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Abstract

Ongoing climate change affects complex and long-lived infrastructures like electricity systems. Particularly for decarbonized electricity systems based on variable renewable energies, there is a variety of impact mechanisms working differently in size and direction. Main impacts for Europe include changes in wind and solar resources, hydro power, cooling water availability for thermoelectric generation and electricity demand. Hence, it is not only important to understand the total effects, i.e., how much welfare may be gained when accounting for climate change impacts in all dimensions, but also to disentangle various effects in terms of their marginal contribution to the potential welfare loss. This paper applies a two-stage modeling framework to assess RCP8.5 climate change impacts on the European electricity system. Thereby, the performance of two electricity system design strategies – one based on no anticipation of climate change and one anticipating impacts of climate change – is studied under a variety of climate change impacts. Impacts on wind and solar resources are found to cause the largest system effects in 2100. Combined climate change impacts increase system costs of a system designed without climate change anticipation due to increased fuel and carbon permit costs. Applying a system design strategy with climate change anticipation increases the cost-optimal share of variable renewable energy based on additional wind offshore capacity in 2100, at a reduction in nuclear, wind onshore and solar PV capacity. Compared to a no anticipation strategy, total system costs are reduced.

Keywords: Climate Change, Variable renewable energy, Power system modeling

JEL classification: C61, Q41, Q42, Q48, Q54

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1. Introduction

The current nationally stated mitigation plans are expected to lead to a global warming of about 3 °C above pre-industrial levels by 2100 (IPCC (2018a)). Increasing the mitigation ambition levels is therefore key for a successful implementation of the central *well below 2 °C* statement of the Paris Agreement (United Nations (2015)). Scientific evidence indicates that ongoing climate change, particularly when reaching levels beyond 2 °C, will have severe consequences such as increasing surface temperatures, changes in water and wind availability and a rising frequency of extreme weather events (IPCC (2014), IPCC (2018a)).

The analysis of climate change scenarios suggests various ways of how changes in climate will affect complex and long-lived infrastructures like electricity systems.[1] Particularly for decarbonized electricity systems based on variable renewable energies (VRE), there are important and ample effects and mechanisms, how a changing climate will affect the (well-)functioning of electricity systems within the next 50 to 100 years.[2] For Europe, which is the focus of this analysis, most important are effects on VRE resources (both availability and gradients), hydro power availability, cooling water availability for thermal power plants and electricity consumption. Each of these effects may work differently in size, direction and transmission mechanism. E.g., periods with low wind speeds are expected to increase, potentially increasing the need for back-up energy (Moemken et al. (2018), Weber et al. (2018)). Low summer river flows with high water temperatures are expected to increase in frequency, affecting cooling water availability of thermoelectric power plants (Vliet et al. (2013), Tobin et al. (2018)). The hydro power potential is expected to experience on average a decrease in Europe due to changed precipitation patterns (Vliet et al. (2013), Schlott et al. (2018)). Furthermore, electricity demand for heating is expected to decrease in northern Europe, while electricity demand for cooling will increase in southern Europe (Eskeland and Mideksa (2010), Wenz et al. (2017)).[3] Hence, it is not only important to understand the total effects, i.e., how much welfare may be gained when accounting for climate change impacts in all dimensions, but also to disentangle various effects in terms of their marginal contribution to the potential welfare loss. This may be particularly relevant when accounting

[1]The technical lifetime of certain electricity sector assets like hydro and nuclear power plants, as well as grid infrastructure, spans time frames of 40 up to 80 years.

[2]Cost-optimal decarbonized electricity systems are expected to be largely based on VRE in light of recent VRE cost reductions, particularly for wind and solar PV, in combination with increasing awareness and regulation of environmental externalities (e.g., Ueckerdt et al. (2017), IPCC (2018b), IEA (2017)).

[3]Climate change impacts on biomass yield are not accounted for in this study, as the changes in biomass yield for electricity generation are expected to be small and the overall biomass energy potential in Europe is limited (IEA (2018)).

for uncertainties in climate change scenarios and discussing policy reactions and priorities.

In this paper, we will contribute to fill this research gap. Based on a detailed partial equilibrium model for the European electricity sector, we compare the evolution of electricity systems up to 2120, which in the planning, i.e. investment, either neglect climate change, or account for climate change. In the dispatch, of course, both systems have to cope with climate change. The difference between the two investment strategies will inform us on the order of magnitude of consequences that are caused when ignoring climate change in electricity system planning. Furthermore, each of the different effects of climate change may vary in its order of magnitude of impact on electricity systems. We will therefore disentangle the different effects by comparing isolated climate change effects to a world without climate change, focusing on an electricity system, which was planned without anticipation of climate change.

The analysis is based on a two-stage modeling framework building on a numerical large-scale partial equilibrium model of the European electricity market. In the first stage, the model is run in a long-term investment planning mode in order to derive the evolution of two cost-optimal power plant capacity mixes from 2015 until the year 2120, based on the two design strategies without and with climate change anticipation. For computational tractability, hereby a reduced temporal resolution based on typical days is applied. In the second stage, the model is run in a high-resolution dispatch mode with fixed power plant capacities from the first stage, representing a full year in hourly resolution. Thereby, the two systems are dispatched for a set of scenarios representing climate change impacts on wind and solar resources, hydro resources, cooling water availability for thermoelectric generation and electricity demand. This setup allows to investigate, on the one hand, the order of magnitude of isolated climate change impacts on an electricity system, which was designed without anticipation of climate change impacts. On the other hand, the performance of the two electricity system design strategies can be analyzed in a scenario representing the best-guess expectation of future climate change impacts, i.e. a scenario, where all climate change impacts occur combined. Variable renewable energy resource availability without and with climate change impacts is represented by a high-resolution dataset based on the EURO-CORDEX project. The analysis builds on one of the official scenarios of the IPCC reports on climate change, namely RCP8.5, which represents a scenario with very high greenhouse gas (GHG) emissions and accordingly drastic climate change. Far-reaching impacts on the worlds population and ecosystems are expected in consequence of a RCP8.5 climate crisis.[4]

[4]RCP8.5 is characterized by an increase in radiative forcing of 8.5 W/m^2 around the year 2100 relative to

Our analysis shows that the RCP8.5 climate change impact on wind and solar energy resource availability has the largest consequences for the European electricity system, compared to climate change impacts on hydro power, cooling water availability for thermoelectric generation and electricity demand. All isolated climate change effects on the supply side lead to a reduction in the availability of the respective technology, resulting in compensating electricity generation by other generation technologies. Additionaly, effects on electricity demand also require an increase in generation. A system designed without anticipation of climate change reacts to all isolated climate change effects with increased gas and biomass electricity generation in order to comply with the decarbonization target, however to different extents. The predominant impact of a reduction in VRE availability follows the intuition that systems based on high VRE shares, which are not allowed to adjust their investments, react sensibly – even to small changes in VRE availability. When subject to all climate change effects combined, system costs in 2100 increase by 24 bn EUR, or 12 %, due to increased fuel and carbon permit costs compared to a world without climate change, and marginal electricity generation costs show strong increases of 15 to 75 EUR/MWh. Applying a system design strategy based on climate change anticipation results in a trend towards wind offshore capacity in 2100, while nuclear, wind onshore and solar PV capacities are reduced. Overall, the share of VRE electricity generation is increased. The trend towards wind offshore is driven by a combination of reduced base-load nuclear capacity, cost structures and local capacity factor reductions in wind due to climate change, resulting in a shift in competitiveness towards wind offshore. Compared to a system designed without climate change anticipation, the climate change anticipating system reduces total system costs by 3.6 bn EUR in 2100 in a world with all RCP8.5 climate change impacts combined. Marginal electricity generation costs can thereby be reduced in most countries, with reductions ranging from -12 to -46 EUR/MWh.

Our contribution with respect to the existing literature is to i) analyze major impacts of RCP8.5 climate change on cost-optimal electricity system planning in a consistent manner, taking into account existing generation assets and path dependencies, and ii) to disentangle

pre-industrial values. The Representative Concentration Pathways (RCPs) describe different 21st century pathways of GHG emissions and atmospheric concentrations, air pollutant emissions and land use. The last IPCC reports on climate change were based on four RCPs, consisting of a stringent mitigation scenario (RCP2.6), two intermediate scenarios (RCP4.5 and RCP6.0) and one scenario with very high GHG emissions (RCP8.5). Business-as-usual scenarios without additional efforts to constrain emissions lead to pathways ranging between RCP6.0 and RCP8.5 (IPCC (2014)). Only RCP2.6 is representative of a scenario that aims to keep global warming likely below 2 °C above pre-industrial temperatures, in line with the Paris Agreement (United Nations (2015)).

various climate change impacts on electricity systems and compare their order of magnitude. Tobin et al. (2018) also assess climate change impacts on wind, solar PV, hydro and thermoelectric power generators. Their study focuses on how these single power generators are impacted, applying a consistent modeling approach. However it does not account for system effects between generators in a cost-optimizing framework. Nahmmacher et al. (2016b) analyze, how different power system design strategies are able to deal with shocks on the European power system, such as heat waves or periods of low wind production. The study investigates short-term shocks, which may be caused by climate change, however the focus does not lie on assessing the impacts of climate change based on a consistent framework within a specific climate change scenario. Wohland et al. (2017) and Weber et al. (2018) focus on back-up energy requirements in the European electricity system under RCP8.5 climate change impacts on wind energy. The studies are based on a back-up energy minimization problem, representing a simplified electricity system without a detailed representation of dispatchable power plant characteristics and climate change impacts other than on wind. They find an increase in long periods of low wind generation and seasonal variability, resulting in increased back-up requirements. Kozarcanin et al. (2018) use a simplified representation of wind, solar and a generic dispatchable power source to analyze climate change impacts on the European electricity system and key metrics such as short-term variability. Complex system interactions are not accounted for. Schlott et al. (2018) apply a detailed greenfield power system investment model to derive the cost-optimal European capacities of power plants and transmission lines under RCP8.5 climate change impacts on wind, solar and hydro power. They find an increase in the share of solar PV in the cost-optimal power system under climate change. The greenfield approach, however, does not take into consideration path dependencies of the power plant mix during the transition towards a decarbonized electricity system.[5] Also, interaction effects between base-load nuclear generation and VRE are not accounted for. Various studies investigate isolated impacts of climate change on VRE generation (e.g., Reyers et al. (2016), Moemken et al. (2018), Tobin et al. (2016), Tobin et al. (2015), Jerez et al. (2015)). However, these studies focus on meteorological aspects and isolated impacts on electricity generation from wind or solar PV, without a detailed representation of the entire electricity system. Additionally, none of the literature mentioned above disentangles and compares the single effects of climate change and assesses the order of magnitude of their impact on the electricity system.

[5] In a greenfield model, the power plant capacity mix in each considered model year is built without consideration of existing capacities from preceeding model years.

The remainder of the paper is structured as follows. Section 2 introduces the methodology. Section 3 introduces the scenario framework and data. Section 4 discusses the resulting impacts of climate change on electricity systems, based on a large-scale application for the European electricity system. Section 5 concludes.

2. Methodology

Throughout the paper, notation as listed in Table 1 is applied. Unless otherwise noted, bold capital letters indicate sets, lowercase letters parameters and bold lowercase letters optimization variables.

Sets		
$i \in \mathbf{I}$		Technologies
$m, n \in \mathbf{M}$		Markets
$y \in \mathbf{Y}$		Years
$d \in \mathbf{D}$		Days (**D**: Typical days or all days)
$h \in \mathbf{H}$		Hours (**H**: Reduced hours or all hours)
Parameters		
l	MWh	Exogenous electricity demand
l_{peak}	MWh	Peak electricity demand
x	-	Availability of electricity generator
$\bar{x}$	MW	Electricity generation capacity for dispatch
v	-	Capacity value of electricity generators
$\bar{k}$	MW	Transmission capacity
η	-	Efficiency
δ	EUR/MW	Fixed costs
γ	EUR/MW	Variable costs electricity generation
κ_i	tCO_2eq/MWh	Fuel-specific emission factor
GHG_{cap}	tCO_2eq	Greenhouse gas emissions cap
TC	bn. EUR	Total costs
Variables		
$\bar{\mathbf{x}}$	MW	Electricity generation capacity
$\mathbf{g}$	MWh	Electricity generation
$\mathbf{k}$	MWh	Electricity transmission between markets

Table 1: Model sets, parameters and variables.

2.1. Investment and dispatch model

In order to investigate the impacts of climate change on the European electricity system, this analysis applies a partial equilibrium model that determines the cost minimal configuration of the European electricity system, considering investment decisions as well as dispatch of power plants. The investment and dispatch model is based on optimization problem (1).[6] The commonly applied assumptions of market clearing under perfect competition, i.e. absence of market distortions, and inelastic demand, e.g. due to the lack of real-time pricing, allows to treat the problem as a cost minimization problem. With the complete time frame being optimized at once, the problem can be interpreted as a social planner problem where a social planner with perfect foresight minimizes total system costs for investment in generation capacity and the operation of generation and transmission between markets.

The objective function (1a) minimizes total costs TC over the complete time period, i.e., the sum of the fixed costs of generation capacity $\bar{\mathbf{x}}_{i,m,y}$ and variable costs of generation $\mathbf{g}_{i,m,y,d,h}$ of technology i in market m. The objective function is subject to various constraints: an equilibrium condition (1b) for supply and demand, two capacity constraints (1c) and (1d) to restrict generation and transmission, an electricity trade constraint (1e) for consistency, a peak capacity constraint (1f) to ensure sufficient firm capacity and a decarbonization constraint (1g) to limit carbon emissions for climate change mitigation.[7]

$$\min \ TC = \sum_{i,m,y} \delta_{i,m,y} \bar{\mathbf{x}}_{i,m,y} + \sum_{i,m,y,d,h} \gamma_{i,m,y,d,h} \mathbf{g}_{i,m,y,d,h} \tag{1a}$$

$$\text{s.t.} \quad l_{m,y,d,h} = \sum_{i} \mathbf{g}_{i,m,y,d,h} + \sum_{n} \mathbf{k}_{n,m,y,d,h} \qquad \forall m, y, d, h, m \neq n \tag{1b}$$

$$\mathbf{g}_{i,m,y,d,h} \leq x_{i,m,y,d,h} \bar{\mathbf{x}}_{i,m,y} \qquad \forall i, m, y, d, h \tag{1c}$$

$$|\mathbf{k}_{m,n,y,d,h}| \leq \bar{k}_{m,n,y} \qquad \forall m, n, y, d, h, m \neq n \tag{1d}$$

$$\mathbf{k}_{m,n,y,d,h} = -\mathbf{k}_{n,m,y,d,h} \qquad \forall m, n, y, d, h, m \neq n \tag{1e}$$

$$l_{m,y,peak} \leq \sum_{i} v_{i,m} \bar{\mathbf{x}}_{i,m,y} \qquad \forall m \tag{1f}$$

$$GHG_{y,cap} \geq \sum_{i,m,d,h} \kappa_i \, \mathbf{g}_{i,m,y,d,h} / \eta_{i,m} \qquad \forall y \tag{1g}$$

for technologies $i \in \mathbf{I}$, markets $m, n \in \mathbf{M}$ and time $y, d, h \in \mathbf{Y}, \mathbf{D}, \mathbf{H}$.

The large-scale model for the European electricity market applied in this analysis follows the same basic model structure as in Problem (1), however additional features are included in order to improve the representation of technical properties of electricity systems and

[6] See, e.g., Turvey and Anderson (1977) for a similar formulation of the integrated optimization problem for investment and operation in electricity systems.

[7] See, e.g., Peter and Wagner (2018) for a more comprehensive description of the constraints.

politically implied restrictions. Such features include for example capacity investment and decommissioning constraints, ramping and storage constraints, as well as a module for power-to-x processes such as electrolysis, which allows the model to produce carbon-neutral gases for use in the electricity sector in order to further decarbonize it. The model was originally presented in Richter (2011) and has been applied for example in Bertsch et al. (2016) and Peter and Wagner (2018). An extended version of the model including the power-to-x module is described in Helgeson and Peter (2018). The subsequent analysis covers the European electricity market represented by a total of 27 European countries.[8]

2.2. Performance of investment strategies without and with climate change anticipation

The goal of this analysis is to study the performance of electricity systems designed without and with anticipation of climate change under a variety of possible futures of climate change impacts. Thereby, a two-stage modeling framework is applied, based on a long-term investment planning stage and a high-resolution dispatch stage.

In the first stage, the long-term investment planning model (1) is run based on two design strategies, one without climate change anticipation (*No-CC-anticipation*) and one with climate change anticipation (*CC-anticipation*). It covers a time period from 2015 to 2120, applying 10-year time steps from 2020 onwards. Running investment planning models for such large time periods at full temporal resolution results in prohibitively high solving times. Therefore, for computational tractability, in this first stage, the investment and dispatch model applies a reduced temporal resolution based on 16 typical days.[9] In order to represent a full year, the typical days are scaled up by multiplying each typical day with its frequency of occurrence. Each typical day consists of eight time slices representing three consecutive hours.

In the second stage, the dispatch of the two power systems, *No-CC-anticipation* and *CC-anticipation*, is recalculated under a variety of possible climate change futures. As such, the performance of the two design strategies under different climate change impact scenarios can be assessed. In this second stage, the cost-optimal power plant capacities resulting from the two investment planning model runs are fixed, i.e. the capacity variables $\bar{\mathbf{x}}$ are treated as parameters $\bar{x}$:

[8] Austria (AT), Belgium (BE), Bulgaria (BG), Switzerland (CH), Czech Republic (CZ), Germany (DE), Denmark (DK), Estonia (EE), Spain (ES), Finland (FI), France (FR), Great Britain (GB), Greece (GR), Croatia (HR), Hungary (HU), Ireland (IE), Italy (IT), Lithuania (LT), Latvia (LV), Netherlands (NL), Norway (NO), Poland (PL), Portugal (PT), Romania (RO), Sweden (SE), Slovenia (SI), Slovakia (SK).

[9] As shown by Nahmmacher et al. (2016b), even less than 10 typical days are sufficient to obtain investment planning results that are similar to results based on a 365-day resolution.

$$\bar{x}_{i,m,y,dispatch} = \bar{\mathbf{x}}_{i,m,y,invest} \tag{2}$$

The dispatch of power plants is then calculated for single years running optimization problem (1) with fixed power plant capacities (2). Calculating single years without the investment stage allows to apply the full temporal resolution and consequently to consider the full variability and flexibility needs of the power system.

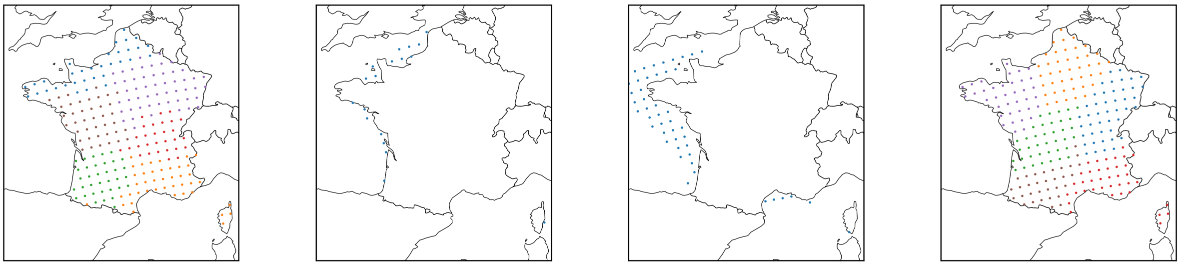
2.3. Clustering of variable renewable energy and load data

In order to study power systems with high shares of variable renewable energy, a detailed representation of weather-dependent renewable energy sources is required. However, in order to keep the large-scale investment planning model computationally tractable, the spatial and temporal resolution of wind and solar as well as load data has to be reduced. This analysis applies a two-step clustering approach as described in Peter and Wagner (2018), which will be briefly introduced in the following. A description of the utilized high-resolution data set will be given in Section 3.2.

In a first step, the spatial resolution is reduced by clustering the spatially high-resolved wind and solar data into representative wind and solar regions, where the number of regions for wind onshore and solar is chosen based on the surface area of each country. Wind offshore is accounted for by two regions per country, where applicable, with one region with water depths smaller than 50 m for bottom-fixed offshore wind turbines and one region with water depths between 50 m and 150 m for floating offshore wind turbines. Aggregated over Europe, this results in 54 representative regions for wind onshore and solar, respectively, and 41 representative regions for wind offshore.[10] Wind onshore, wind offshore and solar are clustered independently in order to capture the spatial properties of the different energy sources. As clustering method, this analysis applies the k-means clustering algorithm. After the spatial clustering, the time series of the representative regions are calculated by averaging over all data points within the respective cluster. Figure 1 shows exemplary spatial clustering results for France, where each data point is represented by a dot and color coding represents the resulting representative regions.

In a second step, a temporal clustering is performed in order to identify typical days at full hourly resolution. The goal of the temporal clustering is to reduce the temporal resolution without losing the statistical properties of weather-dependent VRE and load. As

[10]See Table B.7 in Appendix A for a complete list of the number of representative regions per country and variable renewable energy resource.



(a) Wind onshore (b) Wind offshore <50m (c) Wind offshore >50m (d) Solar

Figure 1: Results of spatial clustering for France for different variable renewable energy sources.

input for the temporal clustering, the spatially reduced VRE data, i.e. the time series of the representative regions determined in the first clustering step, and load time series on a country-level are combined as described in Section 3.2. This analysis applies a ward clustering algorithm for the temporal clustering and follows the approach presented in Nahmmacher et al. (2016a).

3. Scenario Definition and Data

3.1. Scenario definition

The scenarios applied in this study are based on two electricity system design strategies. The *No-CC-anticipation* system is based on a strategy of no climate change impacts anticipation. As such, for the investment planning, the social planner assumes no changes in, e.g. wind resources or cooling water availability due to climate change. The *CC-anticipation* system, on the other hand, foresees and takes into account impacts of climate change when planning power plant capacity investments.[11]

The two system designs are then dispatched under a variety of possible futures. Thereby, a set of seven scenarios is analyzed in order to study the order of magnitude of isolated climate change impacts and compare the performance of the two electricity system designs under all climate change impacts combined (Table 2). The first scenario, *No-CC*, represents the *No-CC-anticipation* system dispatched under no climate change impacts. The next four scenarios are defined by the *No-CC-anticipation* system being subject to four isolated impacts of climate change during high-resolution dispatch, namely impacts on variable renewable energy resources (*CC-VRE*), impacts on hydro power (*CC-hydro*), impacts

[11] Note that the impacts of climate change applied in the first stage (investment planning) are assumed to emerge from 2050 onwards.

on cooling water availability for thermal power plants (*CC-therm*) and impacts on electricity demand (*CC-eldem*). In the last two scenarios, *CC-all* and *CC-all-anticipation*, the two system designs *No-CC-anticipation* and *CC-anticipation* are dispatched under all climate change impacts combined.

Scenario name	Investment stage	Dispatch stage
No-CC	No climate change anticipation	No climate change impacts
CC-VRE	No climate change anticipation	Climate change impact on VRE
CC-hydro	No climate change anticipation	Climate change impact on hydro power
CC-therm	No climate change anticipation	Climate change impact on thermoelectric power
CC-eldem	No climate change anticipation	Climate change impact on electricity demand
CC-all	No climate change anticipation	All climate change impacts combined
CC-all-anticipation	Climate change anticipation	All climate change impacts combined

Table 2: Scenario definition

Comparing the five scenarios *CC-VRE*, *CC-hydro*, *CC-therm*, *CC-eldem*, and *CC-all* to scenario *No-CC* then allows to analyze and compare the order of magnitude of the isolated and combined impacts of climate change on the *No-CC-anticipation* system, respectively. Subsequently, a comparison of scenario *CC-all-anticipation* to scenario *CC-all* analyzes the behaviour of the two system designs when dispatched under a future with climate change impacts. Thereby, the performance of the two systems in dealing with climate change impacts can be assessed.

Next to the differences in scenario definition discussed in Table 2, all scenarios are based on an identical scenario framework as described in the following. The European electricity sector is subject to a decarbonization of minus 95 % in 2050 compared to 1990, implemented as yearly CO_2 quotas. From 2050 until 2120, the CO_2 quota is kept constant. Additional emission reduction targets for the intermediate years require a 21 % reduction in 2020 compared to 2005 and 43 % reduction in 2030 compared to 2005. For 2040, the emission reduction target is linearly interpolated. The emission reduction targets for 2020, 2030 and 2050 are based on official reduction targets formulated by the European Commission.[12]

Existing capacities in 2015 are taken from a detailed database developed at the Institute of Energy Economics at the University of Cologne, which is mainly based on the Platts WEPP Database (Platts (2016)) and constantly updated. Based on these start values, the model optimizes the European electricity system until the year 2120 in 10-year time steps from 2020 onwards. Investment into nuclear power is only allowed for countries with

[12]See https://ec.europa.eu/clima/policies/strategies for detailed explanations.

no existing nuclear phase-out policies. Investments in carbon capture and storage (CCS) technologies are not allowed due to a general lack of social acceptance in European countries. Fuel costs and investment costs for new generation capacities are based on the World Energy Outlook 2017 (International Energy Agency (2017)). Yearly national electricity consumption is assumed to develop according to the ENTSO-E Ten-Year Network Development Plan 2018 (ENTSO-E (2018)) with the values being kept constant from 2040 onwards. Transmission between countries is represented by net transfer capacities (NTC), which are assumed to be extended according to the ENTSO-E Ten-Year Network Development Plan 2018 (ENTSO-E (2018)). See Appendix B for a detailed presentation of numerical assumptions.

3.2. Data for variable renewable electricity generation and load

Next to the parameters used for scenario definition described in the previous section, a detailed representation of weather-dependent renewable energy sources is required in order to study power systems with high shares of VRE. This analysis applies a dataset for wind and solar resources for the historical 30-year time period (1970 - 1999) based on the EURO-CORDEX project (Jacob et al. (2014)).[13] The original data is resolved on a 0.11° grid (about 12.5 km) in 3-hourly resolution. For computational tractability, every fourth grid point of the original data was considered for this analysis, resulting in a grid of about 50 km in 3-hourly resolution. Wind speeds, which are available at 10 m, are extrapolated via power law to the respective hub height as in Henckes et al. (2019). Subsequently, wind speeds are converted to electricity generation via power curves based on state-of-the-art onshore and offshore wind power plants according to Henckes et al. (2019).[14] Based on this, a consistent hourly[15] 30-year time series of wind power capacity factors over whole Europe is generated for historical climate wind speeds (1970 - 1999).

Solar data is generated based on solar irradiance data of the EURO-CORDEX project for the same 50 km grid over Europe as for wind power generation. The methodology used to convert solar irradiance to electricity is described in detail in Frank et al. (2018) and Henckes et al. (2019). Again, based on this, a consistent hourly 30-year time series of

[13]The standard WMO climate normal is defined as a 30-year average, according to the World Meteorological Organisation (WMO) (Arguez and Vose (2011)). The EURO-CORDEX project provides - next to historical time periods - also data for future climate projections. Such data will be used to estimate impacts of climate change on wind and solar, as described in Section 3.3.1.

[14]This analysis is based on the onshore wind turbine Enercon E-126 EP4 and the offshore wind turbine Vestas V164. Power curves for both turbines were determined based on technical data on the manufacturer websites.

[15]The hourly time series are generated by taking identical values for each 3-hour interval of the original data in 3-hourly resolution.

solar power capacity factors over whole Europe is generated for historical climate irradation (1970 - 1999).

Load is assumed to be inelastic except for electricity demand from storage and power-to-x processes, which is part of the integrated optimization and thus endogenously determined. The assumption of inelastic load can be justified by Lijesen (2007), who found that price responsiveness during times of scarcity is low. Load data is based on hourly national vertical load[16] data for all considered countries for the years 2011 - 2015, taken from ENTSO-E (2016). It is important to note that such historical load measurements are the result of a functioning electricity market and may therefore include some price responsiveness of consumers or load shedding. Nevertheless, historical load is commonly seen as the best approximation of actual load time series. After normalization, the load data is scaled with the assumed yearly future electricity demand development in order to generate consistent time series.[17]

In order to generate a good representation of the joint probability space of wind, solar and load, each of the five load years in then combined with the 30 years of VRE data, while wind and solar data are kept synchronous.[18] This results in an ensemble of 150 synthetic years of hourly load and VRE data for historical climate data (1970 - 1999).

For the investment planning model, the 150 synthetic years are then used as input for the temporal clustering as described in Section 2.3, resulting in one year represented by 16 typical days.

For the high-resolution dispatch calculations, the 150 synthetic years are clustered to one year represented by 365 typical days. In doing so, the high-resolution dispatch can be run with a typical year generated from a large ensemble of data.

3.3. Description of climate change impacts

The impacts of climate change and resulting interaction effects within the power system can be isolated and analyzed by comparing the power system dispatch based on future climate projection data to the power system dispatch based on historical data, assuming that historical climate is still prevailing in the future in a world without climate change.

[16] National vertical load = national net electricity consumption + network losses.

[17] By scaling the normalized historical load time series with a future demand development scenario, it is assumed that the temporal structure of electricity demand does not change in the future. Possible changes in the temporal demand structure, e.g. from increasing electrification of the mobility or heat sector, are therefore not accounted for. However, changes in the temporal demand structure from storage and power-to-x processes are endogenously accounted for via the integrated optimization.

[18] Note that hereby, stochastic independence between load and VRE is assumed. Correlations between wind and solar, however, are accounted for via applying synchronous time series.

This analysis focuses on climate change scenario RCP8.5 (Meinshausen et al. (2011)), the most extreme scenario used in the latest IPCC reports. The likely range of global average temperature increase by the end of century (2081 - 2100) associated with RCP8.5 amounts to 3.2 - 5.4 °C compared to pre-industrial levels (1850 - 1900), resulting in severe climate change impacts (IPCC (2014)).[19] In combination with the 95 % decarbonization target for the European power sector, the realization of the RCP8.5 climate change scenario is constrained to a scenario of prevalent inaction with respect to decarbonization on continents other than Europe. As such, the underlying scenario of this analysis can be interpreted as an extreme scenario with strong climate action in the European power sector, accompanied with a strong weather-dependency due to VRE, and inexistent climate action in the rest of the world.

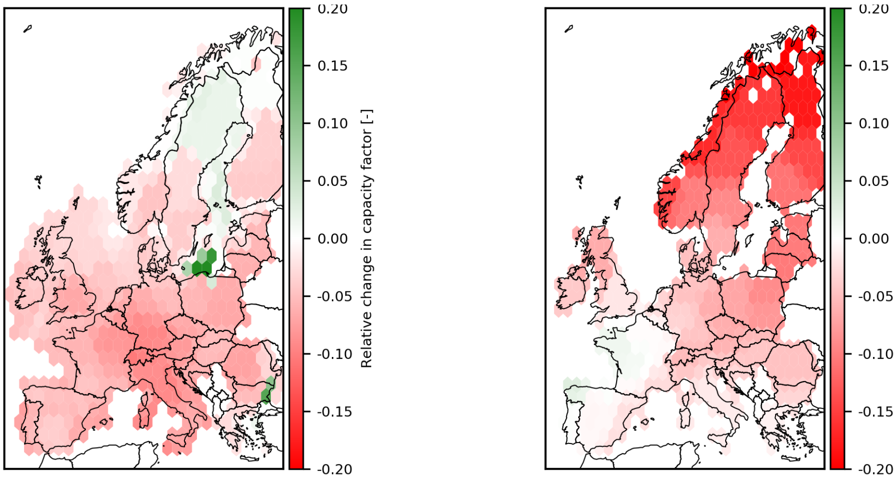
3.3.1. Impact of climate change on wind and solar generation

In order to study the impact of climate change on wind and solar power generation, data representing future changes in wind and solar energy potentials over Europe at a high temporal resolution are required. Such climate change affected weather datasets are, amongst others, available as ensemble members of the EURO-CORDEX project (Jacob et al. (2014)). Additional to the historical 30-year period (1970 - 1999), wind and solar power generation timeseries were calculated for a future 30-year period with RCP8.5 climate projection (2070 - 2099). In order to guarantee consistency, both 30-year periods were calculated using the same GCM-RCM[20] model chain: EC-EARTH (GCM) and RCA4 (RCM) from the EURO-CORDEX project. The original data from the RCM simulations is resolved on a 0.11° grid (about 12.5 km) in 3-hourly resolution. As for the historical data, for computational tractability, every fourth grid point of the original data is considered in this analysis, resulting in a grid of about 50 km in 3-hourly resolution. Wind speeds at 10 m are extrapolated to hub height and converted to electricity analogous to the historical dataset. Combined with the five load years, again 150 synthetic years are used as input for the temporal clustering as described in Section 3.2.

The resulting relative change in capacity factors of wind and solar energy due to RCP8.5

[19]Climate change impacts of RCP8.5 include more frequent hot temperature extremes and heat waves, extreme precipitation events, increased ocean acidification and sea level rise, strong reduction in near-surface permafrost and global glacier volume. Associated future risks of a RCP8.5 climate crisis affect food security, poverty, displacement of people, intensify competition for water and exacerbate already existing health problems (IPCC (2014)).

[20]Generation circulation models / global climate models (GCM) are global numerical climate models on a coarse spatial grid, which replicate large-scale circulation features of the climate. In order to increase the spatial resolution, GCM data are then used to drive regional climate models (RCM), which yield regionally higher resolved data, e.g. for Europe.



(a) Wind power

(b) Solar power

Figure 2: Relative change in wind and solar power capacity factor in 2100.

climate change in 2100 is shown in Figure 2. The general trend of a reduction in wind onshore capacity factor of -5 % to -15 % in central and southern Europe, and an increase in capacity factor by 5 % to 15 % in some parts of northern Europe is in line with previous literature (e.g., Moemken et al. (2018)). Changes in solar PV capacity factor include reductions in central and northern Europe from -2 % to -20 % and small increases in southwestern Europe by 2 %, similar to results in, e.g., Jerez et al. (2015).

3.3.2. Impacts of climate change on hydro generation

In order to estimate the impact of climate change scenario RCP8.5 on hydro power potential in Europe, this analysis builds on data provided by Schlott et al. (2018). They use three ensemble members of the EURO-CORDEX project as climate change affected weather datasets for water runoff under RCP8.5. Historical hydro inflow is characterized by major seasonal patterns. For example in Norway, Austria and Italy, one can observe major peaks during late spring due to snow melting and large inflow in autumn with its predominant rainfall. Climate change reduces the size of the spring peaks considerably, while at the beginning and end of the year, inflow increases (Schlott et al. (2018)). In Spain, however, the seasonal inflow pattern looks different: It shows homogeneous amounts during the whole year except for summer, where the inflow is almost inexistent. Climate change exacerbates this pattern in Spain, combined with a considerable overall reduction in total inflow (Schlott et al. (2018)).

In this analysis, country-specific average values of yearly changes in hydro potential from three ensemble members of the EURO-CORDEX project used in Schlott et al. (2018)

Austria	+18.4 | +12.3 %	Germany	-0.6 | -1.7 %	Norway	+2.6 | +21.1 %
Belgium	-0.5 | +1.6 %	Great Brit.	+4.6 | +4.5 %	Poland	+1.8 | +1.0 %
Bulgaria	-18.2 | -17.9 %	Greece	-29.4 | -27.6 %	Portugal	-18.8 | -20.1 %
Croatia	-7.6 | -10.5 %	Hungary	-5.1 | -6.3 %	Romania	-4.2 | -0.2 %
Czech Rep.	+0.7 | +1.9 %	Ireland	-2.1 | -2.6 %	Slovakia	n.a. | +1.3 %
Denmark	n.a. | +0.6 %	Italy	-3.6 | -5.7 %	Slovenia	-3.4 | -4.6 %
Estonia	n.a. | +20.6 %	Latvia	n.a. | +18.2 %	Spain	-23.3 | -24.1 %
Finland	+0.5 | +23.9 %	Lithuania	+23.9 | +24.7 %	Sweden	+1.8 | +25.6 %
France	-7.5 | -9.7 %	Netherlands	n.a. | -2.3 %	Switzerland	+20.5 | +15.3 %

Table 3: Changes in availability for hydro potential (Reservoir | Run-of-river), based on Schlott et al. (2018).

were applied (Table 3). The end-of-century hydro potential changes in European countries range between -29 % and 24 % for reservoir hydro inflow, and between -28 % and 26 % for run-of-river hydro.

3.3.3. Impacts of climate change on thermoelectric generation

Climate change is likely to impact cooling water availability for thermoelectric power plants. In particular coal-fired and nuclear power plants rely on large volumes of cooling water. Compared to other sectors like agriculture, industry or domestic use, the thermoelectric power sector has the largest share in water consumption, accounting for about 43 % of total surface water withdrawal (Vliet et al. (2013)). In recent warm and dry summers (e.g. 2003, 2006, 2009 and 2018), several thermoelectric power plants, in particular nuclear power plants, were forced to reduce electricity generation because of environmental restrictions on cooling water use based on water availability and legal temperature limits (Förster and Lilliestam (2010)). Several studies use simulations of daily river flow and water temperature projections using a physically based hydrological-water temperature modeling framework (e.g., Vliet et al. (2013), Tobin et al. (2018)). Their results show in line that due to climate change, periods with low summer river flows in combination with high water temperatures are expected to occur more frequently in Europe. Low flow values, defined as the 10-percentile of daily river flow, are projected to decline all over Europe except for Scandinavia. Strongest declines are expected in southern and south-eastern European countries like Spain, Italy, Bulgaria, Romania and Greece.

This analysis builds on data from Tobin et al. (2018) to estimate the impacts of climate change on cooling water availability of thermoelectric power plants (Table 4).[21] The re-

[21] The estimated impacts in Tobin et al. (2018) are discussed to be upper range estimates, as all thermo-

Austria	-8.3 %	Germany	-8.3 %	Norway	0.0 %
Belgium	-7.9 %	Great Britain	-8.3 %	Poland	-6.4 %
Bulgaria	-10.7 %	Greece	-10.0 %	Portugal	-0.8 %
Croatia	-8.4 %	Hungary	-5.6 %	Romania	-9.0 %
Czech Republic	-7.3 %	Ireland	-4.0 %	Slovakia	-7.7 %
Denmark	0.0 %	Italy	-8.9 %	Slovenia	-9.4 %
Estonia	-8.4 %	Latvia	-8.8 %	Spain	-10.9 %
Finland	-5.1 %	Lithuania	-8.6 %	Sweden	-5.5 %
France	-8.6 %	Netherlands	-8.4 %	Switzerland	-9.6 %

Table 4: Changes in availability in thermoelectric generation, based on Tobin et al. (2018) and Vliet et al. (2013).

ductions in thermoelectric power plant availability are imposed on nuclear, lignite and coal power plants.[22] Yearly availability reduction values in European countries range between -10.9 % and 0 %.

3.3.4. Impacts of climate change on electricity demand

Next to electricity supply, climate change is also expected to impact electricity demand due to adaptive responses to a changing environment. Short-term human responses to weather shocks and long-term adaptation to changing climatic conditions will alter electricity consumption in all sectors (Wenz et al. (2017)). Electricity demand for heating is projected to decrease in northern Europe and electricity demand for cooling will increase in southern Europe (Eskeland and Mideksa (2010)). Wenz et al. (2017) statistically estimate country-level dose-response functions between total electricity load and ambient temperature. The dose-response functions are then used to compute national electricity loads for temperatures that lie outside each country´s currently observed temperature range. This allows the authors to impose end-of-century climate under RCP8.5 on today´s European economies, ceteris paribus, e.g., with respect to the economic structure. They find a significant north-south polarization across Europe with increases in annual electriciy consumption in southern and western Europa and decreases in northern Europe.

electric power plants are assumed to be using river water (see discussion in Tobin et al. (2018)). To account for this and possible adaptive measures to reduce cooling water dependence, a factor accounting for adaptive measures based on Vliet et al. (2013) was applied on the cooling water availability reduction values from Tobin et al. (2018).

[22]Note that in some locations, lignite power plant cooling systems are connected to mine water, which reduces their vulnerability to low river flow occurrences. This does, however, not affect the results of this analysis, as in decarbonized power systems, lignite power plants without carbon capture and storage play no role.

Austria	-1.0 %	Germany	-0.8 %	Norway	-0.3 %
Belgium	-0.7 %	Great Britain	-1.7 %	Poland	-1.1 %
Bulgaria	+5.5 %	Greece	+7.3 %	Portugal	+3.6 %
Croatia	-2.5 %	Hungary	+0.6 %	Romania	+1.6 %
Czech Republic	-1.2 %	Ireland	-1.1 %	Slovakia	-0.8 %
Denmark	-1.4 %	Italy	+1.3 %	Slovenia	+0.4 %
Estonia	-3.0 %	Latvia	-2.4 %	Spain	+5.2 %
Finland	-2.5 %	Lithuania	-1.8 %	Sweden	-3.0 %
France	+0.9 %	Netherlands	-0.4 %	Switzerland	-1.3 %

Table 5: Changes in electricity demand, based on Wenz et al. (2017).

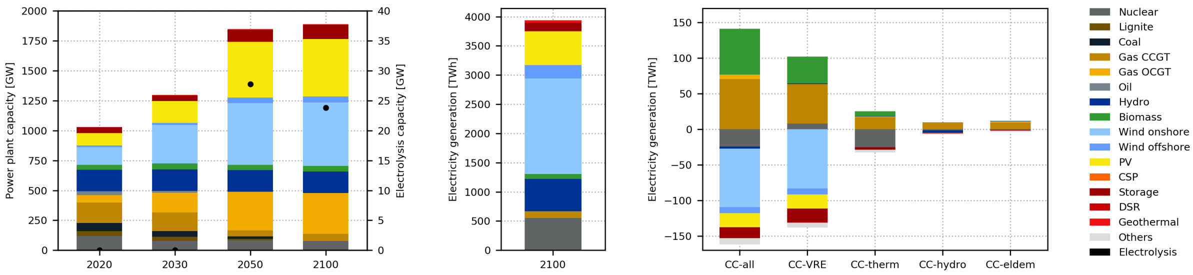
In this analysis, data from Wenz et al. (2017) were used to estimate the end-of-century changes in annual electricity consumption under RCP8.5 (Table 5). As relative percentage changes are calculated with respect to today´s economies, this analysis applies the changes to today´s electricity consumption in order to add the absolute change in consumption to the future development of country-level electricity consumption. The end-of-century electricity consumption changes in European countries range between -3 % and 7 %.

4. Results

Based on the introduced modeling framework and parametrization, this section assesses the resulting impacts of climate change on the European electricity system. Section 4.1 starts with a brief discussion of general trends of the cost-optimal capacity mix towards the end-of-century under a 95 % decarbonization target for the *No-CC-anticipation* system, i.e., a system without climate change anticipation. Based on this and given the assumptions on climate change impacts presented before, the performance of the *No-CC-anticipation* system under various climate change impacts is discussed. By comparing the effects, predominant impacts of climate change on the electricity system can be identified. Section 4.2 then discusses the cost-optimal *CC-anticipation* system, which anticipates climate change impacts. The section concludes by discussing allocation effects for wind and solar generation capacities as a consequence of climate change impacts.

4.1. Impacts of climate change on a system with no climate change anticipation strategy

The transition towards a cost-optimal 95 % decarbonization of the European electricity sector is driven by large-scale investments in wind and solar, as shown for the *No-CC-anticipation* system in Figure 3(a). In 2100, wind onshore capacity reaches 530 GW, wind offshore 50 GW and solar PV 481 GW. Nuclear power still plays a role in 2100 (79 GW), its cost-optimal capacity is however reduced by 35 % compared to 2020 due to competitive disadvantages. Flexibility is provided by interconnector capacities, storage (116 GW), hydro power (180 GW) and mainly open-cycle gas turbines (343 GW OCGT, 57 GW CCGT). After 2050, the cost-optimal mix of power plants sees only slight changes, mainly driven by the decommissioning of coal and nuclear power plants being replaced by VRE and gas power plants. In 2040, 1 GW of electrolysis starts to feed-in hydrogen into the gas grid for subsequent re-electrification. In 2050, the electrolysis capacity for decarbonized gas production reaches 28 GW, while in 2100, it is slightly reduced to 24 GW as the residual power system is further decarbonized via other technologies. Figure 3(b) presents the high-resolution dispatch of the *No-CC-anticipation* system in 2100 for a world without climate change impacts. About 63 % of electricity generation comes from VRE (42 % wind onshore, 6 % wind offshore, 15 % solar PV), 14 % from nuclear and hydro, respectively, 3 % from gas (with 18 % of the gas being decarbonized via hydrogen feed-in) and 2 % from biomass. In 2050, a small amount of lignite and coal capacity is kept online for capacity provision (Figure 3(a)), however its electricity generation is phased-out before 2050 due to decarbonization constraints.[23]



(a) Capacity (b) Generation (c) Generation difference in 2100

Figure 3: Power plant/electrolysis capacity, electricity generation in 2100, and difference in electricity generation in 2100 due to climate change impacts (*No-CC-anticipation* system).

In order to study the effects of climate change on the *No-CC-anticipation* system, the system is dispatched under various impacts of climate change as described in Section 3.3. Figure 3(c) shows the resulting difference in electricity generation compared to the dispatch in a world without climate change. Comparing the order of magnitude of isolated impacts, climate change impacts on wind and solar resources have the largest consequences for electricity generation (*CC-VRE*). The reduced resource availability of VRE results in reduced

[23]The suitability and economic business case of lignite and coal power plants being used for flexible capacity provision at very low capacity factors is debatable and would need a further in-depth analysis beyond the scope of this work.

electricity generation, mainly from wind onshore, but also wind offshore and solar PV. Given the fixed power plant fleet of the *No-CC-anticipation* system, the lack in electricity generation is offset by increased utilization of generation assets with upwards potential in capacity factor, such as gas and biomass power plants.

The next largest impact on the electricity system, however on a much smaller level, stems from climate change impacts on thermoelectric generation due to changes in cooling water availability (*CC-therm*). Mainly coal-fired and nuclear power plants will be affected due to their large consumption of cooling water. However, in view of the 95 % decarbonization target, in 2100 only nuclear capacity is still part of the cost-optimal power plant mix, whereas coal power plants mostly exit the market until 2050. The reduction in cooling water availability leads to an aggregated reduction in nuclear power generation of 25 TWh (4.6 %) in 2100. The missing generation is mainly compensated by gas generation (partly biogas), combined with some additional biomass generation and a gas fuel-switch from other generation sources to stay within the decarbonization target.

Impacts of climate change on hydro power potential lead to an aggregated reduction in hydro generation of 4 TWh on a European level (*CC-hydro*). On a region-specific scale, however, local climate change impacts on hydro potential are much larger, resulting in changes in hydro generation ranging between -29 % and 24 % for reservoir hydro, and between -28 % and 26 % for run-of-river hydro. The reduction in hydro generation on a European level is mainly compensated by increased gas generation (partly fueled with decarbonized gas from hydrogen feed-in and biogas), and minor shifts with other generation sources to keep the emissions balance.

Impacts of climate change on electricity demand stem from adaptive responses to changing climatic conditions (*CC-eldem*). On a European level, the cumulative change in electricity demand amounts to 8 TWh of additional demand. With heterogenous demand changes in different countries, ranging between -3 % and 7 %, the reaction of the electricity system also differs between countries. As a general trend on a European level, the additional demand is to large parts supplied by additional gas generation, which is partly decarbonized with feed-in hydrogen. To keep the emissions balance, some fuel-switch to gas from other generation with higher emission factors is observed.

All climate change impacts combined lead to cumulative effects on the power system due to decreased VRE, nuclear, hydro and storage generation (*CC-all*). The missing generation is replaced by gas and biomass generation, combined with a fuel-switch to gas from other generation to comply with the decarbonization target.

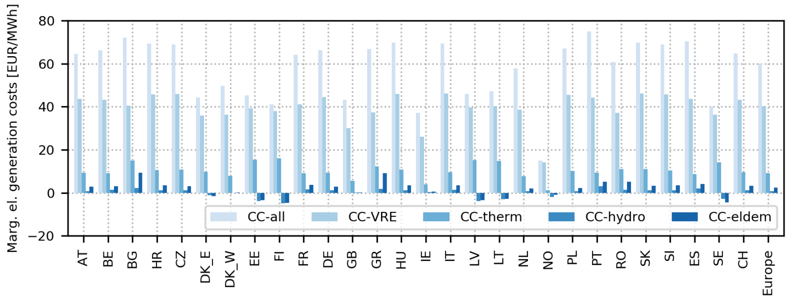


Figure 4: Differences in marginal electricity generation costs in 2100 due to climate change impacts (*No-CC-anticipation* system).

The changes in electricity generation mix due to climate change impacts translate into changes in marginal electricity generation costs (Figure 4). In line with Figure 3(c), the reduction in wind and solar generation (*CC-VRE*) due to climate change have the largest effect on annual mean marginal electricity generation costs, with absolute and relative increases ranging from 14 to 46 EUR/MWh and 43 % to 69 %, respectively. The impact of climate change on thermoelectric generation due to cooling water restrictions (*CC-therm*) also shows an increasing effect on marginal electricity generation costs, however on a much smaller scale with increases ranging from 1 to 16 EUR/MWh (9 % to 43 %). Impacts of climate change on hydro resource potential (*CC-hydro*) shows heterogeneous effects on marginal electricity generation costs, in line with the opposite direction of change. I.e., increasing hydro potential leads to decreasing marginal electricity generation costs. Resulting changes in marginal electricity generation costs range between -5 and 3 EUR/MWh (-9 % to 3 %). Changes in demand due to climate change (*CC-eldem*) also result in heterogeneous changes in marginal electricity generation costs, in line with the sign change compared to the dispatch in a world without climate change. Values range between -5 and 9 EUR/MWh (-8 % to 11 %). All climate change impacts combined (*CC-all*) lead to strong increases in marginal electricity generation costs between 15 and 75 EUR/MWh (100 % to 178 %).

The general trend of higher biomass and gas generation, partly fueled with decarbonized gas from hydrogen feed-in and biogas, combined with a fuel-switch from higher emitting other generation to gas results in higher fuel costs in 2100 (Figure 5).

Also, given the fixed decarbonization target and reduced generation from low-carbon technologies, the endogenous prices for carbon permits are bound to increase, resulting in higher spendings for carbon permits. Note that, as the power plant fleet is fixed in all scenarios (*No-CC-anticipation* system), capital costs and fixed operation and maintenance (FOM) costs do not change. Absolute and relative aggregated additional system costs over

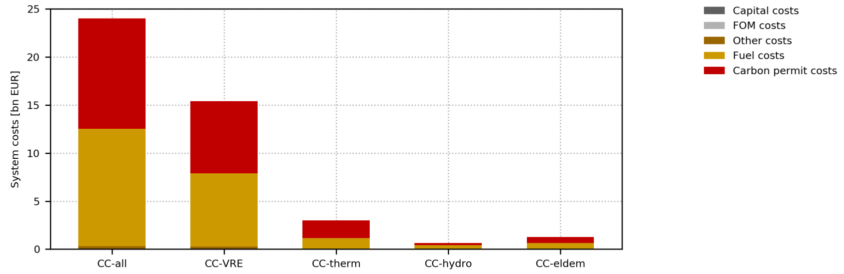


Figure 5: Difference in system costs in 2100 due to climate change impacts (*No-CC-anticipation* system).

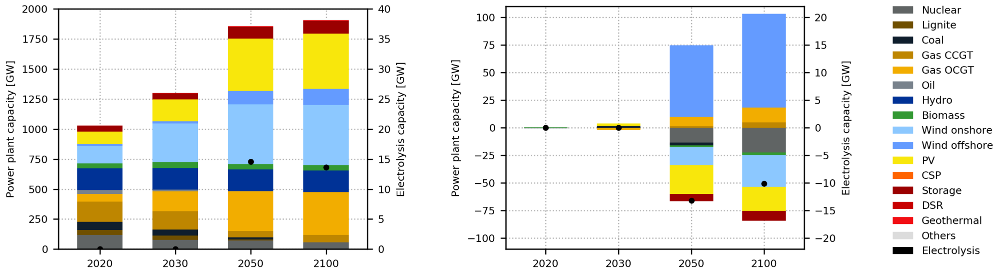
Europe amount to 15.4 bn EUR (8 %) in 2100 for changing wind and solar resources due to climate change (*CC-VRE*), and to 0.6 bn EUR to 3.0 bn EUR (0.3 % to 1.6 %) for changes in thermoelectric cooling water availability (*CC-therm*), hydro potential (*CC-hydro*) and electricity demand (*CC-eldemand*). Combined impacts of climate change on the *No-CC-anticipation* system result in additional costs of 24 bn EUR in 2100, which represents an increase of 12 %.

4.2. Impacts of climate change on a system with climate change anticipation strategy

In order to investigate changes in optimal system configuration when anticipating impacts of climate change, the investment planning model is run based on a climate change anticipation strategy, i.e., taking into consideration expected impacts of climate change. Thereby, from 2050 onwards, the social planner sees in perfect foresight what changes to wind, solar and hydro resources are expected to occur, as well as to which extent cooling water will be available and how electricity consumption will evolve under strong RCP8.5 climate change.

Figure 6(a) shows the resulting evolution of the cost-optimal European power plant mix for a 95 % decarbonization target with anticipation of climate change impacts. Again, in the long term, the *CC-anticipation* power system is mainly based on wind and solar capacity, while hydro, storage and gas serve as back-up capacity.

In contrast to the *No-CC-anticipation* system, the *CC-anticipation* system takes into consideration impacts of climate change. As such, the expected reduced availability of cooling water for nuclear power plants results in a 22 GW reduction in cost-optimal nuclear capacity in Europe in 2100 (Figure 6(b)). Also, expected reduced wind onshore and solar resource potentials result in 29 GW less wind onshore and 22 GW less solar PV capacity. At the same time, wind offshore sees a large increase of 85 GW over Europe. Apparently, even though wind offshore wind speeds are also expected to slightly decline in most parts

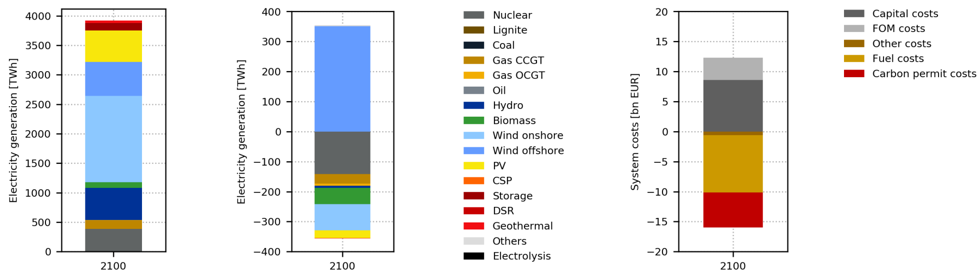


(a) Capacity

(b) Capacity difference

Figure 6: Power plant/electrolysis capacity (*CC-anticipation* system) and capacity difference compared to *No-CC-anticipation* system.

of Europe as a result of climate change (Figure 2), the combination of reduced base-load nuclear capacity, cost structures and local capacity factor reductions leads to a shift in competitiveness between wind onshore and offshore. Overall, the *CC-anticipation* system increases its VRE share, compared to the *No-CC-anticipation* system. Due to the reduced variability of the changed mix of VRE towards wind offshore, cost-optimal storage capacity is reduced by 9 GW. Also, 18 GW of additional gas capacities are built (13 GW OCGT, 5 GW CCGT). The expectation of higher marginal electricity generation costs in the *CC-anticipation* system results in a reduction of cost-optimal electrolysis capacity by 10 GW, because the competitiveness of other decarbonization options, such as biogas, is increased compared to the higher power-to-x fuel prices.



(a) Generation

(b) Generation difference

(c) System costs / emissions difference

Figure 7: Electricity generation in 2100 (*CC-anticipation* system) and difference in generation, system costs and emissions in 2100 compared to *No-CC-anticipation* system, dispatched under combined climate change impacts.

Cost-optimal electricity generation of the *CC-anticipation* system under combined climate change impacts in 2100 is characterized by a stronger dominance of VRE electricity generation, accounting for a share of 66 % (Figure 7(a)). In line with the difference in installed capacity, electricity generation from wind offshore increases to 15 % of total generation, while the share of wind onshore and nuclear decreases to 38 % and 10 %, respectively.

In order to assess the system performance in a world with climate change, in scenarios *CC-all* and *CC-all-anticipation*, the two strategies *No-CC-anticipation* and *CC-anticipation* are dispatched under all climate change impacts combined. In the *CC-anticipation* system, electricity generation from wind offshore sees a strong increase of 351 TWh compared to the *No-CC-anticipation* system under combined climate change impacts (Figure 7(b)). It partly replaces the increased gas and biomass generation being dispatched in the *No-CC-anticipation* system when subject to combined climate change impacts. On the other hand, it compensates for reduced nuclear, hydro, wind onshore and solar PV electricity generation due to their reduced capacity factors and resulting reduced cost-optimal capacities under combined climate change impacts.

Reduced nuclear, gas (partly from power-to-x) and biomass generation translates into reduced fuel costs of -9.5 bn EUR in 2100 (Figure 7(c)). As the *CC-anticipation* system is able to optimize its investments in decarbonized technologies, the carbon permit price is reduced compared to the *No-CC-anticipation* system, leading to a reduction in carbon permit costs of -5.8 bn EUR. While the *CC-anticipation* system features increased capital and fixed operation and maintenance costs, mainly driven by wind offshore investments, they are overcompensated by the fuel and carbon permit cost reductions. As a result, the cost-optimal power plant mix of the *CC-anticipation* system outperforms the *No-CC-anticipation* system in terms of total system costs by -3.6 bn EUR in 2100, which represents a reduction of -1.7 %.

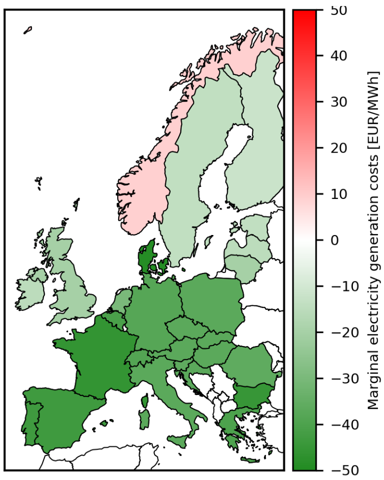


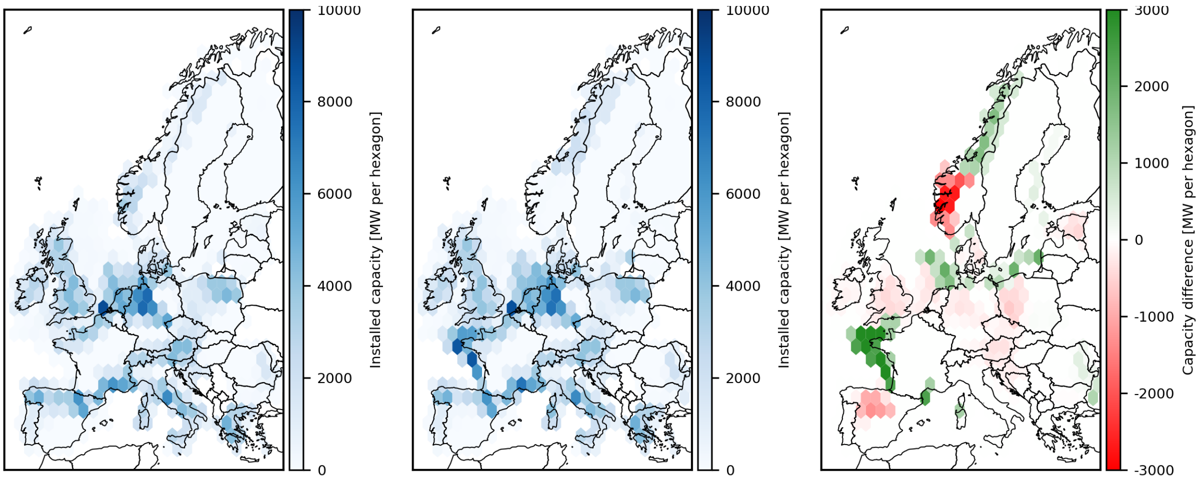
Figure 8: Difference in marginal electricity generation costs of the *CC-anticipation* system compared to the *No-CC-anticipation* system, dispatched under combined climate change impacts.

As the *CC-anticipation* system is optimized with respect to climate change impacts, its cost-optimal power plant mix leads in most parts of Europe to lower marginal electricity generation costs when dispatched under combined climate change impacts, compared to the *No-CC-anticipation* system (Figure 8).

This is mainly the result of increased VRE generation in the *CC-anticipation* system compared to increased gas and biomass generation in the *No-CC-anticipation* system, with resulting higher fuel and carbon permit costs to compensate for unforeseen climate change impacts. Interestingly, however, in Norway, a reduction in wind onshore capacity in the *CC-anticipation* system due to lower wind onshore capacity factors leads to an increase in marginal electricity generation costs compared to the *No-CC-anticipation* system. Reductions in marginal electricity generation costs in single countries range from -12 to -46 EUR/MWh, except for Norway with an increase of 9 EUR/MWh. On average, the marginal electricity generation costs in Europe decrease by -34 EUR/MWh.

4.2.1. Allocation effects of climate change anticipation on wind and solar capacity

The impact of climate change on wind and solar resources (Figure 2) on the one hand, and the configuration of the residual power system on the other hand influence the optimal allocation of wind onshore, wind offshore and solar PV capacity.



(a) Wind power capacity in 2100: No CC anticipation

(b) Wind power capacity in 2100: CC anticipation

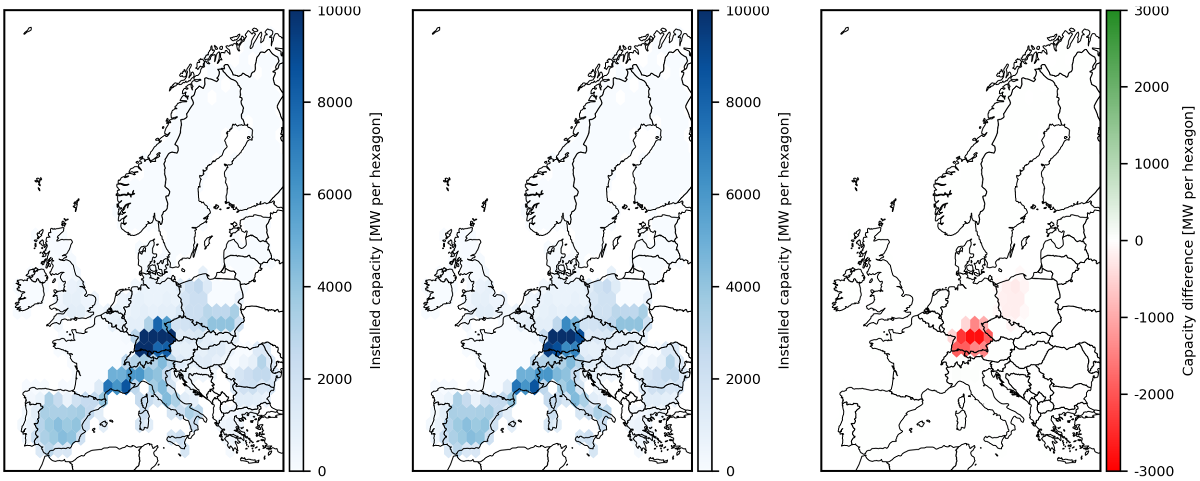
(c) Difference CC anticipation vs no CC anticipation

Figure 9: Allocation effects in optimal wind onshore and offshore capacity of the *CC-anticipation* system compared to the *No-CC-anticipation* system in 2100.

Figure 9(a) and 9(b) show the optimal allocation of wind onshore and offshore capacity in the *No-CC-anticipation* system and the *CC-anticipation* system, respectively. The resulting allocation effects are depicted in Figure 9(c).

Wind onshore capacity is overall reduced by 29 GW over Europe in 2100. Spain and Norway see a reduction in wind onshore capacity of -7 GW and -6 GW, respectively, while in Norway, there is a shift in optimal capacity allocation from south to the north. Great Britain, Germany, Poland, Austria, Slovenia, and Estonia also face reductions in cost-optimal wind onshore capacity, however at amounts lower than -4 GW. Relative reduction values compared to the total capacity per country range from -3 % to -10 %.

Wind offshore capacity is strongly increased by a total amount of 85 GW in Europe in 2100. The increased offshore wind capacity in the optimal *CC-anticipation* system is mainly located in north-western France (66 GW), the North Sea coast of Germany (10 GW) and Denmark (4 GW), as well as the Baltic Sea coast of Poland (5 GW) and Lithuania (3 GW). The changes in wind offshore capacity allocation is particularly relevant for grid reinforcement planning, due to the high grid connection costs of offshore wind sites and the long lifetime of grid infrastructure.



(a) Solar power capacity in 2100: No CC anticipation

(b) Solar power capacity in 2100: CC anticipation

(c) Difference CC anticipation vs no CC anticipation

Figure 10: Allocation effects in optimal solar PV capacity of the *CC-anticipation* system compared to the *No-CC-anticipation* system in 2100.

Changes in cost-optimal solar PV capacity allocation over Europe are depicted in Figure 10. Total solar PV capacity is reduced by -22 GW in 2100. Allocation effects of the *CC-anticipation* system compared to the *No-CC-anticipation* system can be observed in southern Germany (-20 GW, -16 %) and western Poland (-2 GW, -2 %).

5. Conclusion

This article analyzes the impacts of drastic climate change (RCP8.5) on the European electricity system by applying a two-stage modeling framework based on a large-scale partial equilibrium model of the European electricity market. Two electricity systems, which are based on a no climate change anticipation strategy and a climate change anticipation strategy, are dispatched under climate change impacts on wind and solar resources, hydro resources, cooling water availability for thermoelectric generation and electricity demand. Thereby, the order of magnitude of isolated climate change impacts on the no climate change anticipation electricity system is assessed. Building on that, the performance of the two electricity system design strategies is analyzed in a scenario representing the best-guess expectation of future climate change impacts, i.e. a scenario where all climate change impacts are combined.

The analysis shows that the RCP8.5 climate change impact on wind and solar energy resource availability has the largest consequences for the European electricity system, compared to climate change impacts on hydro power, cooling water availability and electricity demand. A system designed without anticipation of climate change impacts reacts to combined climate change impacts with increased gas and biomass electricity generation to compensate for the reduced capacity factors of wind and solar, reduced hydro generation, reduced nuclear generation due to cooling water constraints and increased demand due to climate change. In consequence, system costs in 2100 increase by 24 bn EUR, or 12 %, due to increased fuel and carbon permit costs. Marginal electricity generation costs show strong absolute and relative increases of 15 to 75 EUR/MWh and 100 % to 178 %, respectively. Applying a system design strategy based on climate change anticipation results in a large increase in cost-optimal wind offshore capacity in 2100 (85 GW), at a reduction of 29 GW wind onshore, 22 GW solar PV and 9 GW storage capacity. Consequently, overall cost-optimal VRE capacity increases. Nuclear capacity is reduced by 22 GW due to lower cooling water availability and resulting competitive disadvantages. The trend towards wind offshore is driven by a combination of reduced base-load nuclear capacity, cost structures and local capacity factor reductions in wind due to climate change, resulting in a shift in competitiveness towards offshore. Compared to a system designed without climate change anticipation, the climate change anticipating system reduces total system costs by 3.6 bn EUR in 2100 in a world with RCP8.5 climate change impacts. Marginal electricity generation costs can thereby be reduced by -12 to -46 EUR/MWh, except for Norway, where reduced wind onshore capacity factors due to climate change lead to an increase in marginal electricity generation costs of 9 EUR/MWh.

Our results imply that impacts of climate change show non-negligible effects on electricity systems with system cost increases up to 12 % when climate change impacts are not anticipated. Ramping up climate ambition to comply with the Paris Agreement and designing mitigation measures to avoid drastic RCP8.5 climate change impacts should therefore be treated with highest priority in order to limit economic damage in a world beyond 1.5 °C global warming, compared to a world with 1.5 °C (Burke et al. (2018), IPCC (2018a)). However, in order to be prepared for futures beyond 2 °C, which are likely from today's perspective, long-term electricity system planning based on energy scenarios from numerical optimization models should account for impacts of climate change. In particular considering the long technical lifetime of certain assets like hydro and nuclear power plants, as well as grid infrastructure, some decisions on the end-of-century electricity system design may have to be taken in the years to come. Thereby, in particular allocation effects in optimal wind onshore and wind offshore capacity should be accounted for. In order to reach cost-optimal allocation as a market outcome, the regulator may design a market environment focusing on transparent price signals, e.g., via nodal pricing. Considering the order of magnitude of isolated climate change impacts, next to impacts on VRE, the regulator is advised to take into consideration constraints in cooling water availability when setting the regulatory framework for cost-optimal power plant investments, including the choice of cooling technology.

In future work, this analysis could be extended to account for different climate change scenarios based on various GCM-RCM model chain combinations to account for the uncertainty of single climate model runs. Furthermore, the effect of increasing the temporal granularity of the impacts on hydro power potential, cooling water availability and electricity consumption could be analyzed. Finally, further research could extend this analysis towards robust decision making considering the uncertainty of different climate change futures.

Appendix A. Abbreviations

AT	Austria	FI	Finland	NL	Netherlands
BE	Belgium	FR	France	NO	Norway
BG	Bulgaria	GB	Great Britain	PL	Poland
CH	Switzerland	GR	Greece	PT	Portugal
CZ	Czech Republic	HR	Croatia	RO	Romania
DE	Germany	HU	Hungary	SE	Sweden
DK (East)	Eastern Denmark	IE	Ireland	SI	Slovenia
DK (West)	Western Denmark	IT	Italy	SK	Slovakia
EE	Estonia	LT	Lithuania		
ES	Spain	LV	Latvia		

Table A.1: Country codes

a	Years
bn	Billion
CCGT	Combined-cycle gas turbine
CCU	Carbon capture and utilization
CO_2	Carbon dioxide
CSP	Concentrated solar power
DSR	Demand side response
EUR	Euro
FOM	Fixed operation and maintenance
GCM	Generation circulation pathway / global climate model
GHG	Greenhouse gas
GW	Gigawatt
IPCC	Intergovernmental Panel on Climate Change
LCOE	Levelized costs of electricity
NTC	Net transmission capacity
OCGT	Open-cycle gas turbine
PV	Photovoltaics
RCM	Regional climate model
RCP	Representative concentration pathway
t	Ton
TWh	Terawatt hour
VRE	Variable renewable energy
WMO	World Meteorological Organization

Table A.2: Abbreviations

Appendix B. Numerical assumptions

Technology	**2015**	**2020**	**2030**	**2040**	**2050**	**...**	**2120**
Wind onshore	1656	1602	1548	1512	1476	...	1476
Wind offshore (bottom-fixed, <50 m depth)	3493	3168	2473	2236	2061	...	2061
Wind offshore (floating, >50 m depth)	3749	3460	2581	2300	2099	...	2099
Photovoltaics (roof)	1440	1152	972	882	792	...	792
Photovoltaics (ground)	1188	936	774	702	630	...	630
CSP	4494	3989	3429	3102	2805	...	2805
Biomass (solid)	3298	3297	3295	3293	3287	...	3287
Biomass (gas)	2826	2826	2826	2826	2826	...	2826
Geothermal	12752	10504	9500	9035	9026	...	9026
Hydro (river)	5000	5000	5000	5000	5000	...	5000
Compressed air storage	1100	1100	1100	1100	1100	...	1100
Pump storage	2336	1237	1237	1237	1237	...	1237
Battery	1000	1000	750	650	550	...	550
Nuclear	5940	5400	4590	4050	4050	...	4050
OCGT	450	450	450	450	450	...	450
CCGT	1031	900	900	900	900	...	900
IGCC	2350	2350	2350	2300	2300	...	2300
Coal	1800	1800	1800	1800	1800	...	1800
Coal (advanced)	1980	1980	1980	1980	1980	...	1980
Lignite	1596	1596	1596	1596	1596	...	1596

Table B.3: Assumptions on generation technology investment costs (EUR/kW). Conventional power plants, PV and wind onshore are based on scenario *New Policies* in World Energy Outlook 2017 (International Energy Agency (2017)). Wind offshore is based on Myhr et al. (2014), Heidari (2017), Engel (2014).

Technology	FOM costs (EUR/kW/a)	Net efficiency (-)	Technical lifetime (a)
Wind onshore	13	1	25
Wind offshore (bottom-fixed, <50 m depth)	93	1	25
Wind offshore (floating, >50 m depth)	93	1	25
Photovoltaics (roof)	17	1	25
Photovoltaics (ground)	15	1	25
CSP	100	0.37	25
Biomass (solid)	120	0.30	30
Biomass (gas)	165	0.40	30
Geothermal	300	0.23	30
Hydro (river)	12	1	60
Compressed air storage	9	0.70	40
Pump storage	12	0.76	60
Battery	10	0.90	20
Nuclear	101-156	0.33	60
OCGT	19	0.28-0.40	25
CCGT	24-29	0.39-0.60	30
IGCC	44-80	0.46-0.50	30
Coal	44-60	0.37-0.46	45
Coal (advanced)	64	0.49	45
Lignite	46-53	0.32-0.46	45

Table B.4: Assumptions on techno-economic parameters of electricity generators, based on scenario *New Policies* in World Energy Outlook 2017 (International Energy Agency (2017)) and Knaut et al. (2016).

Country	2015	2020	2030	2040	2050	...	2120
AT	70	73	77	81	81	...	81
BE	85	87	96	92	92	...	92
BG	33	41	34	44	44	...	44
CH	63	62	72	58	58	...	58
CZ	63	69	71	76	76	...	76
DE	521	565	576	576	576	...	576
DK_E	13	15	15	21	21	...	21
DK_W	20	26	24	33	33	...	33
EE	8	9	9	11	11	...	11
ES	263	268	273	290	290	...	290
FI	82	90	90	102	102	...	102
FR	475	481	501	469	469	...	469
GB	333	328	373	341	341	...	341
GR	51	57	55	70	70	...	70
HR	17	19	18	25	25	...	25
HU	41	43	42	52	52	...	52
IE	27	31	30	41	41	...	41
IT	314	326	318	405	405	...	405
LT	11	12	11	15	15	...	15
LV	7	8	9	10	10	...	10
NL	113	115	118	137	137	...	137
NO	128	136	152	148	148	...	148
PL	151	163	185	251	251	...	251
PT	49	51	49	58	58	...	58
RO	55	58	61	73	73	...	73
SE	136	142	160	146	146	...	146
SI	14	13	16	21	21	...	21
SK	27	29	33	36	36	...	36

Table B.5: Assumptions on the future development of net electricity demand including network losses (TWh), based on scenarios *Best Estimate* (2020), *European Commission* (2030), *Global Climate Action* (2040 - 2120) in TYNDP2018 (ENTSO-E (2018)).

Fuel type	2015	2020	2030	2040	2050	...	2120
Nuclear	3	3	3	3	3	...	3
Lignite	2	3	3	3	3	...	3
Coal	9	10	11	11	11	...	11
Oil	22	33	49	58	58	...	58
Natural gas	15	19	25	28	28	...	28

Table B.6: Assumptions on gross fuel prices ($\mathrm{EUR/MWh_{th}}$), based on scenario *New Policies* in World Energy Outlook 2017 (International Energy Agency (2017)).

	Number of clusters			
Country	**Wind onshore**	**Wind offshore (<50 m depth)**	**Wind offshore (>50 m depth)**	**Solar**
AT	1	0	0	1
BE	1	1	0	1
BG	1	1	1	1
CH	1	0	0	1
CY	1	0	0	1
CZ	1	0	0	1
DE	4	1	0	4
DK_E	1	1	1	1
DK_W	1	1	1	1
EE	1	1	1	1
ES	5	1	1	5
FI	3	1	1	3
FR	6	1	1	6
GB	2	1	1	2
GR	1	1	1	1
HR	1	1	1	1
HU	1	0	0	1
IE	1	1	1	1
IT	3	1	1	3
LT	1	1	1	1
LU	1	0	0	1
LV	1	1	1	1
NL	1	1	0	1
NO	4	1	1	4
PL	3	1	1	3
PT	1	1	1	1
RO	2	1	1	2
SE	4	1	1	4
SI	1	0	0	1
SK	1	0	0	1

Table B.7: Number of spatial clusters for VRE per country.

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