COMILLAS
UNIVERSIDAD PONTIFICIA
ICAI

Master Degree in Industrial Engineering

Master's Thesis

A case for the European electric network in 2030

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Madrid
January 2023

Declaro, bajo mi responsabilidad, que el Proyecto presentado con el título *A case for the European electric network in 2030* en la ETS de Ingeniería - ICAI de la Universidad Pontificia Comillas en el

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A Andrés y a Eric por todo el conocimiento compartido, el aprendizaje y la disponibilidad,

a mis padres por las oportunidades infinitas,

a Toni y Marta por la escucha incansable.

Casos de descarbonización para la red eléctrica europea en 2030

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Entidad colaboradora: Instituto de Investigación Tecnológica (IIT)

Resumen

La transición energética está remodelando los sistemas eléctricos de todo el mundo. La descarbonización es una solución necesaria para reconducir el estado de nuestro planeta hacia un futuro más sostenible. Sin embargo, no sólo vale con reducir las emisiones de carbono. Las redes del futuro deben asegurar el acceso a electricidad asequible, confiable y no contaminante. Si bien, esto no es un trabajo fácil. La complejidad del sistema eléctrico y los múltiples factores que lo influyen crean la necesidad de un estudio detallado sobre la red para diseñar soluciones efectivas. Para procurar un sistema enérgetico sostenible en el futuro es necesario establecer estrategias a medio y largo plazo que tengan en cuenta todos los agentes participantes en la red.

Con este fin, la asociación ENTSO-E (Red Europea de Operadores de Redes de Transporte de Electricidad) genera varias predicciones sobre el futuro de la red, evaluando la estabilidad de la generación e identificando los proyectos de inversión más necesarios. Este trabajo replica posibles escenarios para la red eléctrica europea para 2030, analizando el papel de la red, las unidades de generación y la participación ciudadana. Se pretende así estudiar el impacto de las diferentes soluciones de transición enérgetica con sus ventajas e inconvenientes y encontrar relaciones entre las diferentes variables del sistema. Para ello, se hará uso de openTEPES, un modelo desarrollado por el IIT de la Universidad Pontificia de Comillas que tiene como objetivo evaluar las futuras necesidades de generación, almacenamiento y red. Los principales resultados son las directrices para la futura

estructura de los sistemas de generación y transmisión.

Basándose en los mismos inputs que utiliza ENTSOE, los casos replicados son: *National Trends, National Trends Low Thermal, Global Ambition* y *Distributed Energy*; todos ellos con año objetivo 2030. Los dos primeros son escenarios bottom up que proyectan la PNEC actual y la información proporcionada por los GRT; los dos últimos son escenarios bottom-up que exploran la expansión de las energías renovables, los BESS y la DSR, adoptando una mentalidad más centralizada para el primer caso y descentralizada para el segundo. Los resultados de todos los casos muestran el despacho de energía por hora, la puesta en marcha de las plantas, los costes de producción, la cuota de renovables, el ENS total y la utilización de la red. En la tabla siguiente se muestra un resumen de los resultados.

Table 1: Resultados relevantes de los casos de estudio

	NT2030	**NT2030 Low Thermal**	**GA2030**	**DE2030**
Coste total del sistema [MEUR]	26665.56	56513.88	43614.88	36908.49
Coste total del sistema pu [€/MWh]	6.67	14.14	11.55	9.51
Emisiones totales [Mton CO_2]	97.5	95.42	62.02	65.28
Cuota de renovables	72.1%	76.5%	84.9%	86.1%
ENS total [GWh]	236.23	2134.31	1596.89	1145.51
Utilización de la red	66%	66%	67%	68%

Como puede observarse en la tabla, el mayor compromiso de los escenarios GA2030 y DE2030 conduce a una reducción de las emisiones y a un mayor uso de las energías renovables, aunque esta planificación tiene un gran impacto en la fiabilidad de la red. Las tasas de ENS aumentan considerablemente en estos dos escenarios, lo que conlleva un mayor coste (en total y pu). La utiliación de la red es más inestable en todos los escenarios.

Para NT2030, los resultados prevén reducciones de emisiones que cumplen y superan los objetivos actuales, al tiempo que proporcionan una red estable y unos costes de generación asequibles. En el caso de que los planes actuales conduzcan a un desmantelamiento más temprano de las unidades térmicas, se muestra el caso NT2030 Low Thermal. Este cambio en la capacidad térmica conduce principalmente a una mayor inestabilidad de la red, con casi 10 veces más ENS. Como consecuencia, los costes totales del sistema aumentan drásticamente. Las emisiones se reducen ligeramente y la cuota de renovables también aumenta moderadamente. En conclusión, la disminución temprana del desmantelamiento térmico no es necesariamente beneficiosa para el sistema, sino que implica mayores costes y menor fiabilidad. Para que sea eficaz, los cambios repentinos en los planes de desmantelamiento deben ir acompañados de un desarrollo adecuado de la red y de la sustitución de la capacidad térmica actual por energías renovables y baterías.

GA2030 y DE2030 muestran una mayor eficiencia y concienciación ciudadana, la demanda de electricidad se reduce ligeramente incluso después de electrificar los sistemas de transporte y calefacción. Un mayor compromiso con la COP26 se traduce en ambos casos en una mayor inversión en renovables. Gracias a ello, GA2030 muestra un gran aumento de la capacidad eólica marina instalada, así como más energía solar fotovoltaica y baterías. En el caso de DE2030, esta inversión procede principalmente de fuentes privadas dispuestas a desarrollar plantas de autoabastecimiento formadas por plantas solares fotovoltaicas, eólicas terrestres y baterías. La eólica terrestre no es tan relevante y las tecnologías de base tienden a ser las nucleares. Ambos escenarios muestran una disminución de las capacidades térmicas.

Los resultados de estos dos casos muestran unos costes de generación más bajos derivados de un mayor uso de las energías renovables y unos niveles de emisión de carbono más bajos. Sin embargo, los costes totales del sistema son considerablemente más altos debido a la gran inestabilidad de algunos nodos. Los niveles de ENS son entre 5 y 7 veces mayores que en el caso base. Esto se debe a una distribución desigual de las capacidades en el continente. Si las tecnologías dependientes del clima se concentran en algunas zonas del sistema, se necesita una red densa para repartir la energía verde por los nodos en caso de que no haya sol o viento. El uso excesivo de la red lleva al colapso del sistema, provocando apagones. Otra forma posible de verlo es construir plantas distribuidas de forma equitativa para que la dependencia del clima sea menor y los patrones de producción sean más suaves. En este caso, también se necesita una red alta para transportar la energía desde las zonas soleadas a los nodos de baja generación. En ambos casos, es necesario un desarrollo adecuado de la red. Además, las baterías y los sistemas de almacenamiento de energía también son cruciales para proporcionar reservas de funcionamiento y uniformidad en el suministro.

El caso concreto de España muestra circunstancias ligeramente diferentes a las del resto del continente. Es un nodo más aislado, con mayores recursos eólicos y solares y potentes centrales hidroeléctricas, pero carece de suficiente energía nuclear. Los planes nacionales para el desmantelamiento de las centrales térmicas son bastante ambiciosos, y buscan una reducción del 23% de las emisiones de carbono respecto a los niveles de 1990, así como una cuota de generación renovable del 74%. España no presenta ENS en ninguno de los escenarios, lo que demuestra que es un sistema estable. Las previsiones sobre las emisiones de CO_2 son notablemente mejores que los objetivos: 1Mt CO_2 para NT2030, 0,25Mt CO_2 para GA2030, y 0,22Mt CO_2 para DE2030. Esta tendencia coincide con la cuota de generación renovable, también por encima de los objetivos nacionales, que alcanza el 82% para NT2030, y alrededor del 90% para los dos casos GA2030 y DE2030. No se espera que la demanda varíe mucho para los casos alternativos, mostrando entre +1% y -4% de cambios respecto a los niveles actuales. En todos los casos, España importa energía de Francia y la exporta a Portugal, siendo un importador neto. La utilización de las líneas se sitúa en torno al 60% para NT2030 y ligeramente superior para GA2030 y DE2030. Las tecnologías más utilizadas son la eólica terrestre y la solar fotovoltaica en todos los casos. La eólica marina no tendrá un gran impacto como en otros países. En general, España muestra unos resultados muy prometedores en cuanto a las cuotas de renovables, manteniendo la estabilidad del sistema. Deben llevarse a cabo planes ambiciosos para desplegar al máximo las capacidades solares y eólicas y convertirse en un exportador neto.

En conclusión, un enfoque holístico del problema es crucial para ofrecer soluciones eficientes y sostenibles. El desmantelamiento de unidades térmicas, el despliegue de energías renovables o el desarrollo de la red son soluciones inútiles si sólo se lleva a cabo una de ellas. Por el contrario, un enfoque colectivo coordinado en el que participen organismos privados y públicos es la mejor manera de lograr la neutralidad en carbono en el horizonte a medio plazo.

Palabras clave: transición energética, red eléctrica europea, 2030, emisiones de CO2, fiabilidad del sistema

A case for the European electric network in 2030

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Executive summary

The energy transition is reshaping electricity systems around the world. Decarbonisation is a necessary solution to reshape the state of our planet towards a more sustainable future. However, reducing carbon emissions is not enough. The grids of the future must ensure access to affordable, secure, and clean electricity. But this is not an easy job. The complexity of the electricity system and the multiple factors that influence it create the need for a detailed study of the grid to design effective solutions. In order to ensure a sustainable energy system in the future, it is necessary to establish medium and long-term strategies that take into account all players involved in the grid.

To this end, the ENTSO-E (European Network of Transmission System Operators for Electricity) association generates several predictions about the future of the grid, assessing the stability of generation and identifying the most necessary investment projects. This project replicates possible scenarios for the European electricity grid in 2030, analysing the role of the grid, generation units and citizen participation. The aim is to study the impact of the different energy transition solutions with their advantages and disadvantages and to find relationships between the different variables of the system. For this purpose, openTEPES will be used, this is a model developed by the IIT of the Comillas Pontifical University that aims to assess future generation, storage and grid needs. The main results are the guidelines for the future structure of the generation and transmission systems.

Based on the same inputs that ENTSOE uses, the cases replicated are: National Trends, National Trends Low Thermal, Global Ambition and Distributed Energy; all of them with target year 2030. The first two are bottom-up scenarios that project current PNEC and info provided by TSOs; the last two are bottom-up scenarios that explore the expansion of renewable energy, BESS, and DSR, adopting a more centralized mindset for the first case and a decentralized one for the latter. Outputs for all cases show hourly energy dispatch, commissioning of plants, costs of production, share of renewables, total ENS, and network utilization. A summary of results is shown in the table below.

Table 2: Summary figures for all cases

	NT2030	**NT2030 Low Thermal**	**GA2030**	**DE2030**
Total system cost [MEUR]	26665.56	56513.88	43614.88	36908.49
Total system cost pu [€/MWh]	6.67	14.14	11.55	9.51
Total emissions [Mton CO_2]	97.5	95.42	62.02	65.28
Share of renewables	72.1%	76.5%	84.9%	86.1%
Total ENS [GWh]	236.23	2134.31	1596.89	1145.51
Network utilization	66%	66%	67%	68%

As it can be observed in table 4.1, higher commitment of scenarios GA2030 and DE2030 lead to lower emissions and higher usage of renewables, nevertheless this planning has a huge impact of the network reliability. ENS rates rise sharply for these two scenarios, leading to higher cost (in total and pu). Network utilization is more less stable across scenarios.

For the NT2030, results show emission reductions that overpass current objectives, while providing a secure network and affordable costs of generation. In the case of variations in current plans leading to earlier decommissioning of thermal units, NT2030 Low Thermal is forecasted. This change in thermal capacity mainly leads to higher instability of the network, with almost 10 times more ENS. Consequently, total system costs increase dramatically. Emissions are slightly reduced, and the share of renewables also increases moderately. In conclusion, the early decrease in thermal decommissioning do not necessarily benefit the system, while involving higher costs and lower reliability. To be effective, sudden changes in the speed of capacity plans must be matched with proper network development and substitution of current thermal capacity with renewables and batteries.

GA2030 and DE2030 shows higher efficiency and citizen awareness, demand for electricity is slightly reduced even after energy transition. A greater commitment to COP26 is shown in both cases showing a greater investment in renewables. GA2030 shows a great increase in installed offshore wind capacities, as well as more PV solar and batteries. In the case of DE2030, this investment comes mainly from private sources willing to develop self-supplying plants formed by PV solar and onshore wind plants and batteries. Offshore wind is not as relevant and the base technology tends to be the nuclear decreasing thermal capacity.

Results for these two cases show lower generating costs derived from a higher use of renewables and lower carbon emission levels. Nevertheless, total system costs are considerably higher due to the huge instability of some nodes. ENS levels are 5-7 times higher than the base case, due to a unequal distribution of capacities across the continent. If weather-dependent technologies are concentrated in some areas of the system, a dense network is needed to spread green energy across nodes. The overuse of the network leads to the collapse of the system, causing power outages. Another possible way of seeing it is to build plants equally distributed so that dependence on weather is lowered and production patterns are smoother. In this case, a high network is also needed to transport energy from sunny areas to low-generating nodes. In both ways, proper network development is needed. Moreover, batteries and ESS are also crucial for providing operating reserves and uniformity in supply.

The specific case for Spain shows slightly different circumstances than the rest of Europe, being a more isolated node with higher wind and solar resources and powerful hydro plants, but lacking enough nuclear power. National plans for the decommissioning of thermal plants are quite ambitious, looking for a 23% reduction of carbon emission compared to 1990 levels, as well as a renewable generating share of 74%. Spain does not show ENS in any of the scenarios, which proves to be a secure system. Forecast on CO_2 emmisions are notably better than objectives: 1Mt CO_2 for NT2030, 0.25Mt CO_2 for GA2030, and 0.22Mt CO_2 for DE2030. This trend is matched with the share of renewable generation, also above national objectives reaching 82% for NT2030, and around 90% for GA2030 and DE2030. Demand is not expected to vary greatly for alternative cases, showing from +1% to -4% changes from current levels. In all cases, Spain imports energy from France and exports it to Portugal, being a net importer. The utilization of the lines is around 60% for NT2030 and slightly higher for GA2030 and DE2030. Most used technologies are onshore wind and PV solar for all cases. Offshore wind will not have a huge impact as in other countries. Overall, Spain shows very promising results in renewable shares while keeping the system stable. Ambitious plans must be carried out to deploy solar and wind capacities to its fullest extent and become a net exporter.

In conclusion, a holistic approach of the problem is crucial to provide sustainable efficient solutions. The decommissioning of thermal units, the deployment of renewable energy or the development of the network are useless solutions if only one of them is carried out. In contrast, a collective coordinated approach involving private and public bodies is the best way to achieve carbon neutrality in the mid-term horizon.

Key words: energy transition, European electric network, 2030, CO2 emissions, system reliability

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Acronyms

AC Alternating Current. 25

aFRR Automatic Frequency Restoration Reserve. 29

CBA Cost Based Analysis. 19

CBNTC Cross Border Net Transfer Capacities. 21, 33

CCSU Carbon Capture Storage Units. 3

CY Climate Year. 8, 31

DC Direct Current. 25

DE2030 Distributed Energy 2030. 58

DSR Demand-Side Response. 3, 19, 21

EFOR Equivalent Forced Outage Rate. 30

ENS Energy Not Served. 25

ENTSO-E European Network of Transmission System Operators for Electricity. 11, 18, 21, 33, 50, 58

ERAA European Resource Adequacy Assessment. 8, 9, 11, 18, 19, 21, 25–27, 29–31, 33, 36

ESS Energy Storage System. ix, 21, 78

EV Electric Vehicle. 26

FCR Frequency Containment Reserve. 29

FRR Frequency Restoration Reserve. 29

GA2030 Global Ambition 2030. 58

mFRR Manual Frequence Restoration Reserve. 29

NECP National Energy and Climate Plan. 9, 11

O&M Operations and Maintenance. 30

openTEPES Open Generation, Storage, and Transmission Operation and Expansion Planning Model with RES and ESS. 18, 19

p.u. Per Unit. 33

PECD Pan-European Climate Database. 13, 31, 32

PEMMDB Pan-European Market Modelling Database. 13, 19–21, 29–32, 50

PSCL Pumped Storage Closed Loop. 19, 20, 29, 31, 32, 44, 47

PSOL Pumped Storage Open Loop. 19, 20, 31, 32, 44, 47

RoR Run-of-River. 19, 20, 32, 47

RR Replacement Reserve. 29

TRAPUNTA Temperature Regression and loAd Projection with UNcertainty Analysis. 13

TYNDP Ten-Year Network Development Plan. 19, 23, 58

Chapter 1

Introduction

1.1 Introduction

Electricity is a crucial element in our lives. Our whole society is built around it and it is nearly impossible to imagine a world without light, internet, heat, power, phones, or even cars. Since 1752, the electricity has flooded our history, enabling development in all aspects and providing higher standards of living. Nowadays, the electricity sector is in many ways different to that key attached to a kite string that Mr Edinson used in his famous experiment. Electric cars, solar panels, carbon capture technologies, or green hydrogen production are just some of the disruptive technologies that are changing the system's structure and dynamics. Moreover, decarbonization and electrification of the industry are creating new challenges and needs. Therefore, the grid must evolve around three aspects to prepare for the future: the security of the supply, the sustainable development of the system and the affordability of electricity tariffs.

Trends driving the demand of electricity can be divided into two segments: traditional demographic and technical tendencies, and urgent sustainable measures. On the first place, we find causes such as globalization, wealth upturn in developing countries, new technologies requiring electricity, and population increase that will project an increment in demand. Thanks to globalization, both developed and developing countries have suffered never-before-seen growth in their economies and industries. Although developed countries are seeing how their birth rates are plugging, developing countries show completely opposite trends, even having to control birth to avoid overpopulation. Other causes fostering electricity usage are the consumerism that seems to have inundated all societies and the rising need for electricity in our day-to-day tools. It is estimated that the rise in energy demand over the following years will be by 1.3% each year to 2040.[5]

On the second place, an increasing awareness on resource management and sustainability have reshaped trends across all industries in order to achieve net zero carbon economy by 2050. Not only it is more economic to use less resources but also more appealing for consumers. Thus, producers are making electronic devices increasingly efficient and even recycling materials, leading to a reduced electricity usage per device. Nevertheless, that down-loping factor is not enough to balance the global increase. Energy intensive industries are being criticized and consumers are shifting to more efficient alternatives, as it is the case of plastics or 3D printing in architecture instead of iron and steel. Moreover, this pressure does not only apply to scope 1 of carbon footprint but to the whole process. When broadening the scope, it is not as easy to cut down energy usage but rather to switch to greener energies, leading again to an increase in electricity demand. For example, the iron or the pesticide industry are joining hands with electricity procurers to build PV power plants in their factories and even invest in hydrogen plants, leaving coal and oil to the past. Transport is also suffering a structural transformation since the irruption of EV vehicles and trucks. The aero and naval industry will be the next to change. These drivers stem from very different roots and origins but are robust and consistent, hence positioning electricity as the key for a sustainable future. Forecasts of these trends are presented in the figure 1.1.

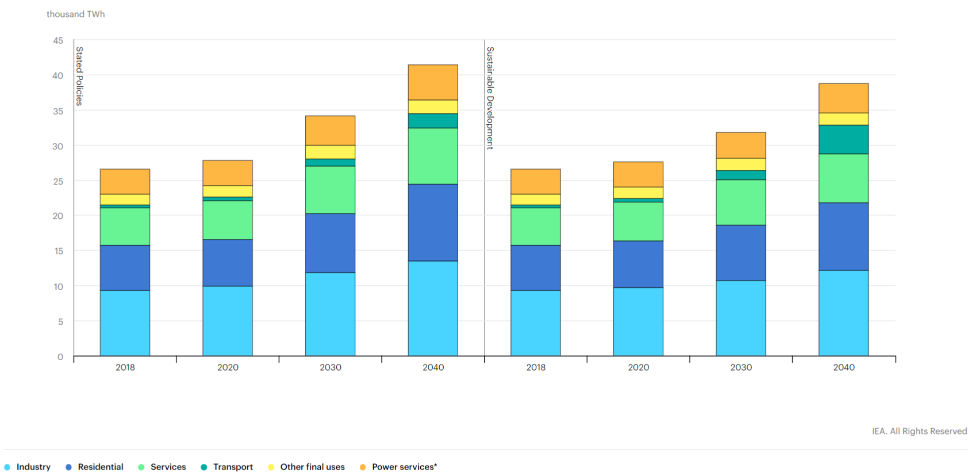

Figure 1.1: Electricity demand by sector and scenario, 2018-2040 [1]

A completely new geopolitical chessboard is thus laid out in which coal and oil are increasingly losing their weight. This decline gives way to new utilities such as copper for power lines, lithium and other minerals for batteries, land for the construction of wind and photovoltaic power plants, and even the security of network information to prevent hacks. This way, new opportunities and threats emerge. Increased electricity use means not only more generation, but also a distribution grid with higher capacity, greater difficulty in coordinating and securitizing demand, and the requirement for tighter coordination between countries. It is therefore crucial that the energy transition taking place is carried out properly and robustly, leaving no sector or area behind. Otherwise, the imbalance would lead to very negative impacts on investment and supply.

Given the significance of this change in economic, political, and ecological terms, it is important to establish aligned strategies between the many countries, the electricity industry players and consumers involved in the grid. To do so, all factors must be taken into account: the evolution of demand due to the patterns detailed above, the impact of climate on renewables and of the later on system inertia, the cost of raw materials and CO_2 rates, and so many other details that affect the complex electricity system. In addition, these strategies must ensure that the ultimate goal of this change is to provide clean, secure and affordable electricity, without forgetting that electricity is a commodity.

As it was introduced before, electricity is a vital utility. A stable and reliable supply provides the security of the whole system, as street and traffic lights, alarms and communications rely on electricity. Proof of this is the Manhattan blackout of July 2019, a power cut that stopped the city for three hours. Thanks to balancing reserves, these events are more rare each time, but the growing complexity of the grid poses some questions on the future security. Although predictive systems are continuously improved and energy is better dispatched each time, the increase in the renewable generation of electricity involves a greater instability of demand. A higher interconnected Pan-European network presents a viable solution to this issue.

Another relevant aspect is sustainability. Decarbonization is in everyone's mouth and the electric industry is no exception. There is an urgent need to reshape the sector to reach sustainable GHG emission levels and succeed in stopping climate change. To achieve this, increasing trends in demand must be matched with higher efficiency, bigger shares of renewables, GHG emission reductions and stronger carbon price signals. In Europe, the sum of greenhouse gasses coming from transportation, industry and power rises up to 77% of total emissions. [6, 7] These figures pinpoint the pressure to electrify the industry, and use all available resources to approach the problem. Amongst these, not only RES, nuclear and hydro storage are relevant. But also batteries, CCSU, hydrogen, Power2X and DSR can be key team players to meet Europe's Green Deal goals. The development of these technologies is requiring relevant amounts of resources, investigation, and investments. The expected shift in the market size of each technology is presented in Figure 1.2

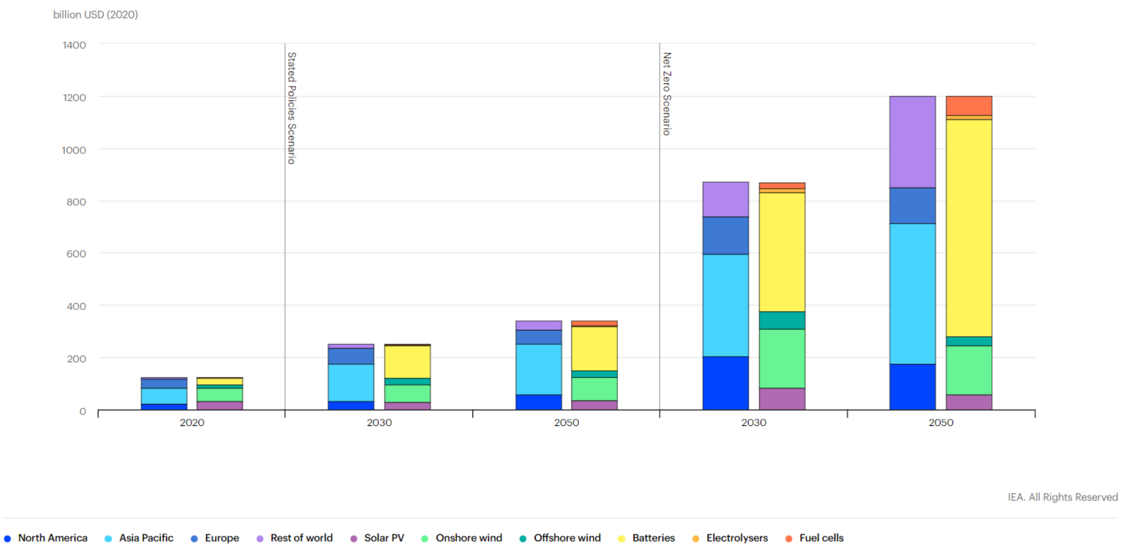

Figure 1.2: Estimated market sizes for selected clean energy technologies by technology and region, 2020-2050 [1]

Finally, any sustainable solution must meet certain economic requirements to be viable. In addition to providing a clean and secure power supply, the electricity tariff must be kept to an affordable minimum. The development of an interconnected grid will make it possible to leverage different demand patterns across countries to smooth the peaks of the global curve. Hence, there will be no need for such large and costly peaking generation units. In addition, this interconnection will also allow to homogenize the supply of renewables across Europe, as climate varies from one place to the other. One other important step towards a cheaper supply is the higher involvement of consumers. Providing more information on prices and time frames will allow users to change their behavior accordingly to prices and availability. Demand side response will be a great ally when base generation units such as coal power plants phase out.

The European Union is aware of these issues and has committed to tackling them. With respect to the electricity network, Europe aims to integrate the Pan-European energy markets to provide a secure, sustainable and affordable supply. To reach the Green Deal objectives, a set of intelligent effective investments in the grid must be well-planned. With this aim, the European Network of Transmission System Operators for Electricity (ENTSO-E) has developed a series of packages that outline what are the most relevant needs of the future network and which projects are of common interest. These are the Mid-term Adequacy Forecast (MAF), which has evolved in time to the European Resource Adequacy Assesment (ERAA), and the Ten Year Network Development Plan (TYNDP). In these researches, large datasets are treated to forecast what the demand will look like in the upcoming years, different time scopes are set for each research with different objectives. For MAF, and the ERAA, the aim of these researches is to assess the adequacy of the system. For the TYNDP, these studies aim to plan the expansion of the grid by prioritizing projects. Having different objectives, the nature of the input data is coherent for all studies. Although predicting the future is impossible, probabilistic methodologies help lay out the most relevant aspects that will affect the tomorrow's network. With these forecasts, the EU aims to provide countries with a framework to help develop national plans. Nevertheless, further complementary national information must be matched and more specific programs must be developed.

1.2 Motivation

Global warming is one of the most relevant problems in society and without sustainable development, it will be impossible to maintain the current growth rate and conditions. Electricity is a key factor in the decarbonization of the planet and engineers are one of the best prepared professionals to address it. It is in their hands not only to develop innovative technologies to generate electricity in a clean way, but also to provide systems with the necessary support to achieve the energy transition. If solutions are developed but no means are provided to reach them, all work will be in vain. Therefore, it is vital to allocate the necessary resources to develop a grid that is capable of supporting new changes and needs.

As mentioned above, the ultimate goal of the energy transition must be access to clean, secure, and cheap electricity. However, given the trends and developments in the energy sector, this is no easy task. With the growing importance of renewables, hydrogen and responsive demand, new factors such as climate, CO_2 rates, electricity prices, and system inertia must be taken into account. In this way, the electric dispatch becomes even more complicated if possible. Thus, it is of vital importance to understand all actors in the system and their correlation.

The Institute for Research in Technology (IIT), which belongs to the School of

Engineering (ICAI) of Comillas Pontifical University of Madrid (Comillas), promotes research and postgraduate training in diverse technological fields. Amongst these, the Energy Systems Models Area focuses in developing models for supporting decisions and techno-economic analysis of generation, transmission and distribution systems in the energy sector. [8] OpenTEPES is a model developed by the IIT that evaluates generation, storage, and transmission needs as well as planning optimal investments for meeting the forecasted demand at a minimum cost.[9] Similarly to ENTSO-E models, openTEPES is able to provide the user with robust guidelines for the future grid.

The need to understand in depth where the energy system is heading and what are the most relevant aspects to achieve the energy transition, together with the ease of access to powerful tools such as those developed at the IIT, have given rise to this project. The aim of this report is to generate a case that outlines the future grid of Europe in a medium term horizon in terms of generation and transmission, identifying the main drivers of decarbonization. Furthermore, a comparison will be drawn between the outcomes obtained with openTEPES with the ones presented in the ERAA2021 and TYNDP using the same input information. Different scenarios will be modeled, similar to the ones regarded in the TYNDP outlook and sensitivity analysis on parameters such as CO_2 prices or fuel prices will be carried out. By doing so, the model will prove to be a sufficiently powerful and robust tool for decision making. In conclusion, the main motivation of this project can be summarized in two keypoints: identify factors affecting the future of the grid to understand its behavior and see the impact of the different future scenarios in the network expansion.

1.3 Objectives

The final aim of this project is to create a package of future scenarios that describe the possible future of the European grid for 2030 by outlining the main risks the network and system faces, the possible solutions and the needed transformations to achieve the decarbonization of the sector. To do so, the following objectives will be pursued:

1. Identify key factors that affect the future of the Pan-European electricity network.

2. Get to deeply understand how does the system work and what are the key solutions to achieve net emissions objectives.

3. Learn how to manage a predictive model.

4. Prove that openTEPES is a powerful tool able to forecast future scenarios as ENTSOE's models do.

1.4 Resources

In order to achieve the objectives above, two types of resources are required: the input data, estimations and state of art provided by ENTSOE, and the openTEPES model.

1.4.1 Input data

As one of the objectives is to prove the potential of openTEPES, the input data must be the same as the one used by ENTSOE for its many reports. This is the only way to compare final results. On this aspect, ENTSO-E provides several datasets for academic research. These databases are explicitely built on TSOs indications and forecasts, and implicitly built on historical data from neighbouring countries. The main databases to be used are: PEMMDB, PECD and Network database. The Pan European Market Modelling Database (PEMMDB) gathers information about installed capacities for nonRES and RES, hydro storage capacities, demand forecast, DSR, forced outage plans, fuel cost and technical characteristics for each type of technology. Moeover, the PanEuropean Climate Database gathers historical information about weather variables for years ranging from 1982 to 2017. This dataset is relevant for solar, wind and hydro generation. As each climate year is different accros Europe, it is recommended to use several years with different probabilities. Finally, network information provided by TSOs includes net transfer capacities between nodes, the type of lines, reactive and loss data, and the voltage needed.

The databases are updated every year in order to build accurate reports. To do this, TSOs are provided with templates, guidelines, a scenario proposal, and support by providing webinars for consultation. This methodology ensures standardization and uniformity of data across countries. Once gathered, the data is reviewed and checked to identify potential errors and infeasibilities. Finally, this databases are used for the different reports. The latest version can be obtained from ERAA 2021 website `https://www.entsoe.eu/outlooks/eraa/eraa-downloads/` and from the TYNDP 2022 website `https://tyndp.entsoe.eu/maps-data/`

1.4.2 openTEPES

The other relevant resource is the openTEPES model, a tool developed by the IIT. The Open Generation, Storage, and Transmission Operation and Expansion Planning Model with RES and ESS evaluates demand, generation capacities and storage, and plans the dispatch of energy at minimum costs for time horizons of 5-10-20 years. This tool can be used to select optimal investments as well as to identify future needs of the grids and plan dispatch. To meet the scope of this project, only operation and dispatch decisions will be analyzed.

In terms of the optimization and the mathematical approach of this model, it is defined as the following:

> "OpenTEPES is a network constrained unit commitment (NCUC) based on a tight and compact formulation including operating reserves with a DC power flow (DCPF) including line switching decisions. Network ohmic losses are considered proportional to the line flow. It considers different energy storage systems (ESS)"
>
> (Andrés Ramos, 2022)

Nevertheless, the complexity of the mathematical approach of the model and the little expertise with Python have left the modelling of openTEPES out of the scope of this project. From now on, the model will be used as a black box and only inputs and outputs will be analyzed.

1.5 Methodology

The methodology of this project can be divided into three sections:

- Gathering of the input data: For this part a meticulous procedure is needed. To obtain comparable results, input data must be the same for both models. Hence, same databases must be used, target years must be defined, and the climate years to reference must be stated. Chapter 3.1 will define the approach followed.
- Comparison of output data: The comparison will be applied only to results and not to procedures. The results presented by ENTSO-E in the selected outlook will be contrasted with the openTEPES results. Nevertheless, differences in the procedure might be taken into account when comparing. ERAA holds a large database with several CY that exceed the scope of this project.

In consequence, ENS and Network usage results will be compared but are not expected to be identical.

- Sensitivity analysis and scenarios presentation: In this case, different scenarios departing from the base case are presented in order to analyze the impact the different factors have in the system. Benchmarking can be done against ERAA, but also NECP for the different cases.

1.6 How to read this document

The following document is divided into xx chapters. Please find below a list of the content and purpose of each chapter for an easier reading:

1. **Introduction**, an statement of the current situation is given, the problem and its main causes are analyzed, and a scope for the current project is defined. The resources and methodology to be used are outlined in order to achieve the objectives agreed.

2. **State of art**, a comparison between the different reports developed by ENTSOE is carried out, identifying similarities and differences.

3. **Cases of study**, four cases are developed. National Trends 2030 is the base case, which replicates the ERAA Outlook and follows a bottom-up approach. Then, National Trends with Low Thermal capacities is a variation of the base case. Finally, Global Ambition 2030 and Distributed Energy 2030 study different development of renewables, following the story lines of TYNDP2022. They follow a top-down approach. For each of these scenarios, main drivers for changes are outlined; information about input data and its sources is explained; results are analyzed, and conclusions are drawn.

4. **Conclusions**, main outcomes of the analysis are described, reflections on the methodology and project development are outlined, and further possible research lines are pinpointed.

Chapter 2

State of art

The aim of this chapter is to present the different outlooks that ENTSO-E builds. These are: MAF, TYNDP, e-Highway, and last but most updated, ERAA. NECP are also mentioned and explained.

The European Resource Adequacy Assessment (ERAA) and the Ten-Year Network Development Plan (TYNDP) are two documents that explore the future of the Pan-European electricity grid from different perspectives. Both documents are carried out by ENTSO-E (European Network of Transmission System Operators for Electricity), an international non-profit association that gathers 42 TSOs from 35 countries. Their mission is to carry out development plans from a common standpoint with the objective of:

> "Ensuring the security of the interconnected power system in all time frames at pan-European level and the optimal functioning and development of the European interconnected electricity markets, while enabling the integration of electricity generated from renewable energy sources and of emerging technologies."
>
> (ENTSOE mission statement, 2021)

With this purpose, they have different initiatives that gather information from different sources and natures, and then design development plans that lead and complement National Development plans. The previous outlook to ERAA was MAF (Medium Adequacy Forecast). MAF and TYNDP are two of these initiatives. Although sharing some target year, assumptions, and sets of input data, they hold two completely different scopes.

Some other relevant outlooks taken as reference for this project are the eHighway and the NECP for each country, although these are not devloped by ENTSO-

E. The first one was developed in 2016 as an European project to address long term horizons. It projects the power grid infrastructure for 2050 for five different scenarios depending on the development of economy, RES capacities, nuclear acceptance, CCS, and some other aspects. A cost benefit analysis is also presented. Besides that, NECP (National Energy and Climate Plans) were carried out by each country for the period from 2021 to 2030. They are aligned with ERAA and TYNDP but show more detailed measures, policies, and projects. NECP in Spain falls under the responsibility of MITECo, who builds the plan based on REE knowledge (Spanish TSO).

Another relevant and more updated outlook is the ERAA 2022, the European Resource Adequacy Assessment. This assessment builds on MAF and includes further analysis to meet the Clean Energy Package. It has a 10 years ahead time horizon, includes economic viability assessments, and studies the impact of capacity mechanisms. From 2021 on, ERAA substitutes MAF due to its broader scope and its more robust modeling techniques (including Flow-based analysis). Further information about this outlook is given in the second section of this chapter 2.2.

2.1 A comparative on TYNDP and ERAA

In first place, ERAA stands as an adequacy forecast: an evaluation of a power system's available resources and projected electricity demand to identify supply and demand mismatch risks under a variety of scenarios. [10] As so, the main outputs of this report are the generation, transmission, and overall adequacy levels for the target year expressed by indicators such as Loss of Load Expectation (LOLE) and Expected Energy Not Served (EENS). An example of this can be seen in 2.1: and 2.2. On the contrary, the TYNDP stands as a development plan, thus it includes several expected projects for the participating countries. Furthermore, in the TYNDP outlook, a Cost-Benefit Analysis (CBA) is carried out for each project and different scenarios are presented. It could be said that the ERAA and the TYNDP are complementary reports, as they identify network needs from different perspectives that then are covered by the transmission and storage projects.

Secondly, ERAA and TYNDP share the same target years and scenarios. They show three different scenarios with various target years. These are the National Trends scenario (with 2025, 2030, 2040, 2050 TY), the Distributed Energy Scenario, and the Global Ambition Scenario (both with 2030, 2040 and 2050 TY). For ERAA, National Trend is the divided into two> NT and NT with Low Thermal Capacity,which includes an accelerated phase-out of thermal plants. The drivers

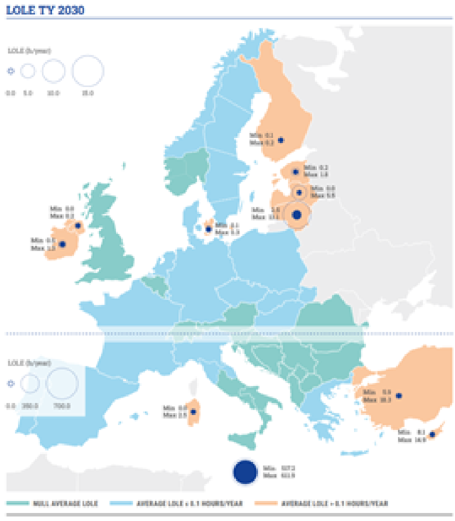

Figure 2.1: LOLE values for TY 2030 presented in the ERAA Main Report [2]

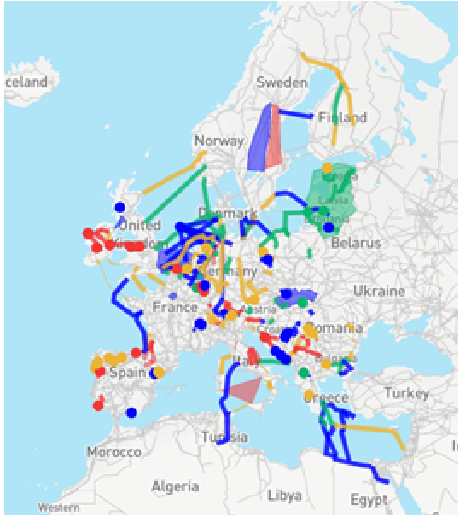

Figure 2.2: TYNDP 2020 project map with transmission and storage projects [3]

that make the scenarios different are shown in figure 2.3. To build coherent and robust outlooks between both models, the simulation inputs for the ERAA report are aligned with the National Trends scenario data. Both reports build on the same databases, which hep build the bottom-up scenario National Trends.[3, 11] A main distinction is the incorporation of the gas grid data in the TYNDP to include Power-to-Gas and Power-to-Liquid. This is possible by working conjunctively with ENTSOG.

ERAA provides more updated sets of information as a report is carried out every year in contrast with the biannually frequency of the TYNDP. This difference in the assiduity of the reports can be crucial in the energy sector for the times being, as rapid changes are having place.

Regarding the input data used for each outlook, both use sets provided by TSOs for the generation side, the grid side, and the demand side. Large amounts of information involving climate conditions, planned outages, random outages, and power capacities are required to provide robust results. Furthermore, it must be remarked that these outlooks focus on the cross border NTC, disregarding intrazonal connections and, hence analyzing the big picture. On the one side, ERAA follows a bottom-up approach that combines information provided by TSOs with random MC simulations on the weather and random outages building on three datasets: PEMMDB (Pan-European Market Modelling Database), PECD (Pan- European Climate Database) and TRAPUNTA (Temperature Regression and loAd Projec-

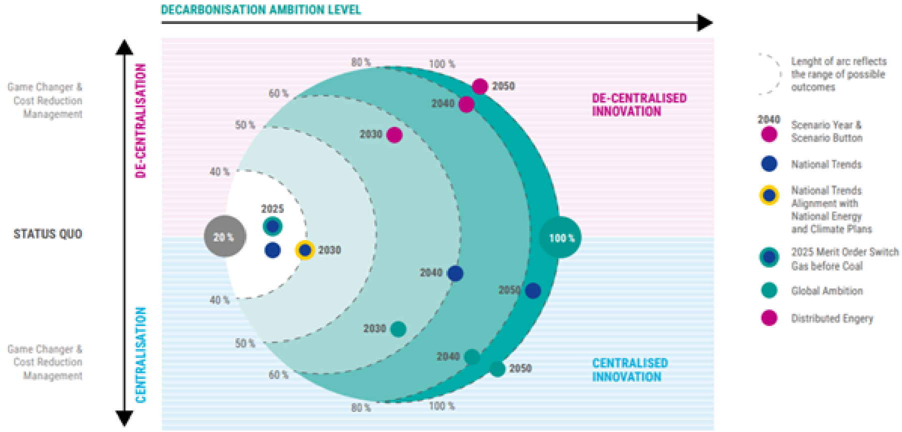

Figure 2.3: Key drivers for different scenario storylines [4]

tion with UNcertainty Analysis). On the other, TYNDP uses those datasets as inputs, adds the projects received from TSOs, merges the models to create a probable grid picture and, finally, obtains net transmission capacity from the market simulation output.

With respect to the general workflow, bellow the procedure followed by ENTSO-E to build each outlook is briefly explained:

- For ERAA: the data is fed into five modelling tools for the first TY and climate year, M random outage patterns are initially assigned and then, each modelling tool provides an optimised solution. If convergence between tools is not reached, M is increased until convergence is reached. After this, an extra final step for optimising the hydro storage is carried out. To prove confidence in the results, further outage patterns are fed into the model providing similar outputs.

- For TYNDP: PEMMDB, PECD and TRAPUNTA are used to project the different scenarios. From these, different needs are identified, then an analysis is carried out to pinpoint where increasing CBNTC would be more cost-efficient. Afterwards, information from all transmission and storage projects across Europe is collected and a CBA is carried out for each project and scenario. In the end, some projects are classified as Projects of Common Interest (PCI) depending on their general impact and CBA.

Finally, it must be pointed out that both outlooks follow an iterative process, hence they are in perpetual state of work in progress to stay up to date with the latest data and probabilistic techniques. In fact, the European Resource Adequacy Assessment (ERAA) is the sucessor of the Medium-Term Adequacy Forecast (MAF), an outlook that forecasted NAtional Trends up to 2030 with no economic analysis.

To conclude, ERAA and the TYNDP share the common interest on offering relevant information about the future of the electricity grid to enhance decision making of our governors and regulators. ENTSO-E hopes for a secure, economic, and sustainable network that will be able to adapt to the Energy Transition. With this aim, both outlooks gather up information from many different natures to provide a vision on adequacy risks (ERAA) and the most beneficial transmission and storage projects (TYNDP). The main differences between each outlook our summarised in the table below:

Table 2.1: Main comparable aspects between ERAA and TYNDP

	ERAA	**TYNDP**
Purpose	Forecast of Adequacy	Forecast on grid development
Author	ENTSO-E	ENTSO-E
Target Year	2025, 2030	2025, 2030, 2040, 2050
Objectives	Provide data to make correct decisions over investment and production to meet adequacy goals	Security of supply, price, sustainaibility by analysing(CBA) different projects for each scenario
Main outcomes	LOLE and EENS from 2025 up to 2050 for each country	Map with upcoming projects and selected PCIs
Scenarios	National trends (2), and Central Scenario with/without Capcity Mechanisms	National trends, Global Ambition and Distributed Energy
Input data	PEMMDB, PECD and TRAPUNTA	PEMMDB, PECD and TRAPUNTA and Planned projects

2.2 Deep dive into ERAA

As introduced before, ERAA is the new version of MAF. As so, it shares the same objectives and perspectives. The European Resource Adequacy Assessment aims to forecast the needs of the grid for the upcoming ten years in order to identify potential adequacy risks in terms of EENS and LOLE. For this, it uses the same databases: PECD, PEMMDB and CBNTC. Being an adequacy assessment, this outlook holds a conservative view on climate, demand and installed capacities, always tending to the worst case scenario to be on the safe side. A consequence of this is the modeling of the 36 available climate years joined with the N random outage plans explained above. This leads to Nx32 Monte Carlo simulations, procuring a pretty accurate and reliable result.[12]

The innovations introduced by ERAA are mainly the following: the introduction of various scenarios, wider time horizons, the Economic Viability Assessment(EVA), and the modeling of crossborder flows using Flow-Based techniques. Thanks to the different scenarios, ERAA is able to assess the impact of Capacity Mechanisms in the grid and to compare different levels of Thermal capacities outage.

We can find four different scenarios: National Estimates, which is the equivalent to the MAF scenario; National Estimates with Low Thermal capacities which is the same as NE but applying a higher phase out of thermal capacities such as coal or lignite; Central scenario without Capacity Mechanism which is the NE after apply EVA to all projects and identifying non-economic units and taking them out of the system (most of the thermal units); Central scenario with Capacity Mechanism same as previous but using capacity mechanisms. Capacity Mechanisms are a solution for those units that are always available for generating energy even though this might not be profitable. When providing energy, these units are payed with capacity payments as well as with the normal earnings, hence encouraging electricity operators to participate. It is a way of serving energy at a lower price than the VoLL but a higher cost than any other unit in the system. Target years for National Estimates scenarios are 2025 and 2030, and 2025 for the Central scenarios.[13]

The Economic Viability Assement is applied for year 2025. For this assessment, an initial operation plan is outlined. Then, the revenues are contrasted with the CAPEX and OPEX costs for each unit. Those units that become non-profitable are taken out of the system or phased out and a new operation dispatch is carried out. This results in a lower thermal capacity accross Europe but a higher adequacy risk. The Flow Base technique is just applied as a proof of concept at this stage, and estimated to be applied in upcoming ERAAs.

As it can be observed, the ERAA is a leap forward from MAF to TYNDP. It maintains the same objectives and conservative perspectives as MAF, but starts applying scenarios and economic assessments to define the most interesting technologies to implement or phase out and the possible outcomes if using different strategies. ERAA is a very complete forecast with longer time horizons than MAF and wider scenarios that provide the most appropriate balance between MAF and TYNDP. Therefore ERAA 2021 will be the reference hereon for this project.

Chapter 3

Cases of study

To conquer the objectives of this project, four cases have been developed to understand the European electric system, and to identify upcoming challenges and key drivers of change. The first case National Trends 2030 is the base case, which replicates ERAA 2021 and uses the same input data.[13] This case follows a bottom-up approach, gathering information from all European TSOs and NECPs. Three further cases stem from the first one. National Trends with Low Thermal capacity 2030 studies the impact of higher decommissioning of thermal plants on the grid by decreasing thermal capacities of NT2030, and leaving everything else the same. It can be considered a bottom-up approach. Global Trends 2030 and Distributed Energy 2030 are bottom-up scenarios that follow the story lines presented by TYNDP2022. They investigate the system position given different landscapes for development of technologies. [4].

This chapter presents all four scenarios by first outlining the main drivers of change in the future; then describing the input data, its sources and motives; and finally presenting the output results and analyzing them.

Table 3.1: Presentation of cases of study

	NT2030	**NT2030 Low Thermal**	**GA2030**	**DE2030**
Year	2030	2030	2030	2030
Approach	Bottom Up	Bottom Up	Bottom Up	Bottom Up
Sources	ERAA 2021	ERAA 2021	ERAA 2021	ERAA 2021
			TYNDP 2022	TYNDP 2022
Benchmark	ERAA 2021	ERAA 2021	TYNDP 2022	TYNDP 2022

3.1 Base case- National Trends 2030

This first case is the base of the whole project, hence the most important one. As outlined in the Introduction, this case aims to replicate the outlook ERAA 2021 provided by ENTSO-E. To do so, an extensive recompilation of data has been carried out to match the input data as well as possible. Nevertheless, given the dimension of files and the technical resources available, some shortcuts have been applied to build a manageable model. As mentioned before, this case follows a bottom up approach in which the estimates for generation capacities, demand and network capacities have been forecasted by each TSOs in line with their NECP and planned projects, and then gathered by ENTSO-E. The following subsection explains the underlying reasons for these estimates and the sources for each file. After that, results are presented and compared to the ERAA outlook.

3.1.1 Input data for National Trends 2030

Data collection is the first of three steps in the methodology of this project. As being sequential in nature, it is of vital importance to carry out a detailed and documented data collection work. A possible mistake at this stage will affect the rest of the project and may turn out into errors in the output. In this chapter, the source of each data is detailed and the reason for it is studied. This is to conquer, on the one hand, the replicability of the project in future updates and, on the other hand, the understanding of the different trends and drivers of the components of the electricity market.

To introduce information into openTEPES, several csv files of two natures are needed: dictionaries and data inputs. The dictionaries are used to define the different types of time sequences, technologies, nodes and other geographical divisions, etc. The data files are the ones with all the information applied to the case. Databases from ENTSO-E consist of several excel files that have been reshaped and reorganized to fit openTEPES style. Each subsubsection of this chapter is corresponded with a csv input file in openTEPES.

Dictionary-Scenario

For this project, each climate year is a potential scenario for the model. As weather-dependent variables can give path to different scenarios. ERAA uses all available climate years (1982-2018) to forecast the assessment. Nevertheless, given the broad scope of the project and the available hardware, these scenarios have been reduced. On the other hand, TYNDP uses three significant years for its forecast: CY1982, CY1984, and CY2007. Those years are applied with a probability of 0.235, 0.265 and 0.5 respectively. These probabilities are obtained from the TYNDP CBA Implementation Guideline, SCENARIOS (2.1 in CBA 3), page 8 of 55. The idea is to include a normal, a dry and a wet year climatically speaking. Still, our computers are not powerful enough to compute such sizes. Therefore, to build a bearable scenario, climate year 2007 is chosen as it is the one with the highest impact on probability.

Dictionary-Period

Although now openTEPES is a dinamic project, at the time this project was developed, openTEPES was an static model. This means it applied to one single year, and so each case would have to refer to one year. The most relevant year for the scope of the project and bearing in mind that ERAA is the reference is year 2030. Adequacy assessments do not make sense for longer time horizons as accuracy decreases the further we go in time. Nevertheless, sensitivity analysis and technology impact studies can be developed for other years (2040,2050).

Dictionary-Stage

There is only one stage.

Dictionary-LoadLevel

Load level is hourly. There are 8736 hours in the model as December 30 is considered by openTEPES the last day of the year.

Dictionary-Technology

To keep coherence between the datasets used and the information gathered in annex 1 of ERAA, the types of technology have been extracted from the 'PEMMDB National Estimates' excel - National Estimates 2030 sheet. This file can be downloaded at: `https://www.\acrshort{entsoe}.eu/outlooks/\acrshort{eraa}/\acrshort{eraa}-downloads/`. In this sheet, the main technologies are detailed and solar and wind are divided into their underlying technologies. Hence, these are the selected values or technologies:Nuclear, Lignite, HardCoal, Gas, Oil, Hydro-RoR&Pondage, Hydro-Reservoir, Hydro-PSOL, Hydro-PSCL, Batteries, WindOnshore, WindOffshore, Solar (Thermal), Solar (Photovoltaic), OthersRenewable, OthersNon-renewable, Biofuel, DSR. Others Renewable are considered to be geotermal, marine, waste, and small biomass. Others non renewable are considered to be heavy oil, light oil and shale oil.

Dictionary-Generation

As well as the types of technology, these values are extracted from 'PEMMDB National Estimates' excel. To keep simplicity in the model, not every plant is defined as a generator, but instead, the whole capacity of that technology for a certain node is defined. In this way, every similar plant is grouped into one. The code for these groups is '[Technology]_[Node]'. The only generator that is not included in this excel file and that has been added afterwards is the Vianden Pumped Storage Power Plant (Hydro-PSCL_LUV1).[14] This plant is of special interest and relevance for the adequacy of Luxembourg and Germany and, although not appearing in the National Estimates excel file, it is recognized in the hydro database. Any other missing plant is assumed to be insignificant for the whole resolution of the model.

There is a total of 484 generators, the total capacity and the number of generators are gathered in the 3.2. These figures are the expected installed capacity in each country for 2030 provided by each TSO.

Table 3.2: Summary of defined generators

Technology	**Generators (ud)**	**Capacity (GW)**
Batteries	34	41.5
Biofuel	11	7.6
DSR	30	35.4
Gas	39	212.4
Hard Coal	10	27.8
Hydro - PSCL	23	44.6
Hydro - PSOL	20	63.3
Hydro - Reservoir	32	101.0
Hydro - RoR & Pondage	35	67.6
Lignite	13	43.4
Nuclear	8	95.8
Oil	16	6.7
Others non-renewable	34	54.5
Others renewable	44	41.5
Solar (Photovoltaic)	50	389.2
Solar (Thermal)	9	13.6
Wind Offshore	26	97.4
Wind Onshore	50	336.2
Total	484	1679.4

Main drivers of change are the decommissioning of thermal units, the construction of several solar and wind plants, and the use of DSR and batteries. Although this last factor varies from some forecasts to others. There will also be the commissioning of some hydro plants and some combined cycles.

Dictionary-Storage

This dictionary refers to the type of cycles followed by the ESS units. Daily and weekly cycles have been chosen in order to keep a balance between simplicity and reliability of the information.

Dictionary-Nodes

The scope of the ERAA includes 37 countries explicitly modelled through 56 zones. It considers all EU member states, as well as the ENTSO-E perimeter beyond EU.[13] Nevertheless, to be consistent, another four nodes have been added to the system. These are nodes that appear in the PEMMDB and CBNTC databases that do not refer to a country itself but to special units or nodes of junction. These are Italy VI (ITVI), Polan Exporting 0 (PLE0) and Luxenburg V1 (LUV1). Contrarily, one of the initial nodes has been taken out of the model for technical reasons. This is the node Poland Imports 0 (PLI0). As analyzed, Poland organises its nodes in three: PL00 for all the demand and generation, the PLE0 for exporting lines, and PLI0 or importing lines. Nevertheless, the rest of the lines are organised so that lines have both ways of flow. For this reason, PLI0 has been removed and its values have been applied to PLE0 back values. Note that this two nodes do not show any demand nor generation. Another important detail is the node UA00, which only refers to Bursthym Thermal Power Plant Island and not to the whole Ukraine. Historically, Ukraine has always been connected to the Russian grid, although the country recently switched its connections to the European grid in 2022 due to the ongoing war against Russia. Given that the data was collected before 2022, the Node_UA00 only accounts for the coal plant and its related installations, as this is the only capacity in Ukraine that has been connected to the European grid since 2013.

Find below a map and a list of the nodes included in the model. As it may be observed, neighboring countries are not modeled, thus, do not have a node. Some countries are divided into several nodes due to its geography. Furthermore, Iceland is not included as it is independent from the European system.

Nodes:

Node_AL00	Node_DKW1	Node_ITCN	Node_LV00	Node_RS00
Node_AT00	Node_EE00	Node_ITCS	Node_ME00	Node_SE01
Node_BA00	Node_ES00	Node_ITN1	Node_MK00	Node_SE02
Node_BE00	Node_FI00	Node_ITS1	Node_MT00	Node_SE03
Node_BG00	Node_FR00	Node_ITSA	Node_NL00	Node_SE04
Node_CH00	Node_FR15	Node_ITSI	Node_NOM1	Node_SI00
Node_CY00	Node_GR00	Node_ITVI	Node_NON1	Node_SK00
Node_CZ00	Node_GR03	Node_LT00	Node_NOS0	Node_TR00
Node_DE00	Node_HR00	Node_LUB1	Node_PL00	Node_UK00
Node_DEKF	Node_HU00	Node_LUF1	Node_PLE0	Node_UKNI
Node_DKE1	Node_IE00	Node_LUG1	Node_PT00	
Node_DKKF	Node_ITCA	Node_LUV1	Node_RO00	

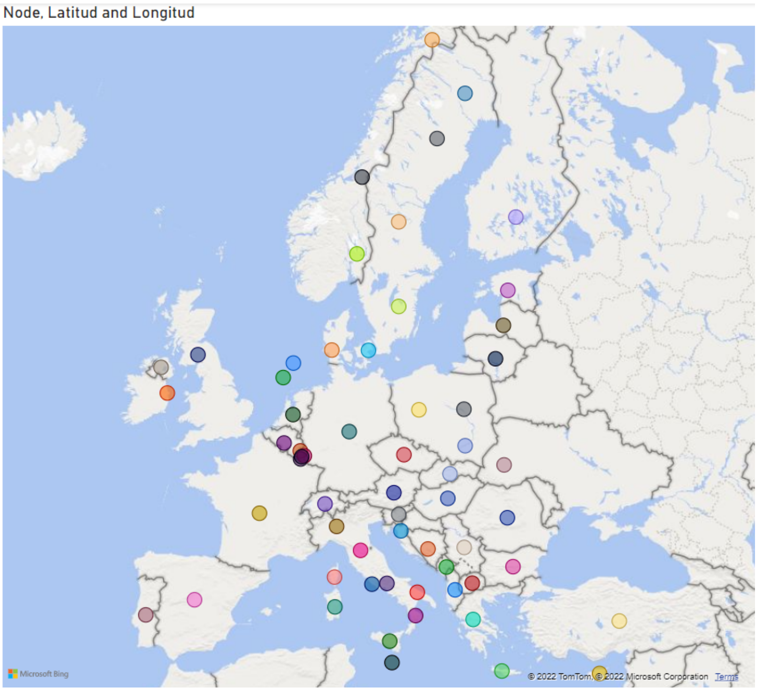

Figure 3.1: Location of nodes

Note that the locations shown above are merely indicative and should not be taken as definite. The connection between countries is grouped for the simplicity of the model; hence, it does not mean that lines pass exactly through those points.

Dictionary- Zones, Area and Region

Once the nodes have been defined, they must be assigned to a zone, an area and a region. To keep this information simple and precise, table 3.3 resumes the categories. Zones are the same as nodes. Areas refer to countries. Finally, areas are grouped into the following regions, extracted from TYNDP 2020 Regional Investment Plans:

- BS – Baltic Sea
- CCE – Continental Central East
- CCS – Continental Central South
- CSE – Continental South East
- CSW – Continental South West
- NS – North Sea External - Not in the UE

Table 3.3: Classification for each node

Node	Zone	Area	Region	Country
Node_AL00	AL00	AL	CSE	Albania
Node_AT00	AT00	AT	CCS	Austria
Node_BA00	BA00	BA	CSE	Bosnia and Herzegovina
Node_BE00	BE00	BE	NS	Belgium
Node_BG00	BG00	BG	CSE	Bulgaria
Node_CH00	CH00	CH	CCS	Switzerland
Node_CY00	CY00	CY	CSE	Cyprus
Node_CZ00	CZ00	CZ	CCE	Czech Republic
Node_DE00	DE00	DE	CCS	Germany
Node_DEKF	DEKF	DE	CCS	Germany
Node_DKE1	DKE1	DK	NS	Denmark
Node_DKKF	DKKF	DK	NS	Denmark
Node_DKW1	DKW1	DK	NS	Denmark
Node_EE00	EE00	EE	BS	Estonia
Node_ES00	ES00	ES	CSW	Spain
Node_FI00	FI00	FI	BS	Finland
Node_FR00	FR00	FR	CSW	France
Node_FR15	FR15	FR	CSW	France

Node	**Zone**	**Area**	**Region**	**Country**
Node_GR00	GR00	GR	CSE	Greece
Node_GR03	GR03	GR	CSE	Greece
Node_HR00	HR00	HR	CCE	Croatia
Node_HU00	HU00	HU	CCE	Hungary
Node_IE00	IE00	IE	NS	Ireland
Node_ITCA	ITCA	IT	CSE	Italy
Node_ITCN	ITCN	IT	CSE	Italy
Node_ITCS	ITCS	IT	CSE	Italy
Node_ITN1	ITN1	IT	CSE	Italy
Node_ITS1	ITS1	IT	CSE	Italy
Node_ITSA	ITSA	IT	CSE	Italy
Node_ITSI	ITSI	IT	CSE	Italy
Node_ITVI	ITVI	IT	CSE	Italy
Node_LT00	LT00	LT	BS	Lithuania
Node_LUB1	LUB1	LU	CCS	Luxembourg
Node_LUF1	LUF1	LU	CCS	Luxembourg
Node_LUG1	LUG1	LU	CCS	Luxembourg
Node_LUV1	LUV1	LU	CCS	Luxembourg
Node_LV00	LV00	LV	BS	Latvia
Node_ME00	ME00	ME	CSE	Montenegro
Node_MK00	MK00	MK	CSE	North Macedonia
Node_MT00	MT00	MT	CSE	Malta
Node_NL00	NL00	NL	NS	Netherlands
Node_NOM1	NOM1	NO	NS	Norway
Node_NON1	NON1	NO	NS	Norway
Node_NOS0	NOS0	NO	NS	Norway
Node_PL00	PL00	PL	CCE	Poland
Node_PLE0	PLE0	PL	CCE	Poland
Node_PLI0	PLI0	PL	CCE	Poland
Node_PT00	PT00	PT	CSW	Portugal
Node_RO00	RO00	RO	CCE	Romania
Node_RS00	RS00	RS	CSE	Serbia
Node_SE01	SE01	SE	BS	Sweden
Node_SE02	SE02	SE	BS	Sweden
Node_SE03	SE03	SE	BS	Sweden
Node_SE04	SE04	SE	BS	Sweden
Node_SI00	SI00	SI	CCE	Slovenia
Node_SK00	SK00	SK	CSE	Slovakia
Node_TR00	TR00	TR	External	Turkey
Node_UK00	UK00	UK	BS	United Kingdom
Node_UKNI	UKNI	UK	BS	United Kingdom

Dictionary- Circuit y line

These two dictionaries refer to the type of lines that may exist and whether there are more than one circuits or not. In the case of the project, lines are only divided into Alternating Current (AC) and Direct Current (DC) and only one circuit is modeled per each type of current, ac1 and dc1.

Data- Option

This file is used to define the options of use of the openTEPES model and so it has little to do with input data and more with the type of modeling that is being pursued. In this case, the deployment of the analysis is continuous, meaning the dispatch is not a 0-1 decision but a portion or fraction of what is available. Investing decisions are not relevant to the case and so they are also defined as continuous for the simplicity of the model.

Data- Parameter

This file gathers general system parameters of the system such as:

- ENS cost: this refers to the cost of energy not served or Value of Lost Load. For this, please refer to the price of cap given in the ERAA outlook. For 2021, this is 15k€/MWh.
- CO_2 cost: The forecasts for carbon prices for 2030 has varied greatly between 2020 and 2021, raising from 27€ to the actual estimate of 70€/ton CO_2 in one year. This estimation can be found in Annex 1 of ERAA: Assumptions, page 39. [15]
- Upward Reserve Activation: no relevant information is found in the papers with regards this parameter. A generalization is set to 0.25.
- Downward Reserve Activation: no relevant information is found in the papers with regards this parameter. A generalization is set to 0.25.
- Minimum Ratio Downward to upward: no relevant information is found in the papers with regards this parameter. A generalization is set to 0.
- Maximum Ratio Downward to upward: no relevant information is found in the papers with regards this parameter. A generalization is set to 1.
- Base power: Reference used for the , set as 100 MW as other cases in openTEPES

- Reference Node: This is a reference that can be chosen at taste, in this case, Spain has been set as the reference node (ES00).
- Time step: defines the duration of the load levels. For a quicker resolution, 4 can be set; for a more accurate result, 1 is set.

Data- Scenario

As explained in the Dictionary- Scenario, the scenarios are used to deal with short-term uncertainties. Using three climate years as a reference would be ideal, but the model would be unmanageable. Hence, the only scenario used is CY2007.

Data- Stage

Stages are use to divided the year into relevant portions with different weights. As this is not the case, only one stage with all the weight is activated.

Data- Reserve Margin

The model allows to set different adequacy reserve margins per each area, hence country. Nevertheless, as ERAA is an adequacy forecast in itself with its respective conservative perspective, this margins are not needed. The whole model is already incorporating the margin in each data, so it would be double counting.

Data- Duration

The duration of the load levels is normally set as 1 h. It might also be used to obtain detail of a certain week or day by setting the rest of durations to 0.

Data- Demand

Demand by node ad load level is presented in MW. This information is extracted from the Demand Database of the ERAA outlook. The database presents forecasts for National Estimates 2030 based in each climate year conditions. For the case, year 2007 is selected. No transformation is applied as this forecast already includes the increase of demand due to electrification of the industry, EV charge, electric heat pumps and so on. It also includes the effect of raising temperatures and the increase in efficiency.

In the table 3.4, pre-pandemic yearly demand is shown for each country in the model as well as the forecasted demand and the growth. Pre-pandemic values have been extracted from IEA data sources. [6] As it can be seen, growth varies from one country to the other. The highest worth is estimated to happen in Turkey (59%) due to their rapid development and their lower electrification in 2019 when compared to other countries, although no specific causes are given. The following is Denmark, whose growth is explained by electrification of heating and transport as well as the increase in large data centers.[15] In the third place is Malta with a growth of 34% due to macroeconomic factors as well as electric vehicles, heat-pumps, data centres and shore-to-ship charging according to ERAA. [15] On the other hand, countries showing decrease in the demand are Estonia(-6%), France (-1%), and United Kingdom (-1%). In these countries, the improvements on efficiency surpass the increase in electrification of transport, heating and other factors.

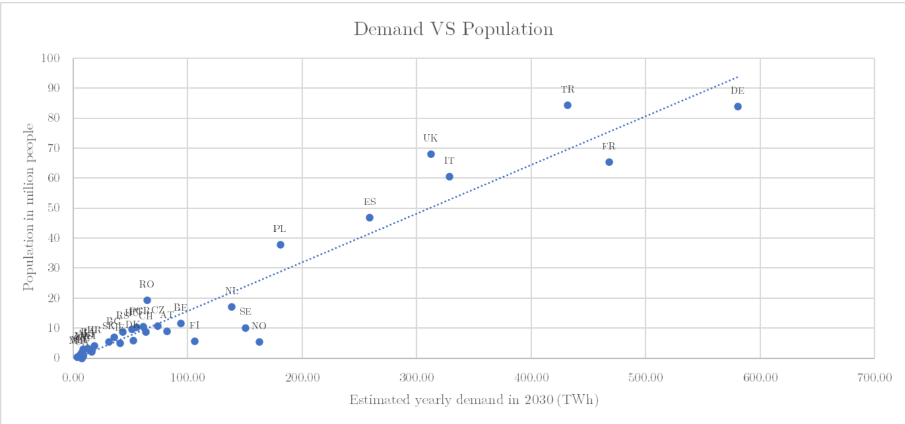

Figure 3.2: Expected demand per capita

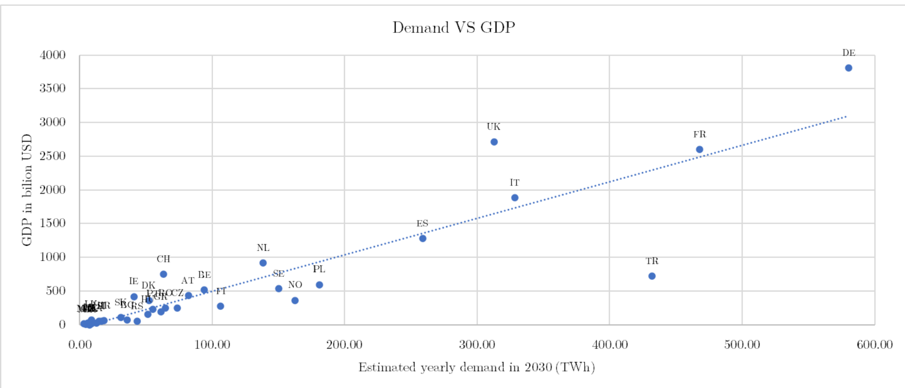

Figure 3.3: Demand per GDP

Table 3.4: Estimated growth in yearly demand by country

Country	2019 (TWh)	2030(TWh)	Estimated growth
Albania	6.60	8.73	32%
Austria	74.10	82.05	11%
Bosnia and Herzegovina	12.50	12.62	1%
Belgium	88.30	94.08	7%
Bulgaria	35.70	36.08	1%
Switzerland	63.10	63.40	0%
Cyprus	5.00	6.34	27%
Czech Republic	69.60	73.91	6%
Germany	548.90	580.48	6%
Denmark	33.70	52.35	55%
Estonia	9.30	8.76	-6%
Spain	255.30	258.74	1%
Finland	86.00	106.45	24%
France	475.10	468.04	-1%
Greece	54.90	61.27	12%
Croatia	17.20	18.47	7%
Hungary	43.50	51.55	19%
Ireland	29.30	40.93	40%
Italy	314.20	328.59	5%
Lithuania	12.40	14.73	19%
Luxembourg	7.60	8.73	15%
Latvia	7.10	7.60	7%
Montenegro	3.20	4.59	43%
North Macedonia	6.70	8.40	25%
Malta	2.60	3.49	34%
Netherlands	116.90	138.47	18%
Norway	127.10	162.63	28%
Poland	165.70	180.86	9%
Portugal	51.60	55.46	7%
Romania	54.60	64.75	19%
Serbia	33.30	43.42	30%
Sweden	131.40	150.47	15%
Slovenia	14.90	16.28	9%
Slovakia	28.40	31.26	10%
Turkey	272.00	432.09	59%
United Kingdom	317.3	312.67	-1%

With regards energy intensity per capita, the graphs above confirm the positive relationship between electricity consumption and GDP on one side, and population on the other. Moreover, these graphs show us how, once the values have been standardized, some countries are more energy intensive than other (demand per capita). The top five most energy intensive countries are expected to be Norway, Finland, Sweden, Luxembourg, and Austria (from highest to lowest). This is due to the colder climates, the electrified heating system and the higher standards of living, as well as the higher awareness of climate issues and the quick adoption of electrified solutions. On the bottom of the list we find Albania, Romania, Bosnia and Herzegovina (from lowest to highest intensity), countries with a lower GDP per capita and less developed.

Data- Inertia

System inertia by area. This case does not study the system inertia, thus this file is left blank.

Data- Operating Reserve Up and Down

Upward operating reserves (include aFRR, mFRR and RR for electricity balancing from ENTSO-E) Operating reserves for each area are not given as so. The information presented by ERAA is the FCR and FRR. The first of these is not considered for the model and the second one can be assumed as the total Operating reserve. Another approach is to develop a self estimate by using the sum of the 2% of demand, plus 10% of the wind generation, and the capacity of the biggest generator in the area. To keep some coherence between the other datasets and this one, the first alternative has been chosen. Data can be found in the PEMMDB-National Estimates excel- Reserve requirements sheet. Since only one value is provided per area, this value has been applied to every load level only for upward operating reserves. Downward operating reserves are not considered as crucial and can be ignored as no data is provided.

The raw data has been modified to make the model feasible. If the initial data was introduced in the model, the model was infeasible due to the lack of enough network and generation capacity in some areas. These areas are Hungary, Malta, and Estonia. To make the model feasible, the values provided in ERAA for the upward operating reserve for this areas were removed and a 10% of their peak demand was placed instead. A 10% of demand is perceived as a reasonable amount of reserve for a country. The data provided seemed to high due to the isolation of the nodes or the infrastucture of the country.

Data- Generation

Generation data is obtained from different sources depending on the technology. Maximum capacities are extracted from PEMMDB-National Estimates excel- NE2030 sheet. This sheet contains forecasted installed capacities by node and technology for 2030, given national plans and units in construction. As mentioned before, the only generator that does not appear in this database but that is of great relevance is the PSCL of Luxembourg (LUV1), which has been added afterwards.

For the Demand Side Response, there is a particular database shared by ERAA that establishes different price bands and the available capacity and hours for each of these price bands and nodes. The database is called Demand Database and can be downloaded from their website. The specific excel file is 'Demand and DSR'. To fit openTEPES variables, DSR units have been defined similarly to batteries with a performance of 1. The maximum generation is the capacities declared in the PEMMDB National Estimates and then, the storage capacity is the sumproduct of the capacities and hours for each price band. The same value is applied for charge capacity and a efficiency of 100% is declared.

For the batteries, an efficiency of 0.9 is applied, figure extracted from Annex 3 of the ERAA report. The storage capacity has to be manually extracted from the tableaus shared in the ERAA website (`https://tableau.entsoe.eu/t/SystemDevelopment/views/Annex1-Storage-in-the-marketstoragecapacities/`), as no especific database is shared for this technology. Moreover, the maximum charge capacity is defined to be the same as the maximum generation capacity. The initial storage for batteries at the beginning of each stage is set to half the maximum capacity, as stated in the Annex 3 of ERAA report. Daily storage is the type of storage selected for all batteries, this is a personal decision that is believed to hold the balance between detail and simplicity.

Thermal units capacities and characteristics are extracted from the PEMMDB National Estimates. Fuel costs an CO_2 emissions are stated per technology, same as up and down time, start up costs, ramp up and ramp down, EFOR and O&M variable costs. Some of these characteristics are stated by node, reflecting the age of the units and its expected state. Units with no specific values are filled in with general information for the corresponding technology. The only detail that is not directly extracted is the linear term and the fuel cost for biofuels and other non-renewable technologies. For the latter, a symbolic fuel cost of 0.5€ per netGJ, same cost as nuclear fuel. In the ERAA database, the efficiency is presented as a percentage (MWh_e/MWh_t). To introduce this information into the model, the figures have modified to meet the linear term by using the following expression:

$$\frac{MCal_t}{MWh_e} = \frac{MWh_t}{MWh_e} \cdot \frac{Mcal_t}{MWh_t} \tag{3.1}$$

According to Annex 3, Biofuel units are expected to have no CO_2 emissions and less expensive fuel costs. No information is given about other technical details and no specific fue price is set. Therefore, a price of 2€ has been assigned as a symbolical figure.

For the hydro generators, all information is given in the PEMMDB-Hydro. Maximum generating capacities are the same as the ones presented in the PEMMDB-National Estimates. For the pumped storage units, a pumping capacity and a generating capacity is stated. Maximum storage is also collected in the hydro database. Initial storage is frequently stated as 0.5 of the maximum capacity, same as the batteries. Run of river units have no storage capacity. Any variable capacities are introduced in the variable files.

For other renewables and other non renewable units, only maximum generation capacity is stated. For solar and wind generation, only the maximum capacities are stated in this file. Variable generation is introduced in its respective file. Efficiencies of these technologies is already included in the variable generation file, as no technology reaches its maximum. Increasing efficiency is already taken into consideration as the presented relative production for 2030 is higher than for 2025.

With regards to the units that contribute to the operating reserve, some technologies have been left aside. Solar, wind, biofuels and run of river do not contribute to the operating reserves.

Data- VariableMaxGeneration

Variable maximum power generation by load level. This file is used to introduce variations in capacity for reneweables such as wind and solar. A different maximum generating capacity is defined for each hour of the year depending on the weather. This information is gathered in the PECD, which can be downloaded in the ERAA website. The data from PECD gives the variability in relative terms (0-1) for the different climate years available and for each node. To transform the data for openTEPES, 2007 has been chosen as the CY and the relative terms have been multiplied by the total available capacity of each node. Variable generation is available for onshore and offshore wind, thermal and photovoltaic solar. Apart from incorporating the weather dependent factor for these sources of energy, the improvements in technology are also taken into account. This way, given the same climate year, the estimated maximum capacity is higher for 2030 than for 2025 as the improvements are to capture more potential.

Another relevant piece of information is the variable generation for hydro generators. For these, the PEMMDB-Hydro database holds the variable generation by day or week for each generator, node and climate year available. This variability applies for all types of hydro generation: Run of rivers, PSCL, PSOL and reservoirs. In this case, information is already presented in MW, so no transformation is needed. Those generators that do not present information are left blank.

Data- VariableMinGeneration

Variable minimum power generation by load level. Similarly to the file above, this file applies for all possible variable min generation. This is the case of the hydro generation. Data is extracted from the same file as VarMaxGeneration: PECD-Hydro year 2007, with no transformation of the data needed. Those generators that do not present information are left blank.

Data- VariableMaxConsumption

There is no information for variable maximum power consumption by load level and generator.

Data- VariableMinConsumption

There is no information for variable minimum power consumption by load level and generator.

Data- EnergyInflows

Energy inflows to an ESS. This file is used to introduce in the model the water inflows of the rain and rivers into reservoirs and pondages. The information is extracted from the PEMMDB- Hydro Inflows. This database is formed by an excel file per node, which gathers information for Run of river, Reservoirs, Pumped storage Open Loop and Pumped storage Closed loop and for all the climate years available.

In order to be coherent, year 2007 has been selected. Information is available in daily resolution for RoR and weekly for Reservoirs and PSOL (PSCL does not receive any inflows). To adapt those resolutions to the hourly resolution of openTEPES, the inflows are introduced each day or week and the type of storage is set as Daily or Weekly.

Data- EnergyOutflows

Energy outflows from an ESS for Power-to-X (H2 production), EV mobility or irrigation. For the case, this file is left empty for the model to optimise it.

Data- VariableMaxStorage

Maximum storage of the ESS by load level (empty).

Data- VariableMinStorage

Minimum storage of the ESS by load level (empty).

Data- Network

Network capacities are referenced as Cross Border Net Transfer Capacities (CB-NTC). The database for networks can be found in the ERAA download web "Net transfer capacities". This is a database that gathers the estimations of countries capacities from all TSOs for years 2025 and 2030. In this case, 2030 is used. This estimate includes actual lines and future projects; that is the reason why many lines show higher capacities for 2030 than for 2025. In the excel file, each "line" is declared with just one way, thus doubling the number of lines. For openTEPES, these values have been grouped into one line with two possible ways of flow. The only change that has been done to the database is the change of PLI0 to PLE0, which has already been mentioned before.

This database divides the lines into AC an DC, as openTEPES does. A voltage of 400kV is set for all lines. For reactance, a cos phi of 0.95 is considered, which is translated into a 0.03 p.u. factor. These data is not specifically set in ERAA, it has been extracted from TYNDP2020_CBA_Implementation_Guideline, pag 39 of 55. The standard use by ENTSO-E for the security factor is 0.7, found both in the ERAA Annex 3 and TYNDP Implementation guideline. The hurdle costs are 0.01 €/MWh. For the case of the Forced Outage Rates (FOR) per interconnector: standard assumptions of 0% for HVAC and 6% for HVDC are applied if TSOs do not provide specific FOR values.

Data- NodeLocation

Node location in latitude and longitude is used to map the nodes and calculate the distance of the lines and the losses in transportation. As stated in the dictionary, these locations are indicative and not accurate. Refer to 3.1 for more information.

3.1.2 Output results for National Trends 2030

After having gathered all the input data, the second step of the methodology of the project is pursued. In this phase, the output results for the National Trends 2030 are analyzed and compared to the ERAA 2021. Results on costs, emissions, share of technologies, network utilization, ENS, commitment of units, and curtailment are shown.

Cost summary

The cost of the system for the year 2030 can be summarized as the following:

Table 3.5: Cost summary of the system

Cost/Payment	[MEUR]
Total System Cost	26,665.56
Generation Operation Cost	16,321.70
Emission Cost	6,800.45
Reliability Cost	3,543.41

An average cost of electricity can be calculated as Total system cost (26665.56 MEUR) divided by Total demand (3996.37 TWh), obtaining a value of 6.67€/MWh. This value is surprisingly low when compared to current market values as it is not the marginal cost of electricity, but the average. Some factors must be explained to understand this figure. In first place, the model assumes that renewable energies have no O&M cost, hence represent no cost for the system (being more than 50% of the production renewable). Secondly, this figure represents the cost of the system, not the cost of electricity passed to consumers. For the latter, the different auction mechanisms have impact on the price, raising it. Thirdly, no investment decisions are considered, meaning that fixed costs and initial investments are not considered. These costs are quite relevant given the rates of increase for renewable technologies. Due to this factor, we can conclude that the average cost of electricity for the system is not the same as the marginal cost of electricity and therefore, does not directly relate to market values. Nevertheless, it will be useful when comparing results between scenarios.

Technology output

The generation of electricity per technologies is summarized in graph 3.4. Renewables take up to 72.1% of generation (considering DSR and biofuel as renewables), a figure slightly above 2030 objectives (70% of renewables).[16] Wind onshore stands as the most used technology with a 18.5%, followed by hydro- Run of river and pondage (11.8%), and offshore wind (9.7%). Among non renewable technologies, other non renewable technologies account for the biggest share (10.2%), followed by nuclear generation (5.1%). Other non-renewable share might be slightly biased as their cost is notably lower due to lack of information. In this sense, it is possible that this technology ends up being more expensive and so being substituted by other types of non-renewables.

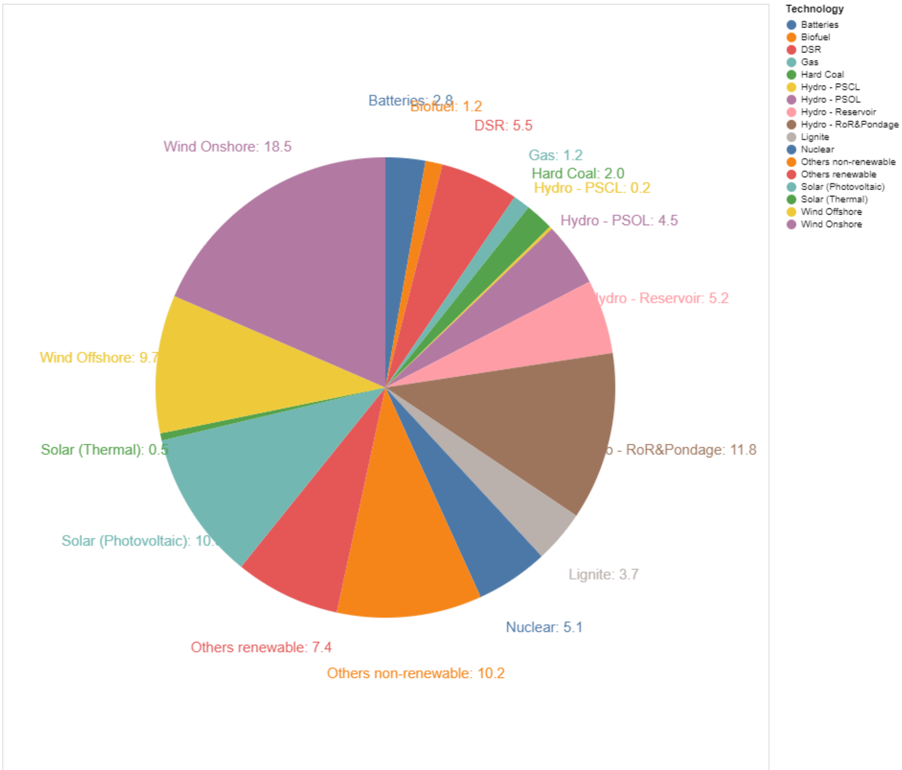

Figure 3.4: Share of technologies (%)

Total CO_2 emissions

Total CO_2 emissions add up to 97.5 Mton CO_2, with lignite being the most pollutant one not only in absolute terms, as it is the most used, but also in relative terms. Overall, this figure is a great achievement in accordance with the carbon emission reduction targets. In line with the objectives, the target for emissions associated to electricity generation in 2030 is calculated to be around 600 Mton CO_2 equivalent. [17, 18, 19]. This means that the emissions achieved in the National Trends scenario are just 16.67% of the objective levels, a very promising and slightly over-positive figure. Nevertheless, this analysis is also biased as it does no consider emmissions for Other Non Renewable sources while these commonly have a share of emissions. Same happens for biofuels or combined cycles. For these reasons, emissions are considered to be higher.

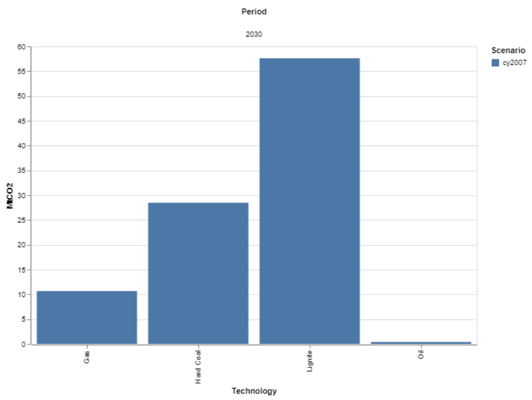

Figure 3.5: Carbon emissions per technology

Energy Not Served (ENS)

The total amount of Energy Not Served adds up to 236.23 GWh, with the affected countries being Hungary (201.67GWh), Burshtyn TES (Ukraine) (33.97GWh), and Malta(0.59GWh). If counted as hours not served, Burshtyn TES (Ukraine) is the most affected with losses in 228 periods (hours), followed by Hungary with 123, and Malta with 33 hours. The values presented in the ERAA 2021 Outlook are much bigger, although allocated in a similar way. Malta is also outlined as an area with high risk of scarcity. In the ERAA, Poland is identified as another highly risky area, as well as Lithuania. Furthermore, Hungary was one of the countries that had problems with its operating reserves. The case of the Burshtyn TES is an interesting one, as it is supposed to be a generating node with little demand and high levels of exports. In contrast, showing ENS means that the generation and transmission capacities are not sufficient to meet the demand. Differences in results can also be due to the smaller size of this model, which only takes into account climate year 2007 and thus, might be less accurate.

Network usage

Part of the Energy Not Served is explained by the network utilization. As it can be seen in the image 3.6, the corridor that connects Malta to the rest of the system is completely saturated. The same happens for the case of Burshtyn TES. In the case of Hungary, it appears to be highly interconnected with its neighbors, as seven corridors connect the country and five of them are not being fully used. Nevertheless, the image is an snapshot of the grid for the first hour. Further periods might lead to a higher network utilization, leaving Hungary with ENS periods.

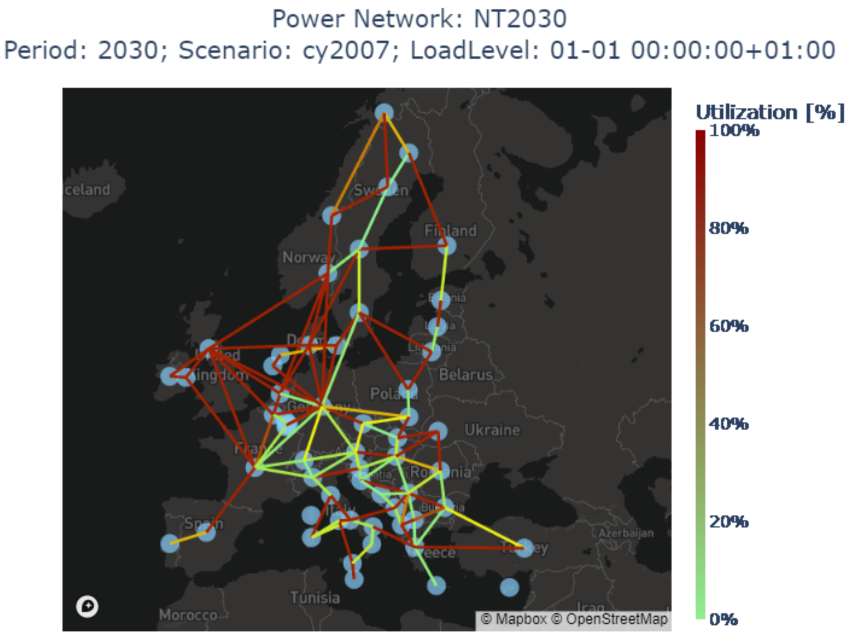

Figure 3.6: Network utilization for the first hour of year 2030

Regarding the bigger picture, we identify several areas that appear to be very saturated. This is the case of the various connections between the UK and Ireland with the rest of the continent, the case of the connection between Spain and France, and the case of Denmark. The map helps to compare the current estimated network with the Projects of Common Interest identified in the TYNDP 2020. As observed in image 3.7, projects considered as of Common Interest (PCI) (in consideration and in plan but not permitted yet) cover some of these connections. Higher interconnection between the different islands and mainland is regarded all across Europe. An interesting point of this map is the Northern Sea Wind Power Hub, a project that aims to construct an offshore windfarm of 12GW to supply Denmark, Germany and the Netherlands.

Another way of regarding future investments on network development is by looking at the short run marginal cost (SRMC) of lines. In figure 3.8, this parameter is shown by hour and network. Several lines show a SRMC of 15.000€/MWh, same price as the ENS. This means that an extra MWh in those nodes will not be able to be served, as the lines are at its fullest capacity. If the lines' capacity was increase by 1 MW, the system would be saving that much money per hour.

This is the case for nodes like Hungary, Burshtyn TES, or Malta, which showed high levels of ENS. Investment in network development in these nodes is highly recommended.

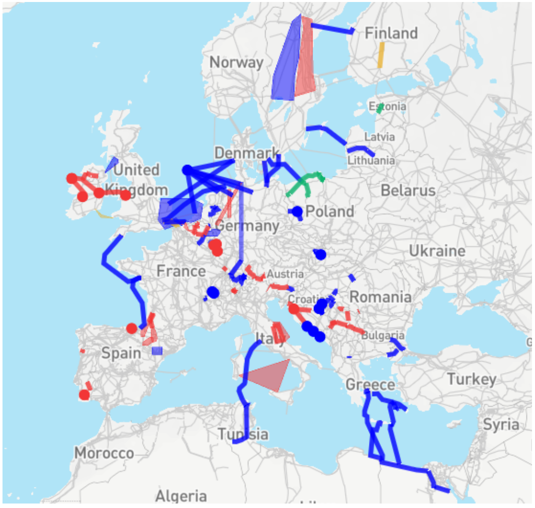

Figure 3.7: Transmission projects, planned and under consideration. [3]

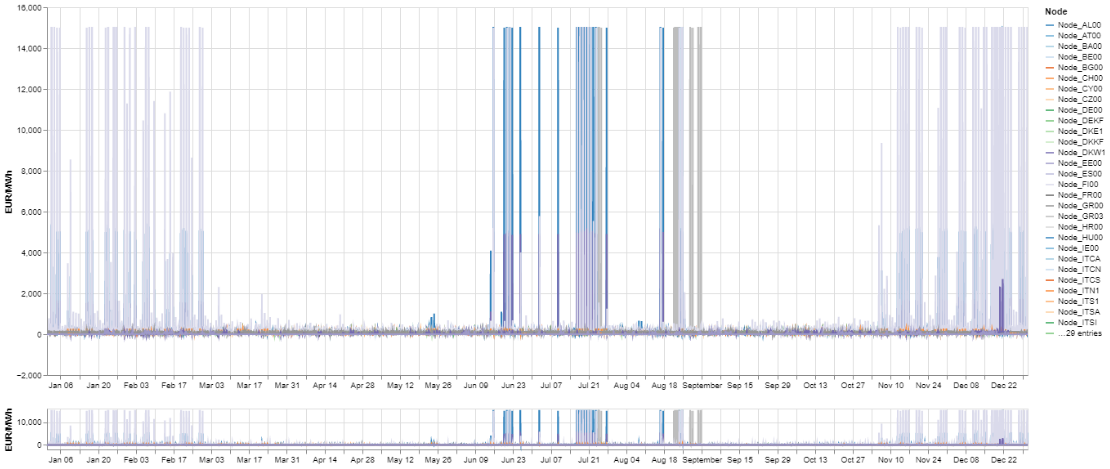

Figure 3.8: Short run marginal cost of network.

Relevant Patterns of consumption

To be able to understand how generation of different technologies is added up to meet demand, the first weeks of January and July have been plotted. The following changes can be observed: although peak demand is at the same level, in July there is lower demand for energy at night. Moreover, during daytime, solar production is quite higher in July as it is probably more sunny. In contrast, offshore wind production is slightly lower for July. Weekdays show higher demand than weekend, and the peak hours are 12pm and 6pm for January, and 11am-12pm for July (probably when most AC are being used).

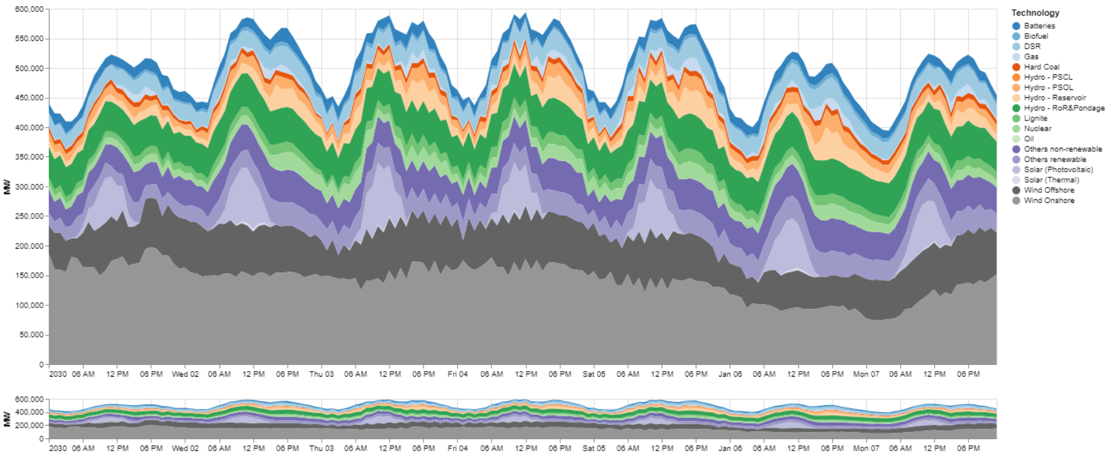

Figure 3.9: Demand and production profiles for the first week of January.

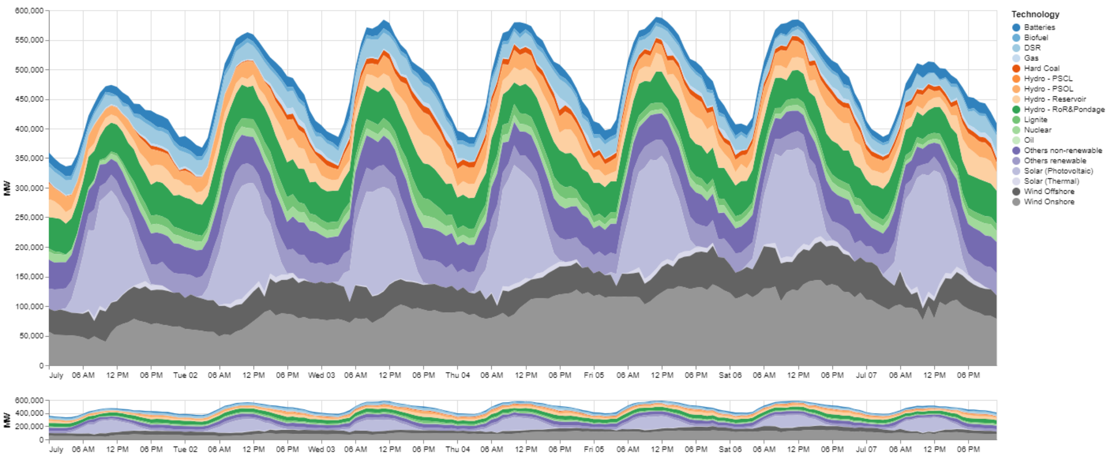

Figure 3.10: Demand and production profiles for the first week of July.

CO_2 price sensitivity analysis

To understand how does the price of CO_2 affect the model, a sensitivity analysis has been carried out for the first week of January. Although the forecast price of CO_2 is set at 70€/ton in the base case, 100€/ton and 40€/ton have also been analyzed. Final figures in table 3.6 show how the impact of CO_2 prices is not as relevant as it may seem. Generation operating costs do not change as much as the dispatch of technologies does not change. With regards ENS, it is true that lower CO_2 promote thermal generation, enhancing the systems stability. Naturally, it has an impact on the system cost, as higher prices lead to higher emission costs and the other way around. Total emissions vary slightly across cases, only changing around 1% in comparison with the 42% change in price.

Taking this into account, it is concluded that CO_2 prices cannot be used as a direct measure to foster decarbonization once their equilibrium price has passed. In the beginning, CO_2 price has penalized thermal technologies, so renewables appear more attractive for investments. But once that first penalization is achieved, higher prices only lead to higher costs, and to more expensive electricity prices, while minimally reducing emissions and raising ENS.

Table 3.6: Sensitivity analysis for CO_2 prices for the first week of January

	40€/ton	**70€/ton**	**100€/ton**
Cost/Payment	[MEUR]	[MEUR]	[MEUR]
Total System Cost	345.69	393.99	441.63
Generation Investment Cost	0	0	0
Generation Retirement Cost	0	0	0
Network Investment Cost	0	0	0
Generation Operation Cost	270.04	271.67	272.81
Consumption Operation Cost	0	0	0
Emission Cost	65.08	111.63	158.13
Reliability Cost	10.58	10.70	10.70
Total emissions	1.63	1.59	1.58
Total ENS	0.71	0.71	0.71

Fuel cost sensitivity

Recent events in Europe have increase volatility of fuel prices. Gas and oil prices have experienced rapid increases, revealing the fragility of the system. To understand how will fuel prices affect future scenarios, a fuel cost sensitivity analysis has been carried out. This analysis consists on modeling the first week of January with three cases: the base price, the high price, and the low price. In the high price scenario, fossil fuel prices rise by 100%. This means gas costs 17.8€/net

GJ; lignite costs around 4.8€/net GJ; coal, 5€/net GJ; and oil costs 24€/net GJ. On the contrary, in the low case, prices decrease by 50%. Therefore, costs stay as following: gas 4.45 €/net GJ; lignite 1.2€/net GJ; coal 1.25€/net GJ; and oil 6€/net GJ.

In light of results shown in table 3.7, it can be concluded that even substantial changes in fuel prices do not change the whole system dispatch allocation. As it can be seen, total emissions are nearly the same for each case. Same happens for the ENS, meaning that the increase in prices do not reach the level in which not serving energy is worthier than generating it. Moreover, the high difference in total price between nuclear and fuel technologies makes it possible for nuclear to be more profitable that half-price fuels.

Table 3.7: Sensitivity analysis for fuel prices for the first week of January

	Half prices	**Initial prices**	**Doubled prices**
Cost/Payment	[MEUR]	[MEUR]	[MEUR]
Total System Cost	291.81	394.00	594.10
Generation Investment Cost	0	0	0
Generation Retirement Cost	0	0	0
Network Investment Cost	0	0	0
Generation Operation Cost	172.58	271.67	471.61
Consumption Operation Cost	0	0	0
Emission Cost	108.65	110.69	111.78
Reliability Cost	10.57	10.70	10.704
Total emissions [Mton CO_2]	1.55	1.59	1.60
Total ENS [GWh]	0.70	0.71	0.71

The only visible effect that changes in prices have in the whole system is the change in the total system cost due to higher or lower generating costs. This means that the volatility in fuel prices do not compromise the stability of the system, nor the energy transition. Nevertheless, these changes in prices are passed down the value chain, affecting the final consumer and putting at risk the affordability of electricity. That is the reason why they must be kept between reasonable ranges.

Rank of greener countries

Although the model regards the European electricity system as one, this subsection analyzes the contribution of each country to the green generation of electricity and the reduction of CO_2 emissions. Firstly, a rank is shown with the share of renewable generation on each country. Note that this is different to the share of renewable installed capacity. Countries are organized from the least renewable generator to the most. Sencondly, a graph with emissions per GWh per country is shown.

From the data shown in table 3.8, small isolated islands tend to have higher non-renewable plants as they need to rely on their own supply in case their connections are saturated. Also, they count with less available space for solar and wind farms when compared to mainland countries. This is the clear case for Malta (MT) and Cyprus (CY). To no surprise, Bursthyn TES (UA) is also located at the top of the table. This is because it accounts only for the thermal unit, which mostly exports non-renewable energy to neighboring areas.

The following most intense in non-renewables countries all pertain to the East of Europe: Czeck Republic, Slovakia, Bulgary, Poland, Hungary, Turkey, and Estonia. These countries have joined the EU not so long ago when compared to others, they tend to have lower GDPs per capita, and are not as attractive for investing in green infrastructure. Those are some of the reasons why they tend to have a higher use of non renewable sources.

23 out of 74 countries are below the average usage (24%), which means the distribution is skewed to the right, with less countries producing more emissions and more countries doing a great effort to cut emissions. A clear example of the latter is Norway, Montenegro, Albania, Sweden or Switzerland. Some of these countries show high GDP per capita levels, and others also show great natural and hydro-electrical resources that ensure most, if not all, the supply.

Table 3.8: Share of green energy per country

	Non renewable		Renewable		
Countries	**Energy (TWh)**	**Share**	**Energy (TWh)**	**Share**	**Grand Total**
MT	2.11	83%	0.43	17%	2.54
UA	4.88	74%	1.67	26%	6.55
CZ	47.70	70%	20.00	30%	67.70
CY	4.22	66%	2.14	34%	6.36
SK	23.90	65%	13.03	35%	36.93
BG	27.83	63%	16.11	37%	43.94
PL	103.98	59%	73.71	41%	177.69
HU	15.84	49%	16.40	51%	32.24
TR	197.11	46%	228.51	54%	425.62
EE	4.34	45%	5.33	55%	9.67
NL	63.07	35%	119.69	65%	182.76
MK	2.03	34%	3.89	66%	5.92
DK	18.51	30%	43.50	70%	62.01
LU	0.54	25%	1.62	75%	2.16
SI	3.57	23%	11.62	77%	15.19
RS	9.50	23%	31.02	77%	40.52
FR	113.13	23%	384.38	77%	497.51
RO	14.37	21%	55.50	79%	69.87
BA	2.27	20%	8.90	80%	11.17
BE	17.04	20%	67.22	80%	84.26
ES	48.27	17%	230.00	83%	278.28
DE	107.35	17%	517.42	83%	624.76
IT	58.17	16%	295.74	84%	353.91
LV	0.99	16%	5.20	84%	6.19
UK	55.96	15%	313.62	85%	369.58
IE	5.18	11%	40.16	89%	45.34
GR	6.68	11%	53.12	89%	59.80
FI	12.58	11%	100.07	89%	112.64
PT	6.89	11%	55.89	89%	62.77
HR	1.90	9%	20.33	91%	22.23
LT	1.20	8%	13.72	92%	14.91
AT	8.11	8%	96.43	92%	104.54
CH	5.51	7%	72.59	93%	78.10
SE	7.35	5%	139.50	95%	146.85
NO	0.93	0%	184.57	100%	185.50
ME	0.00	0%	4.49	100%	4.49
AL	0	0%	15.31	100%	15.31
Grand Total	**1003.00**	**24%**	**3262.83**	**76%**	**4265.83**

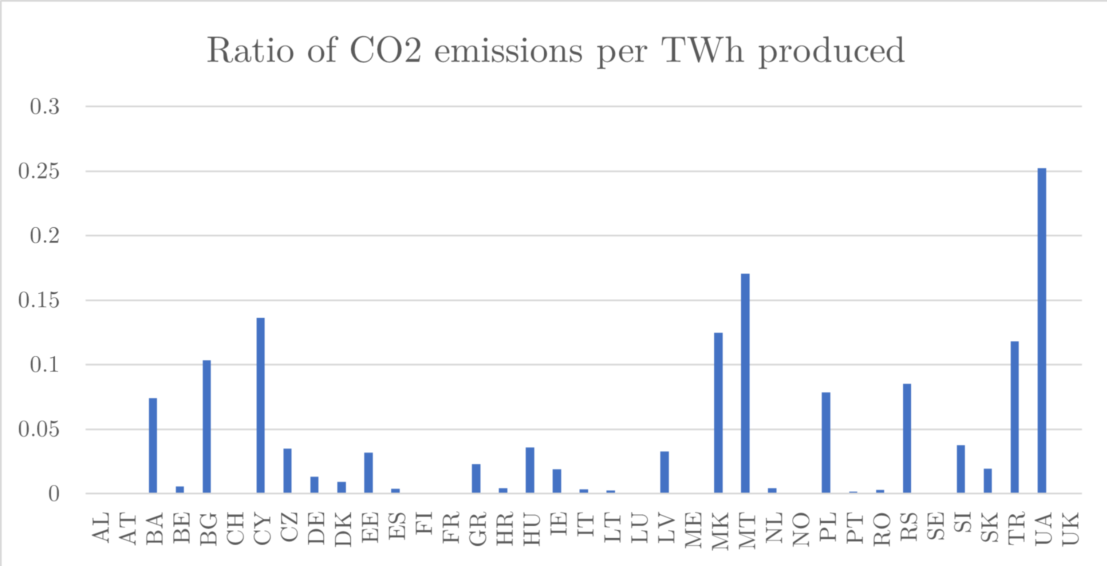

Figure 3.11: Carbon intensity per country

Now that the use of renewable energies has been analyzed, a graph is presented to show the relation between CO_2 emissions and total GWh produced per country. As 3.11 records, the most pollutant countries in relative terms are Bursthyn TES, Malta, Cyprus, Macedonia, and Turkey. These countries where also ranked highly in the previous table. Nevertheless, countries as Czech Republic, Estonia or Slovakia are not that pollutants. This is probably due to a high share of nuclear power among non-renewable energies. Adding up to this, it can be seen that many countries have little to no emissions. This is a clear prove of the commitment from most of the countries in the EU to decarbonization and energy transition.

Commitment of units

The openTEPES model has the power to not only optimally dispatch energy, but also commit units depending on the needs of the system. In the National Trends 2030 model, a significant number of oil and gas units are not committed any hour of the year. On the contrary, every battery unit is committed at all times, same as the controllable hydro units (reservoirs, PSCL, and PSOL).

There are 9 gas units out of 39 that are not committed at any hour (23%), 8 oil units out of 16 (50%), and 1 nuclear unit out of 8 (12.5%). These units are expected to be at full operation in 2030, even though they are proved not to be needed. Nevertheless, it must be said that the system needs this type of units to ensure a stable supply when disruptions happen, turbines in this types of units help the synchronicity of the system, and all these units help providing enough operating reserves. But even so, this data proves the commissioning of new fuel units to be controversial, same as the postponing of decommissioning plans. Alternative solutions to operating reserves and synchronicity such as batteries, flywheels, and other renewable sources offer the same services while being green. Investment in the future must be planned bearing these facts in mind. It would not be wise to immediately shut down every gas or oil plant, but the fixed and operating costs are clearly sunk cost as long as the plants are of no use.

Curtailment of energy

In the completely opposite case, curtailments from renewable energies are GWh that the system cannot absorb at the time they are produced and there are no means to store it. Hence, clean energy that is available and discarded. In the NT2030, the total amount of curtailment adds up to 341.00 TWh, a 8% of the total 4265.83 TWh produced by the whole system.

Different types of technologies account for these curtailments. As observed in the graph 3.12, most of these curtailments happen in the DSR, which in practice is not a curtailment but a lack of use of this lever. Another important share happens in onshore and offshore wind, followed by other renewables, and batteries. The worst part is that this curtailed energy has to then be produced by non renewable sources when the other technologies are at its maximum capacity.

A clear solution to this problem are the storage units, such as batteries, hydrogen, chemical procedures (biofuels), and thermal (brick storage heater). Although its installation is costly, advancements in the future and economies of scale make these solution promising, so that not that much energy is wasted. Another current alternative to avoid curtailments is the hybridization of solar and wind plants so that the capacity access of the plant is bigger while the production is smoothly distributed.

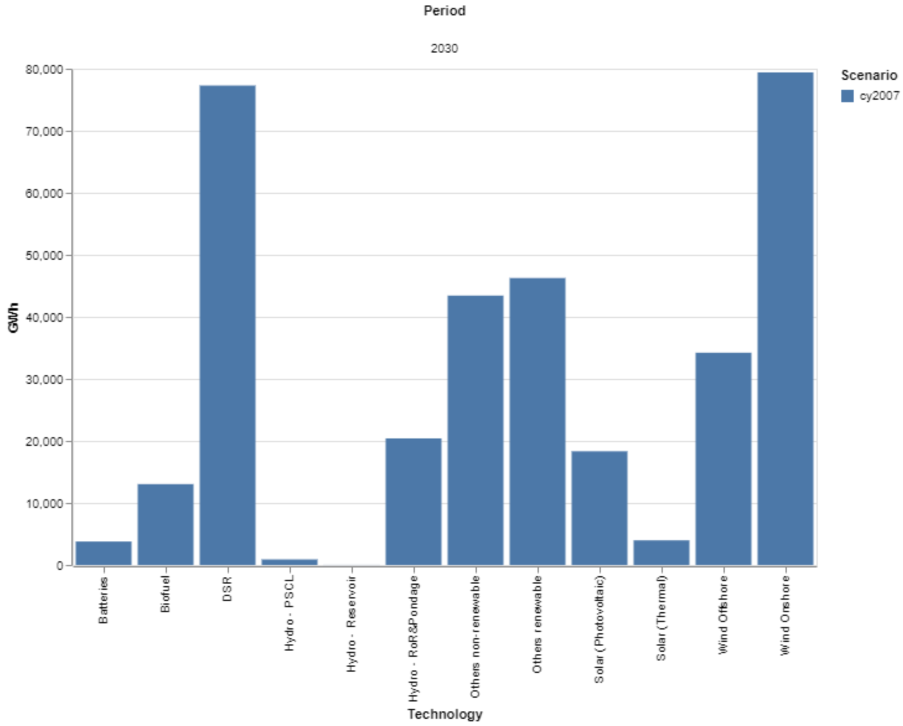

Figure 3.12: Total curtailments per technology for the NT2030

Operating reserves

Operating reserves ensure the stability of the system when sudden changes in demand happen. To be able to face them, certain controllable generation is reserved. Generators that participate in the operating reserves are all thermal units, hydro plants excluding run of river, and batteries. In table 3.9, the minimum, average and maximum values for marginal cost of the upward operating reserve is shown.

Table 3.9: Costs for marginal reserve up (€/MW)

	AL	AT	BA	BE	BG	CH	CY	CZ	DE	DK	EE	ES
min	-	-	-	-	-	-	-	-	-	-	-	- 0.00
mean	2.20	0.07	12.20	2.64	2.03	0.11	1.01	10.48	1.22	55.34	169.73	1.47
max	102.23	4.55	83.64	462.81	34.02	2.36	125.95	3,265.10	186.45	1,905.89	658.93	102.43

	FI	FR	GR	HR	HU	IE	IT	LT	LU	LV	ME	MK
min	-	-	-	-	-	-	-	-	-	-	-	-
mean	1.05	0.32	14.58	4.57	284.87	3.99	3.04	17.12	18.26	56.79	3.69	6.05
max	104.60	70.97	89.60	141.64	11,158.23	152.01	124.47	200.65	1,864.48	266.54	86.40	58.65

	MT	NL	NO	PL	PT	RO	RS	SE	SI	SK	UA	UK
min	-	-	-	-	- 0.00	-	-	-	-	-	-	-
mean	47.54	1.01	-	6.64	2.96	3.15	5.74	-	87.47	38.45	381.32	0.14
max	11,160.82	124.30	-	145.21	46.20	119.67	110.27	-	3,534.97	7,481.91	11,209.29	12.08

High marginal cost means that adding one MW to the system would be very costly as the units providing it are already committed to generating electricity to meet demand. In the contrary, if the marginal cost is null, that means the reserves are being provided by units that have enough capacity and no operating cost, as hydro units. Many areas show null marginal costs for many periods, which is a perfect situation. In the contrary, areas that show ENS and high network usage, also show high marginal costs of upward operating reserves. This is the case of Hungary, Bursthyn TES, and Malta.

Case for Spain

In this subsection, the case for Spain will be specifically analyzed, studying the change in demand, the share of technologies used, the total installed capacities, the network usage, and the ENS.

To start with the demand for 2030 in Spain is expected to be of 258.74 TWh, 1% more than current demand. Although there will be an increase in demand due to the uptake of EVs and electric heating systems, enhancements by 40% in efficiency will be able to balance the total change. [20]

Table 3.10: Installed capacities in Spain in 2030 (MW)

Batteries	2,500.00
Gas	24,498.56
Hydro - PSCL	6,866.40
Hydro - PSOL	2,683.32
Hydro - Reservoir	10,972.20
Hydro - RoR&Pondage	3,640.00
Nuclear	3,041.00
Others non-renewable	3,980.00
Others renewable	1,730.00
Solar (Photovoltaic)	38,404.00
Solar (Thermal)	7,300.00
Wind Offshore	200.00
Wind Onshore	48,350.00
Total installed capacity	154,165.50

With regards the installed capacity in Spain in 2030, total capacity sums up to 154 GW. All coal, oil and lignite units are expected to be decommissioned by 2030. The only operating thermal units will be gas and nuclear ones. No new hydro installations are expected, but a huge effort is to be put in developing solar and wind capacities. Pumping units and batteries are also expected to help the system by providing 12 GW of storage.

From these installed capatities, the model forecasts that 82.2% of generation will be covered by renewable units. This share is above the national objective of 74%. [20] As figure 3.13 shows, major generating technologies are wind onshore, and photovoltaic solar, followed by other renewables. In comparison to the whole continent, wind offshore is less developed, but there is more solar thermal. Nuclear capacities are in line with the average, and batteries slightly falling behind.

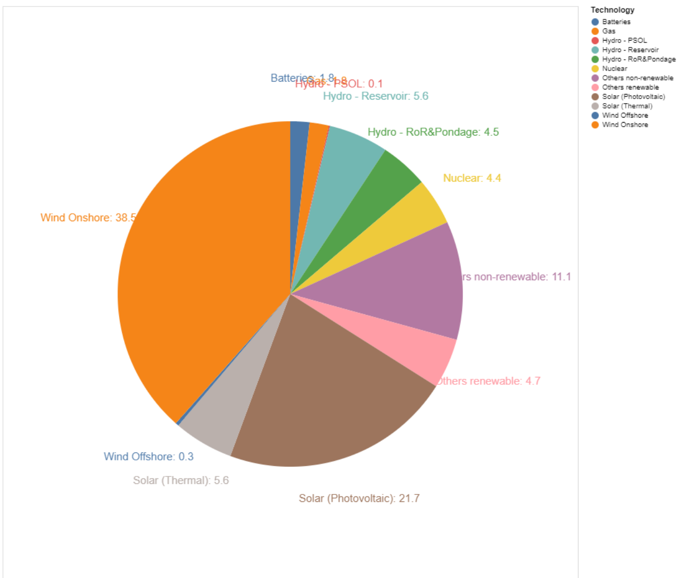

Figure 3.13: Share of generation per technology

With this dispatch, emissions coming from generating electricity add up to 1.01 Mt CO_2 and they steam from gas units. Similarly to what happened to total emissions, this figure is greatly below the expected objectives, which are 43.025 MtCO_2-eq coming from generating electricity.[20]

In total, the average usage of the interconnection between France and Spain is 64.11%, reaching maximum capacity in 34.6% of the time. Total net flow for this line is 11.95 TWh imported from France to Spain. For the interconnection between Spain and Portugal, the average utilization of the line is 58.57%; reaching maximum capacity in nearly 30% of the periods. Total net flow for this line is

2.77TWh exported from Spain to Portugal. In conclusion, Spain imports energy from France and exports to Portugal with interconnections that reach their maximum capacity 30% of the time but that are well designed, as no ENS is expected in any period.

3.2 Alternative case- National Trends 2030 with Low Thermal capacities

The recent COVID-19 crisis has revealed the uncertainty to which we are subject and the interdependence of countries, supply chains, electricity systems, and people due to globalisation. Although this pandemic has been a historic event, no one can promise that events of the same magnitude will take place in the years to come; as for example, the war in Ukraine. With these uncertainties in mind, ENTSO-E develops a complementary case to the National Trends in which it presents a lower thermal capacity, due to a faster than expected decommissioning of thermal plants and a delay in the commissioning of new ones as an answer to COP26 objectives.

3.2.1 Input data for National Trends 2030 with Low Thermal capacities

Input data for this case is the same as for National Trends with the exception of installed capacities for thermal technologies. In this subsection, this change in capacities will be analyzed. To understand any other input information, please refer to the previous section.

ENTSO-E considers that this re-scheduling is to take place in plants using hard coal, lignite, gas, and oil. A total decrease of 36.8GW is expected across Europe. Changes in current plans for commissioning and decommissioning of thermal plants are most probable to happen in Poland with a total decrease of -17201 MW, France with -7368 MW, Germany with -4782 MW and Romania with -4324 MW. Underlying reasons for this forecast are the pressures carried out by the European Union and supported by the Green Deal and the Clean energy for all Europeans package on some of the biggest polluting plants across the EU. A clear example of this is Belchatov plant, the largest coal power plant in Europe, which has been pushed to stop operation in 2026. [21] The most affected technologies will be gas and hard coal units, followed by lignite. Oil will suffer a slight decrease. Changes in capacity are gathered in table 3.11.

The exact changes per node and region can be found out in the excel PEMMDB-National Estimates excel- Low Thermal Cap. 2030 sheet. Figures in this sheet stand for the decrease in NT2030 capacities, hence are subtracted to obtain the current values. As mentioned above, the rest of the data is kept the same. Changes are summarized in table 3.11.

Table 3.11: Capacity reduction with respect to National Estimates 2030 (MW)

	BG00	DE00	FR00	GR00	ITCS	ITN1	ITS1	ITSI	PL00	RO00	Subtotal
Lignite	-	-	-	-	-	-	-	-	6,998	1,192	**8,190**
Hard Coal	-	-	-	-	-	-	-	-	10,203	360	**10,563**
Gas	440	4,782	6,397	825	333	1,374	93	56	-	2,772	**17,072**
Oil	-	-	971	-	-	-	-	-	-	-	**971**
Subtotal	**440**	**4,782**	**7,368**	**825**	**333**	**1,374**	**93**	**56**	**17,201**	**4,324**	**36,796**

3.2.2 Output results for National Trends 2030 with Low Thermal capacities

This subsection shows the results obtained after running the National Trends 2030 with Low Thermal capacities case. Different aspects such as the system costs, the usage of renewables, CO_2 emissions, ENS, network usage, commitment of units, and the curtailment of energy is studied. These information is contrasted with the base case in order to draw conclusions on whether the early decommissioning of thermal units is a good strategy or not.

It must be noted that demand, reserve requirements, network capacities, and renewable and nuclear units do not change from base case. Therefore, those figures will not be summarized. Please refer to the previous section for further information.

Total system costs

Total system cost for year 2030 is 56,513.88 M€, more than double the cost of NT2030. As seen in 3.12, this notable increase in the system cost is due to reliability costs. These costs increase by almost ten times from the base case, meaning there is almost ten times more ENS in the system. Other costs remain the nearly the same, with slight increase in operating costs and slightly decrease in emission costs. Early conclusions can be drawn from these figures: the early decommissioning of thermal units leads to higher unreliability of the system, but does not reduce CO_2 emissions, nor cheapens the electricity generation.

Table 3.12: System costs

Cost/Payment	Base case [MEUR]	Low Thermal [MEUR]
Total System Cost	26665.56	56513.88
Generation Investment Cost	0	0
Generation Retirement Cost	0	0
Network Investment Cost	0	0
Generation Operation Cost	16321.70	17819.76
Consumption Operation Cost	0	0
Emission Cost	6800.45	6679.29
Reliability Cost	3543.41	32014.83

Usage of technologies

Although having reduced the total installed capacities for thermal units by 17.2GW, the dispatch of units does not change in a relevant way. If figure 3.16 and 3.17 are compared, there is only a slight change in the gas and lignite share. 0.5 percent points of lignite production are shifted into gas production. This is a surprising shift given that gas capacity has been reduced in a more notable way than the lignite units. Another possible reason might be that governments might be aiming to impose limits on emissions to reduce overall emissions in Europe.

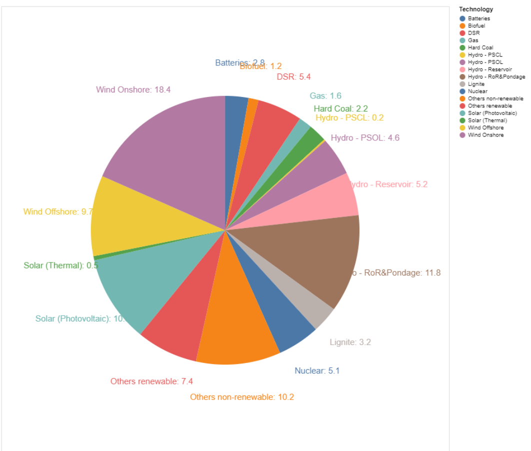

Figure 3.14: Share of technologies for NT2030 Low Thermal

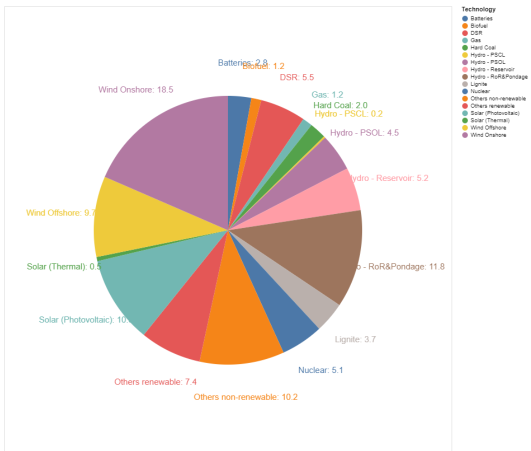

Figure 3.15: Share of technologies for NT2030

System CO_2 emissions

Total CO_2 emissions for 2030 add up to 95.42 Mt CO_2 equivalent. This figure is slightly smaller than in NT2030 (97.5 Mt CO_2). In theory, the early decommissioning of thermal units is done to speed up the energy transition and reduce emissions. Nevertheless, this strategy does not prove to be effective as reductions are not relevant. To achieve objectives, higher commissioning of renewable plants is needed in hand with a proper grid development.

With respects to the technologies that account for the highest emissions, lignite is the most pollutant one. In the Low Thermal case, emissions coming from lignite are slightly reduced, but emissions coming from hard coal and gas increase making global emissions remain the same. Counter intuitively, reductions in capacity are translated into an increase in emissions coming from those technologies. A possible underlying reason for this is the inequality of decommissioning across the system added to the high usage of the network. Meaning that in some areas, lignite units are decommissioned and so, gas and hard coal units around have to cover that generation, as the interconnections in that node are being used to its fullest capacity.

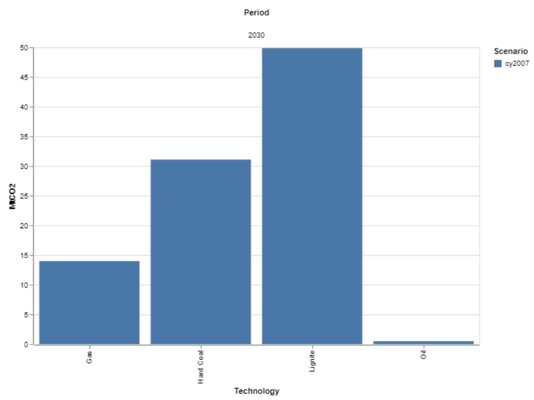

Figure 3.16: Emissions by technology for NT2030 Low Thermal

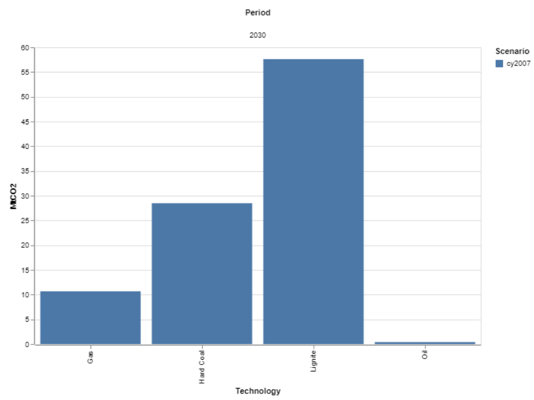

Figure 3.17: Emissions by technology for NT2030

Energy Not Served (ENS)

In the NT2030 Low Thermal case, the total ENS is 2134 GWh, almost ten times more than in NT2030. This energy is given across 59 countries out of 74. Worst impact happens in Poland by far, followed by Hungary. Affected countries are Poland, Hungary, Malta, Bursthyn TES, Czech Republic, Slovakia, Germany, Lithuania, Denmark, and Sweden. The impact of the decrease of thermal units in the reliability system is mapped in figure 3.18. It can be observed that problems are given in the Western and Middle part of Europe, with a higher incidence in neighboring countries to Poland.

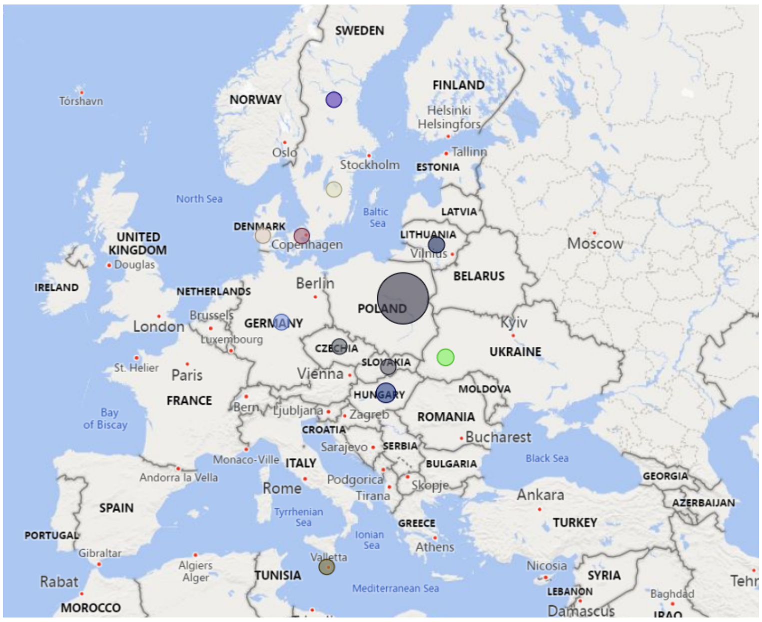

Figure 3.18: Size of impact of ENS per node

By observing the map, it can be concluded that the early decommissioning of thermal units like the one in Poland (-17.2 GW) is a great hazard to the system's reliability, as these plans have strong impacts on neighboring areas. Before carrying out these strategies, the European grid must be developed so that green electricity can be spread across the continent, reaching those areas with lower renewable installed capacity. Another solution is building wind and solar farms there where thermal units are being closed. This way the total grid is not as impacted because green energy substitutes previous generation. Other solutions such as batteries or DSR may arise but one thing is clear, the decommissioning of thermal units without further substitutes to that generation is dangerous for the system's reliability.

Network usage

Network connections have proven to be as relevant to the system functioning as generation units. In the image below, the network usage for the first hour of the year is shown. As a consequence of the decommissioning of thermal units, the flow of electricity now goes from nodes with renewable generation to the nodes that have less generation capacity resulting from these changes.

If compared to figure 3.6, no major changes can be observed. The only differences are that in NT2030 Low Thermal, lines in Norway and Sweden are being used to its full capacity while the flow through Lithuania and Latvia is smaller.

Nevertheless, as the graph only shows the first hour of the year, these similarities and differences might not be indicative. Instead, a contrast analysis on overall usage has been carried out.

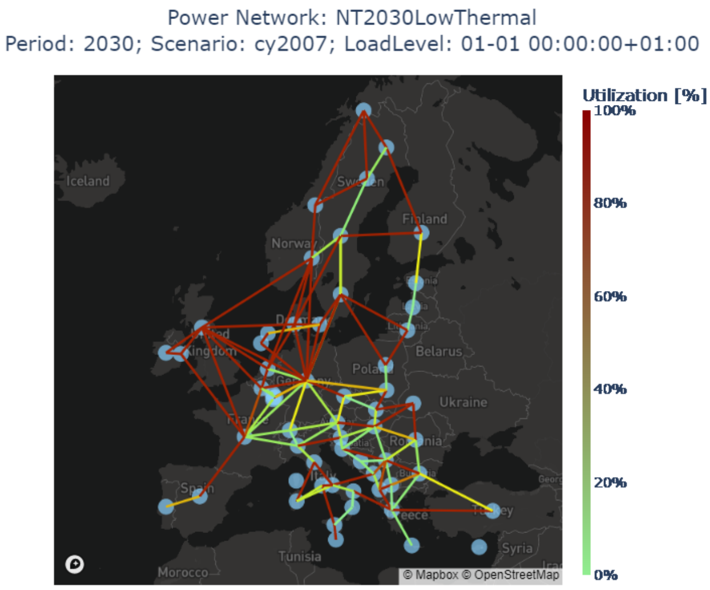

Figure 3.19: Network usage or the first hour of the year for the NT2030 Low Thermal scenario

If the network utilization is studied for all the hours available, same conclusions are reached. Average network utilization for NT2030 Low Thermal is 66.41%. The figure was the same for the NT2030 case. This mean varies significantly for each line, having some lines that are at full capacity for more than 90% of the time and other lines that never reach full capacity. From this, it can be derived that several projects are of great interest for the development of the European network to ease the flow where the network works at full capacity.

Moreover, the SRMC of network has increased notably, same as the increase in ENS. This can be easily observed in figure 3.20, where some nodes reach 15,000 €/GWh in over 10% of the time. These high costs coincide with the moments where ENS happen. The same happened or NT2030, but to a lesser extent.

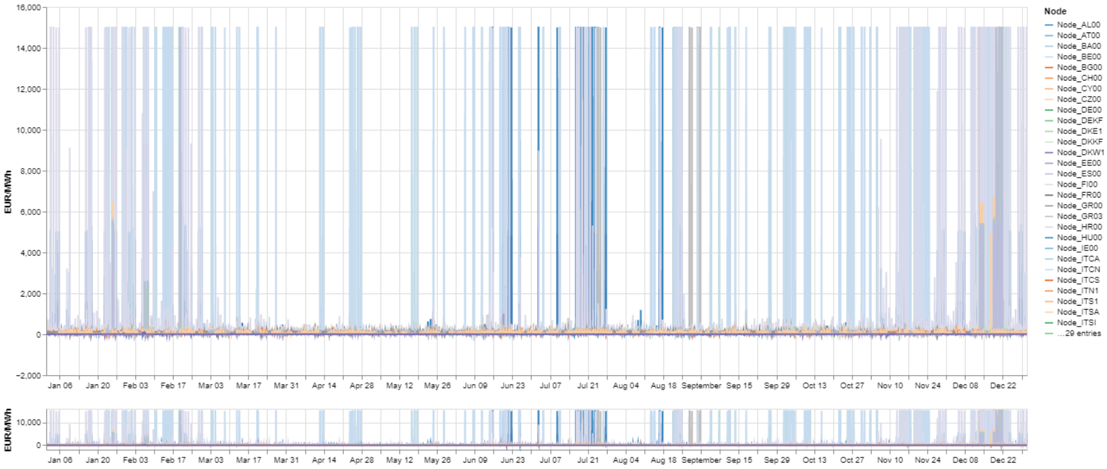

Figure 3.20: SRMC of network for the NT2030 Low Thermal scenario

Unit commitment

Similar figures of unit commitment are reached for the NT2030 LowThermal case, despite the decrease in thermal capacity in some nodes. The only technology that changes notably is gas. In this case, 7 units are not committed at any hour of the year, instead of the 9 that were not committed in the NT2030 case. Please refer to the previous case analysis for further information.

This type of information shows how there are thermal units that are not really needed for generation. Nevertheless, as it has been pinpointed in this analysis, the early decommissioning of these units is not a good strategy if not supported with the correspondent network development, and the provision of alternatives to provide the operating reserves needed.

Energy curtailment

In the NT2030 Low Thermal scenario, the total amount of curtailment adds up to 351.44 TWh, a figure slightly higher than in the base case and a 8% of the total 4267.14 TWh produced by the whole system. Figures are very similar to the base case, which concludes that the problem is not the generation technology used but the storage units available.

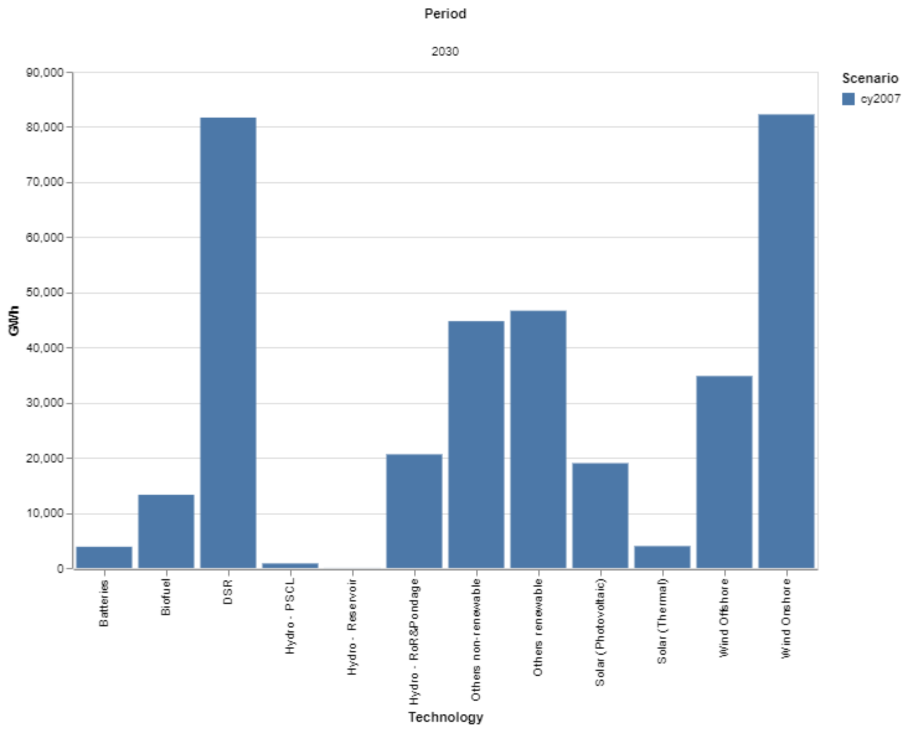

Figure 3.21: Total curtailments per technology for the NT2030 Low Thermal

3.3 Alternative cases- Global Ambition 2030 and Distributed Energy 2030

With the aim to deeply understand the possible future development of the system, ENTSO-E also develops two bottom-up scenarios for the TYNDP 2022. In this cases, greater ambition towards carbon reduction is assumed. Substantial measures are taken to ensure the objectives of the Paris Agreement are achieved: greenhouse reductions of 55% with regards 1990 levels and a maximum increase of temperatures of 1.5ºC. Reliability of the system is not such a relevant issue as it is in ERAA 2021 scenarios. Hence, it is very probable that higher ENS level are forecasted, as these scenarios are not as conservative as NT2030.

Energy transition can be achieved in different ways depending on the evolution of certain technologies and the participation of society. This is the reason why two different scenarios are presented. Both cases recon a general decrease in electricity demand caused by multiple factors. In the one side, the increase in efficiency, new trends in consumers such as demand shifting or the use of public transportation, and the restructuring of the industries towards circularity reduce the total demand of electricity. In the other side, the electrification of heating systems or private transportation is expected to cause an increase in the demand. Nevertheless, that increase is not as big as the other reductions, added to a better insulation of buildings, end up in a total decrease of electricity demand.

The production of electricity to meet this demand can be achieved in different ways. A higher development and use of renewable sources is clear in both cases, matched with a decrease in thermal capacities and a higher participation of prosumers. The main difference between the Global Ambition scenario and the Distributed Energy scenario is the centralization of the generation. In the first case (GA2030), the generation occurs in a more centralized case, taking advantage of economies of scale in new renewable sources (specially in offshore wind capacities). In the second case (DE2030), the uptake of self-production systems such as solar panels with batteries lead to a decentralized generation that will require higher private investments in the infrastructures but that will not saturate the network as much as in the Global Ambition case.

3.3.1 Input data for Global Ambition 2030 and Distributed Energy 2030

To build these cases, National Trends 2030 case has been used as a base. From this, percentage changes have been applied to capacities and demand in line with the drivers mentioned above. The percentage changes have been extracted from the TYNDP 2022 Joint Scenario platform. It must be noted that these changes do not happen equally in every node and so, this approach is not the most accurate one. Nevertheless, the aim of this project is to obtain a general view of the grid and so the accuracy is good enough. In this platform, overall capacities are presented for each scenario. [22] Below, a table with the percentages for each case is presented:

Table 3.13: Percentage changes for GA2030 and DE2030 generation capacities

	National Trends (TYNDP)	Global Ambition	Incr.	Distributed Energy	Incr.
Biofuels	7,395.07	-	-100%	-	-100%
Coal and lignite	82,453.34	37,871.47	-54%	38,963.02	-53%
Gas	321,126.17	219,636.71	-32%	236,381.73	-26%
Hydro	277,930.92	274,298.97	-1%	274,230.37	-1%
Nuclear	104,688.69	107,853.50	3%	82,701.20	-21%
Oil	7,759.90	6,159.78	-21%	6,159.78	-21%
Other Non RES	57,018.96	43,170.49	-24%	43,170.49	-24%
Other RES	43,556.25	55,166.39	27%	55,166.39	27%
Solar	437,265.76	505,032.70	15%	679,069.90	55%
Wind Offshore	107,654.09	170,962.15	59%	127,482.08	18%
Wind Onshore	355,771.96	402,146.70	13%	475,543.72	34%
SUBTOTAL	900,691.81	1,078,141.55	20%	1,282,095.70	42%
Battery	31,936.62	74,835.66	134%	132,648.04	315%
DSR	30,911.16	30,908.19	0%	30,908.19	0%
Hydro Pump Storage	108,967.54	106,099.46	-3%	106,099.46	-3%
SUBTOTAL	171,815.32	211,843.31	23%	269,655.69	57%
TOTAL	1,072,507.13	1,289,984.86	26%	1,551,751.39	45%
Prosumer Node	-	1,950,108.10	*	1,983,212.32	*
Transmission Node	4,642,576.61	2,434,236.78	-48%	2,525,219.47	-46%
Demand change	4,642,576.61	4,384,344.88	-6%	4,508,431.79	-3%

As it can be observed in the table, there is a total decrease of demand of -6% for GA2030 and of -3% for DE2030. This shift is divided into two fields. For transmission nodes there is a high decrease of nearly -50% for both cases. That decrease is shifted into the prosumer nodes (*not regarded in the National Trends scenario), understood as a lower utilization of the electrical grid.

In contrast with the demand, generating capacities suffer a greater change, achieving an increase of 19% for GA2030 and 45% for DE2030 in total installed capacities. This change happens in a different way for each scenario, although there are some common aspects in both scenarios. The decrease of thermal capacities is a clear example of this, showing greater commitment to decarbonization than in the National Trends 2030, mostly centered in coal and lignite plants and followed by gas technologies. This means that current national plans of decommissioning would have to be speed up in a third (+33%) to match estimations. Another huge driver of change in both scenarios is the great increase in usage of batteries, that allow the system to have greater flexibility and reserves. This increase is greater for DE2030 (315%) as prosumer systems often incorporate batteries to storage the energy produced by the sun, allowing a more uniform supply of electricity. For the GA2030 scenario its increase is only of 134%, which is still big but not as impressive. Finally, hydro installations are expected to remain the same with an slight decrease of 1%.

For the Global Ambition scenario, the development of renewables is driven by a major increase in offshore wind, with an increase of nearly 60% due to advancements in the available technology and the reduction of cost due to economies of scale. Onshore wind and solar technologies increase in 13% and 15% respectively, a smaller change compared to the DE2030 scenario. There is a slight increase in nuclear technologies (3%) and a considerable increase or other types of renewables (27%) such as geothermal or biomass technologies. Another interesting fact is that, in contrast with NT2030, no biofuel capacities are considered for this scenario. No changes are expected for the Demand Side Response.

For the Distributed Energy scenario, the major drivers of change in renewable technologies are the increase in installed solar generating capacities(55%) and in batteries (315%). As mentioned before, this is due to an expected increase in self generating capacities in houses and factories. Offshore wind is not as relevant in this case (18%), while onshore wind has a greater increase (34%). Other types of renewables are expected to undergo the same changes as in GA2030. There is a pertinent decrease in nuclear capacity (-21%), as centralized generation and big plants are not needed in this scenario. Biofuels are not considered in this case and DSR is not expected to change either.

Finally, another difference with the NT2030 case are the operating reserves. Figures given by TSOs for NT2030 no longer make sense for these cases, as the infrastructure changes. For GA2030 and DE2030, operating reserves have been built regarding the demand. For the first, a 10% of the demand has been assigned bearing in mind that generation happens in a centralized way and in bigger units, hence with a higher impact if one of them falls down. For the DE2030 case, a 5% of the expected demand has been assigned as operating reserves, due to a more distributed generation impact of unit failure is not as big.

In conclusion, GA2030 and DE2030, show a slight decrease in demand and a relevant increase in generation capacities, composed by an ambitious decrease in thermal generation units and matched with a huge increase of renewables (mainly offshore wind for GA2030 and solar and batteries for DE2030). These changes aim to achieve the Paris Agreement objectives and require of great commitment from authorities, private sectors, and most importantly: citizens.

3.3.2 Output results for Global Ambition 2030 and Distributed Energy 2030

Once the cases were modeled and results were obtained, comparisons and analysis can be carried out for the GA2030 and DE2030 cases. In this subsection, these two cases will be compared between them and contrasted to NT2030. Nevertheless, NT2030 is considered to be a previous step to these two cases and not a benchmark, so comparisons must bear in mind the different approaches of the cases. Similarly to previous cases, analysis will be carried out for total system costs, share of technologies, unit commitment, total emissions, ENS, network utilization, ranking of greener countries, and the case for Spain.

Total system cost

First figures to be compared are the total system costs. In table 3.14, it can be seen that the cost for the GA2030 system is 18% more expensive than the DE2030 system. This contrast is even more notable if we consider that the decrease in electricity demand is bigger for GA2030, hence not only do they have to produce less, but they do it in a more expensive way. The average system cost per GWh produced is of 11.5462 €/MWh for GA2030 and 9.5103 €/GWh for DE2030. The average cost system for the base case NT2030 was of 6.67€/MWh. Therefore, the production of electricity in GA2030 is over 20% more expensive than in DE2030 in relative terms. Also, there is a relative cost increase of 70% from the base case for GA2030 and of 42% for DE2030.

Although generation costs tend to be similar in all cases and even cheaper for GA2030 and DE2030, the great change in costs stem mainly from reliability costs, and partially from emission costs. For the bottom-up scenarios, emission costs are reduced as CO_2 targets are higher and less thermal units are committed. On the contrary, reliability costs for these cases are considerably high, 7 and 5 times higher than the NT2030 costs respectively. This information pinpoints the low stability of the system for cases GA2030 and DE2030, which show higher ENS levels. Reasons for this will be analyzed in the following subsections, trying to understand the benefits and disadvantages of the energy transition. It must be remembered that these two bottom-up scenarios are developed by TYNDP, hence they are not as conservative with ENS as NT2030 cases.

Table 3.14: Total system costs for GA2030 and DE2030

	NT2030	GA2030	DE2030
Cost/Payment	[MEUR]	[MEUR]	[MEUR]
Total System Cost	26665.56	43614.88	36908.49
Generation Operation Cost	16321.70	15319.96	15156.39
Emission Cost	6800.45	4341.545	4569.40
Reliability Cost	3543.41	23953.38	17182.71

Share of technologies

Regarding the share of technologies used for electricity generation, we can observe some expected differences in the use of different kinds of renewables. Regarding levels of renewable generation 84.9% of total generation is renewable for GA2030 and 86.1% of generation is renewable for DE2030. This figure is 10 percentage points above NT2030 forecasts, showing the higher ambition for energy transition of these cases.

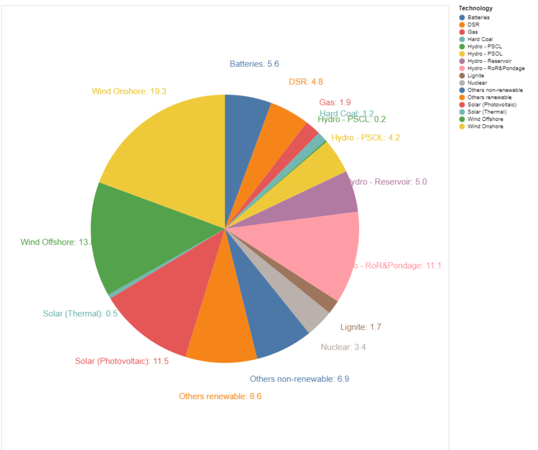

Figure 3.22: Share of technologies for GA2030

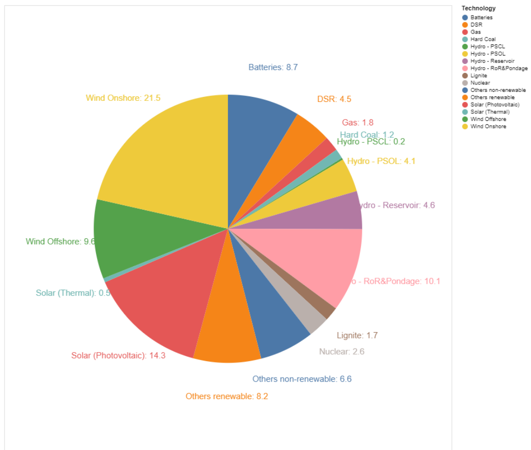

Figure 3.23: Share of technologies for DE2030

In the case of GA2030, the dominant technology is onshore wind (19.3%), followed by offshore wind (13.8%). Total hydro production also has a very relevant role in generation, with more than 20% in total. In this case, solutions offered by prosumers (DSR and batteries) are not as relevant (10% share) given the generation happens in a more centralized way. Among non renewables, alternative techs are the leaders, followed by nuclear power. The less relevant technologies are

Hydro Pumped Storage- Closed Loop and Thermal Solar units.

For DE2030, the uptake of distributed self generating units give more importance to solar panels and batteries. The most relevant technology keeps being wind onshore with 21.5% share, followed by photovoltaic solar (14.3% share). Hydro generation slightly loses some position with 19% of generation and offshore wind is not as developed as GA2030, having 9.6% of share. Batteries have almost as much importance as wind offshore with 8.7% of share. Other non renewable is the most used among non renewables, followed by nuclear units.

From these facts, it can be concluded that higher ambition for CO_2 reduction and higher renewable capacity leads to higher renewable share. This increase can happen in different ways depending in the way citizens and institutions behave. For GA2030, economies of scale and development of technology allows a higher production of wind techs (onshore and offshore). For DE2030, higher engagement of citizens shifts that generation to solar panels, onshore wind and batteries. Overall, usage of renewables is slightly higher for DE2030 than for GA2030, but both show great levels when compared to NT2030.

Unit commitment

In relation with the share of each technology and the low usage of non renewables, an analysis on unit commitment has been developed. Some units of the system are not committed at any time of the year, meaning they are not being used at all. These are 3 gas units in Spain, North Macedonia, and Malta; one nuclear unit located in Sweden, 3 oil units: one in France and two the UK; and one or two hard coal units depending on the case, located in Finland and the UK.

Table 3.15: Units never committed in GA2030 and DE2030

	GA2030	DE2030
Batteries	0	0
Gas	3	3
HardCoal	2	1
Hydro-PSCL	0	0
Hydro-PSOL	0	0
Hydro-Reservoir	0	0
Lignite	0	0
Nuclear	1	1
Oil	3	3

The rest of the units are committed at some point of the year and hence, are useful. The need for the non committed units can be explained by the operating reserves requirements, inertia requirements, or lack of budget for its decommissioning. As the model is deterministic, it couples the units with their reduced power, so the more expensive ones may not be needed according to the model, which is not necessarily the case in reality.

CO_2 Emissions

As it was foreseen in the Total System Cost subsection, emissions for these two cases has been notably reduced when compared to NT2030. Total emissions for GA2030 are of 62.02 ton CO_2, while they are of 65.28 ton CO_2 for DE2030. If prorated to emissions per GWh produced, we obtain 16.43 ton CO_2/GWh for GA2030 and 16.82 ton CO_2/GWh for DE2030. Figures for NT2030 were 97.5 ton CO_2 of total emissions and a ratio of 24.39 CO_2/GWh. Similarly to previous cases, these emissions mainly come from lignite, followed by hard coal and gas.

The reduction of emissions for both cases is of around 40% when compared to NT2030. Bearing in mind that NT2030 already involves a huge effort to meet COP26 agreement, it can be concluded that GA2030 and DE2030 present very promising results. The only drawback of these scenarios is the low reliability of these scenarios when it comes to ENS levels. This will be analyzed in the following subsection.

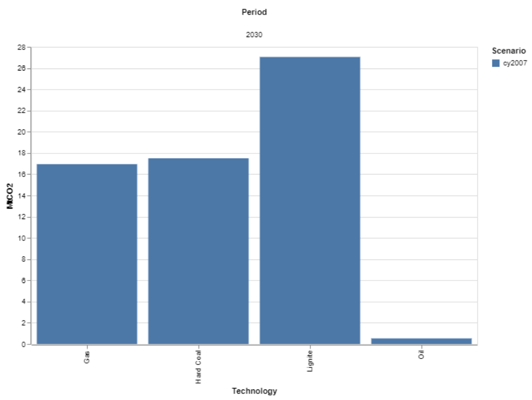

Figure 3.24: CO_2 emissions for GA2030

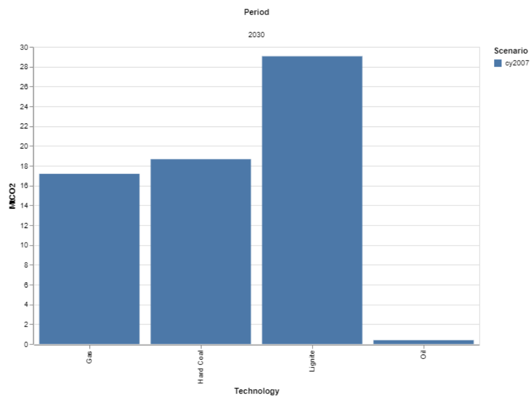

Figure 3.25: CO_2 emissions for DE2030

ENS

Energy not served for both cases has worsen notably, forecasting estimates 1596.89 GWh of ENS per year for GA2030 and 1145.51 GWh of ENS per year for DE2030. This is more than 450% increase when compared to NT2030 (236.23 GWh of ENS).

Transformations in the system lead to lower emissions but also to less reliability, as when renewable energy is not available, thermal and nuclear capacity is not enough to cover all demand and network also tops its maximum capacity, not leaving any other alternative but to stop serving demand. The figures shown by the model are considerably high compared to standards. Nevertheless, the input data is conservative in all aspects as it aims to study availability of the European system. Safety coefficients have been applied to network capacity and generation availability. With this in mind, the analysis of the ENS of the model is considered very negative and might not be realistic.

In the case of GA2030, ENS (GWh) was highest Poland and Hungary. In total, 19 nodes out of 59 nodes were affected. As it happened in previous cases, the most affected area are Central and Eastern Europe, leaving the North and Southwest with no shortages. Isolated islands also tend to have more problems as they are self reliant. Once again, it is proved that neighboring zones affect each other spreading shortages and increasing network flows. One solution to this could be the development of the European network. By increasing network capacity, electricity could be distributed across the continent, smoothing weather-dependent patterns and helping each other with base technologies.

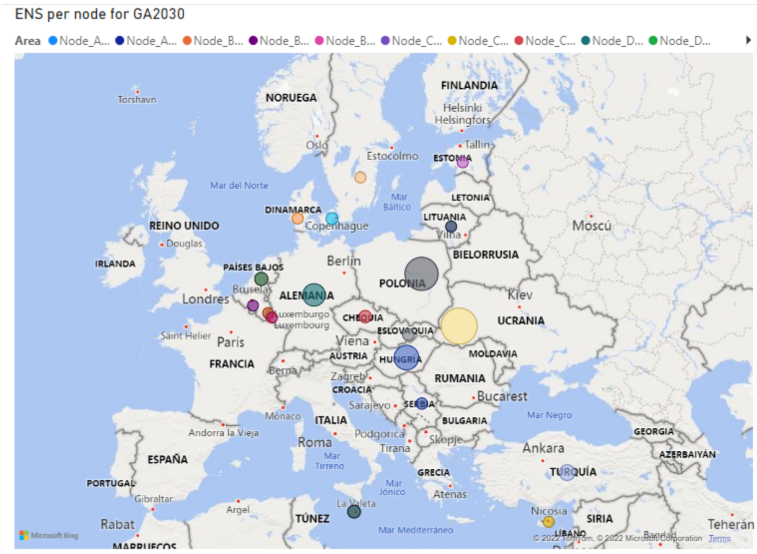

Figure 3.26: Size of impact of ENS per node for GA2030

In the case of DE2030, the scenario is slightly better than GA2030 but still not very reliable. In this forecast, ENS (GWh) was highest for Bursthyn TES at 328.22, followed by Poland and Germany. Bursthyn TES accounted for 28.65% of ENS (GWh), which again surprises. 16 nodes were affected out of the total 59. In this case, distributed energy makes it possible to lower ENS as network usage is not as high and maximum levels are reached later.

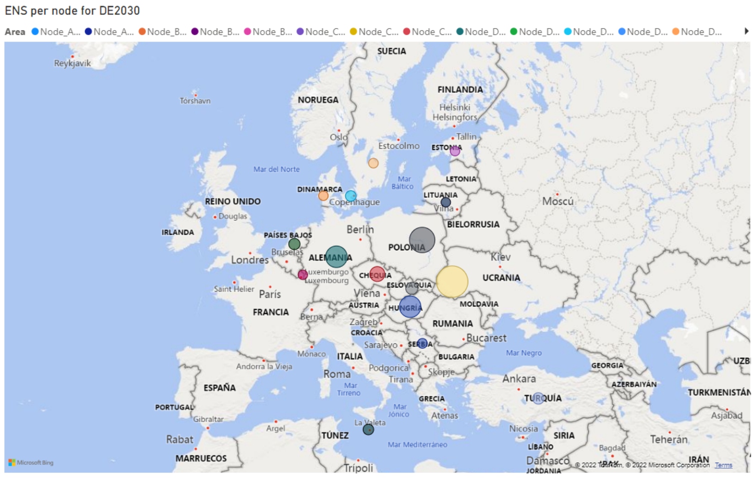

Figure 3.27: Size of impact of ENS per node for DE2030

Network utilization

One of the main reasons for ENS is the collapse of the network. When nodes are not able to produce as much as they need, they import electricity, but this is only possible up until maximum capacity is reached in connecting lines. For these two cases, network usage is considerably high, showing the need for a proper network development in the future. In GA2030, 30 lines out of 112 are at the maximum capacity (with a safety coefficient applied) for more than 85% of the time of the year and for DE2030, 33 lines. A summary of the network usage is shown in 3.16 for all lines and all hours of the year.

Table 3.16: Summary of network usage for GA2030 and DE 2030

	GA2030	DE2030
Minimum	0.00	0.00
Average usage	0.67	0.68
Maximum	0.94	0.94
Standard deviation	0.23	0.22
Average of hours reaching maximum capacity per line	4,191.65	4,319.83
% hours and lines at full capacity	48.0%	49.4%

As it can be seen, utilization changes greatly from some lines to others, but average usage of the network is of 67% for GA2030 and 68% for DE2030. The average percentage of hours that lines are at its maximum capacity is of 48% of time for GA2030 and 49.4% or DE2030. The worst line is the one connecting Germany and Norway. Lines connecting Norway and the Netherlands are also highly utilized. These figures give some light to future plans and investments.

Rank of greener countries

Global climate change is a problem that affects everyone in the world and requires a joint solution to decrease carbon emissions before it is too late. Nevertheless, countries face different economic situations and the existing infrastructures vary around the world. Europe is of no exception, and the countries in it may commit to a bigger or smaller extent depending on levels of investment, social awareness, geopolitical issues, and energy resources. In this subsection, tables rank the countries depending on the use of renewables.

Albania, Norway and Montenegro are the only countries that show no use of non renewables for both cases. Following come Latvia, Sweden, Denmark, and Finland. Countries in Northern Europe have high GDP per capita, hence higher investing power. Moreover, these countries are well known for their citizenship awareness. Those kind of features are key drivers for the transition. In the contrary, the less renewable intensive countries are Malta, Czech Republic, Cyprus, Slovakia, Bulgaria, Bursthyn TES, and Poland for both cases (order might vary slightly for DE2030). Again, these countries show lower economic power and less infrastructure and natural resources. Also, islands like Malta and Cyprus are more prone to using non-renewable units as their low connection to the rest of the grid don't allow them to rely completely on solar and wind generation.

Average renewable generation for the whole continent is 85%, having two third of countries above the average. Countries below average usage tend to use way more non-renewables than countries above, bringing the whole continent down. As stated above, energy transition is an issue affecting everyone and unless there is collective actions are taken, free riders will be able to oust individual initiatives.

Table 3.17: Share of renewable generation per country for GA2030, countries ordered from greener to less green

	Non Renewables		**Renewables**		
Countries	**Energy (TWh)**	**Share (%)**	**Energy (TWh)**	**Share (%)**	**Grand Total**
AL	0.00	0%	12.94	100%	12.94
NO	0.41	0%	169.46	100%	169.86
ME	0.02	0%	4.66	100%	4.68
LV	0.12	2%	7.60	98%	7.72
SE	3.28	2%	164.54	98%	167.82
DK	1.76	4%	46.74	96%	48.50
FI	4.50	4%	100.15	96%	104.65
LT	0.81	5%	15.46	95%	16.27
CH	4.13	5%	77.94	95%	82.08
AT	6.19	5%	116.45	95%	122.64
HR	1.17	5%	21.23	95%	22.40
UK	30.24	6%	437.89	94%	468.13
PT	4.24	7%	58.72	93%	62.97
IE	3.57	7%	45.02	93%	48.59
BA	0.78	8%	9.16	92%	9.94
DE	67.64	10%	624.54	90%	692.18
ES	27.96	10%	257.98	90%	285.93
RO	8.60	11%	69.70	89%	78.31
IT	41.88	11%	325.09	89%	366.97
BE	10.97	12%	83.98	88%	94.95
GR	7.52	13%	52.50	87%	60.02
FR	61.00	13%	414.60	87%	475.60
NL	26.45	13%	178.78	87%	205.23
RS	8.40	16%	42.64	84%	51.04
SI	2.79	18%	12.59	82%	15.38
LU	0.34	18%	1.50	82%	1.84
MK	1.08	21%	4.14	79%	5.22
EE	1.92	25%	5.75	75%	7.68
TR	158.84	36%	282.66	64%	441.50
HU	12.82	39%	19.71	61%	32.52
PL	75.09	45%	93.17	55%	168.26
UA	2.23	48%	2.43	52%	4.65
BG	22.17	56%	17.73	44%	39.90
SK	20.68	58%	15.19	42%	35.87
CY	3.65	60%	2.43	40%	6.08
CZ	35.72	61%	23.31	39%	59.03
MT	1.58	77%	0.48	23%	2.06
Grand Total	660.56	15%	3,818.86	85%	4,479.42

Table 3.18: Share of renewable generation per country for DE2030, countries ordered from greener to less green

	Non Renewables		**Renewables**		
Countries	**Energy (TWh)**	**Share (%)**	**Energy (TWh)**	**Share (%)**	**Grand Total**
AL	0.00	0%	13.47	100%	13.47
NO	0.15	0%	173.10	100%	173.25
ME	0.01	0%	4.77	100%	4.78
LV	0.12	2%	5.49	98%	5.60
SE	3.52	2%	152.37	98%	155.89
DK	1.61	3%	47.21	97%	48.82
AT	6.00	4%	142.47	96%	148.47
FI	4.60	4%	107.43	96%	112.03
CH	4.05	4%	86.37	96%	90.42
HR	1.06	4%	22.44	96%	23.50
BA	0.48	5%	9.70	95%	10.18
LT	0.89	5%	17.55	95%	18.44
PT	3.80	6%	61.47	94%	65.27
ES	24.08	7%	302.67	93%	326.75
IE	4.07	8%	46.70	92%	50.78
UK	40.33	8%	459.67	92%	499.99
GR	5.60	8%	61.81	92%	67.41
DE	72.16	9%	694.79	91%	766.96
IT	39.92	10%	377.47	90%	417.39
RO	6.67	10%	61.03	90%	67.70
BE	11.44	11%	89.71	89%	101.15
FR	56.56	11%	436.23	89%	492.79
NL	28.43	12%	207.50	88%	235.92
SI	2.54	16%	13.31	84%	15.85
MK	0.98	18%	4.55	82%	5.53
LU	0.30	18%	1.38	82%	1.68
EE	1.49	19%	6.54	81%	8.03
RS	7.96	19%	34.18	81%	42.14
HU	12.41	35%	22.77	65%	35.19
TR	152.48	37%	260.54	63%	413.02
PL	81.11	47%	91.04	53%	172.15
BG	18.26	48%	19.91	52%	38.17
UA	2.47	52%	2.30	48%	4.78
CY	3.35	52%	3.04	48%	6.39
SK	18.10	55%	14.99	45%	33.09
CZ	35.42	57%	26.38	43%	61.79
MT	1.58	73%	0.58	27%	2.16
Grand Total	653.99	14%	4,082.95	86%	4,736.94

With regards CO_2 emissions, countries are compared in relative terms as countries with higher demand are prone to emit more. Figures 3.28 and 3.29 show CO_2 emissions per TWh produced. In general terms, emissions are notably lower than in NT2030, as explained in previous subsections. If figures 3.28 and 3.29 are compared to figure 3.11, columns are notably lower and there are less countries above the average ratio.

The most polluting country by far is Turkey with around 1 Mton CO_2/TWh in GA2030 and 0.9 Mton CO_2/TWh in DE2030. Following comes the Netherlands (aprox. 0.5Mton CO_2/TWh), and Cyprus with 0.1 Mton CO_2/TWh. The average emissions are 0.13 Mton CO_2/TWh for both cases. This means only two countries are above average and affect the rest of them. Countries with zero CO_2 emissions in electricity generation are Austria, France, Final, Switzerland, and Norway in different orders depending on the case.

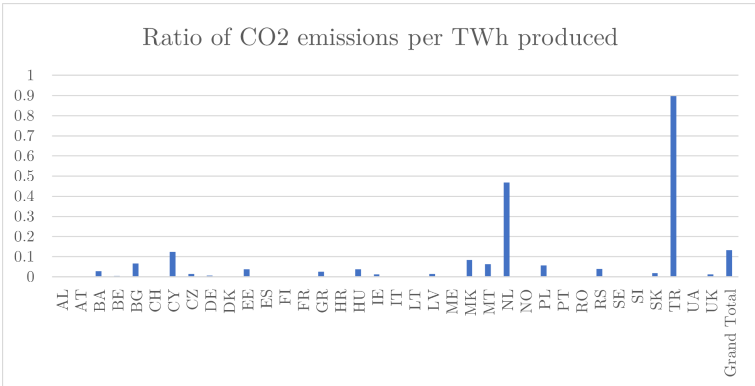

Figure 3.28: Ratio of CO2 emmisions per TWh per country for GA2030

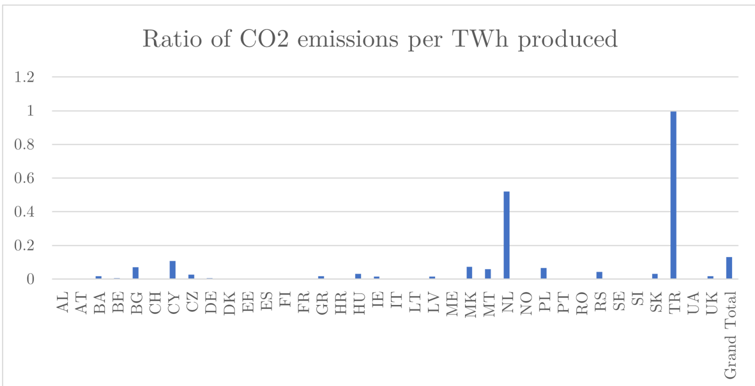

Figure 3.29: Ratio of CO2 emmisions per TWh per country for DE2030

Case for Spain

Being GA2030 and DE2030 bottom-up scenarios, it does not make sense to analyze changes in demand or installed capacities. Still, changes in installed capacities for both cases are shown in table 3.19. As expected, for GA2030 there is a notable increase in offshore wind and nuclear, and a decrease in gas units. Hydro units remain the same, and solar and onshore wind expect to increase capacities. For DE2030 case, there is a very notable increase in batteries, PV solar, and onshore wind. Nuclear decrease as well as gas units, and offshore wind does not increase as much.

Table 3.19: Installed capacities in Spain for GA2030 and DE2030 (MW)

	GA2030	**DE2030**
Batteries	5858.13	10383.69
Gas	16755.98	18033.45
Hydro - PSCL	6776.67	6774.97
Hydro - PSOL	2648.25	2647.59
Hydro - Reservoir	10828.82	10826.11
Hydro - RoR&Pondage	3592.43	3591.53
Nuclear	3132.93	2402.30
Others non-renewable	3013.35	3013.35
Others renewable	2191.14	2191.14
Solar (Photovoltaic)	44355.81	59641.08
Solar (Thermal)	8431.34	11336.84
Wind Offshore	317.61	236.83
Wind Onshore	54652.4	64627.18
Total installed capacity	**162554.90**	**195706.10**

With respects how this installed capacity is used, Spain shows slightly different results to European trends. Renewable generation takes up to 90.2% share in GA2030 and 92.7% in DE2030, better shares than average. Onshore wind is the most used technology by far (41.5% and 40.5% respectively), followed by PV solar with 23.7% in GA2030 26.7% in DE2030. Offshore wind will not be a very developed technology in Spain as there is not enough maritime platform and so initial costs are very high. In the contrary, both onshore wind and PV solar show higher commitment than in the rest of Europe. This is due to the specific weather conditions of the country. Batteries have almost double the share in DE2030 (7.0%) than in GA2030 (4.1%). This difference is absorbed by hydro, nuclear,and other non renewable production in the GA2030 case. Furthermore, thermal solar production also has a bigger share that the rest of countries due to existing capacities.

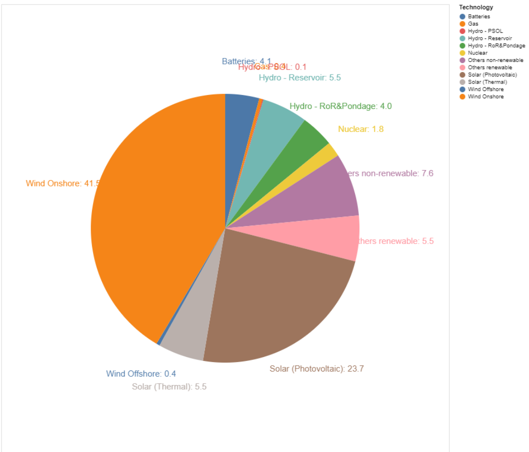

Figure 3.30: Spanish share of technologies for GA2030

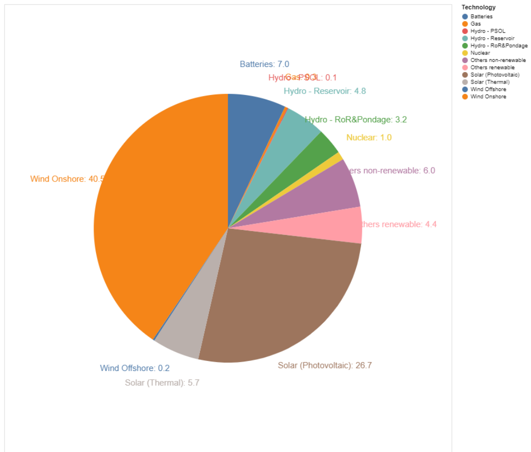

Figure 3.31: Spanish share of technologies for DE2030

The higher share of renewables in generation lead to lower CO_2 emissions. Total emissions add up to 0.25 Mt CO_2 for GA2030 and 0.22 Mt CO_2 for DE2030. These figures are very low when compared to national plans, hence offer a positive forecasting. The ratio per TWh produced is also very low: 0.000890197 $MtCO_2/TWh$ for GA2030 and 0.000667357 $MtCO_2/TWh$ for DE2030. Added to this, there is no ENS for neither of the cases. Which shows how a country can reduce its emissions while maintain acceptable reliability levels. Nevertheless, it must be said that Spain has optimal weather conditions that foster solar and wind generation.

Regarding network usage, Spain is connected to France and Portugal. As it has been historically happening, Spain is expected to import energy from France and export it to Portugal. For the GA2030 case, 9.19 TWh are imported from France and 1.73TWh are exported to Portugal. For the DE2030, Spain imports less and exports more, meaning it generates more. It imports 5.15 TWh from France and exports 3.01 TWh to Portugal. In fact, Spain has a total generation of 285.93 TWh for the GA2030 case and 326.75 TWh for the DE2030.

These two lines are well designed, as ENS shows. The average utilization in GA2030 for the line connecting France is 54.4% and it is used at full capacity for 21.5% of the time. For the line connecting Portugal, average usage is 76.95% and it works at full capacity for 58.3% of the time. It can be seen that the Portuguese line has a higher utilization rate. In the DE2030 case, the line connecting France has an average utilization rate of 59.1% and it works at full capacity for 28% of the time. The average utilization rate for the line connecting Portugal is 68.98%

and it works at full capacity for 44.42% of the time. Again, the Portuguese line is more used. Moreover, DE2030 shows higher utilization rates for France, but lower for Portugal.

Chapter 4

Conclusions

This chapter summarizes the results and take-aways of the study carried out. The project had the objective to analyze possible future scenarios for the European electricity system for 2030 given different assumptions. By doing this, key drivers of change and the impact of each element is studied, and the power of openTEPES is proven. To summarize findings, this chapter has been divided in three sections. In the first one, conclusions on output results for the different cases are summarized. In the second sections, reflections on the methodology and overall project management are made. Finally, recommendations on the future lines of study are suggested.

4.1 Conclusions on output results

The energy transition is a global challenge to which the European Union is seriously committed. To build a truly sustainable future, not only should carbon emissions be reduced. Strategies must also involve solutions that are socially acceptable, affordable and sufficiently secure. All factors must be taken into account to provide citizens with green, cheap and reliable electricity.

As summarized below, this issue does not have a quick and easy solution, it requires a coordinated, planned and holistic response. It is not just a matter of decommissioning thermal power plants, it requires a development plan for the electricity grid, the commissioning of new renewable plants, more batteries to cover operating reserves and base technologies such as nuclear to serve as a backup in case of shortages of sun and wind.

4.1.1 General ideas

After analyzing all four cases, some general conclusions are repeated along all of them.

First of all, it is clear that the electric system is a very complex system with several factors affecting the final result. Demand, weather-dependent production, operating reserves, network usage and different costs interact with each other. Moreover, events in neighboring areas spread through the system impacting others. Further geopolitical events affect fuel prices raising their volatility and transmitting these fluctuations to consumer prices. Therefore, partial or focal solutions must be studied to see their overall effectiveness.

Secondly, different mechanisms are being used to foster renewable production, carbon prices are one of them. Nevertheless, sensitivity analysis on its cost has shown how higher CO2 costs do not lead to lower emissions but only raise the final price. Hence, one the equilibrium price is reached in the market, no further increase in this is needed. The same case happens with fuel costs. Relevant changes in fuel costs do not change overall energy dispatch nor emissions. They just have an impact on final prices. Therefore, it can be concluded that further policies on fuel and CO2 prices do not necessarily lead to reduction in emissions and might be counterproductive.

In the third case, analysis for specific weeks of the year show how demand and variable production changes along the year. On the one side, decommissioning of thermal units and higher solar and wind production raise the fluctuation of generation capacities. On the other side, batteries, DSR, hydraulic, pumping and a higher interconnection help smooth these patterns giving stability to the system. Overall, new agents increase the complexity of the system. This is the reason why there is a need for leveraging technologies to offer better energy forecasts and plan the dispatch in a safer way.

Furthermore, the contribution of each country to emission reductions is not uniform across cases. Giving place to some countries wiping off the efforts of others. In this case, it does not mean that any one country has worse or less well-intentions than another. But there are certain aspects that encourage or delay contribution. In this case, lower GDP, lack of new infrastructure, low levels of private investment, or scarcity of energy resources may lead some countries to have a worse impact on this challenge. It is therefore important to allocate resources equitably in order to provide a unified and uniform response.

On the other hand, the relationship between the use of renewables and a country's emissions is not as strong as one might imagine. Nuclear energy is the cause of this. Nuclear power is a way of not emitting CO2 while providing the system with a base load technology that is not considered renewable. This type of technology might be the solution to have affordable reliable electricity, while reducing emissions.

Finally, it is made clear along cases that the early decommissioning of thermal units poses a threat to the system's reliability unless paired with plans to cover the lost capacity. Batteries can be a great ally in this, followed by a higher interconnected network and more solar and wind farms.

4.1.2 Reflections on particular cases

Depending on the case, different objectives are pursued. Reducing emissions can be done in different ways, and each one of them have relevant different impacts in other aspects of the network. In this subsection, the specific results for each case is outlined. The following table summarizes main figures for each case:

Table 4.1: Summary figures for all cases

	NT2030	**NT2030 Low Thermal**	**GA2030**	**DE2030**
Total system cost [MEUR]	26665.56	56513.88	43614.88	36908.49
Total system cost pu [€/MWh]	6.67	14.14	11.55	9.51
Total emissions [Mton CO_2]	97.5	95.42	62.02	65.28
Share of renewables	72.1%	76.5%	84.9%	86.1%
Total ENS [GWh]	236.23	2134.31	1596.89	1145.51
Network utilization	66%	66%	67%	68%

As it can be observed in table 4.1, higher commitment of bottom-up scenarios GA2030 and DE2030 lead to lower emissions and higher usage of renewables, nevertheless this planning has a huge impact of the system reliability. ENS rates rise sharply for these two scenarios, leading to higher cost (in total and pu). Network utilization is more less stable across scenarios.

For the NT2030, the current forecasts provided by the TSOs are used to build the model. Outputs foresee emission reductions that meet and overpass current objectives in more than six times, while providing a stable network and affordable costs of generation. In the case of variations in current plans leading to earlier decommissioning of thermal units, NT2030 Low Thermal is forecasted. This scenario decreases the capacity of thermal units in some plants in line with a speed up in current decommissioning processes and the delay of new commissioning plants. This change in thermal capacity mainly leads to higher instability of the network, with almost 10 times more ENS. As a consequence, total system costs increase dramatically. Emissions are slightly reduced, and the share of renewables also increases moderately. In conclusion, the early decrease in thermal decommissioning is not necessarily beneficial to the system, but it involves higher costs and lower reliability. In order to be effective, sudden changes in the speed of capacity plans must be matched with proper network development and substitution of current thermal capacity with renewables and batteries.

GA2030 and DE2030 scenarios are constructed with a bottom-up approach, bearing in mind different development of current technologies and adopting a more centralized mindset for the first case and a decentralized one for the latter. Due to higher efficiency and citizen awareness, demand for electricity is slightly reduced even after electrifying transportation and heating systems. A greater commitment to COP26 is shown in both cases in the form of a greater investment in renewables. This investment leads to building bigger renewable capacities, improving existing technologies and creating economies of scale. Thanks to this, GA2030 shows a great increase in installed offshore wind capacities, as well as more PV solar and batteries. In the case of DE2030, this investment comes mainly from private sources willing to develop self-supplying plants formed by PV solar and onshore wind plants and batteries. Offshore wind is not as relevant and the base technologies tends to be the nuclear. Both scenarios show a decrease in thermal capacities.

Results for these two cases show lower generating costs derived from a higher use of renewables and lower carbon emission levels. Nevertheless, total system costs are considerably higher due to the huge ENS of some nodes. ENS levels are 5-7 times higher than the base case. This is due to a unequal distribution of capacities across the continent. If weather-dependent technologies are concentrated in some areas of the system, a dense network is needed to spread green energy across nodes in case there is no sun or wind. The overuse of the network leads to the collapse of the system, causing power outages. Another possible way of seeing it is to build plants equally distributed so that dependence on weather is lowered and production patterns are smoother. In this case, a high network is also needed to transport energy from sunny areas to low-generating nodes. In both ways, proper network development is needed. Moreover, batteries and ESS are also crucial for providing operating reserves and uniformity in supply.

In conclusion, a holistic approach of the problem is crucial to provide sustainable efficient solutions. The decommissioning of thermal units, the deployment of renewable energy or the development of the network are useless solutions if only one of them is carried out. In contrast, a collective coordinated approach involving private and public bodies is the best way to achieve carbon neutrality in the mid-term horizon.

4.1.3 Case for Spain

Spain shows slightly different circumstances from the rest of the continent. To start with, is a more isolated node as it is a peninsula located in one of the corner of the continent. To follow with, it has higher wind and solar resources and powerful hydro plants, but lacks enough nuclear power. National plans for the decommissioning of thermal plants are quite ambitious, looking for a 23% reduction of carbon emission compared to 1990 levels, as well as a renewable generating share of 74%.

Spain does not show ENS in any of the scenarios, which proves to be a secure system. Forecast on CO_2 emmisions are notably better than objectives: 1Mt CO_2 for NT2030, 0.25Mt CO_2 for GA2030, and 0.22Mt CO_2 for DE2030. This trend is matched with the share of renewable generation, also above national objectives reaching 82% for NT2030, and around 90% for the two bottom-up cases. Demand is not expected to vary greatly for alternative cases, showing from +1% to -4% changes from current levels. In all cases, Spain imports energy from France and imports it to Portugal, being a net importer. The utilization of the lines is around 60% for NT2030 and slightly higher for GA2030 and DE2030. Most used technologies are onshore wind and PV solar for all cases. Offshore wind will not have a huge impact as in other countries.

Overall, Spain shows very promising results with shares of renewable while keeping the system stable. Ambitious plans must be carried out to deploy solar and wind capacities to its fullest extent and become a net exporter.

4.2 Conclusions on the methodology

The main objectives of this project were summarized as following:

1. Identify key factors that affect the future of the Pan-European electricity network.

2. Get to deeply understand how does the system work and what are the key solutions to achieve net emissions objectives.

3. Learn how to manage a prescriptive model.

4. Prove that openTEPES is a powerful tool able to forecast future scenarios as ENTSOE's models do.

In order to obtain them, the process was divided into four parts. First step was a previous step to the development of the model focused on undestanding the current situation and the functioning of the program openTEPES. A research on the state on art was carried out to fully understand the current issue. The main sources of information for this were the outlooks published by MAF2020, TYNDP2020, and ERAA2021. In parallel, the program was installed, the user got to know how to use Python on a very basic basis, and the different input files were studied. The second step came after. In this, the input information from different sources was gathered and modified to fit the templates. Sources were recorded and the drivers of change were described. Once the model was properly built and a feasible solution was delivered, the project moved on to step three. This part consisted on analyzing output results, comparing them to the state of art and drawing conclusions on the impact of each variable to the whole system. Finally, once the main case had been analyzed, alternative scenarios were designed to understand possible future realities, their advancements, and drawbacks. For these three alternative scenarios, the same methodology as in the first was carried out.

After these four steps of the methodology, it can be concluded that the four objectives of the project have been achieved. On the one hand, it has been understood how the system works, how a change in each variable affects the rest, and the relationships between them. Possible solutions for emission reductions have been analyzed, discovering its drawbacks and risks. On the technical side of the project, openTEPES has proven to be a powerful prescriptive model capable of replicating European perspectives. It must be noted that the program is still in development, always improving aspects and including new possibilities. Moreover, bearing a model of such size has been a great challenge given the size of the input data and files. Due to it, the importance of a rigorous and methodical way of working has been noted and learned.

One of the greatest challenges of this project has been the scheduling. Ambitious time objectives were set at the beginning and sudden changes have kept postponing each phase of the project. The lessons learned here show how project scheduling must be more realistic and incorporate some extra time for unexpected events. In addition, postponing the work also led to re-working to update the input information and the input templates. A more compressed work time on the project would have eased the program, even if this work had taken place later in time. However, surrounding circumstances are not always perfect and sometimes projects must be done in a less efficient way to be finished.

4.3 Recommendations for future studies

The issue approached in this project has a rapidly changing nature. Updating the forecast provided by the TSOs is needed when available to obtain a more accurate picture and include future trends and problems. Moreover, as the electric system involves several factors and variables, more research is recommended on the impact of each of the variables on the overall functioning of the system. In addition, it is suggested that the same study is repeated with different climate years (1983, 1985) for a more precise analysis.

In line with the latter, one of the studies can be the impact on decommissioning of the units that are not committed at any time of the year to see if they are of any utility for the system. A variation of this can be substituting non-committed thermal units with solar and wind plants to see if the latter are committed.

In this study, two aspects of the network have been left out: the inertia needs of the system and the sector coupling to include the use of hydrogen. Lack of information in the first aspect led to related input files being left blank and not considering that aspect. However, the substitution of traditional turbines with solar and wind plants poses a threat to the inertia of the system. Alternative technologies are needed to provide solutions to these requirements. Including this aspect in the study would lead to more realistic solutions. For the case of hydrogen, no Ptx systems have been included in the model. Nevertheless, hydrogen is a huge driver of electrification in the future, and heavy investments are being made in this. For this reason, a model that includes energy outflows and inflows to generate and then consume hydrogen would be another more realistic approach. Even more for the long term, in which hydrogen usage is more than present.

Finally, several problems with operating reserves have occurred along the project. The reduction of controllable generating sources lead to a lower generating capacity available for operating reserves. Some reserves have even been modified to have a feasible model. For this reason, further studies on alternative solutions for this problem are recommended.

Appendix A

Alignment of SDG

In 2015, the UN presented the development agenda and the SDO, 17 goals to improve sociey without leaving anyone behind. These goals gather a set of objectives from race and gender equality to climate change, poverty, human, health and well-being. In order to achieve this goals and imprve society, global commitment is needed from all individuals in all their daily actions. This is the reason why some of these goals have also been integrated into this project.

Figure A.1: Sustainable development goals (SDGs)

Being all goals equally important, there is a set of objectives that better align with the aim of this project, aiming to tackle the same issues. These goals are: 7- Affordable and green energy; 11- Sustainable cities and communities; and 13- Climate action. Relating to the goal 7, the project centers its scope in three key elements: the affordability, the security, and the sustainability of the future European electric system. The ultimate aim of the research is to ensure Europe prepares and takes the actions needed so that these key elements are met, providing affordable green energy to European citizens in 2030. Regarding goal 11, the impact of this future system does not only affect the grid, but also requires action from citizens and cities in lines of distributed energy systems, demand side response, or energy storage systems. By incorporating these aspects into the equation, the project fosters sustainable cities and communities. Finally, with regards goal 13, the trigger of this project and o the whole energy transition is the need to reshape our habits to stop climate change and design a sustainable development model. Hence, studying the grid and its needs and designing a strategy to achieve carbon emission goals is the first step in the climate action.

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