant per energy source in each country. In order to consider the variations in the efficiencies of different power plants of the same type, in the model variable electricity generation costs are varied randomly up to ±5% (lignite and coal power plants) or ±10% (gas power plants) around the average values given in Table 2.1. This is done in order to generate a more realistic supply curve.

Tab. 2.1.: Variable electricity generation costs (€/MWh) for 2010 and 2025 (for different CO_2 prices)

Year	2010	2025	2025	2025
CO_2 price (€/tonne)	20	5	22.5	50
nuclear	11.00	11.00	11.00	11.00
lignite	$46.86 \pm 5\%$	$26.33 \pm 5\%$	$47.61 \pm 5\%$	$81.06 \pm 5\%$
coal	$42.62 \pm 5\%$	$26.81 \pm 5\%$	$43.18 \pm 5\%$	$68.89 \pm 5\%$
gas	$52.89 \pm 10\%$	$48.56 \pm 10\%$	$55.88 \pm 10\%$	$67.39 \pm 10\%$
oil	89.54	85.46	98.40	118.74
mixed	94.37	89.93	103.59	125.06
biomass	59.86	53.09	53.09	53.09
hydro	3.00	3.00	3.00	3.00
wind	2.00	2.00	2.00	2.00
solar	0.00	0.00	0.00	0.00

2.3.4. Cross-Border Transmission

The cross-border electricity transmission capacity data are based on ENTSO-E's publicly available Net Transfer Capacity (NTC) values for each interconnector in Europe for 2010 (ENTSO-E, 2011d). For future time horizons, up to 2025, an approach developed by Ricerca sul Sistema Energetico (RSE) (L'Abbate, 2011), and used within two European research projects (REALISEGRID, 2011; SUSPLAN, 2011), was followed. The values of the future "maximum cross-border transmission capacity" (for both flow directions at each border) in the European system were estimated starting from the reference year 2010 (L'Abbate, 2011). The analysis started with available NTC values provided by ENTSO-E for Summer 2010 and Winter 2010-2011 (ENTSO-E, 2011d). The information and data contained in several public sources regarding existing interconnection projects (ongoing, planned, under study, potential) in Europe have been considered. Of these, the key reference was the first ENTSO-E's Ten-Year Network Development Plan (TYNDP) 2010-2020 (ENTSO-E, 2011g). Other data are taken from the former UCTE, NORDEL, BALTSO associations. Public data on projects for merchant lines and data made available by EWEA concerning offshore grid developments were used to complement the information.

Given the difficulty of estimating, for each cross-border corridor, both a Summer and a Winter NTC value, it was decided to use only a single annual value corresponding to the maximum estimated NTC value (in the vast majority of cases, the winter value). Only part of a nominal capacity increase was considered as an effective capacity increment due to internal network constraints, unless the expected transmission

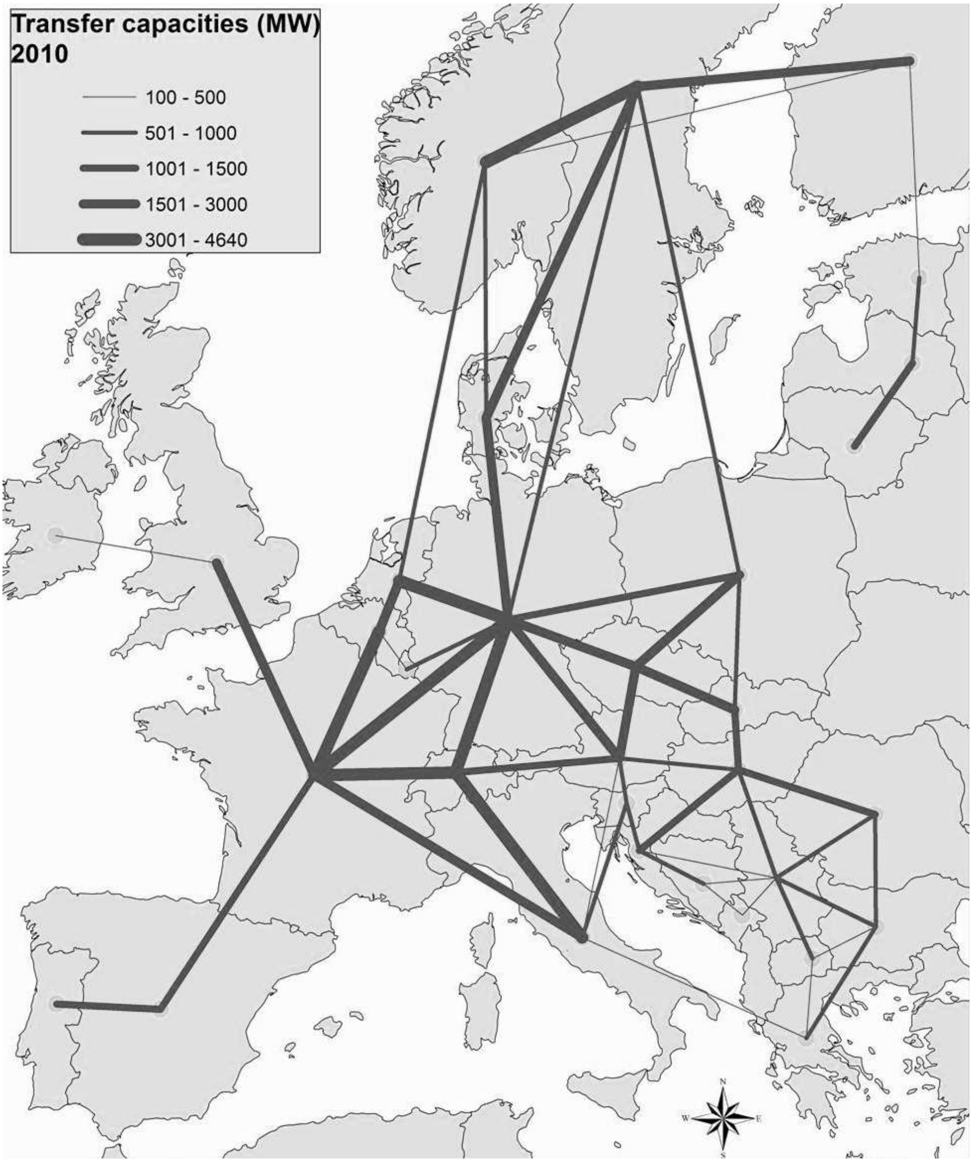


Fig. 2.5.: European cross-border electricity transmission limits in 2010

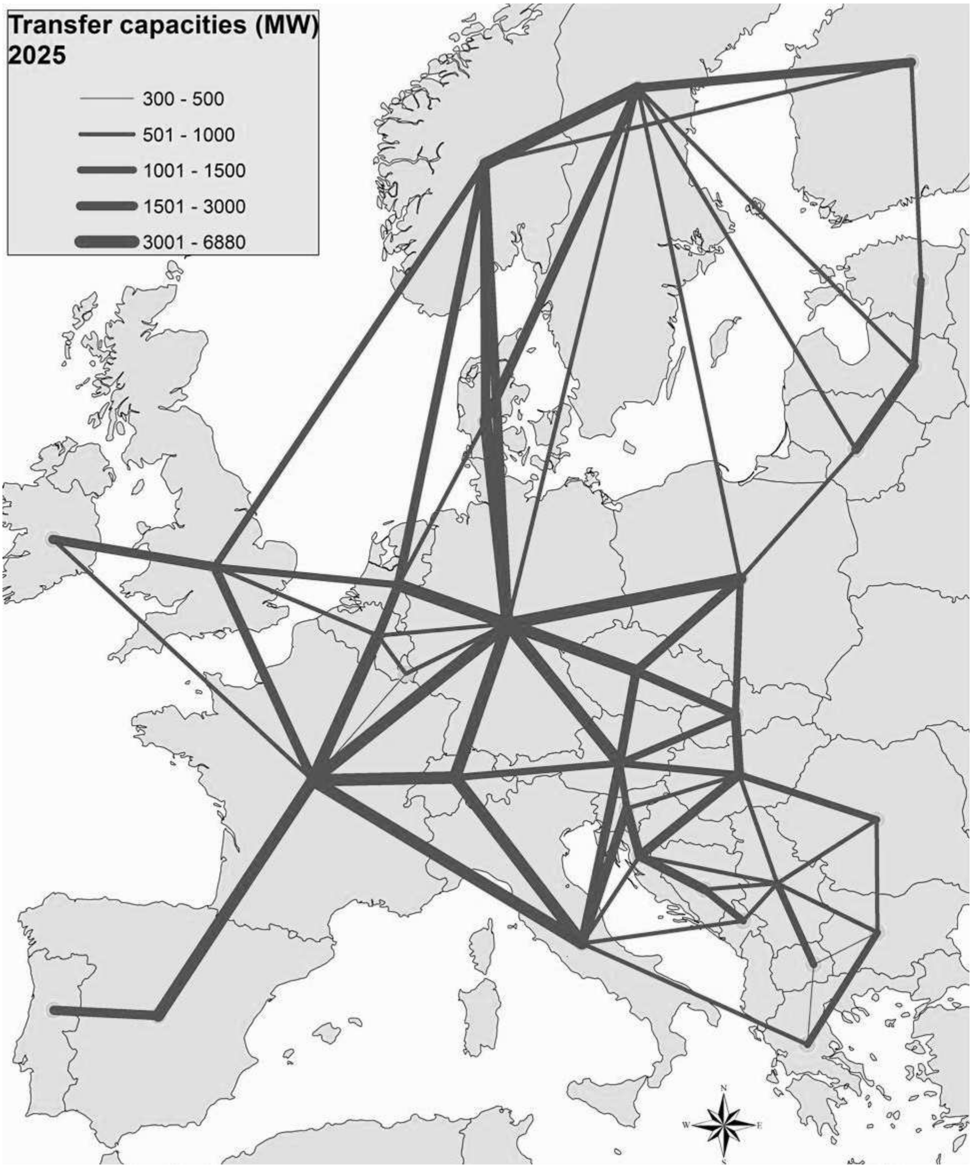


Fig. 2.6.: European cross-border electricity transmission limits in 2025

capacity increment corresponds to an HVDC link or an AC line with Flexible AC Transmission System (FACTS).

Figs. 2.5 and 2.6 show the cross-border electricity transmission limits assumed for 2010 and 2025, respectively. Several increases in cross-border transmission capacities and new interconnectors can be observed in 2025. It is interesting to observe that 10 out of the 15 expected new interconnectors to be built between 2010 and 2025 are sub-sea cables: in the North, Baltic and Adriatic Seas and between Ireland and France. Apart from the expected development of offshore wind generation in the North Sea, the fact that they are easier to realise than overland interconnectors due to a lower planning and permitting burden may explain the predominance of sub-sea interconnectors, even though they are substantially more expensive. Appendix C provides the exact values for the cross-border electricity transmission limits assumed for 2010 and 2025.

2.4. Validation

EUPowerDispatch was validated by comparing its results with publicly available statistics over 2010 (ENTSO-E, 2011f). The model outputs used for the validation are the outcome of a model run representing the European electricity transmission network in 2010 based on the load, net generation capacities and NTC values from ENTSO-E's SO&AF (ENTSO-E, 2011e). The validation is based on the European electricity generation mix and on each country's net yearly power exchanges. Fig. 2.7 shows the electricity generation mix for 2010 from ENTSO-E's statistics and the mix from the simulation results.

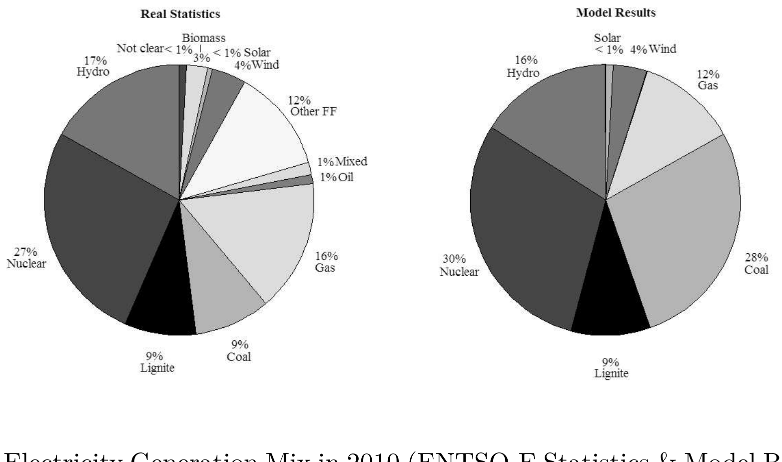


Fig. 2.7.: Electricity Generation Mix in 2010 (ENTSO-E Statistics & Model Results)

The hydro power generation share is very similar but slightly lower in the model results. This difference can easily be explained by the fact that 2010 was a very dry year, particularly for Norway, the country with the highest share of hydro power. Hydro reservoir levels were thus lower at the end of the year than at the start (Nord Pool Spot, 2011), meaning that inflows throughout the year were not enough to meet the load; and reserves from previous years were used. This behaviour is not allowed in the model as hydro reservoir levels at the end of the year are assumed to be equal to the levels at the beginning of the year. Fig. 2.8 shows that the largest difference in hydro power generation between the model results and the annual statistics is observed in Norway.

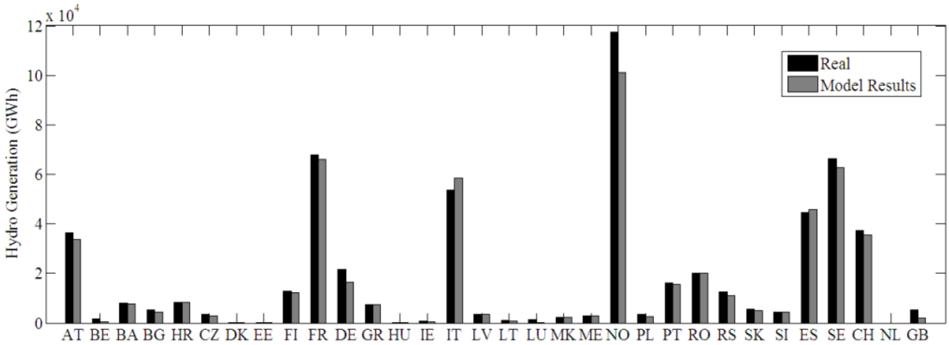


Fig. 2.8.: Hydro Generation in each country in 2010 (ENTSO-E Statistics & Model Results)

The nuclear power generation share is 3 percentage points higher in the model results than in reality. This difference can be explained by the low variable generation cost of nuclear power plants and by the assumed 84.5% availability factor, which in practice may be lower for specific plants. In addition, the model does not represent or take into account the electricity grid, so congestion inside countries is not considered, which may sometimes limit the export/import. In the model, electricity flows are limited only by NTC values, which are assumed to be constant throughout the year. In reality, these values change and transfer capacity limits may not be reached by electricity flows due to internal congestion.

The fossil fuel generation share in the model results coincides with the statistics, corresponding to 49%. However, apart from lignite, some discrepancies in the shares of different fossil fuels are observed. The model results show a higher share of coal and a lower share of gas compared to the statistics. However, the statistics show a large share of "other" (not classified) fossil fuels, which mainly correspond to coal power

plants due to the installed coal-fired electricity generation capacities. Differences in operational characteristics of coal, lignite and gas power plants, the methodology and data sources for calculating variable production costs and the CO_2 price assumption are probably the reasons why coal and lignite run more and gas runs fewer hours in the model than in reality. The shares of oil and mixed fuels shares are not visible in the model results, because the model barely uses them due to their very high variable production costs. Statistics show that each of these two types of power plants only represents 1% of electricity generation in Europe.

The wind and solar energy shares are very similar when comparing the model results and actual statistics. A few differences can be observed at the country level mainly due to the assumptions for installed wind and solar capacity. In a period when renewable energy sources are expanding rapidly, assuming one value for installed wind and/or solar power for the whole year does not always correspond to reality as there can be large differences in installed capacity between January and December. Where renewables are concerned, the main difference between the model results and the statistics is in terms of biomass. This is due to its high variable production cost. The model does not include feed-in tariff or subsidy for renewable energy. In the model, biomass is more expensive than gas in 2010, so it is rarely used. However, this difference due to model assumptions will be reduced when scenarios are modelled to include higher CO_2 prices, which would make biomass cheaper than gas.

Overall, a comparison of the generation mix between the model results and the actual statistics shows that EUPowerDispatch behaves according to reality with small differences due to several modelling assumptions, the model's objective function, which is to minimise overall European electricity dispatch costs (instead of each country having its own objective), and finally the model's physical resolution, which considers cross-border flows while neglecting national electricity grids.

One of the main model outputs is cross-border electricity flows. Therefore, in order to validate the model results, net country exchanges for the whole year are compared with actual statistics (ENTSO-E, 2011f). Fig. 2.9 shows the yearly net exchanges for each European country included in the model both as model results and actual statistics. Positive values correspond to net imports and negative values to net exports.

In Fig. 2.9 it can be observed that yearly net exchanges for each country vary significantly between the model results and the actual statistics. However, apart from Latvia and Serbia, the "sign" of the yearly net exchanges for each country is the same for both the model results and the statistics. In other words, the model

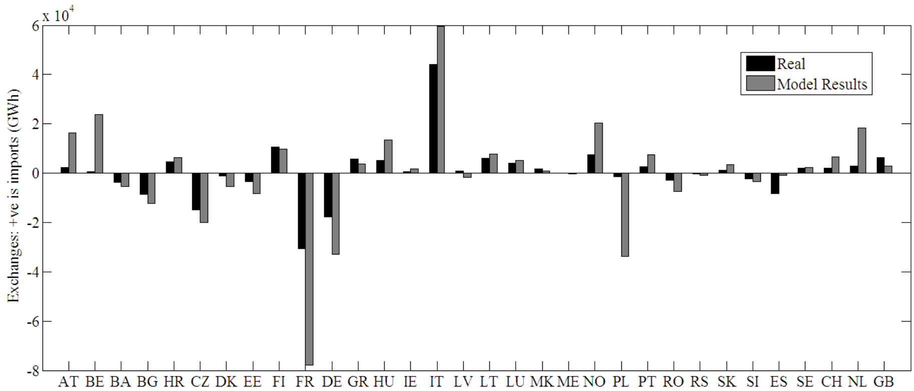


Fig. 2.9.: Yearly net electricity exchanges per country in 2010 (ENTSO-E Statistics & Model Results)

corresponds to the actual behaviour in the average direction of flows throughout the year. In general, the model results show larger net exchanges for each country due to the optimisation process and the lack of internal congestion constraints; the cross-border flows are limited only by the NTC values in the model. In addition, the model's objective function is the minimisation of overall European electricity dispatch costs, which accentuates even more the flows between nodes with different variable electricity generation costs.

3. The Future Needs for European Cross-Border Transmission Capacity

This chapter is based on the results section of the following peer-reviewed journal article:

- Brancucci Martínez-Anido, C., Vandenbergh, M., de Vries, L.J., Alecu, C., Purvins, A., Fulli, G., Huld, T., **Medium-term demand for European cross-border electricity transmission capacity**, *Energy Policy* 61 (2013) 207-222.

3.1. Introduction

The aim of this chapter is to explore the needs for investment in cross-border electricity transmission in Europe by 2025. The demand for investments in cross-border transmission is analysed by considering the expected generation portfolio. The impact of cross-border transmission capacity investment on dispatch costs, on RES curtailment needs, on CO_2 emissions, on energy storage utilisation (hydro storage in this case) and on security of supply (in terms of energy not served) is analysed. The study is performed with EUPowerDispatch, presented in Chapter 2. The positive impacts of cross-border transmission capacity expansion are not compared to the investment costs that they require because these can be very different for each interconnector due to different geological and geographical constraints, different needs for transmission network reinforcements, and different electricity transmission technologies.

This chapter presents two case studies. The first one discusses the evolution of the European electricity transmission network between 2010 and 2025. It comprises model runs for 2010 and 2025 with transmission capacity expansion according to the assumptions and the data sources described in Chapter 2. In the second case study, the model is run only for 2025 without an increase in cross-border transmission capacity after 2010 but with generation and consumption data for 2025. The

results are compared to those of the first case study corresponding to 2025 in order to assess the effects of increasing cross-border interconnection in the European electricity network. In addition, a sensitivity analysis based on the second case study is performed by varying three different model parameters independently : electricity consumption, CO_2 price and RES penetration.

3.2. Expected evolution of the European power system up to 2025

Fig. 3.1 shows the electricity generation mix in 2010 and 2025. The installed generation portfolios are inputs to the model but the actual generation levels are outputs. In order to analyse the evolution of the energy mix in Europe between 2010 and 2025, it is important to note that electricity demand is 15% higher in 2025 than in 2010, as mentioned in section 2.3.1. The expected increase in electricity demand is balanced by an expected increase in installed generation capacity that varies depending on the energy source, as shown in Fig. 2.4.

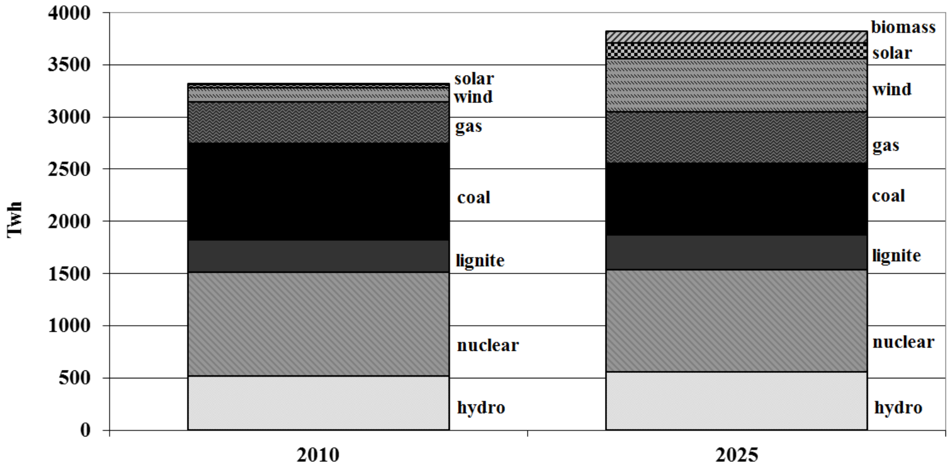


Fig. 3.1.: Energy mix in 2010 and 2025

The results show that hydro generation in Europe increases by 7.9% in 2025 compared to 2010, so its share in the energy mix increases from 15.7% to 16.6%. This small increase is mainly due to the fact that the hydro generation capacity that is expected to be installed in 2025 does not necessarily provide greater available inflows

or run-of-river resources than in 2010. The energy output increase is expected to be lower than the power output increase. It is important to mention that increasing the capacity of hydro power sources will be beneficial for balancing the variability of renewable energy sources.

With respect to nuclear energy, it is assumed that the installed generation capacity in Europe will remain almost constant until 2025. This assumption takes into account the German nuclear phase-out. Available nuclear generation capacity is practically always entirely used in the model due to its low variable cost and the assumptions of perfect competition and no network constraints within countries. The results show that the electricity produced by nuclear power plants decreases by 1.1% in 2025 compared to 2010. Nuclear power is not curtailed due to renewables because the modelled scenarios do not explore very large RES shares.

As shown in Fig. 2.4, the installed generation capacity for both coal and lignite decreases by 2025. However, the load factors of these plants increase in 2025 compared to 2010. The available coal-fired generation capacity is practically always entirely used in 2025. The net result is that electricity produced from coal decreases by 25.8% in 2025, compared to 2010. On the other hand, electricity generation from lignite-fired power plants increases by 5.2%. The load factor of lignite plants was lower than of coal plants in 2010 so the increase by 2025 is higher. Because the CO_2 price is assumed to increase only slightly between 2010 and 2025 (from 20 to 22.5 €/tonne), the variable generation costs of coal and lignite remain almost constant so their position in the merit order is almost unaffected. The CO_2 price would need to rise to about 50 €/tonne to change the merit order (see Table 2.1 on page 31). Gas-fired generation capacity increases by 43% in 2025 compared to 2010. However, its load factor decreases from 26.2% in 2010 to 22.7% in 2025, so its total electricity generation in 2025 is only 23.3% higher than in 2010. As shown in Fig. 3.1, gas-fired electricity generation accounts for 13% of the energy mix in 2025 compared to 12% in 2010. With an increasing penetration of variable RES (e.g. wind and solar), the gas load factor decreases, as expected, as its role becomes more of back-up for wind variability. Oil and mixed-fuel (oil and gas) generation capacities remain almost constant between 2010 and 2025. The two sources have the highest variable generation costs and are therefore used as a last resort when no other generation or import capacities are available. Therefore, power generation from these sources is almost negligible in comparison to the total volume of electricity. The main limitation of the model with respect to these results is that incentives for new built power plants are not considered in electricity dispatch.

In the given scenario, wind generation capacity is the energy source that increases the most between 2010 and 2025, by 181 GW, or in relative terms by 211%. This corresponds to an increase of the share of wind in the European energy mix from 4.1% in 2010 to 13.4% in 2025. Solar (mainly photovoltaic) generation shows the highest relative development, with its capacity increasing nearly fivefold, from 27.8 GW in 2010 to 137 GW in 2025. Biomass electricity generation capacity increases by 154% by 2025. The model results show an increase in the share of biomass in the electricity generation mix from almost zero in 2010 to 2.9% in 2025. The main reason is that biomass becomes a competitive fuel by 2025 because its variable generation cost is assumed to decrease whereas the gas price increases.

Table 3.1 shows the results of the first case study regarding dispatch costs, the curtailment needs of variable RES, pumped hydro storage and CO_2 emissions. Annual dispatch costs include generation dispatch costs and cross-border transmission costs. As Table 3.1 shows, annual dispatch costs increase only by a moderate 3.4% between 2010 and 2025. Considering the 15% demand growth in that period, the average dispatch cost per unit decreases by 10.3%. The main reason for this decrease is the large deployment of RES, which are the sources with the lowest dispatch (marginal) costs. However, the fixed costs of generation and transmission may offset this improvement.

Tab. 3.1.: Main model results for 2010 and 2025 (variations compared to 2010 between parentheses)

	2010	2025
Annual dispatch cost (Million €)	88408	91428 (+3.4%)
Average dispatch cost (€/KWh)	26.69	23.94 (-10.3%)
Wind curtailment (%)	0.056	0.117 (+108%)
Solar curtailment (%)	0.00	0.00
Pumping in hydro reservoirs (TWh)	17.01	8.23 (-52%)
CO_2 emissions (Million tonnes)	1485	1234 (-17%)
CO_2 emissions (tonnes/MWh)	0.448	0.323 (-28%)

Wind curtailment is negligible, both in 2010 and 2025. This is not to say that there will be no wind curtailment, but only that the interconnectors are not the constraints that cause curtailment. If curtailment is necessary, it is due to domestic network constraints. With a higher share of wind, cross-border transmission capacity will become a constraint on wind generation. Similarly, solar curtailment is not observed either; again, this only means that interconnector capacity is not a constraint. As solar energy is dispersed throughout the distribution networks, the capacity of the distribution networks is most likely to be the constraining factor.

The model results show that CO_2 emissions per unit of electricity decline by nearly 28% by 2025, but, because electricity consumption increases by 15%, total CO_2 emissions decrease only by 17%. These results are a small step towards the European Commission's target of a fully decarbonised European power sector by 2050 (EC, 2011). In order to meet this target, the EC estimates that CO_2 emissions must be reduced by 54-68% by 2030. Higher shares of RES and/or carbon capture and storage will be needed to meet the EU's climate policy targets. A reduction in expected European electricity consumption would be beneficial for meeting the desired goals. If the projected electricity consumption growth were mainly due to the (partial) electrification of transport, the results would be more optimistic because of the corresponding decrease of emissions in the transport sector.

Table 3.1 shows that overall hydro pumping (the sum of pumping into seasonal and small reservoirs) in Europe decreases by 2025. The main reason is that the increase in cross-border transmission capacity reduces the need for storage. However, at higher levels of wind and solar, demand for storage may be expected to increase again after 2025.

Given these effects on the generation sector, Figs. 3.2 and 3.3 show the number of congested hours per year in both directions, for each interconnector, in 2010 and 2025 respectively, given the expected development of the transmission network (as described in Chapter 2). For the interconnectors that exist in 2010, the model suggests that the number of congested hours per interconnector will decrease by 2025 compared to 2010, from being congested 41% of the time in average to 31% of the time. This means that the planned development of new interconnectors and the capacity expansion of existing interconnectors alleviate cross-border transmission congestion. For the 15 new interconnectors expected by 2025, the average number of congested hours is 3694; in other words, they are congested 42% of the time. This confirms the demand for these new interconnectors. The fact that the interconnectors are congested indicates that the cross-border flows lead to a lower overall dispatch cost. In reality, interconnector investment is not motivated by network congestion, but by wholesale price differentials and other issues. The reduction in dispatch cost is not related to the number of congested hours but to the differences in wholesale electricity price.

Table 3.2 shows the number of congested hours of the five most congested interconnectors in 2010. Four of the five most congested interconnectors in 2010 represent the well-known Italian electricity imports. When comparing Figs. 3.2 and 3.3, it can be noticed how the congestion of these four interconnectors is alleviated by 2025. One of the reasons for this change is the presence of two new links interconnecting Italy

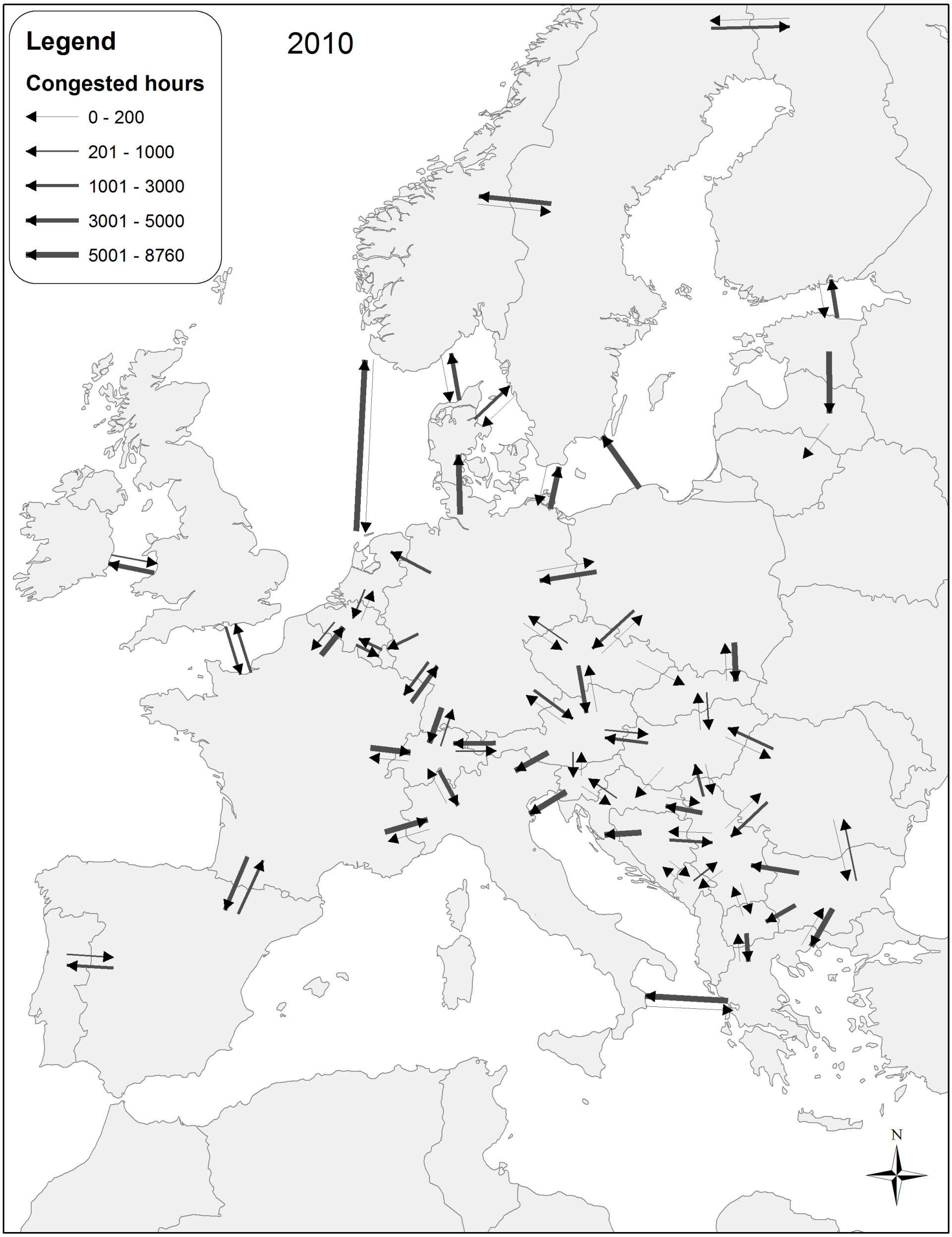


Fig. 3.2.: Cross-border transmission congested hours in 2010

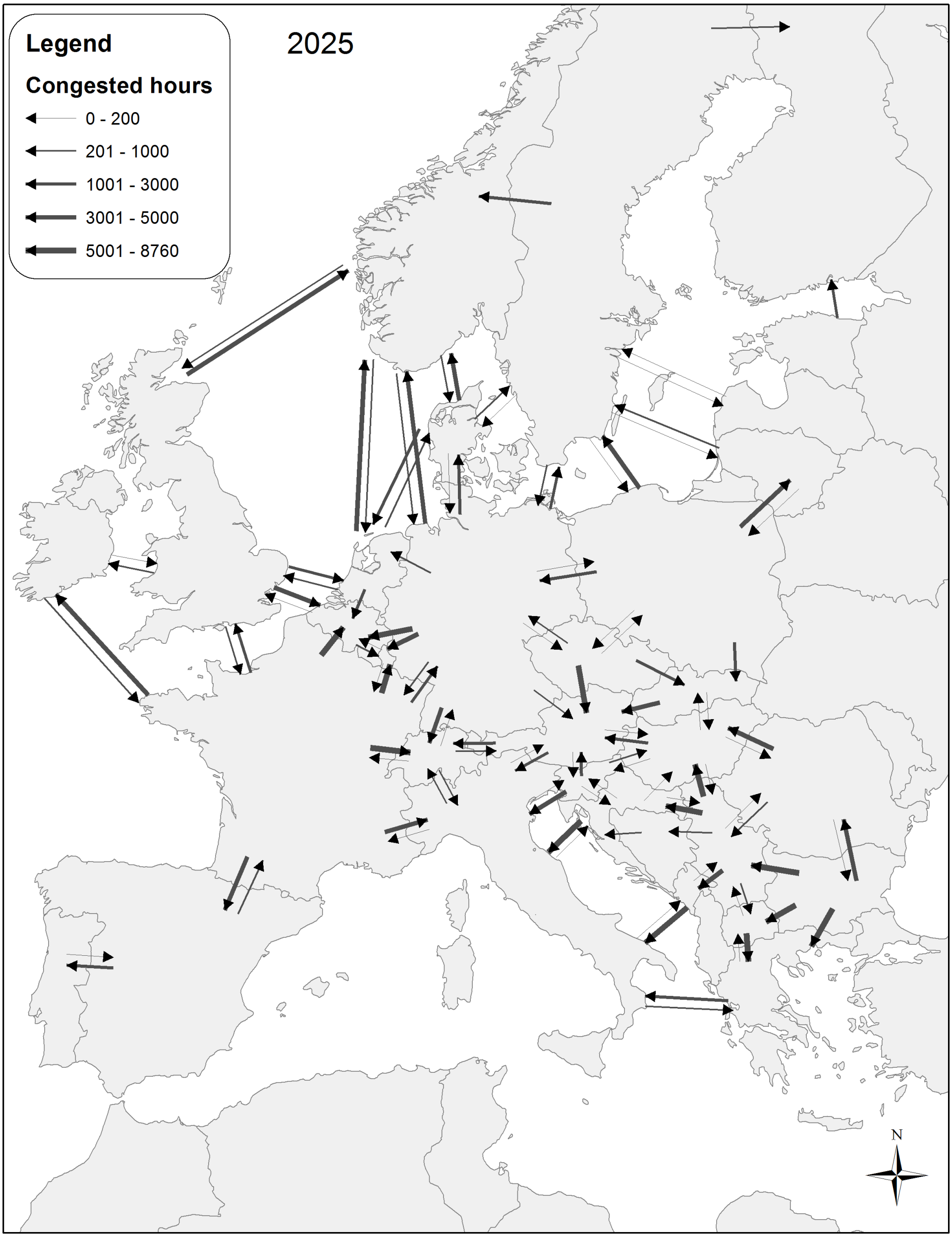


Fig. 3.3.: Cross-border transmission congested hours in 2025

Tab. 3.2.: Number of congested hours for most congested interconnectors in 2010

Country 1	Country 2	Congested hours
Austria	Italy	8465
Slovenia	Italy	8455
Poland	Sweden	7789
France	Italy	7717
Greece	Italy	7099

with Montenegro and Croatia. As shown in Table 3.3, the interconnector between Italy and Montenegro is the third most congested in 2025 and the most congested of the 15 new ones built between 2010 and 2025. Table 3.3 shows that overall congestion decreases and that availability of import capacity for Italy improves in general.

Tab. 3.3.: Number of congested hours for most congested interconnectors in 2025 (interconnectors marked with a * are built after 2010)

Country 1	Country 2	Congested hours
Bulgaria	Greece	8201
Bulgaria	Macedonia	7823
Montenegro*	Italy	7086
Czech Republic	Austria	6798
France*	Luxembourg	6110

Tab. 3.4.: Interconnectors with the highest decrease in congested hours from 2010 to 2025

Country 1	Country 2	Congested hours in 2010	Congested hours in 2025
Estonia	Latvia	6999	0
Italy	Austria	8465	2630
Italy	Slovenia	8455	3516
Belgium	Luxembourg	5311	525
United Kingdom	Ireland	4875	298

The new interconnectors between Sweden and Latvia, between Sweden and Lithuania and between Poland and Latvia remove the congestion from Estonia to Latvia, as shown in Fig. 3.3. Table 3.4 provides details about the five interconnectors with the largest decrease in congested hours in 2025 compared to 2010. The second and third in the ranking connect Italy to Austria and Slovenia; the congestion of both of them is alleviated by the two new Italian interconnectors, as previously discussed. The congestion of the fourth in the list, between Belgium and Luxembourg, is eased by the

new interconnector between France and Luxembourg, which, as shown in Table 3.3, is the fifth most congested interconnector in 2025. The fifth interconnector showing the largest decrease in the number of congested hours by 2025 is the one between the United Kingdom and Ireland. This is mainly because of the increase in interconnector capacity from 450/80 MW to 1850/1000 MW and the new interconnectors between Ireland and France and between the United Kingdom and Belgium, the Netherlands and Norway.

3.3. The needs for cross-border transmission investment in Europe by 2025

In this section, the hypothetical situations in which cross-border transmission capacity is and is not increased between 2010 and 2025 are analysed. Generation and demand increase to 2025 levels according to the latest ENTSO-E's SO&AF, as presented in section 2.3. The reason is to provide an indication of the need for the planned interconnector expansions (although a full cost-benefit analysis is outside the scope of this study).

Tab. 3.5.: Main results for model runs for 2025 with (a) and without (b) an increase in cross-border transmission capacity since 2010 (parentheses show variations compared to (b))

	2025 (a)	2025 (b)
Annual dispatch cost (Million €)	91428 (-1.06%)	92404
Wind curtailment (%)	0.117 (-75%)	0.464
Solar curtailment (%)	0.00	0.00
Pumping in hydro reservoir (TWh)	8.23 (-52%)	17.25
CO_2 emissions (Million tonnes)	1234 (+3.6%)	1191
Unserved load (GWh)	0.00	79

Table 3.5 shows the main results of this second case study with respect to annual dispatch costs, need for RES curtailment, hydro pumping, CO_2 emissions and unserved load. Table 3.5 shows that there is a direct economic benefit of increasing cross-border electricity transmission capacity. Given the 2025 generation and demand scenarios, the planned increase of cross-border electricity transmission capacity between 2010 and 2025 facilitates a 1.06% reduction in annual dispatch cost in 2025. This benefit comes from the enhanced ability to transmit electricity from countries with lower marginal generation cost to countries with more expensive generation. The volume of this benefit depends on the supply curve in each country, which is highly dependent

on the CO_2 price. For instance, a higher CO_2 price causes the marginal generation costs of coal and gas to be closer to each other and therefore reduces the demand for cross-border electricity flows. The sensitivity analysis in section 3.4 provides more insights on the impact of the CO_2 price. A second aspect of economic efficiency that we do not assess is the positive effect on reducing market power that is created by an increase in transmission capacity (Lise et al., 2008).

The planned increase in cross-border transmission capacity does not have a large impact on the need for RES curtailment. Solar curtailment is zero in both transmission capacity scenarios and wind curtailment, even if reduced to a third, is almost negligible in both cases: less than 0.5%. Therefore it can be concluded that the need to curtail RES is generally not caused by cross-border transmission capacity constraints. However, at higher volumes of installed RES generation capacity than assumed in ENTSO-E's SO&AF, the planned cross-border transmission capacity would indeed be needed to avoid significantly more RES curtailment. Nonetheless, RES curtailment may be affected by congestion in national distribution and transmission networks and by stability issues. The sensitivity analysis in section 3.4 shows the impact on the results in the hypothetical case that RES penetration in 2025 is doubled.

Table 3.5 shows an interesting result concerning CO_2 emissions. Higher cross-border transmission capacity throughout Europe has a negative environmental impact in this scenario: CO_2 emissions increase by 3.6%. The reason is that the marginal cost of coal and lignite plants is lower than the marginal cost of gas plants because the CO_2 price is not high enough to have a significant impact on the merit order of generation. More transmission capacity makes it possible to utilise coal and lignite more fully at the cost of gas plants. Section 3.4 considers the case in which the CO_2 price would be high enough to cause the marginal cost of coal plant to be higher than gas.

Another benefit of the planned increase in cross-border electricity transmission capacity that is shown in Table 3.5 is that it contributes to the security of supply. If cross-border transmission were to stay the same as in 2010, the model results show that Europe would have 79 GWh of unserved load in 2025 due to interconnector capacity constraints. This is equivalent to 0.002% of annual load. This result is based on the assumed generation and demand scenarios. If the planned expansion of interconnector capacity takes place, there will be no unserved load due to interconnector constraints. The limited impact of interconnector capacity on security of supply is due to the low growth rate of demand. As long as demand does not change much, not much investment is needed to maintain security of supply. However, the sensitiv-

ity analysis in Section 3.4 shows that if demand grows at the historical rate of 2%, new transmission capacity will be needed to maintain the current level of security of supply in terms of unserved load.

A final result, also shown in Table 3.5, is that use of pumped hydro, both in seasonal and small reservoirs, increases strongly when cross-border transmission capacity is limited. In order to meet the load at every hour of the year at the lowest possible operational cost, the European network maximises the use of energy storage when cross-border transmission capacity is limited. This result clearly shows the (at least partial) complementarity of electricity transmission and energy storage (in the form of hydro pumping). As more energy storage is needed in this scenario to maintain security of supply, less is available for balancing RES. In scenarios with higher volumes of RES, this means that the lack of interconnector capacity will likely become a constraint as there is less remaining storage capacity available. An example of this potential situation is discussed in the following section.

3.4. Sensitivity Analysis

3.4.1. Electricity Consumption

In this section, the impact of the growth rate of demand on the need for transmission capacity is evaluated. First, a case in which energy efficiency measures keep electricity consumption at the same level as in 2010 is considered. As the considered scenario (see section 2.3) assumes a load growth rate of about 0.9% per year, the case in which the demand growth rate is equal to the historical average of about 1.8% will also be reviewed. The main limitation of this analysis is that electricity demand is assumed to be unrelated to electricity generation investment decisions, and vice versa. However, we consider that this assumption is valid for the scope of this research.

Again, the two scenarios for 2025 with (a) and without (b) an increase in cross-border transmission capacity compared to 2010 are considered. Table 3.6, which displays the results, shows how the impact of higher cross-border electricity transmission capacity is largely the same as in the scenario with the expected electricity consumption growth rate. Only the magnitude of the aforementioned impact slightly varies. Interestingly, in absolute terms, cross-border transmission capacity reduces the need for RES curtailment more when electricity demand is lower, because then there are more moments with surplus RES generation in a given country.

Tab. 3.6.: Sensitivity analysis - electricity consumption at 2010 levels. Main results of model runs for 2025 with (a) and without (b) an increase in cross-border transmission capacity since 2010

	2025 (a)	2025 (b)
Annual dispatch cost (Million €)	65809 (-1.91%)	67091
Wind curtailment (%)	0.245 (-72%)	0.865
Solar curtailment (%)	0.00	0.00
Pumping in hydro reservoir (TWh)	15.75 (-31%)	22.96
CO_2 emissions (Million tonnes)	921 (+5.5%)	873
Unserved load (GWh)	0.00	0.00

If demand grows at a rate of 1.9% per year, which is closer to the historical growth rate than the modelled scenario, the planned increase in cross-border transmission capacity is necessary for maintaining security of supply. Table 3.7 shows how the volume of unserved demand increases strongly by 2025 if there is no investment in cross-border transmission capacity. RES curtailment decreases, because the higher consumption of electricity reduces electricity surpluses.

Tab. 3.7.: Sensitivity analysis: high electricity consumption growth rate. Main results for model runs for 2025 with (a) and without (b) an increase in cross-border transmission capacity since 2010

	2025 (a)	2025 (b)
Annual dispatch cost (Million €)	117538 (-0.44%)	118054
Wind curtailment (%)	0.033 (-65%)	0.094
Solar curtailment (%)	0.00	0.00
Pumping in hydro reservoir (TWh)	2.42 (-83%)	14.20
CO_2 emissions (Million tonnes)	1445 (+2.3%)	1413
Unserved load (GWh)	0.00	20458

Tables 3.5, 3.6 and 3.7 show how the economic benefit of the planned expansion in cross-border transmission capacity strongly depends on the growth of electricity consumption between 2010 and 2025. The relative and absolute savings in annual dispatch costs due to the planned investment in cross-border transmission capacity decrease as demand grows faster. This, perhaps counter-intuitive, result is caused by the fact that the number of hours in which natural gas generators are marginal increases as demand increases. This reduces price differences between countries and therefore also reduces the demand for cross-border transmission capacity.

3.4.2. CO_2 Price

This section considers the hypothesis of a high CO_2 price (50 €/tonne) which would cause marginal electricity generation costs to change according to Table 3.8. The key factor is that now the marginal cost of a gas plant is lower than that of lignite and coal plants.

Tab. 3.8.: Fossil fuels marginal generation costs for high CO_2 price (50 €/tonne)

Energy source	Marginal generation cost (€/ MWh)
lignite	$81.06 \pm 5\%$
coal	$68.89 \pm 5\%$
gas	$67.39 \pm 10\%$

Tab. 3.9.: Sensitivity analysis - CO_2 price = 50 €/tonne. Main results of model runs for 2025 with (a) and without (b) an increase in cross-border transmission capacity since 2010

	2025 (a)	2025 (b)
Annual dispatch cost (Million €)	118680 (-0.69%)	119500
Pumping in hydro reservoir (TWh)	4.68 (-61%)	12.09
CO_2 emissions (Million tonnes)	762 (+3.4%)	789

Table 3.9 shows the most relevant results for this case. The changes in RES curtailment and unserved load are not significant. As expected, the annual dispatch cost increases, compared to the scenario with a lower CO_2 price. Interestingly, the need for hydro pumping decreases as well. The main reason is that the marginal generation costs of coal and gas power plants are closer to each other and due to the assumed 75% energy efficiency of hydro pumping, there are fewer situations in which hydro pumping is economically attractive.

CO_2 emissions decrease due to the higher CO_2 price. Interestingly, in this case cross-border electricity transmission capacity contributes to a decrease in CO_2 emissions (which is not true in the base case scenario of section 3.3). In other words, if the CO_2 price is high enough to make gas generation cheaper than coal and lignite, more cross-border transmission capacity reduces CO_2 emissions.

3.4.3. RES Penetration

In this section we now consider a case with a much higher degree of RES penetration. The installed generation capacities of solar and wind in 2025 are assumed to double the forecasts of ENTSO-E's SO&AF (ENTSO-E, 2012a).

Tab. 3.10.: Sensitivity analysis - RES (wind and solar) penetration doubled. Main results of model runs for 2025 with (a) and without (b) an increase in cross-border transmission capacity since 2010

	2025 (a)	2025 (b)
Annual dispatch cost (Million €)	63553 (-6.7%)	68122
Wind curtailment (%)	4.5 (-42%)	7.7
Solar curtailment (%)	0.11 (-80%)	0.56
Pumping in hydro reservoir (TWh)	49.3 (-6.5%)	52.7
CO_2 emissions (Million tonnes)	823 (+0.7%)	817

Table 3.10 shows that the need for RES curtailment increases strongly at higher volumes of RES in both scenarios (with and without an increase in cross-border transmission capacity after 2010). Without investment in cross-border transmission capacity, wind curtailment increases to 7.7%. Wind curtailment is reduced to 4.5% when cross-border transmission capacity is expanded according to ENTSO-E's plans. Solar curtailment remains limited in both scenarios, but the planned transmission investment still reduces it considerably. In addition, Table 3.10 shows how, in case of a much higher volume of RES, the planned investment in cross-border transmission capacity facilitates a much larger reduction (both in absolute and relative terms) of annual dispatch costs. In other words, with a larger share of variable generation (wind and solar), the benefits from additional cross-border transmission capacity with respect to annual dispatch cost reduction increase. With regard to hydro pumping, Table 3.10 shows that the need for pumping increases extremely in this scenario with a large increase of variable RES compared to the base case scenario (see Table 3.5 in 47). However, the impact of investment in cross-border transmission capacity on the need for hydro pumping is smaller, probably because the limits of available pumping capacity are nearly reached.

When comparing Tables 3.9 and 3.10, a non-intuitive result becomes apparent. CO_2 emissions are higher in the scenarios with twice the RES (wind and solar) penetration than in the ones with a higher CO_2 price. In other words, CO_2 emissions are reduced to a larger extent if the CO_2 price is increased from 22.5 to 50 €/tonne than if the expected capacity of RES generation is doubled in 2025 (38% reduction instead of 33%). The reason is that even in the high-RES scenario, RES (also considering hydro

and biomass generation) still provides only half of total electricity generation. With a low CO_2 price, coal and lignite continue to be the most attractive energy sources after the RES and therefore continue to provide a large share of generation, with an increased share of RES mainly reducing generation by gas fired plants. When the CO_2 price is high, gas is the next generation source in the merit order and the role of coal and lignite is reduced significantly. As thermal plants provide a dominant share of electricity generation, this effect is stronger than the effect of more RES.

Finally, it is important to mention that the results presented in this chapter provide an overview of the expected evolution of the European electricity transmission network between 2010 and 2025 and the impacts of the expected investment in cross-border transmission capacity. The comparison of the model results between different generation, demand and transmission scenarios provides insights into the need for investment in cross-border transmission capacity in Europe. The volume of the needed investment depends on the scenarios considered in this study, as well as on the model assumptions and limitations. For instance, meteorological (solar radiation, wind speed and hydro inflows) and demand time series are based on 2010 data. The extrapolation of these time series to 2025 is a limitation of the study, as different patterns and correlations may arise between 2010 and 2025.

3.5. Conclusions

The purpose of this chapter was to assess the need for and the impacts of cross-border transmission investment in Europe. The analysis considered the generation and demand data from the Best Estimate scenarios of ENTSO-E's SO&AF 2011-2025 (for 2010) and SO&AF 2012-2030 (for 2025).

The main conclusion that can be drawn from this chapter is that cross-border transmission capacity will not be a significant constraint for the integration of variable renewable energy sources between 2010 and 2025 at the RES levels expected in ENTSO-E's SO&AF 2012-2030. At higher volumes of RES (around twice the level expected by ENTSO-E), more interconnection capacity will be needed if curtailment is to be avoided.

In addition, the results presented in this chapter show the extent to which the expected investment in cross-border transmission capacity in Europe will lower the cost of generation dispatch. This economic benefit is higher for lower demand growth rates and for scenarios with higher shares of variable RES (wind and solar) because the

number of hours in which natural gas generators are marginal increases as demand increases.

The expected expansion of cross-border transmission capacity by 2025 has a limited impact on the security of supply in the face of the expected low growth rate of electricity consumption in Europe (0.9%). However, if demand grows at the historical rate of 2%, the expected development of cross-border transmission will be needed to maintain the current level of security of supply (in terms of unserved load) in 2025, assuming that generation capacity will develop according to ENTSO-E's scenario.

Given the expected generation portfolio, expected growth in electricity demand and an expected CO_2 price of 22.5 €/tonne, if the planned cross-border transmission investments are realised, total CO_2 emissions from electricity generation in Europe will decrease by only 17% between 2010 and 2025. There is a 28% reduction in the carbon-intensity of electricity generation, but this improvement is partly offset by the growth of electricity consumption. More low-carbon generation and lower electricity demand growth will be needed to meet EU climate policy goals. A CO_2 price of 50 €/tonne would make the marginal generation cost of gas plants lower than coal and lignite, causing a 38% reduction in CO_2 emissions compared to the scenario with a price of 22.5 €/tonne. If twice the expected volume of variable RES were developed by 2025, CO_2 emissions would drop by 33%.

Finally, the results from the two case studies presented in this chapter show how hydro pumping and storage at least partly substitute the demand for cross-border electricity transmission. If a larger volume of variable RES is developed, more storage or back-up generation capacity will be necessary.

4. The Impact of Energy Storage on the Need for Cross-Border Transmission

This chapter is based on the following conference paper:

- Brancucci Martínez-Anido, C., de Vries, L.J., **Are cross-border electricity transmission and pumped hydro storage complementary technologies?**, *10th International Conference on the European Energy Market (EEM13)*, Stockholm, 27-31 May 2013.

4.1. Introduction

The objective of this chapter is to analyse the extent to which cross-border transmission and energy storage substitute or complement each other within the European electricity transmission network. In other words, this chapter explores the differences and the relationship between shifting load in time (energy storage) and space (cross-border transmission). In this study, energy storage is considered in the form of pumped hydro storage.

This study aims to probe the impacts that cross-border transmission and pumped hydro storage investments may have on an electricity system with a high degree of RES (wind and solar) penetration, as well as their impacts on one another. In other words, the potential complementarity of cross-border electricity transmission and pumped hydro storage is analysed. Complementarity is defined as the reciprocal relation in which one variable increases the demand for the other one. This differs from the definition of two variables which substitute one another. When a variable substitutes another one, it reduces the demand for the other one.

The aim of this study is not to analyse the amount of investment (in either physical or monetary terms) in transmission expansion or pumped hydro storage needed for a more efficient RES integration, as the capital costs of cross-border transmission expansion and hydro pumping capacity depend strongly on geographical, geological and institutional conditions. Therefore, it is not possible to generalise the cost of

transmission lines across Europe. Instead, this chapter focuses on the degree to which these two technical assets substitute or complement each other in order to assess the potential impact of an increase in energy storage capacity (in pumped hydro or a different, perhaps new technology) on the demand for cross-border transmission capacity.

EUPowerDispatch, presented in Chapter 2, is used to compare different scenarios with varying cross-border electricity transmission and hydro pumping capacities for a 2025 time horizon. The influence of pumped hydro storage and cross-border transmission capacity on dispatch costs, RES curtailment needs and CO_2 emissions is analysed. Furthermore, the complementarity of pumped hydro storage and cross-border transmission is evaluated by comparing the different scenarios in terms of cross-border transmission flows and hydro pumping utilisation.

This chapter is structured as follows. First, the different modelled scenarios are described. Then, the model results are discussed. Finally, the conclusions are presented.

4.2. Scenarios

The electricity generation capacities for each energy source in each country are based on the 2025 Best Estimate Scenario of the latest SO&AF (ENTSO-E, 2012a), as described in section 2.3. In order to consider a system with high variable RES penetration, the analysis presented in this chapter assumes that solar and wind installed generation capacities are doubled compared to ENTSO-E's scenario. Figs. 4.1 and 4.2 show the assumed solar and wind installed generation capacities, respectively, for each country.

In order to appreciate the difference between variable RES penetration in different countries, Fig. 4.3 shows the assumed installed variable RES generation capacity in each country as a percentage of the peak demand assumed for 2025.

Electricity consumption is assumed for 2025 as given in Section 2.3.1. The CO_2 price is assumed to be equal to 50 €/tonne, just above the threshold that changes the merit order. For the assumed CO_2 price, gas fired power plants have lower variable electricity generation cost than coal and lignite fired plants. The variable electricity generation costs of the different energy sources at the given CO_2 price are provided in Table 2.1 on page 31.

In order to assess the impacts of cross-border transmission and pumped hydro storage on the European electricity system in 2025, as well as their impacts on one another, this study analyses the model results of four different scenarios in which the two following variables vary:

- cross-border transmission capacities
- hydro pumping capacities

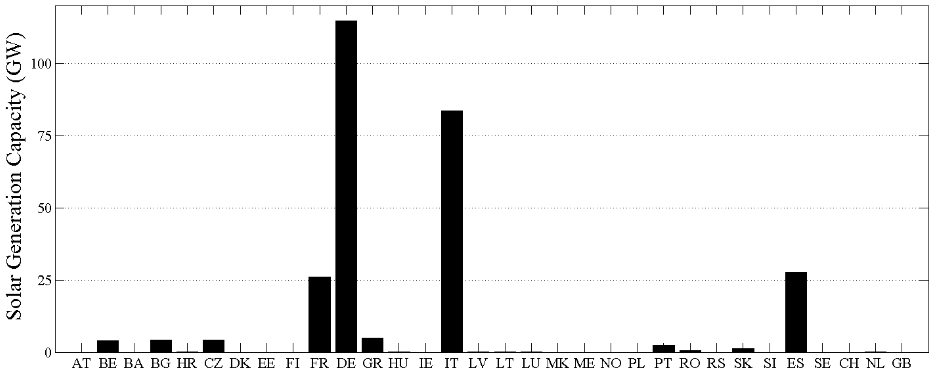


Fig. 4.1.: Solar generation capacities, doubled compared to ENTSO-E's scenario

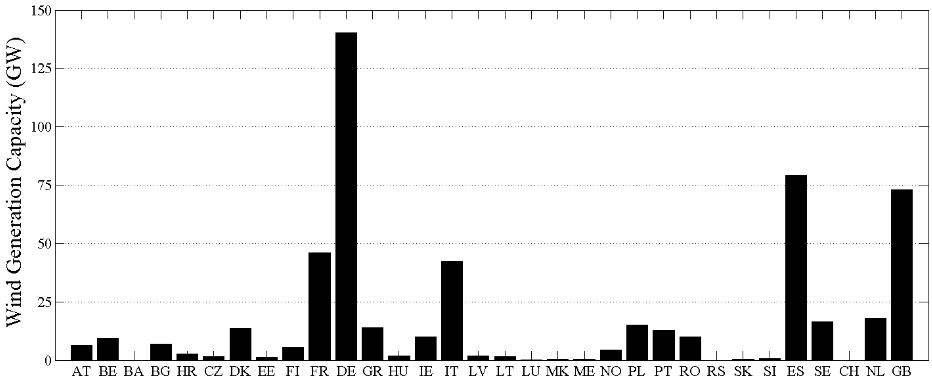


Fig. 4.2.: Wind generation capacities, doubled compared to ENTSO-E's scenario

The study considers two scenarios for cross-border electricity transmission capacities: the net transmission capacities in 2010 and the planned maximum transmission capacities in 2025. The data sources are provided in section 2.3. Hydro pumping capacities per country are based on several sources (see Section 2.2.1). In the reference scenario, hydro pumping capacities are the expected capacities by 2025; in the

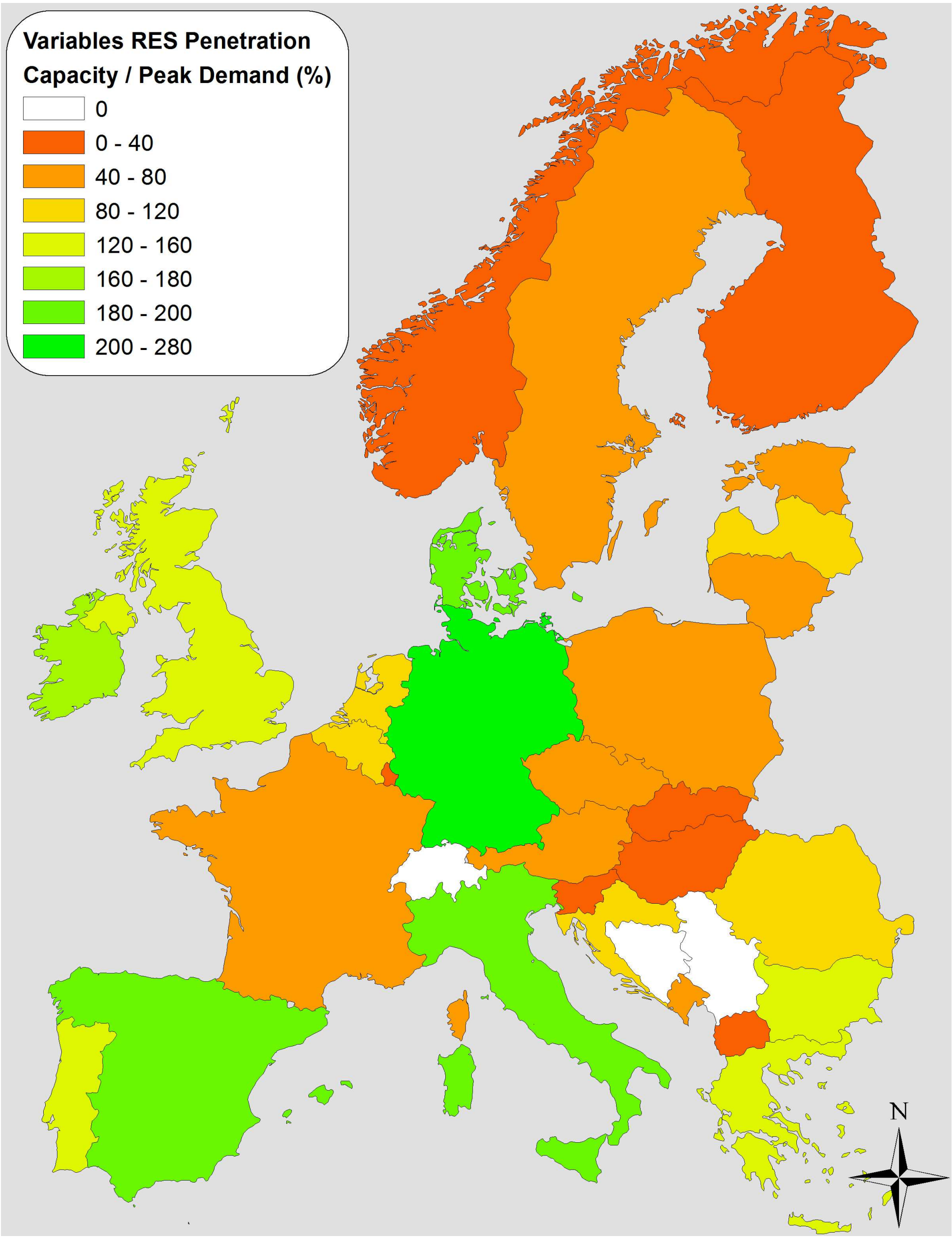


Fig. 4.3.: Variable RES penetration: installed wind and solar generation capacity as a percentage of peak demand

second scenario, hydro pumping capacities are doubled with respect to the reference scenario. Table 4.1 shows the differences between the four scenarios in order to compare their simulation results. Figures 4.4 and 4.5 show the cross-border transmission and hydro pumping capacities assumed for scenarios 1 and 4 respectively.

Tab. 4.1.: Scenarios Definition

Scenario	Cross-border transmission	Hydro pumping capacity
1	2010	reference
2	2025	reference
3	2010	2 x reference
4	2025	2 x reference

Transmission capacity across borders is increased from 78 GW in the 2010 scenario to 137 GW in the 2025 scenario. On the other hand, for hydro pumped storage, a 100% increase in pumping capacity is considered. Therefore, in these countries where zero pumping capacity is planned in 2025, pumping capacity remains zero in the high pumping scenario. Total hydro pumping capacity in Europe is considered to be either 50 GW or 100 GW in the two scenarios.

4.3. Results & discussion

EUPowerDispatch is run for the four scenarios described in the previous section. The results of the four runs (Table 4.2) are compared with respect to annual dispatch costs, RES curtailment needs, CO_2 emissions, cross-border transmission flows and hydro pumping utilisation. Table 4.3 provides the relative values of cross-border transmission and hydro pumping capacity investments in terms of reductions in annual dispatch costs, RES curtailment needs and CO_2 emissions. For instance, the value of cross-border transmission expansion in terms of annual dispatch costs is calculated by subtracting the annual dispatch costs of scenario 2 from the annual dispatch costs of scenario 1.

Cross-border transmission allows electricity to flow from countries with a lower marginal variable generation cost to countries with a higher marginal variable generation cost. Hydro pumped storage instead, allows to pump water into a reservoir when the marginal variable generation cost is lower in order to generate electricity at a very low (almost negligible) variable generation cost when the marginal variable generation cost is higher, either during moments of peak demand or moments when the available electricity from variable RES (wind and solar) is very low. Table 4.2

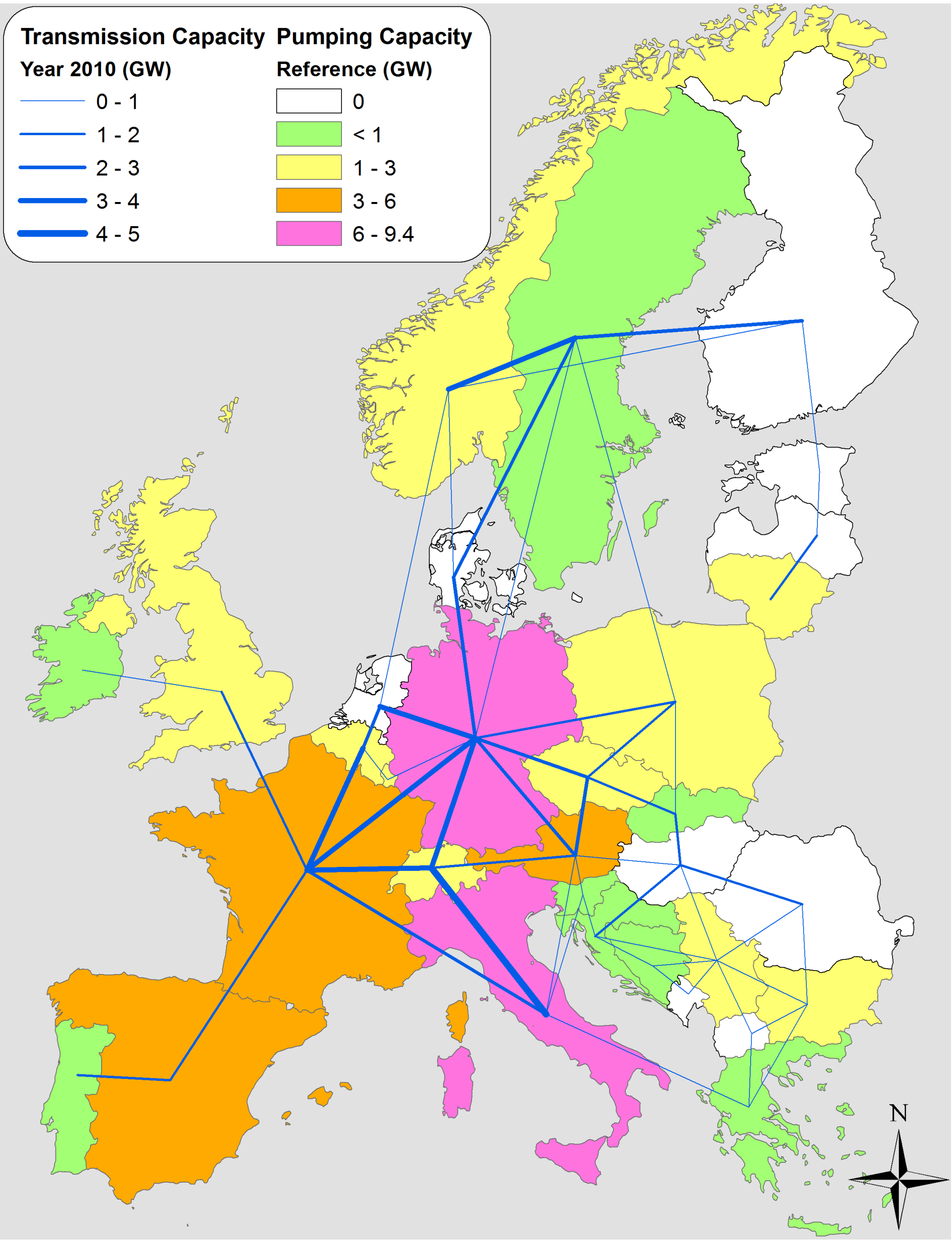


Fig. 4.4.: Cross-Border Transmission and Hydro Pumping Capacities - Scenario 1

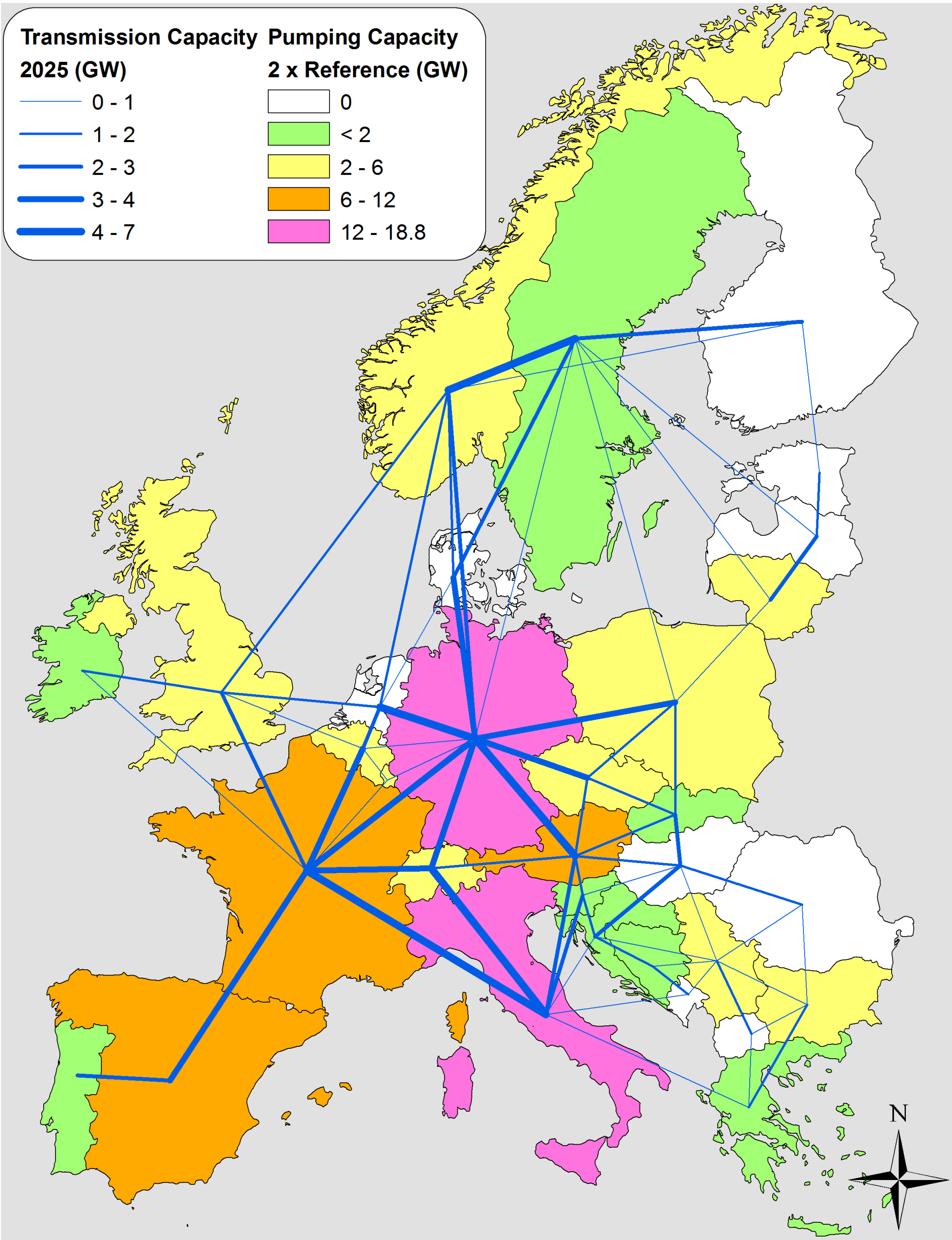


Fig. 4.5.: Cross-Border Transmission and Hydro Pumping Capacities - Scenario 4

Tab. 4.2.: Results for the four scenarios

Scenario	1	2	3	4
Annual Dispatch Cost (M€)	84419	80292	83905	79846
RES Curtailment Needs (%)	5.91	3.41	5.00	2.79
CO_2 Emissions (Million tonnes)	487	430	484	426
Cross-Border Trans. Flows (TWh)	364	567	367	570
Cross-Border Trans. Loading (%)	62.2	51.3	62.8	51.6
Hydro Pumping Utilisation (TWh)	46.2	37.9	60.0	48.3

Tab. 4.3.: Benefits of cross-border transmission and pumped hydro storage investment

Reduction in	V(T)	V(P)	V(P+T)
Annual Dispatch Cost (M€)	4127	515	4573
RES Curtailment Needs (TWh)	33.35	12.16	41.67
CO_2 Emissions (Million tonnes)	56.27	2.42	60.17

shows how annual dispatch costs decrease when cross-border transmission capacity is increased and also when hydro pumping capacity is increased throughout Europe.

As shown in Table 4.3, the values of cross-border transmission and hydro pumping capacity investments in terms of annual dispatch costs are different. However, the net benefits of these investments depend on their relative capital costs, which highly depend on local conditions. However, the results indicate that the two technical assets substitute each other in terms of annual dispatch costs reduction. Overall, the value of both investments is lower than the sum of the values of the individual investments.

Table 4.2 shows how RES curtailment needs decrease substantially when cross-border transmission capacity is increased and also when hydro pumping capacity is increased. In addition, Table 4.3 shows how both technical assets are substitutes in terms of reducing RES curtailment needs.

Figure 4.6 shows in which countries RES curtailment is avoided due to an increase in cross-border transmission capacity, also plotted as additional transmission capacity. Avoided RES curtailment is calculated comparing the results from scenarios 1 and 2 and is given as a percentage of potential RES generation in a country (given the assumed RES installed capacity). For instance, Germany's avoided RES curtailment is the highest in absolute terms but due to its size and its high RES penetration, it is not ranked first in Figure 4.6. Figures 4.3 and 4.6 show how RES curtailment needs are reduced in countries where RES penetration is higher, such as, Ireland, United Kingdom, Denmark, Germany, Italy and Spain. Ireland shows the highest avoided

RES curtailment due to the new interconnector with France and the increased cross-border transmission capacity with the United Kingdom. The latter also benefits a lot in terms of lower RES curtailment needs due to the new interconnectors with Belgium, The Netherlands and Norway.

Figure 4.7 shows in which countries RES curtailment is avoided due to an increase in hydro pumping, also plotted as additional pumping capacity. Avoided RES curtailment is calculated comparing the results from scenarios 1 and 3 and is given as a percentage of potentially available RES generation in a country. RES curtailment needs are reduced more in countries where hydro pumping capacity is increased more. For instance, Italy shows the highest reduction (both in absolute and relative terms) in RES curtailment needs due to having the highest pumping capacity.

The results presented in this study show how both cross-border transmission capacity and hydro pumping capacity reduce variable RES curtailment needs in a power system with a high RES penetration. The magnitude of these impacts varies throughout Europe and depends on several power system characteristics, such as RES penetration level, generation mix and transmission network.

In the four modelled scenarios, the CO_2 price is assumed to be 50 €/tonne, a value at which the marginal generation cost of gas plants is lower than the marginal generation cost of coal and lignite plants. Therefore, the merit order of the most used fossil fuel plants (lignite, coal and gas) corresponds to their CO_2 emissions rate. Table 4.2 shows how CO_2 emissions decrease when cross-border transmission capacity is increased and also when hydro pumping capacity is increased. As for annual dispatch costs and RES curtailment needs, Table 4.3 shows how the values of cross-border transmission and hydro pumping capacity investments in terms of CO_2 emissions are different. However, in this case, the value (in terms of CO_2 emissions reduction) of both investments is higher than the sum of the values of the individual investments. In terms of CO_2 emissions reduction, cross-border transmission and pumped hydro storage complement one another.

Table 4.2 shows that hydro pumping utilisation decreases substantially when cross-border transmission capacity increases. The reason for this behaviour is that cross-border transmission and pumped hydro storage are partly substitutes. In addition, it is cheaper to import electricity from a neighbouring country than using pumped hydro storage. EUPowerDispatch assumes a 75% round-trip hydro pumping efficiency. Instead, cross-border transmission is subject to relatively low costs. In order to reduce the annual dispatch costs in the given generation and transmission scenarios, results show that if cross-border transmission capacity is increased, cross-

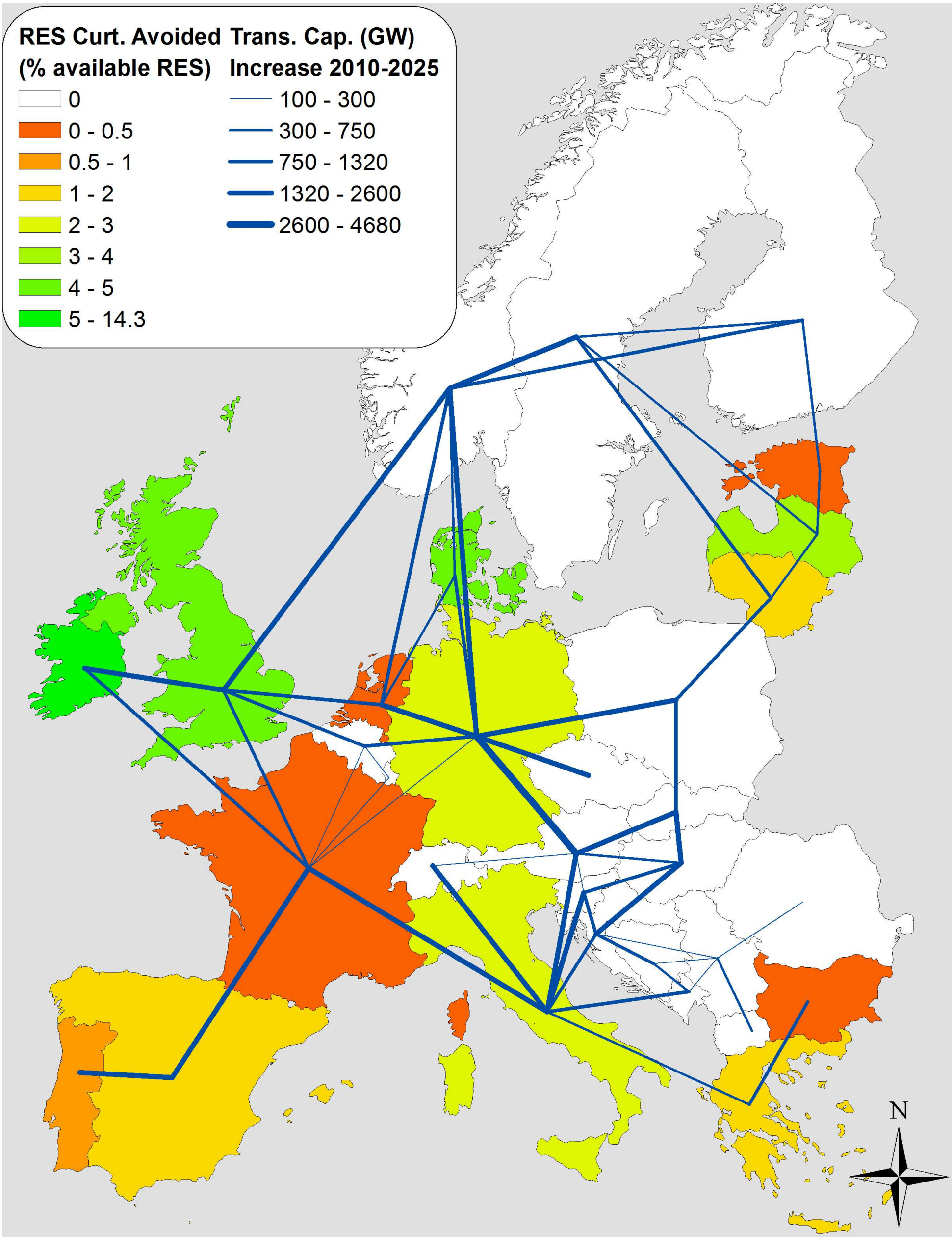


Fig. 4.6.: Avoided RES curtailment due to cross-border transmission development & additional cross-border transmission capacity (difference between scenarios 1 and 2)

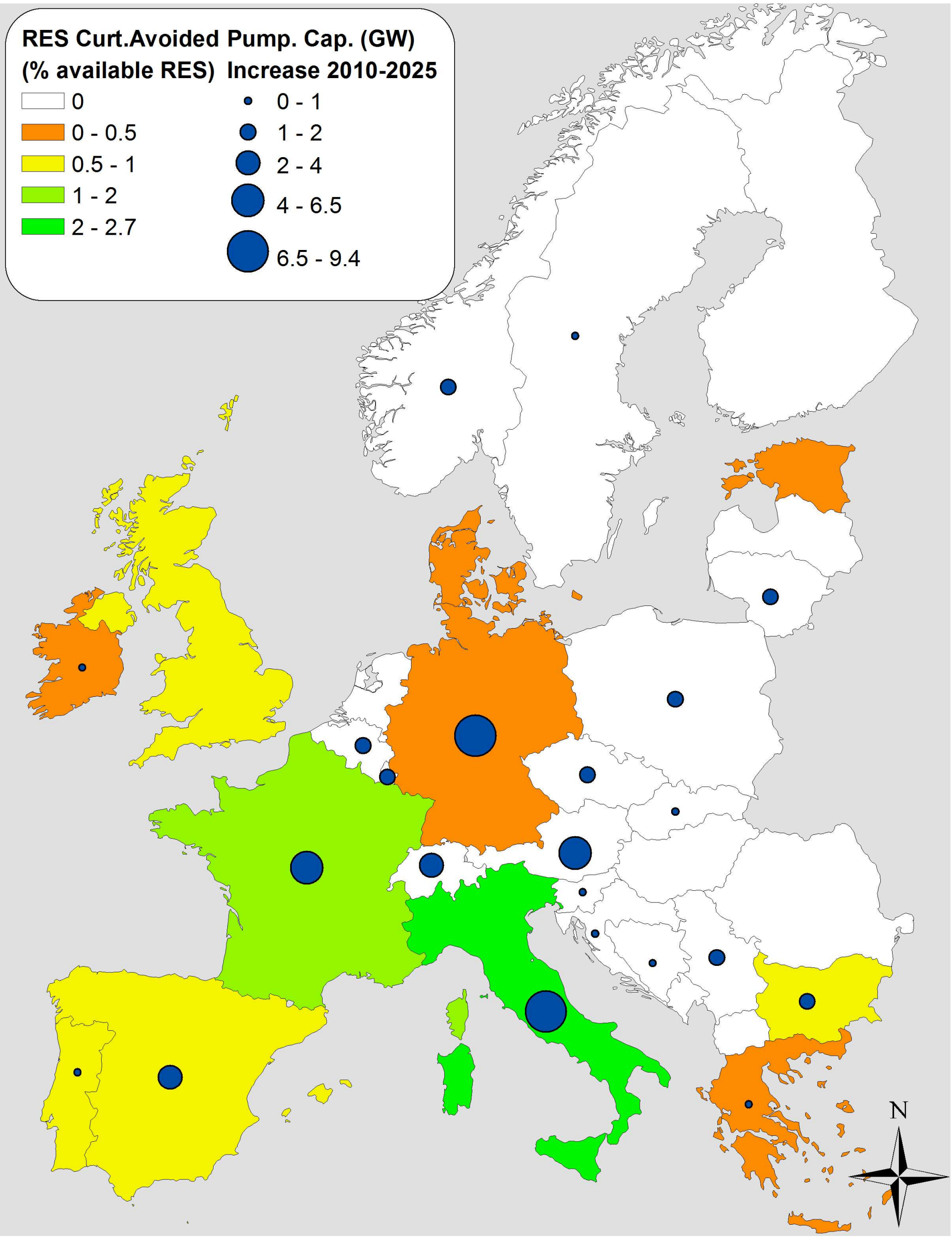


Fig. 4.7.: Avoided RES curtailment due to pumped hydro storage development & additional hydro pumping capacity (difference between scenarios 1 and 3)

border transmission flows increase, reducing the needs for hydro pumping. Electricity flows from countries with lower marginal variable generation costs to countries with higher marginal variable generation costs. Therefore, marginal variable generation costs decrease and fewer situations arise in which hydro pumping is economically attractive.

However, when hydro pumping capacity is increased, cross-border transmission flows increase slightly. This counter-intuitive behaviour can be explained by defining two situations in which hydro pumping capacity is a constraint for hydro pumping in one case and for cross-border transmission flows in another. In the first situation, an increase in pumping capacity would allow a higher pumping utilisation and it would not have a direct impact on cross-border electricity flows. In the second situation, the electricity flow from country "A" to country "B" is constrained because hydro pumping in country "B" is already used at its maximum capacity. In this situation, if hydro pumping capacity in country "B" increases, electricity flow from "A" to "B" would also increase. In this situation, hydro pumping complements cross-border transmission.

4.4. Conclusions

This chapter analysed the impacts of cross-border electricity transmission and hydro pumped storage on a power system with a high variable RES penetration. The results show that the two technical assets analysed have similar impacts on the European electricity system: both of them reduce annual dispatch costs, RES curtailment needs and CO_2 emissions.

In addition, the present study also explores the extent to which cross-border electricity transmission and hydro pumped storage substitute or complement each other within the European electricity transmission network. The results show that hydro pumping utilisation and electricity flows across borders depend on each other's available capacity. The demand for hydro pumping decreases with higher cross-border transmission capacity. On the other hand, paradoxically, cross-border transmission flows increase slightly with higher hydro pumping capacity. Cross-border transmission substitutes (or in other words, reduces the need for) hydro pumping. However, hydro pumping complements (or in other words, increases the need for) cross-border transmission. Plans for cross-border transmission investments should consider hydro pumped storage as an alternative, and as a complementary option.

5. The Impact of Demand Response on the Need for Cross-Border Transmission

This chapter is based on the following peer-reviewed journal article:

- Verzijlbergh, R.A., Brancucci Martínez-Anido, C., Lukszo, Z., de Vries, L.J., **Does controlled electric vehicle charging substitute cross-border transmission capacity?**, *Applied Energy*, accepted for publication.

The content of this chapter represents, in an extended version, my contribution to the journal article.

5.1. Introduction

The objective of this chapter is to analyse the extent to which cross-border transmission and demand response substitute or complement each other within the European electricity transmission network. In other words, this chapter explores the differences and the relationship between shifting load in time (demand response) and space (cross-border transmission). In this study, demand response is considered in the form of controlled electric vehicle (EV) charging.

The aim of this study is to analyse the extent to which controlled charging of a large number of electric vehicles can substitute cross-border electricity transmission capacity. In other words, how do transmission and demand response supplement one another and/or depend on each other in a system with a high RES penetration? Demand response is considered and modelled as the controlled charging of electric vehicles. The vehicle-to-grid concept (or in other words, the possibility of using EV batteries to store electricity and to supply it when demanded by the network) is not considered in the analysis presented in this chapter.

Several studies have analysed EV integration in the electricity network in a high RES context for national or regional systems such as Germany and California (Dallinger et al., 2013), Inner Mongolia (Liu et al., 2013), Northern Europe (Hedegaard et al.,

2012) and Portugal (Carvalho et al., 2012). The study presented in this chapter, instead, investigates the interdependencies between controlled EV charging and cross-border electricity transmission for the majority of the entire interconnected European electricity network.

EUPowerDispatch, presented in Chapter 2, is used to model the impact of controlling the charging of EVs and the impact of cross-border transmission capacity on four main output indicators: annual dispatch costs, RES curtailment needs, unserved load and CO_2 emissions. The analysis is performed assuming a 25% EV penetration in Europe in 2025 and for different levels of RES penetration and CO_2 price. In addition, in order to get better insight into the relation between controlled EV charging and cross-border transmission capacity, their impacts on three internal variables (cross-border transmission flows, cross-border congestion and hydro pumping utilisation) are assessed.

This chapter is structured as follows. First, the new elements in EUPowerDispatch are described and the different scenarios are presented. The next section provides an analysis of the impacts of controlling the charging of EVs and of cross-border transmission capacity on RES integration. Then, the impacts of CO_2 emission pricing on the analysis previously presented are discussed. Finally, the conclusions are presented.

5.2. Methodology and Scenarios

This study presents a new element in EUPowerDispatch: electric vehicles. An EV deployment of 25% (1 out of 4 passenger vehicles is electric) in Europe by 2025, which corresponds to a 5% increase in total electricity consumption, is assumed. 25 types of EV driving behaviour are included. Each of them corresponds to a group of electric vehicles with different driving distances and driving times. EV driving patterns are based on Dutch mobility data (Ministry of Transport Public Works and Water Management, 2009) and scaled to other European countries according to the total number of kilometres driven by passenger cars per country (European Union Road Federation, 2011). For non EU countries, the EV demand is based on their neighbouring countries and scaled with respect to their population sizes.

In order to study the impacts of EV charging control on the European power system, two ways of connecting EVs to the electricity network are considered (Verzijlbergh et al., 2011): uncontrolled and controlled EV charging. In the uncontrolled charging

scenario it is assumed that the drivers charge their cars at home immediately after their last trip of the day with a constant charging power (C_{ev} is constant).

In the controlled charging scenario, instead, the EV charging power (C_{ev}) is an additional optimisation variable of EUPowerDispatch, with additional constraints that are dictated by the EV batteries' state-of-charge, charging power and driving needs. The mathematical formulation of EUPowerDispatch changes slightly. First of all, a new set of elements represents the electric vehicles, as shown in 5.1.

$$ev = \{ev_1, ev_2, ev_3, ...ev_{25}\} \tag{5.1}$$

Secondly, the equilibrium equation (Eq. 2.8) presented in section 2.2.3 is modified by adding a term corresponding to the demand of electricity used to charge the batteries of the electric vehicles (C_{ev}), as shown in Eq. 5.2.

$$\sum_{g=1}^{G}(P_g) + \sum_{h=1}^{H}(P_h) + IMP = D + \sum_{h=1}^{H} PUMP_h + EXP + \sum_{ev_1}^{ev_{25}} C_{ev} \qquad \forall n, t \tag{5.2}$$

$$CMIN_{ev} \leq C_{ev} \leq CMAX_{ev} \qquad \forall n, ev, t \tag{5.3}$$

$$SOCMIN_{ev} \leq SOC_{ev} \leq SOCMAX_{ev} \qquad \forall n, ev, t \tag{5.4}$$

$$SOC_{ev_t} = SOC_{ev_{t-1}} - DR_{ev_{t-1}} \qquad \forall n, ev, t \tag{5.5}$$

Additional constraints (Eqs. 5.3, 5.4 and 5.5)are included in the mathematical formulation in order to model controlled EV charging in the optimisation. Eq. 5.3 expresses the EV charging power needs to be within limits ($CMIN_{ev}$ and $CMAX_{ev}$). Eq. 5.4 provides the EV battery state-of-charge (SOC_{ev}) also to be within limits ($SOCMIN_{ev}$ and $SOCMAX_{ev}$). Finally, the EV battery state-of-charge and the EV charging power are related to each other through Eq. 5.5, which considers the EV battery discharge due to driving (DR_{ev}).

In the analysis two scenario parameters are varied: RES penetration and CO_2 price. Section 5.3 analyses the impact of controlling the charging of EVs and of cross-border transmission capacity on RES integration. Section 5.4 evaluates the impact

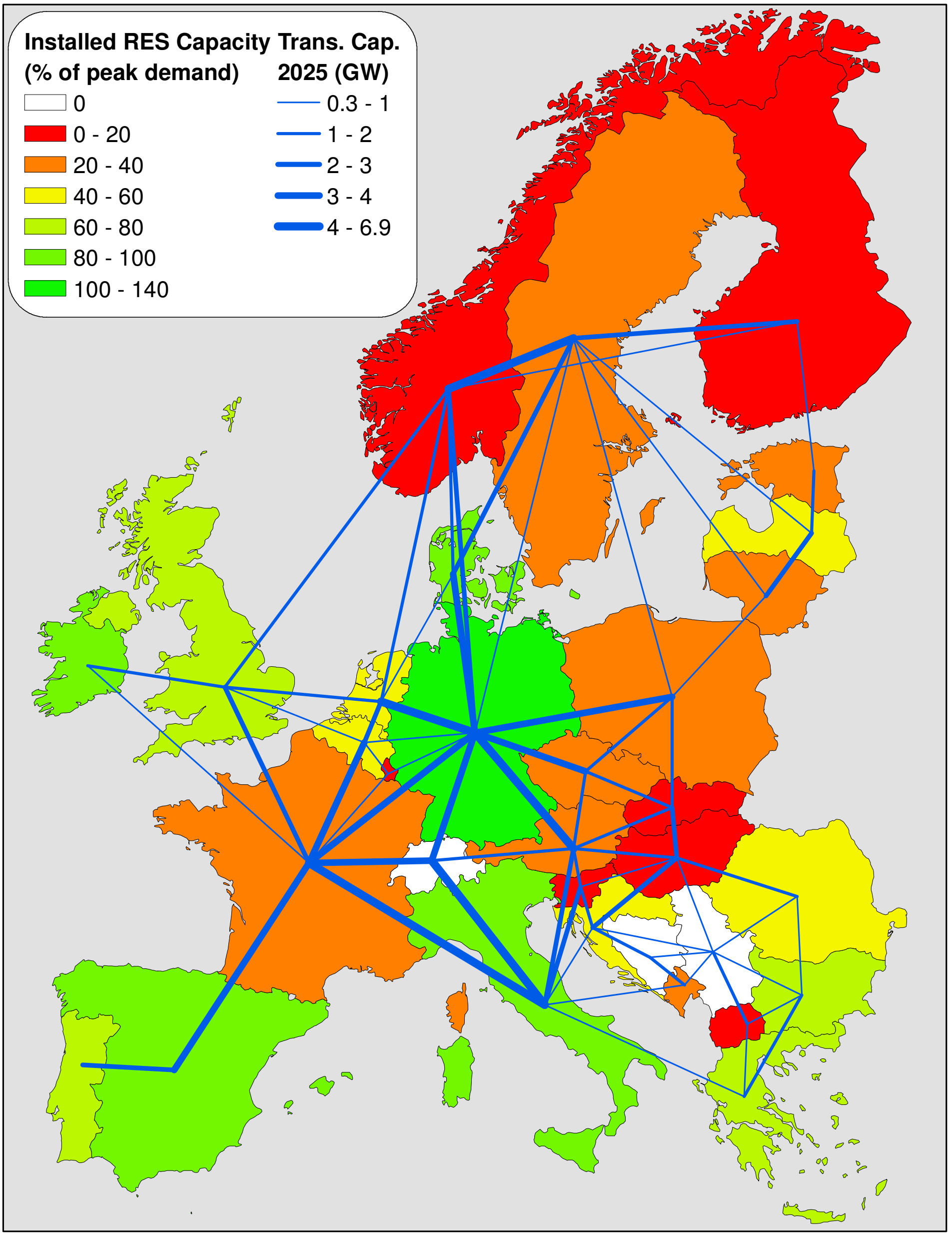


Fig. 5.1.: Cross-border transmission capacities and RES penetration - Scenario Trans. 2025

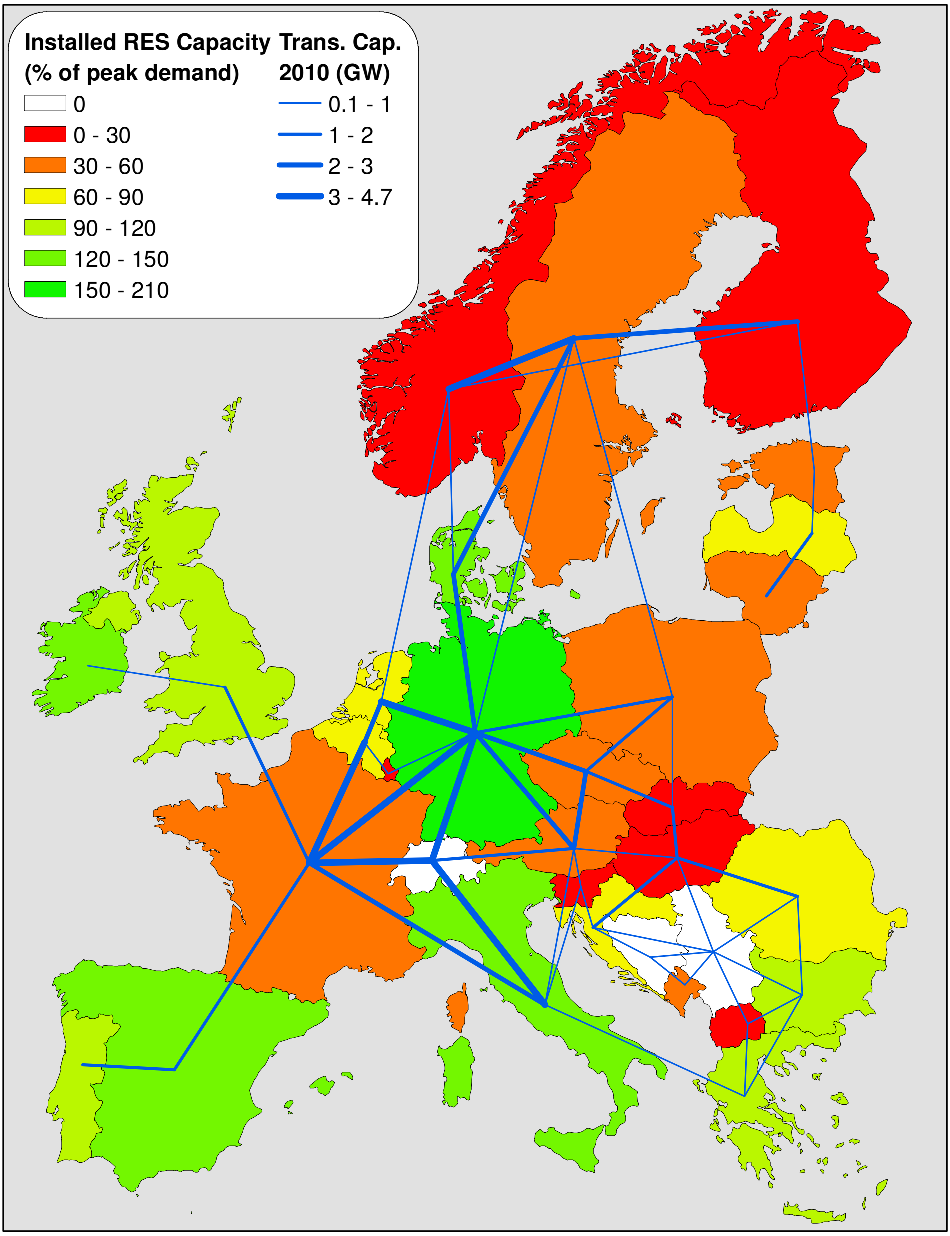


Fig. 5.2.: Cross-border transmission capacities and RES penetration - Scenario Trans. 2010 + 50% RES

of different CO_2 prices. Variations in CO_2 prices are relevant because they may affect the merit order of dispatch and hence the demand for arbitrage.

The potential for arbitrage exists when the difference in dispatch cost between two markets is greater than the cost of arbitrage. The two markets can represent two geographic areas or the same market over time (e.g. day and night). In this analysis, the cost of arbitrage is the variable cost of cross-border transmission and the variable cost of controlled EV charging.

In order to present the results of an analysis that comprises two control variables (controlled EV charging and cross-border transmission capacity) and two scenario parameters (RES penetration and CO_2 price), four scenarios with different combinations of cross-border transmission capacity and RES penetration are defined, as shown in Table 5.1.

Tab. 5.1.: Scenario definition

Scenario	RES Capacity	Transmission Capacity
Trans. 2025	Cap_{2025}	Cap_{2025}
Trans. 2010	Cap_{2025}	Cap_{2010}
Trans. 2025 +50% RES	$1.5*Cap_{2025}$	Cap_{2025}
Trans. 2010 +50% RES	$1.5*Cap_{2025}$	Cap_{2010}

The study considers two levels of RES penetration. In the first case, wind and solar installed generation capacities are the expected capacities by 2025, as presented in section 2.3. In the second case, the installed generation capacities are increased by 50% compared to the first case.

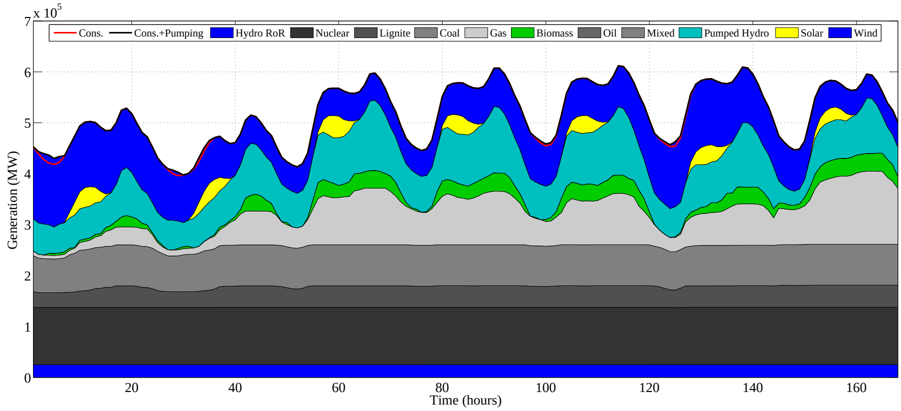
In addition, two levels of cross-border electricity transmission capacity are considered: the net transmission capacities in 2010 and the planned maximum transmission capacities in 2025, as presented in section 2.3. Figs. 5.1 and 5.2 show the cross-border electricity transmission capacities and the RES penetration for each country for scenarios "Trans. 2025" and "Trans. 2010 +50% RES" respectively.

5.3. The impact of controlling the charging of EVs and of cross-border transmission capacity on RES integration

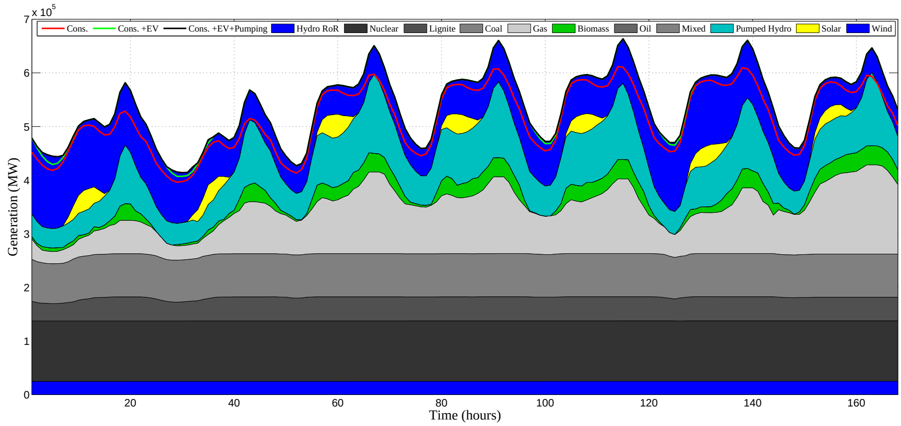
In this section, the degree to which controlled charging of EVs and cross-border transmission capacity are substitutes is assessed. This study analyses the impacts of controlled EV charging and of investment in cross-border transmission capacity on system performance in terms of dispatch costs, RES curtailment needs, unserved load and CO_2 emissions. At the end of this section, the relationships between EV charging control and cross-border transmission capacity and transmission network usage and hydro pumping utilisation will also be reviewed.

This section starts with the effects of cross-border transmission capacity and controlled charging of EVs on the dispatch cost of generation. Essentially, the possibility of inter-temporal arbitrage that is provided by control over the charging rate of EVs and the possibility of inter-locational arbitrage through cross-border transmission are used to lower the dispatch cost by creating a flatter residual load curve for thermal plants, so conventional lignite, coal and gas power plants produce at a more constant rate. This reduces dispatch costs by lowering the number of power plant shut-downs and most importantly, by avoiding the more expensive peaking units as much as possible. This effect occurs year-round, but the effects on cross-border flows are different in summer and winter.

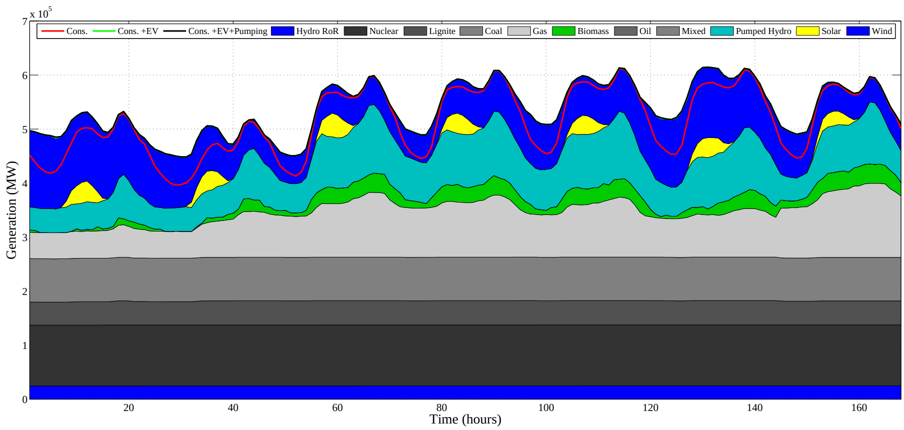
Figs. 5.3 and 5.4 show the generation dispatch in Europe during two representative weeks in winter and summer, both in the uncontrolled and controlled EV charging cases, as well as in the case without EVs, with cross-border transmission capacity and RES penetration according to the Trans. 2025 scenario. The benefits of cross-border transmission and of controlling the charging rate of EVs are strongly affected by solar generation in summer while wind generation is higher in winter. Fig. 5.3 shows that controlling the charging of EVs substantially reduces the winter evening peak that develops in the uncontrolled case, when EVs are charged right after their last arrival at home (which coincides with the typical winter evening peak). On the other hand, in summer, when solar generation is highest during peak demand, as in Fig. 5.4, the mid-day peak is increased due to EV charging in the controlled charging case. Despite the fact that demand is highest during the middle of the day, the marginal cost of generation is lowest at the same time during sunny days, as a result of which controlled EV charging adds to peak demand.



(a) No EVs

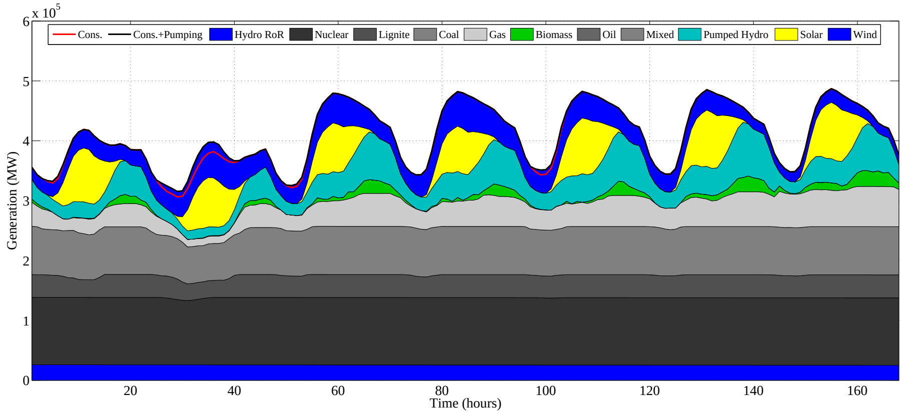


(b) Uncontrolled EV Charging

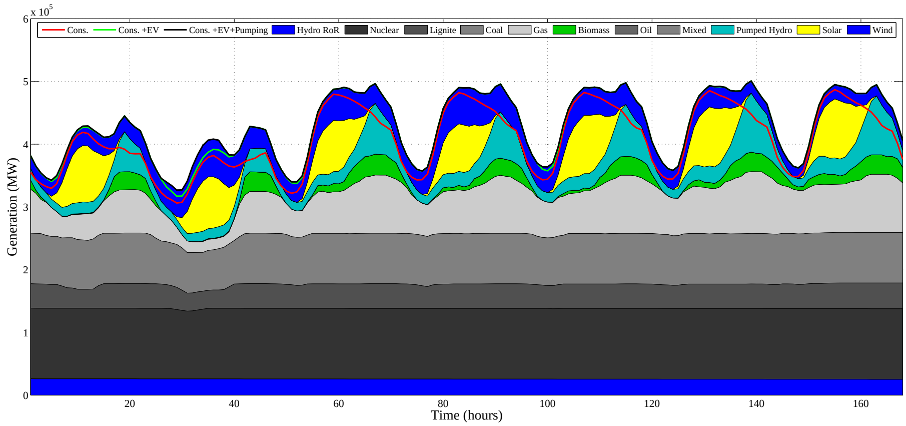


(c) Controlled EV Charging

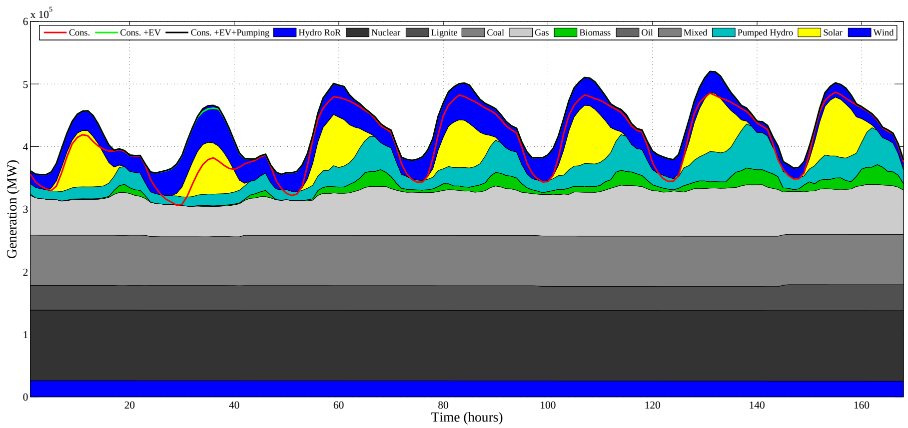
Fig. 5.3.: Generation dispatch in a winter week for the 32 countries in EUPowerDispatch



(a) No EVs



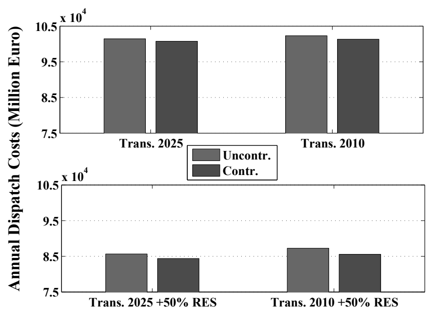
(b) Uncontrolled EV Charging



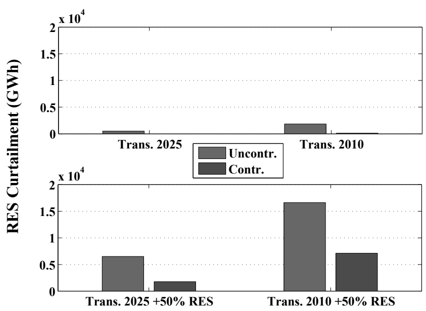
(c) Controlled EV Charging

Fig. 5.4.: Generation dispatch in a summer week for the 32 countries in EUPowerDispatch

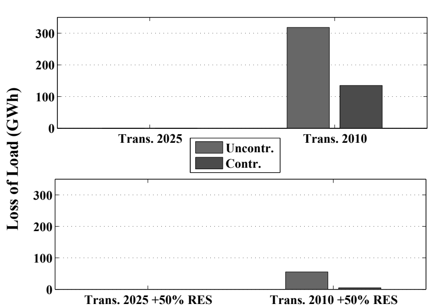
Fig. 5.5(a) shows the annual dispatch costs, both in case of uncontrolled and controlled EV charging in the four scenarios. The charts in Fig. 5.5(a) show the annual dispatch cost for all countries in EUPowerDispatch. The annual dispatch costs are reduced both by an increase in cross-border transmission capacity and by controlling the charging of large numbers of EVs. To a degree, both options are substitutes. The value of transmission decreases when controlled EV charging is implemented and the value of controlled EV charging decreases with increasing volume of cross-border transmission capacity. The relation between cross-border transmission capacity and controlled EV charging changes with the volume of intermittent RES. The top part of Fig. 5.5(a) represents the ENTSO-E scenario for RES development. The value of the increase in cross-border transmission capacity as planned by ENTSO-E is given by the difference in dispatch costs between the Trans. 2010 and the Trans. 2025 scenarios. Without controlled EV charging, the value of the planned transmission increase is 862 M€ per year. Controlled EV charging reduces this value to 571 M€ per year. This reduction of 34% signals the fact that controlled EV charging partly substitutes cross-border transmission capacity.



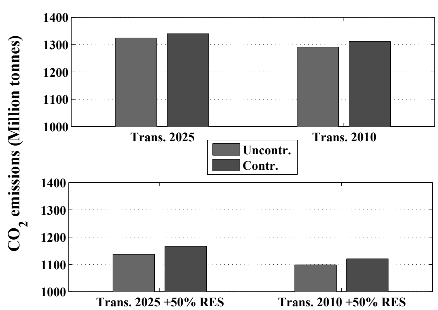
(a) Annual dispatch cost



(b) Annual RES curtailment needs



(c) Annual Loss of load



(d) Annual CO_2 emissions

Fig. 5.5.: Results in terms of four main output indicators

In the +50 % RES scenario (represented by the lower part of Fig. 5.5(a)), the value of the planned transmission increase is 1615 M€ per year with uncontrolled EV charging. With controlled charging, this value drops to 1174 M€ per year. This is only a 27 % reduction. The smaller relative decrease in the value of transmission due to controlled EV charging is due to the fact that with higher volumes of intermittent RES, increasingly more situations develop in which transmission and controlled EV charging are complementary with respect to reducing dispatch costs. In these cases, the local capacity for EV load shifting is saturated. Then, an increase in cross-border transmission capacity provides access to load shifting in neighbouring electricity systems. In this situation, the results are also affected by the fact that the model hits a defined controlled EV charging capacity constraint. The model behaviour at these break points is sensitive to this capacity assumption. However, in any future power system, the capacity of controlled EV charging (or of any other type of load shifting mechanism) will not be infinite, but it will be limited. Therefore, this analysis is relevant within the scope of this chapter. The extent to which an increase in cross-border transmission capacity provides access to load shifting depends on the latter's capacity as well as on the system's need for arbitrage.

In the +50 % RES scenario, EV charging control and cross-border transmission capacity still are substitutes in most of the European system. At even higher RES penetration scenarios, the two options will increasingly complement one another with respect to minimising dispatch costs and with respect to minimising RES curtailment.

Vice versa, the value of controlling the charging of EVs is affected by the volume of cross-border transmission capacity. In the base case RES scenario (the top part of Fig. 5.5(a)), the value of controlled EV charging is lower in the Trans. 2025 scenario (966 M€ per year) than in the Trans. 2010 scenario (676 M€ per year). The expected expansion of cross-border transmission capacity thus decreases the value of controlled EV charging by 30 %. So cross-border transmission capacity can substitute for controlled EV charging as well. In the +50 % RES scenario, the relative difference becomes smaller: then the expected expansion of cross-border transmission capacity decreases the value of controlled EV charging by 26% (from 1709 M€ to 1268 M€ per year). This observed decrease in substitutability can again be ascribed to an increasing occurrence of situations (specific moments on specific interconnectors) in which transmission and demand flexibility complement each other. So the benefits of EV charging control in terms of lower dispatch costs increase with the share of RES and decrease with the volume of cross-border transmission capacity.

Table 5.2 shows the additional annual dispatch costs due to the extra EV load for the 25% EV penetration in Europe in 2025 for all four scenarios. In the Trans. 2025 scenario, controlled EV charging reduces the additional annual dispatch costs of integrating EVs in the European electricity network (-6.7%) compared to the uncontrolled EV scenario. As previously described, the economic benefits of EV charging control in terms of reduction in additional annual dispatch costs compared to the uncontrolled EV scenario increase both with lower cross-border transmission capacity (-9.8%) and with higher RES penetration (-13.2%).

Tab. 5.2.: Additional annual dispatch costs compared to the situation without EVs (Million €)

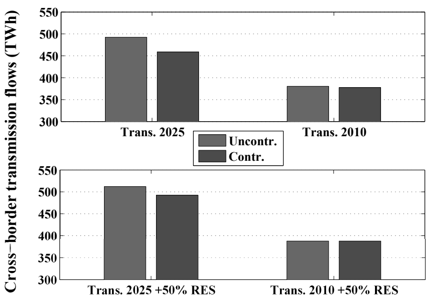
Scenario	Uncontrolled EVs	Controlled EVs	Difference (%)
Trans. 2025	10025	9349	-6.7
Trans. 2010	9910	8944	-9.8
Trans. 2025 +50% RES	9583	8315	-13.2
Trans. 2010 +50% RES	9238	7529	-18.5

In the expected RES scenario, there will be almost no need for curtailing intermittent RES due to cross-border transmission capacity constraints, as is shown in Fig. 5.5(b). In the +50 % RES scenario, however, a significant volume of RES will need to be curtailed in the absence of transmission investment and of controlled EV charging. Interestingly, in all scenarios, both options (controlled EV charging and cross-border transmission capacity investments) lead to a similar reduction in RES curtailment, indicating the substitutability of the two. In this case, inter-locational and inter-temporal arbitrage are substitutes.

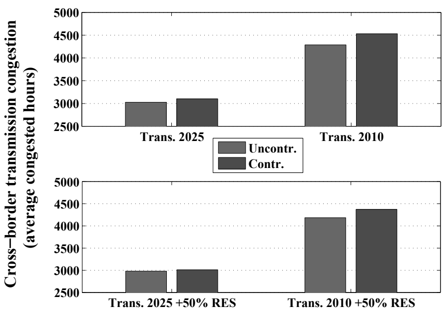
Similarly, the risk of electricity shortages can be reduced by controlled EV charging and by investing in cross-border transmission capacity. As mentioned before, a 25% EV penetration would cause a 5% increase in electricity demand in Europe in 2025. When EVs are modelled as being charged after their last arrival at home, the charging would coincide with the evening peak in winter and would therefore increase peak demand, see Fig. 5.3(a). In an extreme case, this increase in peak demand could threaten reliability and the security of electricity supply. Fig. 5.5(c) shows that in a situation without investment in transmission capacity (Trans. 2010), controlled EV charging substantially reduces the volume of energy not served. The main reason is that controlled EV charging reduces high demand peaks by shifting the electricity demand for EV charging (as shown in Fig. 5.3(b)), especially during low generation from variable RES. So also in this way, control over EV charging functions as a substitute for transmission investment. However, in the considered scenario, it cannot

compensate for all planned investment in cross-border transmission capacity, so it is only a partial substitute.

As arbitrage options affect generation dispatch, they also have an impact on CO_2 emissions. As shown in Fig. 5.5(d), EV charging control increases CO_2 emissions compared to the case in which EV charging is not controlled. The reason is the smoothening effect on the dispatch of thermal plants. In order to reduce dispatch costs, gas plants run fewer hours and the coal plants run more hours. The same is true for investment in cross-border transmission capacity: as more transmission capacity allows for more arbitrage between markets, this leads to a smoothening of the demand for thermal plants. The assumed CO_2 price, 22.5 €/tonne, is not high enough to make coal less attractive than natural gas. (See Table 2.1). As a result, cost minimisation leads to more coal combustion and therefore to higher CO_2 emissions. The next section will review alternative CO_2 price scenarios.



(a) Cross-border transmission flows



(b) Cross-border congestion

Fig. 5.6.: Cross-border electricity transmission

Before continuing with the analysis of the impact of CO_2 prices, some interesting dynamics with respect to cross-border electricity flows should be highlighted. Fig. 5.6(a) shows how in the Trans. 2025 scenario, EV charging control reduces cross-border electricity flows. If cross-border transmission capacities are limited (Trans. 2010), the total volume of electricity flows across borders is hardly affected by the control of EV charging. The reason is that in the latter case, the volume of cross-border transmission capacity is so limited that the reduction in the demand for cross-border transmission capacity due to controlled EV charging hardly leads to a reduction in flows.

Fig. 5.6(b) shows that congestion (measured as the average number of congested hours of each interconnector) is increased by the introduction of controlled EV

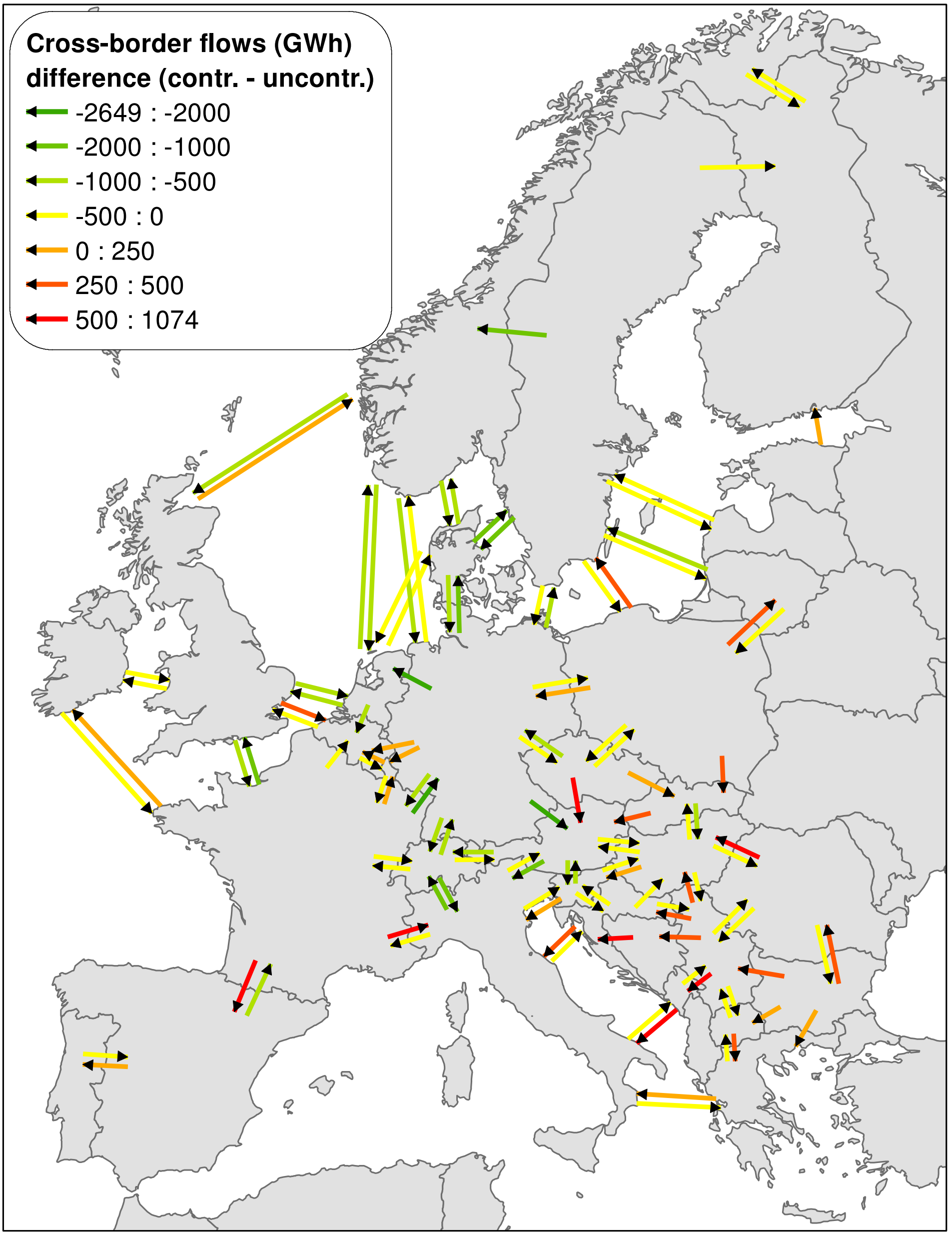


Fig. 5.7.: Changes in cross-border transmission flows due to controlled EV charging

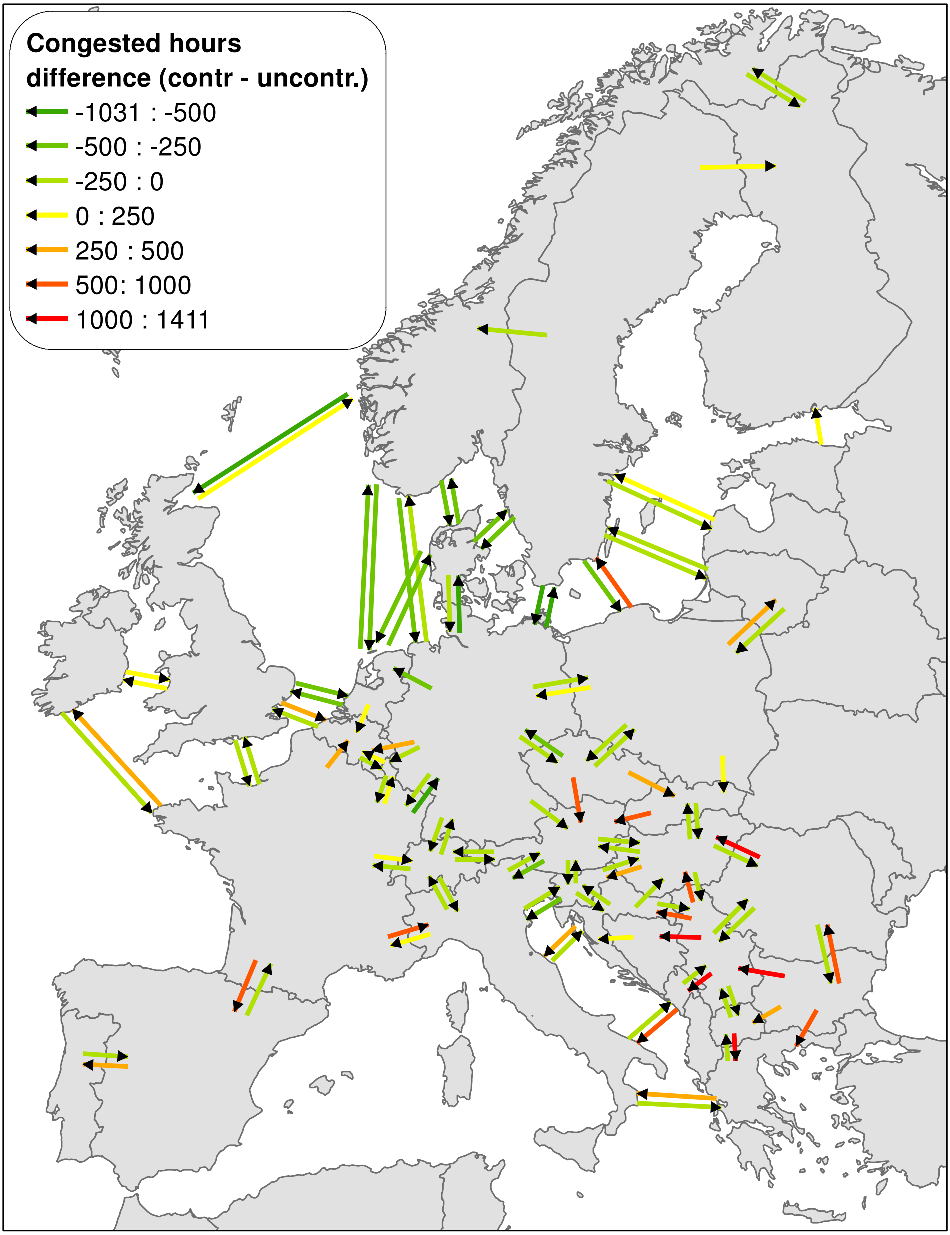


Fig. 5.8.: Changes in cross-border congestion due to controlled EV charging

charging. This is in apparent contradiction to the reduction in total cross-border electricity flows. This is due to the fact that some interconnectors are needed to access EVs in neighbouring systems. The results show that cross-border transmission capacity and controlled EV charging are partly substitutes, partly complementary. Without sufficient transmission capacity, the arbitrage possibilities that are offered by controlled charging cause an increase in congestion. The fact that controlled EV charging does not cause the total volume of cross-border flows to increase means that this arbitrage only occurs between specific combinations of countries with large differences in the marginal cost of generation. In most combinations of countries, however, controlled EV charging reduces the demand for cross-border transmission capacity because the inter-temporal arbitrage that is facilitated by the EVs substitutes for inter-locational arbitrage.

Our recent publication (Verzijlbergh et al., 2013) describes these effects for a single interconnector; in the reality of the meshed European transmission network, both cases may occur simultaneously on different interconnectors. Which case occurs is a function of the generation portfolios and the presence of pumped hydro as an alternative storage option in the connected electricity systems. Figs. 5.7 and 5.8 show how the changes in electricity flows and congestion due to controlled EV charging are different per interconnector and depend on the direction of the flow. The two maps represent a whole year; however, for each interconnector, the situation changes by the hour. So the degree to which controlled EV charging and cross-border transmission capacity substitute or complement one another depends on the interconnector, the direction of the flow and the moment in time.

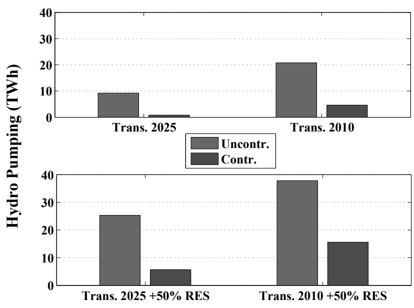


Fig. 5.9.: Hydro pumping utilisation

Another interesting impact of EV charging control is related to hydro pumping utilisation. The model assumes a round-trip efficiency of 75% for hydro pumping. Therefore, in order to minimise dispatch costs, the system prefers to shift EV charg-

ing rather than shifting the system load by pumping water into hydro reservoirs. As shown in Fig. 5.9, when EV charging is controlled, hydro pumping therefore decreases substantially. This behaviour is observed in all four modelled scenarios.

5.4. The impact of the CO_2 price

All analyses in the previous section were made with an assumed CO_2 price of 22.5 €/tonne. In order to consider the uncertainty regarding future CO_2 prices, this section will discuss the impacts of two additional CO_2 prices, 5 and 50 €/tonne, on the four scenarios. Intuitively, a higher CO_2 price leads to higher annual dispatch costs, but the CO_2 price should not affect the need for RES curtailment and security of supply (measured as unserved load).

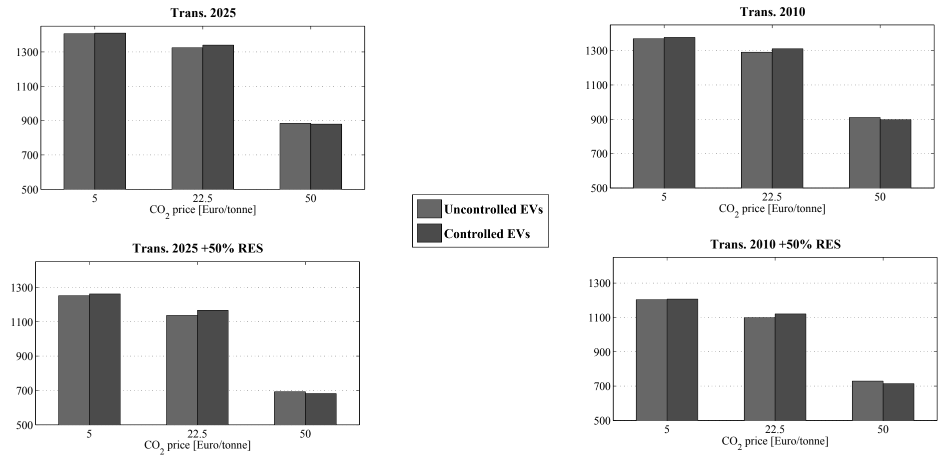


Fig. 5.10.: Annual CO_2 emissions (Million tonnes) for different CO_2 prices

Fig. 5.10 shows the CO_2 emissions in the European power system for three different CO_2 prices and for the considered RES and transmission scenarios. Controlled charging of EVs only causes a reduction of CO_2 emissions when the CO_2 price is 50 €/tonne (with respect to the uncontrolled EV scenario). The reason is that this CO_2 price level is just above the threshold at which the variable generation cost of gas power plants becomes lower than the variable generation cost of the more CO_2 emitting coal and lignite power plants (as shown in Table 2.1 on page 31). When dispatch costs are minimised, controlled EV charging leads to a reduction of CO_2

emissions, as the CO_2-intensive generation now is more expensive than low-carbon generation.

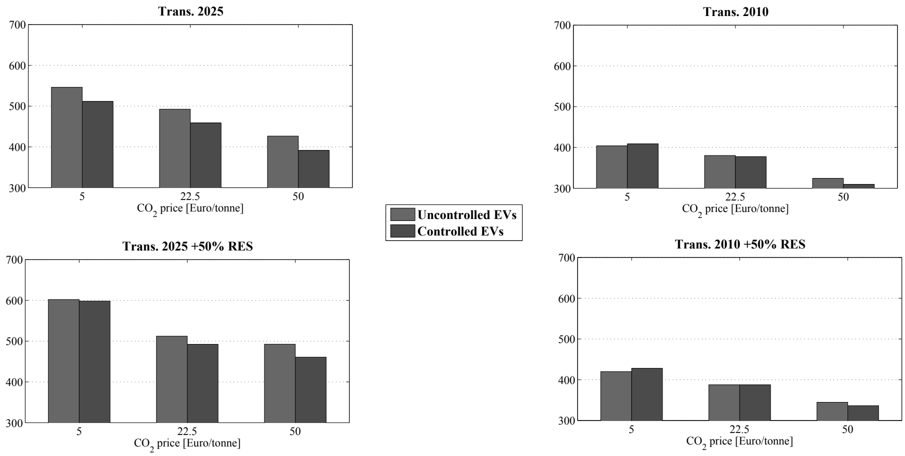


Fig. 5.11.: Cross-border transmission flows (TWh) for different CO_2 prices

As shown in Fig. 5.11, cross-border electricity flows decrease when the CO_2 price increases. The reason is that the variable generation costs of lignite, coal and gas power plants become closer to each other and therefore cross-border transmission flows become less economically valuable. It is important to remember that EUPowerDispatch includes small cross-border transmission costs (described in Chapter 2) in the objective equation. As the CO_2 price increases, controlled charging of EVs leads to a larger reduction of cross-border transmission flows. The reason is that in the high CO_2 price scenario, the variable costs of gas and coal plants are relatively close to each other. As a result, the arbitrage provided by controlled EV charging reduces the demand for cross-border transmission capacity relatively quickly. For the same reason, congestion decreases when the CO_2 price is increased, as shown in Fig. 5.12.

In the low cross-border transmission capacity scenario (Trans. 2010), cross-border electricity flows increase slightly due to EV charging control when the CO_2 price is 5 €/tonne. In this case, cross-border transmission is limited and economically very attractive due to the large difference between the variable generation costs of coal, lignite and gas power plants. Controlled EV charging expands the number of hours during which interconnectors can be used for arbitrage between electricity systems by shifting the arbitrage over time. Consequently, controlled EV charging also increases the number of congested hours, as can be seen in Fig. 5.12. In this

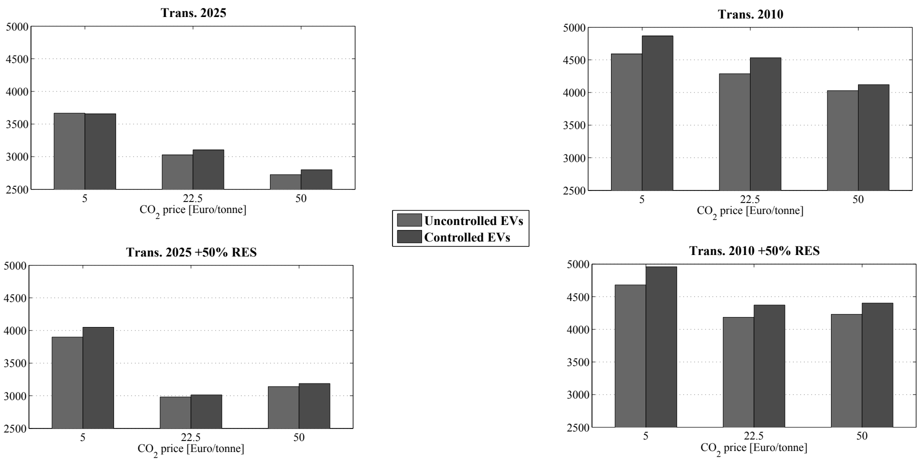


Fig. 5.12.: Cross-border transmission congestion (hours) for different CO_2 prices

case, cross-border transmission capacity is a complement to controlled EV charging, as it is a constraint to using EV flexibility in other countries.

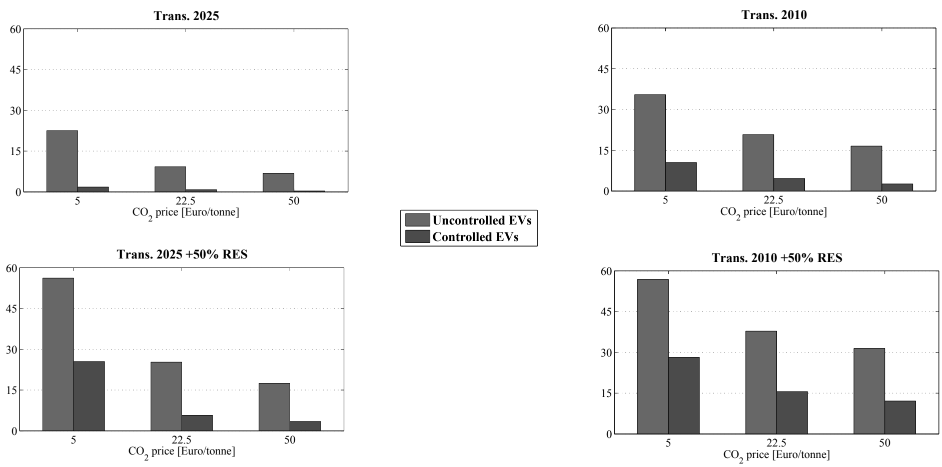


Fig. 5.13.: Hydro pumping (TWh) for different CO_2 prices

Similarly to the previous findings about cross-border transmission, Fig. 5.13 shows how hydro pumping utilisation is also less economically attractive at higher CO_2 prices due to the smaller differences between the variable generation costs of gas and coal generation. The impact of the CO_2 price on hydro pumping utilisation

is higher than on cross-border transmission flows (Fig. 5.11) due to the assumed round-trip efficiency of 75% for hydro pumping.

5.5. Conclusions

This chapter analysed the extent to which controlled charging of a large number of electric vehicles can substitute for cross-border electricity transmission capacity in Europe in 2025. EUPowerDispatch was used to compare the impacts of controlled EV charging and cross-border transmission capacity on annual dispatch costs, RES curtailment needs, CO_2 emissions, security of supply and hydro pumping utilisation for different levels of RES penetration and CO_2 price. In addition, the impacts on cross-border transmission flows and on cross-border transmission congestion were discussed.

The results showed that both EV charging control and cross-border transmission capacity reduce electricity dispatch costs, variable RES curtailment needs, hydro pumping utilisation and unserved load. In all four modelled scenarios, controlling EV charging provides an economic benefit in terms of dispatch costs. For the expected RES penetration and cross-border transmission capacity in Europe in 2025, EV charging control would reduce the additional dispatch costs to accommodate a 25% penetration of EVs by 6.7% compared to the uncontrolled EV scenario. In the case of a 50% higher RES penetration, this benefit would increase up to 13.2%.

The extent to which cross-border transmission and controlled EV charging substitute one another depends on the need for arbitrage in the European electricity system. The demand for arbitrage is high when RES penetration is higher, but lower when CO_2 prices are high because the costs of coal and gas generation become similar.

EV charging control and cross-border transmission are partly substitutes and partly complements. When the demand for arbitrage is low, controlled EV charging can substitute for a certain volume of cross-border transmission capacity. The higher the need for arbitrage, the more the two complement one another with respect to reducing dispatch costs. EV control can be used to adjust demand over time to fluctuations in supply, thereby flattening the residual load (the part provided by thermal generators). Cross-border transmission can spread fluctuations in supply geographically, thereby reducing the impact per system, but because it does not offer inter-temporal arbitrage its potential to flatten residual load is limited. In other words, when the demand for arbitrage becomes higher, both are needed because more frequently situations will occur in which the potential of controlling EVs and storage

in one country is insufficient for absorbing fluctuations in RES. Then cross-border transmission capacity is needed to provide access to storage and/or controlled EVs in another country.

The study presented in this chapter provides valuable insights to be considered in the potential investment decisions that Europe will have to face in order to meet the decarbonisation goals set by the European Commission for 2050. The analysis presented shows how demand response (in this case, EV charging control) is not only a competitor of cross-border electricity transmission. As the penetration of variable RES in the European electricity system increases, both are needed to complement one another. However, their optimal mix depends on their relative costs and on the future evolution of the European power system as well as the future European energy policy.

6. Electricity Imports from North Africa

This chapter is based on the following peer-reviewed journal article:

- Brancucci Martínez-Anido, C., L'Abbate, A., Migliavacca, G., Calisti, R., Soranno, M., Fulli, G., Alecu, C., de Vries, L.J., **Effects of North-African electricity import on the European and the Italian power systems: a techno-economic analysis**, *Electric Power Systems Research* 96 (2013) 119-132.

6.1. Introduction

Several European initiatives consider the electrical integration of the Euro-Mediterranean region a key priority for meeting future EU energy policy goals. Ambitious plans include the development of renewable energy sources in the region as well as transmission interconnectors between the two shores of the Mediterranean Sea. The success of such initiatives, in addition to several techno-economic, political, environmental, regulatory and financial obstacles, depends on the ability of the European electricity network to suitably accommodate large electricity imports from North Africa.

Against this background, two tightly interrelated studies, both within a 2030 time horizon for network layout, generation set and system demand evolutions, are described: one from a European perspective and one from a national (Italian) perspective (Brancucci Martínez-Anido et al., 2013a). This chapter presents the former study. It investigates the effect of North-African imports on the European power system in terms of cross-border electricity flows and total marginal generation costs (corridor-based approach). The latter, taking account of border conditions from the former study, performs an in-depth analysis of the impact of North-African imports on the Italian grid, highlighting system criticalities and possible solutions on a national/regional scale in Italy (grid-based approach). The Italian study was performed by an Italian research Institute, Ricerca sul Sistema Energetico (RSE). The methodology and results related to the impacts on the Italian power systems are

not provided in this chapter. In the discussion, however, the main results from the Italian study are used to complement the results from the European study. The reference time horizon chosen for the present analysis is 2030 in accordance with TSOs' studies that most realistically consider bulk power transport between North Africa and South Europe as feasible not before 2030 (ENTSO-E, 2011g; TERNA, 2011b).

This chapter is structured as follows. First, an overview of the Euro-Mediterranean framework is described in Section 6.2. The next section (6.3) describes the methodology and the scenarios used in the European study. Section 6.4 discusses the results, including a summary of the main findings of the Italian study, and finally, Section 6.5 presents the conclusions.

6.2. Overview of the Euro-Mediterranean framework

Towards the achievement of the three main targets (system competitiveness, environmental sustainability, security of energy supply) of EU energy policy, the electrical integration of the Euro-Mediterranean region represents a key priority (EC, 2010a). In the context of the ambitious EU 2020 and 2050 sustainability targets (EC, 2011a), particular focus is on the countries of the so-called MENA (Middle East and North Africa) region, which are located around (or close to) the Mediterranean Basin and feature a sizable potential for RES generation. This has been the main trigger of the launch of the Mediterranean Solar Plan (MSP) by the EU in 2008. Also other initiatives (DII, 2012; Medgrid, 2012) aim at fostering the development of RES generation in the MENA region and the related transmission interconnection capacity between the two shores of the Mediterranean Sea.

However, these goals are impeded by several techno-economic, socio-political, environmental, regulatory and financing issues (MED-EMIP, 2010). Additional obstacles arise from transporting North-African energy to the large load centres located in Central Europe. The success of the various ambitious initiatives (DII, 2012; Medgrid, 2012; MED-EMIP, 2010) depends on the ability of the European transmission grid to accommodate massive (RES but also non-RES, mainly gas-based) power injections from Africa. These may add on to other large RES-based flows from South Europe, mostly due to boosting solar penetration. Considering the simultaneous occurrence of increasingly large RES derived flows from North and North-West Europe (mainly due to onshore and offshore wind generation), it has to be expected that in the future significant bottlenecks will arise in the European transmission system. For this

reason, the European network will need to be reinforced considerably (ENTSO-E, 2011g). The need for a pan-European highway for integrating large volumes of RES has been highlighted by the European Commission in its recent energy infrastructure policy documents (EC, 2010a; EC, 2011c) as well as by ENTSO-E.

In this situation, the key roles of Italy and Spain, the closest countries to Africa, clearly emerge. In Italy, some critical sections of the two North-South transmission backbones (along the Tyrrhenian and the Adriatic Seas) are nowadays regularly congested and they would be even more stressed by the foreseen large power flows from Africa. In addition, the geographically closest injection areas for energy import (Sicily and Sardinia) are both weakly connected to the mainland. Due to its peculiar geographical position, favourable for importing energy both from Central and South-East Europe and from Africa, Italy may become an important Mediterranean electricity hub. Depending on the prevailing flows, the internal Italian network could be stressed in a completely different manner.

6.3. Methodology and Scenarios

The impacts of North-African electricity imports on the European power system in 2030 have been studied with the use of EUPowerDispatch, described in Chapter 2. However, the study presented in this chapter was the first application of EUPowerDispatch, therefore, an older version of the model was used. After publishing this study, EUPowerDispatch has been further developed. The differences between the latest version of EUPowerDispatch, described in Chapter 2, and the first version, used for this study, include the following modelling choices.

First of all, the installed generation capacity of gas power plants per country was modelled as a single virtual power plant, as is the case for nuclear, oil and mixed (oil and gas) power plants. In the latest version of EUPowerDispatch, instead, gas fired power plants are treated and modelled similarly to lignite and coal fired power plants. As described in Chapter 2, the total installed coal, lignite or gas based generation capacity in a country is divided into single power plants with a maximum rated capacity of 1000 MW. In the model version used in this chapter, instead, both for coal and lignite, the total installed electricity generation capacity in a country is divided into single power plants with a maximum rated capacity of 750 MW. In addition, in this study, lignite and coal power plants are constrained by keeping the time between shut-down and start-up and vice versa to a minimum of 4 hours. In the newest version of EUPowerDispatch, instead, in order to better capture the

impacts of RES variability, this constraint was substituted by including start-up and shut-down costs, as well as ramp-up and ramp-down rates, as described in Chapter 2. Moreover, cross-border transmission flows are not subject to any cost or losses in the version of the model used in the study presented in this chapter. However, at a later stage, EUPowerDispatch was further developed by including cross-border transmission costs, as detailed in Chapter 2.

In addition to the methodological differences presented above between the current study and the model described in Chapter 2, the generation, demand and cross-border transmission scenarios are different from the ones presented in Section 2.3.

Concerning the data inputs for building up the 2030 European study model, the installed generation capacities for each energy source in the analysed European countries are based on the 2025 Best Estimate Scenario of ENTSO-E's SO&AF 2011 – 2025 (ENTSO-E, 2011e). The notable exceptions are represented by the systems of Italy and Germany for which the scenario dataset has been updated taking into due account the German nuclear phase-out plans, the Italian current situation related to the dismantling of the nuclear programme, and the Italian and German extremely large deployment of PV installations. The same ENTSO-E scenario is used to calculate the expected electricity consumption increase in Europe between 2010 and 2030 (EC, 2010b).

Table 6.1 shows the variable electricity generation costs that are assumed for 2030 in every European country. The values are based on the data used in TradeWind (Korpas et al., 2007), assuming a CO_2 tax of 35 €/tonne. The variable generation cost of electricity from North Africa is assumed to be 41.25 €/MWh, which is lower than European fossil-fired sources but higher than European nuclear sources. This value takes also into account the fact that the interconnections from North Africa, as originally planned, will also serve to dispatch thermal (mainly gas-based) generation. In a sensitivity analysis, this North-African generation cost is varied to a value of 10.52 €/MWh, taking into account a much higher solar contribution with respect to the thermal one.

Tab. 6.1.: Variable electricity generation cost per energy source (€/MWh)

Nuclear	Lignite	Coal	Gas	Oil
11.0	62.9	55.0	61.9	108.7

Mixed fuels	Hydro	Wind	Solar	Biomass
114.5	3.0	2.0	0.0	53.1

The cross-border electricity transmission capacities considered for 2030 in Europe are the same as in Fig. 2.6 in Section 2.3.4 with an additional interconnector between the United Kingdom and Germany with a maximum transfer capacity of 1000 MW.

Four synchronous areas can be recognised around the Mediterranean basin: the European continental network, to which the North Western Maghreb countries (Morocco, Algeria and Tunisia) are synchronously coupled; the system of the interconnected North Eastern Maghreb (Libya, Egypt) and Mashreq countries (Jordan, Syria and Lebanon); the system of Israel and Palestinian Territories; the network of Turkey. Upon completion of ongoing developments, the Turkish system is expected to be fully synchronised with the European continental network by 2013 (a trial parallel operation of the two systems is currently in place) (MED-EMIP, 2010). For the interconnection expansion between North-African and European systems, realistic estimations have been carried out, shifting the implementation of very ambitious plans (DII, 2012; Trieb et al., 2009) to the post-2030 period. Thus, each corridor analysed at the cross-Mediterranean interface, namely at Spain-Morocco, Spain-Algeria as well as at Italy-Tunisia, Italy-Algeria, Italy-Libya borders, in the most optimistic scenario has been considered as carrying a maximum transfer capacity equal to 2000 MW.

In order to analyse the effects of power imports from Africa on the interconnected European electricity system and the Italian grid, three main scenarios, pessimistic ("A"), reference ("B") and optimistic ("C"), are assumed in terms of the interconnectors between North Africa and Europe and their maximum transfer capacity. Table 6.2 shows the maximum transfer capacities from Africa for the three scenarios (see also Fig. 6.1).

Tab. 6.2.: Interconnection capacities (MW) between Africa and Europe for the three main scenarios

Interconnector	Pessimistic scenario "A"	Reference scenario "B"	Optimistic scenario "C"
Morocco-Spain	1400	2000	2000
Tunisia-Italy	1000	1000	2000
Algeria-Spain	1000	1000	2000
Algeria-Italy	-	1000	2000
Libya-Italy	-	1000	2000

In addition, in order to better understand the effects and the possible benefits of importing electricity from Africa, the model is run for a scenario with no power imports from Africa (scenario "D"). Finally, a sensitivity analysis based on the optimistic sce-

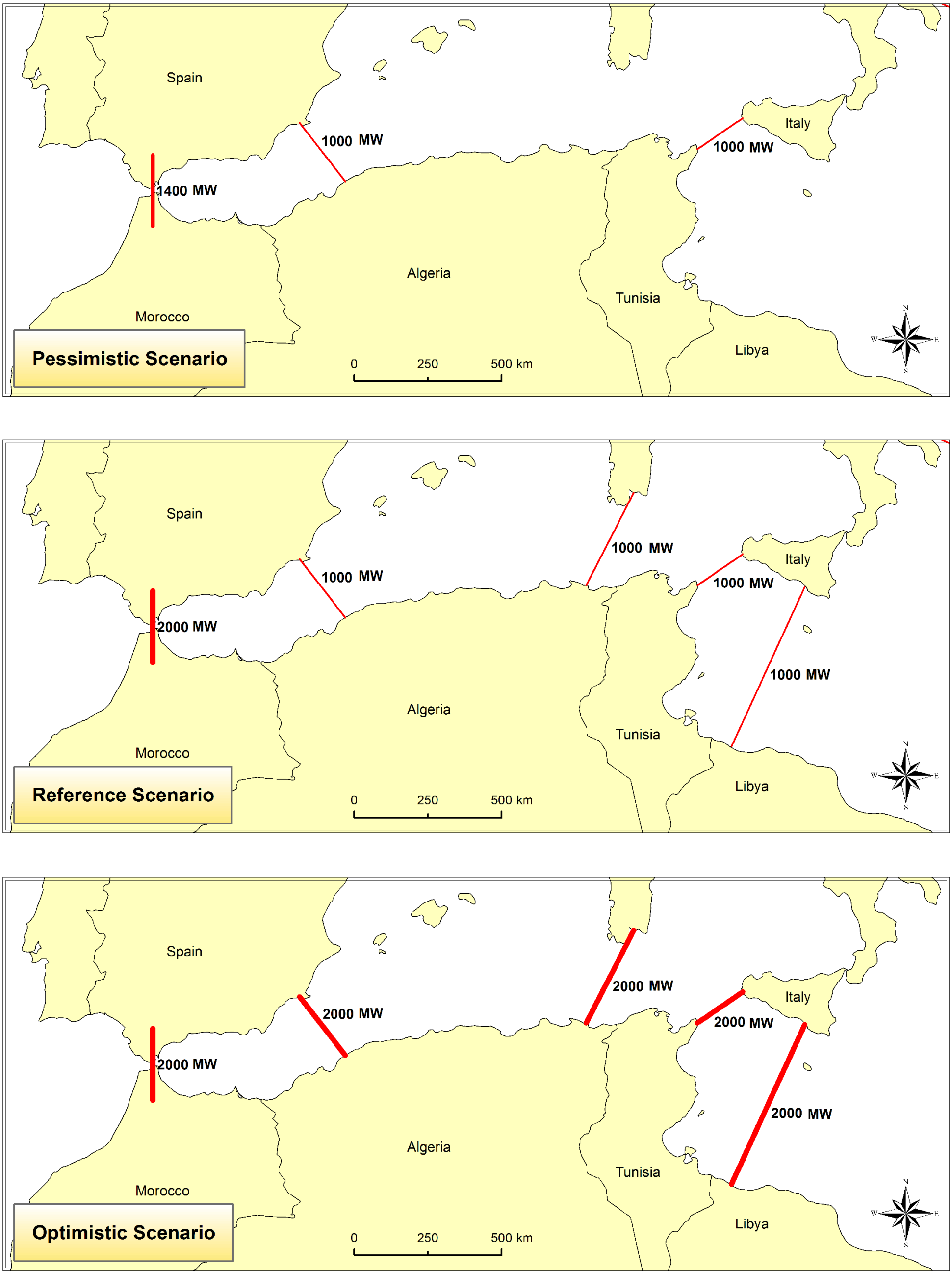


Fig. 6.1.: The three main 2030 scenarios for the interconnection between North Africa and Europe

nario with the African interconnectors is performed by lowering the African variable electricity generation cost (from 41.25 to 10.52 €/MWh) below the European variable electricity generation cost of nuclear sources, varying therefore the merit order (scenario "C1").

EUPowerDispatch is run for each of the previously defined 2030 scenarios. The European perspective on power imports from North Africa in 2030 is assessed in terms of three variables: the annual cross-border net exchanges, the hourly marginal energy source in each European country and the economic impacts of the power imports from Africa on the total annual variable electricity generation costs in Europe.

6.4. Results & Discussion

The main and most visible finding is that in each of the three scenarios, the interconnectors between North Africa and Italy are practically 100% loaded during every hour of the year. The interconnectors between North Africa and Spain are also fully loaded during 99.9% of the hours of the year. In the case of Spain, the results of scenario C show how there are very few hours of the year during which the cheaper local energy sources (including hydro, wind, solar, nuclear) and in some cases the imports (mainly from Portugal) are sufficient for meeting the local load and therefore the power imports from Africa are not needed. Only during some hours of the year the African imports are the marginal energy source in Spain (and/or Portugal) and the interconnectors are not fully loaded. Fig. 6.2 shows the Spanish energy mix (for scenario C) for a 12-hour period in February during which the electricity imports from North Africa are only partially needed or not needed at all due to the low electricity demand and the availability of cheaper energy sources (nuclear, hydro and wind) during few hours. In addition, it can be observed how the excess wind is exported (to both neighbouring systems of France and Portugal) and pumped into the hydro reservoirs.

Fig. 6.3 shows the annual cross-border net exchanges in Europe in each of the three main scenarios. A first observation is that the net power exchanges tend to follow the direction from South to North. In addition, in contrast with the present situation, Spain and Italy are net exporters of electricity. Together with the expected high installed generation capacities of wind and solar sources in Spain and Italy, the power imports from Africa contribute strongly to this behaviour. The optimistic scenario, which represents a larger import from Africa, shows higher Italian and Spanish power exports than the reference and pessimistic scenarios do. It is important to highlight

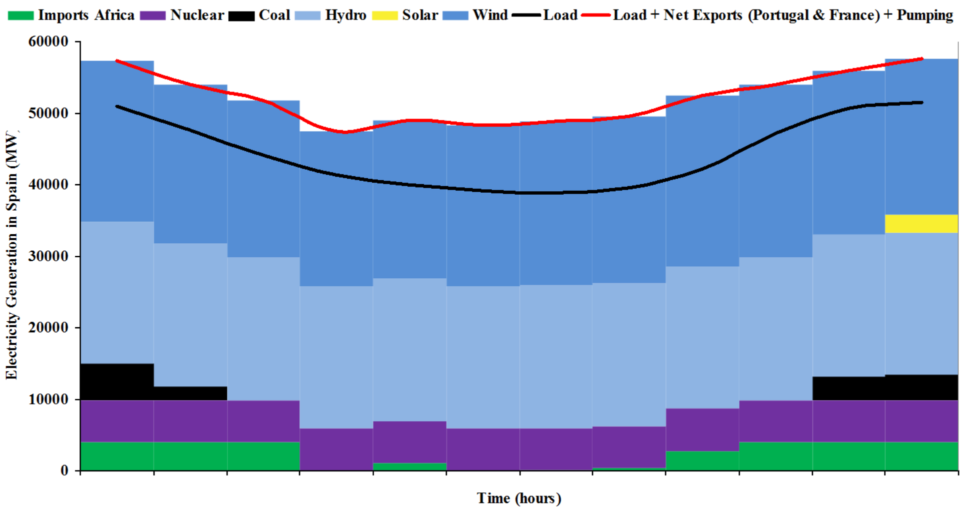


Fig. 6.2.: Energy mix for Spain in period of none or marginal imports from North Africa

the assumption behind the European analysis that the North-African power imports and/or the Spanish and Italian exports are not limited by internal transmission congestions or loop flows. The Italian study in the next section analyses this issue more in detail by focusing on the Italian grid in all its aspects.

An interesting result of the European study is the number of hours in a year during which each of the energy sources is the marginal generation technology in Italy, Spain and their neighbouring countries. As shown in Table 6.3, gas is the marginal energy source during the majority of the hours of the year. As interconnection capacities between North Africa and Europe increase, the number of hours during which African generation is marginal increase in Spain and Portugal. In addition, there are few hours during which hydro power is the marginal source. During these hours the interconnectors between Africa and Spain are not used, as previously mentioned. For Italy, instead, the African imports, in this analysis, do not represent in any scenario the marginal source, which is consistent with the finding that the African interconnectors to the Italian grid are practically constantly 100% loaded (the situation will however look different in the Italian study considering the whole national system and the internal grid bottlenecks). Furthermore, the imports from Africa cause changes to marginal generation sources throughout the year in the entire European power system causing, during some hours in the year, lower electricity prices, although the effects decrease from South to North.

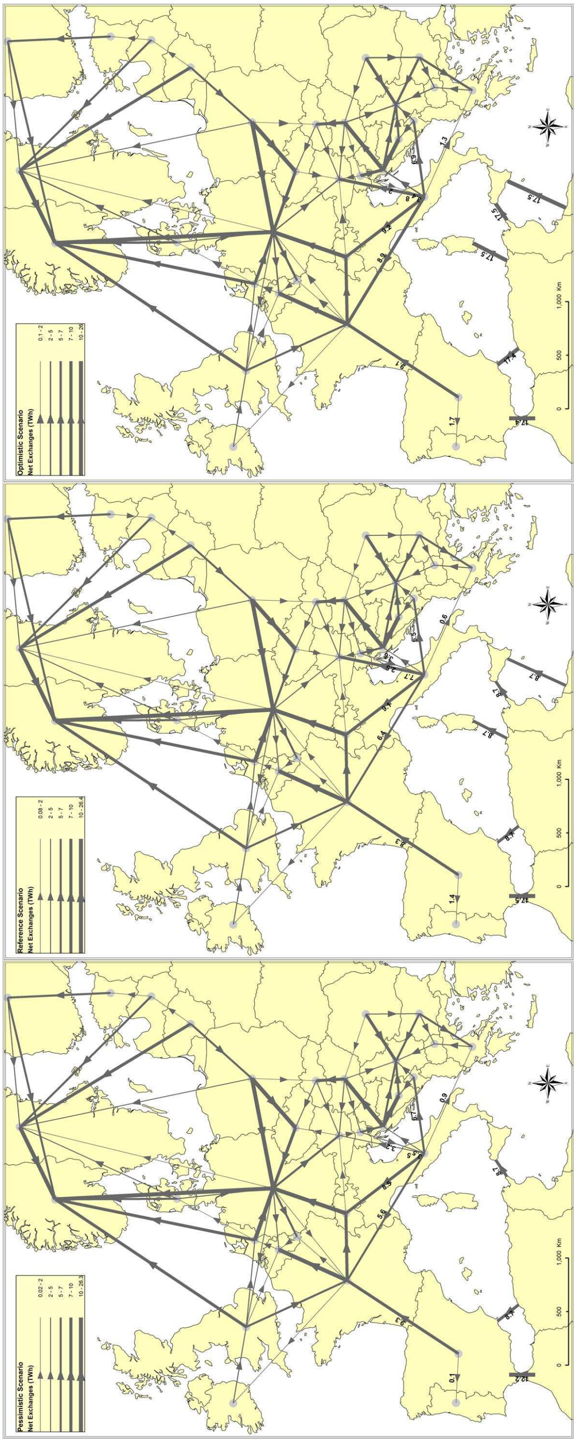


Fig. 6.3.: Annual cross-border net exchanges for the pessimistic, reference and optimistic scenarios

Tab. 6.3.: Hours of marginal energy sources. Number of hours in the year during which an energy source is the marginal generator in a country

Energy source	ES	PT	FR	IT	GR	ME	HR	SI	AT	CH	DE
Scenario without African power imports ("D")											
Hydro	0	22	0	0	14	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0	0
Africa gen.	0	0	0	0	0	0	0	0	0	0	0
Biomass	58	30	31	0	8	0	0	0	0	0	0
Coal	139	281	45	3	40	2	3	3	3	3	9
Gas	8538	8402	8283	8733	8234	6802	8666	8666	8496	8434	8444
Lignite	1	1	370	0	440	1932	67	67	237	299	283
Oil	0	0	7	0	0	0	0	0	0	0	0
Optimistic scenario ("C")											
Hydro	0	22	0	0	14	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0	0
Africa gen.	60	26	0	0	0	0	0	0	0	0	0
Biomass	138	84	33	1	6	0	0	0	0	1	0
Coal	262	339	65	21	46	4	15	15	15	20	21
Gas	8276	8265	8252	8714	8290	6779	8654	8654	8482	8408	8423
Lignite	0	0	379	0	380	1953	67	67	239	307	292
Oil	0	0	7	0	0	0	0	0	0	0	0

It is also important to mention that the electricity imports from North Africa replace gas (mainly) and coal (slightly) – fired power plants generation. The reduction of electricity generation from gas and coal increases as the electricity imports from North Africa increase. However, the maximum power output from gas power plants is not reduced during the year in any European country (apart from Spain) due to the electricity imports from North Africa. The only exception concerns Spain whose maximum gas power output is reduced by 536 MW in the optimistic scenario ("C"). These results show the key role of gas-fired power plants in an electricity network with high penetration of variable renewable energy sources. In addition, it is shown that as electricity imports from North Africa increase, the need for back-up gas-fired power plants decreases (as shown for Spain). However, if cross-border interconnection capacities would increase, gas-fired power plants could be needed and used more to export electricity to Northern Europe, especially in periods of low wind.

A sensitivity analysis has been performed by using the optimistic scenario and assuming a lower variable generation cost for North-African imports. The results are very similar in terms of the overall behaviour of the European power system. A small change occurs in the loading of the interconnection between Africa and Spain. Due to the lower variable generation cost, more power is transported from Africa to Spain. However, this difference is almost insignificant due to the already extremely high average loading of the cross-Mediterranean interconnectors.

Finally, the three main scenarios ("A", "B" and "C") and the one used for the sensitivity analysis ("C1") are compared to the scenario without North-African imports ("D") in terms of annual electricity variable generation costs for whole Europe. Table 6.4 shows the savings in terms of annual variable generation costs for each of the 4 scenarios compared to the one without interconnections between North Africa and Europe.

Tab. 6.4.: Economic evaluation

Scenario	A	B	C	C1	D
Annual system variable generation cost (Billion €)	134.16	133.70	132.98	130.29	134.76
Annual savings compared to scenario D (Million €)	605	1071	1786	4469	-
Annual electricity generation in Africa (TWh)	29.69	52.39	87.29	87.35	-
Annual African variable generation costs (Billion €)	1.225	2.161	3.601	0.919	-
Annual threshold value for investment (Billion €)	1.830	3.232	5.387	5.388	-

The fourth scenario ("C1") shows a much higher potential for savings due to the lower variable generation cost of the electricity produced in Africa. However, this difference (between scenarios "C" and "C1") does not affect the threshold value below which the investment would be profitable. The threshold value, which is also provided in Table 6.4, gives the value below which the investment annuity of importing power from North Africa to Europe can be profitable. The investment annuity should be calculated considering the overall project's lifetime, the "annual-correspondent" generation and transmission investments and the annual fixed and variable generation costs. The investment annuity is related to the annual savings presented in Table 6.4 which correspond to the reduction in variable electricity generation costs. They do not correspond to differences in electricity prices or in firm revenues. The values presented in Table 6.4 are valuable when comparing different investment scenarios but they must be carefully treated when performing a cost-benefit analysis.

6.4.1. Main results from the Italian analysis

The same boundary conditions seen in the European study have been applied to the Italian case at 2030, considering then the three main scenarios ("A", "B" and "C") together with the sensitivity variant ("C1") and the base scenario ("D") with no link between Africa and Europe. The runs of REMARK (Brancucci Martínez-Anido et al., 2013a) have provided several results, which are summarised in terms of zonal balances and inter-zonal exchange flows and in terms of average marginal zonal prices.

A first important outcome of the Italian analysis is that there is a clear, relevant flow of electricity from North Africa to Italy (Sicily and Sardinia). This import reaches its peak in scenario "C" (and similarly in case "C1") as expected, but in relative terms the case "B" sees the most favourable conditions. In the latter scenario, for most hours during the year the interconnectors are almost fully loaded; for very few hours Sicily is also able to export electricity to Tunisia and Libya. This applies also in the other relevant cases. In scenario "C" (and similarly in case "C1") the maximum utilisation of each corridor's capacity amounts to ca. 80%, while in the case "B" this value can reach even 99%. This difference means that an increase of each interconnector's capacity (from 1000 to 2000 MW) does not necessarily lead to an increased import from North Africa to Italy because internal grid constraints limit this flow, and also due to local RES generation in Sardinia and Sicily that is dispatched prior to North-African electricity. In fact, this occurs in "C" (and similarly in "C1") in Sardinia and can be highlighted by the capacity limits of inter-zonal links

with the Italian peninsula. In the case of Sicily, instead, the constraint of the link with the South zone plays a major role in this not full exploitation of North-African import.

Another important outcome of the Italian study is that in all cases, at the interfaces with the Alpine region, Italy is a net electricity exporter to the bordering countries of Switzerland, Austria, Slovenia, while a net import to Italy is recorded from France. This is partially in line with the trends that emerged in the European study, and can be observed already in case "D": this also reveals the impact of the large capacities of wind and solar RES installed in Italy. The main differences with the European study partially depend on the internal grid bottlenecks and cross-border constraints that make the RES generation, mostly concentrated in the Southern and insular parts of the Italian peninsula, reach the North-Eastern borders to be exported to Slovenia, while the contrary occurs at the North-Western borders with France. The same applies to the African imports and their impact on Northern borders.

Concerning the flows at its Eastern borders with the Balkan region, here the situation is even clearer as Italy is heavily exporting to Montenegro in all cases and this export does not notably change with the increase of import from North Africa. A similar situation occurs at the interface with Greece, although the amount of exported energy is lower with respect to the one with Montenegro. The net flow balance with Croatia and Albania sees also Italy exporting in all cases; the export trend recorded with Albania is impacted by the increase of import from North Africa.

Another important result of the Italian study is that, with the increased import from North Africa, the net flows of electricity are more and more directed from the islands and from the South of the country up to the North where the large load centres are concentrated. This can be seen from all cases, with an increase trend from scenario "D" up to scenario "C" (and similarly "C1") where the net power flow between the zones (from Sicily and South to North) reaches its limit. This confirms the African import influence as well as the impact of Italian RES generation location.

The Italian analysis, performed by RSE, has led to the conclusion that several areas in the Italian system present a critical situation, especially in the scenarios "B", "C" and "C1". These stressed portions of the grid are mainly located in Sardinia, around the metropolitan areas of Rome, Naples, Milan, in Tuscany, in Center-South along the Tyrrhenian and Adriatic axes and at the interfaces between South and Sicily as well as between Center-South and South.

6.5. Conclusions

This chapter investigated the effects of the North-African electricity imports on the European power system in a 2030 perspective. The analysis was performed by combining two methodologies (Brancucci Martínez-Anido et al., 2013a), making use of models of the European system and of the Italian transmission grid. Within a common set of assumptions, the two interrelated studies analysed the North-African import impact in terms of marginal prices in the European countries and in the Italian market zones as well as inter-zonal flows for the different scenarios. The approach proved its feasibility: the outcomes of the two studies are affected by grid constraints.

The results show a decrease of the electricity prices during some hours in the year in Europe due to North-African electricity import. However, the impact of electricity imports on final European consumer bills will depend on the costs of building electricity generation capacity in North Africa and cross-Mediterranean transmission capacity.

The European study highlights that net electricity exchanges tend to follow the direction from South to North. Also, Italy's potential of becoming a Mediterranean electricity hub is emphasised. The Italian study shows that the North-African import effects are relevant, leading to internal grid congestion and price reduction in Sicily and Sardinia. The transmission limits between the two islands and the Italian peninsula as well as on the interfaces between South and Center-South zones play a major role.

7. European Transmission Network Reliability

This chapter is based on the following peer-reviewed journal article and conference paper:

- Brancucci Martínez-Anido, C., Bolado, R., de Vries, L.J., Fulli, G., Vandenbergh, M., Masera, M., **European power grid reliability indicators, what do they really tell?**, *Electric Power Systems Research* 90 (2012) 79-84.
- Brancucci Martínez-Anido, C., de Vries, L.J., Bolado, R., Fulli, G., **Cross-Border Electricity Transmission Capacity for Network Reliability**, *4th International Conference on Power Engineering, Energy and Electrical Drives*, Istanbul, 13-17 May 2013.

7.1. Introduction

The European power grid is one of the largest and most complex physical network ever made by human kind. Electricity demand in Europe has been and will keep increasing. In this context an essential challenge for the European Network of Transmission System Operators for Electricity (ENTSO-E) is to ensure a coordinated, reliable and secure operation of the electricity transmission network (ENTSO-E, 2011h). ENTSO-E measures network reliability as the system's ability to deliver electricity to all points of utilisation within acceptable standards and in the amounts desired (ENTSO-E, 2010). The assessment of the power grid's reliability has been an ambitious and attractive, as well as necessary, research field over the past decades. Failures in the electricity transmission grid have various causes and most of the times are extremely difficult to analyse due to their complex nature and cascading effects that lead to large disruptions.

This chapter presents two studies that analyse the impact of electricity transmission on network reliability. The two studies independently analyse the impacts of network topology and of cross-border transmission capacity on network reliability. In the two studies, network reliability is assessed using monthly statistics of major fault events on electricity transmission networks.

The first study analyses the impact of national (internal) network interconnectivity on the occurrence of major fault events and on three reliability indicators: Energy Not Supplied (ENS), Total Loss of Power (TLP) and Restoration Time (RT). It intends to expand previous work on the impact of topology upon the reliability of the European power grid (Rosas-Casals & Corominas-Murtra, 2009; Solé et al., 2008; Rosas-Casals, 2010) by extending the time frame of fault events. In addition, a different statistical method from one previously used in literature (Rosas-Casals & Corominas-Murtra, 2009) is applied to gain a better understanding of the relationship between network topology and its reliability. The sensitivity of the analysis to the data set is discussed, mainly with reference to extreme events. The usefulness of reliability indicators is questioned in the context of analysing the impact of network topology upon transmission network reliability.

The second study, by contrast, investigates the impact of cross-border electricity transmission capacity, as well as of generation capacity, on network reliability. Monthly empirical data on network reliability and generation and cross-border transmission capacities from 18 different European countries for a time span of 10 years is used.

Finally, the last section of this chapter summarises the conclusions from the previous two sections.

7.2. European power grid reliability indicators, what do they really tell?

7.2.1. Reliability characteristics

Our analysis of the reliability of the European transmission network in this section uses the reliability indicators published by ENTSO-E (ENTSO-E, 2011i). The data is available for each major fault event of the former Union for the Coordination of the Transmission of Electricity (UCTE) between January 2002 and March 2011.

Three reliability indicators by ENTSO-E are considered. The first is an estimation of Energy Not Supplied (ENS) to the final customers due to incidents in the transmission network and is given in MWh (ENTSO-E, 2010). The second is the Total Loss of Power (TLP), which is given in MW and is a measure of generation shortfall. Finally, the Restoration Time (RT), measured in minutes, corresponds to the time from the outage/disturbance until the system frequency returns to its nominal

value (Eprice, 2010). A total of 862 fault events are taken into account from the 15 countries under analysis . A fault event in the transmission network is defined as an incident which causes loss of generation or transmission power capacity or the inability to serve the expected load. In other words, a fault event occurs when at least one of the three reliability indicators (ENS, TLP and RT) is larger than zero.

Fig. 7.1 shows the percentages of non-zero values for the three indicators. Some events show a zero in one or two of the three indicators, pointing out the different nature and condition of the events. In addition, due to the definitions of the three indicators, the values for each of them are not strongly correlated; in fact the correlation coefficients are 0.16 (ENS – TLP), 0.38 (ENS – RT) and 0.14 (TLP – RT). For each fault event ENTSO-E provides the cause from one of four categories, namely overload, transmission network failure (operation failure, protection device failure, etc.), external reasons (weather conditions, force majeure, etc.) and other or unknown reasons. ENTSO-E (UCTE in the past) receives information regarding major fault events from each transmission system operator across Europe. It must be noted that it is the TSO's responsibility to collect and provide correct data to ENTSO-E. This responsibility should be required of all administrative bodies in the electricity supply chain.

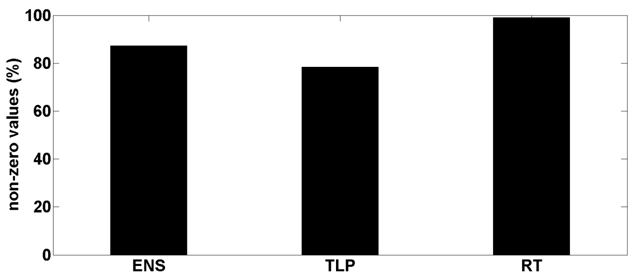


Fig. 7.1.: Percentage of non-zero values for ENS, TLP and RT

The events are not evenly distributed throughout the countries under analysis. Fig. 7.2 shows the number of events per country. A large discrepancy between countries can be noticed. The largest countries in terms of nodes and interconnectors (France, Spain and Germany) account for 58% of the total number of events in the 15 countries under observation. Fig. 7.3 shows the sum of each reliability indicator per country for the nine years under analysis. In the three plots it can be observed how a few countries account for a large portion of the total sum of one indicator. For instance, Spain experienced 64% of the total loss of power since 2002, while Italy and Poland

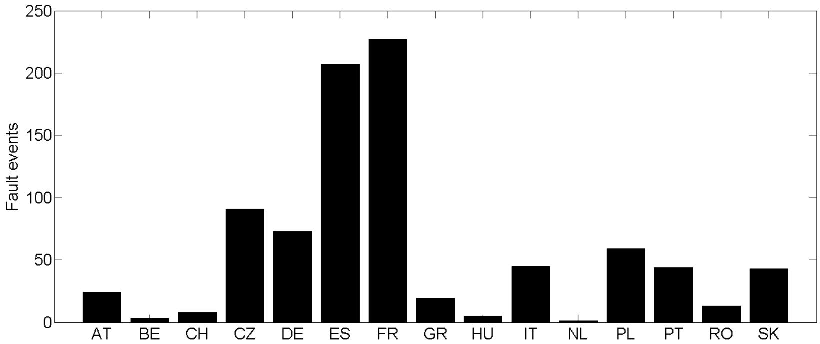


Fig. 7.2.: Number of fault events per country (January 2002 - March 2011)

accounted respectively for 32.2% and 31.8% of the total energy not supplied, and Poland added up 38% of the total restoration time.

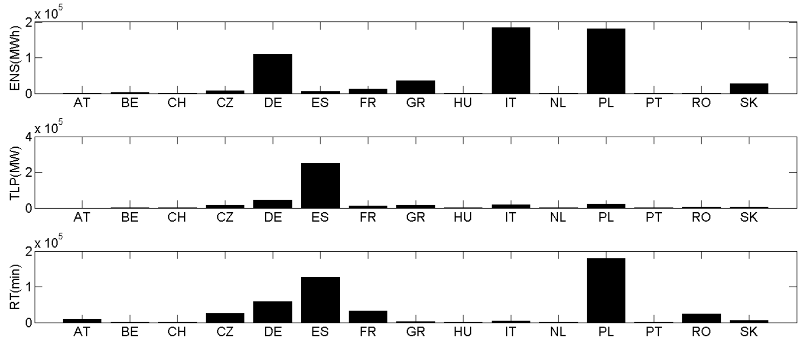


Fig. 7.3.: Total ENS, TLP and RT per country (January 2002 - March 2011)

For each of the three reliability indicators, 862 values are given (one per fault event). The sums for each indicator accounting for all the events are given in Table 7.1. This shows the three largest values for each indicator, as well as the portion of the total indicator's sum that they represent and the country in which the fault event occurred. It can be observed how a few events have a large impact on each indicator. This is especially apparent for ENS.

Fig. 7.4 shows the Lorenz curve for the three reliability indicators and, as in Table 1, it can be observed that a small fraction of events accounts for a large fraction of the sum of each reliability indicator. In other words, for the case of ENS, one event accounts for 32% of the total ENS in the UCTE region since 2002. TLP shows a less

Tab. 7.1.: Highest values of the reliability indicators

	ENS (MWh)	TLP (MW)	RT (min)
Total	571'025	393'505	470'204
Highest	180'000 - 32% (IT)	31'990 - 8% (ES)	50'432 - 11% (PL)
2^{nd} highest	168'000 - 29% (PL)	26'746 - 7% (ES)	37'486 - 8% (DE)
3^{rd} highest	24'824 - 4% (DE)	24'120 - 6% (DE)	32'126 - 7% (PL)

uneven distribution but there still is a great difference between the contribution of the many low values and a few high values to the total TLP sum. This feature is of particular relevance for the analyses described in the next section. Rare extreme events must be considered with caution.

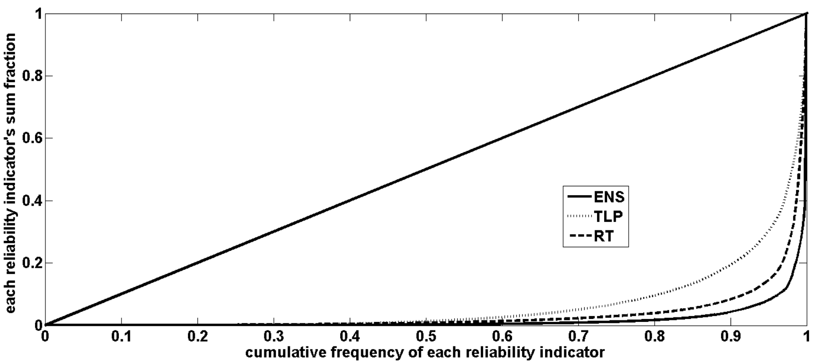


Fig. 7.4.: Lorenz curve for the three reliability indicators

7.2.2. Relations with topological characteristics

The first goal of this section is to expand the time frame of similar analyses previously developed by other authors (Rosas-Casals & Corominas-Murtra, 2009; Solé et al., 2008; Rosas-Casals, 2010), aiming at deriving a relation between the topology of a power grid and its reliability indicators. The topology is analysed in terms of the interconnectivity of the 15 power grids under analysis (in other words, how interconnected grid nodes are to other nodes of the same grid). Past research (Rosas-Casals & Corominas-Murtra, 2009) analysed events up to 2008 (latest data available at that time). In this study the same approach will be applied with a time frame covering the period up to March 2011. In addition, a different statistical methodology is proposed to gain a better understanding of the relationship between network topology and its reliability.

The topology of a power grid can be described using graph theory (Bondy & Murty, 2008) as a set of nodes connected by a set of links. Each link connects a pair of nodes. An important characteristic of a node is the degree k, equal to the number of edges connecting it to other nodes. In order to characterise the topological robustness of a power grid the cumulated degree distribution is used. It corresponds to the probability that a node chosen at random has a degree k or larger (Rosas-Casals et al., 2007). UCTE power grids have exponential cumulated degree distributions (Rosas-Casals et al., 2007), as given in Eq. 7.1.

$$P\left(K \geq k\right) = C \cdot e^{\frac{-k}{\gamma}} \tag{7.1}$$

C is a normalisation constant and γ is the exponential degree distribution exponent. The larger γ is, the more interconnected a power grid is (inside its borders, not taking into account the interconnectivity with other networks). The values of γ for each country under analysis are taken from a study in which a mean field theory approach is used to analytically predict the fragility of the power grids (Solé et al., 2008). The results of the latter study suggest an increased robustness against intentional attacks for power grids with $\gamma < 1.5$. The power grids are divided in two groups (Rosas-Casals & Corominas-Murtra, 2009), one with $\gamma < 1.5$ (robust group) and the other one with $\gamma > 1.5$ (fragile group). The robust group corresponds to the less interconnected grids and the fragile group to the more interconnected ones.

The 15 countries under analysis are therefore divided in two groups (less and more interconnected) depending on their topological nature. Fig. 7.5a shows the two groups' power grid characteristics and reliability indicators shares. The power grid characteristics are energy share (ES), power share (PS) and size share (SS). They are obtained by summing the energy consumed in a year, the peak power in the year and the number of nodes of each power grid in a group respectively. The sum is then divided by the total sum over all the countries in both groups. By using one-year hourly electricity consumption data (ENTSO-E, 2011a) for each country, it is shown that the two groups have similar yearly energy consumption and maximum peak power. Therefore, even if the more interconnected group accounts for 60% of the total number of nodes, it is assumed that the two groups' reliability indicators can be compared.

Fig. 7.5b shows previously presented results (Rosas-Casals & Corominas-Murtra, 2009) updated until March 2011. The more interconnected group experiences 80% (684) of the total number of fault events since 2002 and shows a very large share in two of the three indicators, TLP and RT (around 80%). However, ENS is higher for

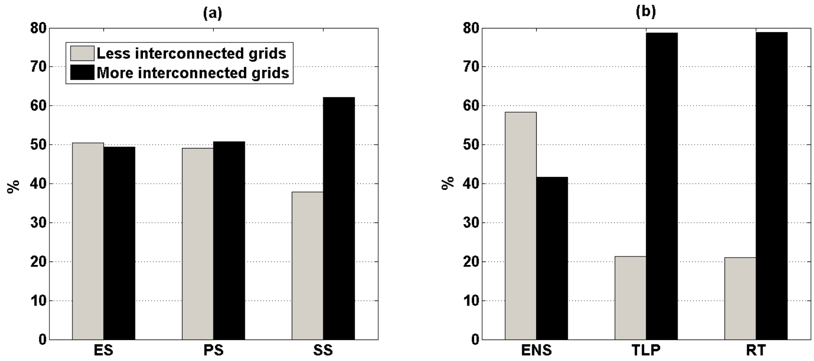


Fig. 7.5.: (a) Topology vs. power grid characteristics: Energy Share (ES), Power Share (PS) and Size Share (SS). (b) Topology vs. reliability indicators: Energy Not Supplied (ENS), Total Loss of Power (TLP) & Restoration Time (RT). Less interconnected countries: AT, BE, NL, DE, IT, RO, GR. More interconnected countries: PT, PL, SK, CH, CZ, FR, HU, ES.

the less interconnected group. The latter statement shows an opposite outcome compared to the results presented in the past (Rosas-Casals & Corominas-Murtra, 2009) where ENS is also larger for the more interconnected group (in the reference mentioned as the fragile group). Observing the reliability indicators data representing the fault events that have happened in the UCTE countries since 2002 and described in the previous section of this chapter, we conclude that, especially in the case of the ENS indicator, a single event can change the final result of the analysis.

In order to better illustrate this, Fig. 7.6 applies the same technique for two different cases. They both represent fault events up to 2008, as in the analysis presented in the past (Rosas-Casals & Corominas-Murtra, 2009). In the first case the Italian blackout from September 2003, which caused 180000 MWh of energy not supplied (ENTSO-E, 2011i), a total loss of power of 12400 MW (Berizzi, 2004) and a restoration time of 1092 minutes (ENTSO-E, 2011i), is not taken into account. In the second case, it is included. The results for the TLP and RT indicators are very similar, but the result for the ENS indicator is substantially different if the single event of the Italian 2003 blackout is taken into account or ignored. This example highlights the vulnerability of such an analysis to the data set characterised by extreme events. In addition, the relatively short temporal span for statistically sound results must be considered, as well as the probable network topology evolution over time.

Figs. 7.5 and 7.6 show that the ENS result is dependent on single events such as the Italian 2003 blackout which on its own accounts for more than 30% of the total ENS

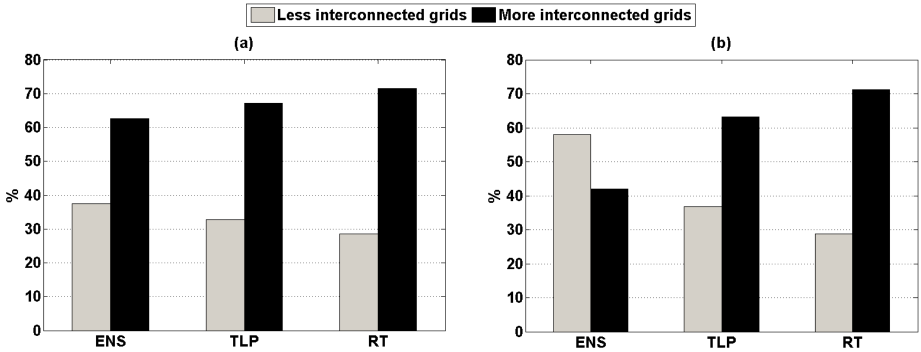


Fig. 7.6.: The Italian 2003 blackout example. (a) Without Italian 2003 blackout. (b) With Italian 2003 blackout.

in the UCTE countries since 2002. Such dependence is also valid for TLP and RT to a lower extent. In fact, Fig. 7.4 shows how a small fraction of the three reliability indicators account for a very large fraction of their total sum.

7.2.3. Improving the methodology

The second goal of this section is to propose a more robust statistical tool to analyse the relationship between network topology and reliability. The methodology proposed in the past (Rosas-Casals & Corominas-Murtra, 2009), which compares the relative shares of the indicator's sums for the two network groups, is not a robust statistical tool when the data is highly contingent on a few extreme events which account for a very large portion of the total ENS (mainly), TLP and RT since 2002. In addition, no test that determines if the differences found are statistically significant is known. We propose to observe single events rather than summing their reliability indicators in order to avoid results being outweighed by extreme values. Therefore, comparisons between the Empirical Cumulative Distribution Functions (ECDF) for each reliability indicator between the two groups are performed. In addition, these comparisons are supported by the Kolmogorov-Smirnov (KS) statistical test (Massey, 1951).

Fig. 7.7 compares the ECDF for the ENS indicator between the two network groups. For the more interconnected grids, ENS is systematically lower. However, if the largest event (the 2003 Italian blackout previously mentioned) is not taken into account, the plot would not show the last step of the grey line (less interconnected group) and the ENS share (shown in Fig. 7.5) would change drastically, which sug-

gests that the less interconnected grids show lower ENS. Fig. 7.7, however, shows how along the whole plot, the line representing the more interconnected grids is always behind, giving a lower ENS. In addition, the KS test gives a p-value in the order of 10^{-15} proving that the difference represented in Fig. 7.7 is statistically significant.

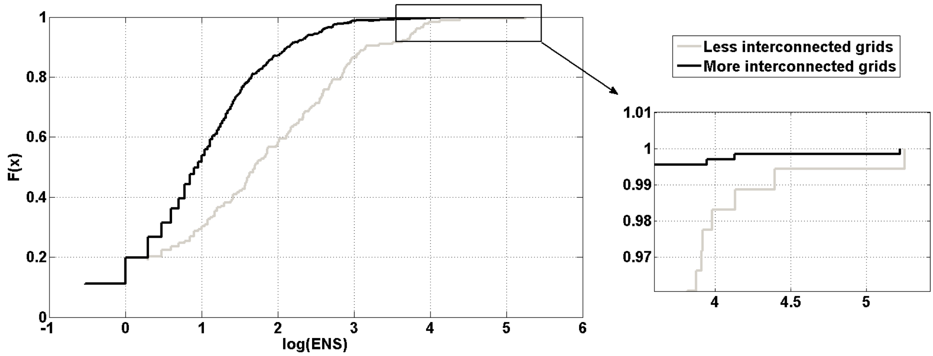


Fig. 7.7.: ECDF of ENS indicator for less and more interconnected grids.

The same approach is used to compare the TLP and RT indicators between the two groups. Figs. 7.8 and 7.9 compare the ECDF for the TLP and RT respectively for the two network groups. The KS test gives statistically significant p-values, in the order of 10^{-11} and 10^{-7} respectively. The two plots show very similar results. The TLP and RT shares are much larger (80%) for the more interconnected group (Fig. 7.5), however the ECDF plots show how for the majority of the events the more interconnected group has lower TLP and RT values. At higher TLP and RT values, the two lines cross each other. The higher TLP and RT shares for the more interconnected group are mainly given by the fact that it experiences more fault events, especially in the range of larger TLP and RT values.

Due to the limited data availability on past fault events in European power grids and the complex and stochastic nature of such events, including very few extreme cases, it is difficult to identify a firm relationship between the interconnectivity of a power grid and its reliability, particularly if the shares of the reliability indicators' sums are used as means of comparison. Results show that the more interconnected grids experience 80% of the total number of events. In spite of this, the comparisons of the ECDF for the three reliability indicators between less and more interconnected groups show that more national interconnected power grids in Europe have systematically lower

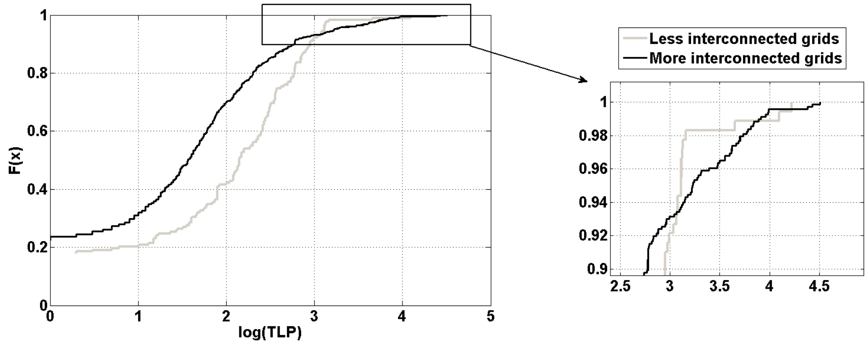


Fig. 7.8.: ECDF of TLP indicator for less and more interconnected grids.

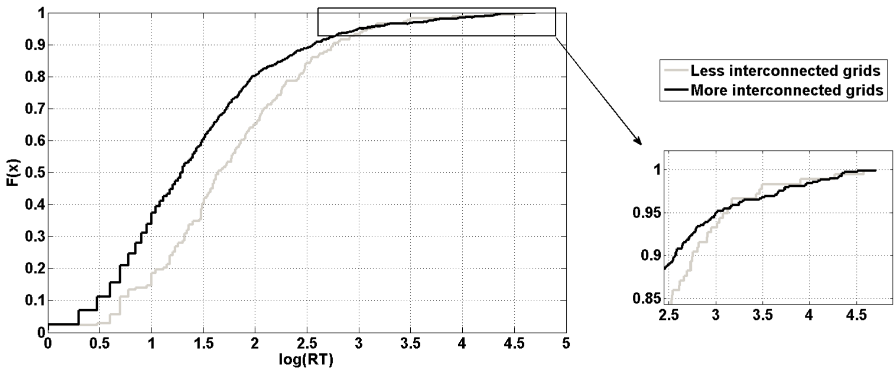


Fig. 7.9.: ECDF of RT indicator for less and more interconnected grids.

ENS, TLP and RT. This outcome partly corresponds with the common security standard (n-1) which is more easily met with higher interconnectivity.

It is important to mention that, as already shown in the literature (Rosas-Casals, 2010; Rosas-Casals & Solé, 2011), the distribution functions of the three reliability indicators are fat-tailed. In addition, the tails of the network groups' distributions for the three indicators cross each other. The two latter statements support the sensitivity of the analysis to rare extreme events, mainly when comparing the relative share of the indicators' sums.

The results presented throughout this section are based on the topological grid data for a single time point. The fact that the grid has evolved over time should have some influence on the analysis. However, this influence of the topological evolution

on the results has been neglected because data on topological evolution was not available.

7.3. Cross-border electricity transmission capacity for network reliability

As described in the previous section , several studies (Solé et al., 2008; Rosas-Casals & Corominas-Murtra, 2009; Brancucci Martínez-Anido et al., 2012) analyse the impact of topology on network reliability in terms of network interconnectivity, defined as how interconnected grid nodes are to other nodes of the same grid. In other words, network topology does not take into account the interconnections with bordering networks. This section, instead, explores the impact of cross-border electricity transmission capacity on network reliability.

The study presented in this section focuses on the European electricity transmission network; it considers 18 European countries[2], members of the former UCTE and of ENTSO-E.

The research question that is addressed in this section is how network reliability is affected by import capacity, remaining margin and their sum. The analysis is based on data regarding major fault events in the 18 electricity networks considered.

7.3.1. Methodology

The study presented in this section is based on a methodology which examines empirical data from several European electricity transmission networks.

Since January 2002, UCTE and ENTSO-E have been publishing monthly statistics on the major fault events in electricity transmission networks of their member countries. During the same period, UCTE and ENTSO-E have also been publishing annual System Adequacy Retrospect Reports which provide monthly electricity generation and consumption statistics for each country.

The analysis is based on 2160 observations. Each observation consists of a country-month. In other words, the study considers 18 countries for 10 years (18 countries x 10 years x 12 months per year = 2160 observations). For each observation the following network variables are derived from the monthly statistics:

[2] Austria, Belgium, Switzerland, Czech Republic, Germany, Spain, France, Greece, Hungary, Italy, The Netherlands, Poland, Portugal, Romania, Slovakia, Croatia, Slovenia, Luxembourg.

- Import Capacity / Peak Load [IC/PL]
- Remaining Margin / Peak Load [RM/PL]
- (Remaining Margin + Import Capacity) / Peak Load [(RM+IC)/PL]

Import capacity (IC), measured in GW, is defined as the maximum value between the 12 registered electricity imports during the monthly reference hour (e.g. 11 am of third Wednesday of the month). Remaining margin (RM), measured in GW, is defined as the difference between the monthly reliable available capacity (RAC) and the monthly peak electricity consumption. RAC is equal to the difference between the net generation capacity and the unavailable capacity. RM can be either positive or negative. Peak load (PL), measured in GW, is defined as the monthly peak electricity consumption.

The study presented in this section looks at the relationship between network reliability and import capacity, remaining margin, and their sum by analysing the number of fault events, defined as any incident which causes non-zero ENS and/or TLP. The three variables are normalised with the monthly peak electricity consumption in order to be able to compare European electricity systems of different dimensions in terms of electricity consumption and to consider the seasonal variations in electricity consumption.

For the 18 countries considered, 925 major fault events have been registered between 2002 and 2011 (both included). For each documented fault, a value for each of the three previously described network variables has been assigned, given the known country where and the month and year when it happened.

The same approach is followed for each of the three network variables (IC/PL, RM/PL, (RM+IC)/PL). In order to see if any of these variables have an impact on network reliability, the number of fault events and the number of observations, as well as their ratio, are classified for different ranges of the network variables. The aim of this approach is to see if there is any relationship between the aforementioned network variables and network reliability, measured as the occurrence of major fault events.

7.3.2. Results & Discussion

Figs. 7.10, 7.11 and 7.12 show three bar plots which represent:

- The number of fault events

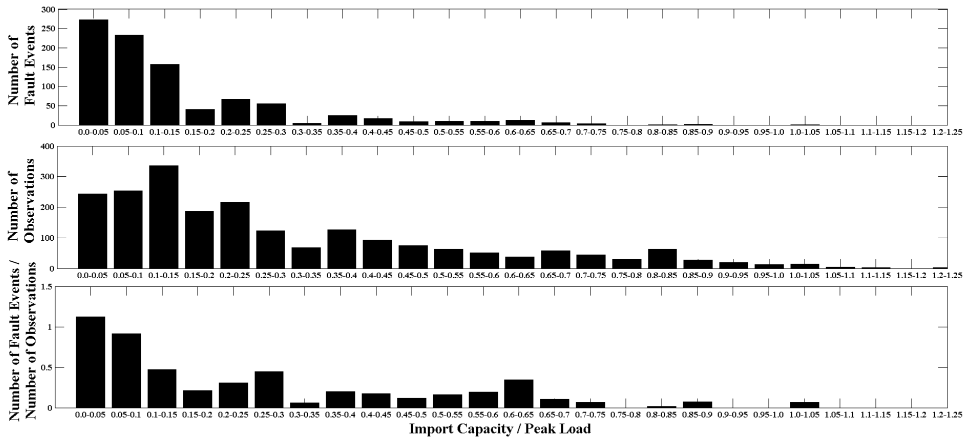


Fig. 7.10.: Import Capacity / Peak Load

- The number of observations
- The number of fault events / the number of observations

for different ranges of the following network variables:

- IC / PL
- RM / PL
- (RM + IC) / PL.

The top bar plot in Fig. 7.10 shows how the majority of the registered fault events were experienced during periods with a lower ratio between import capacity (IC) and monthly peak load (PL) in the network. The second bar plot shows how the number of observations decreases as the ratio between IC and PL increases. The bottom plot shows how the frequency of fault events decreases as the ratio IC/PL increases. However, the reduction in the frequency is not consistent; there is an increase for values of IC/PL between 0.45 and 0.65.

The influence of import capacity on an electricity network depends on network characteristics such as generation technologies and installed capacities. In order to account for the generation portfolio in our analysis, we consider the remaining margin for each observation. The same bar plots as in Fig. 7.10 are provided in Fig. 7.11 as a function of the ratio between RM and PL. In general, it can be concluded that the majority of fault events happen for values of RM/PL lower than 0.45. Nonetheless, it is not possible to conclude that the frequency of fault events in the 2160 observations considered decreases as the ratio between RM and PL increases.

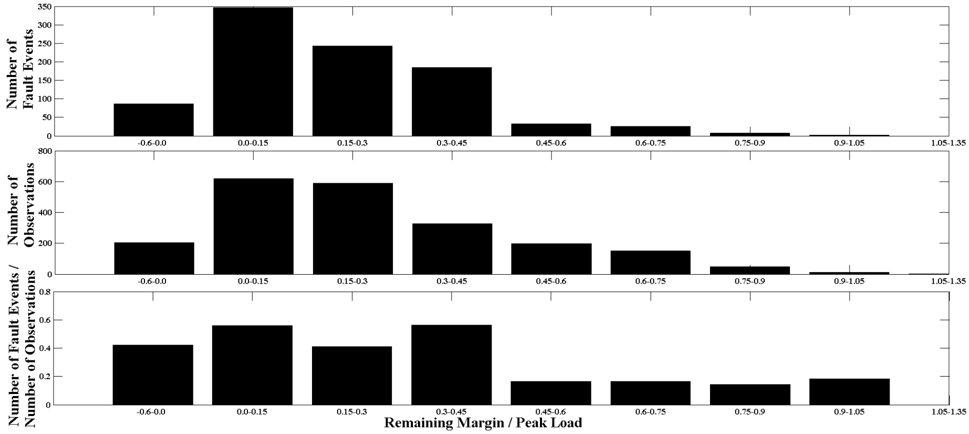


Fig. 7.11.: Remaining Margin / Peak Load

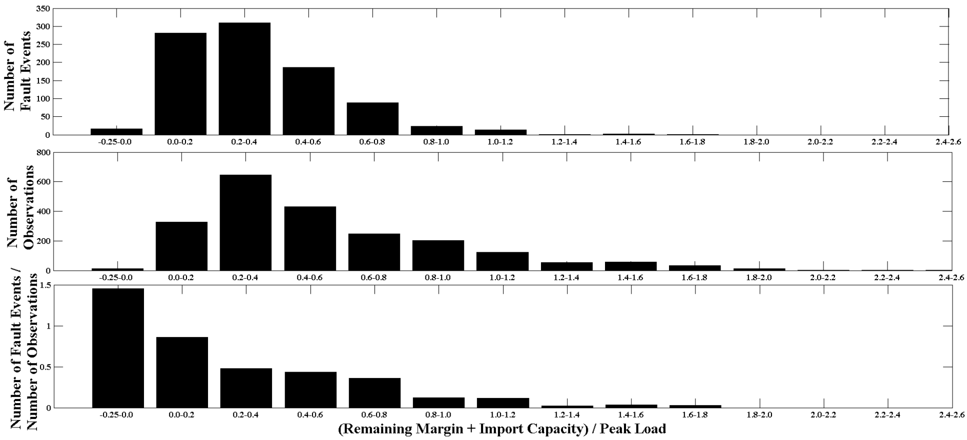


Fig. 7.12.: (Remaining Margin + Import Capacity) / Peak Load

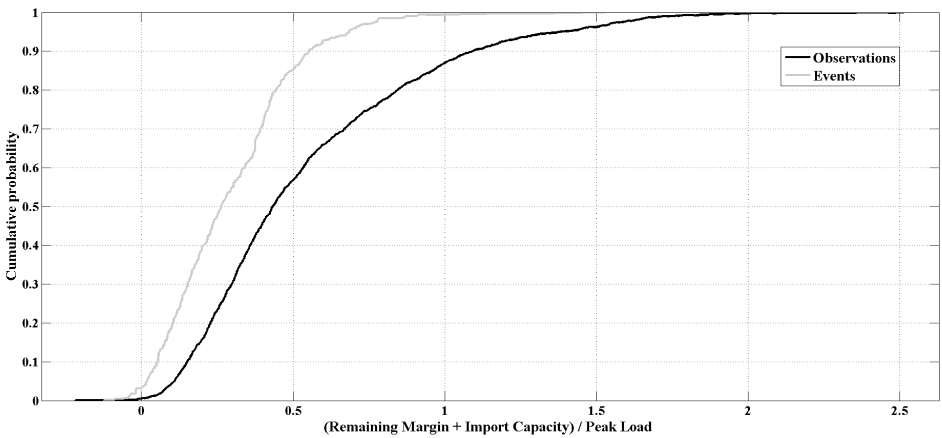


Fig. 7.13.: Cumulative probability distribution

As reliability is likely to be a function of total available generation capacity, we also analysed the relation between the sum of the remaining margin and import capacity on the one hand and peak load on the other hand. Fig. 7.12 shows similar plots as in the previous two figures, but now as a function of the sum (RM+IC)/PL. The most interesting result is represented in the bottom bar plot. It is clear that as the normalised sum between the remaining margin and import capacity increases, the frequency of major fault events in a European network between 2002 and 2011 decreases considerably. The plot of the frequency of fault events versus the ratio (RM+IC)/PL follows a decreasing exponential function almost perfectly.

Fig. 7.13 shows the cumulative probability distribution functions of having an observation (black line) and a major fault event (grey line) for increasing values of the sum of the remaining margin and import capacity, divided over peak load ((RM + IC) / PL). The grey line illustrates the percentage of fault events that have been experienced at moments when the ratio (RM+IC)/PL was lower than a specified value; for instance, 85% of the 925 registered events happened when the ratio (RM+IC)/PL was lower than 0.5. When comparing the two lines, it can be observed how the grey line is always above the black line. For low values of the ratio (RM+IC)/PL ($<$ 0.5), the vertical distance between the two lines increases as the ratio increases. In other words, the frequency of fault events decreases as the normalised sum between the remaining margin and import capacity increases. It can be concluded that the available generation capacity, accounting for both the internally available capacity and the available import capacity, is evidently an important factor for ensuring network reliability, at least in terms of avoiding major fault events. The consequences

of such events, which can be of very different scales, are not taken into account in this study.

When looking at Figs. 7.10 and 7.11, it can be stated that when comparing the impacts of import capacity, remaining margin and their sum on network reliability, import capacity shows a clearer impact on the frequency of fault events than remaining margin. However, the most interesting and clear result is illustrated in Figs. 7.12 and 7.13; a higher sum of remaining margin and import capacity ensures a more reliable network.

7.4. Conclusion

In this section, the conclusions from the two studies presented in this chapter are discussed.

The first study has shown that comparing the sums of reliability indicators of major fault events for groups of countries with less and more interconnection is not a robust statistical tool. Instead, the study proposes to compare the Empirical Cumulative Distribution Functions for each indicator with the support of the Kolmogorov-Smirnov test. The fat tails of the distributions of the reliability indicators indicate the sensitivity of the analysis to rare extreme events. The study concludes that transmission grid reliability indicators must be used carefully. Rare, extreme events can account for a very large portion of the total energy not supplied, total loss of power or total interruption time.

In addition, from the first study we can observe that more (internally) interconnected power grids have experienced four times as many fault events as the less interconnected ones. On the other hand, they show significantly better values for all of the three reliability indicators for the largest portion of their distributions. This means that the majority of these fault events in more interconnected networks has a smaller impact on reliability than the fault events in less interconnected networks. These results confirm the conventional wisdom that more interconnected networks are more reliable. However, it is interesting that the higher reliability is not a consequence of fewer faults, but of the smaller consequences of most faults. From the available data, it cannot be concluded why the number of faults is not lower in more interconnected networks, as it only contains key performance indicators and a basic description of the causes.

In the second study, empirical data of several electricity transmission networks have been used to investigate the impacts of import capacity and the remaining margin on network reliability. Results show how increasing the sum between remaining margin and import capacity corresponds with higher reliability (fewer fault events) in the network. Increasing European cross-border electricity interconnections would definitely contribute to meeting the EU energy policy goal of increasing and ensuring security of electricity supply. However, from the first study we learn that the optimum level of system reliability is not having the minimum number of faults, but it is related to having faults with the smallest consequences in terms of energy not supplied, total loss of power and restoration time. Finally, investments in electricity generation and transmission with the purpose of increasing the system's reliability should always make sure that the costs do not far outweigh the benefits.

8. Conclusions

8.1. Conclusions & Policy Recommendations

The results presented in this thesis show that the cross-border transmission investment plans expected by ENTSO-E are adequate and their impacts in terms of reductions in dispatch cost, RES curtailment and unserved load vary depending on the evolution of the power system, mainly in terms of demand evolution, RES penetration and CO_2 price.

Dispatch costs

Given the expectations concerning the future generation portfolio, the growth in electricity demand and a CO_2 price of 22.5 €/tonne, the cross-border transmission capacity expansion by 2025 expected by ENTSO-E will reduce dispatch costs by 1%. This reduction is higher for lower demand growth rates because the number of hours in which costly natural gas generators are marginal is reduced as a result of lower demand. If the share of wind and solar energy sources doubles the forecasts and amounts to about 35% of the European energy mix, the expected investment in cross-border transmission will reduce dispatch costs by almost 6.7%.

Moreover, if investments in cross-border transmission between North Africa and Spain and Italy take place (as well as in electricity generation in North Africa with "low" variable cost), electricity dispatch costs would be further reduced and net European electricity exchanges would follow the direction from South to North.

However, the impact of cross-border transmission investment on the electricity bills of the European consumers will depend on the impact of the investment on electricity prices (not necessarily related to dispatch costs) and on the capital costs of such investment.

RES curtailment needs

Cross-border transmission capacity will not be a significant constraint for RES integration between 2010 and 2025 at the RES levels expected by ENTSO-E. However, at higher volumes of RES, more interconnection capacity would be needed if curtailment were to be avoided. For example, if the share of wind and solar energy sources is doubled, the expected investment in cross-border transmission will reduce wind curtailment by 42%, from 7.7% to 4.5%. Solar curtailment would be limited but still considerably reduced.

Network stability issues and national distribution and internal transmission network congestion are more likely constraints for the integration of variable RES. For instance, the study that analyses the impacts of North-African electricity imports on the European and the Italian power systems shows how internal grid congestion can limit electricity flows across borders and therefore could necessitate RES curtailment.

Energy storage & demand response

Two case studies presented in this thesis show how investments in energy storage, modelled as hydro pumping capacity, and in demand response, modelled as controlled EV charging, also reduce dispatch costs and variable RES curtailment needs. The extent to which energy storage and demand response substitute or complement the need for cross-border transmission investment depends on the need for arbitrage in the interconnected European power system.

The potential for arbitrage exists when the difference in dispatch cost between two markets is greater than the cost of arbitrage. The two markets can represent two geographic areas or the same market over time (e.g. day and night). In this thesis, the cost of arbitrage is the variable cost of cross-border transmission, the variable cost of hydro pumping and the variable cost of controlled EV charging.

The need for arbitrage varies hour by hour and geographically as it depends on the supply curve of a specific country at each moment in time. A higher RES penetration causes higher variability in the supply curve and therefore increases the demand for arbitrage in the system. The same applies to scenarios in which the CO_2 price is low and the difference in variable electricity generation costs between coal and gas fired power plants is high.

In a future generation scenario with doubled wind and solar installed generation capacities than expected by ENTSO-E, the demand for hydro pumping decreases with higher cross-border transmission capacity. The reason for this behaviour is that cross-border transmission and pumped hydro storage are partly substitutes. In addition, in most cases it is cheaper to import electricity from a neighbouring country than using pumped hydro storage. In EUPowerDispatch the cost of importing electricity corresponds to the difference in dispatch costs between the two countries (plus the cross-border transmission losses) and the cost of hydro pumped storage is related to the assumed 75% hydro pumping efficiency.

On the other hand, paradoxically, cross-border transmission increases slightly if hydro pumping capacity is doubled compared to ENTSO-E scenarios. This counter-intuitive behaviour results from situations in which the higher volumes of RES lead to an increase in demand for storage and access to storage facilities in neighbouring markets is limited due to cross-border transmission constraints.

EV control can be used to adjust demand over time to fluctuations in supply, thereby flattening the residual load. The extent to which cross-border transmission and controlled EV charging substitute one another depends on the need for arbitrage in the European electricity system. EV charging control and cross-border transmission are partly substitutes and partly complements. When the demand for arbitrage is low, controlled EV charging can substitute for a certain volume of cross-border transmission capacity. The higher the need for arbitrage, the more the two complement one another with respect to reducing dispatch costs and RES curtailment.

Cross-border transmission can spread fluctuations in supply geographically, thereby reducing the impact per system, but because it does not offer inter-temporal arbitrage its potential to flatten residual load is limited. In other words, when demand for arbitrage becomes higher, both (controlled EV charging and cross-border transmission) are needed because the potential of controlling EVs and storage in one country is insufficient for absorbing fluctuations in RES. Then cross-border transmission capacity is needed to provide access to storage and/or controlled EVs in another country.

In reality, cross-border transmission flows, as well as hydro pumping and load shifting, are initiated by differences in electricity prices between two countries or two moments in time, and not necessarily by differences in dispatch costs. However, the analyses performed with EUPowerDispatch and presented in this thesis are adequate and relevant for the scope of exploring the extent to which energy storage and

demand response substitute or complement the need for cross-border transmission investment.

Security of supply

The expected expansion of cross-border transmission capacity by 2025 has a limited impact on unserved load in the face of the expected low growth rate of electricity consumption in Europe (0.9%). However, if demand grows at the historical rate of 2%, the expected development of cross-border transmission will be needed to maintain the current level of security of supply in 2025 by avoiding 20 TWh of unserved load in Europe. Moreover, statistics of 18 European countries since 2002 show that as the normalised sum between remaining margin and import capacity increases, the frequency of major fault events in a European network between 2002 and 2011 decreases considerably. However, fewer fault events is not necessarily a sign of better network reliability.

EU energy policy

The research presented in this thesis shows how cross-border electricity transmission investment will have a positive impact on the following two EU energy policy objectives: economic efficiency and security of supply. In terms of economic efficiency, the results presented in the thesis show how cross-border transmission investment would reduce dispatch costs and variable RES curtailment needs. With respect to security of supply, the results show how cross-border transmission investment reduces unserved load and the frequency of major fault events.

Cross-border transmission investment will also have a positive impact on competitiveness within the electricity market. However, the latter is not directly discussed throughout the thesis. Higher interconnection capacity would allow larger cross-border electricity flows and would allow generators to sell their electricity to countries with higher prices. Especially in an interconnected system with a high RES penetration, cross-border transmission investment would allow trade in renewable electricity that would otherwise be curtailed. ENTSO-E latest TYNDP (ENTSO-E, 2012b) has identified 100 bottlenecks in the European network by the end of the decade and half of them are directly related to market integration. Cross-border transmission development would facilitate grid access to all market participants and it would contribute to social welfare by internal market integration and harmonisation.

In order to integrate a very high RES penetration in the coming decades, Europe's power system will have to face several infrastructural changes. Important investments will have to be made in time in order to accommodate the variability of a high penetration of variable RES. A single technological solution will not be enough in order to cope with the expected needs for arbitrage. The complementarity and substitution potential of energy storage and demand response with respect to electricity transmission need to be better understood in order to plan efficient investments. However, the optimal mix between these three technologies depends on their relative costs and on the future evolution of the European power system. This evolution will lie within the fundamental forces of supply and demand, which are crucially dependent not only on RES and carbon policies but also on the socio-economic development of Europe.

CO_2 emissions

Given the expectations concerning the future generation portfolio, the growth in electricity demand and a CO_2 price of 22.5 €/tonne, and assuming that planned cross-border transmission investments are realised, the total CO_2 emissions from electricity generation in Europe will decrease by only 17% between 2010 and 2025. Despite a 28% reduction in the carbon-intensity of electricity generation, this improvement is partly offset by the growth of electricity consumption. These results are a small step towards the European Commission's target of a fully decarbonised European power sector by 2050.

In order to meet this target, the EC estimates that CO_2 emissions must be reduced by 54-68% by 2030 compared to 1990 levels. More low-carbon generation and lower electricity demand growth will be needed to meet EU climate policy goals. A reduction in expected European electricity consumption would be beneficial for meeting the desired goals. If the projected electricity consumption growth were mainly due to the (partial) electrification of transport, the results would be more optimistic because of the corresponding decrease of emissions in the transport sector.

A CO_2 price of 50 €/tonne would make the marginal generation cost of gas plants lower than coal and lignite, causing a 38% reduction in CO_2 emissions compared to the scenario with a price of 22.5 €/tonne. In addition, if the CO_2 price is high enough so that the merit order represents the carbon content of the generating technologies, cross-border transmission investment will also reduce CO_2 emissions. Instead, if twice the expected volume of variable RES were developed by 2025, CO_2 emissions would drop by 33% in the 22.5 €/tonne scenario. This means that, ceteris

paribus, a carbon tax favouring gas over coal does more to reduce emissions than a doubling of RES without a high carbon price.

Cross-border electricity transmission investment will have a positive impact on the EU policy goal of environmental sustainability and towards the goal of decarbonising the European power sector when one or both of the following two conditions apply. The first condition is that there is a large share of renewable energy sources in the generation mix. In this case, cross-border-transmission capacity expansion would reduce wind and solar energy curtailment and therefore further reduce CO_2 emissions. The second condition is that the CO_2 price is high enough so that carbon-intensive generation technologies come late in the merit order. In this case, cross-border transmission investment will reduce CO_2 emissions by facilitating the dispatch of cheaper generators which, because of the high CO_2 price, are also less carbon-intensive. However, if European carbon policy will not lead to such a high CO_2 price, investments in cross-border transmission, as well as in energy storage and demand response, will lead to higher CO_2 emissions. In other words, if carbon policy is not effective, the economic objective of reducing electricity generation dispatch costs will make it more difficult to reach Europe's climate policy goals.

8.2. Reflections & scientific recommendations

In this section, the methodological choices are reviewed. The resulting reflections lead to recommendations for future research.

In order to analyse the needs for cross-border electricity transmission investment in Europe, EUPowerDispatch is used to study the impacts of different generation, demand and cross-border transmission scenarios on the European power system. The assumptions and the model design choices within EUPowerDispatch determine the relevance of the results presented in the different studies discussed throughout the thesis.

Transmission network

As discussed in Chapter 2, EUPowerDispatch models each of the 32 interconnected countries represented within the model as single nodes, neglecting internal national transmission network congestion. The study presented in Chapter 6, in which the effects of North-African electricity imports on the European and the Italian power systems are analysed using EUPowerDispatch and a detailed Italian network model

respectively, shows how the impact of cross-border transmission investment can not be fully appreciated without taking into account internal network congestion. As shown in the model validation in Section 2.4, EUPowerDispatch outputs yield higher cross-border electricity flows than what it is actually experienced in the European power system. The main reason for this is that, sometimes, economically attractive electricity flows across borders are hindered by congestion in the transmission lines across the countries or near the borders. In addition, EUPowerDispatch does not model loop flows when modelling electricity flows from one country to another. These can be very relevant when analysing cross-border flows in a highly interconnected region such as Central Europe. However, due to the unavailability of transmission data as well as data on available generation and load distribution within a country for an entire year, these impacts can not be considered. Despite these limitations, EUPowerDispatch and its applications provide significant insights into the need for cross-border electricity transmission investment in Europe, assuming consistent transmission investments that minimise internal network congestion.

In order to perform a cost-benefit analysis for a specific cross-border transmission investment, a detailed network analysis of the two countries being interconnected would provide more accurate results in terms of reductions in dispatch costs and RES curtailment needs. A detailed European network model which takes into account the intra-day and seasonal variability of RES is not possible due to the high computational requirements. However, EUPowerDispatch could be used to complement the regional or two-country detailed network model by providing the marginal electricity generation costs in the neighbouring countries for each hour of the year. This approach could be similar to the one performed in the collaborative study presented in Chapter 6 in which the marginal electricity generation costs calculated by EUPowerDispatch for each hour of the year for the Italian neighbouring countries were used as inputs in the analysis performed with a detailed Italian network model.

Electricity consumption and weather data

The electricity consumption time-series as well as the weather data, including wind speed, solar radiation, run-of-river and natural hydro inflow time-series, used as inputs for EUPowerDispatch in the studies presented in Chapters 3 to 6 are taken from 2010 real data and statistics. Therefore, any potential correlations between them are relevant only for 2010. The qualitative results summarised in this chapter would not differ if demand and weather data were taken from another year. However, quantita-

tive results such as dispatch costs, RES curtailment needs and CO_2 emissions would definitely differ to a small extent between countries. Therefore, future research could analyse the impact of consumption and weather patterns for different years on the outputs of EUPowerDispatch. Moreover, different correlations between demand and available RES could be interesting for analysing the extent to which cross-border transmission, demand response and energy storage substitute and/or complement one another in high RES scenarios.

Weather forecasts

EUPowerDispatch assumes perfect knowledge of one-year hydro inflow forecasts and of one-week wind speed and solar radiation forecasts. In real life this is not possible and the forecast errors experienced when scheduling electricity generation would accentuate the need for cross-border transmission investment in Europe. Forecasts errors and uncertainty in wind and solar power output as well as in hydro precipitation enhance the need for arbitrage in the system. For future research, it would be interesting to study the impact of forecast errors as well as of forecast time ranges on the needs for cross-border transmission capacity, energy storage and/or demand response.

Deterministic approach

The studies performed with EUPowerDispatch compare the results of different runs, each analysing a different deterministic scenario. In other words, each EUPowerDispatch run assumes a set of given power system parameters and it does not consider uncertainty. Future research could integrate a stochastic approach within EUPowerDispatch to study the impact of, for example, uncertain fuel prices, CO_2 price, demand growth, and other system parameters which in the current version of the model are assumed in a deterministic way.

Cost-benefit analysis

EUPowerDispatch quantifies economic benefits of cross-border transmission capacity only in terms of reduced electricity generation dispatch costs. Future work should ideally include the capital costs of cross-border transmission, as well as of energy storage (e.g. hydro pumping) and of required infrastructure for implementing demand response (e.g. controlled EV charging) in the analysis. Ideally, these costs

could be used to assess the adequacy of investments in cross-border transmission, energy storage and demand response mechanism by comparing the present or the expected future infrastructure with the optimal level. However, in reality, optimality is not a straightforward and objective concept for infrastructure systems.

Due to the difficulty of obtaining the necessary data and of defining the right exogenous system parameters, these studies may be limited to smaller regions than the 32 European countries of this study and to specific scenarios. Such a cost-benefit analysis can provide more insight in the optimal mix of cross-border transmission, energy storage and demand response by looking at different future scenarios with varying RES penetration levels.

A. GAMS Code for EUPowerDispatch's Weekly Model

Appendix A provides the GAMS code for EUPowerDispatch's weekly model.

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```
* 1 WEEK Model (168 time steps / hours) for 32 nodes

* Definition of weekly output variables from GAMS to Matlab
$set matout "'matsol.gdx', costs, h_lflow, h_ngen, h_liggen, h_coalgen, h_gas»
gen, h_oilgen, h_mixedgen, h_PSP1, h_PSP1out, h_PSP1in, h_PSP2, h_PSP2out, h_»
PSP2in, h_solgen, h_wongen, h_woffgen, xgen, h_biogen, xld, on, on2, on3, su,»
 su2, su3 ";

*Definition of sets
SETS
h       hours (168 hours in a week)   /h1*h168/
c       columns in excel files  /c1*c50/
x       interconnections (71 lines*2directions) /x1*x142/
n       nodes (32 countries)  /n1*n32/
cl      coal power plants  /cl1*cl100/
lg      lignite power plants  /lg1*lg100/
gs         gas power plants   /gs1*gs100/
hfirst(h) first hour of the week
hlast(h)  last hour of the week
;

*Definition of first and last hours of the week
hfirst(h) = yes$(ord(h) eq 1);
hlast(h) = yes$(ord(h) eq card(h));

*Definition of scalars
SCALARS
*Variable electricity generation costs for each type of plant (euros per MWh)»
.
nucp      nuclear
oilp      oil
mixedp    mixed oil and gas
hydrop    hydro
wonp      onshore wind
woffp     offshore wind
solp      solar
biop      biomass
expensivep expensive generation (value of loss load)
;

*Definition of parameters
PARAMETERS
h_ligdata(n,lg,c)   data for lignite power plants
h_cldata(n,cl,c)  data for coal power plants
h_gasdata(n,gs,c)   data for gas power plants

onstart(n,cl)       on-off binary of coal plants before start of the week
on2start(n,lg)      on-off binary of lignite plants before start of the week
on3start(n,gs)      on-off binary of gas plants at before start of the week
clstart(n,cl)       generation level of coal plants before start of the week
lgstart(n,lg)       generation level of lignite plants before start of the we»
ek
gsstart(n,gs)       generation level of gas plants before start of the week

marcos(c)          input matrix of variable electricity generation costs
h_gendata(c,n)     input matrix of installed generation capacities
h_nuccap(n)        nuclear installed generation capacity
h_ligcap(n)        lignite installed generation capacity
h_coalcap(n)       coal installed generation capacity
h_gascap(n)        gas installed generation capacity
h_oilcap(n)        oil installed generation capacity
```

Fig. A.1.: GAMS code for EUPowerDispatch's weekly model - Part 1

```
h_mixedcap(n)       mixed oil and gas installed generation capacity
h_PSP1cap(n)        seasonal hydro reservoir capacity
h_PSP1max(n)        seasonal hydro generation capacity
h_PUMP1max(n)       seasonal hydro pumping capacity
h_PSP2cap(n)        pure hydro pumping reservoir capacity
h_PUMP2max(n)       pure hydro pumping capacity
h_biocap(n)         biomass installed generation capacity

h_linedata(x,c)   input matrix of cross-border transmission data
frombus(x)        starting node of line x
tobus(x)          ending node of line x
h_losses(x)       losses of line x
h_NTCpos(x)       NTC of line x
incidence(x,n)    incidence matrix

h_load(n,h)      load
h_ror1(n,h)      run of river
h_ror2(n,h)      natural inflow into seasonal hydro reservoir
h_sol(n,h)       available solar generation
h_won(n,h)       available onshore wind generation
h_woff(n,h)      available offshore wind generation

PSP1levelstart(n)   seasonal hydro reservoir level at the start of the week
PSP1levelend(n)     seasonal hydro reservoir level at the end of the week

windonmaxcap(n)    onshore wind installed generation capacity
windoffmaxcap(n)   offshore wind installed generation capacity
solmaxcap(n)       solar installed generation capacity
;

*Importing data from Matlab to GAMS
execute_load "matdata.gdx" h_gendata, h_linedata, h_load, h_ror1, h_ror2, h_s»
ol, h_won, h_woff, PSP1levelstart, PSP1levelend, marcos, h_ligdata, h_cldata,»
 h_gasdata, onstart, on2start, on3start, clstart, lgstart, gsstart ;

*Organizing variable elecricity generation costs (euros per MWh)
nucp = marcos('c1');
oilp = marcos('c5');
mixedp = marcos('c6');
solp = marcos('c7');
wonp = marcos('c8');
woffp = marcos('c9');
hydrop = marcos('c10');
biop = marcos('c11');
expensivep = 10000;

*Organizing transmission data
frombus(x) = h_linedata(x,'c1');
tobus(x) = h_linedata(x,'c2');
h_losses(x) = h_linedata(x,'c3');
h_NTCpos(x) = h_linedata(x,'c4');

*Incidence Matrix
incidence(x,n)=0;
Loop (x,
         Loop(n$(ord(n) eq frombus(x)), incidence(x,n) = incidence(x,n) +1);
         Loop(n$(ord(n) eq tobus(x)), incidence(x,n) = incidence(x,n) -1);
);

*Organizing installed generation capacities
h_nuccap(n) = h_gendata('c1',n)*1000*0.845;
```

Fig. A.2.: GAMS code for EUPowerDispatch's weekly model - Part 2

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```
h_ligcap(n) = h_gendata('c2',n)*1000*0.90;
h_coalcap(n) = h_gendata('c3',n)*1000*0.90;
h_gascap(n) = h_gendata('c4',n)*1000*0.90;
h_oilcap(n) = h_gendata('c5',n)*1000*0.90;
h_mixedcap(n) = h_gendata('c6',n)*1000*0.90;
h_PSP1cap(n) = h_gendata('c11',n)*1000;
h_PSP1max(n) = h_gendata('c13',n)*1000;
h_PUMP1max(n) = h_gendata('c14',n)*1000;
h_PSP2cap(n) = h_gendata('c12',n)*1000;
h_PUMP2max(n) = h_gendata('c15',n)*1000;
h_biocap(n) = h_gendata('c10',n)*1000;
windonmaxcap(n) = h_gendata('c7',n)*1000;
windoffmaxcap(n) = h_gendata('c8',n)*1000;
solmaxcap(n) = h_gendata('c9',n)*1000;

*Definition of variables
VARIABLES
h_netoutput(n,h) electricity exports
h_lflow(x,h)     lineflow
costs            weekly electricity dispatch costs
;

*Definition of positive variables
POSITIVE VARIABLES
h_ngen(n,h)          nuclear generation
h_liggen(n,lg,h)     lignite generation
h_coalgen(n,cl,h)    coal generation
h_gasgen(n,gs,h)     gas generation
h_oilgen(n,h)        oil generation
h_mixedgen(n,h)      mixed oil and gas generation
h_PSP1(n,h)          seasonal hydro reservoir level
h_PSP1out(n,h)       seasonal hydro generation
h_PSP1in(n,h)        seasonal hydro pumping
h_PSP2(n,h)          pure hydro pumping reservoir level
h_PSP2out(n,h)       pure hydro pumping generation
h_PSP2in(n,h)        pure hydro pumping
h_solgen(n,h)        solar generation
h_wongen(n,h)        onshore wind generation
h_woffgen(n,h)       offshore wind generation
h_biogen(n,h)        biomass generation
xgen(n,h)            expensive generation
xld(n,h)             expensive load
;

*Definition of binary variables
BINARY VARIABLE
on(n,cl,h)           on-off binary value for coal power plants
on2(n,lg,h)          on-off binary value for lignite power plants
on3(n,gs,h)          on-off binary value for gas power plants

su(n,cl,h)           start-up binary value for coal power plants
su2(n,lg,h)          start-up binary value for lignite power plants
su3(n,gs,h)          start-up binary value for gas power plants

sd(n,cl,h)           shut-down binary value for coal power plants
sd2(n,lg,h)          shut-down binary value for lignite power plants
sd3(n,gs,h)          shut-down binary value for gas power plants
;

*Definition of equations
EQUATIONS
```

Fig. A.3.: GAMS code for EUPowerDispatch's weekly model - Part 3

```
h_output            net output equation
h_equilibrium       equilibrium equation
h_lineflow_pos      NTC limit in positive direction
h_lineflow_neg      NTC limit in negative direction
h_nucgenlim         maximum nuclear generation
h_nucgenlim2        minimum nuclear generation
h_nucgenlim3        ramp-up limit for nuclear generation
h_nucgenlim4        ramp-down limit for nuclear generation
liggencons          maximum lignite generation
liggencons2         minimum lignite generation
coalgencons         maximum coal generation
coalgencons2        minimum coal generation
gasgencons          maximum gas generation
gasgencons2         minimum gas generation
h_oilgenlim         maximum oil generation
h_mixedgenlim       maximum mixed oil and gas generation
h_biogenlim         maximum biomass generation
h_biogenlim2        maximum total biomass generation for the entire week
h_PSP1outlim        maximum generation for seasonal hydro
h_PSP1inlim         maximum pumping for seasonal hydro
h_PSP2outlim        maximum generation for pure pumping hydro
h_PSP2inlim         maximum pumping for pure pumping hydro
h_PSP1caplim        inter-temporal relationship for hydro resevoir level for s»
easonal hydro
h_PSP2caplim        inter-temporal relationship for hydro resevoir level for p»
ure pumping hydro
h_PSP1lim           maximum reservoir level for seasonal hydro
h_PSP2lim           maximum reservoir level for pure pumping hydro
h_solgenlim         maximum solar generation
h_wongenlim         maximum onshore wind generation
h_woffgenlim        maximum offshore wind generation
h_PSP1start         reservoir level at the start of the week for seasonal hydr»
o
h_PSP1end           reservoir level at the end of the week for seasonal hydro
h_PSP2start         reservoir level at the start of the week for pure pumping »
hydro
h_PSP2end           reservoir level at the end of the week for pure pumping hy»
dro
PSP1minequation     minimum reservoir level for seasonal hydro
logic               start-up and shut-down logic for coal plants
logic2              start-up and shut-down logic for lignite plants
logic3              start-up and shut-down logic for gas plants
rampup              maximum ramp-up for coal plants
rampup2             maximum ramp-up for lignite plants
rampup3             maximum ramp-up for gas plants
rampdown            maximum ramp-down for coal plants
rampdown2           maximum ramp-down for lignite plants
rampdown3           maximum ramp-down for gas plants
logicI              start-up and shut-down logic for coal plants at start of t»
he week
logic2I             start-up and shut-down logic for lignite plants at start o»
f the week
logic3I             start-up and shut-down logic for gas plants at start of th»
e week
rampupI             maximum ramp-up for coal plants at the start of the week
rampup2I            maximum ramp-up for lignite plants at start of the week
rampup3I            maximum ramp-up for gas plants at start of the week
rampdownI           maximum ramp-down for coal plants at start of the week
rampdown2I          maximum ramp-down for lignite plants at start of the week
rampdown3I          maximum ramp-down for gas plants at start of the week
h_costs_eq          objective function
```

Fig. A.4.: GAMS code for EUPowerDispatch's weekly model - Part 4

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```
;

*Equations
h_output(n,h)..
h_netoutput(n,h) -SUM(x$(h_NTCpos(x)>0),h_lflow(x,h)*incidence(x,n)) =e= 0;

h_equilibrium(n,h)..
h_ngen(n,h)$(h_nuccap(n)>0)
+ SUM(lg$(h_ligdata(n,lg,'c2')>0),h_liggen(n,lg,h))
+ SUM(cl$(h_cldata(n,cl,'c2')>0),h_coalgen(n,cl,h))
+ SUM(gs$(h_gasdata(n,gs,'c2')>0),h_gasgen(n,gs,h))
+ h_oilgen(n,h)$(h_oilcap(n)>0) + h_mixedgen(n,h)$(h_mixedcap(n)>0)
+ h_solgen(n,h)$(solmaxcap(n)>0) + h_wongen(n,h) + h_woffgen(n,h)+ h_ror1(n,h»
)
+ h_biogen(n,h)$(h_biocap(n)>0) + h_PSP1out(n,h)$(h_PSP1max(n)>0)
+ h_PSP2out(n,h)$(h_PUMP2max(n)>0) - h_PSP1in(n,h)$(h_PUMP1max(n)>0)
- h_PSP2in(n,h)$(h_PUMP2max(n)>0) - h_load(n,h) - h_netoutput(n,h)
+ xgen(n,h) - xld(n,h) =e= 0;

h_lineflow_pos(x,h)..
h_lflow(x,h) =l= h_NTCpos(x);

h_lineflow_neg(x,h)..
h_lflow(x,h) =g= 0;

h_nucgenlim(n,h)$(h_nuccap(n)>0)..
h_ngen(n,h) =l= h_nuccap(n);

h_nucgenlim2(n,h)$(h_nuccap(n)>0)..
h_ngen(n,h) =g= 0.7*h_nuccap(n);

h_nucgenlim3(n,h)$(h_nuccap(n)>0 and ord(h) GT 1)..
h_ngen(n,h) - h_ngen(n,h-1) =l= 0.02*h_nuccap(n);

h_nucgenlim4(n,h)$(h_nuccap(n)>0 and ord(h) GT 1)..
h_ngen(n,h) - h_ngen(n,h-1) =g= -0.02*h_nuccap(n);

liggencons(n,lg,h)$(h_ligcap(n)>0 and h_ligdata(n,lg,'c2')>0)..
h_liggen(n,lg,h) =l= on2(n,lg,h)*h_ligdata(n,lg,'c2');

liggencons2(n,lg,h)$(h_ligcap(n)>0 and h_ligdata(n,lg,'c2')>0)..
h_liggen(n,lg,h) =g= on2(n,lg,h)*h_ligdata(n,lg,'c1');

coalgencons(n,cl,h)$(h_coalcap(n)>0 and h_cldata(n,cl,'c2')>0)..
h_coalgen(n,cl,h) =l= on(n,cl,h)*h_cldata(n,cl,'c2');

coalgencons2(n,cl,h)$(h_coalcap(n)>0 and h_cldata(n,cl,'c2')>0)..
h_coalgen(n,cl,h) =g= on(n,cl,h)*h_cldata(n,cl,'c1');

gasgencons(n,gs,h)$(h_gascap(n)>0 and h_gasdata(n,gs,'c2')>0)..
h_gasgen(n,gs,h) =l= on3(n,gs,h)*h_gasdata(n,gs,'c2');

gasgencons2(n,gs,h)$(h_gascap(n)>0 and h_gasdata(n,gs,'c2')>0)..
h_gasgen(n,gs,h) =g= on3(n,gs,h)*h_gasdata(n,gs,'c1');

h_oilgenlim(n,h)$(h_oilcap(n)>0)..
h_oilgen(n,h) =l= h_oilcap(n);

h_mixedgenlim(n,h)$(h_mixedcap(n)>0)..
h_mixedgen(n,h) =l= h_mixedcap(n);

```

Fig. A.5.: GAMS code for EUPowerDispatch's weekly model - Part 5

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```
h_biogenlim(n,h)$(h_biocap(n)>0)..
h_biogen(n,h) =l= h_biocap(n);
h_biogenlim2(n)$(h_biocap(n)>0)..
SUM(h,h_biogen(n,h)) =l= h_biocap(n)*168*0.5;
h_PSP1outlim(n,h)$(h_PSP1cap(n)>0)..
h_PSP1out(n,h) =l= h_PSP1max(n);
h_PSP1inlim(n,h)$(h_PSP1cap(n)>0)..
h_PSP1in(n,h) =l= h_PUMP1max(n);
h_PSP2outlim(n,h)$(h_PSP2cap(n)>0)..
h_PSP2out(n,h) =l= h_PUMP2max(n);
h_PSP2inlim(n,h)$(h_PSP2cap(n)>0)..
h_PSP2in(n,h) =l= h_PUMP2max(n);
h_PSP1caplim(n,h)$(h_PSP1cap(n)>0 and ord(h) GT 1)..
h_PSP1(n,h) =e= h_PSP1(n,h-1) + 0.75*h_PSP1in(n,h-1) + h_ror2(n,h-1)
- h_PSP1out(n,h-1);
h_PSP2caplim(n,h)$(h_PSP2cap(n)>0 and ord(h) GT 1)..
h_PSP2(n,h) =e= h_PSP2(n,h-1) + 0.75*h_PSP2in(n,h-1) - h_PSP2out(n,h-1);
h_PSP1lim(n,h)$(h_PSP1cap(n)>0)..
h_PSP1(n,h) =l= h_PSP1cap(n);
h_PSP2lim(n,h)$(h_PSP2cap(n)>0)..
h_PSP2(n,h) =l= h_PSP2cap(n);
h_solgenlim(n,h)$(solmaxcap(n)>0)..
h_solgen(n,h) =l= h_sol(n,h);
h_wongenlim(n,h)..
h_wongen(n,h) =l= h_won(n,h);
h_woffgenlim(n,h)..
h_woffgen(n,h) =l= h_woff(n,h);
h_PSP1start(n,hfirst)$(h_PSP1cap(n)>0)..
h_PSP1(n,hfirst) =e= PSP1levelstart(n)*h_PSP1cap(n)/100;
h_PSP1end(n,hlast)$(h_PSP1cap(n)>0)..
h_PSP1(n,hlast)+ 0.75*h_PSP1in(n,hlast) + h_ror2(n,hlast)
- h_PSP1out(n,hlast) =e= PSP1levelend(n)*h_PSP1cap(n)/100;
h_PSP2start(n,hfirst)$(h_PSP2cap(n)>0)..
h_PSP2(n,hfirst) =e= 50*h_PSP2cap(n)/100;
h_PSP2end(n,hlast)$(h_PSP2cap(n)>0)..
h_PSP2(n,hlast)+ 0.75*h_PSP2in(n,hlast)
- h_PSP2out(n,hlast) =e= 50*h_PSP2cap(n)/100;
PSP1minequation(n,h)$(h_PSP1cap(n)>0)..
h_PSP1(n,h) =g= 0.25*h_PSP1cap(n);
logic(n,cl,h)$(ord(h) GT 1 and h_cldata(n,cl,'c2')>0)..
su(n,cl,h) - sd(n,cl,h) =e= on(n,cl,h) - on(n,cl,h-1);
logic2(n,lg,h)$(ord(h) GT 1 and h_ligdata(n,lg,'c2')>0)..
```

Fig. A.6.: GAMS code for EUPowerDispatch’s weekly model - Part 6

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```
su2(n,lg,h) -  sd2(n,lg,h) =e= on2(n,lg,h) - on2(n,lg,h-1);

logic3(n,gs,h)$(ord(h) GT 1 and h_gasdata(n,gs,'c2')>0)..
su3(n,gs,h) - sd3(n,gs,h) =e= on3(n,gs,h) - on3(n,gs,h-1);

logicI(n,cl,hfirst)$(h_cldata(n,cl,'c2')>0)..
su(n,cl,hfirst) -  sd(n,cl,hfirst) =e= on(n,cl,hfirst) - onstart(n,cl);

logic2I(n,lg,hfirst)$(h_ligdata(n,lg,'c2')>0)..
su2(n,lg,hfirst) - sd2(n,lg,hfirst) =e= on2(n,lg,hfirst) - on2start(n,lg);

logic3I(n,gs,hfirst)$(h_gasdata(n,gs,'c2')>0)..
su3(n,gs,hfirst) - sd3(n,gs,hfirst) =e= on3(n,gs,hfirst) - on3start(n,gs);

rampup(n,cl,h)$(ord(h) GT 1 and h_cldata(n,cl,'c2')>0)..
h_coalgen(n,cl,h) - h_coalgen(n,cl,h-1) =l= h_cldata(n,cl,'c3');

rampup2(n,lg,h)$(ord(h) GT 1 and h_ligdata(n,lg,'c2')>0)..
h_liggen(n,lg,h) - h_liggen(n,lg,h-1) =l= h_ligdata(n,lg,'c3');

rampup3(n,gs,h)$(ord(h) GT 1 and h_gasdata(n,gs,'c2')>0)..
h_gasgen(n,gs,h) - h_gasgen(n,gs,h-1) =l= h_gasdata(n,gs,'c3');

rampupI(n,cl,hfirst)$(h_cldata(n,cl,'c2')>0)..
h_coalgen(n,cl,hfirst) - clstart(n,cl) =l= h_cldata(n,cl,'c3');

rampup2I(n,lg,hfirst)$(h_ligdata(n,lg,'c2')>0)..
h_liggen(n,lg,hfirst) - lgstart(n,lg) =l= h_ligdata(n,lg,'c3');

rampup3I(n,gs,hfirst)$(h_gasdata(n,gs,'c2')>0)..
h_gasgen(n,gs,hfirst) - gsstart(n,gs) =l= h_gasdata(n,gs,'c3');

rampdown(n,cl,h)$(ord(h) GT 1 and h_cldata(n,cl,'c2')>0)..
h_coalgen(n,cl,h-1) - h_coalgen(n,cl,h) =l= h_cldata(n,cl,'c4');

rampdown2(n,lg,h)$(ord(h) GT 1 and h_ligdata(n,lg,'c2')>0)..
h_liggen(n,lg,h-1) - h_liggen(n,lg,h) =l= h_ligdata(n,lg,'c4');

rampdown3(n,gs,h)$(ord(h) GT 1 and h_gasdata(n,gs,'c2')>0)..
h_gasgen(n,gs,h-1) - h_gasgen(n,gs,h) =l= h_gasdata(n,gs,'c4');

rampdownI(n,cl,hfirst)$(h_cldata(n,cl,'c2')>0)..
clstart(n,cl) - h_coalgen(n,cl,hfirst) =l= h_cldata(n,cl,'c4');

rampdown2I(n,lg,hfirst)$(h_ligdata(n,lg,'c2')>0)..
lgstart(n,lg) - h_liggen(n,lg,hfirst) =l= h_ligdata(n,lg,'c4');

rampdown3I(n,gs,hfirst)$(h_gasdata(n,gs,'c2')>0)..
gsstart(n,gs) - h_gasgen(n,gs,hfirst) =l= h_gasdata(n,gs,'c4');

h_costs_eq..
costs =e= SUM((n,h)$(h_nuccap(n)>0),h_ngen(n,h)*nucp)
+ SUM((n,lg,h)$(h_ligdata(n,lg,'c2')>0),h_liggen(n,lg,h)*h_ligdata(n,lg,'c5')»
)
+ SUM((n,cl,h)$(h_cldata(n,cl,'c2')>0),h_coalgen(n,cl,h)*h_coaldata(n,cl,'c5'»
))
+ SUM((n,gs,h)$(h_gasdata(n,gs,'c2')>0),h_gasgen(n,gs,h)*h_gasdata(n,gs,'c5')»
)
+ SUM((n,h)$(h_oilcap(n)>0),h_oilgen(n,h)*oilp)
+ SUM((n,h)$(h_mixedcap(n)>0),h_mixedgen(n,h)*mixedp)
+ SUM((n,h)$(solmaxcap(n)>0),h_solgen(n,h)*solp)
```

Fig. A.7.: GAMS code for EUPowerDispatch's weekly model - Part 7

```
+ SUM((n,h),h_wongen(n,h)*wonp)
+ SUM((n,h),h_woffgen(n,h)*woffp)
+ SUM((n,h)$(h_biocap(n)>0),h_biogen(n,h)*biop)
+ SUM((n,h)$(h_PSP1max(n)>0),h_PSP1out(n,h)*hydrop)
+ SUM((n,h)$(h_PUMP2max(n)>0),h_PSP2out(n,h)*hydrop)
+ SUM((n,h),h_ror1(n,h)*hydrop)
+ SUM((n,h),xgen(n,h)*expensivep)
+ SUM((n,h),xld(n,h)*expensivep)
+ SUM((n,cl,h)$(h_coaldata(n,cl,'c2')>0),su(n,cl,h)*h_coaldata(n,cl,'c6'))
+ SUM((n,lg,h)$(h_ligdata(n,lg,'c2')>0),su2(n,lg,h)*h_ligdata(n,lg,'c6'))
+ SUM((n,gs,h)$(h_gasdata(n,gs,'c2')>0),su3(n,gs,h)*h_gasdata(n,gs,'c6'))
+ SUM((x,h),h_lflow(x,h)*h_losses(x));

*Defition of the weekly model
MODEL EUROPE_WEEK
/all/;

*Setting the optimization parameters
option iterlim = 100000000;
option reslim = 10000000000000000000;
option OPTCR = 0.001;
option MIP = Cplex;
EUROPE_WEEK.OptFile = 1;

*Solving the model
solve EUROPE_WEEK using mip minimizing costs;

*Set the output to Matlab
execute_unload %matout%;

```

Fig. A.8.: GAMS code for EUPowerDispatch's weekly model - Part 8

B. Installed Generation Capacities

Appendix B provides the installed electricity generation capacities for each energy source for the each of the 32 countries included in EUPowerDispatch for 2010 and 2025. The electricity generation capacities for 2010 are based on the January 2011 values of the Best Estimate Scenario (scenario B) of ENTSO-E's SO&AF 2011 - 2025. For 2025, instead, they are based on the July 2025 values of the Best Estimate Scenario (scenario B) of ENTSO-E's SO&AF 2012 - 2030. Tables B.1, B.2 and B.3 refer to 2010. Instead, Tables B.4, B.5 and B.6 refer to 2025.

Tab. B.1.: Installed electricity generation capacities in 2010 (GW) - Part 1

	AT	BE	BA	BG	HR	CZ	DK	EE	FI	FR	DE
Nuclear	0	5.94	0	2	0	3.5	0	0	2.7	63.3	20.3
Lignite	0	0	1.51	3.53	0	7.2	0	0	0	0	21.2
Hard Coal	1.618	0.64	0	2.14	0.3	1.5	2.58	2.03	3.8	8	29.5
Gas	4.131	7.44	0	0.45	0.5	0.6	2.61	0.22	2.5	6.9	22.1
Oil	0.885	0.37	0	0	0.3	0	0.99	0	1.4	9.2	3.3
Mixed	1.35	0.23	0	0.44	0.8	0.1	1.92	0.09	0	0	0
Wind (on)	1.1	0.82	0	0.38	0.1	0.4	3.21	0.16	0.2	5.5	28.8
Wind (off)	0	0.2	0	0	0	0	0.74	0	0	5.5	0.2
Solar	0	0.59	0	0	0	2.2	0	0	0	1	18.1
Biomass	0.416	0.76	0	0	0	0.2	0.4	0	1.9	1.1	4.1
P_{seasto}	6.6	0	0.95	1.922	1.4	1.15	0	0	3.1	12.5	6.7
$PUMP_{seasto}$	2.9	0	0.4	0	0.3	0	0	0	0	0	6
$P_{pumpsto}$	0	1.3	0	0.938	0	1.15	0	0	0	6	0
R_{seasto} (GWh)	3100	0	1440	960	1440	512	0	0	5500	9550	40
$R_{pumpsto}$ (GWh)	0	5	0	20	0	28	0	0	0	450	0

Tab. B.2.: Installed electricity generation capacities in 2010 (GW) - Part 2

	GR	HU	IE	IT	LV	LT	LU	MK	ME	NO	PL
Nuclear	0	1.9	0	0	0	0	0	0	0	0	0
Lignite	4.46	0.85	0.35	0	0	0	0	0.7	0.21	0	8.08
Hard Coal	0	0.5	0.85	6.6	0	0	0	0	0	0	20.8
Gas	3.63	3.53	4.03	23	0.78	0.03	0.5	0.3	0	1.1	0.78
Oil	0.7	0.41	1.01	16.5	0	0.15	0	0.2	0	0.1	0
Mixed	0	0.86	0	24.9	0.06	2.41	0	0	0	0	0
Wind (on)	1	0.3	1.61	6	0.1	0.2	0.04	0	0	0.5	1.65
Wind (off)	0	0	0.04	0	0	0	0	0	0	0	0
Solar	0.12	0	0	1	0	0	0.03	0	0	0	0
Biomass	0.04	0.5	0.08	0	0.03	0.03	0.02	0	0	0	0.08
P_{seasto}	3.05	0	0	7.7	0	0.76	1.1	0.6	0.66	30.2	0.55
$PUMP_{seasto}$	0.571	0	0	0	0	0.76	1.1	0	0	1.3	0
$P_{pumpsto}$	0	0	0.29	9.2	0	0	0	0	0	0	1.4
R_{seasto} (GWh)	2400	0	0	7600	0	10.8	10	500	245	84300	405
$R_{pumpsto}$ (GWh)	0	0	1.43	300	0	0	0	0	0	0	5

Tab. B.3.: Installed electricity generation capacities in 2010 (GW) - Part 3

	PT	RO	RS	SK	SI	ES	SE	CH	NL	GB
Nuclear	0	1.3	0	1.81	0.7	7.5	9.6	3.2	0.5	10.42
Lignite	0	3.88	4.95	0.38	0.6	3.4	0	0	0	0
Hard Coal	1.76	1.35	0	0.4	0.22	7.6	0.3	0	4.1	28.17
Gas	3.44	0.76	0.31	1.28	0.08	30.4	0.9	0.1	17.4	33.21
Oil	1.11	0	0	0.19	0	1.5	4.2	0	0.2	3.44
Mixed	0	2.56	0	0.68	0.31	0	0.4	0	1.2	0
Wind (on)	4.25	0.38	0	0.05	0.03	19.8	1.6	0	2.1	2.92
Wind (off)	0	0	0	0	0	0	0.2	0	0.2	1.17
Solar	0.14	0	0	0.12	0	4.4	0	0	0.1	0
Biomass	0.1	0.01	0	0.13	0	0.8	2.8	0	0.7	0.1
P_{seasto}	2.51	3.69	0.39	0	0	13	16.4	11	0	0
$PUMP_{seasto}$	0.24	0	0	0	0	0	0.04	1.6	0	0
$P_{pumpsto}$	0	0	0.6	0.9	0.18	2.7	0	0	0	2.9
R_{seasto} (GWh)	2600	4300	1806	0	0	18430	33758	8775	0	0
$R_{pumpsto}$ (GWh)	0	0	194	6	2.43	70	0	0	0	27.6

Tab. B.4.: Installed electricity generation capacities in 2025 (GW) - Part 1

	AT	BE	BA	BG	HR	CZ	DK	EE	FI	FR	DE
Nuclear	0	1.05	0	4	0	6.7	0	1	7.5	65	0
Lignite	0	0	2.11	4	0	5.7	0	0	0	0	15.7
Hard Coal	0.81	0	0	2.14	1.2	0.7	1.82	0.97	0.7	3.9	25
Gas	4.46	10.07	0	1.7	1.7	2.6	2.48	0.53	2.4	8.3	40.1
Oil	0.28	0	0	0	0	0	0.73	0.04	1.2	10.2	1.6
Mixed	5.65	0.8	0	0	0.2	0.1	1.25	0.22	2	0	0
Wind (on)	3.1	2.54	0	3.4	1.4	0.8	4.22	0.4	1.8	19	52.6
Wind (off)	0	2.19	0	0	0	0	2.54	0.25	1	4	17.5
Solar	0	2.01	0	2.1	0.1	2.1	0	0	0	13	57.3
Biomass	2.3	2.45	0	0	0.2	0.5	0.45	0.03	3.3	2	8.7
P_{seasto}	3100	0	1440	960	1440	512	0	0	5500	9550	40
$PUMP_{seasto}$	0	5	0	20	0	28	0	0	0	450	0
$P_{pumpsto}$	9.58	0	0.95	2.29	1.65	1.15	0	0	3.1	12.5	9
R_{seasto} (GWh)	4.21	0	0.4	0	0.35	0	0	0	0	0	8.06
$R_{pumpsto}$ (GWh)	0	1.3	0	1.12	0	1.15	0	0	0	6	0

Tab. B.5.: Installed electricity generation capacities in 2025 (GW) - Part 2

	GR	HU	IE	IT	LV	LT	LU	MK	ME	NO	PL
Nuclear	0	3	0	0	0	1.36	0	0	0	0	3.04
Lignite	2.28	0.48	0	0	0	0	0	1.3	0.5	0	6.93
Hard Coal	0	0	0	7	0	0	0	0	0	0	20.15
Gas	7.57	5.9	4.96	29.1	1	0.99	0.58	0.6	0	1.1	2.92
Oil	0.8	0	0.21	19.8	0	0.2	0	0	0	0.1	0
Mixed	0	0	0	26	0.07	1.33	0	0	0	0	0
Wind (on)	7	0.9	4.5	21.2	0.5	0.8	0.11	0.2	0.18	2.2	7.56
Wind (off)	0	0	0.56	0	0.4	0	0	0	0	0	0
Solar	2.5	0.08	0	41.8	0.02	0.02	0.06	0	0	0	0
Biomass	0.3	0.76	0.26	3.6	0.3	0.23	0	0	0	0	0.75
P_{seasto}	2400	0	0	7600	0	10.8	10	500	245	84300	405
$PUMP_{seasto}$	0	0	1.43	300	0	0	0	0	0	0	5
$P_{pumpsto}$	4.73	0	0	7.8386	0	1.15976	1.2969	1.2	0.81444	31	0.55
R_{seasto} (GWh)	0.88	0	0	0	0	1.15976	1.2969	0	0	1.33	0
$R_{pumpsto}$ (GWh)	0	0	0.36	9.3656	0	0	0	0	0	0	1.4

Tab. B.6.: Installed electricity generation capacities in 2025 (GW) - Part 3

	PT	RO	RS	SK	SI	ES	SE	CH	NL	GB
Nuclear	0	2.63	0	2.4	1.8	7	10.4	2.1	2	12.23
Lignite	0	3.66	7.21	0.2	0.85	1.3	0	0	0	0
Hard Coal	0	1.98	0	0.2	0.35	4.7	0	0	7.5	10.29
Gas	4.56	2.48	0.69	1.07	0.69	42.8	0.9	1.3	24.2	39.19
Oil	0	0	0	0.19	0	0	2.8	0	0.2	0
Mixed	0	1.69	0	1.57	0.23	0.3	0.5	0	1.2	0
Wind (on)	6.25	5	0	0.2	0.34	37.8	8	0	5	9.62
Wind (off)	0.09	0	0	0	0	1.8	0.2	0	4	26.91
Solar	1.16	0.3	0	0.6	0	13.8	0	0	0.1	0
Biomass	0.25	0.2	0	0.28	0	2.5	4	0	0.9	2.04
P_{seasto}	2600	4300	1806	0	0	18430	33758	8775	0	0
$PUMP_{seasto}$	0	0	194	6	2.43	70	0	0	0	27.6
$P_{pumpsto}$	5.03	4.87	0.76	0	0	17.39	16.4	15.3	0	0
R_{seasto} (GWh)	0.48	0	0	0	0	0	0.04	2.23	0	0
$R_{pumpsto}$ (GWh)	0	0	1.16	0.9	0.58	3.61	0	0	0	2.9

C. Cross-Border Transmission Capacities

Appendix C provides the cross-border electricity transmission capacities assumed in EUPowerDispatch for 2010 and 2025. The cross-border electricity transmission capacity data are based on ENTSO-E's publicly available Net Transfer Capacity (NTC) values for each interconnector in Europe for 2010 (ENTSO-E, 2011d). For future time horizons, up to 2025, an approach developed by RSE (L'Abbate, 2011) and used within two European research projects (REALISEGRID, 2011; SUSPLAN, 2011) was followed. Tables C.1 and C.2 show the cross-border transmission capacities assumed for 2010 and 2025 in both directions between the interconnected countries.

Tab. C.1.: Cross-border transmission capacities assumed for 2010 and 2025 (MW) - Part 1

		2010		**2025**	
From	**To**	**pos**	**neg**	**pos**	**neg**
PT	ES	1300	1500	3000	3000
ES	FR	500	1400	4000	4000
FR	IT	2650	995	4200	2595
FR	CH	3200	2300	3200	2300
FR	DE	2900	3050	3000	3150
FR	BE	3400	2300	3700	2800
FR	GB	2000	2000	3000	3000
GB	IE	450	80	1850	1850
BE	NL	2400	2400	2400	2400
DE	LU	980	0	980	0
DE	NL	3850	3000	5350	4500
NL	NO	700	700	1700	1700
DE	DK	1500	2050	2650	3150
DK	NO	950	950	1600	1600
DK	SE	2440	1980	2440	1980
DE	SE	600	600	600	600
NO	SE	2950	3050	5450	5250
SE	FI	2050	1650	2800	2700
SE	PL	600	600	600	600
FI	EE	350	350	1000	1000
EE	LV	750	850	1300	1400
LV	LT	1300	1500	1900	2100
DE	PL	1200	1100	3100	3000
DE	CZ	800	2300	2300	3800
CZ	PL	800	2000	800	2000
DE	AT	2200	2000	6880	6880
CZ	AT	2180	1200	2000	1100
CZ	SK	2000	1000	2000	1000
PL	SK	600	500	1500	1400
AT	HU	700	800	1500	1200
SK	HU	1500	600	3000	2100
IT	CH	1810	4640	3710	6540
CH	AT	1200	1200	1400	1400
IT	AT	285	220	2200	2200
IT	SI	650	650	2150	2150
AT	SI	900	900	1200	1200
SI	HR	1000	1000	1900	1900
HR	HU	1500	1000	3000	2500
HR	RS	430	420	680	600
HU	RO	600	1400	600	1400
RO	BG	950	950	950	950

Tab. C.2.: Cross-border transmission capacities assumed for 2010 and 2025 (MW) - Part 2

		2010		**2025**	
From	**To**	**pos**	**neg**	**pos**	**neg**
BG	GR	600	500	1500	1400
IT	GR	500	500	1000	1000
BG	MK	450	250	450	250
MK	RS	600	350	1100	600
BG	RS	650	500	650	500
RS	RO	700	650	500	850
RS	BA	400	480	650	750
HR	BA	630	700	1530	1600
BA	ME	500	480	1250	1250
ME	RS	450	400	700	650
CH	DE	3200	1500	3200	1500
MK	GR	350	300	350	300
HU	RS	600	600	600	600
NL	GB	0	0	1320	1320
SE	LT	0	0	1000	1000
PL	LT	0	0	1000	1000
SI	HU	0	0	900	900
IT	ME	0	0	1000	1000
GB	NO	0	0	1400	1400
NL	DK	0	0	600	600
DE	NO	0	0	2400	2400
IT	HR	0	0	1000	1000
IE	FR	0	0	1000	1000
GB	BE	0	0	1000	1000
DE	BE	0	0	1000	1000
AT	SK	0	0	1500	1500
BE	LU	300	300	600	600
NO	FI	100	100	1000	1000
FR	LU	0	0	300	300
SE	LV	0	0	700	700

Glossary

Acronyms

ACER	Agency for the Cooperation of Energy Regulators
BALTSO	Baltic Transmission System Operators
CO_2	Carbon dioxide
DEM	Digital Elevation Model
ECDF	Empirical Cumulative Distribution Function
EC	European Commission
ENS	Energy Not Supplied
ENTSO-E	European Network of Transmission System Operators for Electricity
EU	European Union
EV	electric vehicle
EWEA	European Wind Energy Association
FACTS	Flexible AC Transmission System
GAMS	General Algebraic Modelling System
GISCO	Geographical Information System at the European Commission
GW	gigawatt
IPCC	Intergovernmental Panel on Climate Change
KS	Kolmogorov-Smirnov
MCFP	Minimum Cost Flow Problem
MENA	Middle East and North Africa
MSP	Mediterranean Solar Plan
MW	megawatt
NGC	Net Generating Capacity
NTC	Net Transfer Capacity
NUTS	Nomenclature of Units for Territorial Statistics

PTDF	Power Transfer Distribution Factors
PV	photovoltaic
RAC	Reliable Available Capacity
RES	Renewable Energy Sources
RT	Restoration Time
SO&AF	Scenario Outlook & Adequacy Forecast
TLP	Total Loss of Power
TYNDP	Ten-Year Network Development Plan
UCTE	Union for the Coordination of the Transmission of Electricity

Mathematical Notations

C_{ev}	EV charging power	[MW]
$CMAX_{ev}$	maximum EV charging power	[MW]
$CMIN_{ev}$	minimum EV charging power	[MW]
D	electricity demand	$[MW]$
DR_{ev}	EV battery discharge due to driving	[MW]
EXP	electricity exports	$[MW]$
F	cross-border electricity transmission flow	$[MW]$
IMP	electricity imports	$[MW]$
INF	natural inflow into hydro reservoir	$[MWh]$
L	hydro reservoir level	$[MWh]$
$LMAX$	maximum hydro reservoir level	$[MWh]$
$LMIN$	minimum hydro reservoir level	$[MWh]$
P	power generation	$[MW]$
$PMAX$	maximum power generation	$[MW]$
$PMIN$	minimum power generation	$[MW]$
$PUMP$	hydro pumping	$[MW]$
$PUMPMAX$	maximum hydro pumping capacity	$[MW]$
$PUMPMIN$	minimum hydro pumping capacity	$[MW]$
ROR	run of river flow	$[MWh]$
SDC	shut-down generator cost	[€]
SOC_{ev}	EV battery state-of-charge	[MWh]

$SOCMAX_{ev}$	maximum EV battery state-of-charge	[MWh]
$SOCMIN_{ev}$	minimum EV battery state-of-charge	[MWh]
SUC	start-up generator cost	[€]
TC	cross-border electricity transmission cost	[€$/MWh$]
VC	variable electricity generation cost	[€$/MWh$]
on	on/off binary variable	$[-]$
sd	shut-down binary variable	$[-]$
su	start-up binary variable	$[-]$

Subscripts

bio	biomass power plant	$[-]$
$coal$	coal power plant	$[-]$
ev	electric vehicle type	$[-]$
g	generator	$[-]$
gas	gas power plant	$[-]$
h	hydro generator	$[-]$
i	interconnector	$[-]$
lig	lignite power plant	$[-]$
$mixed$	mixed (oil & gas) power plant	$[-]$
n	node	$[-]$
nuc	nuclear power plant	$[-]$
oil	oil power plant	$[-]$
$pumpsto$	pure pumping hydro storage	$[-]$
ror	run of river	$[-]$
$seasto$	hydro seasonal storage	$[-]$
sol	solar (photovoltaic) generator	$[-]$
t	time	$[h]$
$woff$	offshore wind generator	$[-]$
won	onshore wind generator	$[-]$

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Summary

Background

In the coming decades, several trends driven by different policy goals may lead to an increase in cross-border electricity flows in Europe. First of all, the penetration of variable renewable energy sources (RES) is expected to increase substantially. The European Council (EUCO, 2011) reconfirmed in February 2011 the European Union (EU) objective of reducing greenhouse gas emissions by 80-95% by 2050 compared to 1990, in the context of necessary reductions according to the Intergovernmental Panel on Climate Change (IPCC) by developed countries as a group. This challenge is supported by Europe's most ambitious energy policy goal: the decarbonisation of the European power sector by 2050 (EC, 2011a). The European Commission's Energy Roadmap 2050 (EC, 2011b) expects RES share to reach at least 55% in gross final energy consumption in 2050 in all its scenarios. The primary challenge arising from the expected large penetration of RES is how to cope with the variability and unpredictability of wind speed and solar radiation. In order to integrate these renewable energy sources in the European electricity system, investments in transmission expansion, energy storage and demand response are foreseen which will impact cross-border electricity flows.

A related trend that will impact cross-border electricity flows is the potential RES development in the Middle East and North Africa (MENA) region and the electrical integration of the Euro-Mediterranean region. Other trends that will impact electricity flows across borders are the electrification of transport and the charging strategies of electric vehicles (EVs) as well as the possible shifts in electricity generation dispatch due to the evolution of CO_2 prices.

Research question

Given the long-term renewable energy panorama and the expected trends in the European electricity system, the aim of this thesis is to analyse the need for cross-border electricity transmission investment in Europe with respect to two of the three

pillars of EU energy policy: sustainability and security of supply. The third pillar, competitiveness, is outside the scope of this research.

The impacts of possible changes in generation and demand patterns on the adequacy of cross-border transmission capacity are investigated mainly by analysing the simulation results of a mathematical model, EUPowerDispatch. Its objective is to analyse the impact of cross-border electricity transmission investment on the European power system. The development of EUPowerDispatch and its applications constitute the main results of the research presented in the thesis.

Methodology

EUPowerDispatch is a minimum-cost unit-commitment dispatch model of the European electricity transmission network. It is an optimisation model that minimises electricity dispatch costs in 32 interconnected European countries. The model is solved in the General Algebraic Modelling System (GAMS) as a mixed-integer linear problem using the CPLEX solver. Offline input/output data processing is performed using Matlab.

EUPowerDispatch is designed to study a power system with high RES penetration. Due to the variable nature of RES, a high time resolution is of paramount importance for analysing their impacts on network planning and operation. Therefore, EUPowerDispatch's time step is set to one hour. In addition, the model simulates the European transmission network for an entire year in order to account for RES variability in terms of seasonality and possible long periods (weeks/fortnights) of low or high wind. EUPowerDispatch uses actual weather data in terms of wind speed, solar radiation and precipitation for the same entire year. This feature allows the model to account for potential correlations that may affect the management and operation of the European electricity transmission network.

The distinctive feature of EUPowerDispatch compared with other models is the annual management of energy storage. The energy storage elements represented in the model are hydro reservoirs, which, depending on the country, may have natural inflows and/or pumping capacity. The detailed modelling of hydro energy sources in the model provides support for the annual management of hydro reservoirs, which is valuable for balancing purposes as well as for reducing overall annual electricity dispatch costs in managing a transmission network with very high RES penetration.

Countries are each represented as a single node, meaning that internal network constraints are not included in the model. The reasons are computational capacity limits

and the unavailability of detailed data on the distribution of electricity consumption and generation throughout the countries considered in the model. Instead, EUPowerDispatch focuses on cross-border connections, for which the EU has specific policy objectives. The number of cross-border interconnectors varies depending on the time horizon of the scenario under consideration. Because power flows are determined by the specific volume of demand and dispatch of generation at each moment, the dispatch of generation in each country is modelled for every hour of a given year under perfect competition conditions. Demand is modelled as perfectly price-inelastic. Due to computational capacity limits, the model is unable to run a whole year with a one-hour time step. Therefore, a preliminary yearly run with weekly time steps is used to set the hydro seasonal reservoir levels at the start and end of each week in each node. Within each week, generation dispatch is optimised assuming full knowledge about generator cost and availability, including variable RES.

The inputs of EUPowerDispatch are net generation capacities for each energy source at each node, variable electricity generation costs for each energy source, load time series at each node, cross-border transmission limits and costs, and weather data at each node. The latter includes time series of wind speed, solar radiation, run-of-river flow, and inflow to hydro reservoirs. The main outputs of EUPowerDispatch are generation by each energy source in the generation portfolio at each node, electricity dispatch costs, cross-border electricity flows, CO_2 emissions, variable RES (wind and solar) curtailment needs, and unserved load. These variables are calculated for every hour of the year.

The generation and consumption scenarios used in the different analyses presented in the thesis and used as inputs in EUPowerDispatch are based on data published by the European Network of Transmission System Operators for Electricity (ENTSO-E). Future electricity generation capacities are based on the 2025 Best Estimate Scenario of ENTSO-E's Scenario Outlook and Adequacy Forecast (SO&AF) 2012-2030. Demand time series at national level are based on 2010 electricity consumption time series published by ENTSO-E for each country. Cross-border electricity transmission capacities are based on the present Net Transfer Capacities (NTCs) published by ENTSO-E and the expected evolution of the European interconnection capacities by 2025 based on ENTSO-E's Ten Year Network Development Plan (TYNDP) and other sources.

EUPowerDispatch was validated by comparing its results with ENTSO-E's statistics over 2010. A comparison of the European generation mix between the model results and the actual statistics shows that EUPowerDispatch behaves according to reality, with minor differences attributable to various modelling assumptions, the

model's objective function (which is to minimise overall European variable electricity production costs instead of each country having its own objective) and the model's physical resolution, which considers cross-border flows while neglecting national electricity grids. In addition, the model corresponds to the actual average bilateral flows of net electricity exchanges between countries throughout the year. However, the model results show larger net exchanges due to the optimisation process and the lack of internal congestion constraints.

EUPowerDispatch is used in four studies in which the need for cross-border electricity transmission investment in Europe is investigated from different perspectives and considering different generation and consumption scenarios.

Future European cross-border transmission capacity needs

The first study discusses the evolution of the European electricity transmission network between 2010 and 2025 and it assesses the impacts of the expected investments in cross-border transmission capacity in Europe by 2025 on dispatch costs, on RES curtailment needs, on CO_2 emissions, on hydro pumping utilisation and on unserved load. In addition, a sensitivity analysis is performed by assessing the latter's impact on different levels of electricity consumption, RES penetration and CO_2 price.

The results show that cross-border transmission capacity will not be a significant constraint for the integration of variable renewable energy sources between 2010 and 2025 at the RES levels expected by ENTSO-E. However, at higher volumes of RES, more interconnection capacity would be needed if curtailment were to be avoided. Network stability issues and national distribution and transmission network congestion are more likely constraints for the integration of variable RES, although this is not explicitly considered in the model. In addition, the reduction in dispatch costs provided by the expected investment in cross-border transmission is higher for lower demand growth rates and for scenarios with higher shares of variable RES because the number of hours in which costly natural gas generators are marginal is reduced as a result of lower demand. The expected expansion of cross-border transmission capacity by 2025 has a limited impact on security of supply in the face of the expected low growth rate of electricity consumption in Europe (0.9%). However, if demand grows at the historical rate of 2%, the expected development of cross-border transmission will be needed to maintain the current level of security of supply in 2025, assuming that generation capacity will develop according to ENTSO-E's scenario.

Given the expectations concerning the future generation portfolio, the growth in electricity demand and a CO_2 price of 22.5 €/tonne, and assuming that planned cross-border transmission investments are realised, then total CO_2 emissions from electricity generation in Europe will decrease by only 17% between 2010 and 2025. There is a 28% reduction in the carbon-intensity of electricity generation, but this improvement is partly offset by the growth of electricity consumption. More low-carbon generation and lower electricity demand growth will be needed to meet EU climate policy goals. A CO_2 price of 50 €/tonne would make the marginal generation cost of gas plants lower than coal and lignite, causing a 38% reduction in CO_2 emissions compared to the scenario with a price of 22.5 €/tonne. Instead, if twice the expected volume of variable RES were developed by 2025, CO_2 emissions would drop by 33% in the 22.5 €/tonne scenario. This means that, ceteris paribus, a carbon tax favouring gas over coal does more to reduce emissions than a doubling of RES without a high carbon price.

Cross-border transmission vs. energy storage & demand response

The next two studies independently analyse the extent to which investments in energy storage and demand response can either substitute or complement the need for cross-border transmission investment in Europe. Complementarity is defined as the reciprocal relation whereby an increase in one variable increases the demand for another. Substitution, on the other hand, refers to the capacity of one variable to replace demand for the other. The impacts of investments in hydro pumping capacity and in controlled electric vehicle (EV) charging are compared with the impacts of cross-border transmission investment on dispatch costs, on RES curtailment needs, on CO_2 emissions, on unserved load, and on one another for high RES scenarios.

Cross-border transmission capacity as well as hydro pumping capacity and controlled EV charging reduce dispatch costs, RES curtailment needs, unserved load and CO_2 emissions (for a CO_2 price of 50 €/tonne). The demand for hydro pumping decreases with higher cross-border transmission capacity. On the other hand, paradoxically, cross-border transmission flows increase slightly with higher hydro pumping capacity. The results from the second study show how cross-border transmission and pumped hydro storage substitute one another yet under certain conditions they can also be considered as complementary technologies.

The extent to which cross-border transmission and controlled EV charging substitute one another depends on the need for arbitrage (i.e. the flexibility of generation

dispatch) in the European electricity supply system. The demand for arbitrage is high when RES penetration is higher, but lower when CO_2 prices are high because the costs of coal and gas fired generation become similar. The results from the third study show how EV charging control and cross-border transmission are partly substitutes and partly complements. When the demand for arbitrage is low, controlled EV charging can substitute for a certain volume of cross-border transmission capacity. The higher the need for arbitrage, the more the two complement one another with respect to reducing dispatch costs. In other words, when demand for arbitrage becomes higher, both are needed because the potential of controlling EVs and storage in one country is insufficient for absorbing fluctuations in RES. Cross-border transmission capacity is then needed to provide access to storage and/or controlled EVs in another country.

Electricity imports from North Africa

In the fourth study, EUPowerDispatch investigates the effects of North-African imports on the European power system. The analysis was performed in combination with a detailed analysis of the impacts on the Italian transmission grid. Within a common set of assumptions, the two interrelated studies analysed the North-African import impact in terms of marginal prices in the European countries and the Italian market zones as well as cross-border electricity flows for the different scenarios. In both studies, the outcomes are affected by grid constraints.

The results show a general decrease of the electricity prices in Europe due to North-African electricity imports. The European study highlights that net electricity exchanges tend to follow the direction from South to North. Moreover, Italy's potential of becoming a Mediterranean electricity hub is emphasised. The Italian study shows that the North-African import effects are relevant, leading to internal grid congestion and price reductions in Sicily and Sardinia. The transmission limits between the two islands and the Italian peninsula as well as on the interfaces between the South and Centre-South zones play a major role.

European transmission network reliability

In addition to the four studies performed with EUPowerDispatch, the impact of electricity transmission on network reliability is discussed. Two additional studies independently analyse the impacts of network topology and of cross-border transmission

capacity on network reliability. In the two studies, network reliability is assessed using monthly statistics of major fault events on electricity transmission networks. The first study analyses the impact of national (internal) network interconnectivity on the occurrence of major fault events and on three reliability indicators: Energy Not Supplied (ENS), Total Loss of Power (TLP) and Restoration Time (RT). The second study, by contrast, analyses the impact of remaining margin and import capacity on the occurrence of major fault events.

The results from the first study show that more (internally) interconnected European power grids have experienced four times as many fault events as the less interconnected ones. On the other hand, they show significantly better values for all of the three reliability indicators for the largest portion of their cumulative distribution functions. This means that the majority of fault events in more interconnected networks have a smaller impact on reliability than fault events in less interconnected networks. These results confirm the conventional wisdom that more highly interconnected networks tend to be more reliable. It is, however, interesting to note that the higher reliability is not a consequence of fewer faults, but of the smaller consequences of most faults. Results from the second study show how increasing the sum between remaining margin and import capacity corresponds to fewer fault events in the network. However, fewer fault events is not necessarily a sign of better network reliability.

Conclusions

The research presented in this thesis shows how cross-border electricity transmission investment will have a positive impact on the following two EU energy policy objectives: economic efficiency and security of supply. In terms of economic efficiency, the results presented in the thesis show how the cross-border transmission capacity expansion by 2025 expected by ENTSO-E will reduce dispatch costs by 1%. In addition, at the RES levels expected by ENTSO-E, cross-border transmission capacity will not be a significant constraint for RES integration between 2010 and 2025. However, if the share of wind and solar energy sources doubles the forecasts and equals about 35% of the European energy mix, the expected investment in cross-border transmission will reduce dispatch costs by almost 6.7% and will reduce wind curtailment from 7.7% to 4.5%. Cross-border transmission investment will also have a positive impact on competitiveness within the electricity market. However, the latter is not directly discussed in this thesis.

With respect to security of supply, the results show how cross-border transmission investment reduces unserved load. Moreover, statistics of 18 European countries since 2002 show that as the normalised sum between remaining margin and import capacity increases, the frequency of major fault events in the European network between 2002 and 2011 decreases considerably.

In order to reach the challenging decarbonisation goal by 2050, Europe's power system will have to face several infrastructural changes. Substantial investments will have to be made on time in order to accommodate a high penetration of variable RES. A single technological solution will not be enough in order to cope with the expected needs for arbitrage. The complementarity and substitution potential of energy storage and demand response with respect to electricity transmission need to be better understood in order to ensure efficient investments. However, the optimal mix between these three options depends on their relative costs and on the future evolution of the European power system. This evolution will be shaped by the fundamental forces of supply and demand, which are crucially dependent not only on RES and carbon policies but also on the socio-economic development of Europe.

Cross-border electricity transmission investment will have a positive impact on the EU policy goal of environmental sustainability and towards the goal of decarbonising the European power sector when one or both of the following two conditions apply. The first condition is that there is a large share of renewable energy sources in the generation mix. In this case, cross-border transmission capacity expansion would reduce wind and solar energy curtailment and therefore further reduce CO_2 emissions. The second condition is that the CO_2 price is high enough so that carbon-intensive generation technologies come late in the merit order. In this case, cross-border transmission investment will reduce CO_2 emissions by facilitating the dispatch of cheaper generators which, because of the high CO_2 price, are also less carbon-intensive. However, if European carbon policy will not lead to such a high CO_2 price, investments in cross-border transmission, as well as in energy storage and demand response, will lead to higher CO_2 emissions. In other words, if carbon policy is not effective, the economic objective of reducing electricity generation dispatch costs will make it more difficult to reach Europe's climate policy goals.

Samenvatting

Achtergrond

In de komende tientallen jaren kunnen diverse ontwikkelingen die het resultaat zijn van verschillende beleidsdoelen leiden tot een toename in grensoverschrijdende elektriciteitstransport in Europa. Allereerst wordt verwacht dat het aandeel duurzame energiebronnen sterk toe zal nemen. De Europese Raad (EUCO, 2011) heeft, in de context van de voor alle ontwikkelde landen gezamenlijk noodzakelijke reductie volgens het Intergovernmental Panel on Climate Change (IPCC), in februari 2011 de EU doelstelling van 85-90% broeikasgasreductie in 2050 t.o.v. 1990 herbevestigd. Deze uitdaging wordt gesteund door Europa's meest ambitieuze doelstelling van het energiebeleid: het volledig koolstofvrij maken van de Europese elektriciteitssector (EC, 2011a). De energie-routekaart voor 2050 van de Europese Commissie (EC, 2011b) verwacht in alle scenario's dat het aandeel duurzame energie in 2050 ten minste 55% van het primaire energieverbruik zal bedragen. De voornaamste uitdaging die voortkomt uit de verwachte toename van duurzame energie is om te kunnen omgaan met de variabiliteit en onvoorspelbaarheid van wind en zon. Om deze duurzame bronnen in het Europese elektriciteitssysteem te integreren worden investeringen in de uitbreiding van transmissiecapaciteit, energie-opslag en vraagrespons (demand response) verwacht, die het grensoverschrijdende transport van elektriciteit zullen beïnvloeden.

Een gerelateerde trend die het grensoverschrijdende transport van elektriciteit zal beïnvloeden is de mogelijke ontwikkeling van duurzame energie in het Midden-Oosten en Noord-Afrika en de elektrische integratie van de Europees-Mediterrane regio. Andere trends die het transport van elektriciteit over grenzen beïnvloeden zijn zowel de elektrificatie van transport en het laadgedrag van elektrische auto's als de mogelijke verschuivingen in de inzet van elektriciteitscentrales door ontwikkelingen van CO_2 prijzen.

Onderzoeksvraag

Het doel van deze dissertatie is, gegeven het lange termijn energiepanorama en de verwachte veranderingen in het Europese elektriciteitssysteem, de behoefte aan investeringen in grensoverschrijdende transmissie te analyseren ten aanzien van twee van de drie pijlers van het EU energiebeleid: duurzaamheid en leveringszekerheid. De derde pijler, competitiviteit, valt buiten het kader van dit onderzoek.

De invloed van mogelijke veranderingen in aanbod- en vraagpatronen op de toereikendheid van grensoverschrijdende transmissiecapaciteit worden voornamelijk onderzocht door het analyseren van de simulatieresultaten van een wiskundig model, EUPowerDispatch. Het doel is de invloed van investeringen in grensoverschrijdende transmissiecapaciteit op het Europese elektriciteitssysteem te analyseren. De ontwikkeling en het toepassen van EUPowerDispatch vormen de belangrijkste resultaten die in deze thesis gepresenteerd worden.

Methodologie

EUPowerDispatch is een model van het Europese elektriciteitsnetwerk waarbij kosten van het gebruik van elektriciteitscentrales wordt geminimaliseerd. Het is een optimalisatiemodel dat de marginale productiekosten van elektriciteit in 32 onderling verbonden Europese landen minimaliseert. Het model wordt opgelost in het General Algebraic Modelling System (GAMS) als een mixed-integer lineair probleem gebruikmakend van de CPLEX oplos-module. Het offline verwerken van invoer en uitvoerdata gebeurt met behulp van Matlab.

EUPowerDispatch is ontworpen om een elektriciteitssysteem met een hoog aandeel duurzame energie te bestuderen. Vanwege de variabele aard van duurzame bronnen is een hoge tijdsresolutie van cruciaal belang om de effecten van duurzame energie op de planning en bedrijfsvoering van elektriciteitssystemen te analyseren. Daarom is voor de tijdstap van EUPowerDispatch een waarde van een uur gekozen. Bovendien simuleert het model het Europese transmissienetwerk voor een periode van een geheel jaar zodat de variabiliteit van de duurzame energie op verschillende tijdsschalen zoals seizoenen of lange periodes zonder wind in beschouwing genomen kan worden. EUPowerDispatch gebruikt meteorologische gegevens van windsnelheid, zonnestraling en neerslag voor hetzelfde gehele jaar. Dit kenmerk zorgt ervoor dat het model mogelijke correlaties die het management en de bedrijfsvoering van het Europese transmissienetwerk beïnvloeden in beschouwing kan nemen.

Het onderscheidende kenmerk van EUPowerDispatch vergeleken met andere modellen is het jaarlijkse management van energie-opslag. De elementen van energieopslag die door het model gerepresenteerd worden zijn waterkrachtreservoirs (stuwmeren) die, per land verschillend, natuurlijk instroom en/of pompcapaciteit hebben. Het gedetailleerd modelleren van waterkracht in het model ondersteunt ook het management van stuwmeren, wat waardevol is voor balanceringsdoeleinden alsmede voor het reduceren van de kosten van elektriciteitsproductie in een systeem met een hoge penetratie duurzame energie.

Landen worden gerepresenteerd door een enkele node in het netwerk, wat betekent dat alle interne netwerkbeperkingen niet gemodelleerd worden. De redenen hiervoor zijn computationele limieten en het gebrek aan beschikbaarheid van gedetailleerde gegevens over de verdeling van elektriciteitsvraag en aanbod in de gemodelleerde landen. In plaats daarvan focust EUPowerDispatch op grensoverschrijdende connecties waarvoor de EU specifieke beleidsdoelen kent. Het aantal grensoverschrijdende interconnectoren verschilt afhankelijk van de tijdshorizon van de beschouwde scenario's. Omdat vermogensstromen worden bepaald door de grootte van de vraag en de inzet van centrales op ieder specifiek moment, is de inzet van elektriciteitsproductie in ieder land voor ieder uur van het jaar gemodelleerd onder condities van perfecte competitie. Elektriciteitsvraag is als volkomen inelastisch gemodelleerd. Vanwege computationele limieten kan het model niet een heel jaar in één keer doorrekenen met een tijdstap van een uur. Daarom wordt er een voorbereidende run gedaan met een tijdstap van een week om de optimale standen aan het begin en eind van de week van de waterreservoirs in elk land te bepalen. Binnen een week wordt de elektriciteitsproductie geoptimaliseerd waarbij volledige kennis over kosten en beschikbaarheid van iedere centrale, inclusief de duurzame bronnen, wordt aangenomen.

De invoervariabelen van EUPowerDispatch zijn de netto productiecapaciteiten per energiebron voor elke node, variabele kosten voor elektriciteitsproductie voor iedere type productie, de tijdseries van elektriciteitsvraag per node, grensoverschrijdende transmissielimieten en weergegevens voor iedere node. De laatste bestaan uit windsnelheid, zonnestraling, stroming in rivieren en instroom in de waterreservoirs. De belangrijkste uitvoer van EUPowerDispatch zijn de elektriciteitsproductie per bron in de productieportfolio in iedere node, de productiekosten, grensoverschrijdende elektriciteitstransporten, CO_2-emissies, de verspilde duurzame energie (curtailment) en de hoeveelheid niet-geleverde energie (unserved load). Deze variabelen worden voor ieder uur per jaar uitgerekend.

De aanbod- en vraagscenario's die in de diverse analyses in dit proefschrift worden gepresenteerd en die de invoer zijn van EUPowerDispatch zijn gebaseerd op gegevens

die door de European Network of Transmission System Operators for Electricity (ENTSO-E) gepubliceerd zijn. De toekomstige productiecapaciteit is gebaseerd op het 2025 Best Estimate Scenario van ENTSO-E's Scenario Outlook and Adequacy Forcast (SO&AF) 2012-2030. De vraagprofielen op nationaal niveau zijn gebaseerd op de door ENTSO-E gepubliceerde consumptie-tijdreeksen van ieder land. Grensoverschrijdende transmissiecapaciteit is gebaseerd op de huidige Net Transfer Capacities (NTCs) gepubliceerd door ENTSO-E en de verwachte ontwikkeling van de Europese interconnectiecapaciteit in 2025 is gebaseerd op ENTSO-E's Ten Year Development Plan (TYNDP) en andere bronnen.

EUPowerDispatch is gevalideerd door de resultaten te vergelijken met ENTSO-E statistieken van 2010. Een vergelijking van de Europese productieverhouding (van diverse bronnen) tussen de modelresultaten en de eigenlijke statistieken laat zien dat EUPowerDispatch zich volgens de realiteit gedraagt, met kleine verschillen die toe te schrijven zijn aan diverse aannames, de doelfunctie van het model (het minimaliseren van de totale Europese productiekosten i.p.v. aparte doelfuncties per land) en de fysieke resolutie van het model die de interne netwerken in landen negeert. Bovendien komt het model overeen met de gemiddelde jaarlijkse bilaterale vermogenstransporten tussen de landen onderling. Wel laat het model grotere uitwisselingen zien vanwege het optimalisatieproces en het gebrek aan interne netwerkbeperkingen.

EUPowerDispatch wordt gebruikt in vier studies waarin de noodzaak voor investeringen in grensoverschrijdende transmissie in Europa vanuit verschillende perspectieven en met verschillende vraag- en aanbodscenario's wordt onderzocht.

Toekomstige behoefte aan Europese grensoverschrijdende transmissiecapaciteit

De eerste studie behandelt de ontwikkeling van het Europese transmissienetwerk tussen 2010 en 2025 en ze analyseert de impact van de verwachte netwerkinvesteringen op productiekosten, het verspillen van duurzame energie, CO_2-emissies, het gebruik van waterkracht en de hoeveelheid niet-geleverde energie. Ook wordt er een gevoeligheidsanalyse uitgevoerd door de invloed van verschillende niveaus van elektriciteitsvraag, duurzame energie en CO_2-prijs op de hoeveelheid ongedekte elektriciteitsvraag te behandelen.

Uit de resultaten blijkt dat grensoverschrijdende transmissiecapaciteit geen significante beperking zal zijn voor de integratie van duurzame energiebronnen tussen 2010 en 2025 volgens de ENTSO-E scenario's. Voor een nog hogere penetratie duurzame

energie is echter wel meer interconnectiecapaciteit nodig om het verspillen van duurzame energie te vermijden. Het is waarschijnlijker dat issues rond netwerkstabiliteit en de nationale distributie- en transmissienetwerken de integratie van duurzame energiebronnen beperken, hoewel deze niet expliciet worden gemodelleerd. Hiernaast is de reductie in productiekosten door de verwachte investeringen in transmissiecapaciteit groter bij een lagere groei van de elektriciteitsvraag en voor scenario's met een hoger aandeel duurzame energie omdat het aantal uren dat dure gascentrales de marginale centrales zijn beperkt is door de lagere vraag. De verwachte uitbreiding van transmissiecapaciteit in 2025 heeft slechts een geringe invloed op de leveringszekerheid vanwege de lage groei in de elektriciteitsvraag van Europa (0.9%). Als de vraag echter groeit met de historische waarde van 2% is de verwachte ontwikkeling van transmissiecapaciteit wel nodig om het huidige niveau van leveringszekerheid te behouden in 2025, mits de ontwikkeling in het productiepark zich volgens de ENTSO-E scenario's voltrekt.

Gegeven de verwachtingen van het toekomstig productiepark, de groei in elektriciteitsvraag en een CO_2-prijs van 22.5 €/ton, en aannemend dat de geplande interconnectie-investeringen worden gerealiseerd, zal de CO_2-emissie t.g.v. elektriciteitsproductie in Europa met slechts 17% afnemen tussen 2010 en 2025. Er is weliswaar een een 28% reductie van de koolstof-intensiteit (carbon-intensity), maar deze verbetering wordt deels tenietgedaan door de groei in elektriciteitsvraag. Meer koolstof-arme elektriciteitsproductie en een lagere groei van elektriciteitsverbruik zullen nodig zijn om de EU klimaatdoelstellingen te realiseren. Een CO_2-prijs van 50 €/ton zou de marginale productiekosten van gascentrales lager maken dan die van kolen, wat zou leiden tot een 38% lagere uitstoot in vergelijking met het scenario van een CO_2-prijs van 22.5 €/ton. Anderzijds, als het volume duurzame energie zou verdubbelen t.o.v. de verwachtingen, zou de CO_2 uitstoot maar met 33% afnemen in het 22.5 €/ton scenario. Dit houdt in dat, ceteris paribus, een CO_2-belasting die gas boven kolen stelt meer emissies reduceert dan een verdubbeling van duurzame bronnen zonder een hoge CO_2-prijs.

Grensoverschrijdende transmissie vs. energie-opslag en vraagrespons

De volgende twee studies analyseren onafhankelijk van elkaar de mate waarin investeringen in energie-opslag en vraagrespons de noodzaak tot investeringen in grensoverschrijdende transmissiecapaciteit kunnen vervangen dan wel complementeren. Complementariteit is gedefinieerd als de reciproce relatie waarbij een

toename in de ene variabele leidt tot een toename in de vraag van de andere variabele. Substitutie daarentegen, refereert naar het vermogen van een variabele om de vraag naar de andere te vervangen. De impacts van investering in waterkrachtcentrales met pompcapaciteit en in het gestuurd laden van elektrische auto's (EVs) worden vergeleken met de impacts van investeringen in grensoverschrijdende transmissie op de kosten van elektriciteitsproductie, het verspillen van duurzame energie, CO_2-uitstoot, niet-geleverde energie, en op elkaar.

Zowel grensoverschrijdende transmissiecapaciteit als waterkracht pompcapaciteit en het gestuurd laden van EVs reduceren de elektriciteitsproductiekosten, de noodzaak tot verspilling van duurzame energie, niet-geleverde energie en CO_2-uitstoot (voor een CO_2-prijs van 50 €/ton). De vraag naar het pompen van waterkrachtcentrales vermindert bij een hogere grensoverschrijdende transmissiecapaciteit. Aan de andere kant neemt paradoxaal genoeg het grensoverschrijdende transport van elektriciteit toe bij een hogere pompcapaciteit van waterkrachtcentrales. De resultaten van deze studie laten zien dat grensoverschrijdende transmissie en waterkracht elkaar substitueren, maar dat ze onder bepaalde condities ook als complementaire technologie gezien kunnen worden.

De mate waarin grensoverschrijdende transmissie en het gestuurd laden van EVs elkaar vervangen hangt af van de mate waarin arbitrage (i.e. de flexibiliteit in elektriciteitsproductie) nodig is in het Europese elektriciteitssysteem. De vraag naar arbitrage is hoger als de penetratie van duurzame energie hoger is, maar ze is lager bij hoge CO_2-prijzen omdat de marginale kosten van kolen- en gascentrales dan dichter bij elkaar komen te liggen. Het resultaat van deze studie laat zien hoe grensoverschrijdende transmissiecapaciteit en het gestuurd laden van EVs deels substituten en deels complementair zijn. Als de vraag naar arbitrage laag is, kan het gestuurde laden van EVs een zeker volume aan grensoverschrijdende transmissie vervangen. Hoe hoger de vraag naar arbitrage, hoe meer de twee technologieën elkaar complementeren in het reduceren van de kosten van elektriciteitsproductie. Met andere woorden, als de vraag naar arbitrage toeneemt, zijn beide nodig omdat het gecombineerde potentieel van de regelbare EV-vraag en energie-opslag in een land onvoldoende is om de fluctuaties in duurzame energieproductie op te vangen. Grensoverschrijdende transmissie is dan nodig om toegang te verschaffen naar het EV- en opslagpotentieel in andere landen.

Elektriciteitsimport vanuit Noord-Afrika

In de vierde studie wordt m.b.v. EUPowerDispatch het effect van Noord-Afrikaanse elektriciteitsimport op het Europese elektriciteitssysteem onderzocht. Deze analyse is uitgevoerd in combinatie met een gedetailleerde analyse van de impacts van het Italiaanse transmissienetwerk. Met een aantal gezamenlijke aannames is in deze twee studies de invloed van de Noord-Afrikaanse import bestudeerd in termen van zowel de marginale elektriciteitsprijzen in Europese landen en Italiaanse markt-zones als de grensoverschrijdende elektriciteitstransporten in verschillende scenario's. Netwerkbeperkingen bleken in beide studies de resultaten te beïnvloeden.

De resultaten laten in het algemeen een afname van de elektriciteitsprijzen in Europa zien als gevolg van de Noord-Afrikaanse elektriciteitsimporten. Uit de Europese studie komt vooral naar voren dat de netto vermogensuitwisselingen de richting van zuid naar noord lijken te volgen. Hiernaast wordt de positie van Italië als Mediterrane elektriciteitshub benadrukt. De Italiaanse studie laat zien dat de Noord-Afrikaanse importen significant leiden tot interne congestie en prijsdalingen op Sicilië en Sardinië. Zowel de transmissie-limieten tussen de twee eilanden en het Italiaanse vasteland als ook de grenzen tussen de zuidelijke en midden-zuidelijke zones spelen een belangrijke rol.

Betrouwbaarheid van het Europese transmissienetwerk

Naast de vier hierboven besproken studies die m.b.v. EUPowerDispatch zijn uitgevoerd, wordt ook de invloed van het elektriciteitstransport op de betrouwbaarheid van het netwerk besproken. Twee aanvullende studies analyseren onafhankelijk van elkaar de impact van netwerktopologie en grensoverschrijdende transmissiecapaciteit op de betrouwbaarheid van het netwerk. In deze twee studies wordt de betrouwbaarheid van het netwerk beoordeeld gebruikmakend van maandelijkse statistieken van grote stroomstoringen op de transmissienetwerken. De eerste studie analyseert de invloed van de mate van (interne) onderlinge verbondenheid van de netwerken op het voorkomen van grote stroomstoringen en op drie indicatoren van betrouwbaarheid: de hoeveelheid niet geleverde energie (Energy Not Supplied, ENS) het totale vermogensverlies (Total Loss of Power, TLP) en hersteltijd (Restoration Time, RT). De tweede studie, daarentegen, analyseert de invloed van de resterende marge en importcapaciteit op het voorkomen van grote stroomstoringen.

De resultaten van de eerste studie laten zien dat de meer (intern) verbonden Europese netwerken vier keer zoveel stroomstoringen hebben ervaren dan degene die

minder verbonden zijn. Aan de andere kant laten deze significant betere waarden zien voor alle drie de betrouwbaarheidsindicatoren voor het grootste deel van de cumulatieve kansverdelingsfuncties. Dit betekent dat de meerderheid van de stroomstoringen in de meer verbonden netwerken een kleinere impact op de betrouwbaarheid hebben dan de stroomstoringen in de minder verbonden netwerken. Deze resultaten bevestigen de gangbare opvatting dat meer verbonden netwerken betrouwbaarder zijn. Het is echter wel interessant om vast te stellen dat deze hogere betrouwbaarheid niet het gevolg is van minder storingen, maar juist van de kleinere consequenties van deze storingen. De resultaten van de tweede studie laten zien hoe een toename van de som van de resterende marge en importcapaciteit overeenkomt met een hogere betrouwbaarheid (minder storingen) in het netwerk.

Conclusies

Het onderzoek gepresenteerd in dit proefschrift laat zien hoe grensoverschrijdende transmissiecapaciteit een positieve impact heeft op de volgende twee doelen van het EU energie-beleid: economische efficiëntie en leveringszekerheid. In termen van economische efficiëntie laten de resultaten zien hoe volgens de ENTSO-E scenario's voor 2025 de verwachte uitbreidingen in grensoverschrijdende transmissiecapaciteit de kosten van elektriciteitsproductie met 1% verlagen. Hiernaast zal de grensoverschrijdende transmissiecapaciteit volgens de ENTSO-E scenario's voor het geïnstalleerd vermogen aan duurzame energie geen significante beperking vormen voor de integratie van duurzame bronnen tussen 2010 en 2025. Als de hoeveelheid wind- en zonne-energie echter zal verdubbelen t.o.v. de verwachtingen en in totaal 35% van de energie-mix zal vormen, dan zorgt grensoverschrijdende transmissie voor een reductie van 6.7% in productiekosten en neemt verspilling van wind af van 7.7% tot 4.5%. Investeringen in grensoverschrijdende transmissie zullen ook een positief effect hebben op concurrentie binnen de elektriciteitsmarkt. Dit laatste is echter niet direct besproken in dit proefschrift.

Aangaande de leveringszekerheid laten de resultaten zien dat investeringen in grensoverschrijdende transmissie de hoeveelheid niet-geleverde energie doet afnemen. Bovendien laten statistieken van 18 Europese landen vanaf 2002 zien dat als de genormaliseerde som van resterende marge en importcapaciteit toeneemt, de frequentie van grote stroomstoringen aanzienlijk afneemt in het Europese netwerk tussen 2002 en 2011.

Om het ambitieuze koolstofvrije doel in 2050 te halen zal het Europese elektriciteitssysteem een aantal infrastructurele veranderingen moeten ondergaan.

Aanzienlijke investeringen zullen op tijd gedaan moeten worden om een hoog aandeel variabele duurzame energie te kunnen accommoderen. Eén enkele technische oplossing zal niet genoeg zijn om aan de verwachte vraag naar energie-arbitrage te voldoen. Het vervangings- en aanvullingspotentieel van energie-opslag en vraagrespons m.b.t. grensoverschrijdende transmissie zal beter begrepen moeten worden om efficiënte investeringen te garanderen. De optimale mix van deze opties zal echter afhangen van hun relatieve kosten en de toekomstige ontwikkeling van het Europese elektriciteitssysteem. Deze ontwikkeling zal gevormd worden door de fundamentele krachten van vraag en aanbod, die op cruciale wijze afhangen van niet alleen beleid t.a.v. duurzaam energie en koolstof, maar ook van de socio-economische ontwikkelingen in Europa.

Investeringen in grensoverschrijdende transmissiecapaciteit zullen een positief effect hebben op het EU beleidsdoel van duurzaamheid en met m.b.t. het doel van het koolstof-vrij maken van de Europese elektriciteitssector als aan tenminste één van de volgende voorwaarden voldaan is. De eerste is dat er een hoog aandeel duurzame energie in de mix van elektriciteitsproductie is. In dit geval zou grensoverschrijdende transmissie de verspilling van wind- en zonne-energie verlagen en daardoor de CO_2-uitstoot verder doen afnemen. De tweede voorwaarde is dat de CO_2-prijs hoog genoeg is om de koolstof-intensieve productietechnologieën als laatste in de inzetorde (merit order) van centrales te plaatsen. In dit geval zal grensoverschrijdende transmissie ervoor zorgen dat CO_2-uitstoot gereduceerd wordt door het inzetten van de goedkopere centrales te faciliteren, die vanwege de hoge CO_2-prijs ook de minst koolstof-intensieve zijn. Als het Europese CO_2-beleid echter niet leidt tot zulke hoge CO_2-prijzen, dan zullen zowel investeringen in grensoverschrijdende transmissiecapaciteit als ook in energie-opslag en vraagrespons leiden tot hogere CO_2-emissies. Met andere woorden, als het CO_2-beleid niet effectief is, zal de economische doelstelling om de kosten voor elektriciteitsproductie te verlagen het moeilijker maken om Europa's klimaatdoelstellingen te halen.

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Curriculum Vitae

Carlo Brancucci Martínez-Anido was born on 26 May 1987 in La Coruña (Spain). He finished high school at the European School of Varese (Italy) in 2005. After, he followed a 4-year Master in Aeronautical Engineering (M.Eng) at Bristol University (United Kingdom). He spent the third year (2007-2008) at the University of California, Davis (United States). He graduated in 2009 and defended his Master thesis titled 'Mitigation of the Climatic Effects of Short-Haul Air Traffic (A Comparison between Turboprop and Turbofan Powered Aircraft)'.

In July 2010, Carlo started working as a researcher at the Smart Electricity Systems & Interoperability research group of the Joint Research Centre - Institute for Energy and Transport (JRC-IET), the in-house scientific service of the European Commission. At the same time, he started his PhD research at Delft University of Technology, in the Energy & Industry section within the Faculty of Technology, Policy and Management. During his research, Carlo wrote and presented several conference papers, published four journal papers and was co-author of a book chapter.

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