EconomiX

Interconnection as Climate Policy? Assessing the impact of the EU 15% interconnection target on CO_2 Emissions with PyPSA-Eur

Amady Léchenet

2026-10 Document de Travail/ Working Paper

EconomiX - UMR 7235 Bâtiment Maurice Allais
Université Paris Nanterre 200, Avenue de la République
92001 Nanterre Cedex

Site Web : economix.fr
Contact : secreteriat@economix.fr

cnrs

Université Paris Nanterre

Highlights

Interconnection as Climate Policy? Assessing the impact of the EU 15% interconnection target on CO_2 Emissions with PyPSA-Eur*

LÉCHENET Amady

- We assess the impact of reaching the 15% interconnection target on the power mix and associated CO_2 emissions.
- We use the open-source PyPSA-Eur modeling framework to optimize different electricity systems.
- Different scenarios include technical power system constraints and both network and environmental policy compliance constraints to solve during optimization.
- Our findings show that reaching the 15% cross-border capacity taken alone yields marginal effects on CO_2 emissions by 2030.
- The cost-optimal electricity systems show that significant changes in electricity generation and decreases in GHG emissions are obtained with enhanced cross-border interconnections below the threshold of 15%.

Interconnection as Climate Policy? Assessing the impact of the EU 15% interconnection target on CO_2 Emissions with PyPSA-Eur

LÉCHENET Amady[a,*]

[a] *EconomiX-CNRS - University of Paris Nanterre, 200 Avenue de la République, Nanterre Cedex, 92001, France*

Abstract

This paper assesses whether the European Union's target of achieving 15% cross-border electricity interconnection by 2030 can ease the mitigation of CO_2 emissions. Using the open-source Python for Power System Analysis (PyPSA)-Eur modeling framework, we develop a large-scale linear optimization model of power systems of France, Germany, Belgium, the Netherlands, and Luxembourg. The model endogenously optimizes generation, storage, and transmission capacities under technical constraints, while incorporating policy constraints in the form of both a minimum interconnection requirement and alternative CO_2 emission caps. Our results show that implementing the interconnection target alone yields only marginal carbon reductions relative to the baseline. Although 15% is not cost-optimal for each country, significant changes in electricity generation and decreases in Greenhouse Gas (GHG) emissions are obtained with enhanced cross-border interconnections. Grid development significantly facilitates deeper decarbonization by enabling higher renewable penetration, reducing flexible fossil-based generation, and reshaping cross-border electricity flows.

[⋆] I would like to thank Quentin Hoarau, Valérie Mignon, and Benjamin Trouvé for their useful comments and suggestions, as well as seminar participants at EconomiX - University of Paris Nanterre.

[*] Corresponding author

Email address: a.lechenet@parisnanterre.fr (LÉCHENET Amady)

Keywords: Market coupling, cross-border interconnection, CO_2 mitigation, power system optimization, Renewable Energy Sources (RES) integration
JEL: Q42, Q43, Q47, Q48, Q51

---

1. Introduction

Scientific consensus has widely recognized the central role of anthropogenic GHG emissions - mainly carbon dioxide (CO_2) - in the observed increase in global temperatures since the preindustrial era (IPCC, 2007). The global energy sector, including the fuels consumed for electricity and heat generation, is consistently identified as the largest contributor to human-induced CO_2 emissions, reaching a new all-time high of 37.8 Gt CO_2 in 2024 (IAE, 2025b). Within total energy-related CO_2 emissions, the power sector occupies a distinctive position: although it remains the main contributor to global emissions with 13.8 Gt CO_2 in 2024 (IAE, 2025a), roughly 40% of global energy-related emissions,[1] it represents a key lever to deep decarbonization of the economy. In this context, this paper assesses whether the European Union's target of achieving 15% cross-border electricity interconnection capacity by 2030 can facilitate the decarbonization of the power sector.

The European Union's emission reduction trajectory, partly offset at the global level by the increasing emissions of more carbon-intensive emerging and developing economies, led energy supply to become the second largest source of GHG emissions in the EU for the first time in 2024 (European Environment Agency, 2025)[2]. This trend is significantly driven by the decrease in the power sector and structural shifts in the electricity mix over the past two decades (Graham et al., 2025). The integration of cleaner energy sources for power generation supported by policy mandates, falling technology costs and market incentives introduced by the European Union's Emissions Trading System (ETS) have made Europe to be the least CO_2

[1] This share is slightly decreasing, while staying in the same order of magnitude compared to the 2015 level (Ang and Su, 2016).

[2] Domestic transport: 25%. Energy supply: 23%. Industry: 19%.

intensive region worldwide for electricity generation (European Commission, 2024; IAE, 2025a).[3] Still, efforts should be pursued and increased to comply with both European legislation[4] and the Paris Agreement temperature goals (UNFCCC, 2015).

Therefore, most attention has been paid to energy transition pathways[5] to increase the share of renewable carbon-free generation within the power mix. However, a central challenge introduced by high shares of Variable Renewable Energy Sources (VRES) is the flexibility of the power system that refers to the ability to match supply and demand in real time. Flexibility options include dispatchable generation, energy storage (e.g., batteries, pumped hydro), demand response, sector coupling (e.g., vehicle-to-grid technologies), and market coupling. In this context, cross-border electricity interconnections serve as a systemic flexibility instrument by allowing power exchanges between regions with differing production profiles and demand patterns. The economic literature on the integration of the electricity market (see Section 2) demonstrates that interconnections can lower system costs and facilitate the deployment of low-carbon technologies under competitive market conditions. Thus, Transmission System Operator(s) (TSO(s)), policy makers and academic advisors[6] often emphasize this argument to justify network development plans. However, the net environmental impact of interconnections remains ambiguous ex ante. Increased transmission capacity may sometimes favor the dispatch of fossil-fueled generation in exporting regions, depending on relative marginal costs and regulatory frameworks. This ambiguity underscores the need to evaluate the effects of grid expansion on

[3]From 2022 to 2023 the carbon dioxide due to electricity and heat generation fell by 24% in the EU ETS.

[4]The European Climate Law enshrines the objective of achieving net-zero GHG by 2050, and the "Fit for 55" legislative package (European Parliament and the Council of the European Union, 2021) commits the EU to reduce net emissions by at least 55% by 2030 relative to 1990 levels across the economy. Under Fit for 55, ETS sectors - including power generation - are subject to increasingly stringent caps to reach -62% by 2030 compared to 2005 levels (European Commission, 2021).

[5]For a historical critique of the concept of energy transition, see Fressoz (2024).

[6]Joskow, Transmission Capacity Expansion Is Needed to Decarbonize the Electricity Sector Efficiently, Joule (2020), https://doi.org/10.1016/j.joule.2019.10.011.

production portfolios and aggregate emissions.

The EU Climate and Energy framework endorsed by the European Council in 2014 set for each member state an objective of total electricity interconnection capacity of 15% of its own domestic production capacities by 2030.[7] Recent reports indicate that most of Western European countries that are below this threshold are expected to miss the target.[8] Using the PyPSA-Eur modeling framework, we assess the impact of this interconnection target on the European electricity generation mix and the resulting CO_2 emissions.

This paper contributes to the literature on electricity market integration and decarbonization in three ways. First, it provides a quantitative assessment of the European Union's 15% cross-border electricity interconnection target by 2030 using a detailed power system optimization model. Second, it evaluates how increased transmission capacity affects the allocation of flexibility options and the structure of electricity generation across interconnected countries. Third, it assesses the environmental implications of grid expansion by examining the impact of alternative system-wide CO_2 emission caps on optimal cross-border transmission levels, and the interaction between interconnection policies and alternative CO_2 emission constraints. Our results show that implementing the interconnection target alone leads to only marginal reductions in CO_2 emissions relative to the baseline, and slight shifts in the power generation mix. Although 15% is not cost-optimal for each country, significant changes in electricity generation and decreases in GHG are obtained with enhanced cross-border interconnections, suggesting substitutions within flexibility options. The replacement of fossil-based dispatchable generation by transmission infrastructures enables higher renewable penetration, reducing both the need for re-

[7] *REGULATION (EU) 2018/1999 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL - of 11 December 2018 on the Governance of the Energy Union and Climate action*, European Parliament and the Council of the European Union (2018).

[8] Geneletti and Cremona (2025). Effective interconnection rates per country are available at https://energy.ec.europa.eu/topics/infrastructure/electricity-interconnection-targets_en.

newable curtailment and the requirement of flexible fossil plants. Thus, it facilitates deeper decarbonization, even more in the context of stringent CO_2 emission caps. Last but not least, stronger cross-border interconnections associated with CO_2 policy constraints reshape cross-border electricity flows at the expense of Germany, the most carbon-intensive country in our sample.

The rest of the paper is organized as follows. Section 2 reviews the literature and Section 3 describes the modeling framework. Following the data presentation in Section 4, Section 5 details the scenario design and policy assumptions. Section 6 is devoted to our findings, and Section 7 concludes the paper.

2. Related literature

The literature on market integration applied to energy markets, especially electricity markets, has generated a large body of research. Whether researchers focus on the degree of market integration and its consequences on commercial outcomes (Newbery et al., 2016; Bower, 2004; Robinson, 2007, 2008; Zachmann, 2008; Huisman and Kiliç, 2013), technical considerations (Chalvatzis and Ioannidis, 2017; Van Den Bergh et al., 2016; Schönheit et al., 2022; Fabra, 2023), or the main obstacles that prevent deeper integration, this topic has been widely explored.

A first strand of the literature highlights the economic benefits associated with the integration of electricity markets and the development of cross-border interconnections. Brinkerink et al. (2019), for instance, provide a typology of expected benefits and challenges related to the integration of power markets and the expansion of cross-border interconnectors. Although their review focuses on intercontinental "supergrids", many of the identified mechanisms also apply to smaller regional networks. In particular, interconnections can constitute a cost-effective alternative to meeting growing electricity demand in one region compared with the construction of new generation capacity (Abrell and Rausch, 2016). Conversely, they may increase the profitability of renewable investments by creating additional outlets for Renewable

Energy Sources-Based Electricity (RES-E) production. Market coupling also contributes to reducing price discrepancies between areas while improving the diversity of power sources and, consequently, the security of supply (Abrell and Rausch, 2016).

A second strand of the literature emphasizes the role of grid expansion and interconnections in facilitating the integration of VRES. In this perspective, transmission networks can be viewed as a key flexibility instrument allowing electricity systems to accommodate higher shares of intermittent generation (OECD, 2013). Flexibility options such as enhanced cross-border electricity exchanges, energy storage capacities,[9] dispatchable generation and demand-side response are necessary to maintain the balance between supply and demand in systems with large shares of VRES. Interconnections between neighboring power systems allow regions experiencing low renewable generation to import electricity from areas with higher renewable output, thereby mitigating the variability of renewable production. As a result, grid development can reduce congestion in transmission networks and limit the curtailment of renewable generation (Allard et al., 2020). Consistent with the expected increase in renewable deployment in Europe,[10] Child et al. (2019) show that a cost-optimized scenario compatible with a 100% renewable electricity system in Europe relies on a high level of regional interconnection, with additional cost savings achieved as transmission capacity expands. Similarly, the Ten Year Network Development Plan (TYNDP) 2024 report[11] indicates that expanding cross-border capacity could significantly reduce renewable curtailment, potentially avoiding around 30 TWh of curtailed electricity per year in the European Union by 2030. Geographical differences in renewable resource potential[12] and time-zone differences further reinforce the po-

[9] For further developments specifically dedicated to storage capacity as a flexibility option, see Zafirakis et al. (2015); Gunkel et al. (2020).

[10] In the *REPowerEU Plan communication*, European Commission (2022), the Commission proposed to increase the target in the Renewable Energy Directive to 45% of renewables within the total electricity production by 2030.

[11] ENTSO-E (2025).

[12] Periods of high consumption on each side of the transmission pathway occur simultaneously with off-peak hours on the other side, roughly reflecting the day-night cycle on each side.

tential gains from cross-border electricity trade (Boie et al., 2016). Empirical studies also provide evidence on the interaction between renewable generation and cross-border electricity trade. Using a panel fixed-effects model, Boz et al. (2021) show that the interaction between wind and solar generation and cross-border electricity trade tends to reduce the share of gas-fired generation in the long run. Their results also indicate that increased cross-border electricity trade is associated with a greater use of RES-E[13] in countries experiencing positive economic growth. Similarly, Jha et al. (2022) find empirical support for a positive causal effect from cross-border electricity trade on the share of renewable generation.

A third strand of the literature focuses more specifically on the environmental implications of grid expansion and electricity trade. The environmental impact of electricity networks can arise either directly, through the life cycle of network infrastructures (construction, maintenance and decommissioning), or indirectly through their effects on electricity generation mixes and cross-border electricity flows. Regarding direct impacts, Jorge and Hertwich (2014) show that upgrading the European power grid to accommodate higher shares of intermittent generation would lead to an increase of 10.7 Mt of CO_2 emissions and 11.2 Mt Fe eq. by 2020.[14]

Most studies, however, focus on the indirect effects of increased cross-border electricity trade on greenhouse gas emissions. Deng et al. (2024) show that improved grid integration facilitates the integration of VRES and delays the use of fossil-based generation technologies, thereby contributing to lower GHG. In a global modeling framework, Aboumahboub et al. (2012) show that large-scale wind deployment combined with high carbon prices could reduce CO_2 emissions by 78% relative to 2020 levels, provided that transmission interconnections are significantly expanded. However, other studies highlight that the environmental impact of grid expansion is not

[13]The share of solar and wind in total electricity production compared to the share of solar and wind in total installed capacity.

[14]Modeling based on the *Ten-Year Network Development Plan 2012*, ENTSO-E (2012).

necessarily unambiguously positive. Mezősi et al. (2016), analyzing the European Union's 10% interconnection target, find that improved market integration could slightly increase CO_2 emissions if considered in isolation. Similar results are obtained by Brancucci Martínez-Anido et al. (2013), who emphasize the importance of combining grid expansion with appropriate carbon pricing policies. Abrell and Rausch (2016) reach comparable conclusions: while greater interconnection can reduce emissions in systems with sufficiently high shares of renewable energy, grid expansion at lower renewable penetration levels may instead facilitate the dispatch of low-cost, high-emission coal-fired generation. Evidence from China points to similar mechanisms (Li et al., 2016).

Overall, the literature suggests that the environmental consequences of expanding electricity interconnections depend crucially on the structure of the generation mix and the policy framework governing electricity markets. In particular, the level of renewable penetration and the coordination of climate and energy policies across interconnected countries appear to be key determinants of the resulting emissions outcomes.[15] Recent work by Beltrami et al. (2024) further emphasizes the role of international electricity trade in shaping emission patterns across countries by improving the measurement of Marginal Emission Factors (MEFs), which capture the emissions associated with the marginal unit of electricity generation.[16] Their results show that cross-border electricity trade can significantly modify the carbon content of electricity consumption depending on the exporting country.[17]

[15] Within the European Union, the energy policy belongs to the shared competence between the Union and the Member States according to Article 4, paragraph 2, i) TFEU (Treaty on the Functioning of the European Union). Article 194 TFEU defines the EU energy policy goals, strictly regulated on behalf of the subsidiarity principle laid down in Article 5 TEU (Treaty on European Union). Hence, legal framework around energy policy questions both the EU and the Member States means of influence to converge towards optimal RES policies.

[16] As opposed to the overall carbon footprint of the grid given by Average Emission Factors (AEFs).

[17] The study focuses on the German case and shows that the additional German electricity sector emissions for any additional MWh of exported electricity to neighboring markets amounts to 0.94 tons of CO_2 on average, which is quite intense and suggests that extra-demand is met thanks to

Against this background, the present paper evaluates the implications of the European Union's 15% cross-border electricity interconnection target for the evolution of the electricity generation mix and associated CO_2 emissions. Using the PyPSA-Eur modeling framework, we analyze how increased transmission capacity interacts with different emission constraints to shape electricity production and cross-border power flows in Western Europe.

3. Modeling framework: PyPSA-Eur

3.1. Components and model structure

This paper builds on the open-source PyPSA framework (Brown et al., 2018) and the PyPSA-Eur workflow extension (Hörsch et al., 2018). The model represents the power system as a network of buses connected by transmission lines and links, with generators, storage units, and loads attached to each node. Power flows are modeled using a linearized approximation of the Alternating Current (AC) power flow equations. The PyPSA-Eur workflow is based on open data (see Section 4) and covers the entire European Network of Transmission System Operators for Electricity (ENTSOE) area. The model offers a wide range of configurable settings to design various scenarios, as well as allowing users to implement additional custom constraints. We use both tools to implement the specific policy constraints in terms of the minimum cross-border interconnection rate and the carbon emission caps (see Section 5).

The large-scale linear optimization model of the European electricity system is designed to compute the long term cost-optimal power system, including both investment costs and short-term costs. The optimization solves a cost-minimization problem, which determines generation, storage, and transmission capacities, as well as dispatch at hourly resolution, subject to operational and policy constraints (see Section 3.4). The problem is formulated as a linear program and solved using the

hard coal- or lignite-fired german power plant.

HiGHS solver by default.[18]

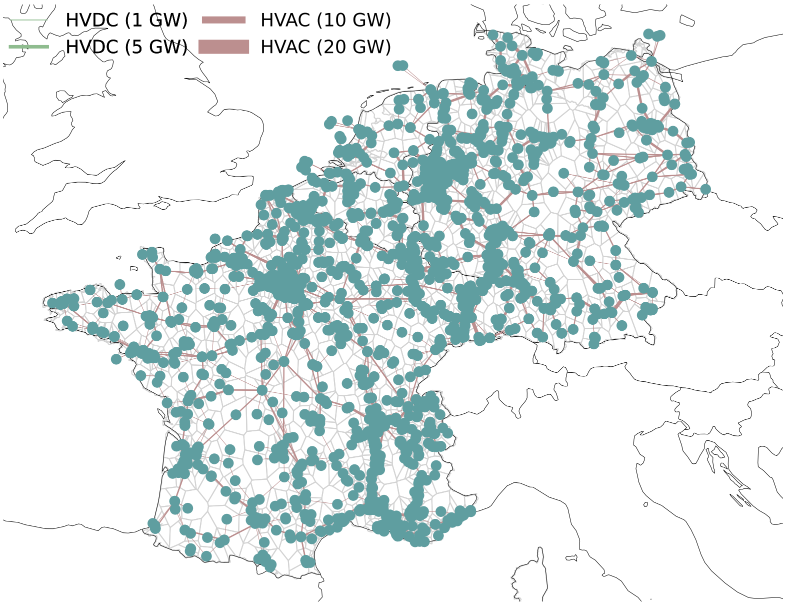
3.2. Temporal and spatial resolution

The electricity system is represented using a nodal network structure, where each node corresponds to an aggregated geographical region. To keep our model computationally manageable, the geographical scope of our analysis is reduced to France, Germany, Belgium, the Netherlands, and Luxembourg, represented in a spatial resolution of 10 clusters as shown in Figure 1b. This clustering approach enables a detailed representation of spatial heterogeneity while maintaining computational tractability.[19]

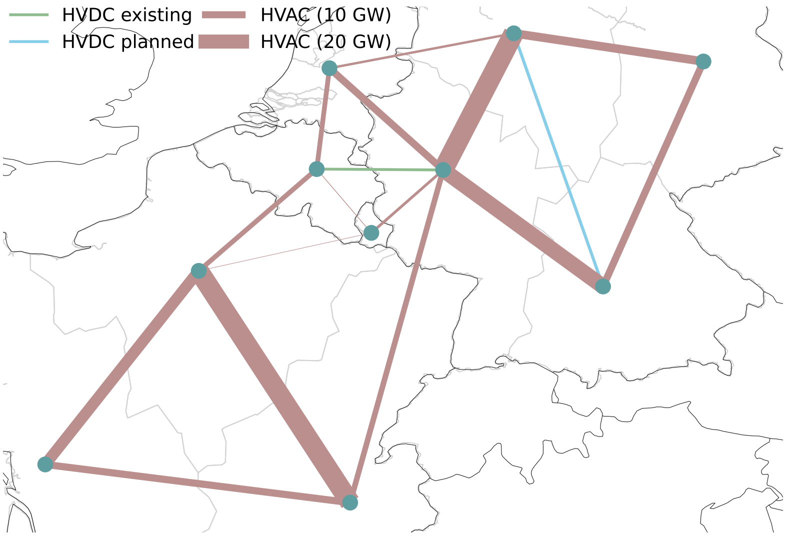
The temporal resolution of the model is hourly over one full year, resulting in 8760 hourly time steps. This resolution allows capturing the variability of electricity demand and renewable generation, particularly wind and solar power. Weather-dependent renewable generation and demand profiles are therefore represented using historical hourly time series of 2019 exogenously defined representative meteorological year (see Section 4.2 and Table 1). The hourly resolution ensures that both short-term operational constraints and long-term investment decisions are accurately represented within the optimization framework.

[18]Alternative solvers are compatible with PyPSA.

[19]A detailed description of the clustering method is given in Horsch and Brown (2017).



(a) Base network



(b) 10 clustered network

Figure 1: Representative networks

Note: This figure displays the base network covering the countries of our panel (1a) and the 10 clustered network used in our optimization problem (1b).

3.3. Foresight and investment formulation

In addition, the model uses an "overnight" optimization formulation. This setting ensures that the model is implemented on a single-year target, representing a cost-optimal equilibrium of the electricity system for the selected target year. As we focus on the year 2030, the cost assumptions for the technologies involved correspond to projections for 2030 (see Section 4.4 and Table 2). This formulation supposes perfect foresight within the modeled year, assuming that demand and renewable generation profiles are known in advance and that all investment decisions are assumed to be made simultaneously for 2030 without inter-temporal dynamics.[20]

The model therefore determines the optimal capacity expansion and dispatch strategy required to meet electricity demand at minimum cost while satisfying all technical and policy constraints. Both investment and operational decisions are optimized jointly to minimize total system costs, including annualized capital costs (Capital Expenditures (CAPEX)) and operational costs (Operational Expenditures (OPEX)). This approach is widely used in large-scale power system planning models and enables a direct comparison between different policy and infrastructure scenarios.

To address the issue of compliance with the network development policy, minimum cross-border interconnection requirements are explicitly modeled in some scenarios prior to the endogenous determination of transmission expansion by PyPSA. Indeed, we introduce a country-level interconnection capacity constraint that requires the total transnational transmission capacity to meet at least a minimum share of domestic generation capacity, reflecting the 15% interconnection target set by the EU. Furthermore, selected scenarios impose annual emission caps of CO_2 consistent with alternative policy assumptions for the 2030 temporal horizon.

[20]This foresight option "overnight" is opposed to the "myopic" configuration in which investments decisions in successive planning horizons are built on top of the previous planning horizon; details are available at https://pypsa-eur.readthedocs.io/en/latest/foresight.html.

3.4. Mathematical formulation: linear optimization problem

Based on Brown et al. (2018) and Hörsch et al. (2018), we define the following indices applied to the sets of decision variables. Each bus $n \in N$ represents a spatial node of the network belonging to the country $c \in C$ and is connected to other buses through AC lines $l \in L$ and High Voltage Direct Current (HVDC) links $k \in K$. Each bus is composed of generation-type installations $g \in G$ and storage units $h \in H$. The time-step is defined by the index $t \in T$ (hours). The first set of decision variables represents the investment variables composed of G_g the installed capacity of the generator type g; F_l the transmission capacity of the line l; H_k the transmission capacity of the link k; and E_s the energy storage capacity. The dispatch variables represent the second set of decision variables. The output of the generator g at each time t is defined by $p_{g,t}$ whereas $f_{l,t}$ and $h_{l,t}$ are the power flows on line l and link k, respectively. The storage state of charge is defined by $soc_{s,t}$. PyPSA-Eur minimizes total system costs through the given objective function:

$$\min \left[\sum_g c_g^{inv} G_g + \sum_l c_l^{inv} F_l + \sum_k c_k^{inv} H_k + \sum_t w_t \left(\sum_g c_g^{var} p_{g,t} \right) \right] \tag{1}$$

where c^{inv} represents the annualized capital cost, c^{var} the generation-dependent marginal cost, and w_t the snapshot weight. The minimization function is subject to the power balance constraint at each node given by Equation (2):

$$\sum_{g \in n} p_{g,t} + \sum_{s \in n} p_{s,t}^{out} - \sum_{s \in n} p_{s,t}^{in} - d_{n,t} = \sum_{l \in n} f_{l,t} + \sum_{k \in n} h_{k,t} \tag{2}$$

where $p_{s,t}^{in} \geq 0$ represents the charging phase when storage units absorb power, while $p_{s,t}^{out} \geq 0$ corresponds to the discharging phase when power is injected into the network.

The generator dispatch limits are given by Equation (3) where $a_{g,t}$ denotes the availability factor applied to the wind and solar series and G_g^{max} is the maximum geographical renewable potential derived from land-use data (see Section 4.2.2). There is no unit commitment in the generator pattern:

$$0 \leq p_{g,t} \leq G_g \cdot a_{g,t} \tag{3}$$

$$G_g \leq G_g^{max} \tag{4}$$

The transmission capacity constraints are defined as follows for both AC lines and HVDC links:

$$-F_l \leq f_{l,t} \leq F_l \tag{5}$$

$$-H_k \leq h_{k,t} \leq H_k \tag{6}$$

Linearized power flow corresponding to the Direct Current (DC) approximation is defined as follows, with B_l the susceptance and θ the voltage angle:

$$f_{l,t} = B_l(\theta_{n,t} - \theta_{m,t}) \tag{7}$$

The storage dynamics are defined by Equations (8) and (9), where η^{in} is the efficiency of the storage unit during the storage phase and η^{out} the efficiency during the dispatch:

$$soc_{s,t} = soc_{s,t-1} + \eta^{in} p_{s,t}^{in} - \frac{1}{\eta^{out}} p_{s,t}^{out} \tag{8}$$

$$0 \leq soc_{s,t} \leq E_s \tag{9}$$

When implemented, additional constraints related to carbon emissions and minimum level of cross-border transmission capacity are given by the following Equations (10) and (11):

$$\sum_t \sum_g e_g p_{g,t} \leq CAP \tag{10}$$

$$\sum_{l \in \partial c} F_l + \sum_{k \in \partial c} H_k \geq 0.15 \cdot GenCap_c^{ref} \quad (11)$$

where e_g is the emission factor (tCO_2/MWh), CAP is a scenario-dependent limit, ∂c cross-border lines incident to the country c, and $GenCap_c^{ref}$ is the installed generation capacity in our baseline scenario. The interconnection constraint is defined relative to the installed generation capacity at the baseline in order to preserve the exogenous nature of the policy target.[21] The factor 0.15 represents the 15% interconnection target set by the European Commission to be reached by 2030.[22]

4. Input data

PyPSA-based models are data-driven modeling tools that require large amounts of data to build and solve electricity networks. The global workflow is designed to retrieve and clean the data from different datasets and sources. Hörsch et al. (2018) describe the input data processing in PyPSA-Eur in its very first implementation, which has since been improved in different ways. Table 1 gives an overview of the main tools and data providers used for each input dataset in our model.[23]

[21]Unlike, using endogenous generation capacity would create a structural coupling between investment decisions in generation and transmission, potentially leading to distorted optimization behavior.

[22]The interconnection ratio used in this paper is defined as the sum of nominal (thermal) cross-border transmission capacities incident to a country divided by its installed generation capacity, which differs from the indicator of the European Commission, which relies on commercially available Net-Transfer Capacity (NTC). As a result, the values reported here are structurally higher, reflecting physical transfer limits rather than market-based.

[23]The complete data inventory that we used is available in the /data_inventory.csv file of our project repository. PyPSA-Eur documentation also maintains the updated list of data sources at https://pypsa-eur.readthedocs.io/en/latest/data_sources.html.

Table 1: Input data

Input data	Additional external process tool	Main raw dataset or sources	Owner
Base network	OpenStreetMap (OSM) Overpass Turbo API	OSM Data NUTS Data	OSM contributors Eurostat
Generation			
Conventional generation	powerplantmatching (PPM) toolset	Open Power System Data (OPSD) Global Energy Observatory (GEO) OSM Power Plants	PPM contributors
Renewable generation	PPM toolset atlite software	ERA5 SARAH3 CORINE Natura2000 LUISA EEZ Global Shipping Traffic Density GEBCO NUTS EIA - Hydroelectric data Runoff data	ECMWF CMSAF Copernicus EEA JRC MarineRegions Worldbank GEBCO Comilation Group Eurostat EIA F. Neumann
Demand		OPSD ENTSOE Transparency Platform JRC IDEES JRC Energy Atlas JRC Ardeco	 ENTSOE JRC JRC JRC
Technology costs & emission factors		technology-data repository	technologydata contributors

Note: This table reports the main data sets/sources implied to generate the input data of our PyPSA-Eur model. Column 2 "Additional external process tool" only refers to specific toolboxes and software used to retrieve and clean raw data, in addition to the standard PyPSA-Eur workflow (e.g., "Demand" input data only relies on PyPSA-Eur rules and scripts to retrieve clean raw data, before building the demand time series required for the optimization).

4.1. Base network

The network topology, buses, generators, transformers, converters, transmission lines and links are derived from the open access OpenStreetMap[24] dataset to build the European high-voltage transmission grid. The way in which the base network is contructed from OpenStreetMap data is described in the PyPSA-eur documentation[25] and in Xiong et al. (2024).

4.2. Generation

4.2.1. Conventional generation

Conventional generators include 8 carrier-types, including nuclear, oil, Open-Cycle Gas Turbines (OCGT), Combined-Cycle Gas Turbines (CCGT), coal, lignite, geothermal, and biomass power plants. The complete dataset of power plants used by PyPSA-Eur is produced by using the powerplantmatching (PPM) tool.[26] OCGT technology is modeled as an extendable carrier. Its aggregate capacity can increase during the optimization process subject to a building location constraint so that OCGT generator units can only be expanded where they already exist today.

4.2.2. Renewable generation

Renewable generation power plants are obtained following the same mechanism as conventional plants on the basis of historical data, and are then combined with meteorological data to account for their weather-dependent availability. Thus, the atlite tool (Hofmann et al., 2021) is used to compute the time series of the hourly capacity factor (parameter $a_{g,t}$ in Equation (3)) for renewable plants. The time-varying hydro-electric and wind turbine profiles are derived from the ERA5 dataset[27] while the SARAH-3[28] provides solar irradiation data to compute the photovoltaic

[24] Previous version of PyPSA-Eur used to retrieve network data from ENTSOE Interactive Map as described in Hörsch et al. (2018).

[25] The detailed documentation is available at https://pypsa-eur.readthedocs.io/en/latest/data-base-network.html.

[26] Further documentation on the PPM tool is available in Gotzens et al. (2026) and at https://powerplantmatching.readthedocs.io/en/latest/.

[27] Source: European Center for Medium Range Weather Forecasts (ECMWF).

[28] Source: EUMETSAT Climate Monitoring Satellite Application Facility (CMSAF).

generation capacity factor. We chose 2019 as the reference weather year because it is close to the average of global temperature from 2015 to 2025.[29] Like OCGT, wind and solar generation are modeled as extendable technologies.[30] The maximum installable capacities for wind and solar generation (parameter G_g^{max} in Equation (4)) are determined using geographical eligibility analyses performed with atlite. These analyses combine land-use data,[31] protected areas,[32] and offshore constraints[33] to derive spatially explicit capacity potentials at each network node.

4.3. Demand

Electricity demand is represented as an exogenous, inelastic hourly time series based on historical data from ENTSOE. National demand profiles are spatially disaggregated to network nodes proportionally to regional population and economic activity indicators,[34] ensuring consistency with the geographical structure of the transmission network. This approach preserves both the temporal variability observed in historical data and the spatial distribution of electricity consumption across regions.

4.4. Technology costs and emission factors

The technology cost assumptions are based on publicly available cost datasets, including capital costs (CAPEX), operating costs (Fixed Operational and Maintenance (FOM); Variable Operational and Maintenance (VOM)), efficiencies and lifetimes. Investment costs are annualized using standard financial assumptions.[35] Data are derived from a variety of sources synthesized in the Energy System Technology

[29] ERA5 database (source: ECMWF).

[30] Battery storage units are also modeled as extendable technologies.

[31] CORINE Land Cover database (source: Copernicus), LUISA Base map database (source: JRC).

[32] Source: Natura2000 protected areas database (source: European Environment Agency).

[33] Exclusive Economic Zone (EEZ) maritime boundaries database (source: Marine Regions), Global Shipping Traffic Density database (source: Worldbank), GEBCO Oceans database (source: GEBCO Comilation Group).

[34] Mainly JRC IDEES, JRC Energy Atlas and JRC Ardeco databases (source: JRC).

[35] Investment costs given under CAPEX column are annualized to net present costs, using an annuity factor α depending on a discount rate r set to 7%, over the technology lifetime n: $\alpha = \frac{1-(1+r)^{-n}}{r}$.

Data repository.[36] In addition, technology-specific emission factors associated with fuel combustion are also implemented in the costs file. The assumptions on energy system technologies and CO_2 emissions are chosen for the year 2030 relevant with the target year optimization of our analysis. The following Table 2 gives the cost assumptions and emission factors for the key technologies of the model.

Table 2: Relevant cost and emission factors assumptions in 2030

	CAPEX (unit)	FOM (%/year)	VOM (€/MWh)	Fuel (€/MWh_{th})	Emission factor (tCO_2/MWh_{th})	Lifetime (years)	Expandable
Transmission							
Overhead HVAC	750.0 (€/MW/km)	1.5	-	-	-	40	Yes
Underground/Submarine HVAC	4510.0 (€/MW/km)	2.5	-	-	-	40	Yes
Overhead HVDC	600.0 (€/MW/km)	1.5	-	-	-	40	Yes
Underground HVDC	4070.0 (€/MW/km)	2.5	-	-	-	40	Yes
Submarine HVDC	3220.0 (€/MW/km)	2.5	-	-	-	40	Yes
Technology							
Nuclear	-	1.27	4.459	7.4536	0	40	No
Oil	-	2.463	8.0148	43.6295	0.2571	25	No
OCGT	581.3949 (€/kW)	1.7795	6.0111	28.4158[37]	0.198	25	Yes
CCGT	-	3.3494	4.2329	28.4158	0.198	25	No
Coal	-	1.31	4.1005	7.8202	0.3361	40	No
Lignite	-	1.31	4.1005	7.9423	0.4069	40	No
Geothermal	-	2.0	0[38]	0	0.12	30	No
Biomass	-	4.5269	2.8049[39]	9.3506	0[40]	30	No
Waste	-	2.355	35.4254	0	0	25	No
Solar	683.1462 (€/kW)	1.9495	0.0134	0	0	40	Yes
Offwind	2114.991 (€/kW)	2.3185	0.0267	0	0	30	Yes
Onwind	1383.3059 (€/kW)	1.2167	1.8033	0	0	30	Yes
Hydro	-	1.0	0	0	0	80	No
Run-of-River	-	2.0	0	0	0	80	
Storage							
Battery storage	189.861 (€/kWh)	-	-	-	-	25	Yes
Pumped-Hydro-Storage[41]	-	1.0	-	-	-	80	No
Reservoir and Dam[42]	-	0.43	-	-	-	60	No

Note: This table reports the main cost and emission factors assumptions for the reference year 2030, implemented in the techno-economic optimization process in our PyPSA-Eur model. Values in column 2 "CAPEX" are only reported for extendable carriers, highlighting the idea that new investments would be required.

[36] Further descriptions of data sources related to technology costs are available at https://technology-data.readthedocs.io/en/latest/.

5. Scenario design and policy assumptions

5.1. Baseline

The baseline scenario (B) represents the cost-optimal electricity system in the absence of additional policy constraints on cross-border interconnection capacity or CO_2 emissions beyond those included in the standard model formulation. It serves as a reference case against which all subsequent scenarios are compared.

Generation, storage, and transmission capacities are treated as endogenous investment variables. The model determines the optimal expansion of conventional and renewable extendable generation technologies, electricity storage systems, and cross-border transmission infrastructure simultaneously, subject only to the technical and operational constraints described in Section 3.4 from Equations (1) to (9). Transmission capacities of both AC lines and HVDC links are therefore optimized within the cost-minimization framework, allowing the model to determine economically efficient interconnection levels across countries. In this scenario, no minimum interconnection requirement is imposed and no additional CO_2 emission cap is introduced. The resulting system configuration corresponds to the least-cost equilibrium under assumed technology costs, demand profiles, and the availability of renewable resources for 2030.

Importantly, the baseline scenario provides the reference generation capacities at the country level, which are subsequently used to compute the minimum intercon-

[37]Fuel and emission factor values from OCGT and CCGT are reported under the label "gas" in the cost file.

[38]This value is not defined in the cost file, thus the value of 0 comes from Aghahosseini and Breyer (2020) where the geothermal FOM value of 2%/year was taken.

[39]This value comes from the label "biomass EOP (Electricity-Only-Plant)" in the cost file.

[40]The label "solid biomass" alternatively gives the value 0.3667.

[41]PHS is modeled as a Link component in PyPSA that converts storage to power generation and vice versa.

[42]This parameter is modeled as a Store component in PyPSA and corresponds to the label "Pumped-Storage-Hydro-store" in the cost file.

nection targets in the transmission expansion (TE) scenarios. For each country c, total installed generation capacity obtained in the baseline is used to define the 15% interconnection benchmark applied in Section 5.2. This ensures internal consistency between the reference system configuration and the policy-based interconnection constraint introduced in the subsequent scenarios.

5.2. Cross-border transmission expansion (TE) constraint

To assess the implications of minimum interconnection requirements, we introduce a policy-based constraint that reflects the EU's interconnection target for 2030. This target aims to ensure that each Member State maintains a level of cross-border transmission capacity equivalent to at least 15% of its installed generation capacity and allows us to isolate the structural and economic impacts of enforcing minimum cross-border interconnection standards within a cost-optimal electricity system framework.

In order to translate this policy objective into a model-consistent constraint, we define country-specific interconnection benchmarks based on the baseline scenario described in Section 5.1. For each country $c \in C$, the total installed generation capacity in the baseline scenario is calculated as:

$$GenCap_c^{ref} = \sum_{g \in G_c} G_g^{baseline} \tag{12}$$

where G_c denotes the set of generators located in country c, and $G_g^{baseline}$ is the optimized installed capacity of the generator g in the baseline scenario (B). The minimum required interconnection capacity constraint is then defined in Equation 11. In the TE scenario, this benchmark is imposed as a lower bound on the total cross-border transmission capacity incident to each country. Only cross-border elements are included in this aggregation.

Transmission capacities remain endogenous decision variables in this scenario. By defining the benchmark relative to the optimized baseline generation capacity, the 15% *TE* constraint is internally consistent with the modeled system configuration and avoids exogenous assumptions about national capacity levels. The model is therefore free to determine economically optimal interconnection levels above the minimum threshold, but it cannot fall below the 15% benchmark. This formulation ensures that the interconnection target acts as a binding floor rather than a fixed capacity requirement, consistent with the definition provided by the European Commission.

5.3. CO_2 cap assumptions

Combating global warming through the shift in energy mixes of our economies must regard carbon emissions in absolute terms. As future demand is expected to increase due to the electrification of transport, heating, and industrial processes, it is of primary importance to differentiate between relative shares and absolute emission reductions, as cumulative CO_2 emissions continue to accumulate over time even when carbon intensity declines. Annual assessments suggest continued growth in renewable output, but also highlight that fossil fuel generation persists in many countries, reflecting both technological and institutional inertia in energy systems.

In addition to the interconnection constraint introduced in Section 5.2, we complete the analysis with emission constraints. On the one hand, we assess the impact of alternative system-wide CO_2 emission caps on optimal cross-border transmission levels. On the other hand, we test how the interaction between the 15% transmission expansion policy constraint and the alternative CO_2 emission caps modifies the power network output.

These caps are implemented as annual upper bounds on total electricity-sector emissions in the five modeled countries to ensure a reduction in total GHG and not only the increasing share of carbon-free RES. Total CO_2 emissions are calculated as the sum of emissions from fossil-fuel-based electricity generation over all time steps as described in Equation (10). The emission constraint is applied at the aggregated regional level (France, Germany, Belgium, the Netherlands, and Luxembourg combined), rather than individually for each country. This formulation reflects the integrated nature of the electricity market and allows cross-border trade to contribute to cost-efficient emission reductions. Three levels of the emission cap are considered:[43]

- C_{250} (emissions cap = 250 $MtCO_2$): a relatively relaxed constraint that allows moderate fossil fuel generation while limiting overall emissions.
- C_{190} (emissions cap = 190 $MtCO_2$): a policy-based constraint aligned with projected levels for 2030 according to the assumptions of the EU's climate policy.
- C_{120} (emissions cap = 120 $MtCO_2$): a stringent constraint that represents a high-ambition decarbonization pathway.

The CO_2 caps are implemented in combination with the 15% cross-border *TE* constraint for the scenarios $TE{+}C_{250}$, $TE{+}C_{190}$, and $TE{+}C_{120}$, while the scenarios C_{250}, C_{190}, and C_{120} relax the *TE* requirement to compare the outcome of the optimization. Table 3 displays the different constraints applied for each scenario. Generation, storage, and transmission capacities remain endogenous decision variables, and the model determines the least-cost system configuration capable of meeting both the interconnection requirement and the specified emission limit. By comparing these scenarios, we evaluate how varying levels of climate stringency interact with minimum interconnection standards and influence optimal generation mixes, cross-border flows, system costs, and infrastructure deployment.

Table 3: Summary of scenarios

	B	TE	TE+C_{250}	C_{250}	TE+C_{190}	C_{190}	TE+C_{120}	C_{120}
TE 15%	-	✓	✓	-	✓	-	✓	-
CO_2 emission cap:								
250 $MtCO_2$	-	-	✓	✓	-	-	-	-
190 $MtCO_2$	-	-	-	-	✓	✓	-	-
120 $MtCO_2$	-	-	-	-	-	-	✓	✓

[43] The three levels calculation method is described in Appendix A.

6. Results and discussion

6.1. Cross-border interconnection levels

Our first result shows that the baseline optimized system by 2030, in the absence of policy constraints, consistently results in an increase in cross-border capacity compared to the current system for all countries. However, this increase does not yet meet the 15% target for countries that were below this rate initially. Hence, the second and main focus of our analysis addresses how the lower cross-border transmission capacity bound interacts with the other constraints of the model. The results reported in Table 4 and in figure 2 suggest that for Germany and France, which did not reach the 15% cap in the baseline, the interconnection target acts as an imposed threshold to meet, but without any additional benefits from exceeding this threshold.[44] Indeed, Germany and France reach the 15% level when it is mandated but do not go beyond it to further minimize system costs.[45]

Furthermore, our results suggest that grid development is not the cost-effective tool to reach CO_2 reduction caps. The analysis of *C-type* scenarios shows that for the three levels of emission defined (250 $MtCO_2$, 190 $MtCO_2$, and 120 $MtCO_2$) the cost-optimal electricity system is obtained at interconnection levels below 15% for Germany and France when the *TE* constraint is relaxed. Focusing on results where interconnection levels are fully endogenous[46] demonstrates that even though countries tend to increase their interconnection levels from the *Ex ante* configuration (before optimization) to C_{120}, they display specific patterns of variation depending on scenario stringency. The evolution of the cross-border interconnection rate in France and in the Netherlands is linear and continuously grows with carbon emission

[44]Table F.14 in Appendix F confirms this statement for sensibility runs based on 2050 cost assumptions. Despite alternative technology projections for 2050 decrease the transmission infrastructure costs, benefits from exceeding the 15% threshold are only observed for Germany in the most stringent scenario $TE^{2050}+C_{120}$.

[45]The reference values from which the percentages are derived are reported in Table B.11 in Appendix B.

[46]This corresponds to B, C_{250}, C_{190}, and C_{120} scenarios.

stringency. In contrast, Belgium, Germany, and Luxembourg experience fluctuations in the overall growing trend: rate decreases are observed in Belgium between B and C_{250}, in Germany between C_{190} and C_{120}, and in Luxembourg from Baseline to C_{190}. These fluctuations do not affect the linear downward trend in total CO_2 emissions shown in Table 5.

Table 4: Cross-border interconnection levels

	Ex ante (%)	**B** (%)	**TE** (%)	**TE+C_{250}** (%)	**C_{250}** (%)	**TE+C_{190}** (%)	**C_{190}** (%)	**TE+C_{120}** (%)	**C_{120}** (%)
BE	93.3	97.46	127.2	127.03	97.22	126.36	99.99	129.16	124.97
DE	10.73	11.17	15.0	15.0	11.18	15.0	11.2	15.0	10.96
FR	10.74	10.77	15.0	15.0	10.77	15.0	11.27	15.0	14.08
LU	2143.39	2435.08	5682.33	5663.22	2418.56	5657.27	2375.1	5774.96	2387.4
NL	51.51	54.08	55.08	55.15	54.1	55.11	54.21	55.67	54.82

Note: This table reports the percentage of cross-border interconnection per country per scenario based on 2030 cost assumptions. As described in Sections 3.4, 5.1, 5.2 and Equation (12), each percentage level is computed based on generation amount from baseline scenario.

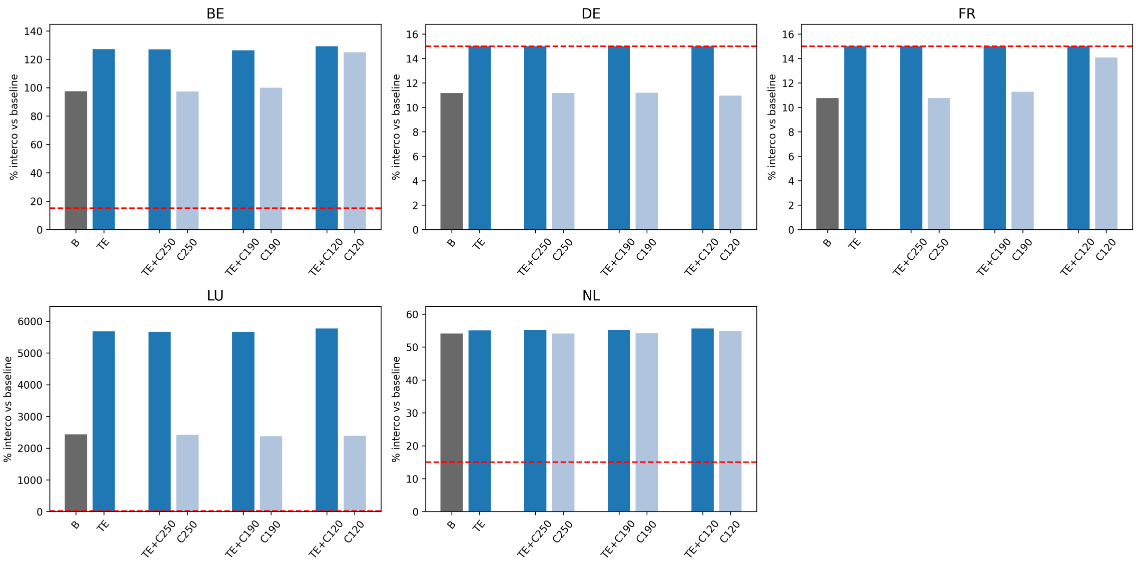


Figure 2: Cross-border interconnection levels vs 15% threshold (in %)

Note: This figure displays the evolution of the cross-border interconnection levels per country compared to the 15% target, depending on the scenario.

6.2. Costs and carbon emissions

Table 5 and Figure 3 report the main conclusions of our analysis. Focusing on the effect of reaching the 15% transmission expansion target highlights that the total CO_2 reduction is marginal compared to the optimized baseline (-0.09%). Hence, considering a sample of five neighboring countries, most of them already highly interconnected, the EU's legislation on cross-border grid development taken alone does not allow for substantial carbon savings by 2030. The multiple optimization scenarios performed confirm that, coupled with strict CO_2 emission limits in $TE{+}C_{250}$, $TE{+}C_{190}$, and $TE{+}C_{120}$ configuration, improving the network infrastructure allows for a drastic reduction in total system emissions at a level that is more than proportional to the increased costs. Nevertheless, the exact same reductions can be achieved at lower total system costs without imposing a flat rate of 15% on all countries within alternative C_{250}, C_{190}, and C_{120} scenarios.

Furthermore, the results confirm the assumption that the increased costs associated with the stringency of climate policies are due to massive CAPEX investment costs in capital-intensive infrastructures. Conversely, marginal costs included in OPEX tend to decrease as RES - characterized by zero fuel costs - represent a greater share of the power mix. The decomposition of Expanded CAPEX shows that most of the additional investment costs are due to AC lines when the cross-border interconnection rate has to meet the 15% threshold. In contrast, Expanded CAPEX are more balanced between the AC lines and battery storage infrastructure when the *TE* constraint is removed, while the investment costs of DC links remain marginal. Finally, massive investment in new solar and wind power capacity is required in the $TE{+}C_{120}$ and C_{120} scenarios to meet the most stringent CO_2 emission targets. This assessment is supported by the power installed capacity data in Table 6, and the power generation data in Table 7, and Figure 4. Sensibility tests reported in Appendix F are performed based on cost assumptions and emission factors for 2050.[47]

[47]The values in Table F.13 emphasize that investment costs in transmission infrastructure, ex-

Table 5: Costs and carbon emissions per scenario

	B	**TE**	**TE+C_{250}**	**C_{250}**	**TE+C_{190}**	**C_{190}**	**TE+C_{120}**	**C_{120}**
Costs								
Objective (G€)	17.73	17.95	17.96	17.75	18.13	17.94	20.08	19.98
CAPEX (G€)	142.53	142.76	142.76	142.53	142.76	142.54	146.00	145.91
Installed CAPEX (G€)	142.50	142.50	142.50	142.50	142.50	142.50	142.50	142.50
Expanded CAPEX (G€)	0.027	0.258	0.258	0.026	0.258	0.042	3.498	3.412
AC Line (M€)	26.16	257.96	257.98	25.91	257.72	41.26	265.11	132.83
DC Link (M€)	0.14	0.13	0.17	0.18	0.14	0.16	0.15	0.18
OCGT (M€)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar (M€)	0.0	0.0	0.0	0.0	0.0	0.0	2363.61	2300.7
Offwind (M€)	0.05	0.04	0.06	0.07	0.05	0.06	0.08	0.1
Onwind (M€)	0.0	0.0	0.0	0.0	0.0	0.0	868.33	978.18
Battery storage (M€)	0.21	0.18	0.24	0.28	0.19	0.24	0.27	0.32
OPEX (G€)	17.71	17.69	17.70	17.72	17.87	17.89	16.58	16.57
Total system cost (G€)	160.23	160.45	160.46	160.25	160.63	160.44	162.58	162.48
Total emissions ($MtCO_2$)	279.18	278.93	250.0	250.0	190.0	190.0	120.0	120.0
Variation against Baseline								
Δ Objective vs B (%)	0.0	1.21	1.28	0.08	2.2	1.14	13.23	12.66
Δ System cost vs B (%)	0.0	0.13	0.14	0.01	0.24	0.13	1.46	1.4
Δ Emissions vs B (%)	0.0	-0.09	-10.45	-10.45	-31.94	-31.94	-57.02	-57.02

Note: this table reports the main results of our sensitivity analysis, including costs and carbon emissions per scenario. The costs assumptions for technologies involved correspond to projections for 2050.

pandable generators, and battery storage are expected to fall in 2050 compared to projections for 2030. In contrast, coal and oil plants observe increases in their fuel costs. Table F.14 and F.15 provide key results regarding optimal interconnection levels, system costs, and carbon emissions.

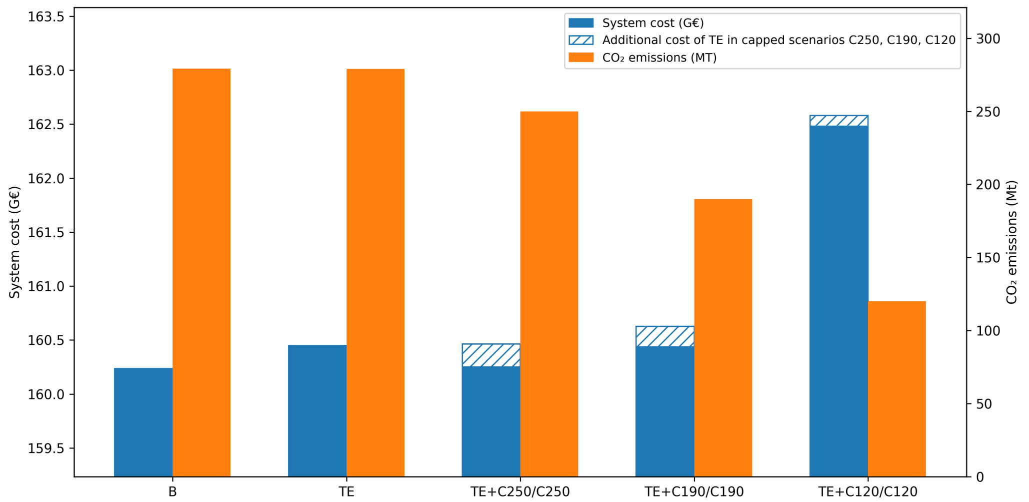


Figure 3: Costs and carbon emissions per scenario

Note: This figure displays the evolution of total optimized system costs and the associated CO_2 emissions, depending on the scenario.

6.3. Power generation reallocation

Examining the evolution of European power mixes shows that improving cross-border interconnection does not yield major capacity substitutions compared to the baseline outcome. Table 6 shows that switching from *B* to *TE* scenario implies a substantial increase of 13.90 GW of AC transmission in parallel with negligible reductions of transmission, generation, and storage capacities.[48] The most significant changes in optimal capacity relate to Solar and Onshore wind installations in the $TE{+}C_{120}$ and C_{120} scenarios, confirming the findings previously drawn from the Expanded CAPEX analysis.[49]

However, this statement is balanced by looking at the effective power generation given in Table 7, and Figure 4. The data show slight changes in electricity generation

[48]When expressed in GW, reductions in generation capacity are not meaningful in Table 6, while the reductions are -0.00013 GW for DC Transmission and -0.00012 GW for battery storage.

[49]Figures C.5 and C.6 in Appendix C display the scenario-varying regional capacity, while Table C.12 and Figure C.7 detail the evolution at the country scale.

when moving from the *B* scenario to the *TE* scenario. These shifts are not necessarily made in favor of clean energy (nuclear: -0.039 TWh, onwind: -0.141 TWh), or at the expense of carbon-based energy (coal: +0.100 TWh, lignite: +0.102 TWh), which explains the very slight reduction in emissions between B and TE.[50]

In *C-type* scenarios that impose emissions cap, the electricity generation mix shifts more clearly towards cleaner but less dispatchable energy sources. Nuclear plant power production increases by around 25 TWh in the $TE{+}C_{250}/C_{250}$ scenarios and by up to around 85-90 TWh in $TE{+}C_{190}/C_{190}$ and $TE{+}C_{120}/C_{120}$ scenarios.[51] Offwind generation tends to slightly decrease in almost all *C-type* scenarios compared to *B*, but is offset by increases in Onwind and Solar production, particularly in the most stringent $TE{+}C_{120}/C_{120}$ configurations (wind $\approx$ +20 TWh, solar $\approx$ +50 TWh). In parallel, flexible-carbon-emitting coal and lignite plants continuously observe substantial production decreases from $TE{+}C_{250}/C_{250}$ (coal $\approx$ -6 TWh, lignite $\approx$ -20 TWh) to $TE{+}C_{120}/C_{120}$ scenarios (coal $\approx$ -82 TWh, lignite $\approx$ -80 TWh). Hence, these results show that increased cross-border interconnections (and in some way increased battery storage capacity) substitute dispatchable generation as a lever of flexibility for the power system. However, the significant increase in power generation from CCGT plants in the $TE{+}C_{120}/C_{120}$ scenarios reflects the need to maintain flexible generation within an energy mix largely dominated by intermittent renewables and non-dispatchable nuclear power.

Supplementary materials are given in Table 8. First, statistics confirm that the share of VRES increases sharply when emissions constraints are at their strictest, and the curtailment, which is very low, indicates that the system is well suited to

[50]Figures D.8 and D.9 in Appendix D display the regional variation of power generation, while Figures D.10, D.11, D.12, D.13, and D.14 show the power generation mix for Belgium, Germany, France, Luxembourg, and the Netherlands, depending on the scenario.

[51]Nuclear technology is modeled as non-expandable. The increase in nuclear power generation is due to the more intensive use of existing power plants. The capacity factor (CF) statistics for nuclear carrier depending on the scenario are: B=0.499; TE=0.499; $TE{+}C_{250}$=0.541; C_{250}=0.542; $TE{+}C_{190}$=0.643; C_{190}=0.643; $TE{+}C_{120}$=0.639; C_{120}=0.636.

renewables. In addition, the curtailment rates at low load periods are reduced when cross-border interconnection levels meet the 15% threshold compared to alternative systems (*B* vs *TE*, *TE+*C_{250} vs C_{250}, *TE+*C_{190} vs C_{190}, and *TE+*C_{120} vs C_{120}). This confirms that grid development and cross-border flows enable to avoid the curtailment of VRES, especially when demand is low, and ease the global penetration of renewables. Furthermore, the moderate evolution of transmission line utilization across scenarios, combined with the increase in curtailment in high-RES configurations (*TE+*C_{120}/C_{120}), suggests that the curtailment is not primarily driven by insufficient transmission capacity at the system level. Rather, it may reflect local mismatches between excess VRES generation and demand, particularly during low-load periods.

Table 6: Installed capacity per carrier per scenario (in GW by default) and variation against baseline

	Ex ante	B	TE	TE+C_{250}	C_{250}	TE+C_{190}	C_{190}	TE+C_{120}	C_{120}
Transmission									
AC	184.78	186.53	200.43	200.40	186.50	200.33	187.03	200.83	190.77
		-	(13.90)	(13.87)	(-0.03)	(13.80)	(0.50)	(14.30)	(4.24)
DC (MW)	1000.00	1001.82	1001.69	1002.16	1002.36	1001.74	1002.03	1001.96	1002.28
		-	(-0.13)	(0.34)	(0.54)	(-0.09)	(0.21)	(0.13)	(0.46)
Generator									
nuclear	70.30	70.30	70.30	70.30	70.30	70.30	70.30	70.30	70.30
		-	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
Offshore Wind (AC)	23.06	23.06	23.06	23.06	23.06	23.06	23.06	23.06	23.06
		-	(-0.00)	(-0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
Offshore Wind (DC) (MW)	0.00	0.14	0.12	0.16	0.18	0.14	0.17	0.23	0.27
		-	(-0.02)	(0.02)	(0.04)	(-0.00)	(0.04)	(0.09)	(0.14)
Onshore Wind	103.82	103.82	103.82	103.82	103.82	103.82	103.82	110.59	111.45
		-	(-0.00)	(-0.00)	(0.00)	(0.00)	(0.00)	(6.77)	(7.62)
Solar	70.15	70.15	70.15	70.15	70.15	70.15	70.15	119.25	117.94
		-	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(49.10)	(47.80)
Run of River	11.20	11.20	11.20	11.20	11.20	11.20	11.20	11.20	11.20
		-	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
geothermal	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
		-	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
biomass	9.49	9.49	9.49	9.49	9.49	9.49	9.49	9.49	9.49
		-	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
waste	4.34	4.34	4.34	4.34	4.34	4.34	4.34	4.34	4.34
		-	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
Combined-Cycle Gas	61.83	61.83	61.83	61.83	61.83	61.83	61.83	61.83	61.83
		-	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
Open-Cycle Gas	6.11	6.11	6.11	6.11	6.11	6.11	6.11	6.11	6.11
		-	(-0.00)	(-0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(-0.00)
coal	26.44	26.44	26.44	26.44	26.44	26.44	26.44	26.44	26.44
		-	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
lignite	20.43	20.43	20.43	20.43	20.43	20.43	20.43	20.43	20.43
		-	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
oil	7.12	7.12	7.12	7.12	7.12	7.12	7.12	7.12	7.12
		-	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
Storage									
Battery Storage (MW)	0.00	1.65	1.42	1.84	2.15	1.51	1.85	2.12	2.51
		-	(-0.23)	(0.19)	(0.50)	(-0.14)	(0.20)	(0.47)	(0.86)
Pumped Hydro Storage	16.04	16.04	16.04	16.04	16.04	16.04	16.04	16.04	16.04
		-	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
Reservoir & Dam	9.03	9.03	9.03	9.03	9.03	9.03	9.03	9.03	9.03
		-	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)

Note: this table displays the optimized amount of installed capacity in GW (by default) of each carrier in the model depending on the scenario. The value in bracket below the main value represents the variation in GW (by default) against the reference baseline value. Due to low amounts, DC Links, Offshore Wind DC, and Battery Storage values are displayed in MW to maintain readability.

Table 7: Power generation per carrier per scenario (in TWh) and variation against baseline

	B	TE	TE+C_{250}	C_{250}	TE+C_{190}	C_{190}	TE+C_{120}	C_{120}
nuclear	307.215	307.175	333.033	333.488	396.049	395.700	393.344	391.927
	-	(-0.039)	(25.818)	(26.274)	(88.835)	(88.486)	(86.130)	(84.712)
offwind-ac	103.054	103.375	103.038	102.595	103.480	102.763	101.967	99.835
	-	(0.321)	(-0.016)	(-0.459)	(0.426)	(-0.291)	(-1.087)	(-3.219)
onwind	237.374	237.232	237.581	237.840	237.128	237.682	255.771	260.042
	-	(-0.141)	(0.207)	(0.466)	(-0.246)	(0.309)	(18.397)	(22.668)
solar	77.328	77.330	77.326	77.327	77.327	77.328	132.369	130.628
	-	(0.002)	(-0.002)	(-0.002)	(-0.001)	(0.000)	(55.041)	(53.300)
ror	42.886	42.887	42.886	42.885	42.886	42.886	42.875	42.870
	-	(0.001)	(-0.000)	(-0.001)	(0.000)	(-0.000)	(-0.011)	(-0.016)
biomass	77.672	77.953	78.091	77.879	78.519	78.293	75.417	75.102
	-	(0.282)	(0.420)	(0.207)	(0.848)	(0.622)	(-2.254)	(-2.569)
CCGT	7.983	7.711	7.726	8.005	7.914	8.364	21.540	22.203
	-	(-0.272)	(-0.257)	(0.023)	(-0.069)	(0.382)	(13.557)	(14.220)
coal	189.971	190.071	184.526	182.987	141.918	146.009	107.887	107.732
	-	(0.100)	(-5.445)	(-6.984)	(-48.053)	(-43.962)	(-82.084)	(-82.239)
lignite	95.968	96.070	75.931	76.722	55.213	50.850	17.021	16.921
	-	(0.102)	(-20.038)	(-19.247)	(-40.755)	(-45.119)	(-78.947)	(-79.047)

Note: this table displays the optimized amount of power generation in TWh of each carrier in the model depending on the scenario. The value in bracket below the main value represents the variation in TWh against the reference baseline value.

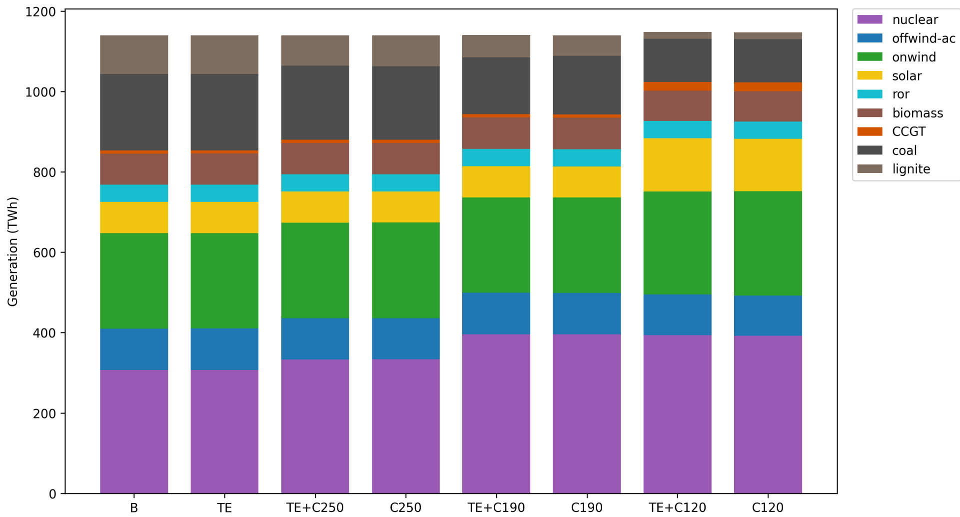


Figure 4: Regional power generation mix (in TWh)

Note: This figure displays the regional electricity generation mix per scenario.

Table 8: VRES integration statistics

Period	Scenario	Generation share	Curtailment rate	Capacity factor	Line use
Annual					
	B	0.365	0.005	0.242	0.250
	TE	0.365	0.005	0.242	0.236
	$\mathbf{TE{+}C_{250}}$	0.365	0.005	0.242	0.223
	$\mathbf{C_{250}}$	0.365	0.005	0.242	0.237
	$\mathbf{TE{+}C_{190}}$	0.365	0.005	0.242	0.197
	$\mathbf{C_{190}}$	0.365	0.005	0.242	0.205
	$\mathbf{TE{+}C_{120}}$	0.426	0.012	0.221	0.197
	$\mathbf{C_{120}}$	0.427	0.013	0.222	0.205
Peak load					
	B	0.317	0.0	0.274	0.270
	TE	0.317	0.0	0.274	0.253
	$\mathbf{TE{+}C_{250}}$	0.317	0.0	0.274	0.252
	$\mathbf{C_{250}}$	0.317	0.0	0.274	0.269
	$\mathbf{TE{+}C_{190}}$	0.317	0.0	0.274	0.250
	$\mathbf{C_{190}}$	0.317	0.0	0.274	0.264
	$\mathbf{TE{+}C_{120}}$	0.361	0.001	0.245	0.220
	$\mathbf{C_{120}}$	0.362	0.001	0.246	0.230
Low load					
	B	0.348	0.007	0.163	0.247
	TE	0.348	0.006	0.163	0.231
	$\mathbf{TE{+}C_{250}}$	0.344	0.006	0.163	0.219
	$\mathbf{C_{250}}$	0.343	0.007	0.163	0.232
	$\mathbf{TE{+}C_{190}}$	0.342	0.006	0.163	0.157
	$\mathbf{C_{190}}$	0.340	0.007	0.163	0.169
	$\mathbf{TE{+}C_{120}}$	0.365	0.011	0.137	0.185
	$\mathbf{C_{120}}$	0.369	0.012	0.138	0.191

Note: this table displays VRES integration statistics (Wind, and Solar) depending on both scenarios and market conditions. *Annual* subset includes all year snapshots whereas *Peak load* and *Low load* includes snapshots representing the top 5% and the bottom 5% of total electrical load, respectively.

6.4. Power flow shifts

Lastly, important changes in power flow balances are observable in Table 9. Apart from changes in the power volume flowing from one area to another, the most striking result is the reversal of the net flow direction at some point. As Germany remains the most carbon-intensive country on average in our sample, the CO_2 cap penalizes German exports. In contrast, French exports become more profitable as long as the carbon cap is low. In *TE+*C_{190}/C_{190} scenarios (Figures E.19 and E.20 in

Appendix E) and beyond towards $TE+C_{120}/C_{120}$ most limiting scenarios, France reverses its power flow balance and becomes a net exporter of electricity with all of its neighboring countries. From Germany's perspective, electricity exports to its neighbors are declining as emission penalties become stricter. In the most restrictive scenarios, Germany becomes a net importer from France and Luxembourg (Figures E.21 and E.22), while the country was a net exporter with almost all of its neighbors in previous configurations despite its carbon-intensity (Figures E.15, E.16, E.17, and E.18).

Table 9: Bilateral power flows (in TWh)

from-to	B	TE	TE+C_{250}	C_{250}	TE+C_{190}	C_{190}	TE+C_{120}	C_{120}
BE-FR	12.138	12.401	1.151	1.408	-26.396	-25.772	-26.029	-24.562
	-	(0.263)	(-10.987)	(-10.730)	(-38.534)	(-37.910)	(-38.167)	(-36.700)
DE-NL	52.806	53.504	47.229	46.904	34.128	29.334	11.980	8.560
	-	(0.698)	(-5.577)	(-5.902)	(-18.678)	(-23.472)	(-40.826)	(-44.246)
DE-FR	24.323	24.885	13.808	13.873	-10.612	-10.798	-16.549	-16.249
	-	(0.562)	(-10.515)	(-10.450)	(-34.935)	(-35.121)	(-40.872)	(-40.573)
DE-LU	14.409	14.491	11.822	11.860	5.437	5.047	-1.722	-1.812
	-	(0.082)	(-2.587)	(-2.549)	(-8.972)	(-9.362)	(-16.131)	(-16.221)
FR-LU	-1.923	-1.978	-0.932	-0.937	1.352	1.354	1.676	1.626
	-	(-0.055)	(0.991)	(0.985)	(3.275)	(3.277)	(3.599)	(3.549)
BE-LU	-7.609	-7.650	-6.011	-6.033	-1.904	-1.480	0.228	0.634
	-	(-0.042)	(1.598)	(1.576)	(5.705)	(6.129)	(7.836)	(8.243)
BE-NL	-30.643	-30.543	-22.275	-22.640	0.324	0.116	8.006	8.027
	-	(0.100)	(8.368)	(8.004)	(30.968)	(30.759)	(38.650)	(38.670)
BE-DE	-8.599	-8.594	-8.033	-8.046	-7.108	-7.380	-0.696	-1.362
	-	(0.005)	(0.566)	(0.553)	(1.491)	(1.220)	(7.903)	(7.237)

Note: this table displays the bilateral power flows (in TWh) between adjacent countries depending on the scenario. The value in bracket below the main value represents the variation in TWh against the reference baseline value.

7. Conclusion

This paper assesses the effect of the European Union's 2030 cross-border electricity interconnection target of 15% on the power generation mix of five European countries and the associated CO_2 emissions. Using the PyPSA framework, we develop several scenarios to optimize the electricity system subject to both technical and policy constraints, including a transmission expansion requirement and alternative carbon emission caps. Our results show that, for the 2030 horizon, achieving the 15% interconnection target alone does not lead to significant carbon emission reductions. Our findings demonstrate that significant GHG reductions can be achieved at lower total system costs without mandating the 15% interconnection threshold.

Furthermore, simply imposing the 15% threshold leads to minor shifts in electricity generation between power plants. However, significant shifts occur as emission constraints become more stringent, to the detriment of dispatchable but high-emission coal and lignite power stations. In this context, increasing interconnections appears to act as a substitute for flexible-carbon-intensive plants, facilitating the integration of renewable energy sources, and reducing the need for VRES curtailment.

Finally, stronger cross-border interconnections significantly alter electricity flow patterns between countries. As CO_2 policy constraints become more stringent, Germany experiences a deterioration in its net power balance with neighboring countries due to the penalty associated with its relatively carbon-intensive electricity generation mix, while France reverses its balance of power flows and becomes a net exporter with all of its partners.

In light of these findings, our results provide a basis for policy recommendations regarding the future of European grid integration. Overall, our analysis suggests that a rigid 15% interconnection target may not be the most cost-effective driver for decarbonization by 2030. Policymakers should instead prioritize flexible, country-specific interconnection levels that align with carbon reduction stringency. Rather than focusing on a flat-rate capacity target, EU strategy should emphasize grid development as a complementary tool to integrate renewables and phase out high-emission dispatchable plants, thereby optimizing both system costs and climate objectives.

Appendix A. CO_2 cap calculation

In the absence of a formally defined 2030 emission target for the power sector at the level of the France–Germany–Belgium–Netherlands–Luxembourg cluster, the estimate of approximately 190 $MtCO_2$ for 2030 is derived through a proportional allocation of the EU ETS constraint.

According to the Report on the functioning of the European carbon market, verified 2023 emissions from "*electricity and heat generation*" under the EU ETS amounted to 552 $MtCO_2e$.[52] We first approximate the 2023 power-sector emissions of the five-country cluster using IEA national CO_2 emissions from fuel combustion data,[53] combined with the reported shares of electricity and heat production in national emissions.[54] For each country i, power-sector emissions E_i^{power} are estimated as a share s_i^{power} of the total emissions E_i^{total} (Equation A.1). Table A.10 reports the corresponding values and we obtain a proxy for the total emissions of the power sector embodied in the regional zone of 266 $MtCO_2$ (Equation A.2). Therefore, share of the cluster in EU ETS electricity-and-heat emissions is equivalent to $\lambda \approx 48.2\%$ (Equation A.3).

$$E_i^{power} = E_i^{total} \times s_i^{power} \tag{A.1}$$

$$E_{zone,2023}^{power} \approx 266 \text{ MtCO}_2 \tag{A.2}$$

$$\lambda = \frac{266}{552} \approx 0.482 \tag{A.3}$$

Then, the EU ETS Directive[55] establishes a legally binding reduction of –62%

[52]European Commission (2024),Table 4, p. 21.

[53]IEA CO_2 Emissions, 2023 edition, International Energy Agency, (2023). The reported emissions are available at https://www.iea.org/regions/europe/emissions, for each country.

[54]IEA CO_2 Emissions, 2023 edition, International Energy Agency, (2023). The reported shares are available at https://www.iea.org/countries/{selected country}/electricity, for each country.

[55]*DIRECTIVE (EU) 2023/959 OF THE EUROPEAN PARLIAMENT AND OF THE COUN-*

Table A.10: Power sector emissions approximation in 2023 (Data source: IEA)

	Total emissions ($MtCO_2$)	**Share of power in emissions (%)**	**Proxy for power sector emissions ($MtCO_2$)**
Germany	549	35	192.2
France	263	11	29
The Netherlands	112	29	32.5
Belgium	77	16	12.3
Luxembourg	6	2	0.1
Total	1007	-	266.1

Note: this table reports the values for total emissions ($MtCO_2$), the share of power sector in total emissions (%), and the derived proxy for power sector emissions ($MtCO_2$) for the five countries of our analysis.

of CO_2 emissions in 2030 relative to 2005 for covered installations. Consistent with the declining cap trajectory, we assume that electricity-and-heat emissions contract proportionally between 2023 and 2030. Applying a representative reduction factor of approximately 30% over the period[56] gives a total reduction pathway reaching 390 $MtCO_2$ in 2030 for the entire EU ETS electricity and heat generation sectors (Equation A.4). Allocating this envelope proportionally to the cluster yields to a CO_2 emission cap of $\approx$ 188 $MtCO_2$ in 2030 (Equation A.5), rounded to 190 $MtCO_2$ in our model.

$$E^{power}_{EU,2030} = 552 \times (1 - 0.30) = 552 \times 0.70 \approx 390 \text{ MtCO}_2 \tag{A.4}$$

$$E^{power}_{zone,2030} = 390 \times 0.482 \approx 188 \text{ MtCO}_2 \tag{A.5}$$

This figure is not a legally defined national or regional target, but a proportional allocation consistent with (i) verified 2023 EU ETS sectoral emissions, (ii) IEA national emissions statistics, and (iii) the legally binding ETS reduction objective for 2030.

CIL - of 10 May 2023 - amending Directive 2003/87/EC establishing a system for greenhouse gas emission allowance trading within the Union and Decision (EU) 2015/1814 concerning the establishment and operation of a market stability reserve for the Union greenhouse gas emission trading system, European Parliament and the Council of the European Union (2023).

[56]This rate is consistent with the tightening annual linear reduction factor described by the European Commission (2024).

Appendix B. Cross-border interconnection calculation

Table B.11: Cross-border interconnection calculation

Country	Scenario	Baseline GenCap (MW)	Interco Cap (MW)	Interconnection level (%)
FR				
	Ex ante	126907.2	13629.5	10.74
	B	126907.2	13670.9	10.77
	TE	126907.2	19036.1	15.0
	TE+C_{250}	126907.2	19036.1	15.0
	TE+C_{190}	126907.2	19036.1	15.0
	TE+C_{120}	126907.2	19036.1	15.0
	C_{250}	126907.2	13669.2	10.77
	C_{190}	126907.2	14297.3	11.27
	C_{120}	126907.2	17867.5	14.08
DE				
	Ex ante	230847.0	24773.4	10.73
	B	230847.0	25790.3	11.17
	TE	230847.0	34627.0	15.0
	TE+C_{250}	230847.0	34627.0	15.0
	TE+C_{190}	230847.0	34627.0	15.0
	TE+C_{120}	230847.0	34627.1	15.0
	C_{250}	230847.0	25799.5	11.18
	C_{190}	230847.0	25843.7	11.2
	C_{120}	230847.0	25290.8	10.96
BE				
	Ex ante	16769.1	15646.1	93.3
	B	16769.1	16342.3	97.46
	TE	16769.1	21329.9	127.2
	TE+C_{250}	16769.1	21301.8	127.03

	TE+C_{190}	16769.1	21188.6	126.36
	TE+C_{120}	16769.1	21659.0	129.16
	C_{250}	16769.1	16302.3	97.22
	C_{190}	16769.1	16767.4	99.99
	C_{120}	16769.1	20956.9	124.97
NL				
	Ex ante	39560.4	20377.2	51.51
	B	39560.4	21394.0	54.08
	TE	39560.4	21790.4	55.08
	TE+C_{250}	39560.4	21818.6	55.15
	TE+C_{190}	39560.4	21802.6	55.11
	TE+C_{120}	39560.4	22023.7	55.67
	C_{250}	39560.4	21403.2	54.1
	C_{190}	39560.4	21447.4	54.21
	C_{120}	39560.4	21688.1	54.82
LU				
	Ex ante	252.8	5418.3	2143.39
	B	252.8	6155.7	2435.08
	TE	252.8	14364.4	5682.33
	TE+C_{250}	252.8	14316.1	5663.22
	TE+C_{190}	252.8	14301.1	5657.27
	TE+C_{120}	252.8	14598.6	5774.96
	C_{250}	252.8	6113.9	2418.56
	C_{190}	252.8	6004.0	2375.1
	C_{120}	252.8	6035.1	2387.4

Note: this table reports the different values from which we derive the cross-border interconnection level depending on each scenario and country.

Appendix C. Installed capacity

Appendix C.1. Global amount and variation

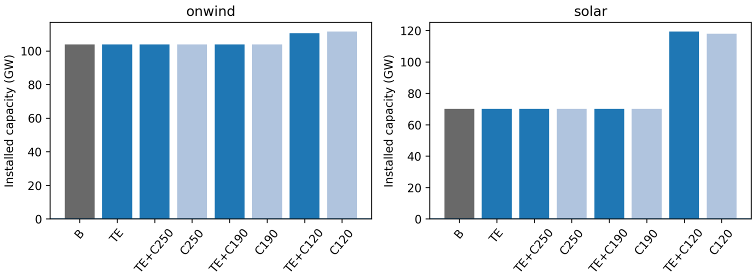


Figure C.5: Installed capacity per carrier per scenario (in GW)

Note: This figure displays the evolution of installed capacity per carrier, depending on the scenario. Scenario-varying carrier only are shown. To maintain readability, minor scenario-varying carrier (offwind-dc, battery) are not displayed here.

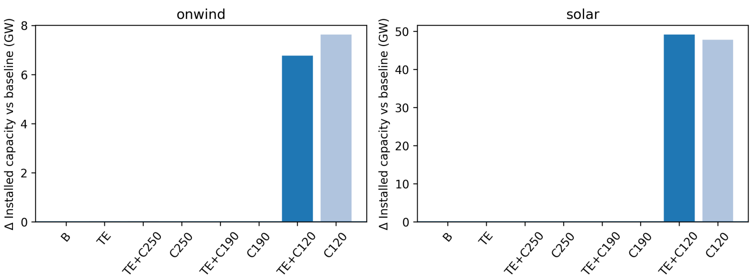


Figure C.6: Variation of installed capacity per carrier per scenario (in GW)

Note: This figure displays the evolution depending on the scenario, of installed capacity per carrier against the baseline amount reference. Scenario-varying carrier only are shown. To maintain readability, minor scenario-varying carrier (offwind-dc, battery) are not displayed here.

Appendix C.2. Country-specific analysis

Table C.12: Variation of optimal capacity against baseline by country and scenario

	Metric	TE	TE+C_{250}	C_{250}	TE+C_{190}	C_{190}	TE+C_{120}	C_{120}
Battery	**Δ total**	-0.2316 MW	0.1917 MW	0.4966 MW	-0.1413 MW	0.2023 MW	0.4719 MW	0.8594 MW
	FR	-0.0487 MW	0.0432 MW	0.1071 MW	-0.0284 MW	0.0435 MW	0.0480 MW	0.1189 MW
	DE	-0.1043 MW	0.0852 MW	0.2223 MW	-0.0645 MW	0.0889 MW	0.2511 MW	0.4310 MW
	BE	-0.0262 MW	0.0206 MW	0.0552 MW	-0.0161 MW	0.0240 MW	0.0540 MW	0.1003 MW
	NL	-0.0269 MW	0.0214 MW	0.0567 MW	-0.0166 MW	0.0235 MW	0.0591 MW	0.1049 MW
	LU	-0.0256 MW	0.0213 MW	0.0552 MW	-0.0157 MW	0.0223 MW	0.0597 MW	0.1043 MW
Offwind-dc	**Δ total**	-0.0190 MW	0.0176 MW	0.0430 MW	-0.0025 MW	0.0370 MW	0.0942 MW	0.1353 MW
	FR	-0.0041 MW	0.0036 MW	0.0090 MW	-0.0019 MW	0.0047 MW	0.0078 MW	0.0144 MW
	DE	-0.0072 MW	0.0071 MW	0.0167 MW	-0.0001 MW	0.0154 MW	0.0457 MW	0.0624 MW
	BE	-0.0040 MW	0.0036 MW	0.0088 MW	-0.0003 MW	0.0088 MW	0.0209 MW	0.0302 MW
	NL	-0.0037 MW	0.0034 MW	0.0084 MW	-0.0002 MW	0.0080 MW	0.0198 MW	0.0284 MW
	LU	0.0000 MW	0.0000 MW	0.0000 MW	0.0000 MW	0.0000 MW	0.0000 MW	0.0000 MW
Onwind	**Δ total**	-0.0002 MW	-0.0002 MW	0.0023 MW	0.0006 MW	0.0027 MW	6.768 GW	7.624 GW
	FR	-0.0000 MW	0.0000 MW	0.0000 MW	-0.0000 MW	0.0000 MW	0.0000 MW	0.0000 MW
	DE	-0.0000 MW	0.0000 MW	0.0000 MW	0.0000 MW	0.0000 MW	0.0000 MW	0.0000 MW
	BE	-0.0001 MW	-0.0001 MW	0.0002 MW	0.0001 MW	0.0008 MW	700.8155 MW	596.0947 MW
	NL	-0.0000 MW	-0.0000 MW	0.0004 MW	0.0004 MW	0.0019 MW	6.067 GW	7.028 GW
	LU	-0.0001 MW	-0.0001 MW	0.0017 MW	0.0001 MW	-0.0000 MW	0.0016 MW	0.0008 MW
Solar	**Δ total**	0.0006 MW	0.0003 MW	0.0129 MW	0.0068 MW	0.0342 MW	49.104 GW	47.797 GW
	FR	-0.0001 MW	-0.0000 MW	0.0008 MW	0.0015 MW	0.0041 MW	6.408 GW	5.397 GW
	DE	-0.0001 MW	-0.0000 MW	0.0012 MW	0.0014 MW	0.0059 MW	27.649 GW	26.866 GW
	BE	-0.0001 MW	0.0001 MW	0.0013 MW	0.0019 MW	0.0229 MW	10.441 GW	11.185 GW
	NL	-0.0000 MW	0.0000 MW	0.0002 MW	0.0002 MW	0.0013 MW	0.0022 MW	0.0013 MW
	LU	0.0009 MW	0.0003 MW	0.0093 MW	0.0019 MW	0.0000 MW	4.606 GW	4.349 GW

Note: this table reports the total variation of optimal capacity for scenario-varying carriers compared to baseline values, and the contribution of each country to the total change in the carrier's capacity.

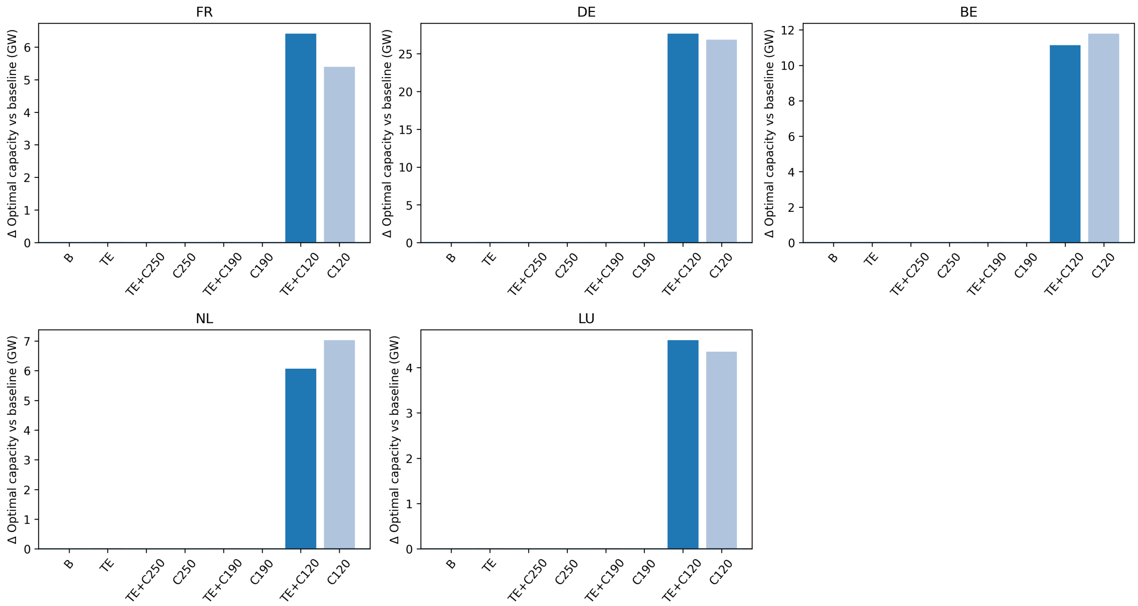


Figure C.7: Variation of optimal capacity (in GW) against baseline

Note: this figure displays the total variation of optimal capacity for scenario-varying carriers compared to baseline values. To maintain readability, minor scenario-varying carrier (offwind-dc, battery) are not displayed here.

Appendix D. Power generation

Appendix D.1. Global amount and variation

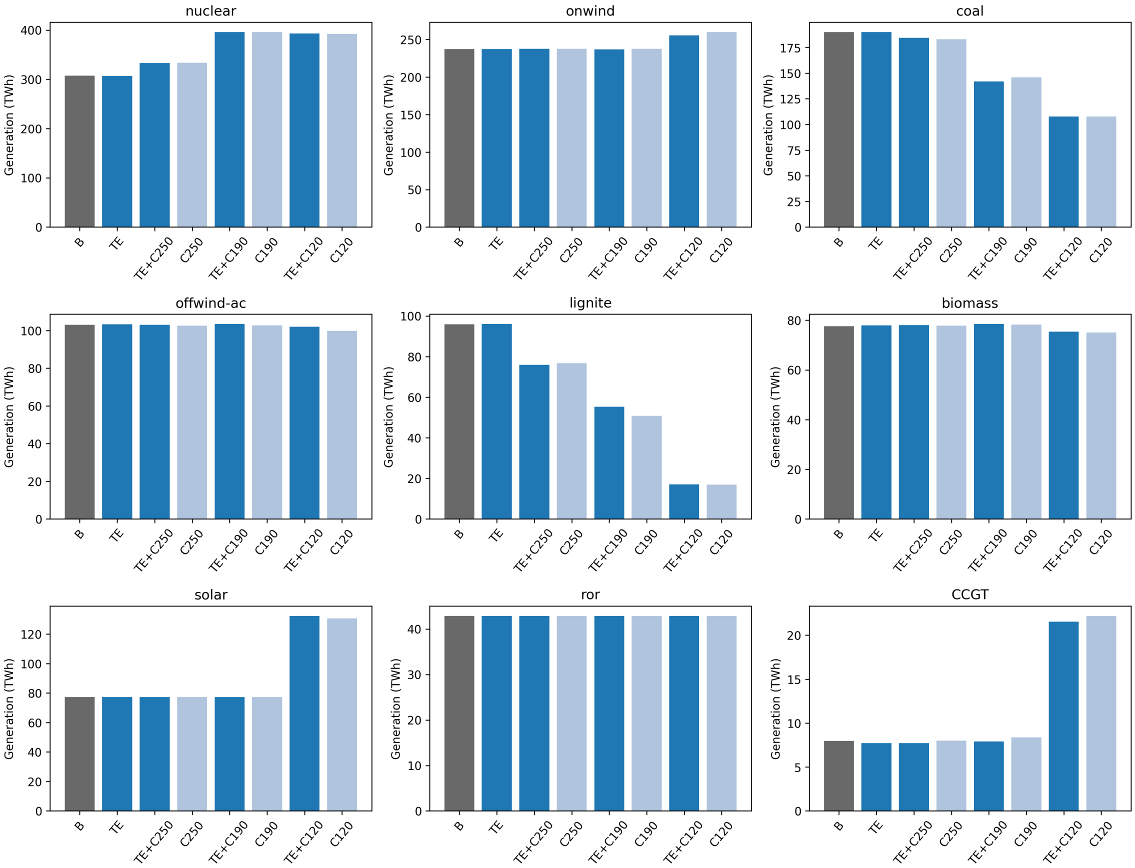


Figure D.8: Power generation per carrier per scenario (in TWh)

Note: This figure displays the evolution of the power generation per carrier depending on the scenario.

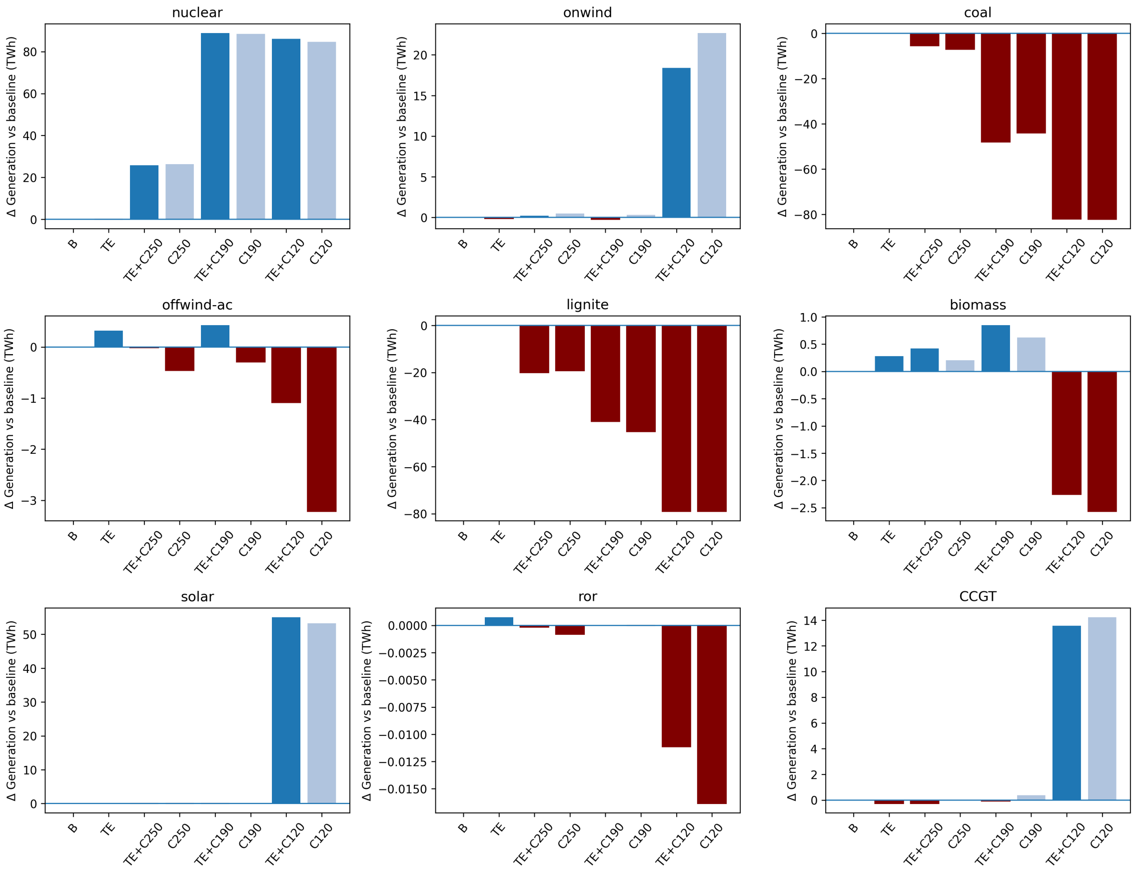


Figure D.9: Variation of power generation (in TWh) against baseline

Note: This figure displays the evolution depending on the scenario, of the power generation per carrier against baseline amount reference.

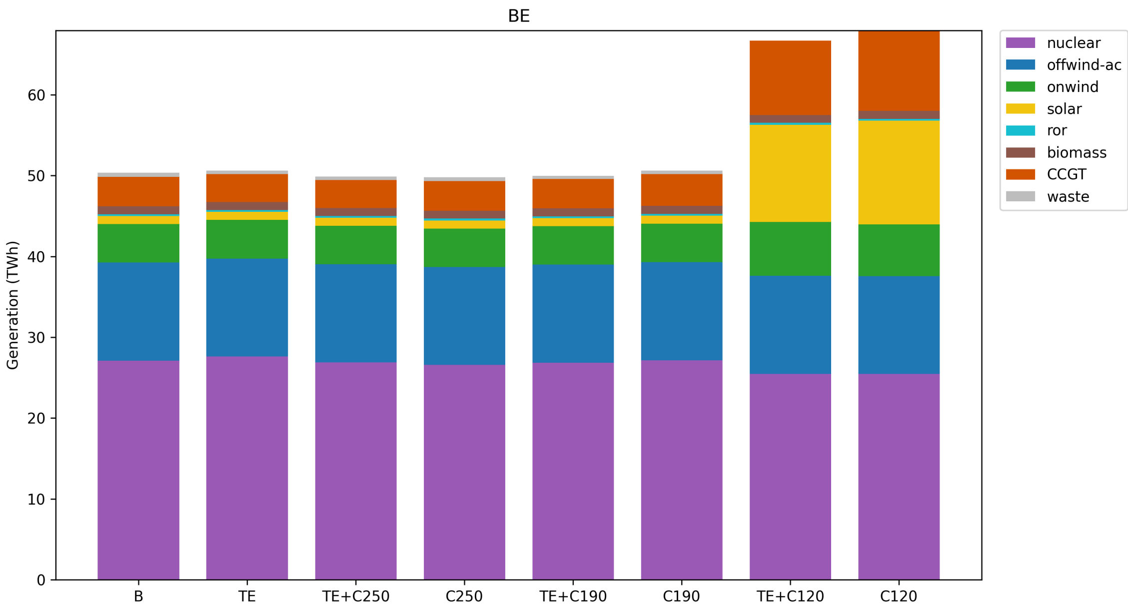


Figure D.10: Belgium: variation of power generation (in TWh)

Note: This figure displays the evolution depending on the scenario, of power generation per carrier. Scenario-varying carrier only are shown.

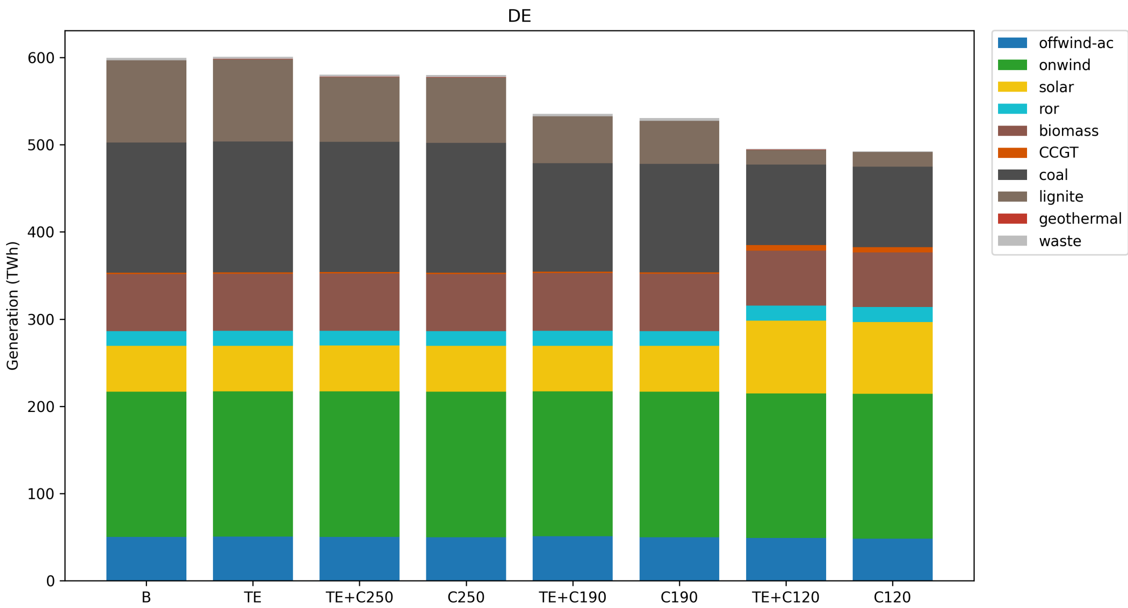


Figure D.11: Germany: variation of power generation (in TWh)

Note: This figure displays the evolution depending on the scenario, of power generation per carrier. Scenario-varying carrier only are shown.

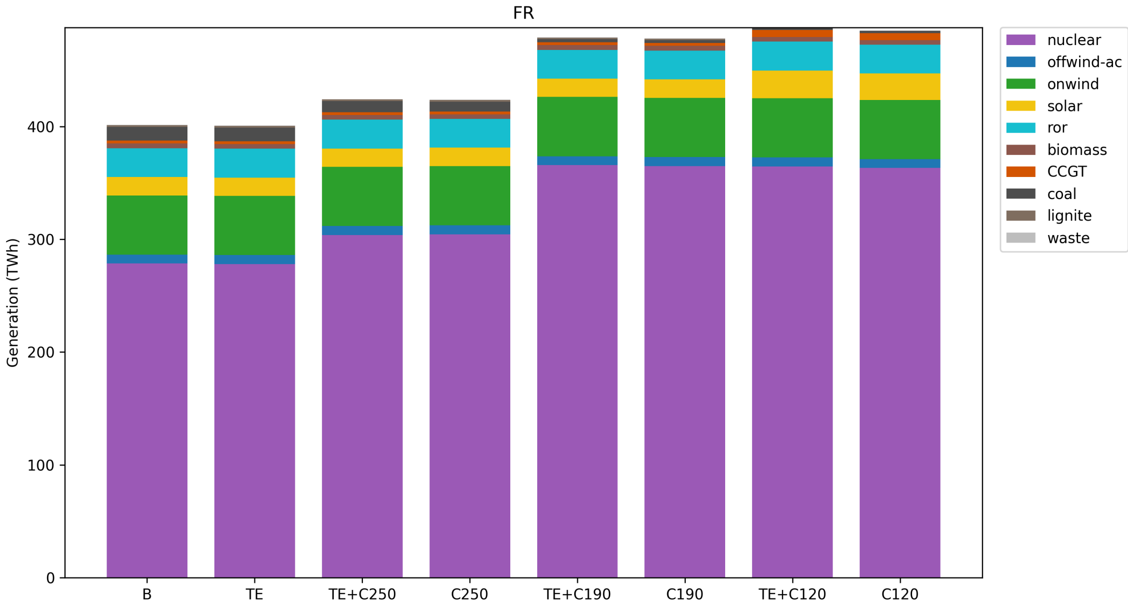


Figure D.12: France: variation of power generation (in TWh)

Note: This figure displays the evolution depending on the scenario, of power generation per carrier. Scenario-varying carrier only are shown.

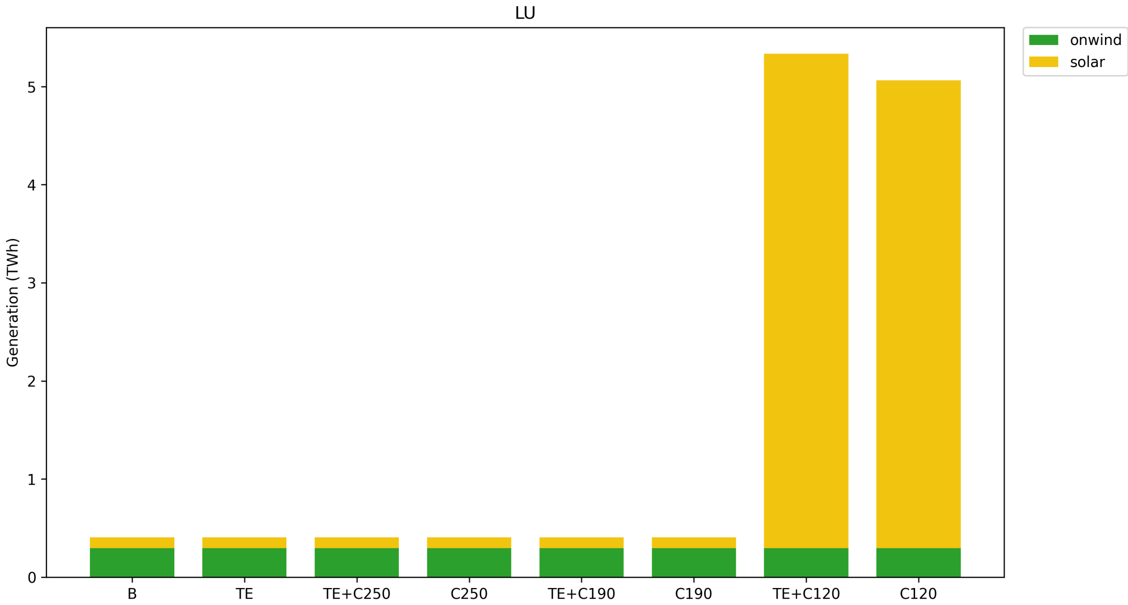


Figure D.13: Luxembourg: variation of power generation (in TWh)

Note: This figure displays the evolution depending on the scenario, of power generation per carrier. Scenario-varying carrier only are shown.

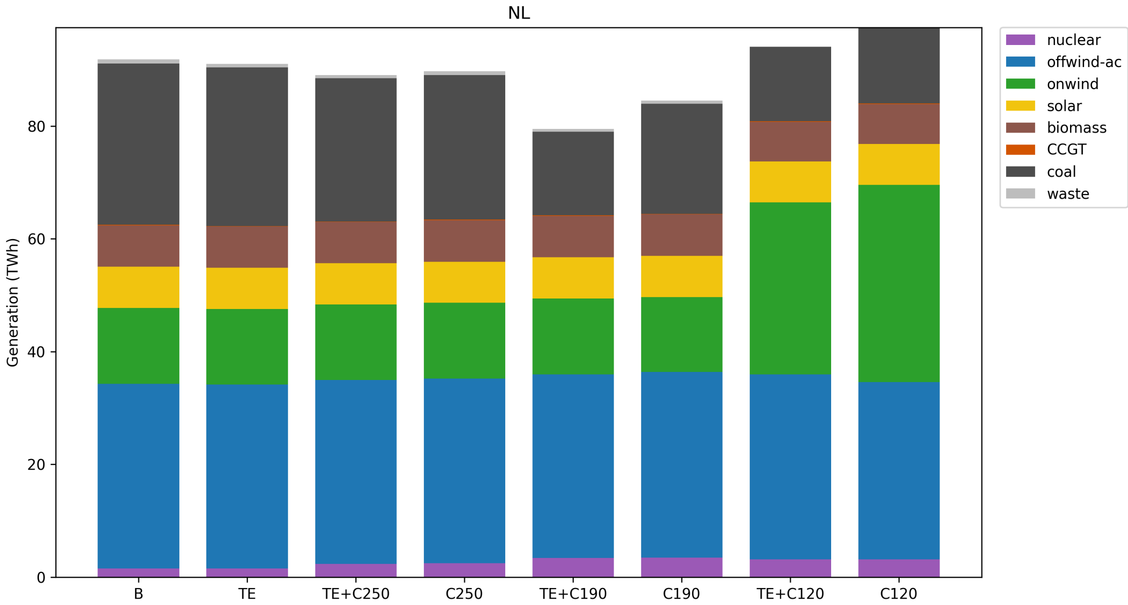


Figure D.14: The Netherlands: variation of power generation (in TWh)

Note: This figure displays the evolution depending on the scenario, of power generation per carrier. Scenario-varying carrier only are shown.

Appendix E. Power flows

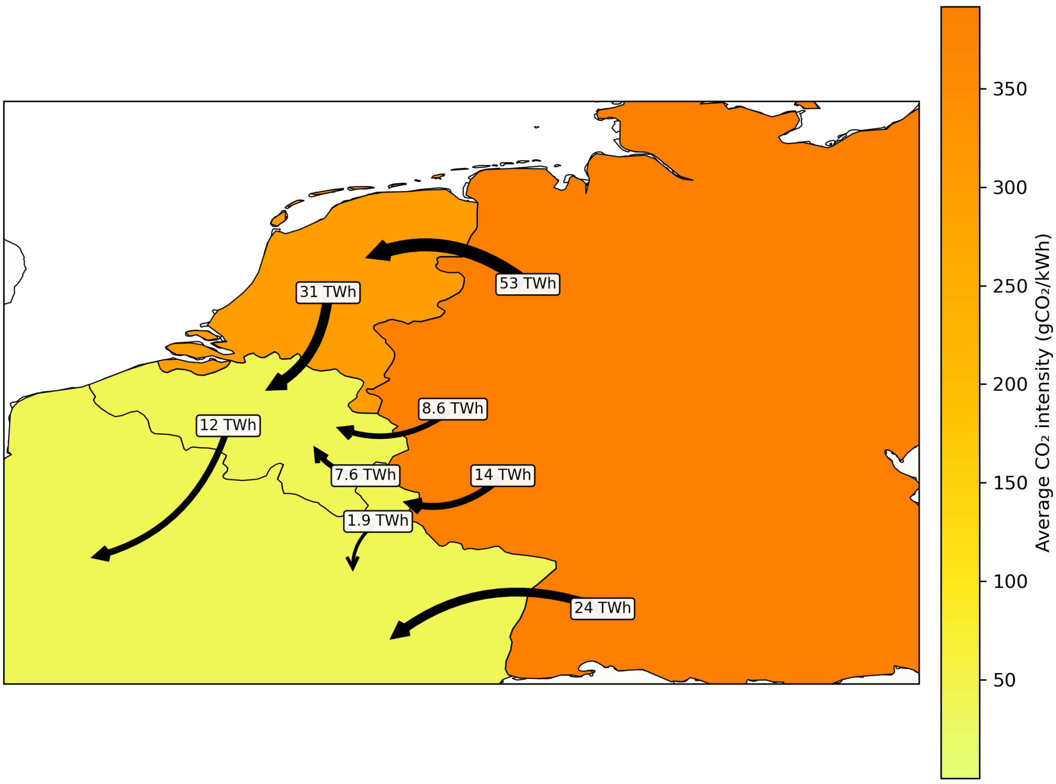


Figure E.15: Baseline: power flows (in TWh)

Note: This figure displays the map of power flows between countries in the baseline scenario (B) and the average carbon intensity of each country.

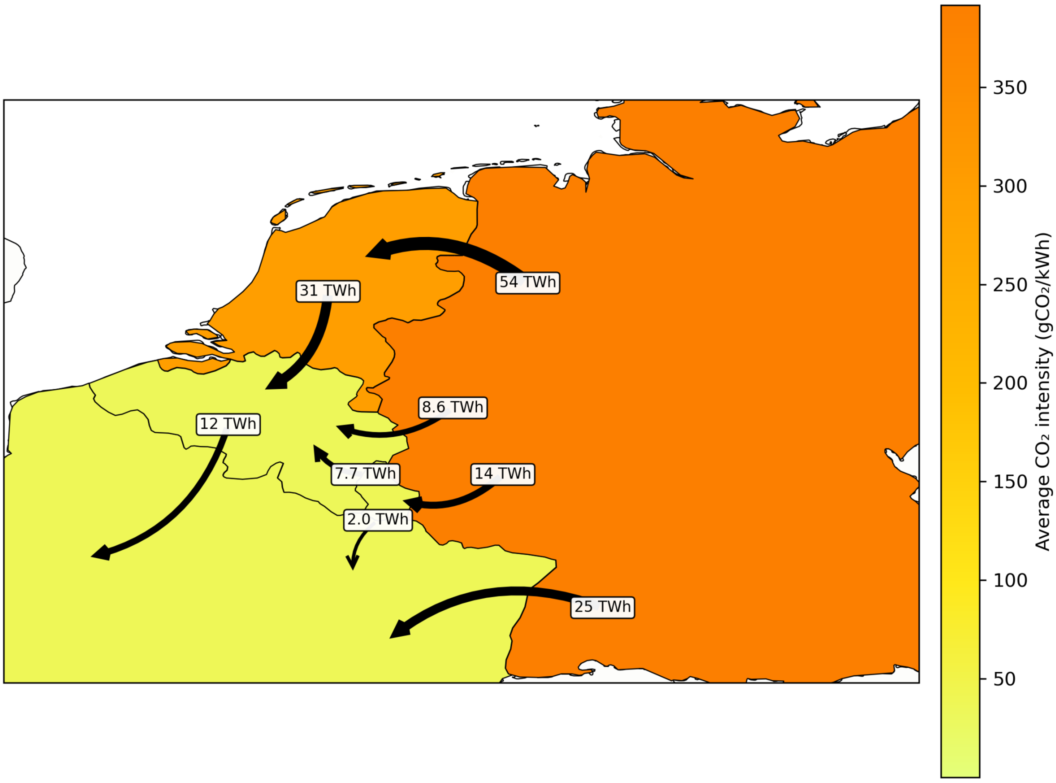


Figure E.16: TE scenario: power flows (in TWh)

Note: This figure displays the map of power flows between countries in the *TE* scenario and the average carbon intensity of each country.

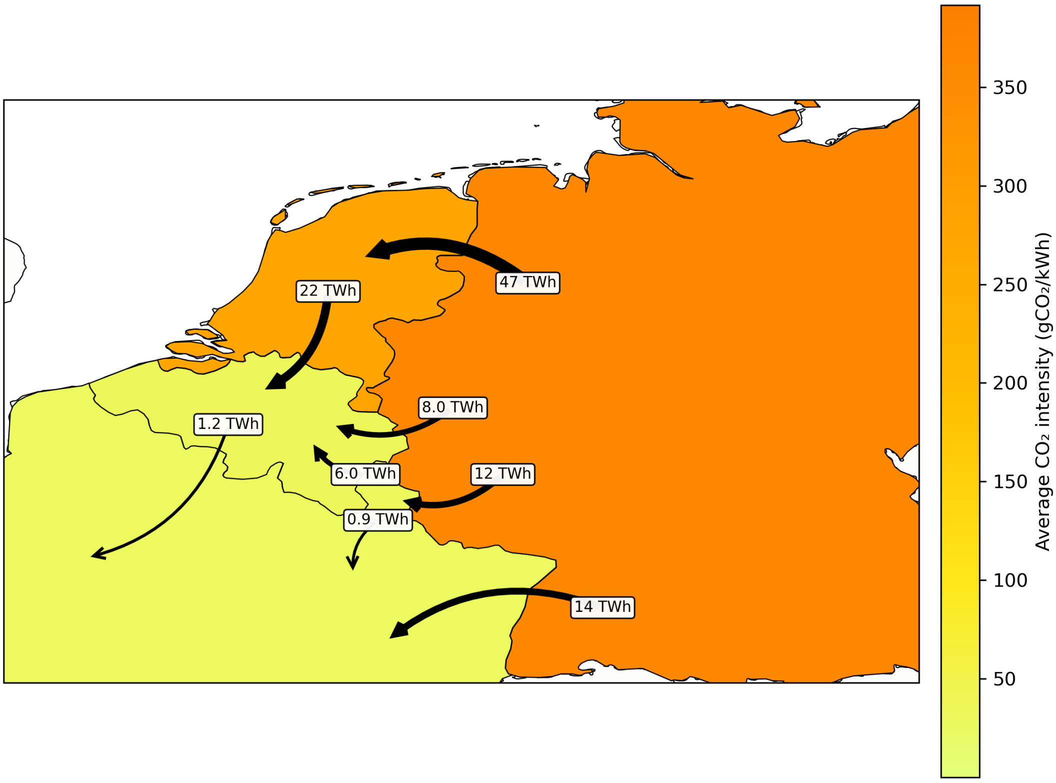


Figure E.17: TE+C_{250} scenario: power flows (in TWh)

Note: This figure displays the map of power flows between countries in the *TE+*C_{250} scenario and the average carbon intensity of each country.

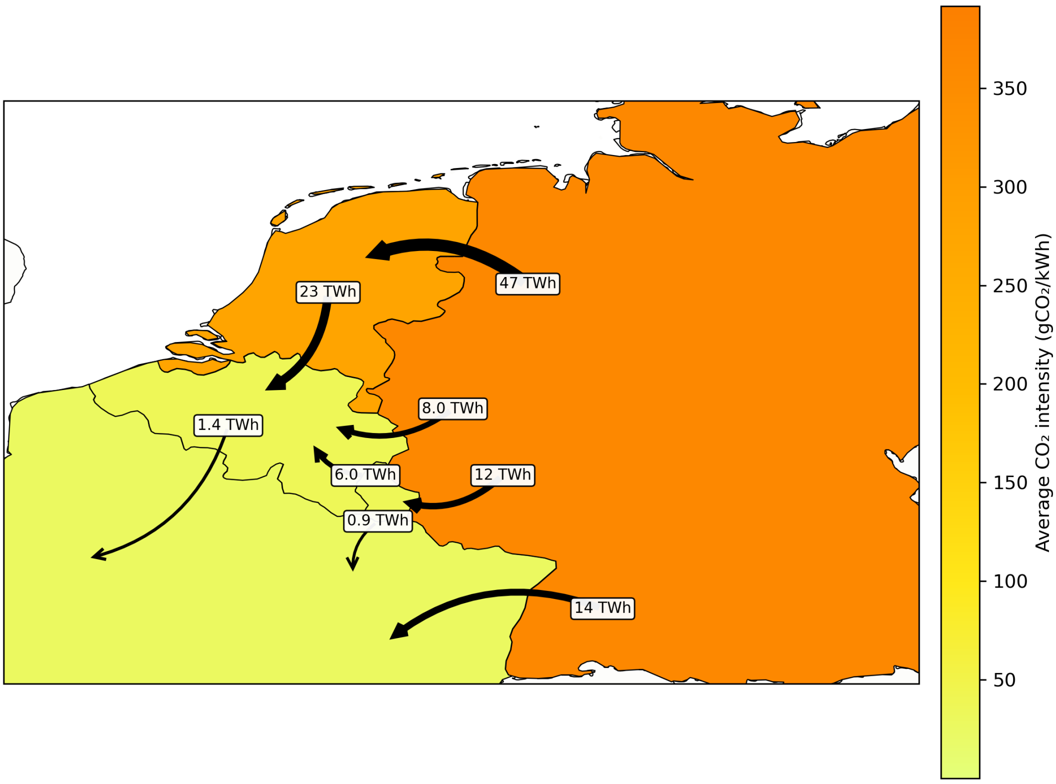


Figure E.18: C_{250} scenario: power flows (in TWh)

Note: This figure displays the map of power flows between countries in the C_{250} scenario and the average carbon intensity of each country.

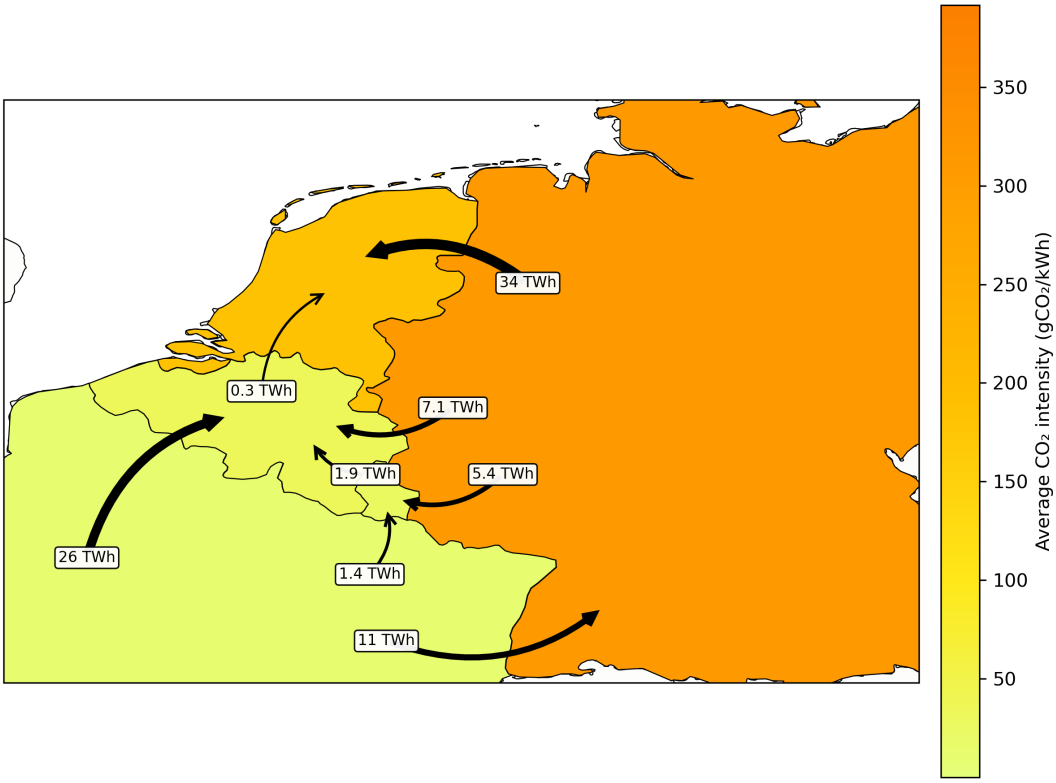


Figure E.19: TE+C_{190} scenario: power flows (in TWh)

Note: This figure displays the map of power flows between countries in the $TE{+}C_{190}$ scenario and the average carbon intensity of each country.

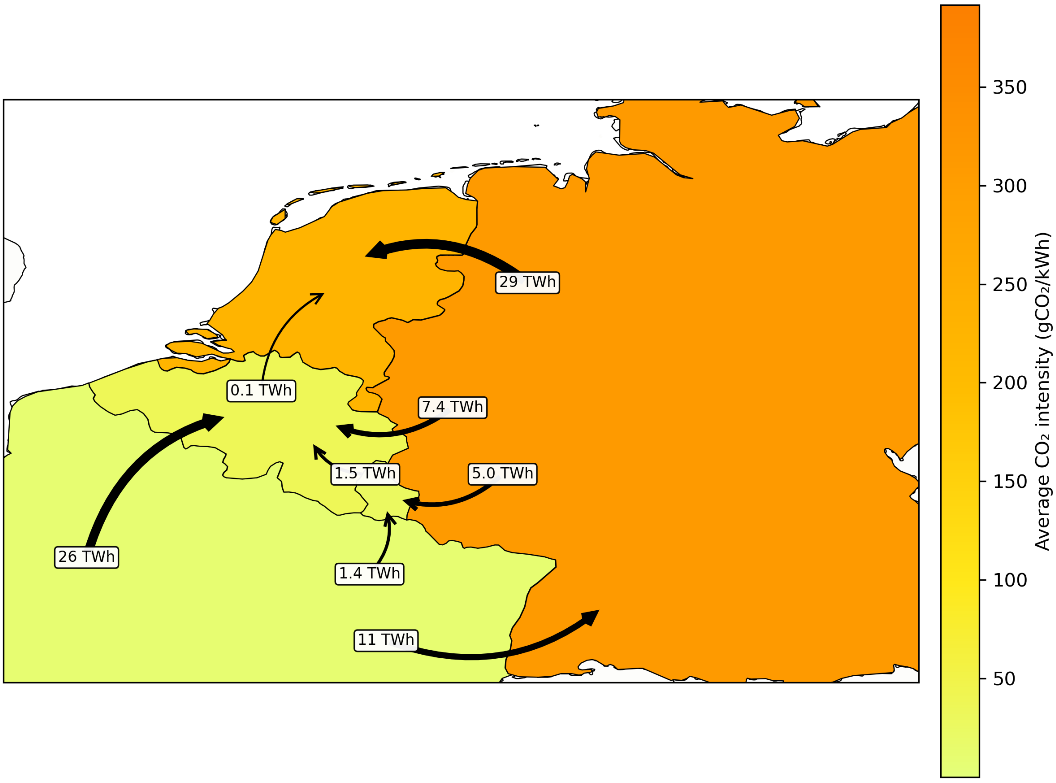


Figure E.20: C_{190} scenario: power flows (in TWh)

Note: This figure displays the map of power flows between countries in the C_{190} scenario and the average carbon intensity of each country.

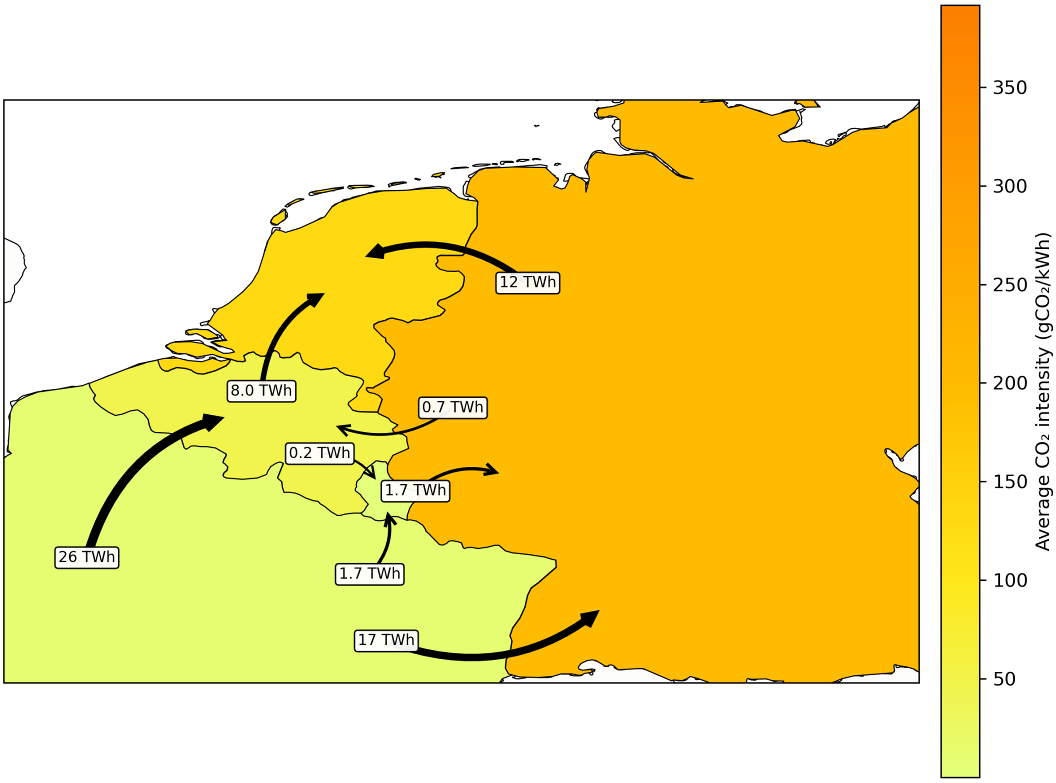


Figure E.21: TE+C_{120} scenario: power flows (in TWh)

Note: This figure displays the map of power flows between countries in the $TE{+}C_{120}$ scenario and the average carbon intensity of each country.

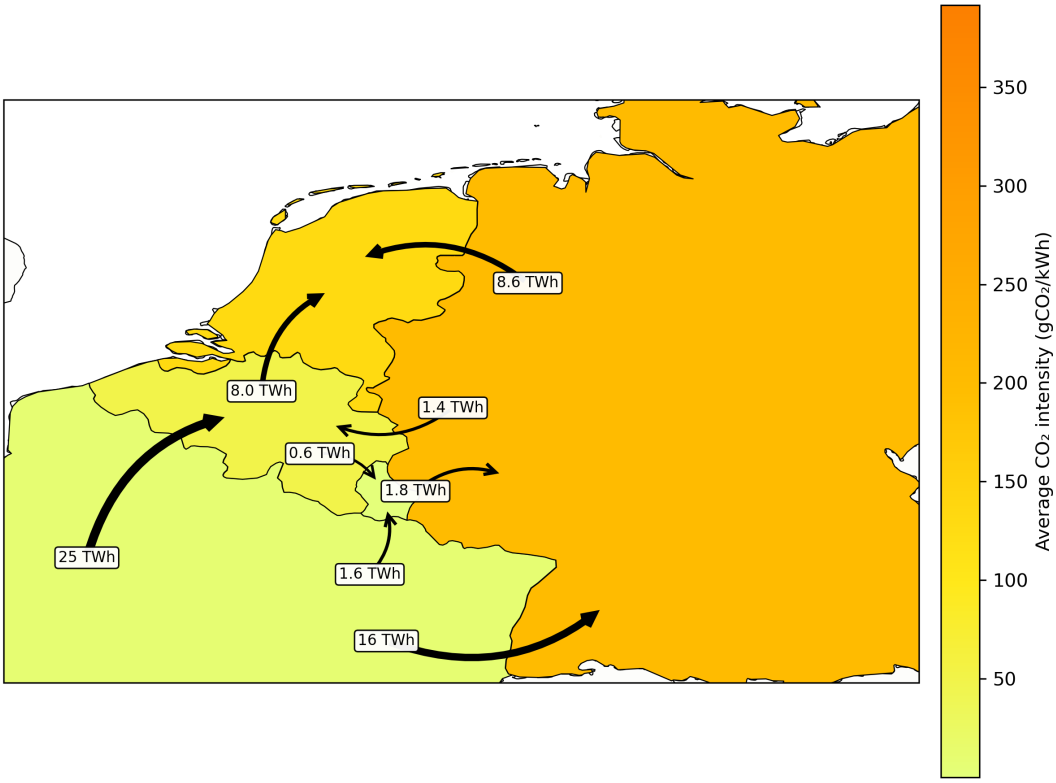


Figure E.22: C_{120} scenario: power flows (in TWh)

Note: This figure displays the map of power flows between countries in the C_{120} scenario and the average carbon intensity of each country.

Appendix F. Sensitivity analysis: 2050 cost assumptions

Table F.13: Relevant cost and emission factors assumptions in 2050

	CAPEX (unit)	FOM (%/year)	VOM (EUR/MWh)	Fuel (EUR/MWh$_{th}$)	Emission factor (tCO_2/MWh$_{th}$)	Lifetime (years)	Expandable
Transmission							
Overhead HVAC/HVDC	442.1414 (EUR/MW/km)	2.0				40	Yes
Underground HVDC	1008.2934 (EUR/MW/km)	0.35				40	Yes
Technology							
Nuclear	-	1.27	3.5464	3.4122	0	40	No
Oil	-	2.4095	6.3493	52.9111	0.2571	25	No
OCGT	435.818 (EUR/kW)	1.8023	4.762	24.568[57]	0.198	25	Yes
CCGT	-	3.25	4.2329	24.568	0.198	25	No
Coal	-	1.31	3.2612	9.5542	0.3361	40	No
Lignite	-	1.31	3.2612	3.2985	0.4069	40	No
Geothermal	-	2.0	0[58]	0	0.12	30	No
Biomass	-	4.5269	2.222[59]	7.4076	0[60]	30	No
Waste		2.2917	27.0247	0	0	25	No
Solar	408.7174 (EUR/kW)	2.0676	0.0106	0	0	40	Yes
Offwind	1523.9311 (EUR/kW)	2.1655	0.0212	0	0	30	Yes
Onwind	1019.1375 (EUR/kW)	1.1775	1.2857	0	0	30	Yes
Hydro	-	1.0	0	0	0	80	No
Run-of-River	-	2.0	0	0	0	80	No
Storage							
Battery storage	79.755 (EUR/kWh)	-	-	-	-	30	Yes
Pumped-Hydro-Storage[61]	-	1.0	-	-	-	80	No
Reservoir and Dam[62]	-	0.43	-	-	-	60	No

Note: This table reports the main cost and emission factors assumptions for the reference year 2050, implemented in the techno-economic optimization process in our PyPSA-Eur model. Values in column 2 "CAPEX" are only reported for extendable carriers, highlighting the idea that new investments would be required.

Table F.15 shows that CO_2 reductions defined in $TE^{2050}+C_{250}$, $TE^{2050}+C_{190}$, and $TE^{2050}+C_{120}$ scenarios are achieved at lower total system costs. This result is associated with greater investment in grid infrastructure, renewable capacity, and batteries, suggesting deeper shifts in electricity generation and flexible assets.

[57]Fuel and emission factor values from OCGT and CCGT are reported under the label "gas" in the cost file.

[58]This value is not defined in the cost file, thus the value of 0 comes from the Aghahosseini and Breyer (2020) paper where the geothermal FOM value of 2%/year was taken.

[59]This value comes from the label "biomass EOP (Electricity-Only-Plant)" in the cost file.

[60]The label "solid biomass" alternatively gives the value 0.3667.

[61]PHS is modeled as a Link component in PyPSA that converts storage to power generation and vice versa.

[62]This parameter is modeled as a Store component in PyPSA and corresponds to the label "Pumped-Storage-Hydro-store" in the cost file.

Table F.14: Sensitivity 20250: cross-border interconnection levels (in %)

	Ex ante^{2050} (%)	**B^{2050}** (%)	**TE^{2050}** (%)	**TE^{2050}+C$_{250}$** (%)	**TE^{2050}+C$_{190}$** (%)	**TE^{2050}+C$_{120}$** (%)
BE	73.2	93.76	118.27	123.21	132.61	146.11
DE	13.7	14.68	15.05	15.0	15.0	17.45
FR	13.9	11.92	15.0	15.0	15.0	15.0
LU	1596.5	1934.33	1938.85	1937.64	1953.49	2007.24
NL	50.7	54.03	56.09	52.64	53.91	64.20

Note: This table reports the percentage of cross-border interconnection per country per scenario based on 2050 cost assumptions. As described in Sections 3.4, 5.1, 5.2 and Equation 12, each percentage level is computed based on generation amount from baseline scenario.

Table F.15: Sensitivity 2050: Costs and carbon emissions per scenario

	B^{2050}	**TE^{2050}**	**TE^{2050}+C$_{250}$**	**TE^{2050}+C$_{190}$**	**TE^{2050}+C$_{120}$**
Costs					
Objective (G€)	13.60	13.64	13.88	14.94	17.37
CAPEX (G€)	94.34	94.42	95.47	97.78	100.77
Installed CAPEX (G€)	91.72	91.72	91.72	91.72	91.72
Expanded CAPEX (G€)	2.62	2.70	3.75	6.06	9.05
AC Line (M€)	47.84	101.64	123.45	136.71	173.96
DC Link (M€)	85.09	114.40	58.39	47.18	86.24
OCGT (M€)	132.78	70.80	0.0	0.0	0.0
Solar (M€)	1814.65	1811.87	2788.02	3648.33	4636.47
Offwind (M€)	0.05	0.04	0.07	0.13	242.51
Onwind (M€)	0.0	0.0	106.13	1530.85	2625.43
Battery storage (M€)	539.31	600.00	675.45	692.71	1290.12
OPEX (G€)	10.98	10.94	10.13	8.88	8.32
Total system cost (G€)	105.32	105.36	105.60	106.66	109.09
Total emissions (MtCO$_2$)	308.66	308.31	250.00	190.00	120.00
Variation against Baseline					
Δ Objective vs B^{2050} (%)	0.0	0.31	2.05	9.83	27.75
Δ System cost vs B^{2050} (%)	0.0	0.04	0.26	1.27	3.58
Δ Emissions vs B^{2050} (%)	0.0	-0.11	-19.0	-38.44	-61.12

Note: this table reports the main results of our sensitivity analysis, including costs and carbon emissions per scenario.

References

Aboumahboub, T., Schaber, K., Wagner, U., Hamacher, T., 2012. On the CO2 emissions of the global electricity supply sector and the influence of renewable power-modeling and optimization. Energy Policy 42, 297–314. URL: https://linkinghub.elsevier.com/retrieve/pii/S0301421511009864, doi:10.1016/j.enpol.2011.11.088.

Abrell, J., Rausch, S., 2016. Cross-country electricity trade, renewable energy and European transmission infrastructure policy. Journal of Environmental Economics and Management 79, 87–113. URL: https://linkinghub.elsevier.com/retrieve/pii/S0095069616300122, doi:10.1016/j.jeem.2016.04.001.

Aghahosseini, A., Breyer, C., 2020. From hot rock to useful energy: A global estimate of enhanced geothermal systems potential. Applied Energy 279, 115769. URL: https://linkinghub.elsevier.com/retrieve/pii/S0306261920312551, doi:10.1016/j.apenergy.2020.115769.

Allard, S., Mima, S., Debusschere, V., Quoc, T.T., Criqui, P., Hadjsaid, N., 2020. European transmission grid expansion as a flexibility option in a scenario of large scale variable renewable energies integration. Energy Economics 87, 104733. URL: https://linkinghub.elsevier.com/retrieve/pii/S0140988320300724, doi:10.1016/j.eneco.2020.104733.

Ang, B., Su, B., 2016. Carbon emission intensity in electricity production: A global analysis. Energy Policy 94, 56–63. URL: https://linkinghub.elsevier.com/retrieve/pii/S0301421516301458, doi:10.1016/j.enpol.2016.03.038.

Beltrami, F., Grossi, L., Liebensteiner, M., 2024. Beyond Borders: Estimating the Marginal Emission Factor of Electricity Trade. URL: https://www.ssrn.com/abstract=5036310, doi:10.2139/ssrn.5036310.

Boie, I., Kost, C., Bohn, S., Agsten, M., Bretschneider, P., Snigovyi, O., Pudlik, M., Ragwitz, M., Schlegl, T., Westermann, D., 2016. Opportunities and challenges of high renewable energy deployment and electricity exchange for North Africa and Europe – Scenarios for power sector and transmission infrastructure in 2030 and 2050. Renewable Energy 87, 130–144. URL: https://linkinghub.elsevier.com/retrieve/pii/S096014811530361X, doi:10.1016/j.renene.2015.10.008.

Bower, J., 2004. Seeking the Single European Electricity Market: Evidence from an Empirical Analysis of Wholesale Market Prices. Technical Report. University Library of Munich, Germany.

Boz, D.E., Sanli, B., Berument, M.H., 2021. The effects of cross-border electricity trade on power production from different energy sources. The Electricity Journal 34, 106953. URL: https://linkinghub.elsevier.com/retrieve/pii/S1040619021000440, doi:10.1016/j.tej.2021.106953.

Brancucci Martínez-Anido, C., Vandenbergh, M., De Vries, L., Alecu, C., Purvins, A., Fulli, G., Huld, T., 2013. Medium-term demand for European cross-border electricity transmission capacity. Energy Policy 61, 207–222. URL: https://linkinghub.elsevier.com/retrieve/pii/S0301421513004254, doi:10.1016/j.enpol.2013.05.073.

Brinkerink, M., Gallachóir, B., Deane, P., 2019. A comprehensive review on the benefits and challenges of global power grids and intercontinental interconnectors. Renewable and Sustainable Energy Reviews 107, 274–287. URL: https://linkinghub.elsevier.com/retrieve/pii/S1364032119301364, doi:10.1016/j.rser.2019.03.003.

Brown, T., Hörsch, J., Schlachtberger, D., 2018. PyPSA: Python for Power System Analysis. Journal of Open Research Software 6, 4. URL: http://arxiv.org/abs/1707.09913, doi:10.5334/jors.188. arXiv:1707.09913 [physics].

Chalvatzis, K.J., Ioannidis, A., 2017. Energy supply security in the EU: Benchmarking diversity and dependence of primary energy. Applied Energy 207, 465–476. URL: https://linkinghub.elsevier.com/retrieve/pii/S0306261917308693, doi:10.1016/j.apenergy.2017.07.010.

Child, M., Kemfert, C., Bogdanov, D., Breyer, C., 2019. Flexible electricity generation, grid exchange and storage for the transition to a 100% renewable energy system in Europe. Renewable Energy 139, 80–101. URL:

https://linkinghub.elsevier.com/retrieve/pii/S0960148119302319, doi:10.1016/j.renene.2019.02.077.

Deng, X., Lv, T., Meng, X., Li, C., Hou, X., Xu, J., Wang, Y., Liu, F., 2024. Assessing the carbon emission reduction effect of flexibility option for integrating variable renewable energy. Energy Economics 132, 107461. URL: https://linkinghub.elsevier.com/retrieve/pii/S0140988324001695, doi:10.1016/j.eneco.2024.107461.

ENTSO-E, 2012. Ten-Year Network Development Plan 2012. Technical Report. ENSTO-E.

ENTSO-E, 2025. Ten-Year Network Development Plan 2024. Opportunities for a more efficient European power system by 2050. Technical Report. ENTSO-E.

European Commission, 2021. Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions – 'Fit for 55': delivering the EU's 2030 climate target on the way to climate neutrality.

European Commission, 2022. REPowerEU Plan.

European Commission, 2024. Report from the Commission to the European Parliament and the Council on the functioning of the European carbon market in 2023. Technical Report COM(2024) 538 final. Brussels.

European Environment Agency (Ed.), 2025. Renewables, electrification and flexibility for a competitive EU energy system transformation by 2030. Publications Office, Luxembourg. doi:10.2800/4558900.

European Parliament and the Council of the European Union, 2018. REGULATION (EU) 2018/ 1999 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL - of 11 December 2018 - on the Governance of the Energy Union and Climate Action. URL: https://eur-lex.europa.eu/eli/reg/2018/1999/oj.

European Parliament and the Council of the European Union, 2021. REGULATION (EU) 2021/1119 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL - of 30 June 2021 - establishing the framework for achieving climate neutrality and amending Regulations (EC) No 401/2009 and (EU) 2018/1999 ('European Climate Law').

European Parliament and the Council of the European Union, 2023. DIRECTIVE (EU) 2023/959 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL - of 10 May 2023 - amending Directive 2003/87/EC establishing a system for greenhouse gas emission allowance trading within the Union and Decision (EU) 2015/1814 concerning the establishment and operation of a market stability reserve for the Union greenhouse gas emission trading system.

Fabra, N., 2023. Reforming European electricity markets: Lessons from the energy crisis. Energy Economics 126, 106963. URL: https://linkinghub.elsevier.com/retrieve/pii/S0140988323004619, doi:10.1016/j.eneco.2023.106963.

Fressoz, J.B., 2024. Sans transition: une nouvelle histoire de l'énergie. Écocène, Éditions du Seuil, Paris.

Geneletti, G., Cremona, E.C., 2025. Money on the line: scaling electricity-nterconnection for Europe's energy future. Technical Report. EMBER. URL: https://ember-energy.org/app/uploads/2025/12/Money-on-the-line-scaling-electricity-interconnection-for-Europes-energy-future.pdf.

Gotzens, F., Heinrichs, H., Hörsch, J., Hofmann, F., 2026. Performing energy modelling exercises in a transparent way - The issue of data quality in power plant databases. URL: https://zenodo.org/doi/10.5281/zenodo.1403220, doi:10.5281/ZENODO.1403220.

Graham, E., Fulghum, N., Altieri, K., 2025. Global Electricity Review 2025. Technical Report. EMBER. URL: https://ember-energy.org/app/uploads/2025/04/Report-Global-Electricity-Review-2025.pdf.

Gunkel, P.A., Bergaentzlé, C., Jensen, I.G., Scheller, F., 2020. From passive to active: Flexibility from electric vehicles in the context of transmission system development. Applied Energy 277, 115526. URL: http://arxiv.org/abs/2011.05830, doi:10.1016/j.apenergy.2020.115526. arXiv:2011.05830 [econ].

Hofmann, F., Hampp, J., Neumann, F., Brown, T., Hörsch, J., 2021. atlite: A Lightweight Python Package for Calculating Renewable Power Potentials and Time Series. Journal of Open Source Software 6, 3294. URL: https://joss.theoj.org/papers/10.21105/joss.03294, doi:10.21105/joss.03294.

Horsch, J., Brown, T., 2017. The role of spatial scale in joint optimisations of generation and transmission for European highly renewable scenarios, in: 2017 14th International Conference on the European Energy Market (EEM), IEEE, Dresden, Germany. pp. 1–7. URL: http://ieeexplore.ieee.org/document/7982024/, doi:10.1109/EEM.2017.7982024.

Huisman, R., Kiliç, M., 2013. A history of European electricity day-ahead prices. Applied Economics 45, 2683–2693. URL: http://www.tandfonline.com/doi/abs/10.1080/00036846.2012.665601, doi:10.1080/00036846.2012.665601.

Hörsch, J., Hofmann, F., Schlachtberger, D., Brown, T., 2018. PyPSA-Eur: An Open Optimisation Model of the European Transmission System. Energy Strategy Reviews 22, 207–215. URL: http://arxiv.org/abs/1806.01613, doi:10.1016/j.esr.2018.08.012. arXiv:1806.01613 [physics].

IAE, 2025a. Electricity 2025. Technical Report. Paris. URL: https://www.iea.org/reports/electricity-2025.

IAE, 2025b. Global Energy Review 2025. Technical Report. Paris. URL: https://www.iea.org/reports/global-energy-review-2025.

IPCC, 2007. Climate change 2007: The physical science basis. Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change. Technical Report. Cambridge, United Kingdom and New York, NY, USA, 996 pp.

Jha, A.P., Mahajan, A., Singh, S.K., Kumar, P., 2022. Renewable energy proliferation for sustainable development: Role of cross-border electricity trade. Renewable Energy 201, 1189–1199. URL: https://linkinghub.elsevier.com/retrieve/pii/S0960148122016871, doi:10.1016/j.renene.2022.11.046.

Jorge, R.S., Hertwich, E.G., 2014. Grid infrastructure for renewable power in Europe: The environmental cost. Energy 69, 760–768. URL: https://linkinghub.elsevier.com/retrieve/pii/S0360544214003363, doi:10.1016/j.energy.2014.03.072.

Joskow, P.L., 2020. Transmission Capacity Expansion Is Needed to Decarbonize the Electricity Sector Efficiently. Joule 4, 1–3. URL: https://linkinghub.elsevier.com/retrieve/pii/S2542435119305276, doi:10.1016/j.joule.2019.10.011.

Li, Y., Lukszo, Z., Weijnen, M., 2016. The impact of inter-regional transmission grid expansion on China's power sector decarbonization. Applied Energy 183, 853–873. URL: https://linkinghub.elsevier.com/retrieve/pii/S0306261916313083, doi:10.1016/j.apenergy.2016.09.006.

Mezősi, A., Pató, Z., Szabó, L., 2016. Assessment of the EU 10% interconnection target in the context of CO_2 mitigation. Climate Policy 16, 658–672. URL: https://www.tandfonline.com/doi/full/10.1080/14693062.2016.1160864, doi:10.1080/14693062.2016.1160864.

Newbery, D., Strbac, G., Viehoff, I., 2016. The benefits of integrating European electricity markets. Energy Policy 94, 253–263. URL: https://linkinghub.elsevier.com/retrieve/pii/S0301421516301513, doi:10.1016/j.enpol.2016.03.047.

OECD, 2013. Cross-Border Trade in Electricity and the Development of Renewables-Based Electric Power: Lessons from Europe. OECD Trade and Environment Working Papers 2013/02. doi:10.1787/5k4869cdwnzr-en. series: OECD Trade and Environment Working Papers Volume: 2013/02.

Robinson, T., 2007. The convergence of electricity prices in Europe. Applied Economics Letters 14, 473–476. URL: https://www.tandfonline.com/doi/full/10.1080/13504850500461597, doi:10.1080/13504850500461597.

Robinson, T., 2008. The Evolution of Electricity Prices in The EU since the Single European Act. Economic Issues 13.

Schönheit, D., Bruninx, K., Kenis, M., Möst, D., 2022. Improved selection of critical network elements for flow-based market coupling based on congestion patterns. Applied Energy 306, 118028. URL: https://linkinghub.elsevier.com/retrieve/pii/S0306261921013258, doi:10.1016/j.apenergy.2021.118028.

UNFCCC, 2015. Paris Agreement.

Van Den Bergh, K., Boury, J., Delarue, E., 2016. The Flow-Based Market Coupling in Central Western Europe: Concepts and definitions. The Electricity Journal 29, 24–29. URL: https://linkinghub.elsevier.com/retrieve/pii/S104061901530004X, doi:10.1016/j.tej.2015.12.004.

Xiong, B., Fioriti, D., Neumann, F., Riepin, I., Brown, T., 2024. Prebuilt Electricity Network for PyPSA-Eur based on OpenStreetMap Data. URL: https://zenodo.org/doi/10.5281/zenodo.14144752, doi:10.5281/ZENODO.14144752.

Zachmann, G., 2008. Electricity wholesale market prices in Europe: Convergence? Energy Economics 30, 1659–1671. URL: https://linkinghub.elsevier.com/retrieve/pii/S0140988307000837, doi:10.1016/j.eneco.2007.07.002.

Zafirakis, D., Chalvatzis, K.J., Baiocchi, G., 2015. Embodied CO2 emissions and cross-border electricity trade in Europe: Rebalancing burden sharing with energy storage. Applied Energy 143, 283–300. URL: https://linkinghub.elsevier.com/retrieve/pii/S0306261914013117, doi:10.1016/j.apenergy.2014.12.054.