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Modelling the European cross-border electricity transmission

Piotr Jędrzejewski

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SE-100 44 STOCKHOLM

KTH Industrial Engineering and Management	**Master of Science Thesis TRITA-ITM-EX 2020:526** **Modelling the European High-voltage electricity transmission** Piotr Jędrzejewski	
Approved 7 September 2020	Examiner Will Usher	Supervisor Hauke Henke
	Commissioner	Contact person Piotr Jędrzejewski

Abstract [ENG]

This Master's thesis describes modelling of the cross-border electricity transmission network of Europe. Under this work an extension of The Open Source Energy Model Base for the European Union (OSeMBE) was developed, implementing interconnections to the already existing model. The model is built using the Open Source Energy Modelling System (OSeMOSYS). The purpose of the model is to find cost optimal shape of the electricity system of Europe in the modelling period from 2015 to 2050. The model was used to analyse plans for the development of the electricity interconnection network, defined by the European Union on the list of Projects of Common Interests. For the thesis four scenarios of the European electricity system's future development were modelled. The aim was to analyse on which borders new interconnection capacity would be beneficial and to test the influence of the interconnection development on the whole electricity system, particularly generation capacities and CO_2 emissions. The electricity flows were analysed on each border. For a better overview in the analysis four regions were defined. The regions are adequate to the four priority corridors for electricity defined in Trans-European Networks for Energy (TEN-E). The major finding of the scenario that optimized the capacity of the interconnections in Europe, was that only 16% of capacities planned as the PCI are needed to be built. Most of those capacities should be developed in the northern Europe, particularly on the subsea borders Germany-Norway, United Kingdom-Norway, Poland-Lithuania, but also land ones Finland-Sweden, Denmark-Germany. The analysis also included utilization factors of the interconnection lines. However, due to the simplifications and limitation of modelling tool OSeMOSYS, the results needs to be taken with certain dose of caution and may serve only for indicating the direction of further analysis. The work conducted under this Master's thesis, might also be a base for the future work, such as deeper look on the already obtained data with purpose to find relationship between electricity generation sources being utilized and interconnections utilization. The model might be also improved by implementation interconnection representation to the borders which were omitted here due to the lack of cost data.

Abstrakt [SE]

Detta examensarbetebeskriver modellering av Europas gränsöverskridande elektriska transmissionsnät. Under detta arbete utvecklades en utvidgning av Open Source Energy Model Base för Europeiska unionen (OSeMBE) för implementering av sammankopplingar med den redan existerande modellen. Modellen är byggd med hjälp av Open Source Energy Modeling System (OSeMOSYS). Syftet med modellen är att hitta en kostnadseffektiv form av Europas elsystem under modelleringsperioden 2015 till 2050. Modellen användes för att validera planer för utveckling av sammankoppling för elnätet, definierade av Europeiska unionen i listan över projekt av gemensamt intresse. Under denna avhandling modellerades fyra scenarier för det europeiska elsystemets framtida utveckling. Målet för scenarierna var att analysera för vilka gränser en ny sammankopplingskapacitet skulle vara till nytta, samt att testa påverkan av samtrafikutvecklingen på hela elsystemet, särskilt produktionskapacitet och koldioxidutsläpp. Därefter analyserades flödena av elektricitet vid varje gräns, och för att förenkla analysen delades området upp i fyra regioner. Regionerna är uppdelade i enlighet med de fyra prioriterade korridorerna för elektricitet, definierade i Transeuropeiska Nät för Energi (TEN-E). Det huvudsakligaresultatet i scenariot som optimerade kapaciteten för sammankopplingarna i Europa var att endast 16% av den kapacitet som planerades som PCI behöver byggas. De flesta av dessa kapaciteter bör utvecklas i norra Europa, särskilt vid havsgränserna Tyskland-Norge, Storbritannien-Norge, Polen-Litauen, men också Finland-Sverige och Danmark-Tyskland. Även användningsfaktorer för samtrafikledningarna analyserades i arbetet.

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Abbreviations

Abbreviation	Full name
AC	Alternating Current
ACER	Agency for the Cooperation of Energy Regulators
BEMIP Electricity	Baltic Energy Market Interconnection Plan in electricity
CBA	Cost-Benefit Analysis
DC	Direct Current
EC	European Commission
HVAC	High Voltage Alternating Current
LCC	Line Commuted Converters
NECP	National Energy and Climate Plan
NSI East	North-south electricity interconnections in central eastern and south eastern Europe
NSI West	North-south electricity interconnections in western Europe
NSOG	North Seas Offshore Grid
OSeMBE	Open Source energy Model Base for the European Union
OSeMOSYS	Open Source energy Modelling System
PCI	Projects of Common Interest
TSO	Transmission System Operator
TYNDP	Ten-year Network Development Plan
VRE	Variable Renewable Energy
VSC	Voltage Source Converters

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1 Introduction

Recent years brought large development of renewable energy sources. In 2019 alone there were 181 GW of new renewable capacities installed, which resulted in achieving 26% of renewable energy in the global electricity mix [1]. Due to the urgency of global warming, acknowledged by 195 countries in the Paris Agreement, this growth is expected to continue and even accelerate in the upcoming years. The need for a reduction of the CO_2 emissions and keeping global average temperature increase below 1.5ºC became an obvious fact which is implemented into the energy policies of many countries. Not only a large reduction of fossil fuel use is planned but even totally abandoning them. On the frontline of the energy transition, there is the European Union, which plans to achieve carbon neutrality by 2050, while some EU member states aiming to do it earlier, namely Finland (2035), Iceland (2040) or Sweden (2045) [2].

Although it is a promising and necessary trend, there are certain technical difficulties that need to be addressed in the early stage of that development. When looking closer at the mix of new renewable capacities, the technologies that are growing the most are solar and wind energy which together accounted for 90% of global renewable additions in 2019, leaving behind more stable and dispatchable technologies such as bioenergy and hydropower [3]. It means that in the soon future, many energy systems will be dominated by Variable Renewable Energy (VRE) bringing a series of issues regarding the balancing of the electricity systems. Fluctuations of the electricity generation in renewable-rich systems are something that already broadly emerges in certain countries, for instance, Germany, causing such abnormal phenomenon like negative hourly energy prices [4].

Europe, where the growth of the VRE is among the strongest, is going to face those challenges as the one of first ones. In order to properly address them, researchers broadly suggest the necessity of increase system flexibility by grid enhancements [5] [6] [7]. Without sufficient balancing measures, VREs will still need large amounts of conventional energy sources as reserve capacity, used in times of insufficient weather conditions and excess electricity from of renewable sources might be curtailed due to low load levels at times of high generation. That would lead to an oversizing of the energy systems, higher costs of electricity and emissions.

There are several different methods that might contribute to the development of a flexible grid, capable to accommodate high shares of VREs. As the first of them, many studies call variable technologies of energy storage such as pumped hydro-power, lithium-ion batteries, hydrogen, power-to-gas or thermal energy storage [8] [9] [10] [11]. Having such a variety of available technologies with different properties enables coupling them with renewable energy sources to develop applications serving specific purposes like short or long-term storage and large scale or distributed energy storage.

Another solution commonly discussed by researchers for improving grid flexibility is demand-side management [12] [13] [14]. This market-based solution combined with the technologies of smart grids allows final energy consumers, traditionally being only passive users, to turn into active market players and benefit from the reduction of their load. Mechanisms such as online pricing may allow shifting the demand peak, and therefore reduce need for the generation capacity.

The third element to increase flexibility is the construction of more transmission lines, particularly at international scale and this is the part on which this work is focusing on. Many studies discuss the potential of cross-border interconnections in the European Union to enable more fluent energy exchange among member-states and therefore introduce more renewables into the grid [15] [16]. The technologies are already commonly used at large scale. However, its main purpose is to provide electricity supply everywhere and enable the trade of energy between countries. Despite its importance, transmission infrastructure and technology were for a long time a relatively neglected area in energy transition studies, while the research had focused primarily on the development of renewable energy and storage technologies [17].

Major advantages over the energy storage and demand side management are technical maturity of transmission technologies and relatively low costs. Both of other two are rather at the beginning of the development and still have potential for improvement and cost reductions. However, the urgency of climate change requires to come up with solutions to be applied now. This does not mean that other measures should be abandoned, in fact, only the proper mix of all three of them will provide complementary and reliable grid flexibility.

Most of the experts working in the field agree about the necessity of large development and reinforcement of the European electricity transmission network and on the benefits such would bring. One of the most important is the reduction of needed reserve capacity by allowing trade among remote countries [16].

Another argument for the development of the interconnection grid described in the literature, relevant particularly in Europe's case, is the abundance of different renewable resources in distanced areas. The geographical dispersion and variability of renewable energy sources imply that these must be connected across large territories to ensure a stable supply [17]. Once there is enough transmission capacity, sources such as photovoltaics from southern Europe, wind energy, particularly offshore located at the North Sea and hydropower of the mountain areas might complement each other and provide weather resilient power for Europe.

Bearing that in mind, this Master's thesis, *Modelling the European cross-border electricity transmission*, focuses on the need of the implementation of Projects of Common Interest (PCI) in the interconnection network in Europe. Initial parts of the report focus on the current state of technology utilized for electricity transmission. The policy of the European Union for energy and climate with particular focus on goals and mechanisms regarding the interconnection network development and implementation of a common energy market is presented.

The main part of the work focuses on the electricity system model covering 30 European countries (European Union with Norway, Switzerland and the United Kingdom), the Open Source energy Model Base for the European Union (OSeMBE). The model uses linear cost-minimization to find an electricity generation mix and cross-border transmission that meets an external defined electricity demand and certain pre-assumed boundaries regarding CO_2 emission reduction and plans for new power plants. The purpose of this work is to extend the existing model with a representation of cross-border electricity interconnections in Europe.

The improved model is used for testing four different scenarios of European interconnection development until 2050, assuming a variable amount of newly installed capacities. That will allow validation of cross-border transmission lines which are already planned or considered, as well as indicate installation of which of them should be prioritized. The results of these scenarios provide insights on the entire European electricity system; therefore, it is possible to see how changing the availability of interconnections affects other segments of the electricity system. The conclusions of the Master's thesis give a overview of how European high voltage cross-border electricity transmission grid could develop, challenges that need to be solved, and potentially where there is the possibility for improvement in the plans of interconnection network development.

2 Power transmission technology review

Modern power systems consist of a broad network of components that generally may be divided into generation, transmission, distribution and load. This study discusses power transmission only, therefore the following chapter gives an overview of the current high voltage energy transmission technologies, both with High Voltage Alternating Current (HVAC) and Direct Current (HVDC). Since the former is already well established and broadly used in transmission systems around the world and the latter is only emerging from niche use but with a large potential of technology and market development, the major focus is put on the HVDC.

2.1 High Voltage Alternating Current

The dispute which of the current types is more suitable in the large power systems: Direct or Alternating, has its origins back in the 19th century, at the very early stage of electricity development. The major protagonists of each solution were the two inventors, Thomas Edison opting for DC and Nicolas Tesla for AC. The argument was won by the latter, due to the possibility of transforming AC's voltage level and therefore, with high voltage transmission, minimizing power losses.

Since then, the world faced the development of dense AC grids transmitting and distributing power on various voltage levels adjusted to needs and application. They are classified as a Low, Medium, High (100-138 kV), Extra High (220-800 kV) and Ultra High (>800 kV) Voltages [18]. For the purpose of this work, the last three are particularly important since those are the ones that are utilized for the large-scale power transmission and they will be all aggregated under the High Voltage term unless stated differently.

The major components of AC high voltage transmission grids are transformers and transmission lines. The role of transformers is to adjust the voltage between the generation, transmission and then distribution levels. Transmission system voltage series are unified within power systems, however, vary from one to another, for example, they are 400/220/110 kV in most of the European countries including UK, Germany, France and Sweden [19].

There are two frequencies in AC power systems, 60 Hz and 50 Hz. The first operates in both the Americas and certain regions of Asia, while the second covers the rest of the world. Japan is an interesting example due to having two systems within the country with two different frequency levels [20].

Additionally, in order to optimize the number of conductors needed for the power transmission, it is common to use three-phase electric power which reduces or cancels the current held by the neutral conductor and increases capacity to conductor ratio between 2 and 3 times, depending on the configuration [20].

The common material for transmission lines is aluminium which might be reinforced with steel or alloys [20]. Most of the connections are overhead since it is the cheapest solution. However, there are many applications of cabling going subsea or underground, especially for HVDC technology. One of the reasons for that alternative is geographical difficulties occurring on the line route, but there is also another important factor. Social acceptance for the overhead lines an issue and cause that many projects need to go underground to avoid protests and comply with the environmental requirements although it is not the cost optimal solution [18].

2.2 High Voltage Direct Current

Unlike HVAC, HVDC technology is using direct current for electricity transmission. Although HVDC is a technology known for decades, it was so far only playing a minor role in the existing transmission systems around the world. That was mainly because alternating current is simpler in adjusting of the voltage with the use of transformers. However, HVDC has many other advantages, which in certain applications might make it serve better than HVAC. Therefore, it started to be in use as well since the 1950s, when power electronics developed enough to allow smoothly convert AC to DC and backward and control such a system. The first HVDC line was built in 1954 in Sweden as a subsea connection between Gotland and the mainland with a capacity of 20 MW, 100 kV voltage and 96 km length [21].

Since then HVDC technology matured and developed massively, currently being utilized globally for many purposes. These are going to be discussed closer in the following sub-chapter. There was a rapid acceleration of new HVDC lines construction since the beginning of 2010s, resulting in total capacities installed globally exceeding 250 GW as for 2017. This trend is expected to continue and reach 400 GW by 2022 based on already announced projects. [22]

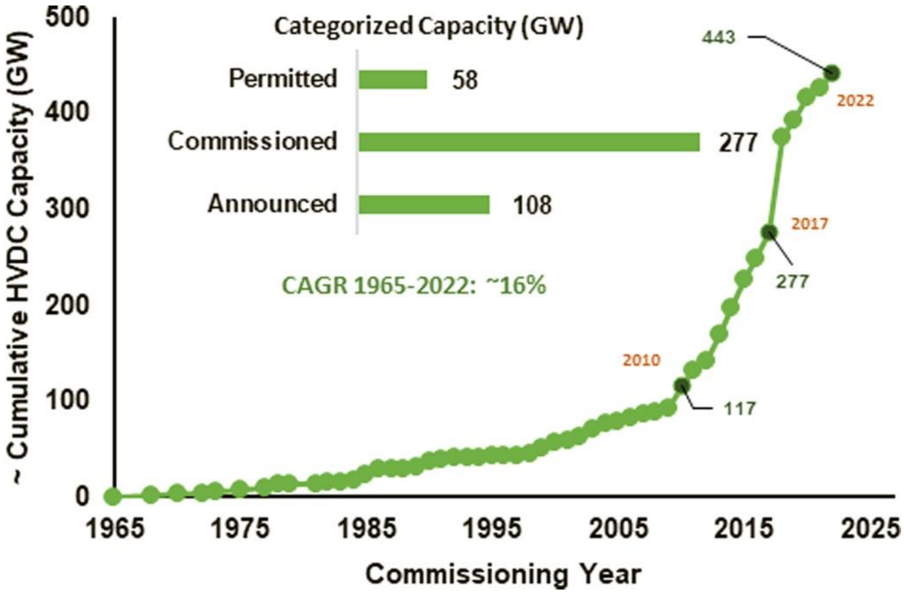

Figure 1 Cumulative capacity of HVDC interconnectors [22]

The region with the largest development of HVDC transmission observed is Asia, which is responsible for 52% of the abovementioned capacity with China and India as the major players dominating the market. Projects based in Europe, being the main area of interest of this work, are the most numerous, however, due to the geographical and demand distribution specifics, they cover only 22% of the global HVDC capacity [22].

2.2.1 Applications and comparison with HVAC

As already mentioned, HVDC technology has some technical advantages over the HVAC. Since there is no capacitive effect and reactive power transmission in direct current flows, the only losses appearing are due to the resistance, reducing overall losses of the line. This allows HVDC lines to be operated without expensive reactive compensators needed for AC lines and achieve very long distances of up to 3000 km [22]. Another important characteristic of HVDC is that it requires fewer cables or conductors leading to smaller cross-sectional area and Right-of-Way space. All those factors positively influence the total cost of the HVDC transmission lines.

However, while operating in an AC dominated system, HVDC lines require to be connected to the rest of the grid through AC/DC converters – inverters and rectifiers. Those are expensive components and their cost is one of the limiting factors for HVDC applications and further market growth. Taking above into account the conclusion is that in comparison with HVAC, HVDC transmission lines have a much higher fixed cost, related to the conversion infrastructure, while their variable costs are lower.

Therefore, for the new projects, there might be found a breakeven distance above which HVDC would be more economically suitable over HVAC. Conducted studies show that typical breakeven distance, depending on the site-specific conditions, varies between 300 km and 800 km for overhead lines and 50 km to 100 km for subsea and underground cables [[18] [23] [24]]. The idea of breakeven distance is depicted at Figure 2.

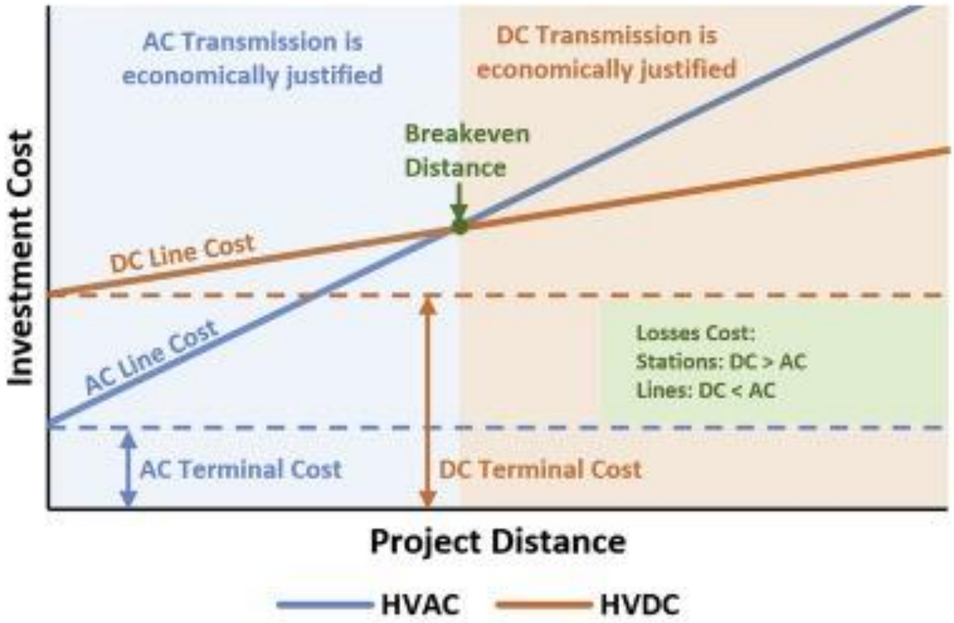

Figure 2 HVAC vs HVDC cost comparison [18]

2.2.1.1 Low-cost interconnection over large distances

There are several different applications for which HVDC solutions are in use nowadays. First of them is low-cost interconnections between countries over large distances. As an additional advantage over AC solutions, DC links maximum length does not have any technical limitation due to absence of reactive power flow generated by the line capacitance. It allows to develop strong connections despite the geographical difficulties such as mountains and seas, resulting in an increase of energy security and trading possibilities.

The longest existing interconnection so far is the nearly 600 km subsea NorNed link between Norway and the Netherlands, but there are already longer projects in the pipeline, for instance, the 720 km long North Sea Link between Norway and the United Kingdom [25] or 770 km long Viking Link between Denmark and the United Kingdom [26].

There are also ideas to expand HVDC links on the inter-continental scale and bring together Europe and North America with the subsea cable through the Atlantic Ocean, but so far they are far from the implementation phase [27]. Another promising project that is discussed, however still being on the feasibility study stage, is IceLink, interconnection of Ireland to the Europe [28] [29]. It is to go via the United Kingdom and its major benefit would be complementing intermittency of growing wind sector with a flexible hydropower resources located in Iceland.

2.2.1.2 Connecting asynchronous grids

The second purpose of using the HVDC lines is to connect neighbouring asynchronous AC systems, which is often also referred to as "Back to Back" or B2B connection. This application is not related to the economic advantage over AC links but is the simpler technical solution of energy transmission between those systems [24]. This necessity might appear for the neighbouring countries, like in the case of LitPol Link at the Polish-Lithuanian border which connects the Continental European grid with the asynchronous system of the Baltic countries [30]. It might be as well utilized within one country as it happens in Japan having systems with different frequencies (50/60 Hz) or the USA with many asynchronous 60 Hz grids [22]. There are currently13 GW of Back-to-Back asynchronous interconnections in operation globally [24].

2.2.1.3 Connecting remote energy resources and loads

HVDC is also used to connect remote energy generation sources to the main grid. It is especially common for renewable energies. Abundant resources are often located far away from centres of demand. A particular example of such HVDC utilization is offshore wind, which together with the technology development in recent years is being placed on the deeper and further locations. In the European Union, a pioneer in offshore wind, there are discussions to build a common Offshore Grid in the North Sea in order to enforce cooperation among the member states and bring benefits from increased possibilities of energy flows among them [31].

However, the largest and longest already operating HVDC link in the world is located in Brazil, connecting the Belo Monte hydroelectric power plant with Rio de Janeiro. It is 2,543 km long and transmit 4 GW of power with the voltage of 800 kV [32]. Unlike lines mentioned previously in the *Low-cost interconnection over large distances*, this link remains within the borders of one country. Therefore, despite being much longer than described interconnections, it was not considered in the length comparison.

2.2.1.4 Accommodating variable renewable energy

With the growth of renewable, intermittent energy sources the need for the flexibility of the grid grew as well. A highly developed transmission grid allows to shift surplus energy from the generation region, where in case of low demand or high generation it could not be consumed, to other areas, when otherwise it would be curtailed.

2.2.2 Converter type technologies

The costliest component of the HVDC transmission lines and at the same time most challenging from the technical point of view are AC/DC converters, which allow to operate HVDC in an AC based grid. There are currently two major types of converters, Line Commutated Converters (LCC) and Voltage Source Converters (VSC). Their specifics are discussed in this sub-chapter.

2.2.2.1 Line Commutated Converters

LCCs were the first developed converter type to convert from AC to DC and are still the most applied ones. Their operation bases on the AC transmission line parameters and their switching frequency matches line frequency. Therefore, they are not able to perform black start and cannot be used for restarting blacked out systems. Another disadvantage is that LCCs allow for the current flow only in one direction, which means that they are classified as a Current Source Converters. In certain applications, like energy transmission from the remote sources, this feature might not be a relevant issue, but for most of the cases, there would be a double converter required at each end of the line in order to enable energy flows in both directions [22].

2.2.2.2 Voltage Source Converters

An alternative for LCCs are VSC converters. They were first introduced in 1997 in Sweden for the 3 MW Hällsjön-Grängesberg connection [33]. Since then the technology faced many improvements resulting in the increasing role of the VSC-HVDC lines and the gradual replacement of LCCs in new installations. They are however not able to operate with the powers exceeding 2 GW.

The main advantage of this type of converter is that they do not require AC grid frequency to control them, instead, they are self-commuting, meaning they relies on their own voltage control signals. This feature makes them independent from the grid and able to operate despite AC network faults and initiate voltage restoration in the post-black out scenario. VSCs also have the possibility of active control and reactive power consumption or generation and therefore support power quality in a weak AC network [22].

3 European Union Energy Policy

Providing secure, sustainable and affordable energy to households and businesses is an important goal for the European Union authorities. There are many actions and policies by the European Union to shape energy markets, increase energy security and decarbonize the economies within the member states. Supporting the development of high voltage cross-border transmission lines is an important part of those activities. The following chapter aims to provide an overview of the EU's energy-related policies and give an introduction to the mechanisms concerning interconnections.

3.1 Third energy package

The EU has a long history of transforming energy sectors within the member states, it takes its roots in the 1990s, when most of the national electricity and natural gas markets were still monopolized. Back then several directives were issued by the EC, regarding energy market liberalization and unbundling, commonly called Energy Packages. The first of them was adopted in 1996 (Directive 96/92/EC) for electricity and 1998 (Directive 98/30/EC) for the gas market and the second in 2003 (Directive 2003/54/EC and the Directive 2003/55/EC) [34]. Their major focus was on the development of market access, the Second Energy Package introduced the free choice of electricity and gas suppliers.

The base for all further energy policies being in force nowadays was the Third Energy Package, introduced in 2009 as Electricity Directive 2009/72/EC, which aimed at improving the functioning of the internal energy market and resolving certain structural problems. It covers the five following areas [35]:

1. **Unbundling**. Unbundling is a separation of the businesses of the energy generation and the operation of the transmission network. Its aim is to provide all energy generation companies with equal access to the service of energy transmission and to avoid situations in which one company holding both, generation and transmission assets, may have an incentive to block their competition's access to the infrastructure. Unbundling might take place in the three different schemes, depending on the member states preferences:
    - ownership unbundling
    - independent system operator
    - independent transmission system operator
2. **Independent regulators**. The Third Energy Package assumes that an independent regulator role is essential for maintaining a competitive internal energy market. Therefore, the requirements for the national energy regulators have been adjusted, with the following outlines:
    - Regulators must be their own legal entity, with authority over their own budget. They must be independent of both industry interests and government; however, national governments are obliged to supply them with sufficient resources.
    - Regulators can issue binding decisions to companies and impose penalties in case they do not comply with their legal obligations.
    - All market agents such as electricity generating companies, network operators, and energy suppliers are obliged to share accurate data about their operations to regulators.
    - Regulators from different EU member states must cooperate in order to promote competition, the opening-up of the market and an efficient and secure energy system.
3. **Agency for the Cooperation of Energy Regulators (ACER)**. The Third Energy Package established ACER, an organization independent from the EC, national governments and companies, who's aim is to support the fully integrated and well-functioning Internal Energy Market and help in cooperation of the different national energy regulators. ACER's works involve [36]:
    - Preparing guidelines for the operation of cross-border gas pipelines and electricity lines.
    - Reviewing the implementation of EU wide network development plans.
    - Deciding on cross-border issues if national regulators cannot agree or ask for intervention.

- Monitoring the operation of the internal market, including issues such as renewable electricity production, consumers' rights, network access and retail prices.

4. **Cross-border cooperation.** The Third Energy Package puts emphasis on the cooperation of the Transmission System Operators (TSO), responsible for the effective transmission of electricity and natural gas. In order to promote this cooperation, two organizations were created the European Network of Transmission System Operators for Electricity and for Gas (ENTSO-E and ENTSO-G), which draft standards and codes for the transmission systems and coordinate the planning of investments into the network development [37]. Due to its large importance for the electricity interconnection grid, ENTSO-E and its actions are going to be discussed in details in the separate subchapter 4.44.4.
5. **Open and fair energy retail**. Stress was put on the protection of consumer rights. They include matters as access to information on energy consumption and the right to choose suppliers.

The third energy package was fundamental in the process of shaping a common internal energy market in the European Union and all further legislation concerning energy, introduced later, were based on it. It also gave more importance to the electricity interconnection network in Europe, acknowledging its important role in the process of market integration and developing mechanisms of coordination of the new capacities' development.

3.2 Energy Union and Clean Energy for All Europeans Package

Following the third energy package, two more significant initiatives of the EU aimed to improve the internal energy market operation as well as to accelerate the energy transition, which is essential for reaching the climate goals of the Paris Agreement. Those initiatives were the Energy Union resulting from the Clean Energy for all Europeans Package. Both are described in the following subchapters.

3.2.1 Energy Union

The Energy Union, aiming at giving European consumers secure, sustainable, competitive and affordable energy, was firstly published, as a broad strategy to strengthen EU's energy cooperation, in 2015 (Communication COM/2015/080) [38]. Since then, the Commission has published several packages of measures and regular progress reports, which monitor the implementation of its key priorities. As one of the major consequences of the Energy Union implementation, there was the Clean Energy for All Europeans Package introduced in 2019 [39], which was a comprehensive update of the third energy package, with the goal of facilitating the transition away from fossil fuels towards cleaner energy.

The Energy Union is built on five pillars, which are [40]:

1. Energy security, solidarity and trust.
2. A fully integrated European energy market.
3. Energy efficiency contributing to the moderation of demand.
4. Decarbonizing the economy.
5. Research, Innovation and Competitiveness.

The introduction of a joint energy policy resulted from the insight that EU Member States would benefit from tightening cooperation within the energy sector and relying on each other to deliver secure energy to their citizens, based on true solidarity and trust. It was acknowledged that over 50% of the energy consumed by the EU is imported, costing Europeans around 400 billion € annually and that such a system brings high risks for EU's energy security. Moreover, 75% of our housing stock is energy inefficient and 94% percent of transport relies on oil products, of which 90% is imported. It was estimated that more than 1 trillion € needed to be invested in the energy sector in the EU from 2015 to 2020 [38]. To tackle such a burden, internal cooperation among member states was considered essential, therefore the Energy Union quickly became one of the ten political priories of the Juncker's Commission (2014-2019).

Under the Energy Union plan, there were many smaller actions undertaken. There were several expert groups established, reviewing 15 different directives and other legal documents concerning energy and updating strategies for energy-related sectors such as natural gas imports, transportation, heating and cooling [41].

Other relevant areas within the scope of the Energy Union were as follows:

- New Deal for energy consumers including empowering consumers and deploying Demand-Side Response;
- Renewable Energy Package including a new Renewable Energy Directive for 2030 and best practices in renewable energy self-consumption;
- Update of the EU Emissions Trading System for 2021-2030 years;
- Monitoring and reporting system for heavy-duty vehicles emissions;
- Financial instruments to support investments in energy efficiency;
- EU Energy and Climate policy diplomacy;
- A new European energy R&I approach to accelerate energy system transformation;
- Data, analysis and intelligence for the Energy Union

This comprehensive approach to the Energy Union has enabled the EU to put in place clear and ambitious targets for 2030 in renewable energy and energy efficiency. It has also enabled the EU to set up equally ambitious policies on clean mobility including emissions for new cars, vans and lorries and provided a solid basis for work towards a modern and prosperous climate-neutral economy by 2050 [42]. Energy and climate targets adopted in 2014 [43], were reviewed and updated under Energy Union works in 2018, as presented in the table below.

Table 1 2030 framework for the climate and energy agreed targets [44].

	Greenhouse gas emission	Renewable Energy	Energy Efficiency
2020	-20%	20%	20%
2030	-40%	32%	32.5%

The topic of cross-border transmission lines is particularly important for the second of the Energy Union's pillars, regarding the integration of the European energy market, since an increase of the interconnection capacity is essential to enable the physical flow of electricity among the European countries and, therefore, trigger energy trading opportunities. Moreover, interconnections contribute largely to the improvement of energy security of the countries, enabling them to import energy from the EU fellow member states, as well as increase the chances for achieving decarbonisation goals, by decreasing the need of reserve capacity and allowing the connection of more renewables to the grid.

Therefore, among the Energy Union actions, there were several important initiatives concerning cross-border transmission lines. First of them was the target set by the European Council in October 2014 for the electricity interconnections with neighbouring countries of each Member State to reach the ability to transport at least 10% of the electricity that is produced by their power plants by 2020. The second was to extend this target for interconnections with 15% to be reached by 2030.

In order to achieve those goals, the EU financially supports the development of cross-border infrastructure via the fund of Connecting Europe Facility (CEF), which grants investments listed as Projects of Common Interests (PCI) with a total budget of €30 billion [45]. Another of the Energy Union priorities is to constantly update the PCIs list with key cross border infrastructure projects that link the energy systems of EU countries.

Since 10% interconnection target and PCIs are one of the most important initiatives of the European Union towards the development of the European cross-border transmission lines network, it is going to be comprehensively described in the separate subchapters 4.2 and 4.3.

The Fourth Report on the State of the Energy Union, published in 2019, reported the progress in achieving Energy Union's goals. The regulatory framework for specific sectors has also been brought up to date, including areas such as smart buildings, energy efficiency, road transportation carbon emissions, land use and eco-design of energy related-products [42].

There was made a large improvement in renewable energy development. Since 2014, the share of renewable energy in the EU energy mix has significantly increased, reaching 17.5 % in 2017. However, it still largely varies across the different sectors and while it achieved a high level for electricity (30.8 %), it requires certain improvements for heating and cooling (19.5%) and especially transportation (7.6% only) sectors. Moreover, for seven Member States, there is some uncertainty on whether they achieve the 2020 renewable targets. Energy efficiency targets were indicated as more difficult to implement than it was expected, and that area will need a lot of effort to make it up. There is also notable progress on the integration of the European energy market, which resulted in electricity wholesale prices decrease by 6.4 % between 2010 and 2017.

The Fourth Report on the State of the Energy Union focuses as well on the progress achieved in the field of cross-border transmission network development and integration of the disconnected regions. So far, over 30 PCIs have been implemented, and around 75 PCIs should be in place by 2022.

An especially significant achievement was noticed in case of the Baltic states, which were once an energy 'island' in the EU, while now, thanks to the new interconnectors with Sweden, Finland and Poland, are interconnected to the rest of the EU with 23.7 % cross-border interconnection. Another region where such an effort for the integration is made is the Iberian Peninsula. With the projects including the construction of power lines crossing the Bay of Biscay, the exchange capacity between France and Spain will double by 2025, bringing Spain closer to the 10 % interconnection target, and progressively integrating the whole Iberian Peninsula into the internal electricity market.

3.2.2 Clean energy for all Europeans package

In parallel to the development of the Energy Union, the European Union started to work on its milestone part, which was another energy package, Clean Energy for All Europeans, released in 2019. The works on it started already in 2014, with the introduction of the European Energy Security Strategy [46], calling for immediate actions aimed at increasing the EU's capacity to overcome major disruptions and the Commission working together with the Member States, regulators, Transmission Systems Operators and operators to improve the Union's energy security. When the works started it was known as the Winter Package.

Shortly after, the Paris Agreement was signed and it was decided to include commitments declared by the EU into the scope of the Winter Package. At the Paris Climate Summit, the EU undertook one of the strictest and most ambitious Intended Nationally Determined Contribution including reduction of its CO_2 emissions by 40% before 2030 [47].

The major reasoning behind that was that the European Union's electricity market is expected to be a major instrument in realizing the transition to a low carbon economy by 2050. This means that EU citizens as well as industrial users should gradually switch to electricity not only as a source of light, heating and cooling but also transportation and all other activities. The electricity should in turn be generated from low carbon, mostly renewable and intermittent sources which on the other hand creates a need for more flexibility and responsiveness, both on the supply and the demand side [48]. In order to achieve this, there was the need to update the energy-related legislation, defined previously in the Third Energy Package.

The EC conducted a revision of the current EU directives and policies, and in November 2016 came up with the eight proposals to facilitate the transition to a clean energy economy and to reform the design and operation of the European Union's electricity market [48]. Those measures proposed by the Commission regarded two categories. The first of them aimed to bring new market design and replace some directives and regulations of the third energy package regarding regulation on the internal electricity market and ACER. The second category aimed at aligning and integrating climate change goals into that market design.

Works over the Winter Package were finalized in May 2019 with the publication of the comprehensive update of the EU directives, bringing changes in the following fields:

1. **Energy performance in buildings.** It is estimated that buildings are responsible for 40% of energy consumption and 36% of CO_2 emissions. Moreover, 35% of them are older than 50 years and 75% is energy inefficient. Therefore, there is a large space for improvement and reduction of energy consumption and emissions in the buildings sector. The Energy Performance of Buildings Directive (EU 2018/844), focused on the areas such as smart buildings, e-mobility in buildings, energy poverty, introduced an obligation on member states to develop national roadmaps to decarbonize buildings by 2050 and increased funding in the buildings' renovations. [49]
2. **Energy Efficiency.** In the revised Directive on Energy Efficiency (EU) 2018/844) European Commission updated the energy efficiency labelling framework and expanded the target of 32.5% of energy efficiency by 2030, previously set to the level of 20% by 2020. Reaching that goal by households, transport and industry will lead to a reduction of energy consumption, less reliant on energy imports, clear information about the consumption and costs, as well as more incentives for producers to invest, create jobs and develop new technologies. [50]
3. **Renewable Energy.** Europe has adopted the most ambitious renewable energy policies in the world, with a target of 32% of renewable energy in the mix by 2030. Reviewed Renewable Energy Directive (2018/2001/EU) introduces more emphasis on the fight against climate change, reduction of air pollution and energy security, allows households, communities and businesses to become clean energy producers and encourages new investments and job creation [51].
4. **Europe's Electricity Market.** The package includes changes in the Electricity Regulation, Electricity Market Directive and rules regarding risk preparedness and ACER's role has been modified EU market rules, empowered final customers and enforced strategic cooperation among EU countries. The first group, electricity market adjustment, included interconnections growth allowing free electricity flow, grid flexibility, handling crisis situations together. There were also set new emission levels for power plants to get public funding and market-based investment mechanisms promoting decarbonisation. Consumers are equipped with legislation giving them the right for more information about energy costs they carry and offers of different suppliers, quick possibility of supplier change, smart meters, dynamic price contract and their own generation potential. EU member states were obliged to define Risk Preparedness Plans and the role of the Agency for Cooperation of Energy Regulators was strengthened, to ensure that the decisions regarding energy, taken on the national level, benefit European citizens. [52]
5. **The governance of the Energy Union and Climate Action.** With the introduction of The Regulation on the Governance of the Energy Union and Climate Action (EU 2018/1999), EU member states were obliged to present 10-year national energy and climate plans (NECP) starting from 2021-2030 as well as monitor and report their energy transformation progress. Those tools are to facilitate assessment and analysis of achieving objectives and targets of the energy union and the climate goals of entire Europe. [53]

All those new EU rules are aimed to provide numerous benefits, from different angles – environmental, economic, security of supply, consumer rights, international, and from a longer time scale. The European Union's objective was to reshape the electricity market in such a way that it is good for the planet, good for growth and jobs, and good for consumers.

3.3 European Green Deal

The most recent EU policy related to energy issues is the European Green Deal, initially announced as a set of legislation reviews in December 2019 [54] and still discussed when this work is published. It is to be a complex solution aiming to make the European Economy sustainable and reduce greenhouse gases emissions to zero by 2050 in a way that will maintain economic growth and will not leave any social group or region behind. So far only a set of propositions was revealed, such as the Circular Economy Action Plan, the European Climate Law and the Investment Plan regarding the funding of the transformation or Just Transition Mechanisms supporting regions in which achievement of climate neutrality is going to be particularly difficult [55].

Unlike all other policies described previously, the European Green Deal does not target only the energy sector, but also other branches of the economy and environment with high climate relevance, such as biodiversity, agriculture, transportation, industry, pollutions and buildings construction. It is the first time that the European Union looks at the climate issue with such a broad perspective and proposes holistic initiatives and strategies for counteracting global warming.

For the energy area, a strategy was published that represents an extension of the current agenda with support for innovation and use of technologies which potential is not fully untapped yet, like offshore wind [56]. One of the most promising fields of its focus is hydrogen, for which the European Clean Hydrogen Alliance has been formed and a separate strategy developed. The development of infrastructure for hydrogen would help to decarbonize the industry and gas sector, as well as provide new energy storage opportunities enabling the integration of more variable renewable energy to the grid [57].

One of the major goals of the Clean Energy plan of European Green Deal remains Energy system integration [58], considering actions towards creating more circular energy system, acceleration of the use of the electricity from renewable sources, promoting renewable and low carbon fuels in sectors hard to electrify and adaptation of energy market infrastructure to complex and integrated energy system. The interconnection of electricity systems and the increase of cross-border cooperation are going to play a vital part in achievement of these goals. Despite there is no separate strategy for them and they are only mentioned under the Clean Energy plan, it is expected that the current policy on the interconnection grid development will be continued and cross-border transmission lines will contribute to the utilization of more renewable energy and achievement of the climate goals.

4 European Union activities towards development of the electricity interconnection infrastructure

In light of the EU's energy policies described above, such as Third Energy Package, Energy Union and Clean Energy for All Europeans package, the development of the cross-border transmission lines might be seen as a true game-changer, enabling ambitious climate goals and market integration. A well-connected European electricity grid will translate into direct savings for the consumer. According to a recent study EU consumers could, each year, save €12-40 billion if energy markets were fully integrated [59]. Therefore, as briefly mentioned previously, there has been a number of initiatives taken in order to facilitate network growth including TEN-E Regulation, setting a target of 10% and 15% of interconnection capacities, creating a list of Projects of Common Interest and partial funding them by EU, as well as giving more competence to European organizations coordinating interconnection development. Details of those mechanisms and institutions, together with the outcome of their work achieved by now are described in the following chapter.

4.1 TEN-E Regulation

The basis for all European Union's coordinated actions towards the construction of more electrical interconnection capacities is Trans European Network-Energy (TEN-E) Regulation from 2013. Before 2013, regulations regarding interconnections, the European Community Guidelines for TEN-E, aimed to financially support analysis and planning of interconnections, mostly feasibility studies, however with a very limited budget of approximately 20 million € annually. Under that funding, the first lists of 'Projects of European Interest' were developed including electricity and natural gas interconnection projects beneficial to many European countries.

The reasoning behind extending the regulation in 2013 was that it was observed that commercial interests do not provide enough incentives for the interconnection investments and therefore, there is more political support needed to energy infrastructure than only conducting feasibility studies of cross-border projects for electricity and gas. Other identified problems were a large number of considered projects and a lack of clarity about what should be criteria for rewarding them with funds and no binding requirements that the projects would be brought to the realization.

Those issues were solved with TEN-E regulation, which created the Connecting Europe Facility (CEF) fund, aiming to support financially the development of trans-European energy, transport and telecommunication networks. In order to be entitled to apply for the EU funding, the projects first need to be qualified as a Projects of Common Interests, which evolved from Projects of European Interest and which list is updated every two years [60]. The rules of the PCI selection process were clearly specified as well and are going to be discussed in the subchapter 4.3.

TEN-E regulation assigned the duty of network planning to the ENTSO-E, which became obliged to prepare and update the Ten Years Network Development Plans. Its development bases on the electricity network model held by ENTSO-E and Cost-Benefit Analysis that they conduct. It is also required to consider all PCIs while creating the TYNDP.

Moreover, under the new TEN-E Regulation nine priority corridors are defined, covering different geographical areas and fields such as electricity, natural gas and oil. It is assumed that the realization of the infrastructure projects will boost integration of the European energy market, connect isolated regions and help accommodate renewable energy to the grid. Their purpose is to define major challenges to be solved with the development of trans-European infrastructure. Four of nine corridors regard electricity and they are as follow [61]:

1. North Sea Offshore Grid (NSOG)
2. North-south electricity interconnections in western Europe (NSI West Electricity)
3. North-south electricity interconnections in central eastern and south eastern Europe (NSI East Electricity)

4. Baltic Energy Market Interconnection Plan in electricity (BEMIP Electricity)

There are also five natural gas and oil corridors but since this work regards electrical interconnections, they are not further discussed, only listed below:

1. North-south gas interconnections in Western Europe (NSI West Gas),
2. North-south gas interconnections in central eastern and south eastern Europe (NSI East Gas),
3. Southern Gas Corridor (SGC),
4. Baltic Energy Market Interconnection Plan in gas (BEMIP Gas),
5. Oil supply connections in central eastern Europe (OSC).

Apart from the corridors, TEN-E regulation also introduced the category of priority thematic areas, whose development is particularly important to achieve European climate and energy goals. Those thematic areas are:

1. Smart grids deployment
2. Electricity highways
3. Cross-border carbon dioxide network

From the electric interconnections point of view, the second priority area, Electricity Highways is the most important. They are meant to be large grids that allow electricity to be transported over long distances across Europe. The realization of this idea started with creating an e-Highway2050 study project, a consortium consisting of ENTSO-E and 15 member TSOs supported by the EU, which developed a methodology to support the planning of the Pan-European Transmission Network by 2050 [62].

The adoption of the TEN-E Regulation brought an important acceleration of the European interconnection network construction. It introduced a consistent framework for their development including clear priorities areas and issues to be tackled, a methodology for assessing potential projects' significance and funds from which the most necessary projects can be granted.

4.2 Electricity Interconnection target

The development of the electricity interconnection among the EU member states had been an important goal for the EU governors since the beginning of the millennia. In 2002 the European Council has set a first Electricity Interconnection target, pushing member states to achieve interconnection capacity amounting to 10% of their generation by 2020. However, it was only handled with more attention in 2014, when the European Commission decided to incorporate it to the European Energy Security Strategy, at the same time suggesting extending it to the level of 15% by 2030. It was stressed that they are both attained via the implementation of Projects of Common Interest in energy infrastructure [63]. Although the target is not binding, member states and their TSOs broadly accepted them and cooperate to achieve it. The percentage level set as target for the interconnection capacities were defined using the formula given in the Equation 1.

Equation 1 Interconnection level computation formula being in force currently.

$$electricity\ interconnection\ level = \frac{net\ transfer\ capacity}{installed\ generation\ capacity}$$

Being aware of the benefits of energy interconnections, Member States have increased their interconnection capacities during the last decades. However, the latest report on the state of the Energy Union (23 November 2017) finds that eleven Member States have not yet reached the 10 % electricity interconnection target, so need to step up their efforts Those states are Bulgaria, Cyprus, Germany, Spain, France, Ireland, Italy, Poland, Portugal, Romania and the United Kingdom. Despite that, EC predicted that only four will be unable to reach the 10% interconnection target by 2020, which are Cyprus, Spain, Poland and the United Kingdom. [64]

The progress on the target is monitored by several bodies, one of which is an Expert Group on electricity interconnection targets, established by the European Commission Decision of March 2016 [65]. The group conducts the meeting on a regular basis and the major outcome of their work is publishing the report "*Towards a sustainable and integrated Europe*" where the current situation is analysed together with efforts necessary to achieve the 2030 goals [66].

One of the conclusions from the report is that the definition of measurement of interconnectivity does not answer the specifics of the European energy system and needs to be updated. The simple ratio of the cross-border transmission and generation capacities were well enough when settled in 2002 when there was no significant discrepancy between peak consumption and installed capacities. Since then, the situation of electricity systems of European countries changed a lot, particularly by increase of the large capacities of VRE. Due to their unstable manner of operation, the need for the capacities installed in the system is larger, despite consumption remaining at the same level. This may lead to decrease of the interconnection level without representing that the energy security actually decreases. By 2030, for when the next interconnection target is set, RES generation in the electricity sector will cover 45% to 60% of the overall demand within Europe and the difference between peak consumption and amount of reserve capacities will even grow.

Taking this into account, it is stated that with the formula proposed in 2002, certain countries with the largest renewable growth, despite keeping the same consumption and building new interconnection capacities might have decreasing interconnection level. Moreover, net transfer capacities, used as a numerator in the formula, highly depends on the current market conditions and due to the conditions of the surrounding network might be periodically limited and lower than the nominal transmission capacity.

Therefore, the Expert Group recommends to extend the definition of the interconnection levels with two additional formulas:

Equation 2 First interconnection level formula update proposed by the Group of Experts for 2030.

$$electricity\ interconnection\ level\ =\ nominal\ transmission\ capacity / peak\ load\ 2030$$

or

Equation 3 Second interconnection level formula update proposed by the Group of Experts for 2030.

$$electricity\ interconnection\ level\ =\ nominal\ transmission\ capacity / installed\ renewable\ generation\ capacity\ 2030$$

Whether the European Commission will implement this change suggested by the experts it is not decided yet. However, the recommendation has strong reasoning and would probably bring a clearer view on the interconnection conditions in Europe.

In order to compare different methodologies of assessing the interconnection level, the author has conducted own computations, using data for 2018 collected for the modelling of the European interconnection network, being the subject of the later stage of this work. Presented values of the interconnection levels are not to indicate what is the actual level of countries' progress on meeting the target, but rather to show how different values might be achieved while using different methodologies. The major disadvantage of these computations is that in the first original method, the author was lacking data of net transfer capacities and nominal transmission capacities were used instead. The difference between the parameters results from the surrounding network capabilities and market conditions, and although it should not be large, it may affect the results.

Table 2 - Interconnection capacities and level of meeting interconnection target for all considered countries, using original 2002 formula and transmission capacity to peak load proposed by the Expert Group, computed by the author

Country	**Interconnection capacity 2019 [GW]**	**Generation capacity 2019 [GW]**	**Peak load 2018 [GW]** [67]	**Interconnection level with 2002 method**	**Interconnection level with the 1st Expert Group's method**

Austria	11.8	21.3	12.1	55%	98%
Belgium	8.6	23.1	13.5	37%	64%
Bulgaria	1.9	12.7	6.5	15%	29%
Croatia	3.2	5.0	3.2	64%	99%
Cyprus	0.0	1.5	1.0	0%	0%
Czech Republic	9.5	20.8	11.1	45%	85%
Denmark	7.4	15.9	6.1	46%	121%
Estonia	1.8	2.8	1.5	65%	120%
Finland	3.9	17.3	14.2	23%	28%
France	22.3	130.7	96.3	17%	23%
Germany	28.4	222.4	79.1	13%	36%
United Kingdom	4.7	78.4	61.4	6%	8%
Greece	1.1	17.1	9.1	6%	12%
Hungary	6.4	9.1	6.6	70%	97%
Ireland	0.5	9.8	4.9	5%	11%
Italy	11.0	94.4	57.6	12%	19%
Latvia	2.0	2.8	1.3	71%	161%
Lithuania	2.4	3.6	2.0	67%	121%
Luxembourg	1.1	0.3	1.0	409%	105%
Malta	0.2	0.7	-	30%	-
Netherlands	11.2	30.5	18.5	37%	61%
Norway	8.7	30.5	24.1	28%	36%
Poland	6.0	42.5	24.5	14%	24%
Portugal	4.0	19.6	8.7	20%	46%
Romania	2.2	18.8	8.9	12%	24%
Slovakia	5.5	7.6	4.5	73%	122%
Slovenia	4.7	3.7	2.4	127%	199%
Spain	7.6	104.7	40.6	7%	19%
Sweden	12.3	40.8	27.4	30%	45%
Switzerland	16.8	16.1	9.8	105%	172%

From the table, it can be clearly noticed that for the vast majority of the countries (with Luxembourg as an only exception), interconnection levels computed with the Expert Group's definition are significantly higher than with the original one. However, the scale of the difference varies among the countries. The ratio of interconnection level obtained with one measurement method to another takes the lowest value (1.22-1.36) for countries such as Finland, United Kingdom, France, Norway whose electricity systems are based on stable generation sources like nuclear, hydro, biomass or fossil fuels, while the highest values (2.25-2.81) occur for Portugal, Spain, Denmark and Germany, which are European leaders in solar and wind energy.

It was noted by the Expert Group that those differences among the countries do not answer the difference in energy security and the new approaches reduce that discrepancy. They also concluded that with the new methodology, the level of 15% for 2030 is too low for the needs of the European countries' interconnection capabilities, and therefore the number needs to be revised on the next meetings of the Expert Group.

Although the author's calculations results do not fully represent real interconnection level as it is computed by the European Commission, there might be clearly stated countries whose interconnection level is significantly lower and those are the same as mentioned at the report of on the state of Energy Union from 2017 [64]. The problems with meeting the targets for Poland, Spain and the United Kingdom, one of the largest EU's energy systems, is that due to their size they need to develop many more interconnections and since they are located at the edges of the EU, energy bridges to the rest of Europe are very narrow. Achieving the interconnection target is a challenge for most of the largest countries, what might be seen for Germany, France or Italy case as well but due to their central geographical position in the EU, they managed to build it.

Particularly interesting is the case of Greece, which according to Table 2 is far below 10% goal. However, the table considers only interconnections with other EU countries extended with Norway and Switzerland, and since Greece has a peripheral location in the EU and is surrounded by non-EU states like Turkey, Macedonia or Albania, their cross-border transmission lines with those states would increase Greece interconnection level.

It is also important to mention the situation of two island countries, Ireland and Cyprus, for which achieving targets is difficult due to the need of laying subsea cables. Ireland has now only one HVDC interconnection with the United Kingdom via the Irish Sea (East West Interconnection [68]). Currently, Ireland strengthens their network with the United Kingdom, both inland with North Ireland (North South Interconnector [69]) and offshore (Greenlink project [70]). Furthermore, there is also a plan to develop the first interconnection between Ireland and France (Celtic interconnector [71]).

In the case of Cyprus, for a long time, it stayed the only EU country with no single interconnection with other countries. However, it is to change in 2023, when the EurAsia Interconnector will be completed linking Cyprus with two other states Israel and Greece, via another poorly interconnected island, Crete [72]. The project is one of the most important PCIs and was co-financed from the funds of Connecting Europe Facility of the European Union.

Looking at the broad picture of the European Countries and their levels of interconnection capacities, it might be stated that despite certain regional difficulties, they mostly meet their target for 2020 and that the cross-border transmission system allows for the exchange of large amounts of the electricity. However, due to the expected large growth of renewable energy share in the European grid, the levels which are satisfying for now soon might be found not enough and there is much work ahead to achieve the next interconnection target for 2030. Despite it remains unclear whether it will be 15% or other number and what will be the methodology, the main message is constant, only fully interconnected grid will allow Europe to integrate their energy market and accommodate more renewable energy.

4.3 Projects of Common Interest

The 10% and 15% interconnection capacity targets are to be achieved with the financial support provided by the EU to the cross-border projects of high importance. The TEN-E Regulation adopted in 2013 [73], together with the Connecting Europe Facility (CEF) [74] enabled to creation a list of Projects of Common Interest which are key infrastructure projects, linking energy systems of EU countries. They are intended to help the EU achieve its energy policy and climate objectives: affordable, secure and sustainable energy for all citizens as well as resulting from the Paris Agreement decarbonisation of the economies.

Interconnections from the PCI list benefit from accelerated planning and permit granting, improved regulatory conditions, lower administrative costs due to streamlined environmental assessment processes, increased public participation via consultations, and increased visibility to investors. Another incentive is that PCIs are entitled to apply for funding from the Connecting Europe Facility. The Projects of Common Interest are designed and implemented by both Transmission System Operators and private investors. Current projects are in different stages of development; some are under construction, but many are still in the early phases of preparation.

The first PCI list was published together with the TEN-E Regulation in 2013 and since then is being updated every two years. There are multiple stakeholders involved in the process of selecting PCI, which aims to ensure broad consensus over the final choice. The five criteria which listed projects needs to meet are:

1. Have a significant impact on at least two EU countries;
2. Enhance market integration and contribute to the integration of EU countries' networks;
3. Increase competition in energy markets by offering alternatives to consumers;
4. Enhance the security of supply;
5. Contribute to the EU's energy and climate goals. They should facilitate the integration of an increasing share of energy from variable renewable energy sources [75].

The selection of the projects is based on the network development plans of national TSOs', together with the TYNDP developed by ENTSO-E and ENTSO-G. During the process, the applications are checked by National Regulatory Authorities according to the criteria of cross-border relevance. Before it goes through the European Commission, Council and Parliament, the list of the chosen projects needs to be accepted by ACER and broadly discussed with the European community during public consultation [60].

The Connecting Europe Facility is a fund mechanism designed to support the development of the cross-border infrastructure in the EU. Apart from the Energy sector, it covers funding of projects related to the fields of Transport and Telecommunication. The total budget of CEF for 2014-2020 is EUR 30.4 billion from which EUR 5.35 billion were allocated to energy projects including electricity, gas and smart cities [60]. Based on the calls for proposals, certain PCIs are rewarded with funds that, despite not covering the full scope of investment, allow to be funded not entirely from the market, reduce the risk and increase credibility while searching for investors.

4.4 ENTSO-E

The organization responsible for overseeing the European grid infrastructure development and ensuring its optimal functioning for the ambitious European climate and energy agenda is the European Network of Transmission System Operators for Electricity (ENTSO-E). It was established by the EU's Third Energy Package and as for 2020 represents 42 electricity Transmission System Operators from 35 countries.

ENTSO-E realizes this duty via many actions, one of which is drafting and contributing to the implementation of network codes for the associated TSOs in order to align electricity systems among the countries and facilitate harmonization and integration of the European electricity market. ENTSO-E is also a platform for the technical collaboration among TSOs on a both the pan-European and regional levels.

One of the key principles of ENTSO-E is the transparency of European energy systems data. Resulting from that, ENTSO-E runs an online platform publishing a broad set of data regarding generation, transmission and load data gathered from the associated TSOs and serving researchers and policymakers for their analysis. Apart from that, ENTSO-E enhances new energy transmission technologies development by coordinating R&D plans, innovation activities and participation in Research programs like Horizon 2020 [76].

ENTSO-E is also responsible for the constant monitoring, reporting and planning of the European interconnection network. It publishes summer and winter outlook reports for electricity generation for the short-term system adequacy overview as well as long-term pan-European network development plans (TYNDPs). The latter identifies transmission projects of trans-European significance beneficiary to be realized within the 10 year time span.

The latest TYNDP was published in 2018 and it suggests 166 transmission and 20 storage projects to be implemented to the European grid by 2030 with a total cost €114 billion and bringing annual savings of €2 to €5 billion on the generation side [77]. In its planning process, ENTSO-E defines different scenarios of the European energy system development including generation sources and demand, identifies needs for cross-border transmission or storage, compares that with the projects already being under consideration, for which it conducts Cost-Benefit Analysis (CBA). CBA's goal is to analyse each project based on the criteria such as energy price differences reduction, renewable energy integration, grid losses reduction, system flexibility and stability, as well as their capital and operational costs. Based on that it is possible to find which projects would be the most beneficial for Europe and should be listed on as the PCI [78]. The next publication of TYNDP is expected in fall 2020.

5 Modelling of the cross-border transmission lines in Europe

The purpose of this chapter is to depict the process of modelling of the interconnection network in Europe.

The modelling conducted for that work has focused on extension of the OSeMBE model, representing the electricity system of 30 European countries (the EU Member States extended with Norway and Switzerland). Work performed in this thesis consist of addition of the cross-border transmission lines modelling to the already existing model. That model, having data about energy generation technologies, energy demand and interconnections among countries, optimizes investment in the new capacities necessary for covering energy needs. The time span of the obtained results of carried modelling was from 2015 to 2060.

The work is based on the OSeMBE model, which quite accurately captures the situation inside of the modelled countries. However, it used a simple approach for the interconnection modelling. Therefore, this work focused on collecting data and utilizing it for the development of a more detailed representation of electrical interconnections among European countries. The whole work was conducted using the Modelling environment OSeMOSYS.

Extension of OSeMBE done under this work, introduces techno-economic data about the construction of the new interconnections. Therefore, it is possible to optimize interconnections capacity in the European electricity system. One might even derive suggestions on which borders there is a need to expand existing interconnections and validate if the investments planned are indeed beneficial. The model extension has an impact not only on the shape of the future interconnections, but also might give different results of the optimal mix of energy generation technologies in comparison with original OSeMBE model on which is based.

Creating new scenarios is simple, therefore the model might serve researchers aiming to analyse closer the development of the European energy sector under different conditions and circumstances.

5.1 The modelling system OSeMOSYS

OSeMOSYS, stands for the Open Source energy Modelling System. It is a systems optimization model for long-term energy planning. It was the first energy system optimization modelling framework which code, and solver were all fully open source [79]. It gives the possibility to conduct energy modelling to the broad community of students, business analysts, government specialists, and energy researchers, without the requirement of financial investment.

OSeMOSYS's objective is to minimize the net present value (NPV) of the energy system to meet given demands for energy services. It considers the operation and capital costs, as well as emission penalties.

OSeMOSYS gives an opportunity for modelling many user-defined constraints of the energy system such as limitations on emissions, total capacities of given technology, annual added capacity or activity of technologies.

5.2 The OSeMBE model [80]

OSeMBE, is the abbreviation for Open Source energy Model Base for the European Union. It is a power sector model of European countries developed within OSeMOSYS. It was created at KTH and described in the Master's thesis *The Open Source Energy Model Base for the European Union (OSEMBE)* [81]. It was done under REEEM project ("Role of technologies in an energy-efficient economy – model-based analysis policy measures and transformation pathways to a sustainable energy system"), funded by the EC within the Horizon 2020 Competitive Low-Carbon Energy program [82]. KTH's Department of Energy Technology was one of the 11 modelling institutions involved in REEEM.

OSeMBE includes 30 European countries as specified in Table 3.

Table 3 Countries considered in OSeMBE model [80].

No	Country	Code	No	Country	Code
1	Austria	AT	16	Latvia	LV
2	Belgium	BE	17	Lithuania	LT
3	Bulgaria	BG	18	Luxembourg	LX
4	Croatia	HR	19	Malta	MT
5	Cyprus	CY	20	Netherlands	NL
6	Czechia	CZ	21	Norway	NO
7	Denmark	DK	22	Poland	PL
8	Estonia	EE	23	Portugal	PO
9	Finland	FI	24	Romania	RO
10	France	FR	25	Slovakia	SK
11	Germany	DE	26	Slovenia	SI
12	Greece	GR	27	Spain	ES
13	Hungary	HU	28	Sweden	SE
14	Ireland	IE	29	Switzerland	CH
15	Italy	IT	30	United Kingdom	UK

Each year under the modelling period is split into time slices which aggregate periods within which levels of load and of generation are similar enough to represent them under one value. There were 15 time slices defined for OSeMBE and that number was the result of multiplying 5 seasons and 3 day brackets (night, day and peak). Although the whole modelling period was from 2015 to 2060, it is considered that the results are accurate only until 2050, therefore observation period is only up to that date.

For each country modelled in OSeMBE, energy technologies and energy commodities are defined as listed below.

Generation technologies: Combined cycle, Combined heat and power, Conventional, Distributed PV, Dam, Pumped Storage, Fuel cell, Gas cycle, Nuclear Power Generation 2, Nuclear Power Generation 3, Internal combustion engine with heat recovery, Offshore Wind, Onshore Wind, Steam cycle, Utility PV and Wave power [80].

Transfer, infrastructure and grid technologies: Transmission and distribution, trans-border electricity transmission, oil refinery [80].

Energy commodities: Biofuel, Biomass, Coal, Electricity, Electricity 1, Electricity 2, Geothermal, Heavy fuel oil, Hydro, Natural gas, Nuclear, Ocean, Oil, Sun, Uranium, Waste and Wind [80].

As in every OSeMOSYS model, all technologies had defined values of techno-economical parameters such as Capital, Fixed and Variable costs and Efficiency, Availability Factor, Capacity Factor, Emissions, Operational Lifetime. Within this framework, for each country, there are implemented data of Residual Capacities of all technologies from 2015 and expectation until the end of modelling period of Electricity Demand together with its profile over the time slices.

In regard to interconnections implemented in the original OSeMBE model, a simplified approach was taken. Modelled interconnections had only defined existing capacities and already announced investments from the list of PCIs. However, there was no data about their costs and therefore, no option for the model to build anything over that and to have any freedom in optimizing the shape of European interconnections network [81].

In this thesis, only the interconnection part of OSeMBE was modified, leaving as it was the rest of the model. Therefore, the description given in this work disregards all previously existing parts of the model, not related to the interconnection system. However, when running simulations of the scenarios of European electricity system development both parts are necessary and achievements of the OSeMBE developers are fundamental for that purpose.

5.3 Methodology of interconnection modelling

This section's aim is to give a comprehensive description of all the phases of the modelling process. It is divided into the two sections. The first consists of description of the all necessary data and its collecting. The second describes the implementation into the model. Both are discussed here in the following subchapters.

This work consists of cross-border transmission lines of the 30 modelled countries of Europe. However, in reality, there are existing and planned or considered connections with the third countries. Despite that, for the purpose of the simplification and compatibility with OSeMBE, EU with Norway and Switzerland are taken as an isolated system without import or exports of electricity with regions and countries such as non-EU Balkan states, Northern Africa, Middle East, Russia etc.

Interconnections among the European countries were modelled within OSeMBE as technologies which link energy commodities of Electricity of two countries. There was no split into the different technologies (like HVDC and HVAC) made in the model, just one common interconnection technology was developed on every border and the reason of that is to be discussed in the subchapter regarding Data collecting for Capacities and costs of the new lines.

Despite the fact that for each modelled border there are two possible cross-border flows, they were aggregated under one technology. The distinction among them is done with a mode of operation so that in each mode of operation another direction of the flow is allowed. The consequence of this approach is that the capacity of the lines has to be the same for both directions, despite that in reality due to the specific technical conditions of the grid at each side of the borders, those capacities might vary. However, the motivation for such a solution is that in the case of modelling another technology for each direction there would be the risk that at the later stage when optimizing the network, there are going to be developed capacities in the one direction only, which is physically impossible. Two-technologies-approach would also bring a problem with the cost of building each of them since all available historical data is given for the lines which operate in both directions.

For each of them there need to be defined the following parameters to allow the model to run properly:

- Residual capacity – a capacity which was already been built before the model observation period
- Capital Cost in M€ per GW
- Fixed Cost in M€ per GW per year
- Variable Cost in M€ per GWh
- Operational lifetime
- Availability factor

5.3.1 Data collection

In order to model European interconnections with high accuracy, information about the current state and plans is essential. Information needed to be collected regarded first already existing capacities and their technical parameters and limitations, and then about new capacities planned to be built, together with their capacities and all costs. It is important to mention that in the OSeMBE model, all interconnections between two given countries, despite in reality they might be several separate lines, are aggregated into one connection per border. Its capacity needs to be equal to the sum of all separate ones, while costs of construction and operation of the new ones is the average cost of new projects per GW or its estimation.

5.3.1.1 Capacities of the existing lines

The first step was to gather data about interconnections being under operation and their technical parameter. For that purpose data for the interconnections were extracted and estimated from the historical data of the whole European electricity system. It was done by collecting a set of data of historical hourly cross-border physical flows from the Transparency platform of ENTSO-E for years 2015 and 2019 and then finding their maximum values [83]. For years 2015-2018 data from 2015 was used and from 2019 onwards, data from 2019.

For each border, the two values of capacities into both directions were compared and the larger of them was used for the modelling. This way, with an assumption that at least once a year each interconnection operates with its maximum technical capacity, it was made sure that model will consider only their technical maximum and no other limitations. Those values were later used as a residual capacity.

An alternative approach would be to look at the data of the Forecasted Transfer Capacities published at the same Transparency platform [84], which are monthly maximum interconnection capacity allowed to be transferred by each TSO (might be also called Net Transfer Capacities). However, their values are not exactly equal to the technical possibilities of the interconnections (Total Transfer Capacities), while computing them TSOs subtract Transmission Reliability Margin which covers the forecast uncertainties of the power flows [85]. That reliability margin might differ from month to month depending among others on renewable energy production, therefore there is no clear value of Net Transfer Capacity for each year, as required for the OSeMOSYS.

That issue of not full utilization of cross-border capacities and variable transfer availability over the year could be solved with the introduction of capacity factors to the interconnections, computed based on the historical flow for every time slice. However, since those capacity factors would not really represent technical limitations but electricity market conditions which might change with the expansion of the interconnections network, in the end, it was decided to abandon that methodology and take the first described approach.

5.3.1.2 Capacities and costs of the new lines

Once having all the necessary information about the current state of the interconnection network in Europe, the second part of data required for modelling European transmission grid was collecting data about interconnections' cost. That was to allow the model to optimize building of the new capacities. That process was based on the research on plenty ongoing, planned or considered investments and their specific characteristics. The data was grouped by border and set of averaged parameters were generated for the transmission technology at each border.

For the generation of the needed parameter multiple sources were used, but the main ones were lists of the Projects of Common Interests [86] [87] published in 2013 and updated in 2015, 2017 and 2019 [88], [89], [90], as well as the list of the projects from the Ten Years Development Plan 2018 of ENTSO-E [29]. Those sources combined gave all information about the capacities of the lines, their locations, expected years of construction and investment and operational costs. Wherever possible, those parameters were cross-checked with the information published by local TSOs and updated if any changes happened from TYDP 2018 publication.

In order to collect enough data about as many borders as possible, research on them included both, projects which are planned, developed or already under construction, as well as projects which were merely considered or far away on the time horizon, therefore there is no certainty that they are ever going to be executed. However, it was assumed that whether they are economically viable or not to actually allow for the investment, the publicly available data about their capacities and costs are accurate enough to serve for this model.

Among the projects gathered there emerged two dominant technologies of transmission, overhead HVAC for the land connections and HVDC cables for the subsea ones. Apart from them, there were some projects where those two were combined or few with on-land DC links or subsea HVAC cables, but their share is neglectable.

Unlike in the case of the energy generation technologies, where cost can be estimated depending on the capacity of the unit, for transmission lines, it is related to both the capacity and the line's length. That brings certain difficulties in modelling since the latter of the parameters is specific for each project and cannot be directly represented in OSeMOSYS. Therefore, having the average cost for the technology inserted to OSeMOSYS is not sufficient to model it, since distances among countries would affect the model reliability too much.

In order to solve this issue, an approach was developed, differing from the one used for energy generation technologies. Instead of relating the cost of the interconnection lines on the specific technology, they are related to the border they are located at. Therefore, instead of having technologies such as subsea HVDC or overhead HVAC with the same costs of construction throughout all Europe, there is one transmission technology per border defined in the model, which parameters represent the average of all interconnections on this border from the database. Cost parameters of those technologies defined in the model do not represent their technical parameters of real technologies such as HVAC or HVDC.

Projects presented in Table 4 and Table 5 are aggregated by border so that it is clear at which border, in which year, what capacities are considered to be built and what is going to be their investment cost and operational cost. While the years of the construction of each capacity was for now kept aside to be used on the later phase when developing different scenarios to be tested, investment cost and operational cost were used to compute weight average of the capital cost and fixed cost of 1 GW of each border-specific technologies.

Table 4 Interconnections form PCI list used for the modelling process together with their key parameters.

PCI number	Country 1	Substation 1	Country 2	Substation 2	Capacity [MW]	Finish year	CAPEX [M Euro]	OPEX [M Euro/ year]
1.3.1	Denmark	Endrup	Germany	Klixbull	500	2023	210	2
1.6	France	La Martyre	Ireland	Great Island/ Knockraha	700	2026	930	8.4
1.7.1	France	Cotentin	Great Britain	Exeter	1400	2023	850	7.6
1.7.3	France	Coquelles	Great Britain	Folkestone	1000	2019	580	4.5
1.7.5	France	Dunkerque	Great Britain	Vicinity of Kingsnorth	1400	2024	906	23.9
1.8.1	Germany	Wilster	Norway	Tonstad	1400	2020	1850	15
1.9.1	Great Britain	Wexford	Ireland	Pemborke	500	2023	396	8
1.10.1	Great Britain	Blythe	Norway	Kvilldal	1400	2021	1850	15.4
1.10.2	Great Britain	Peterhead	Norway	Simadalen	1400	2024	1613	10
1.14	Denmark	Revsing	Great Britain	Bicker Fen	1400	2023	1970	16

1.15	Belgium	Antwerp area	Great Britain	Vicinity of Kemsley	1400	2028	1000	8
1.20	Germany	Wilhelmshaven region	Great Britain	Isle of Grain in Kent	1400	2023	1500	22
2.4	Italy	Codrongianos and Suvereto	France	Lucciana (Corsica)	100	2024	750	7
2.7	France	Nouvelle Aquitaine	Spain	Basque Country	2200	2025	1750	10.2
2.13.1	Ireland	Woodland	Great Britain	Turleenan	950	2023	349	0.6
2.13.2	Ireland	Srananagh	Great Britain	Turleenan	570	2029	396.2	0.79
2.14	Switzerland	Thusis / Sils	Italy	Verderio Inferiore	850	2022	609	1.9
2.17	Portugal	Ponte da Lima	Spain	Beariz	1900	2021	111.5	1.1
2.27.2	Spain	Navarra	France	Landes	1500	2027	1470	9.5
2.27.1	Spain	Aragón	France	Marsillon	1500	2027	1170	6.03
3.1.2	Austria	St. Peter	Germany	Isar	2000	2022	375	3
3.4	Austria	Wurmlach	Italy	Somplago	150	2021	92	1.6
3.7.1	Bulgaria	Maritsa East 1	Greece	N. Santa	1350	2023	80	1.1
3.9.1	Hungary	Žerjavenec / Hévíz	Slovenia	Cirkovce	1200	2021	132.5	0.12
3.10.2	Cyprus	Kofinou	Greece	Korakia, Crete	2000	2023	3844	35.6
3.16.1	Hungary	Gönyű	Slovakia	Gabčikovo	1850	2020	81.63	1.5
3.21	Italy	Salgareda	Slovenia	Divaa/ Bericevo	1000	2027	755	4
4.2.1	Estonia	Kilingi-Nõmme	Latvia	Riga CHP2	600	2020	120	0.6
4.8.10	Poland	Zarnowiec	Lithuania	Darbnai	1000	2025	650	6.5
4.10.1	Finland	Keminmaa	Sweden	Messsaure	900	2025	154	0.24

Table 5 Other than PCI interconnections used for the modelling with their key parameters.

Country 1	Country 2	Capacity [MW]	Finish year	CAPEX [M Euro]	OPEX [M Euro/ year]
Czech Republic	Slovakia	550	2034	86.3	0.6
Denmark	Poland	600	2033	655	13
France	Belgium	1000	2021	140	0.4
France	Germany	300	2025	49	0.7
Germany	Poland	1500	2035	171	2.9
Germany	Switzerland	1000	2034	58	0.3

Germany	Luxemburg	1000	2025	158	1.3
Netherlands	United Kingdom	2000	2030	850	6
Netherlands	Belgium	1000	2022	60	0.1
Romania	Hungary	1117	2030	200	0.8
Sweden	Germany	700	2026	660	1

Despite having a large number of future projects and data for them, not all of the considered European borders are covered. Only 36 out of 60 borders have enough information about the costs to model their future development. Therefore, for the remaining 24 interconnections, their capacities are going to be fixed on the level of 2019, without a possibility of any change. That is a clear disadvantage and limitation of the model, but an attempt of approximation of these interconnection's costs might lead to misleading results and conclusions. It was assumed that if currently there is not even a discussion of new lines to be built there will not be a large variation from the reality to neglect such projects.

Furthermore, there was a need for assigning values for the parameters such as the operational life of the newly built interconnection capacities, their efficiency and availability. For the first of these parameters, according to [91] it was assumed 40 years as it is the minimum requirement of the TSOs nowadays while developing new transmission lines. For the other two parameters, availability factor and efficiency of the interconnections, they were assumed equal to the ones taken in the original OSeMBE model for the transmission system availability and efficiency and therefore equal respectively 0.95 and 0.95. That assumption of equalizing interconnections with the transmission is based on the conclusion that essentially those two technologies are the same and the only thing that differentiates them is location since transmission system covers connections within one country and interconnections link different countries.

5.3.2 Implementation to the model

All the data collected and processed as described in the previous sub-chapter needed to be implemented to the format readable for the OSeMOSYS optimizing solver. The data set was prepared in excel tables given for each parameter.

One of the first tasks to do was proper naming interconnection technologies according to the naming convention of the OSeMBE model, as presented in Table 6.

Table 6 Naming convention of the technologies used in OSeMBE [80].

AA	**BB**	**CC**	**D**	**E**	**F**	**AABBCCDEF**
Country	Commodity	Technology/ connected country	Energy level	Age	Size	Full Technology name

The codes for the modelled countries can be found in Table 3. Commodity used for all interconnection technologies was electricity, so the code used was EL. For the interconnection technologies, the energy level code is P since a primary energy commodity is an output. Age, as for the interconnection was represented with H and size with 1 but those codes do not have any meaning in that case, they are just a residual from the OSeMBE. Therefore, the final name of the interconnection technologies is going to be alike XXELXXPH1, where only countries codes change.

For each border, there is only one technology, but there are 2 modes of operation defined so that electricity flow might happen in both directions. There might be an only one value of the capacity specified for the technology and that is the reason why although in reality sometimes capacities of the interconnections varied depending on the direction of the power flow, for the modelling the larger value from the database was taken into account.

An alternative approach would be to have one technology for each direction with separated capacities. This way however there would be a problem with modelling their costs since for the analysed projects there is one value of capital cost given and as a result of the investment new lines is able to transfer energy in both directions, even if due to some other restrictions those capacities are not equal. Having them modelled separately, with half of the basic cost assigned for each direction might result with unphysical results, therefore it was decided to stick with the first method.

Residual capacities were modelled according to the data of existing capacities between the countries as described in the sub-chapter *Capacities of the existing lines*, with values from 2015 for the period 2015-18 and from 2019 for 2019-2060. It would be reasonable to gradually decrease these values over time, since the old transmission lines are retiring and are going out of the operation. However, due to the long-time of the operation of the transmission lines (much longer than energy generation technologies) and also lack of reliable data about which of them is to retire when, it was decided to leave them constant. It might be also motivated with an argument that the general trend in the European electricity system is to increase the interconnection capacities, so the ones which are shut down would be certainly replaced with the new ones.

Values of the capital costs for the new lines were modelled as described in *Capacities and costs of the new lines*. Regardless of expected technologies development and decrease of their costs, those values were kept constant over the entire time span of the modelling. Costs of the lines which are lacking data are not given so that building new capacities for them will not be modelled.

For the fixed costs, for the 36 interconnection technologies with enough data, they were taken directly as an average operational cost of projects for the given border from *Capacities and costs of the new lines*. For the ones with no data, since the value is needed for the operation of the residual capacities, an average of all projects was taken. For both, it remains constant for the whole modelling period.

Variable costs of the interconnections were considered to be zero, following the assumption that the amount of the energy transmitted by the lines does not influence their operation cost, which was already modelled accurately enough as the fixed costs.

For all of the technologies, there was a need to define a parameter called capacity to activity ratio, defining what would be the energy amount processed by 1 unit of technology if it was operating for the entire year with no pause. Since the units used in the model are GW and GWh, that parameter took the value of 31.536.

Efficiencies of the interconnections were modelled together with specifying what are the inflowing and outflowing energy streams for each interconnection technology, using parameters of Input Activity Ratio and Output Activity Ratio. Those two parameters serve to specify for each mode of operation which commodities enter the technology, and which leave, together with ratios between their energy streams. Therefore, Input Activity Ratio was equal 1 and constant over the whole modelling period, for each technology in 2 Operation Modes with energy commodity for each of them representing Electricity of the countries linked by the given technology. On the other hand, to reflect on the efficiency, Output Activity Ratio had values of 0.95 with the same logic as the previous parameter, with the only difference of swapped Operation Modes.

In the modelling process, there were two more parameters used, however, they were not necessary for the model itself to run, but to impost certain boundaries on the scenarios that are going to be tested and analyzed. Those parameters were Total Annual Max Capacity, which defines what is going to be the maximum capacity of each technology in the system for each year (sum of residual and new built ones) and Total Annual Min Capacity Investment, defining the minimum capacity of the technology to be built per year.

6 Modelled scenarios

The model enhancement as described in the previous chapter takes into account only techno-economical parameters of the interconnections and energy generation technologies but does not consider the broader view of the energy market such as TSOs plans for the cross-border transmission development or time limitation on the new capacities construction pace. However, due to the wide range of OSeMOSYS parameters not included in the modelling yet, it might be adapted to simulate different scenarios of the European electricity system development.

Based on the analysis of the current EU policies and projects of TSOs being developed or planned, four of scenarios have been developed in this work. This chapter describes their motivation and major assumptions as well as technicalities of their modelling process.

6.1 Scenario 1 – Maintaining existing interconnections capacities only

The major assumption of the first scenario modelled within OSeMBE was that there is going to be no more new interconnections in Europe built, and their capacities are going to remain constant as they were defined for 2019.

That assumption clearly is far from reality, since we already know that there are works ongoing on the several projects, and many more have secured founding and permissions. However, the purpose of the scenario is not to see what is certainly going to happen or to optimize the mix of interconnections in Europe, but rather having a look on the rest of European electricity system. The analysis of scenario 1 will look in particular into the energy generation technologies and their development necessary to meet the demand without any new interconnections built throughout the entire modelling period.

In order to model this scenario, there was one extra parameter added to the model compared to the baseline described in chapter *Methodology of interconnection modelling*. That parameter was Total Annual Max Capacity, which for all the interconnection technologies was set equal to the Residual Capacities.

6.2 Scenario 2 – All PCIs realized on time

In the second scenario, it was assumed that all interconnections whose construction is already ongoing or there are listed as the EU's PCI. The full list of projects included in this scenario, together with their capacities and year of construction is presented in Table 4.

Those projects were chosen from the full planned interconnections database developed during the research phase since they are the most probable to be accomplished as scheduled. PCIs that have already secured partial funding from the European Commission and others which are under construction might be expected to be finalized on time. Therefore, this scenario is the most likely to correspond to the reality and future interconnections grid development.

Technically, this scenario was modelled using two parameters, Total Annual Max Capacity and Total Annual Min Capacity Investment. First of them takes values of the residual capacities enlarged by the values of the new capacities from the construction year, while the latter takes values of the capacities built every year. This way model allows to build new capacities only up to the considered projects' capacity and at the same time enforces their construction.

Scenario 2, as well as Scenario 1, do not allow the model to optimize the capacity of the interconnections in the European electricity system, instead, they impose stiff constraints on them and optimize the rest of the system, capacities of energy generation technologies. Therefore, based on them it is only possible to see what the most cost-efficient energy mix for Europe and its cost in both cases would be, without specifying if interconnections planned by European TSOs are the best solution.

Cost analysis of both scenarios is going to be particularly important. It is expected to see Scenario 2 being cheaper to develop, even though there are more lines to be built than in Scenario 1. However, this cost difference is to be covered by the reduced cost of construction of new energy generation technologies. Validation of that hypothesis, together with the analysis of those two different energy mixes of Europe is going to be the major purpose of comparison between those two scenarios.

6.3 Scenario 3 – Optimizing PCIs realization

In order to conduct not only analysis of the European energy mix in the conditions of fixed interconnection development schedules, but also to actually optimize the capacity of interconnections among European countries, two more scenarios were developed. Scenario 3 aims to validate which of the projects used for Scenario 2 (Table 4) are viable from the European electricity system point of view.

For that purpose, the model was allowed to build new capacities of interconnections within the range of maximum capacities of the considered projects. Therefore, it conducts optimization of the installed capacity of the interconnections among the already ongoing and concretely considered projects, in the time span until 2030. The scenario was modelled using the parameter Total Annual Max Capacity, which similar to Scenario 2 took the values of the residual capacities enlarged by the values of the new capacities from the construction year, however, in this case, the Total Annual Min Capacity Investment parameter was not applied, so there was no enforcement of the construction and room for the optimization.

6.4 Scenario 4 – Extending PCIs after 2030

The last modelled scenarios, Scenario 4, has the aim of free optimization of the future European interconnections network capacities over the entire time span of the model and without limitation on the capacity. It was one of the major disadvantages of the Scenario 3, that it takes into account only projects being already under development and which realization time was for 2020-2030 only, with no modelling of what is to happen afterwards.

In Scenario 4 this issue is to be fixed, by removing limits on newly installed capacities after 2030 so that much more connections than in the previous case might be built. The limits for the capacities built before 2030, equal to the capacities of the projects from the Table 4, were maintained. That results from the assumption that project development phase of the new interconnection is demanding and takes a couple of years, so it would not be possible to have new capacities built in the upcoming years if no action for that was taken by now. Since there are no more projects than ones already considered, in the European TSOs' development plans, it might be expected that there will not be any other investments.

Described variation from the Scenario 3, was made by setting the parameter Total Annual Max Capacity for each interconnection equal sum of residual capacities and newly built capacities until the year 2029 and from 2030 onwards removing the limits. Thanks to having data about the projects which were only considered and are not sure to be realized (presented in Table 5) it is also possible for the model to decide on constructing interconnections at the borders not included on the list of PCI projects from Table 4.

7 Results

For each of the scenarios described in the previous chapter, there was performed a simulation aiming to optimize electricity system of European countries. They all brought out the broad set of result, describing various components of the system and their parameters, with a very detailed granularity. To simplify the analysis, there were the most important parameters extracted from the full data, which are:

- Annual Emissions
- Model Period Cost
- New Capacity
- Production by Technology Annual
- Total Annual Capacity
- Total Discounted Cost by Technology

The focus in the results analysis is put on the aspects related to the cross-border transmission development, its operation and influence on the generation. The most important among the analysed scenarios is scenario 3, while scenario 1 and scenario 2 served only for comparison while for scenario 4 the results turned out very similar to scenario 3 and was therefore completely omitted. Scenario 3 is particularly important for the analysis here since it is to find the optimal interconnections mix in Europe.

Therefore, the following chapter gives a description of the new capacities built under the Scenario 3, as well as compares the most important parameters of all three scenarios, such as cost of its operation, electricity generation mix and CO_2 emission. Then, there are discussed more details of electricity flows and utilization factors on each interconnection for each scenario.

7.1 New interconnection capacities developed under Scenario 3

The goal of Scenario 3 was to validate EU interconnection network development plans and find a cost-optimal interconnection capacity set-up for the European electricity system. Unlike in Scenario 1 and Scenario 2, some degree of freedom was given to optimize the new-built capacity of interconnections.

Comparison of Scenario 3 with 1 and 2 is particularly interesting since fixed interconnection capacities modelled in each of them were used as an upper and lower limit for Scenario 3 optimization. Scenario 1 assumes no more new interconnection capacities development above what is already under the operation, while Scenario 2 assumes construction of all new capacities from the PCI list.

For each of 60 interconnection technologies included in the model, there were extracted results of interconnection capacities at the end of the observation period (2050) and they were compared with capacity levels from 2020 and new capacity to be built under PCIs. Those results are presented in Table 7. Since not each of the technologies has respective PCI planned to be developed, for some of them those comparisons remain blank.

Table 7 Capacities of each interconnection developed under the Scenarios 1, 2 and 3.

Code of the Technology	Capacity in 2020 [GW]	Capacity in 2050			PCI capacity [GW]	Level of PCI capacity built in Scenario 3
		Scenario 1 [GW]	Scenario 2 [GW]	Scenario 3 [GW]		
ATELCHPH1	1.89	1.89	1.89	1.89	0.00	-
ATELDEPH1	3.67	3.67	5.67	3.67	2.00	0.0%
ATELHUPH1	1.83	1.83	1.83	1.83	0.00	-
ATELITPH1	0.26	0.26	0.41	0.26	0.15	0.0%

ATELSIPH1	1.55	1.55	1.55	1.55	0.00	-
BEELLUPH1	0.29	0.29	0.29	0.29	0.00	-
BEELUKPH1	1.04	1.04	2.44	1.04	1.40	0.0%
BGELGRPH1	0.56	0.56	1.91	0.84	1.35	20.9%
CYELGRPH1	0.00	0.00	2.00	0.00	2.00	0.0%
CZELATPH1	2.61	2.61	2.61	2.61	0.00	-
CZELSKPH1	2.33	2.33	2.33	2.33	0.00	-
DEELBEPH1	0.00	0.00	1.00	0.00	1.00	0.0%
DEELCHPH1	5.91	5.91	5.91	5.91	0.00	-
DEELCZPH1	2.86	2.86	2.86	2.86	0.00	-
DEELLUPH1	0.79	0.79	0.79	0.79	0.00	-
DEELNLPH1	5.07	5.07	5.37	5.07	0.30	0.0%
DEELNOPH1	0.00	0.00	1.40	1.40	1.40	100.0%
DEELPLPH1	2.03	2.03	2.03	2.03	0.00	-
DEELUKPH1	0.00	0.00	1.40	0.00	1.40	0.0%
DKELDEPH1	2.24	2.24	4.14	2.86	1.90	32.3%
DKELNOPH1	2.35	2.35	2.35	2.35	0.00	-
DKELPLPH1	0.00	0.00	0.00	0.00	0.00	-
DKELSEPH1	2.07	2.07	2.07	2.07	0.00	-
DKELUKPH1	0.00	0.00	1.40	0.00	1.40	0.0%
EEELLTPH1	0.83	0.83	1.43	0.83	0.60	0.0%
FIELEEPH1	1.02	1.02	1.02	1.02	0.00	-
FIELSEPH1	2.77	2.77	3.67	3.55	0.90	86.9%
FRELBEPH1	3.69	3.69	3.69	3.69	0.00	-
FRELCHPH1	4.19	4.19	4.19	4.19	0.00	-
FRELDEPH1	5.22	5.22	5.22	5.22	0.00	-
FRELESPH1	3.64	3.64	8.84	3.77	5.20	2.4%
FRELIEPH1	0.00	0.00	0.70	0.00	0.70	0.0%
FRELUKPH1	2.04	2.04	6.84	2.04	4.80	0.0%
HRELSIPH1	1.50	1.50	1.50	1.50	0.00	-
HUELHRPH1	1.65	1.65	1.65	1.65	0.00	-
HUELSIPH1	0.00	0.00	1.20	0.00	1.20	0.0%
HUELSKPH1	2.01	2.01	3.86	2.01	1.85	0.0%
IEELUKPH1	0.53	0.53	2.55	0.53	2.02	0.0%

ITELCHPH1	4.81	4.81	5.66	4.81	0.85	0.0%
ITELFRPH1	3.56	3.56	4.66	3.56	1.10	0.0%
ITELGRPH1	0.51	0.51	0.51	0.51	0.00	-
ITELMTPH1	0.22	0.22	0.22	0.22	0.00	-
ITELSIPH1	1.68	1.68	2.68	1.68	1.00	0.0%
LTELPLPH1	0.49	0.49	1.49	0.91	1.00	41.6%
LVELLTPH1	1.19	1.19	1.19	1.19	0.00	-
NLELBEPH1	3.61	3.61	3.61	3.61	0.00	-
NLELDKPH1	0.70	0.70	0.70	0.70	0.00	-
NLELNOPH1	0.73	0.73	0.73	0.73	0.00	-
NLELUKPH1	1.09	1.09	1.09	1.09	0.00	-
NOELFIPH1	0.14	0.14	0.14	0.14	0.00	-
PLELCZPH1	1.67	1.67	1.67	1.67	0.00	-
PLELSKPH1	1.19	1.19	1.19	1.19	0.00	-
PTELESPH1	3.98	3.98	5.88	3.98	1.90	0.0%
ROELBGPH1	1.30	1.30	1.30	1.30	0.00	-
ROELHUPH1	0.87	0.87	0.87	0.87	0.00	-
SEELDEPH1	0.61	0.61	0.61	0.61	0.00	-
SEELLTPH1	0.73	0.73	0.73	0.73	0.00	-
SEELNOPH1	5.46	5.46	5.46	5.46	0.00	-
SEELPLPH1	0.60	0.60	0.60	0.60	0.00	-
UKELNOPH1	0.00	0.00	2.80	2.80	2.80	100.0%

In the results presented above, for most of the interconnections there were no new investments done under Scenario 3. Only on 7 borders out of 25 new capacities were built and only in 2 cases, their full planned capacities were built. Those borders are presented in Table 8, in the order of descending level of PCI capacity built, together with the years of those new interconnection capacities development.

Table 8 Location of new interconnection capacities development together with their dates.

Country 1	**Country 2**	**New-built capacity [GW]**	**Years of development**
Germany	Norway	1.4	2033
United Kingdom	Norway	2.8	2030, 2031
Finland	Sweden	0.78	2032-2036 (gradually)
Lithuania	Poland	0.42	2035, 2036
Denmark	Germany	0.61	2034
Bulgaria	Greece	0.28	2035, 2045

France	Spain	0.13	2049, 2050

In none of the 7 cases, years of development of new interconnection capacities does not meet plans of original PCIs, which were to be constructed by 2030. Period of most of new capacities development comes between 2030 and 2036 with a peak in 2035. There are also some interconnections built after 2045 but their significance and capacities are lower than of the first group.

To see a broader view of the level of interconnection development under Scenario 3, those new-built capacities were aggregated and compared with sum of capacities of all European interconnections of other Scenarios. That comparison is presented in Table 9.

Table 9 Sum of the interconnection capacity of whole European electricity system under Scenarios 1, 2 and 3.

Capacity in 2020 [GW]	Scenario 1 [GW]	Scenario 2 [GW]	Scenario 3 [GW]	PCI capacity [GW]	New capacities of Scenario 3 [GW]	Level of PCI capacity in Scenario 3
103.61	103.61	143.83	110.03	40.22	6.42	16.0%

Out of 40.22 GW of new interconnection capacities being currently planned by European countries under PCIs, in Scenario 3 there were only 6.42 GW built, which constitutes 16% of the target. Therefore, instead of the ambitious plan of expanding the capacity of European interconnection network by nearly 40% in 10 years from 2020 to 2030, the optimal scenario results with 6.2% expansion over 30 years by 2050.

7.2 Cost of the scenarios

Total cost of the scenario are understood as the sum of all discounted costs, i.e the capital cost, fixed and variable costs. It concerns every technology included in the model such as import of fuels, their refining, electricity generation technologies, transmission and distribution, including interconnections.

The costs are the major driver for the optimization process, which aims to reduce them as much as possible by the selection of the technologies mix and operation of the energy system to meet the demand. Since the observed period of each scenario was from 2015 to 2050 only, the cost of the electricity system incurred during the last 10 years of it (2051-2060) was neglected in the analysis process. Moreover, there were extracted costs concerning the construction and operation of the interconnection lines to see how they affect the total cost of the scenario. Those results for Scenario 1, Scenario 2 and Scenario 3 are presented in Table 10.

Table 10 Costs of Scenarios 1, 2 and 3 with a breakdown into interconnection and other technologies.

	Scenario 1	Scenario 2	Scenario 3
Total Cost [M€]	2,202,830	2,220,046	2,191,804
Cost of interconnection technologies [M€]	9,894	37,144	12,490
Cost of the rest of technologies [M€]	2,192,937	2,182,901	2,179,314
Share of interconnection cost	0.45%	1.67%	0.57%
Share of the rest cost	99.55%	98.33%	99.43%

First thing to notice from this data is that Scenario 3 has the lowest total cost of the three scenarios, the second is Scenario 1 and Scenario 2 is the most expensive of them. The difference between the cheapest and the costliest one may seem not to be large since it amounts only for 1.3%, however, in the absolute values, it gives over 28 billion of euro. Scenario 3 being cheaper than other two is something that was already expected on the modelling phase since it the purpose of this scenario was to optimize interconnection capacities with Scenarios 1 and 2 being possible solutions of that optimization.

When looking closer into the cost of construction and utilization of interconnections, Scenarios 1 and 3 are at the similar level with a slight advantage of Scenario 1, while Scenario 2 is 3 times more expensive than them. It results from the fact that in that case there were a lot more interconnection capacities built and the difference results from the capital cost of them all. On the other hand, the cost of interconnection technologies in Scenario 1 is only the operational costs, since there were no new cross-border transmission lines developed under that scenario.

Considering the cost of construction and utilization of all technologies except interconnections, then scenario 1 is the most expensive, while for scenarios 2 and 3 values were similar with an advantage of 3.5 billion € for scenario 3. It partially proves the hypothesis that development of more interconnections allows reducing investment into the generation technologies, however, it does not work while looking at Scenario 2, which despite building all possible interconnection capacity has still higher cost of the rest of the technologies, than Scenario 3 which developed only 16% of that interconnection capacity. Scenario 3, the least costly among all Scenarios, owes its advantage over others to the right combination of interconnection and generation technology cost, close to the cheapest in the first case and the cheapest in the latter.

However, for all three scenarios, the cost of the interconnection technologies is small compared to the overall costs. The share is significantly smaller for Scenarios 1 and 3 for which it is approximately 0.5%. For Scenario 2 it amounts 1.67% which is around three times more than in the other scenarios but still very low.

7.3 Energy generation mix of the scenarios

Apart from the interconnections, the model also optimized the electricity generation mix. There were no differences in the boundaries of generation side among the scenarios but due to the differences in modelling of interconnections, there were expected differences in electricity generation from different technologies.

The first result analysed under that subchapter is the total electricity generation during the whole observation period of each Scenario. Values of that parameter are presented in Table 11.

Table 11 Total electricity generation of each Scenario.

	Scenario 1	**Scenario 2**	**Scenario 3**
Total electricity generated [PJ]	460573.8	460853.5	460727.5

Even though the differences between electricity generation are tiny (less than 0.1%), it is interesting to notice that they even exist. Since all scenarios had the same energy demand and the consumption was at the same level, the differences in generation indicate that there have to be different losses. The largest amount of electricity was generated in Scenario 2, followed respectively by Scenario 3 and Scenario 1, what means that the more interconnections developed, the more losses on the transmission appears and the more electricity needs to be generated to cover the same demand.

Another parameter investigated in this section is the electricity generation mix. The purpose of analysing it is to see if the development of interconnections will influence the growth and utilization of different energy sources. In order to simplify the analysis, different energy generation technologies defined in the model are aggregated under the energy source that they use as an input, regardless their geographical location or technology used to convert the energy (for instance offshore wind in the UK and onshore wind in Austria are together under the energy source Wind). Table 12 presents the electricity mix of Europe in each scenario in 2020 as a common starting point, in the middle of the observation period in 2030 and at its end in 2050.

Table 12 Electricity generation mix of Europe under all Scenarios in 2020, 2030 and 2050.

Energy source	**Code of energy source**	**2020**	**2030**			**2050**		
			Scenario 1	Scenario 2	Scenario 3	Scenario 1	Scenario 2	Scenario 3
Biomass	BM	3.4%	7.4%	7.2%	7.4%	12.5%	12.7%	12.6%
Coal	CO	21.1%	10.2%	10.2%	10.3%	2.2%	2.2%	2.3%
Geothermal	GO	0.0%	0.4%	0.4%	0.4%	1.4%	1.4%	1.4%
Heavy Fuel	HF	0.2%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%
Hydro	HY	16.1%	15.7%	15.7%	15.7%	13.1%	13.2%	13.2%
Natural Gas	NG	14.3%	18.1%	17.7%	18.0%	3.9%	4.0%	3.7%
Nuclear	NU	28.4%	20.9%	20.7%	20.7%	20.5%	20.3%	19.9%
Ocean	OC	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Solar	SO	3.6%	4.2%	4.2%	4.2%	11.3%	10.9%	10.9%
Waste	WS	2.6%	6.7%	6.7%	6.7%	5.0%	5.0%	5.0%
Wind	WI	10.3%	16.2%	17.1%	16.5%	30.1%	30.3%	30.9%

Firstly, the general trends in the electricity mix across all scenarios are the same. Those trends include a large reduction of coal and natural gas fuelled power generation. Their shares reduced from 21.1% and 14.3% to 2.2-2.3% and 3.7-4.0% respectively within the time of observation. Another decreasing technology is nuclear power, which is reduced from 28.4% to 19.9-20.5%, however, its role still remains fundamental to the European electricity mix.

The generation decrease from these sources is compensated with other sources, mostly renewables, which share increased significantly. The major one is the wind, which accounts for 10.3% of electricity generation in 2020 and by 2050 becomes the major electricity source in Europe with 30.1-30.9% of generation. The other ones are biomass (from 3.4% to 12.5-12.7%), solar energy (from 3.6% to 10.9-11.3%) and waste to energy (from 2.6% to 5.0%).

There are small differences in the shares of the technologies across the scenarios. The range of those differences varies up to 0.8 pp. and are the largest for wind and nuclear power. However, the detailed reasons for those differences are not going to be investigated in this work. Identifying them would require an analysis of the regional distribution of the generation and considering different time slices which would be very time consuming and would go beyond the scope of this work.

Figure 3 depicts those two described transformations of European electricity generation mix which occurred in the modelling of all scenarios. Since the difference among the scenarios is not clear at that level of detail, it is presented only for Scenario 3.

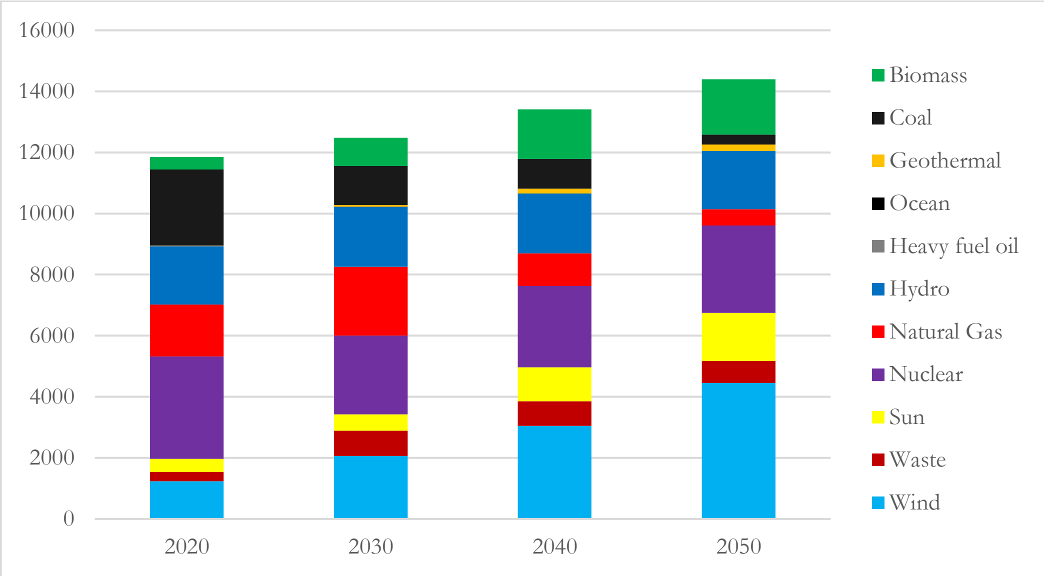

Figure 3 Total electricity generation by source in Scenario 3 in the entire Europe.

7.4 CO_2 emissions of the scenarios

CO_2 emissions are one of the most important parameters when analysing scenarios of the future energy system development. Picturing the climate policy of the EU, the OSeMBE model, on which this work is based, has a limit on CO_2 emissions implemented. This limit affects the selection of new capacities installed by the model, favouring low to zero carbon energy sources.

However, there appear differences in the CO_2 emissions among the scenarios. They result from the differences in energy generation mix presented previously. Table 13 presents aggregated emissions from all technologies for each of the modelled scenarios, for the entire observation period and its last year (2050).

Table 13 CO_2 emissions in the whole observation period and in 2050 for Scenarios 1, 2 and 3.

	CO2 Emissions	
	Whole observation period [M tons]	2050 [M tons]
Scenario 1	14628.9	110.0
Scenario 2	14613.6	111.4
Scenario 3	14615.2	111.8

Similarly like in the previous case, the differences in the results among the scenarios are small and their reasons are not obvious to track. Model uses only the CO_2 emissions that it is allowed to, therefore under all scenarios, emissions follow the limits predefined in OSeMBE.

Nevertheless, in the case of whole observation period emissions, certain trends might be identified. The least amount of CO2 was emitted in Scenario 2, followed by Scenarios 3 and 1, with a difference of approximately 0.1%. That leads to the conclusion that the more interconnections are built, the more low-carbon sources are utilized and less of CO_2 is emitted.

On the other hand, that hypothesis does not find confirmation when looking at 2050 emissions results alone. In that case, Scenario 1 shifts from the last to the first position in terms of least carbon footprint, with 1.3-1.6% of advantage over the other two.

Overall, in both categories, distinctions among scenarios are confusing and not significant enough to be able to give clear conclusions, without deeper investigation into the countries and specific technologies, similarly like in case of the electricity generation mix. Tiny differences between the scenarios might be as well result of minor solver error. Figure 4 depicts the annual level of European electricity system CO2 emissions in Scenario 3. Due to the unnoticeable differences with Scenario 1 and 2, it might serve as an illustration of the two as well.

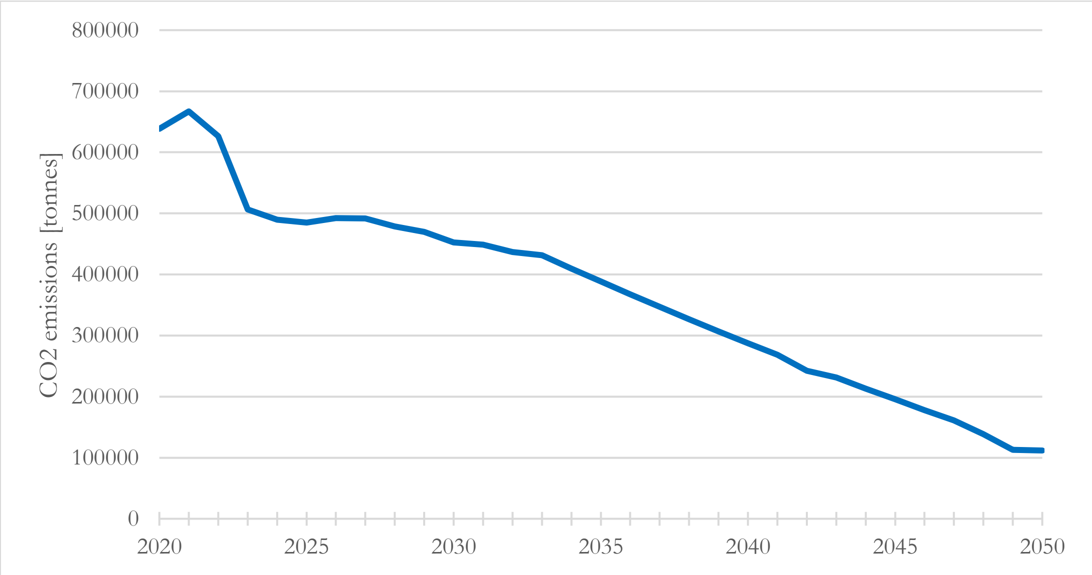

Figure 4 CO2 emissions by year in Scenario 3.

7.5 Electricity exchange

The following part of the report focuses on the electricity exchange between the countries in each scenario. It also analyses utilization factors of cross-border link which is a measure of time when the interconnection operates transmitting its maximum capacity. The formula for computing the utilization factor is given by Equation 4.

Equation 4 Utilization factor of interconnection lines.

$$utilization\ factor = \ electricity\ exchanged\ /(installed\ interconnection\ capacity * 31.536)$$

Due to a large number of modelled interconnections, they were grouped into the four regions, for the simplification of the result analysis process. The regions comply with the electricity priority corridors of the TEN-E regulation. Those corridors are North Seas offshore grid (NSOG), North-south electricity interconnections in Western Europe (NSI West Electricity), North-south electricity interconnections in central eastern and south eastern Europe (NSI East Electricity) and Baltic Energy Market Interconnection Plan in electricity (BEMIP Electricity) and countries belonging to each of them are presented in Table 14.

Table 14 Division of the countries among the corridors.

North Sea Offshore Grid	**North-south electricity interconnections in western Europe**	**North-south electricity interconnections in central eastern and south eastern Europe**	**Baltic Energy Market Interconnection**
Norway	United Kingdom	Germany	Sweden
Sweden	Ireland	Italy	Germany
Germany	Germany	Austria	Denmark
Denmark	Netherlands	Poland	Norway
Netherlands	Belgium	Czech Republic	Poland
Belgium	Luxembourg	Slovenia	Lithuania
Luxembourg	France	Slovakia	Latvia
France	Spain	Hungary	Estonia
United Kingdom	Portugal	Croatia	Finland
Ireland	Austria	Romania	
	Switzerland	Bulgaria	
	Italy	Greece	
		Cyprus	

For every interconnection technology, optimization results gave a value of electricity transferred with it in each direction annually. Knowing the annual capacities of the interconnection as well and summing amount of electricity transmitted in both directions, it was possible to obtain utilization factor for every technology in every year of the observation period. Despite the modelling was conducted from 2015 to 2050, annual distribution is disregarded on this stage yet and results for all years are aggregated under each interconnection.

The first parameters analysed in this section is the sum of all electricity exchanged among European countries during the whole observation period, together with an average utilization factor of the interconnections. Its results for all scenarios are depicted in Table 15.

Table 15 Total exchanged electricity and everage interconnection utilization factor for each scenario.

	Total electricity exchanged through the interconnections [PJ]	Average utilization factor of the interconnections
Scenario 1	38610.7	37.7%
Scenario 2	43923.4	33.6%
Scenario 3	41529.8	40.0%

The largest amount of electricity transmitted among the countries via interconnections, occurred in scenario 2, followed by scenarios 3 and 1. It should be noted that this order is the same as for installed interconnection capacities, leading to the conclusion that the more capacities the more energy exchanged. However, the situation is inverted when looking into the utilization factor of the interconnections, where it is scenario 3 with the highest value of 40%, followed by scenario 1 with 37.7% while scenario 2 score value of 33.6% only. That means that for scenario 2 with the most interconnection capacities developed, they were used least efficiently and the increase in the exchanged electricity did not compensate that drop in utilization factor. Nevertheless, scenario 3, with the highest utilization factor value, remains the most cost-optimal, which may lead to the conclusion that the effectiveness of utilization interconnections is an important factor affecting overall scenario's cost.

Additionally, for the scenario 3, data about electricity exchanged among the countries of every region and its share in total electricity exchanged in Europe, generated electricity and its share in total generated electricity in Europe and ratio of electricity exchanged to generated are presented in Table 16.

Table 16 Details of the electricity exchanged and generated in all regions compared to total values of whole Europe.

Region	Total electricity exchanged [PJ]	Share in electricity exchanged in Europe	Total generated electricity [PJ]	Share in electricity generated in Europe	Ratio of electricity exchanged and generated
North Sea Offshore Grid	18,658	44.9%	261,746	56.8%	7.1%
North-south electricity interconnections in western Europe	16,231	39.1%	341,747	74.2%	4.7%
North-south electricity interconnections in central eastern and south eastern Europe	4,984	12.0%	184,157	40.0%	2.7%
Baltic Energy Market Interconnection	16,107	38.8%	156,510	34.0%	10.3%

The following subchapters analyse the energy exchange within each of the regions in more detail.

7.5.1 North Sea Offshore Grid

Under scenario 3 the North Sea Offshore Grid has developed three interconnections, between Germany and Norway, United Kingdom and Norway, Denmark and Germany. The two first of them are completely new connections of the countries that are not connected anyhow yet and those capacities are built in 100% of the plan. The latter one is an extension of already existing cross-border transmission and despite having more ambitious plans in PCI, it was found that only 32% of that is necessary. The largest interconnection capacity planned to be constructed under the PCIs in this region is between France and the United Kingdom, however, optimization resulted with no new interconnections built on this marine border.

In total those three new investments amount for 4.8 GW, the highest value of new interconnection capacities among all regions. North Sea Offshore Grid is also a region with very large development plans under PCIs, totalling to 18.8 GW, of which only 25.6% are realized in the model.

First result analysed under the regional analysis are, similarly, like in case of all of European countries analyses, total electricity transferred within the regions and average utilization factor. For the North Sea Offshore Grid Region, those values are presented in Table 17.

Table 17 Total electricity exchanged and average interconnections' utilization factor in North Sea Offshore Grid for all Scenarios.

	Electricity transferred [PJ]	Average utilization factor
Scenario 1	10605	54.0%
Scenario 2	19556	42.8%
Scenario 3	18658	58.7%

The largest amount of electricity transferred was noted in scenario 2 and scenario 3 which with the difference of 5% among each other and they over performed scenario 1 by 76% and 84%. In terms of average utilization factor, Scenario 3 reaches the highest value, meaning that performed optimization leads to maximal usage of the available capacities. It is at a similar level for the scenario 1 resulting from lack of available interconnection and significantly lower for scenario 2, which despite having such a large amount of electricity transferred also has the largest interconnections capacities developed.

Within the regions, analysis of energy flows between particular countries was conducted, which were compared among the scenarios. The results are shown in the form of circular graphs on which circumference the countries are represented and the bars between are the visualization of the electricity flows. The thickness of the bars is a representation of the quantity of electricity transferred during the whole modelling period. Each bar has a colourful stripe at the end next to the country from where the electricity flows and a white stripe at the end next to the country to where it flows. The colour of the first stripe represents the country to where the electricity is transferred.

Figure 5, Figure 6 and Figure 7 depict total electricity transferred respectively under Scenarios 1, 2 and 3 in the North Sea Offshore Grid region.

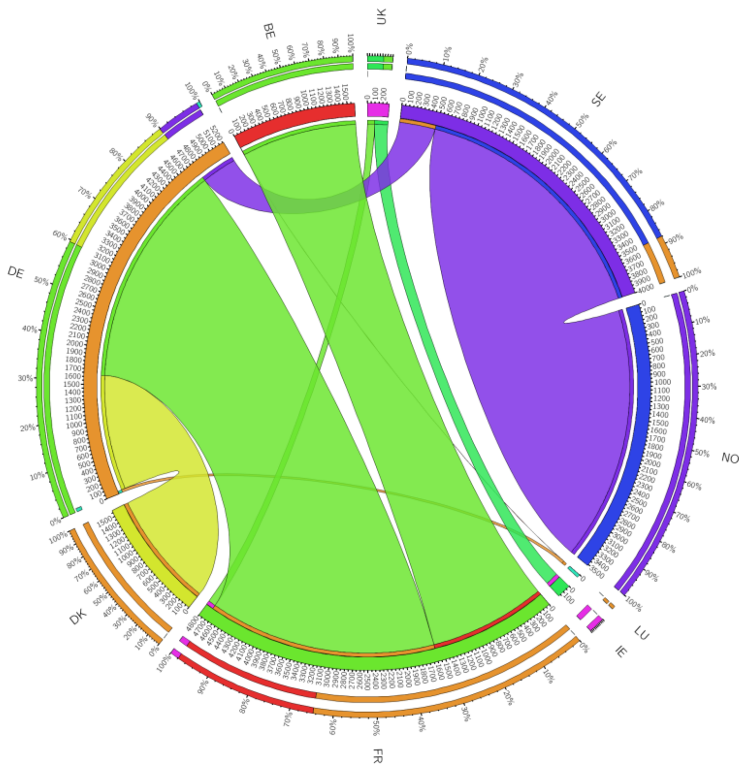

Figure 5 North Sea Offshore Grid electricity exchange in Scenario 1.

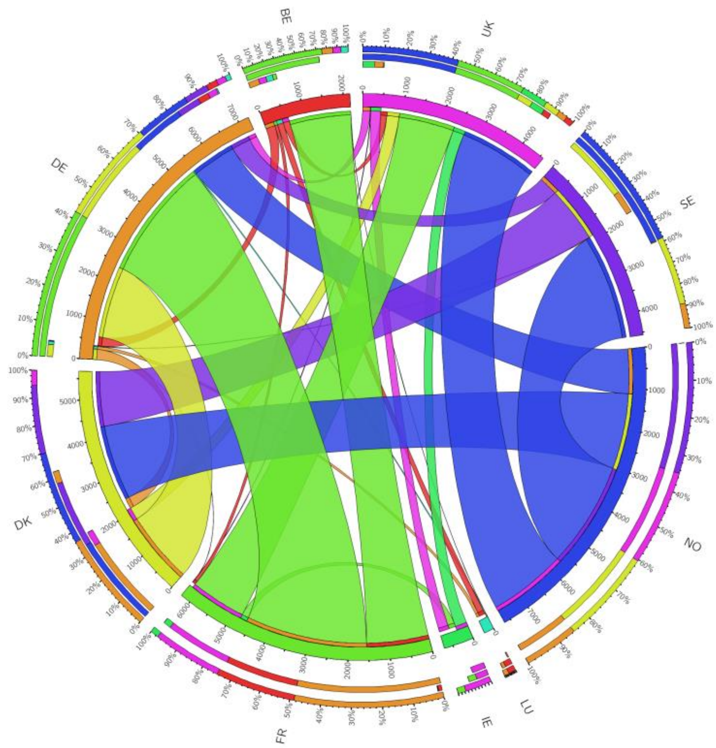

Figure 6 North Sea Offshore Grid electricity exchange in Scenario 2.

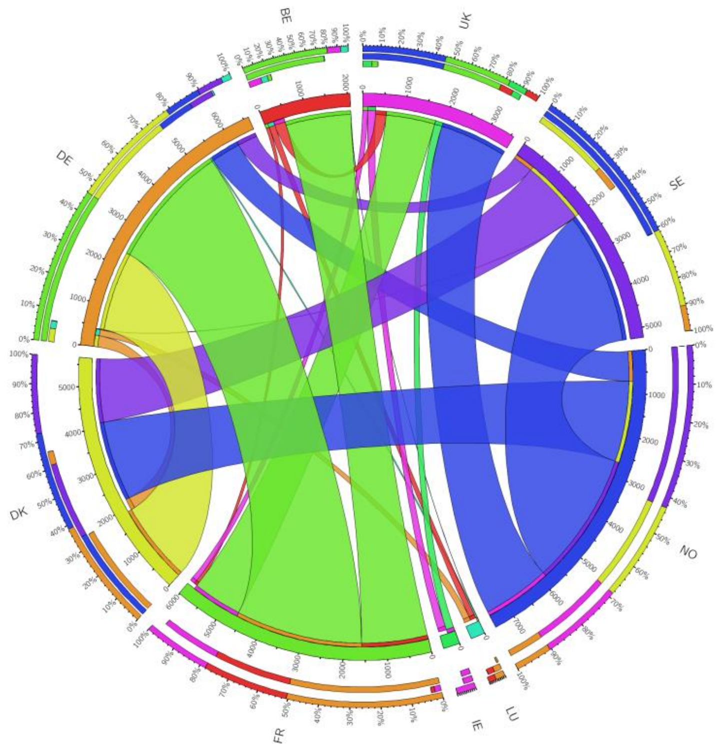

Figure 7 North Sea Offshore Grid electricity exchange in Scenario 3.

From the figures above it can be seen that construction of extra interconnections under scenarios 2 and 3 significantly change the situation of cross-border electricity exchange in the North Sea Offshore Grid. In scenario 1, there are only 9 interconnections being utilized with five major directions on which amount of transferred electricity is significant (larger than 450 PJ which is 2.5% of total scenario 3 electricity transferred). Those large interconnections are from France to Belgium, France to Germany, Denmark to Germany, Sweden to Norway and Sweden to Germany. On the other hand, a large country as the United Kingdom has one of the smallest electricity exchanges with other countries from the region.

The picture gets more complex with extra capacities installed in scenario 2 and 3, however, despite having large differences in those installation amounts between the two scenarios, the electricity flows are very similar in both cases. In the optimized interconnection capacities scenario, scenario 3, there are already 18 interconnections utilized and 10 out of them have large values of energy transferred (over the threshold of 450 PJ). Apart from the ones already described in the scenario 1 case, the other major directions were Norway to Germany, Norway to Denmark, Norway to the United Kingdom, Sweden to Denmark, Denmark to Germany, France to Germany, France to Belgium and France to the United Kingdom. What is the most interesting is that the addition of only 3 new cross-border lines enabled electricity trade on many more borders then only that 3 and doubled the number of directions of electricity exchange both for large flows and all flows.

Apart from looking at the amount of electricity exchanged in each scenario, it is important to analyse how much each interconnection is used. It is represented by the utilization factor of the modelling period. For each interconnection technology, an average of all annual utilization factors was computed. For new capacities, the average was computed only from the year of the construction on. Table 18 presents the average utilization factors for all interconnections of the North Sea Offshore Grid region under all scenarios.

Table 18 Interconnections' utilization factor in North Sea Offshore Grid for all Scenarios.

Country 1 code	Country 2 code	Scenario 1	Scenario 2	Scenario 3
BE	LU	54%	50%	49%
BE	UK	24%	13%	25%
DE	BE	-	23%	-
DE	LU	23%	12%	23%
DE	NO	-	82%	90%
DE	UK	-	16%	-
DK	DE	74%	48%	74%
DK	NO	71%	72%	73%
DK	SE	64%	59%	65%
DK	UK	-	25%	-
FR	BE	40%	39%	40%
FR	DE	53%	52%	52%
FR	IE	-	30%	-
FR	UK	57%	34%	57%
IE	UK	62%	24%	62%
SE	DE	72%	72%	72%
SE	NO	57%	43%	51%
UK	NO	-	77%	90%

On that basis one can indicate borders where under each scenario the highest utilization factors occur, meaning that their role in the European electricity system is fundamental and any failure might harm its stability. To this category, one can count existing interconnections between Sweden and Germany, Denmark and Norway, Denmark and Sweden, Denmark and Germany which are highly utilized under all 3 scenarios.

Those results also confirm the reasoning of building completely new interconnections in scenario 3, between Germany and Norway, the United Kingdom and Norway. In the case of the first two, their utilization factor achieved 90%, being the highest among all.

There are also some borders on which interconnection utilization factors are significantly lower and whose importance in the system is not that high as in the case of the above-described ones. To this group belongs interconnections between Germany and Luxembourg, Belgium and the United Kingdom, for which utilization factor remains below 25%.

7.5.2 North-south electricity interconnections in Western Europe

The North-south electricity interconnections in Western Europe is the one with the largest number of cross-border links already existing at the beginning of the modelling period, which sum to 45.5 GW. Furthermore, it has the most development plans within the Projects of Common Interests, totalling to 22.5 GW. However, in this region the least new interconnections are added, only 0.13 GW. Those 0.13 GW are developed on the border of France and Spain. That capacity represents only 0.6% of the PCI plans for the entire region. At the same time, the France-Spain connection is the largest interconnection capacity planned to be developed as a PCI in the whole model, amounting to 5.2 GW.

The total amount of electricity that is transferred between countries of that region under the whole modelling period, together with the average interconnections' utilization factor is presented in Table 19.

Table 19 Total electricity exchanged and average interconnections' utilization factor in North-south electricity interconnections in western Europe for all Scenarios.

	Electricity transferred [PJ]	Average utilization factor
Scenario 1	16400	36.1%
Scenario 2	17663	27.5%
Scenario 3	16231	35.6%

The above described, the almost unnoticeable difference in the installed interconnection capacities, finds its representation also in the results of the electricity exchange and utilization factors, which has very similar values for Scenarios 1 and 3. Larger differences might be noted for Scenario 2 were due to the vast amount of developed interconnections, the yield of energy transmitted between countries raises by 7.7% but the average utilization factor decreases by 8.6 pp.

The following part focuses on the details of electricity flows at each interconnection, which total for the entire observation period are depicted on the graphs on Figure 8, Figure 9 and Figure 10.

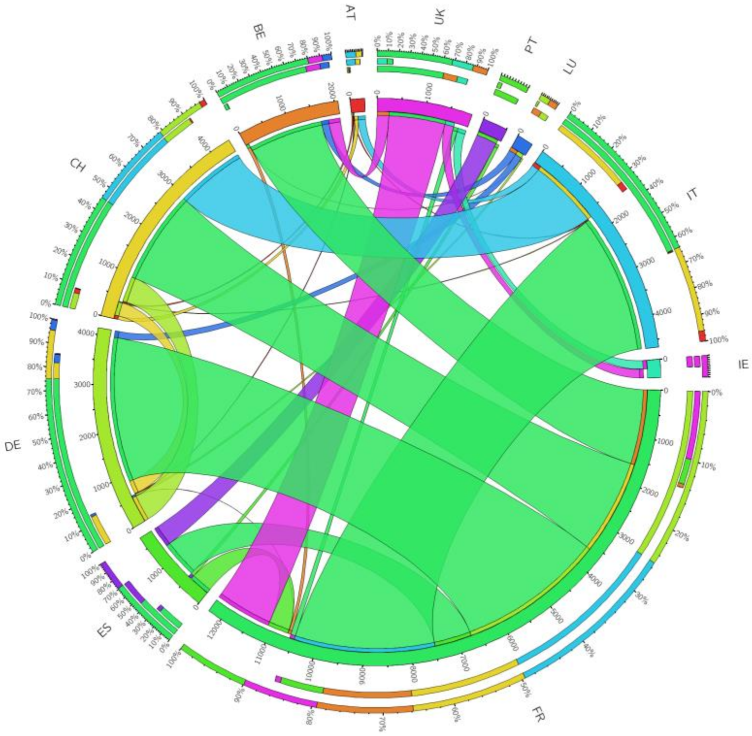

Figure 8 North-south electricity interconnections in western Europe, electricity exchange in Scenario 1.

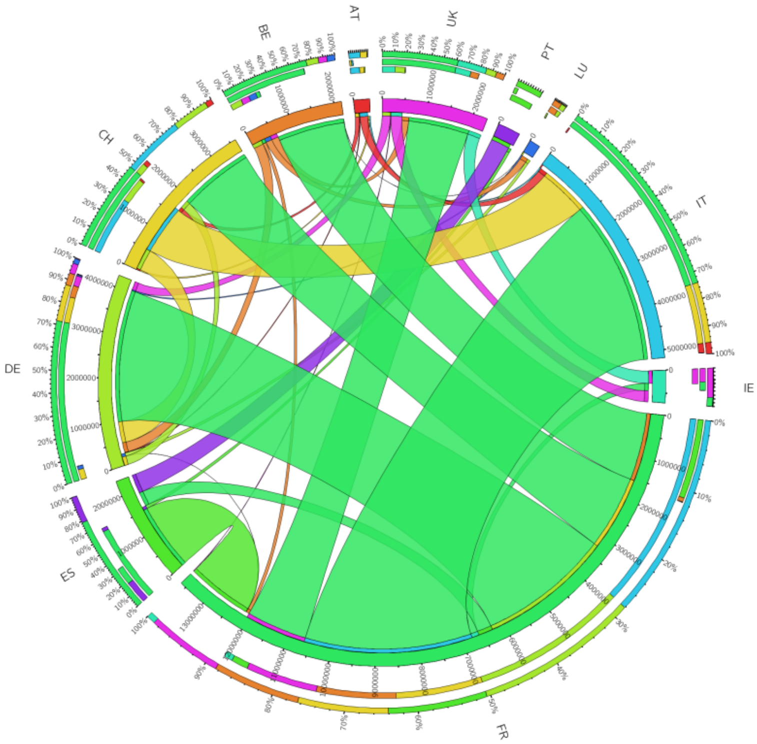

Figure 9 North-south electricity interconnections in western Europe, electricity exchange in Scenario 2.

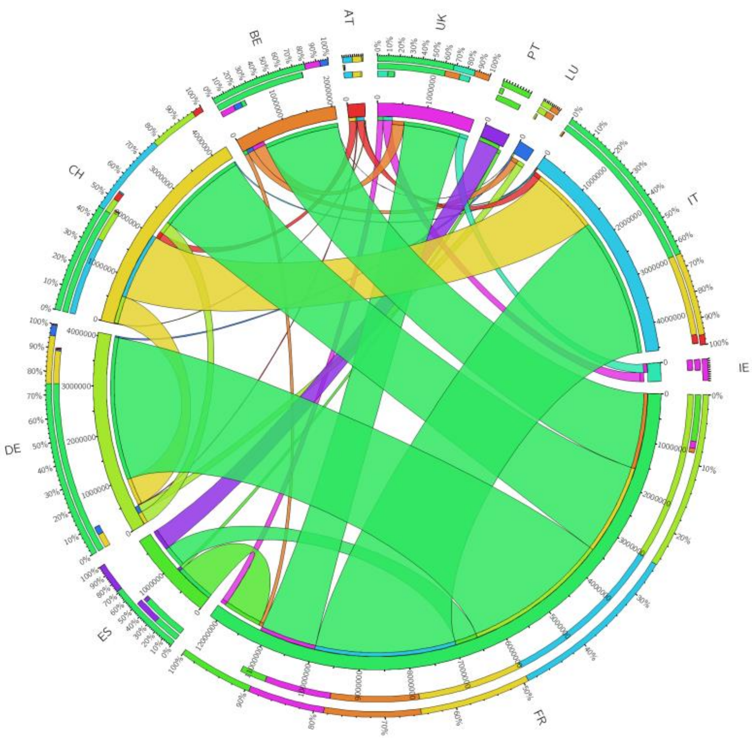

Figure 10 North-south electricity interconnections in western Europe, electricity exchange in Scenario 3.

The north-south electricity interconnections in western Europe have a large number of interconnections in use and regardless the scenario, the picture of the electricity exchanged is very complex. A number of directions of the cross-border flows varying from 27 to 30, with the highest value for scenario 2. When looking only at the major of them, with a threshold of 410 PJ which is 2.5% of total electricity exchanged under scenario 1, there are still 10 of them for each scenario. However, the borders on which such a large flow appears varies from one Scenario to another.

The large interconnections for all of the scenarios are France to Belgium, France to Switzerland, France to Germany, France to Italy, Spain to France, Portugal to Spain. Apart from that, for scenario 1 there are also large flows at the interconnections of the United Kingdom to France, Germany to Switzerland, France to Spain and Italy to Switzerland. For scenario 2 they are France to United Kingdom, Switzerland to Germany and Switzerland to Italy, and for scenario 3 France to the United Kingdom, France to Spain, Switzerland to Germany and Switzerland to Italy.

Despite the similarity of Scenarios 1 and 3, one can note some relevant differences among them, resulting from the variant interconnection capacities in other regions. Those differences occur for instance in opposite directions of the flows at certain borders such as the United Kingdom and France, Italy and Switzerland or Germany and Switzerland.

The major difference introduced by Scenario 2 in comparison to other Scenarios is the appearance of more cross-border electricity exchange, especially at the borders where there were no lines existing before. The yield of electricity transmitted by them, in any case, does not belong to the category of large interconnections, but it is important to mention that such a flow occurs on the directions of France to Ireland, the United Kingdom to Germany, Belgium to the United Kingdom and Belgium to Germany.

Another parameter analyzed for all interconnections of the region was the average utilization factor. Its values for all Scenarios are shown in Table 20.

Table 20 Interconnections' utilization factors in North-south electricity interconnections in western Europe for all Scenarios.

Country 1 code	Country 2 code	Scenario 1	Scenario 2	Scenario 3
AT	CH	5%	6%	8%
AT	DE	0%	0%	0%
AT	IT	58%	49%	55%
BE	LU	54%	50%	49%
BE	UK	24%	13%	25%
DE	BE	-	23%	-
DE	CH	13%	11%	13%
DE	LU	23%	12%	23%
DE	UK	-	16%	-
FR	BE	40%	39%	40%
FR	CH	46%	39%	44%
FR	DE	53%	52%	52%
FR	ES	30%	21%	31%
FR	IE	-	30%	-
FR	UK	57%	34%	57%
IE	UK	62%	24%	62%
IT	CH	27%	19%	26%
IT	FR	75%	77%	74%
PT	ES	12%	8%	12%

The first conclusion appearing from that table is the similarity of the results for scenarios 1 and 3. There are only 4 borders on which difference between utilization factors of those scenarios are larger than 1 pp, namely Belgium and Luxembourg, Austria and Italy, Austria and Switzerland, France and Switzerland and they are all located close to the eastern border of the region. Those differences might result from the fact that those interconnections are affected by new capacities of North-south electricity interconnections in central-eastern and south-eastern Europe region.

The interconnections which are utilized with the highest intensity in the North-south electricity interconnections in the western Europe region are for Scenarios 1 and 3 between Italy and France, Ireland and the United Kingdom, Austria and Italy, France and the United Kingdom. In scenario 2 the situation is quite different and due to having much more capacities installed most of the utilization factors goes down. However, the border between Italy and France remains the leader, while other above-mentioned interconnections drop down and are overtaken by France to Germany and Belgium to Luxembourg interconnections.

On the other end, for all Scenarios, utilization factors take the lowest values for borders between Austria and Germany, Austria and Switzerland, Portugal and Spain, Germany and Switzerland.

7.5.3 North-south electricity interconnections in central-eastern and south-eastern Europe

In terms of the cross-border transmitted electricity, the least out of all four is transmitted via the North-south electricity interconnections in central-eastern and south-eastern Europe. However, according to the PCI list, it has large plans of development in that terms with 9.5 GW of new interconnections capacities to be installed.

Similarly to North-south electricity interconnections in western Europe, under Scenario 3 there were almost no new capacities developed in this region. The only extension of the current grid occurred on the border between Greece and Bulgaria, where new 0.28 GW were added. It gives only 3% of the whole PCI capacities to be built.

Table 21 presents total electricity transferred among the countries of the region under all scenarios, together with their average utilization factors.

Table 21 Total electricity exchanged and average interconnections' utilization factor in North-south electricity interconnections in central-eastern and south-eastern Europe for all scenarios.

	Electricity transferred [PJ]	Average utilization factor
Scenario 1	4953	22.7%
Scenario 2	5826	19.5%
Scenario 3	4984	22.6%

The amount of electricity transferred between countries takes the highest values for the scenario 2, which might be explained with the number of new interconnection capacities developed under that scenario. For scenarios 1 and 3, that values are around 17% lower and very close to each other with a difference of only 0.6%. The same similarity might be noted in the case of average utilization factors, which for scenarios 1 and 3 varies only by 0.1 pp. In the case of scenario 2 that value is lower by 14%.

There are total electricity flows during the observation period at each interconnection of the region shown at Figure 11, Figure 12 and Figure 13.

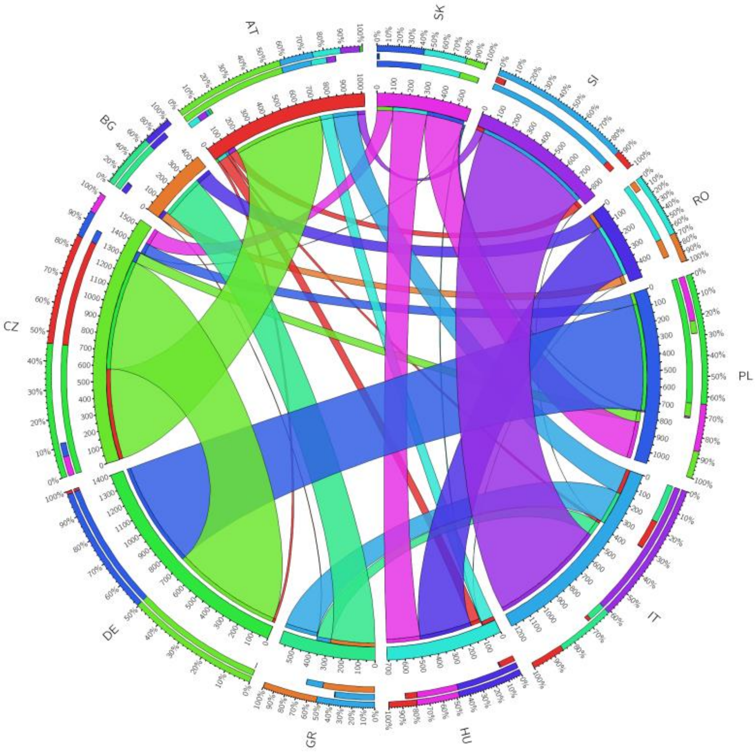

Figure 11 North-south electricity interconnections in central-eastern and south-eastern Europe, electricity exchange in Scenario 1.

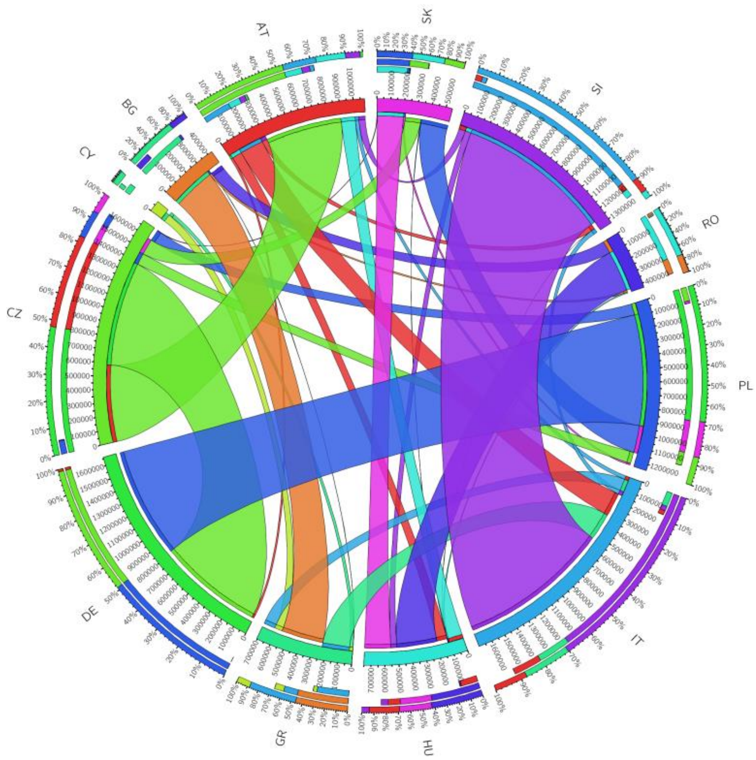

Figure 12 North-south electricity interconnections in central-eastern and south-eastern Europe, electricity exchange in Scenario 2.

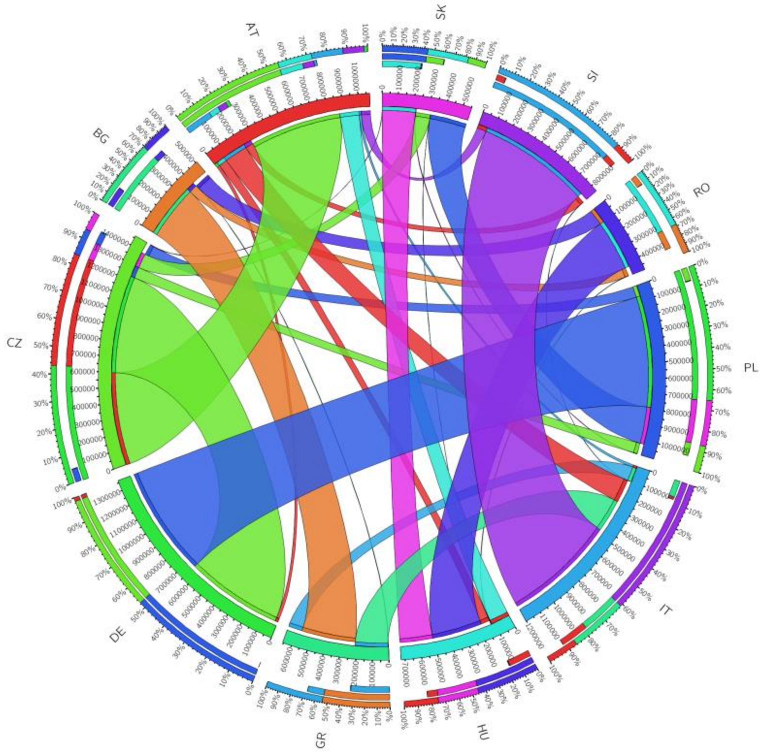

Figure 13 North-south electricity interconnections in central-eastern and south-eastern Europe, electricity exchange in Scenario 3.

From the graphs above it is clear that the North-south electricity interconnections in central-eastern and south-eastern Europe is quite densely interconnected. The number of directions of electricity flows varies from one scenario to another from 28 to 32, with the scenario 2 with the largest number. In each analyzed scenario, there are 10 interconnection directions that exchanged electricity yield might be considered large in regard to the whole region (exceeding 2.5% of total energy flows).

Large interconnections directions which are utilized under all three scenarios are from Poland to Germany, the Czech Republic to Germany, the Czech Republic to Austria, Slovenia to Italy, Slovakia to Hungary and Romania to Hungary. Additionally, in scenario 1 to this category might be included directions from Slovakia to Poland, Italy to Austria, Italy to Greece and Greece to Bulgaria. For scenarios 2 and 3 they are replaced with Austria to Italy, Poland to Slovakia, Bulgaria to Greece and Greece to Italy.

In scenario 2 there were built many new interconnections leading to more electricity exchange among the countries as well. The additional flows noted under this scenario, despite their yield is not enough to be classified as large interconnection flows, happened on the directions from Slovenia to Hungary, Hungary to Slovenia, Greece to Cyprus and Cyprus to Greece.

Table 22 shows the average utilization factors of all interconnections during the observation period in the North-south electricity interconnections in the central-eastern and south-eastern Europe region.

Table 22 Interconnections' utilization factor in North-south electricity interconnections in central-eastern and south-eastern Europe for all Scenarios.

Country 1 code	Country 2 code	Scenario 1	Scenario 2	Scenario 3
AT	DE	0%	0%	0%
AT	HU	7%	9%	9%
AT	IT	58%	49%	55%
AT	SI	6%	5%	6%
BG	GR	44%	29%	46%
CY	GR	-	5%	-
CZ	AT	19%	19%	19%
CZ	SK	4%	4%	4%
DE	CZ	22%	25%	20%
DE	PL	29%	36%	31%
HU	SI	-	4%	-
HU	SK	9%	7%	9%
IT	GR	52%	51%	52%
IT	SI	40%	40%	39%
PL	CZ	7%	9%	7%
PL	SK	18%	16%	17%
RO	BG	10%	7%	10%
RO	HU	36%	34%	35%

Within all three Scenarios, the most used interconnections were the ones between Italy and Greece, Austria and Italy, Italy and Slovenia, for which utilization factors vary from 39% to 52%. In Scenarios 1 and 3 the interconnection between Greece and Bulgaria also takes similarly high values, however the in case of Scenario 2, due to the large increase of capacity and roughly constant power flow, its utilization factor goes down.

In all Scenarios, there is a large group of interconnections that are operating with very low (below 10%) utilization factor. Under this category fall the cross-border transmission lines between Austria and Germany, Czech Republic and Slovakia, Austria and Slovenia, Austria and Hungary, Hungary and Slovakia.

7.5.4 Baltic Energy Market Interconnection

Among all regions the Baltic Energy Market Interconnection is the one with least interconnection capacity installed in 2015. At the beginning of the modelling period only 22.5 GW are installed. Under the PCIs, there are plans to build 5.8 GW of new cross-border transmission lines within the region. Optimization of Scenario 3 showed that it would be reasonable to realize as much as 3.2 GW out of it, what amounts for 55% percent of the plan and is the highest level of PCI plans realization among all of the regions.

Under that scenario, there were developed four extra interconnection capacities, between Norway and Germany, Finland and Sweden, Lithuania and Poland, Denmark and Germany. The only one that was skipped was a line between Estonia and Lithuania.

Total electricity exchanged among the countries and average utilization factors in the whole region are shown at Table 23.

Table 23 Total electricity exchanged and average interconnections' utilization factor in Baltic Energy Market Interconnection for all Scenarios.

	Electricity transferred [PJ]	Average utilization factor
Scenario 1	14463	58.4%
Scenario 2	16489	59.9%
Scenario 3	16107	62.5%

The largest value of electricity exchanged within the Baltic Energy Market Interconnection region occurred under scenario 2, followed by scenario 3 with the result lower by only 2% and scenario 2 with a value lower by the more significant value of 12%. Interconnections are utilized the most effectively in scenario 3, while results for scenario 2 and 1 were respectively lower by 4% and 7%. Surprisingly, the result of the utilization factor is the lowest for Scenario 1 in which in theory it should be "easier" to achieve due to the smaller interconnection capacity. However, a large difference in the transferred electricity balanced that advantage, placing that scenario in the last position, unlike in other scenarios.

It is relevant to note that the Baltic Energy Market Interconnection region has the highest results of the utilization factor among all regions. It means that the regional cooperation of the considered countries is really fundamental and helps to decrease the need for their own generation of electricity.

In Figure 14, Figure 15 and Figure 16, there are presented graphs depicting total electricity flows among the countries of the Baltic Energy Market Interconnection region during the entire observation period.

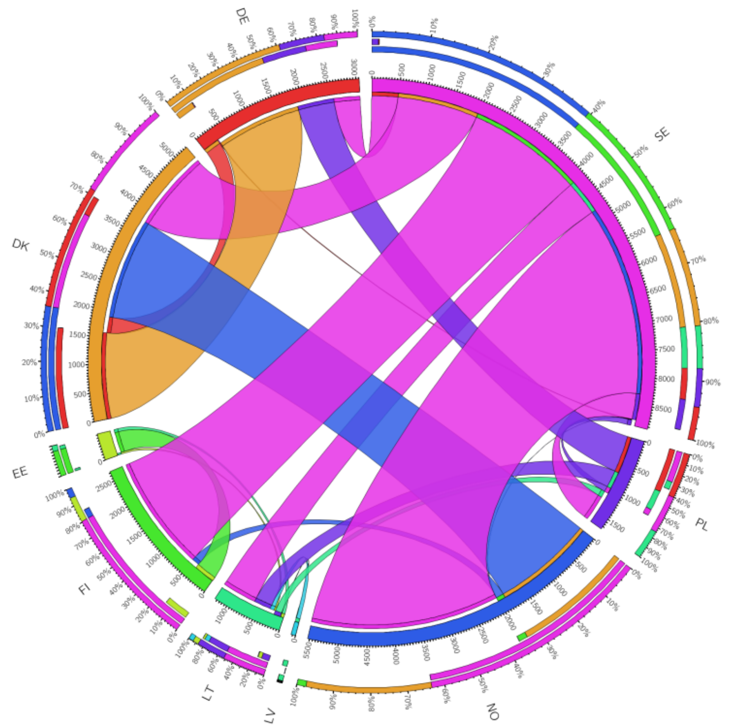

Figure 14 Baltic Energy Market Interconnection electricity exchange in Scenario 1.

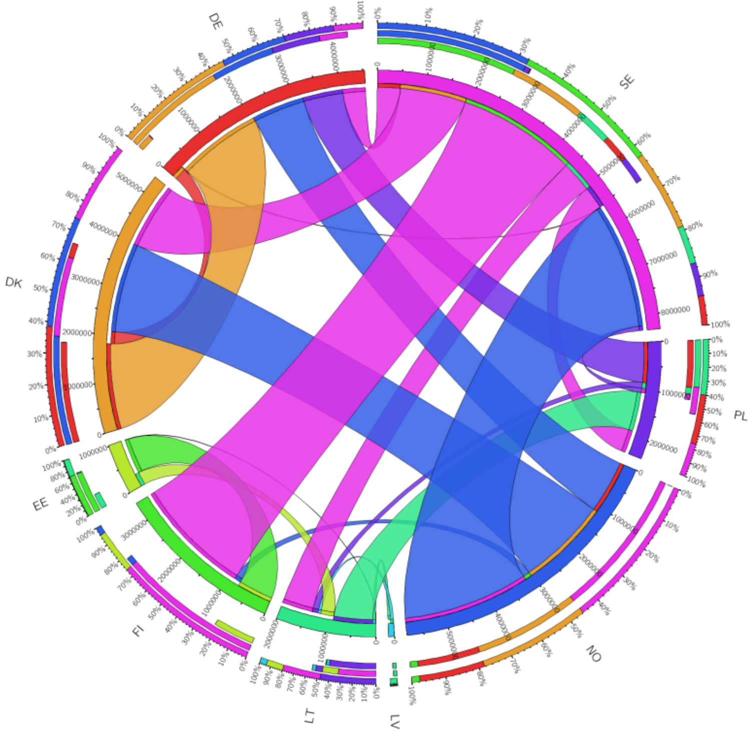

Figure 15 Baltic Energy Market Interconnection electricity exchange in Scenario 2.

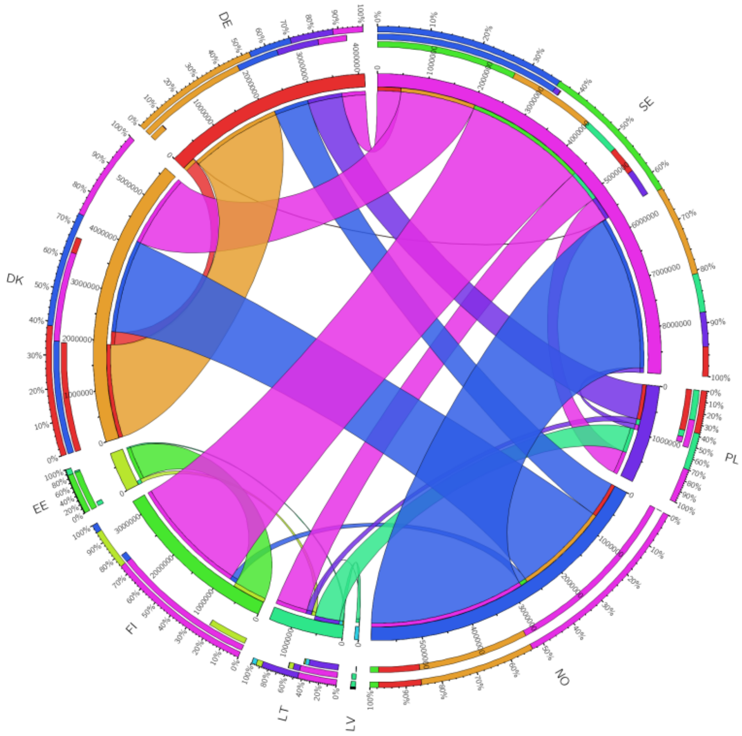

Figure 16 Baltic Energy Market Interconnection electricity exchange in Scenario 3.

Despite having the smallest interconnection capacity at the beginning of the modelling period and the lowest number of countries, under all scenarios, electricity grid of electricity flows in the Baltic Energy Market Interconnection region is dense and operating at a high level. Regardless of the scenario, there are 21 directions of electricity flows, then, the number of large flows, defined as above 2.5% of total electricity exchange (400 PJ) varies from 9 in Scenario 1 to 12 in Scenarios 2 and 3.

The main flow directions at the interconnections that are common for all scenarios are from Sweden to Germany, Sweden to Denmark, Sweden to Poland, Sweden to Lithuania, Sweden to Finland, Denmark to Germany, Norway to Denmark and Poland to Germany. Moreover, for scenario 1 there occurs a large exchange from Sweden to Norway, while in scenarios 2 and 3 there are also electricity flows from Norway to Sweden, Norway to Denmark, Lithuania to Poland and Finland to Estonia.

An eye catching difference between the scenarios is that the flow from Sweden to Norway, which was the largest of all interconnections in scenario 1, is reduced to zero in the other two scenarios and is replaced with the flow into the other direction, remaining the largest interconnection of the region. However in all scenarios Norway is a net electricity exporter.

Moreover, the extension of the interconnections between Poland and Lithuania as well as Finland and Sweden allows a better integration of the Baltic states into the European energy system. That resulted in an increase in electricity exchange at the borders of Poland and Lithuania and Finland and Estonia.

A broader view of the interconnections' utilization during the entire observation period in the Baltic Energy Market Interconnection region is presented in Table 24.

Table 24 Interconnections' utilization factor in Baltic Energy Market Interconnection for all Scenarios.

Country 1 code	Country 2 code	Scenario 1	Scenario 2	Scenario 3
DE	NO	-	82%	90%
DE	PL	29%	36%	31%
DK	DE	74%	48%	74%
DK	NO	71%	72%	73%
DK	SE	64%	59%	65%
EE	LV	9%	20%	11%
FI	EE	33%	64%	59%
FI	SE	69%	64%	68%
LT	PL	77%	69%	78%
LV	LT	6%	9%	6%
NO	FI	86%	86%	88%
SE	DE	72%	72%	72%
SE	LT	87%	88%	88%
SE	NO	57%	43%	51%
SE	PL	85%	84%	85%

The first noticeable information from the table is that most of the interconnections have relatively high utilization factor. Out of 16 interconnections, there are 10 having utilization factors above 50% in Scenarios 1 and 2 and 12 in Scenario 3. The borders on which the intensity of electricity exchange is the highest are Norway and Finland, Sweden and Lithuania, Sweden and Poland, Lithuania and Poland. For Scenarios 2 and 3, the newly built interconnection between Germany and Norway is also listed among them.

The lowest values of the interconnections' utilization factor appear within the Baltic countries, particularly on the borders between Lithuania and Latvia and Estonia and Latvia. That shows that the Baltic countries need to rely more on the cooperation with other electricity systems like Continental Europe or the Scandinavian Nordpool, instead of enforcing interconnections among themselves.

8 Conclusions

The work conducted in this Master's thesis consisted of two major parts. In the first step, data was collected and processed for representing the European cross-border electricity network in a long-term energy planning model. In a second step four scenarios were developed, run and their results analysed. Therefore, the conclusions of the work are also split into two sections. The order of their description was turned so that the results part is presented before the modelling. That change allows to sum up what findings appeared in the scenarios, what are their similarities and differences to the EU plans included in Projects of Common Interests and actual network state as well as the forecast of how future European grid might look and what investments are the most relevant.

The following part regarding model itself uses those findings to give conclusions on the strengths and limitations of the model and its methodology, explains possible reasons of certain discrepancies with the results of other modelling works performed in the similar scope and describes further work that might be conducted based on what has been done.

8.1 Scenarios conclusions

The enhancement of the representation of the cross-border electricity transmission links in the OSeMBE model conducted under this work resulted in a wide range of insights and the conclusions might give indications to researchers and policymakers for further investigation of the optimal shape of the European electricity system and the interconnection network in particular.

In this sense, the most interesting results are the ones of Scenario 3. Scenario 3 has the aim to find an optimal cross-border transmission capacities allocation and verify already settled grid development plans of the European countries defined as the Projects of Common Interest. The results indicate that potentially the construction of only 7 projects is needed summing up to 6.42 GW of new interconnection capacity. In comparison, there are 25 interconnections with a total capacity of 40.22 GW to be developed according to ENTSO-E plans. Another interesting finding from Scenario 3 is the timing of the 7 projects to be realized. While according to the plans they are expected to be executed in the late 2020s, the model optimization allocated their gradual construction for later years, with a peak around 2035 and lasting until 2050.

Those two findings suggest that the plans for the European cross-border transmission network development might be strongly exceeding the actual needs and already existing interconnection capacities are almost sufficient to provide stable operation of the electricity system. However, those findings need to be taken with a caution and require validation with more detailed methodology and without such a confirmation might be taken only as a mere suggestion.

Most of the new-built capacity in scenario 3 is developed using submarine HVDC technology, through the North and Baltic Sea, connecting Norway to the United Kingdom and to Germany or Finland with Sweden and Poland with Lithuania. Currently, between those countries, there are little, or no cross-border transmission lines. An exception is the interconnection of Sweden and Finland, which is already well developed but the study shows that it needs further extension. Those results show that despite the higher cost of laying submarine cables, they are necessary to fully integrate energy markets of Northern Europe.

While comparing the analysed scenarios economically, scenario 3 appears to be the cheapest. What was found unexpected is that scenario 2, with full realization of the PCIs, is costlier than Scenario 1 under which no new interconnections are developed, what leads to the conclusion that the benefits of new cross-border transmission lines comprised in the PCI list do not compensate their cost.

When looking at the cost of the non-interconnection technologies only, it was found that in that field it was Scenario 1 to be the most expensive, followed by Scenario 3 and 2. That proves the hypothesis that interconnections truly reduce the cost of the electricity system operation in terms of necessary investment in generation technologies. However, planning needs to be conducted carefully, to avoid the situation in which that reduction is lower than cross-border transmission cost, as it occurred in Scenario 2.

Under all scenarios, electricity generated in Europe grew around 21.4% strictly following predefined electricity demand implemented to the model. The differences of the energy generation among the scenarios were tiny (<0.1%) but the generation was larger for the scenarios with a larger capacity of the interconnections developed. It resulted from the fact that on every cross-border transmission line additional losses appear, therefore in the scenarios were interconnections are utilized more there needs to be generated more electricity to cover those losses. All in all, the impact of the interconnection development scenario on the amount of electricity generated is minor.

In all scenarios, the projected electricity demand growth is covered with renewable sources and nuclear power, while the role of fossil fuels drastically decreases. However, it is important that the share of specific sources varies slightly among scenarios, being influenced by the interconnection capacity installed. It is particularly visible in case of wind energy which share is higher in Scenarios 2 and 3. Among analysed years, the difference amounts for 0.8-0.9 pp, which in the scale of 30 European countries gives a significant number of extra wind turbines replacing coal and gas-fired plants. That finding confirms that interconnections are indeed capable to help accommodate more renewable energy to the grid and keep its operation stable.

Furthermore, the work also analysed the operation of the trans-border transmission network operation. This analysis showed that for scenario 1 lack of new interconnection affects low electricity exchange but for scenarios 2 and 3, despite the large difference of the installed capacities between them, the amount of electricity exchange is at a similar level. That means that the development of the cross-border transmission network is beneficial only up to a certain level and decision about placing new lines needs to be considered carefully to maximize its profits.

Similar conclusions come from the average interconnections' utilization factors which are the highest for scenario 3 and the lowest for scenario 2. Construction of the massive number of new cross-border transmission lines under the latter one brought a significant cost and did not provide enough improvement of the system operation and increase in electricity exchange.

Analysis of the electricity exchange shows that not all European regions have a similar interconnection situation and needs. As mentioned previously the northern regions of Europe, develop significantly more of new interconnection capacity under scenario 3 than the southern ones. That finding is particularly relevant in the context of capacities planned to be developed according to the PCI plans. Southern regions have plans to construct 21 GW of cross-border transmission lines, while modelling results suggest that only 0.4 GW of them is needed.

A similar trend appears in the electricity exchange – North Sea Offshore Grid and Baltic Sea Energy Market has the highest amount of electricity exchanged as well as utilization factors, which in both cases exceed 55%. The amount of electricity exchanged in those two regions is also similar in case of North-south electricity interconnections in western Europe. However, the latter region is the largest in Europe in terms of electricity generated (74% of entire Europe) and interconnections capacities installed. Therefore, in regard to that information the amount of electricity exchanged is not relatively that high and utilization factor remains at the level of 36%, lower than for NSOG and BSEM.

A good measure for assessing which of the priority corridors is utilizing their cross-border transmission the most intense is the ratio of electricity exchanged to generated in that region. In that field the true leader is the Baltic Energy Market Interconnection region which exchanges over 10% of all electricity that it generates. The reason for it might be that countries of the Baltic region are relatively weakly interconnected, and their energy systems are not that large, therefore cooperation with their neighbours allows them to reduce the cost of electricity system operating. On the other end, there are Western and Eastern North-south electricity interconnection regions with results of respectively only 4.7% and 2.7%.

The regional analysis and inter-scenario comparison also showed that in some cases construction of singular lines enables a better utilization of the ones that are already in operation but due to lack of need were poorly used by now. Together with the new investments, they might create the network of "energy highways" with which electricity might be transferred over large distances not limiting itself to the directly connected countries. That was particularly the case of the North Sea Offshore Grid priority corridor, where construction of only 3 new lines doubled the amount of exchanged energy and lead to an increase of electricity flow directions from 9 to 18.

Summarizing, the most relevant conclusions are that according to the assumptions of the model, only a minor part of the interconnection lines planned as a PCI leads to cost reductions in the European electricity system. The highest need for new investments was found in the regions of the Baltic Sea, followed by the North Sea. That need shows with large amount of newly installed capacities in the model and high utilization factors of the interconnections. The development of the grid in those regions is going in parallel with the development of the subsea HVDC transmission technology, which is fundamental to achieve better integration in these regions. In the priority corridors of Southern Europe, it was found that the need for new interconnection capacities is almost none and utilization factors remain significantly lower than in other regions and they are also less sensitive to the changes introduced among the scenarios.

8.2 Modelling conclusions

The finding that the results of the interconnections optimization are significantly different from the official network development plans raise the question for the reason of the discrepancies. All PCI and their impact on the EU's electricity system are analysed by the national operators as well as ENTSO-E which assesses them all in the pan-European TYNDP, confirming their profitability and necessity for their construction. Would it mean that interconnections that they recommend, in reality, are not that essential to the future of the electricity system operation?

First of all, one needs to remember that the modelling performed in this work took a simplified approach. The first simplification of OSeMBE was a reduction of each country into the singular node, without regional representation. Therefore, the structure of internal transmission systems of the countries was neglected, what influence the quality of the results. It might be particularly the case of large countries, where for some remote province due to the weak connection with the rest of the country it might be easier to import it from abroad.

The second simplification is related to the temporal representation of the modelled period. The model considered 5 seasons of the year and 3 day-periods, what in total gave 15 time-slices, assuming that in each of them there are constant values of load and generation from each technology. Another approach, increasing detail of the model, would be to take into account 12 months and 24 hour representation, with 288 time slices in total. However, such an increase in number of time-slices would lead to significant increase in the computation time and for that reason this approach was not taken.

Another factor that affects results accuracy is that in the model, the electricity system of 30 European countries is considered as an island. Connections to other than modelled countries are not considered. While in central Europe it has no negative outcomes, for the countries on the outskirts the connections with Morocco, Turkey, Russia, Bosnia and Herzegovina, Serbia, Albania and Macedonia are neglected which influences the final results.

Costs optimized by the model are investment costs, fixed and variable operational cost, while on the real energy market, prices of electricity are not created in the simple way of summing those three. Actually, there need to be considered plenty of margins of all market agents, who tend to maximize their profits.

Moreover, another important factor for having broader plans of electricity network development might be that factors are taken into account that go beyond pure economics. Bearing in mind that cooperation in the energy field is one of the major goals of the EU enforced in the policies of the Energy Union it is certain that there were applied factors like energy security, grid stability creating a common electricity market, reduction of price differences among the countries.

The extension of the modelling of the European electricity system with cross-border interconnections conducted under this work resulted in a representation of European power system that allows non-experts to understand how the model works and conduct optimization of their own scenarios. The results are also a valuable source of information about the optimal shape of the future electricity system of Europe.

9 Future Work

Th work conducted for this Master's thesis might serve as a base for further investigation and modelling held by other researchers. Due to the limited time and scope of that work, it was not possible to analyse all result data obtained, and focusing on those omitted outcomes may bring new interesting findings. Those analysis may focus on how electricity system was evolving in particular countries, not the whole Europe put together. Another approach would be to look at the annual data for more years than only every 10 like it was done in this Master's thesis.

However, the most important and interesting analysis of the obtained data should regard searching for the relation of the electricity transmission and types of electricity generation. Modelling resulted with data of generation and transmission for each time-slice, therefore, it would be possible to analyse which electricity generation technologies are more utilized during the time of increased transmission, weather those were renewables or conventional power.

The model that was built in this work may as well be used for modelling new scenarios of European electricity system development. Small adjustments of the model's constraints may be easily done to enforce different scenarios of construction of new capacities of energy generation and interconnection technologies.

When talking about the future works, it needs to be bear in mind that the developed model had certain weaknesses which might be improved in the future. Main one is that the interconnections were modelled only at the limited number of borders, for which data was available. Estimation of the costs of construction and operation of the interconnections at the rest of the borders, implementing those into the model and running the simulations again would possibly give different, more accurate results.

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