Analysis of the European energy system

under the aspects of flexibility and technological progress

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Table of contents

Executive Summary

Against the background of several European countries already using or currently considering the implementation of a capacity remuneration mechanism (CRM) as an extension to the energy-only market (EOM), this report provides a quantitative assessment of the long-term cross-border effects of CRMs in the European electricity system. For this purpose, the electricity market model PowerACE is applied to a region covering multiple interconnected European market areas with different market designs. Several long-term scenario analyses up to 2050 are carried out using the three scenarios “Mod-RES”, “High-RES decentralized” and “High-RES centralized”, which differ in terms of future electricity demand, renewable feed-in and technological composition of the renewable electricity generation. In order to quantitatively assess the long-term cross-border effects of CRMs in the European electricity system, a European EOM is then compared to a setting with national CRM policies for all three scenarios. Following this approach, valuable insights can be derived regarding the impact of national CRM policies on i) amount, location and technology mix of new investments in the electricity sector, ii) the resulting wholesale electricity price developments and iii) generation adequacy.

Across all investigated scenarios and market areas, a strong fuel switch towards gas-fired power plants can be observed as a result of the assumed CO_2 price development. Due to the more extreme assumptions with regard to CO_2 prices in the High-RES scenarios, carbon capture and storage technologies turn out to be profitable towards 2050, while this is not the case in the Mod-RES scenario. Furthermore, in all scenarios, storage technologies only play a minor role under the assumptions made.

With regard to generation adequacy, the introduction of CRMs proves to be an effective measure substantially shifting investment incentives towards the countries implementing the mechanism. The additional generation capacity in these countries in turn reduces both the average wholesale electricity prices and the amount of scarcity situations. Depending on a variety of factors, including the future development of electricity demand and renewable electricity generation as well as the geographical location of a given country, neighbouring countries of those implementing a CRM may face both positive and negative cross-border impacts.

Across all scenarios, CRMs seem to generally increase generation adequacy not only in the country implementing the mechanism, but also in the neighbouring countries, indicating that free riding occurs. Yet, also negative spill over effects can be observed for Denmark and the Netherlands in the Mod-RES scenario. The reduced investment incentives in these countries lead to a decrease of the generation adequacy level. Given the high priority of generation adequacy among policy makers, the European Commission should therefore continue to assess potential CRMs carefully prior to allowing their real-world implementation.

1 The European Debate on Electricity Market Design

Since the liberalization of the electricity markets in the 1990s, the prevailing market design in European countries has been the energy-only market (EOM), in which capacity providers are solely compensated for the amount of electricity they sell on the markets. In this market design, according to theory, scarcity periods lead to peak prices, which enables investors to recover their fixed and capital costs. In other regions of the world, e.g. in several US markets, so-called capacity remuneration mechanisms (CRMs) are a common extension of the EOM with the earliest implementations dating back to the late 1990s (Bublitz *et al.*, 2019). These mechanisms typically aim to reduce the investment risks by offering capacity providers supplementary income on top of the earnings from selling electricity on the market. The additional generation, storage or demand-side capacity may then in turn help to improve generation adequacy, i.e. avoid shortage situations. Following the classification of the European Commission (2016), six generic types of CRMs can be distinguished:

(1) *Tender for new capacity.* Financial support is granted to capacity providers in order to establish the required additional capacity. Different variations are possible, e.g., financing the construction of new capacity or long-term power purchase agreements.
(2) *Strategic reserve.* A certain amount of additional capacity is contracted and held in reserve outside the EOM. The reserve capacity is only operated if specific conditions are met, e.g., a shortage of capacity in the spot market or a price settlement above a certain electricity price.
(3) *Targeted capacity payment.* A central body sets a fixed price paid only to eligible capacity, e.g., selected technology types or newly built capacity.
(4) *Central buyer.* The total amount of required capacity is set by a central body and procured through a central bidding process so that the market determines the price.
(5) *De-central obligation.* An obligation is placed on load-serving entities to individually secure the total capacity they need to meet their consumers' demand. In contrast to the central buyer model, there is no central bidding process. Instead, individual contracts between electricity suppliers and capacity providers are negotiated.
(6) *Market-wide capacity payment.* Based on estimates of the level of capacity payments needed to bring forward the required capacity, a capacity price is determined centrally, which is then paid to all capacity providers in the market.

In recent years, several European countries seem to face threats in terms of the future generation adequacy and therefore have either already implemented some kind of CRM or are currently in the process of evaluating appropriate solutions (see Figure 1). These developments can be attributed to a variety of factors including strongly increasing shares of fluctuating electricity generation from renewable energy sources (RES), decreasing wholesale electricity prices as well as recent phase-out decisions for certain technologies. Yet, the tendency towards applying CRMs to increase investment incentives is conflicting with the European Commission's preference for an EOM in order to trigger new investments and provide signals for decommissioning in case of overcapacities. Moreover, in a highly interconnected electricity system like the European one, the uncoordinated implementation of local mechanisms might lead to potentially adverse cross-border effects, which stands in strong contrast to the European Commission's goal of creating an internal electricity market in Europe (Bublitz *et al.*, 2019).

This report therefore aims to provide a quantitative assessment of the long-term cross-border effects of CRMs in the European electricity system. The electricity market model PowerACE is applied to a region covering Central Western European and some Eastern European countries as well as Denmark and Italy. Different long-term scenario analyses up to 2050 provide valuable insights regarding the impact of national CRM policies on amount and location of new investments, the resulting technology mixes in the electricity sector as well as generation adequacy.

For this purpose, after briefly introducing the basics of the applied modelling approach in Section 2, Section 3 provides an overview of the scenario framework developed within the REFLEX project and some key assumptions. In Section 4, modelling results for the different scenarios are presented and discussed. Section 5 summarises the findings, draws conclusions and gives an outlook on future work.

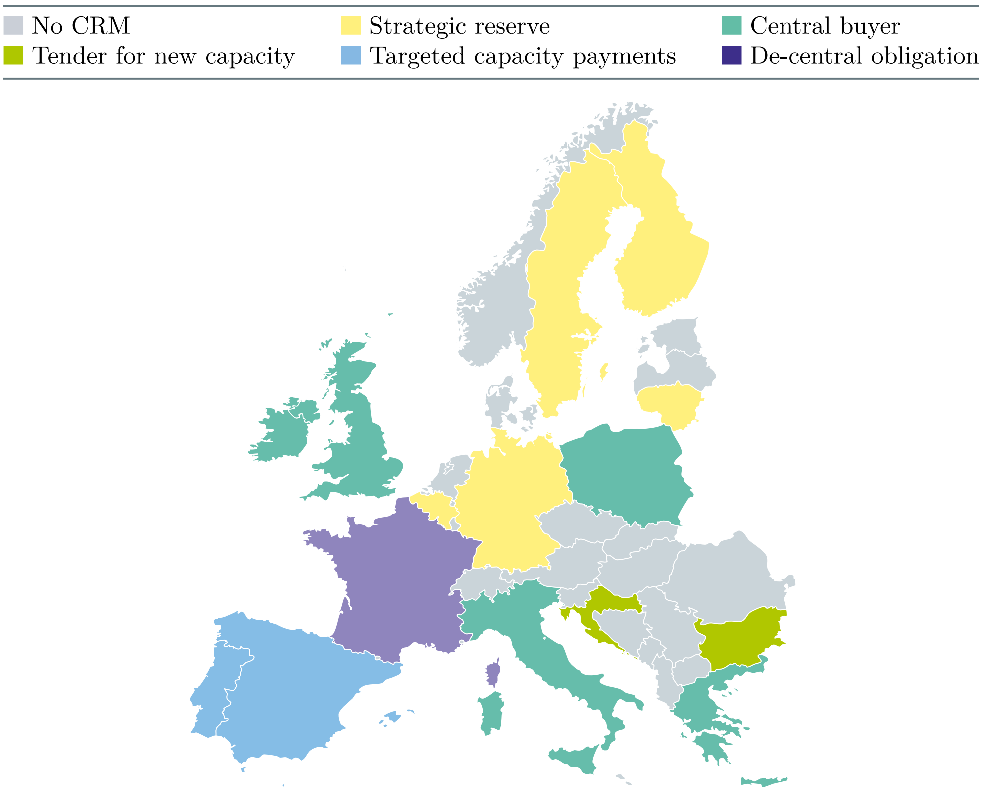

Figure 1: Overview of the future market designs across Europe when all planned CRMs are implemented. Already today, the mechanisms are poorly coordinated, which might intensify due to additional mechanisms being established within the next few years. Source: adapted from Bublitz *et al.* (2019), classification of mechanisms based on European Commission (2016)

2 Agent-Based Modelling Approach

2.1 Overview

PowerACE is an agent-based simulation model developed for the analysis of European electricity markets in long-term scenario analyses. The model runs at hourly resolution (8760 h/a) over a typical time horizon from 2015 up to 2050. As shown in Figure 2, PowerACE covers different market segments with a focus on the day-ahead market and different types of CRMs. Various agents represent the associated market participants, such as utility companies, regulators and consumers. The electricity suppliers can decide on the daily scheduling of their conventional power plants and storage units as well as on the construction of new conventional generation or storage capacities. Thus, the short-term and long-term decision levels are jointly considered and their interactions can be investigated. Ultimately, the development of the markets emerges from the simulated behaviour of all agents.

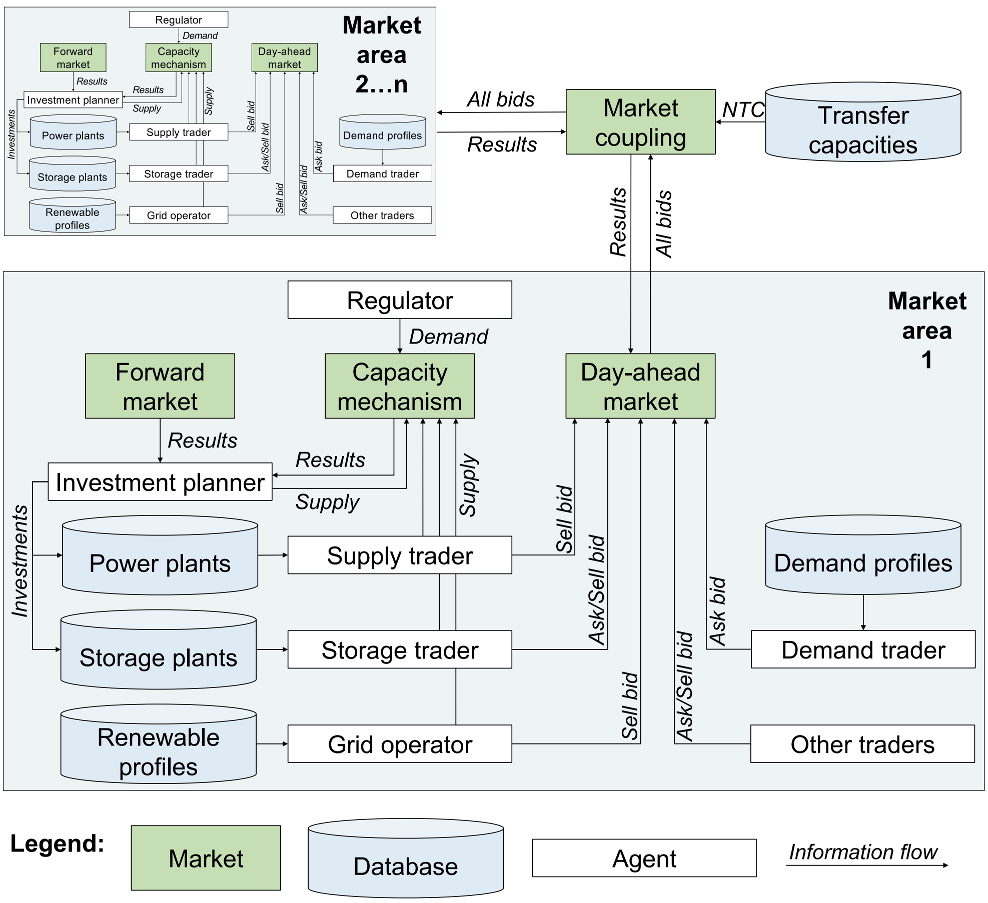

Figure 2: Overview of electricity market model PowerACE. The focus lies on the short-term simulation of the day-ahead markets and long-term investment decisions under consideration of different capacity remuneration mechanisms as well as cross-border effects.

2.2 DAY-AHEAD MARKET SIMULATION

PowerACE is structured into different market areas, in each of which multiple traders are active on the day-ahead market. All agents participating in the market first create a price forecast and then prepare hourly demand and supply bids. The bid prices for the supply bids are primarily based on the variable costs of the respective power plant. In addition, the price forecast is used to estimate the running hours of each power plant and to distribute the expected start-up costs accordingly. Further price-inelastic bids for demand, renewable feed-in and storage units are prepared by a single trader per market area, respectively. For details on the determination of the bid volumes for the storage units, please refer to Fraunholz *et al.* (2017). Once all bids have been prepared, they are submitted to the central market coupling operator. In the market clearing process, supply and demand bids are matched across all market areas, such that welfare is maximized subject to the limited interconnector capacities between the different market areas. For a formal description and details of the market coupling and clearing see Ringler *et al.* (2017). As a result, the information about which bids have been partly or fully accepted is returned to the different traders. Final outcome of the day-ahead market simulation is a market clearing price and corresponding electricity volume for each simulation hour and market area.

2.3 GENERATION AND STORAGE EXPANSION PLANNING

In addition to the short-term decisions on the day-ahead market, the different utility companies modelled as agents in PowerACE can also perform long-term decisions on investments in new flexible power plant and storage capacities at the end of each simulation year. Contrary to the common approach of generation expansion planning with the objective of minimizing total future system costs, again an actor's perspective is taken. Consequently, investments are only carried out if expected to be profitable by the investors according to their respective annuities. The overall investment planning procedure is depicted in Figure 3. The decisions of the different investors are primarily based on their expectations regarding future electricity prices. As these, vice versa, are influenced by the investment decisions of all investors in all interconnected market areas, a complex game with multiple possible strategies opens up. To find a stable outcome for this game, a Nash-equilibrium with the different market areas as players needs to be determined. Therefore, the expansion planning algorithm terminates when all planned investments are profitable and at the same time none of the investors is able to improve his expected payoff by carrying out further investments, i.e., there is no incentive for any investor to unilaterally deviate from the equilibrium outcome.

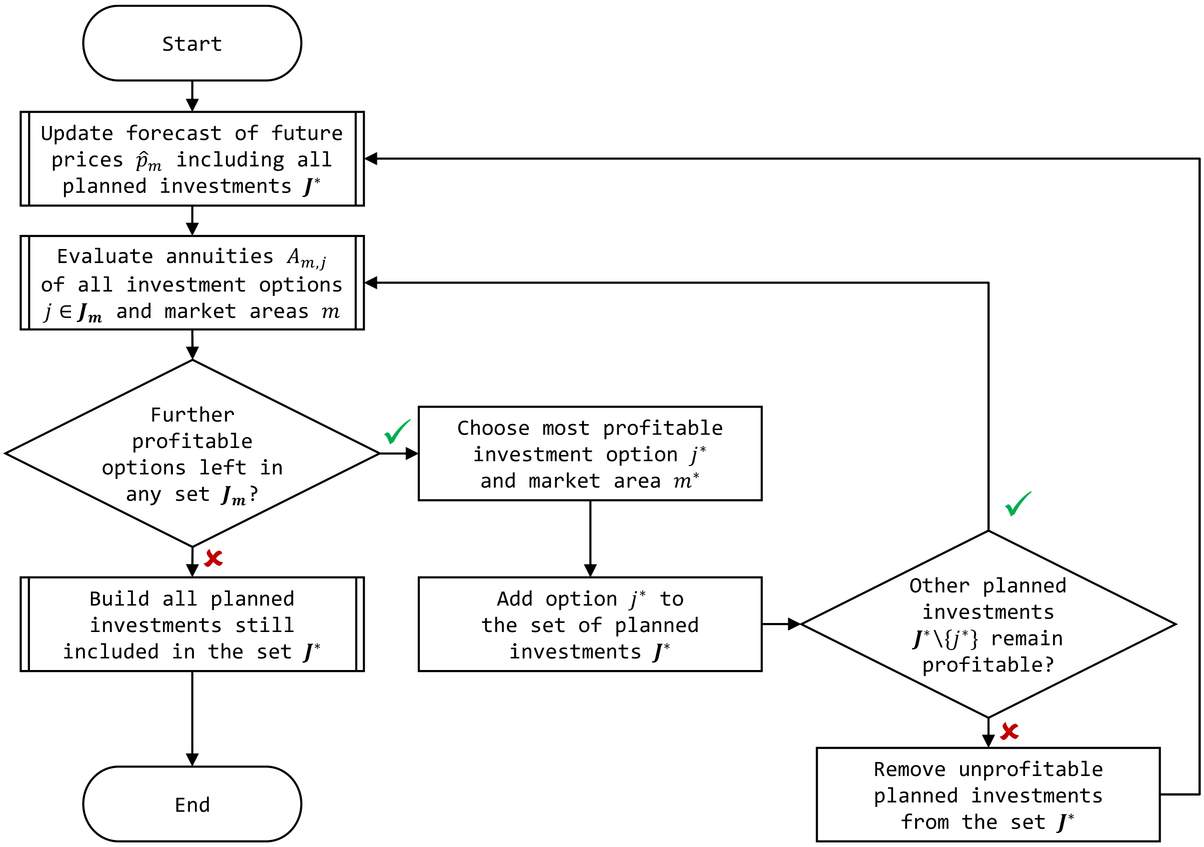

Figure 3: Simplified setup of the generation and storage expansion planning game implemented in PowerACE. The planned investments in all market areas are adjusted in an iterative procedure in order to consider cross-border impacts of investments in neighbouring market areas. The algorithm terminates once a Nash-equilibrium between all market areas has been found.

2.4 Modelled Capacity Remuneration Mechanisms

The following paragraphs briefly introduce the different CRMs implemented in PowerACE, namely a central buyer mechanism and a strategic reserve. For further details, please refer to Keles *et al.* (2016).

In the market areas with an active central buyer mechanism, annual descending clock auctions are carried out in order to contract a specific amount of secured generation and storage capacity. The regulator first sets a reserve margin, which is calculated as the ratio between secured capacity and maximum peak residual demand in the respective year, excluding imports. This margin is an arbitrary value, which controls the desired level of generation adequacy and defines the capacity to be procured in the auction.

Next, the different utility companies provide capacity bids consisting of volume and price. While existing capacity is offered at zero cost, the bids for potential new power plant and storage capacity are based on the respective difference costs. These are directly related to the general investment planning procedure. Investments expected to be profitable even without additional capacity payments bid into the auction at zero cost. If the desired reserve margin is not yet guaranteed through these investments, additional bids of the technology with the lowest negative annuity, i.e. the best, yet not profitable investment option, are placed into the auction. The bid price of these additional investments is determined based on the additional income that would be needed to recover all cost related to the respective investment, the so-called difference costs. Finally, the auction is cleared and all successful participants are compensated with a uniform capacity price, which is paid to the existing power plants and storage units for one year and to new constructions for an arbitrary longer period.

If active in the respective market area, the strategic reserve is contracted once every simulation year via a uniform price auction. The regulator sets a specific capacity target to be procured and the different utility companies can then offer their conventional generation capacities. Once part of the strategic reserve, a power plant is no longer allowed to participate in any other markets. For this reason, earnings from the strategic reserve have to cover all yearly costs of a given power plant, namely fixed costs for operation and maintenance as well as opportunity costs for lost income from e.g. the day-ahead market.

In reality, power plants in a strategic reserve are held outside the day-ahead market and are only dispatched if the market fails to clear. In PowerACE, the strategic reserve bids its full capacity into the day-ahead market at a price marginally below the maximum allowed market price of 3000 EUR/MWh. Consequently, similar to reality, the strategic reserve is only being used as a last resort in extreme scarcity situations. The accepted volume of the strategic reserve bid is then assigned to the different power plants in the reserve based on their variable costs. Although the power plant owners are compensated for the occurring variable costs, the large spread between dispatch price and variable costs is used by the regulator to reduce the total yearly costs of the strategic reserve.

3 Scenario Framework and Central Assumptions

3.1 Mod-RES and High-RES Scenarios

Within the REFLEX project, holistic socio-technical scenarios have been set up based on different scenario storylines, including the definition of the main scenario parameters as well as the societal and political environment. In the following, the key characteristics of the scenarios, which are relevant for this report, are briefly reviewed. For further details please consult Herbst *et al.* (2016a, 2016b).

The framework conditions of the moderate renewable scenario ("Mod-RES") are based on the EU Reference Scenario 2016 (Vita *et al.*, 2016). Mod-RES aims to reflect the development of electricity demand taking into account past dynamics as well as future trends regarding current economic development and energy policies. Therefore, policy targets and actions decided or implemented by the end of 2015 are reflected in Mod-RES. This scenario is not constructed to project the most probable future development, but rather serves as a benchmark to which the policy scenarios with ambitious decarbonisation pathways can be compared.

While the high renewable scenarios ("High-RES") are similar to Mod-RES in terms of population, economic growth and fossil fuel prices, the CO_2 prices are assumed to be higher. Consequently, High-RES represents a world with more ambitious climate policies, including the major target of limiting global temperature increase to 2°C by more drastically reducing greenhouse gas emissions. Moreover, higher contribution from learning curves and need for flexibility options due to a large share of intermittent renewable energy are assumed. In order to capture different potential development paths of a future energy system, two variants of the High-RES scenario have been developed. The major difference relates to the share of decentralized technologies on both generation and supply side in the sectors electricity, heat and transport.

This is also reflected in Figure 4, showing the development of electricity demand and renewable electricity production by technology for the different REFLEX scenarios. The presented values are aggregated over all market areas modelled in PowerACE (see Section 3.2). While the electricity demand grows moderately in the Mod-RES scenario, the substantially higher growth in the "High-RES decentralized" and "High-RES centralized" scenarios results from the various assumptions regarding technological developments and sector coupling. With regard to renewable feed-in, hydropower, biomass and geothermal remain unchanged between the scenarios, while significantly more intermittent renewables, i.e. wind and solar power, are assumed in both High-RES scenarios. While the High-RES decentralized scenario is dominated by decentralized solar power, the High-RES centralized scenario is characterised by higher shares of offshore wind power. For detailed information on the development and composition of the electricity demand as well as the determination of the future electricity generation from RES, please refer to Zöphel *et al.* (2019).

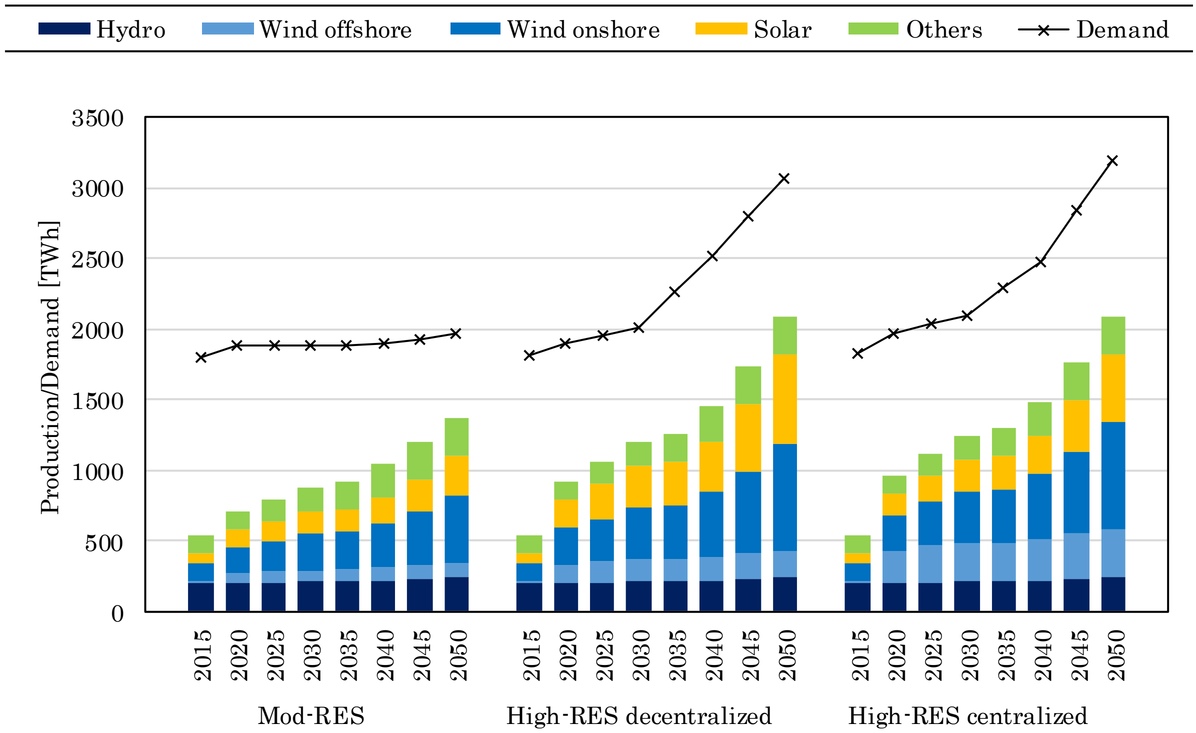

Figure 4: Assumed development of electricity demand and renewable electricity production by technology for the three different REFLEX scenarios. The presented values are aggregated over all market areas modelled in PowerACE (see Figure 5). Both demand and renewable feed-in grow significantly stronger in the two High-RES scenarios as compared to Mod-RES. Regarding the renewable feed-in, the High-RES scenarios are almost identical in terms of the produced electricity, but differ with regard to the composition by technology. Source: REFLEX project data

3.2 Regional Scope and Market Design

All three REFLEX scenarios (Mod-RES, High-RES decentralized, High-RES centralized) are analysed considering two different settings with regard to electricity market design: the “European EOM” which serves as a benchmark and the “National CRM policies” which considers the respective market design of each country as currently implemented or planned. In order to capture a variety of different design options and the corresponding cross-border effects, the regional scope of PowerACE covers Central Western European and some Eastern European countries as well as Denmark and Italy (see Figure 5). Please note, that due to the similarities of the different types of CRMs on an abstract level, the French CRM is modelled using the central buyer implementation in PowerACE, although in reality, a de-central obligation mechanism is used in France. This will not change the effects of the French CRM, since in France the regulator sets a specific capacity level to be contracted, as it is the case in the central buyer mechanism. Moreover, the electrical grid is only considered in a simplified fashion by assuming maximum cross-border transmission capacities, while intra-zonal restrictions are not accounted for.

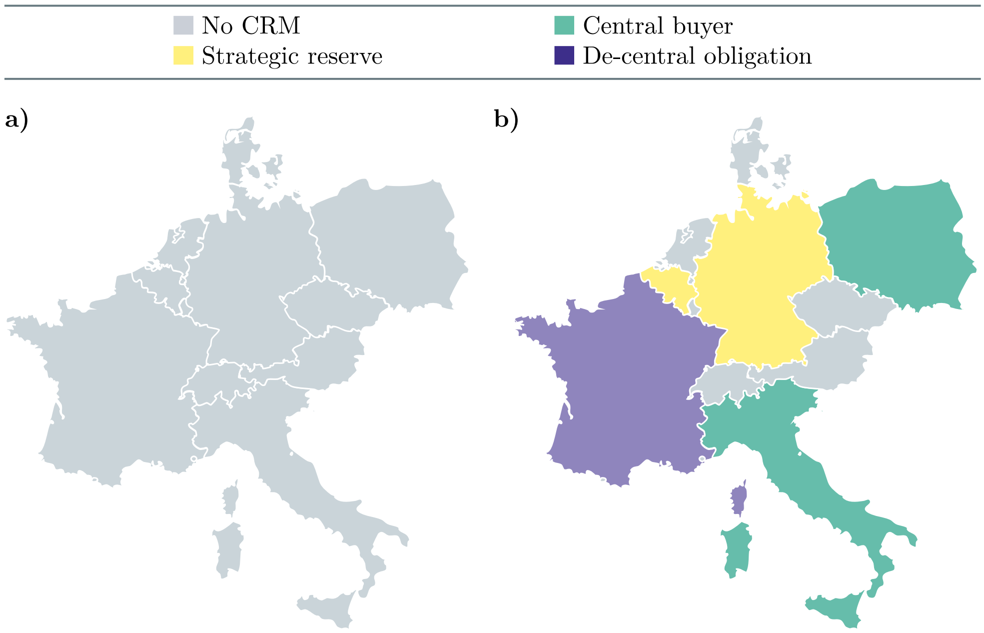

Figure 5: Overview of the market areas modelled in PowerACE and their respective market design in a) the "European EOM" setting and b) the "National CRM policies" setting. In order to capture a variety of different design options and corresponding cross-border effects, the regional scope covers Central Western European and some Eastern European countries as well as Denmark and Italy.

3.3 Investment Options

As introduced in Section 2.3, the different utility companies modelled as agents in PowerACE can perform long-term decisions on investments in new conventional power plant and storage capacities at the end of each simulation year. Contrary, decommissioning of existing power plants is exogenously defined based on the respective age and technical lifetime of the generation units, which remain unchanged for all scenarios. Consequently, the development of the future technology mix across the various scenarios strongly depends on the techno-economic characteristics of the different investment options. Split up into conventional power plants and storage technologies, Table 1 and Table 2 provide an overview of the investment options modelled in PowerACE. As described before, the expansion of RES is an exogenously defined and scenario-specific input to PowerACE, so that no additional investments in renewable technologies are considered model-endogenously. Further assumptions include the restriction of certain investment options to selected market areas for political reasons, such as the German decision to phase-out nuclear power by 2022. Moreover, learning curves have been developed within the REFLEX project to account for increasing efficiencies and decreasing investment related to new technologies, such as carbon capture and storage (CCS) as well as storage technologies. Further details on the determination of the learning curves for the various technologies can be found in Louwen *et al.* (2018a, 2018b).

Table 1: Overview of conventional power plant investment options modelled in PowerACE. Due to the respective political situation, eligibility of the different fuel types varies across the modelled market areas. Source: Schröder *et al.* (2013), Louwen *et al.* (2018a, 2018b), own assumptions

Generation technology	Block size	CCS	Net efficiency[1]	Lifetime	Building time	Specific investment[1]	O&M costs fixed	O&M costs var.[2]
	$[MW_{el}]$	[y/n]	[%]	[a]	[a]	$[\frac{EUR}{kW_{el}}]$	$[\frac{EUR}{kW_{el} \cdot a}]$	$[\frac{EUR}{MWh_{el}}]$
Nuclear	1600	n	33	60	8	6000	60	3.3
Coal	600	n y	45–48 36–41	40	4	1800 3143–2677	60	6 43.1
Lignite	800	n y	43–47 30–33	40	4	1500 3840–3324	30	7 44.4
CCGT	400	n y	60–62 49–52	30	4	800 1216–1078	20	5 24.1
OCGT	400	n	40-42	30	2	400	15	3

Abbreviations: CCGT—combined cycle gas turbine, CCS—carbon capture and storage, OCGT—open cycle gas turbine, O&M—operation and maintenance

[1] As a result of technological learning, these values are assumed to decrease over the simulation period of 2015 until 2050.

[2] Including variable costs for carbon capture, transport and storage, where applicable.

Table 2: Overview of storage investment options modelled in PowerACE. Source: Louwen *et al.* (2018a, 2018b), own assumptions

Storage technology	Block size	Storage capacity	Round-trip efficiency[1]	Lifetime	Building time	Specific investment[1]	O&M costs fixed[1]
	$[MW_{el}]$	$[MWh_{el}]$	[%]	[a]	[a]	$[\frac{EUR}{kW_{el}}]$	$[\frac{EUR}{kW_{el} \cdot a}]$
Pumped Hydro	1000	10000	75	55	4	1667	17
Li-ion Battery	100	400 1000	84–98	15	2	3028–694 7348–1684	61–14 147–34
Redox-flow Battery	100	1000	60–75	20	2	4222–752	84–15
A-CAES	300	3000	60–75	40	2	1095	22

Abbreviations: A-CAES—adiabatic compressed air energy storage, O&M—operation and maintenance

[1] As a result of technological learning, these values are assumed to decrease over the simulation period of 2015 until 2050.

4 Investments in Flexibility Options Considering Different Market Designs

In the following, the simulation results for all three REFLEX scenarios are presented and discussed. Using a European EOM as a benchmark, the focus lies on the impact of the national CRM policies on i) amount, location and technology mix of new investments, ii) the resulting wholesale electricity price developments and iii) generation adequacy.

4.1 Mod-RES Scenario

4.1.1 Development of Conventional Generation and Storage Capacities

By setting a certain capacity target and then offering payments additional to the income from selling electricity on the markets to capacity providers, CRMs shift investment incentives in interconnected electricity markets towards the countries using such a mechanism. In neighbouring countries, investment incentives may stay stable, but are more likely to decrease due to the additional capacity from abroad, which also influences domestic price expectations of potential investors.

For three exemplary countries, Figure 6 presents the development of the total conventional generation and storage capacities throughout the simulation period of 2020 to 2050 for the Mod-RES scenario. Furthermore, the respective yearly national peak residual load, excluding imports/exports and storage is depicted as a reference point. The capacity developments are based on exogenously predefined decommissioning, which is identical for all settings investigated, as well as on model-endogenous investment decisions for different technologies.

Some general trends across the modelled countries can be identified. Firstly, a strong fuel switch towards gas-fired technologies is noticeable, which is mainly driven by increasing CO_2-prices. Secondly, CCS technologies are not part of the future technology mix in any of the modelled countries. Apparently, the CO_2 price development is not high enough to achieve cost-competitiveness in view of the higher initial investment and variable costs as compared to the conventional technologies. Thirdly, apart from some A-CAES plants in Italy (not depicted), no storage investments are realised in the model. This is related to the relatively small share of electricity generation from RES in the Mod-RES scenario. Moreover, the residual load curves provided to PowerACE as exogenous input data are already smoothed by demand-side management measures (for details see Zöphel *et al.*, 2019), which further reduces storage requirements and profitability.

Comparing the European EOM with the national CRM policies, slightly lower total capacities develop in Germany in the long run, despite the introduction of their strategic reserve. Contrary, total capacities in France are significantly higher under the national CRM policies due to the introduction of the French CRM, which shifts investment incentives towards France leading to additional open cycle gas turbines. For this reason, peak-load capacity is no longer required, or more precisely, no longer profitable in the Netherlands, leading to a strong decline of gas turbine investments under the national CRM policies.

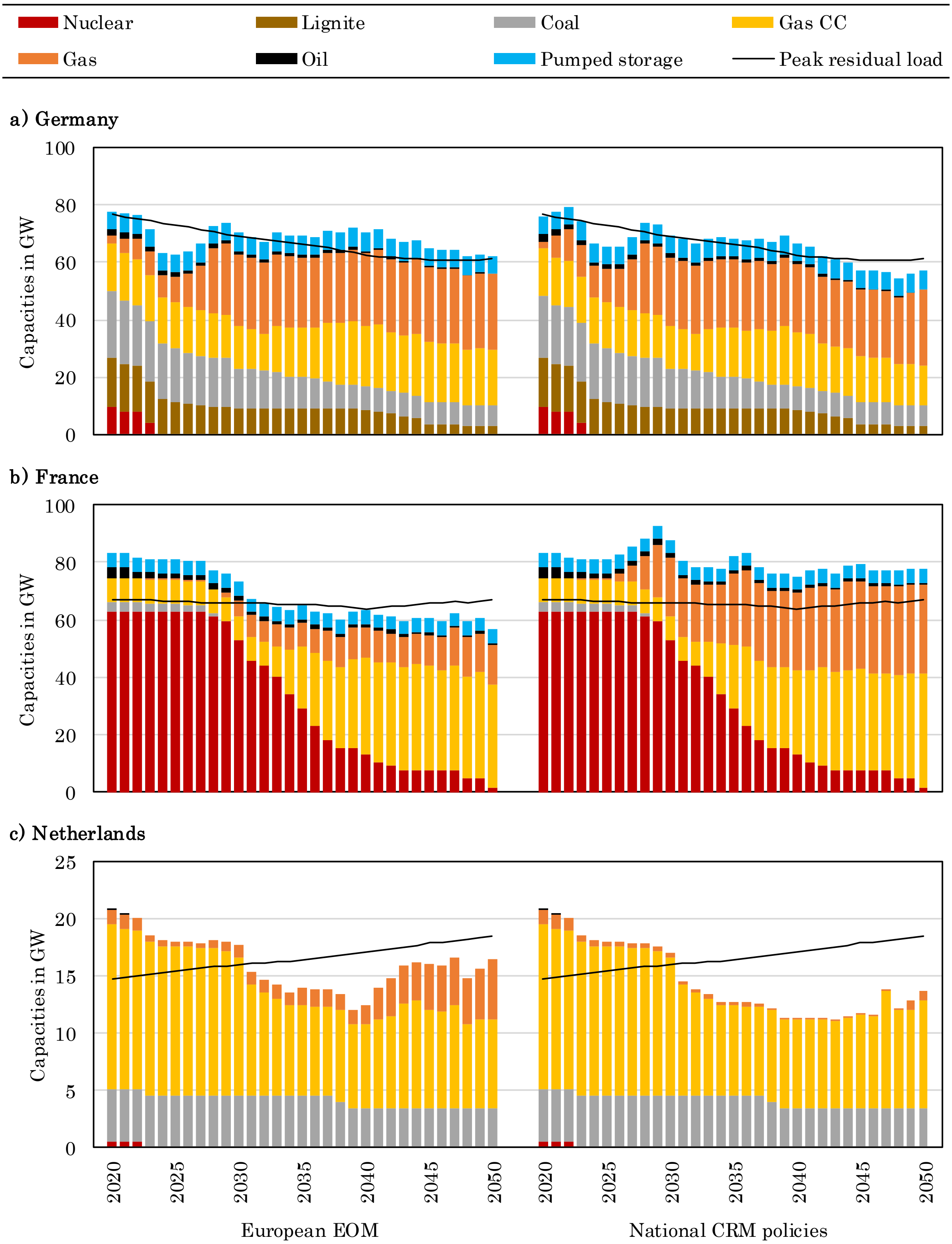

Figure 6: Total generation and storage capacities in the Mod-RES scenario for three exemplary countries. A strong fuel switch towards gas-fired technologies can be observed, while no investments in storage technologies are realised. Despite its strategic reserve, somewhat lower capacities in Germany develop under national CRM policies. In France, significantly more gas turbines are built, while the Netherlands built less due to the market design changes.

4.1.2 Wholesale Electricity Prices

From a theoretical point of view, the introduction of CRMs should reduce the amount of scarcity situations and related peak prices and therefore result in lower electricity wholesale prices in the country using the mechanism. However, additional investments due to a CRM also influence the investment decisions in neighbouring market areas, leading to potential cross-border effects of CRMs in both positive and negative direction.

For the Mod-RES scenario, Figure 7 presents the impact of national CRM policies on average wholesale electricity prices as compared to a European EOM. The respective yearly mean prices under a European EOM market design are the base for the calculation of the price deviations and therefore represented as the 0% line. The yearly relative price differences are then calculated as shown in Equation (1). Since dynamic effects lead to substantial differences between the different simulation years, the values in Figure 7 are shown in the form of a box plot where the mean is marked with ×, the whiskers stand for minimum and maximum values and the boxes represent the first quartile, the median and the third quartile.

$$\Delta p_{year,country}^{\text{relative}} = \frac{\overline{p_{year,country}^{\text{National CRM policies}}} - \overline{p_{year,country}^{\text{European EOM}}}}{\overline{p_{year,country}^{\text{European EOM}}}} \quad (1)$$

Figure 7 shows that the average wholesale prices are somewhat lower almost throughout the simulation period in France (mean −4%) and Italy (mean −3%) under the national CRM policies, indicating that these countries both benefit from the introduction of their CRM. In Switzerland, prices also decrease marginally (mean −1%, but at higher fluctuations than Italy), most likely due to spill over effects of the French CRM. Across all other countries, the average prices show a moderate increase (mean between +3% and +4%) after the introduction of the national CRM policies.

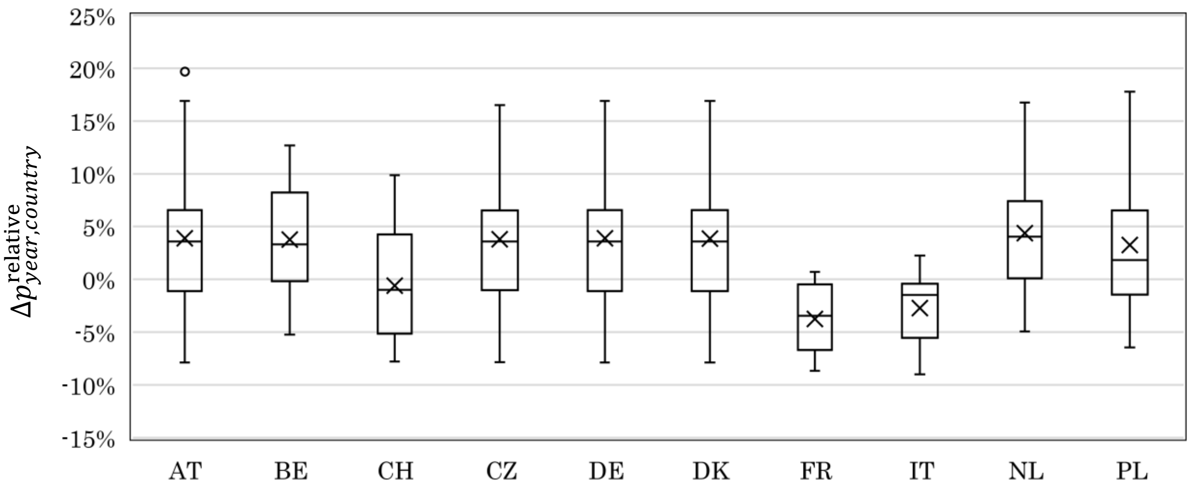

Figure 7: Relative difference between the yearly mean wholesale electricity price under national CRM policies and under a European EOM in the Mod-RES scenario. The box plots present the range of the yearly differences for all years between 2020 and 2050. France and Italy benefit from the introduction of their respective CRMs and therefore face lower average wholesale prices. Switzerland seems to free ride, which also leads to slightly lower prices, while prices in all other countries rise by some percent on average.

This effect is mainly driven by lower investment incentives for peak-load capacity in these countries resulting from the additional capacity in the countries using CRMs. Surprisingly, the introduction of the Polish CRM does not have a price-dampening effect in Poland. A major reason for this finding is, that only relatively little additional capacity is being built in Poland as a result of their CRM, whereas the impact of the respective CRMs is significantly stronger in France and Italy. Free riding by Poland’s neighbouring countries as well as negative spill over effects of the German strategic reserve could be additional drivers.

For the three exemplary countries, Figure 8 presents the same data contained in Figure 7 in a different form. In order to gain a better understanding of the dynamics, the yearly development of the relative price differences is shown and a linear trend curve is then applied to the data points. Although, as already visible in Figure 7, both positive and negative price differences occur for Germany and the Netherlands, the trend suggests, that in the long run, the average prices increase for both of these countries under the national CRM policies. This finding is related to the developments of the conventional generation capacities: towards the end of the simulation period, the gap between the total capacities under a European EOM and under national CRM policies grows for both Germany and the Netherlands (see Figure 6). Contrary, in France, under the national CRM policies, the average prices are lower almost throughout the simulation period. This is a direct outcome of the introduction of the French CRM.

4.1.3 *Impact on Generation Adequacy*

Generation adequacy refers to the ability of an electricity system to provide sufficient generation and storage capacity to cover the residual load at all times. Since the electrical grid is not modelled in PowerACE – apart from the simplified consideration of maximum cross-border transmission capacities – grid restrictions are not considered in the evaluation of the generation adequacy. Yet, the focus of this work is rather on the ability of different electricity market designs to provide adequate investment incentives to achieve a sufficient level of dispatchable generation and storage capacity under consideration of the respective cross-border effects. Therefore, two different indicators – the hours with no successful clearing of the day ahead market and the energy-not-served (ENS) volumes – are considered in order to assess the level of generation adequacy in the different countries under both a European EOM and national CRM policies.

In Table 3, the average yearly hours with no successful clearing of the day-ahead market are shown. This market failure is interpreted as a shortage of generation and storage capacity in one or multiple market areas resulting in the maximum day-ahead market price of 3000 EUR/MWh. It is important to mention that due to the coupling of the different market areas, the maximum day-ahead price often occurs in multiple market areas at the same time, even if only one area faces an actual scarcity situation. For the same reason, the introduction of national CRM policies affects all modelled market areas positively in terms of the hours with no successful market clearing. Yet, even in the market areas introducing a CRM, hours with “imported” scarcity situations and therefore with the maximum day-ahead price still occur to some extent.

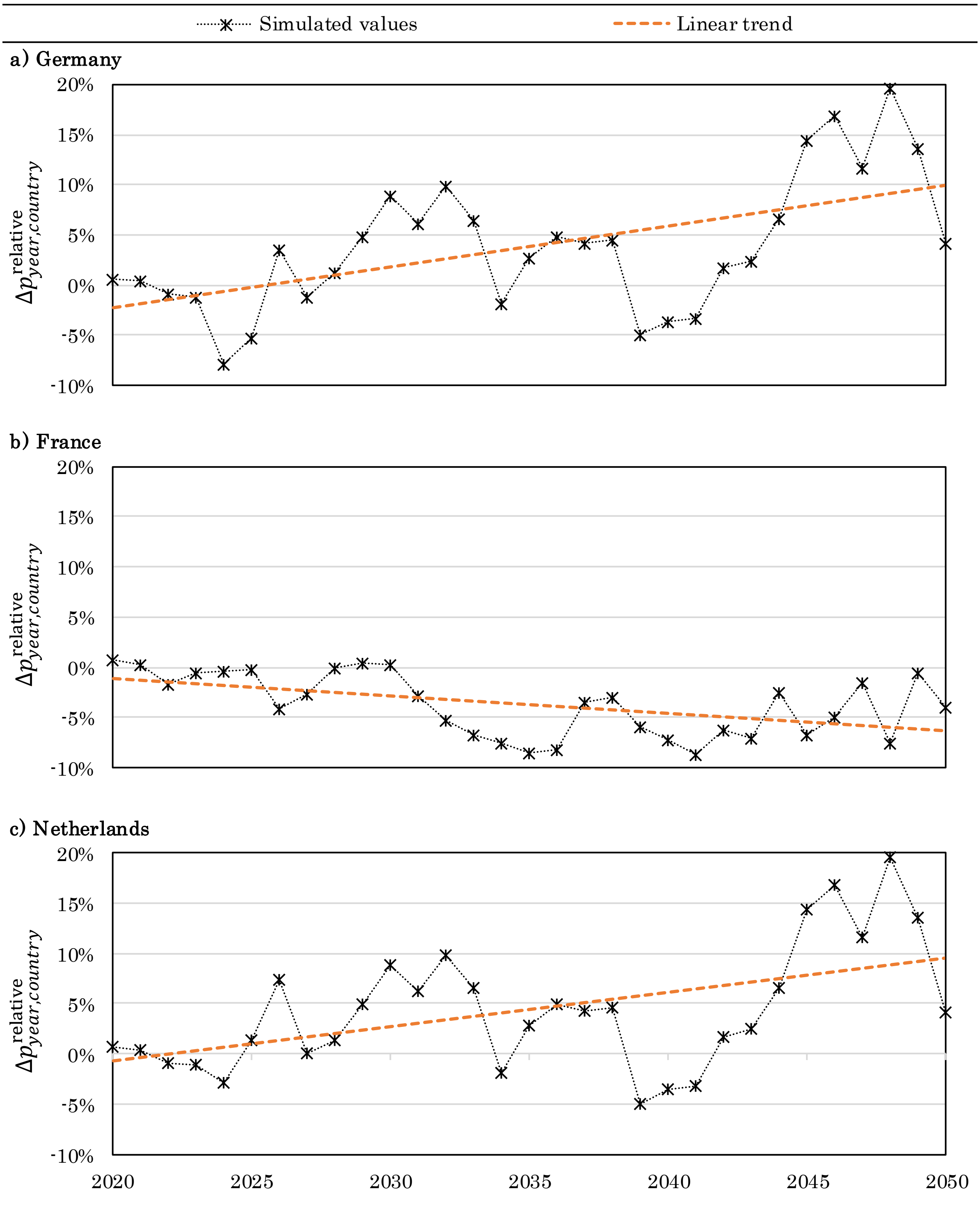

Figure 8: Development of the relative price differences between the yearly averages of the wholesale electricity prices under national CRM policies as compared to a European EOM in the Mod-RES scenario. Three exemplary countries are shown: in the long run, Germany and the Netherlands are confronted with increasing average prices under the national CRM policies, while France benefits from the introduction of their CRM leading to lower average prices.

Table 3: Mean yearly hours with no successful clearing of the day-ahead market, i.e. the maximum day-ahead market price of 3000 EUR/MWh due to a shortage of generation and storage capacity, in the Mod-RES scenario. The different colours represent the respective market designs as introduced in Section 3.2. All values are averaged over the years 2020 to 2050. While all modelled market areas are positively affected by the national CRM policies, even the countries introducing a CRM still face some hours with “imported” scarcity situations.

Scenario	Unit	AT	BE	CH	CZ	DE	DK	FR	IT	NL	PL
European EOM	[h/a]	35	29	36	35	35	35	26	21	31	31
National CRM policies	[h/a]	25	18	18	25	25	25	9	7	24	23
Change	[-]	−27%	−38%	−50%	−27%	−27%	−27%	−68%	−68%	−22%	−26%

Table 4: Mean yearly ENS volumes, i.e. demand that is curtailed due to a shortage of generation and storage capacity, in the Mod-RES scenario. The different colours represent the respective market designs as introduced in Section 3.2. All values are averaged over the years 2020 to 2050. While France and Italy both manage to reduce their ENS volumes by 100% as a consequence of introducing their CRMs, the remaining countries are affected by either positive or negative spill over effects of the market design changes in their neighbouring countries.

Scenario	Unit	AT	BE	CH	CZ	DE	DK	FR	IT	NL	PL
European EOM	[GWh/a]	21	13	7	13	86	10	66	43	20	3
National CRM policies	[GWh/a]	7	8	0	11	42	14	0	0	34	1
Change	[-]	−66%	−32%	−97%	−12%	−52%	+47%	−100%	−100%	+65%	−69%

Table 4 provides an overview of the ENS volumes, which represent the electricity demand that needs to be curtailed due to a shortage of generation and storage capacity. As compared to the hours with no successful day-ahead market clearing, this indicator offers a more precise picture of where scarcity situations actually occur and which market areas are positively or negatively affected by the market design changes under national CRM policies.

In the Mod-RES scenario, France and Italy both manage to reduce their ENS volumes by 100% as a consequence of introducing their CRMs. Contrary, in Poland, some small ENS volumes remain despite implementing a CRM, likely due to their additional capacity being used by the surrounding countries. Belgium and Germany, both using a strategic reserve under the national CRM policies, as well as the majority of other countries not using any CRM, achieve substantial reductions of their ENS volumes. These findings indicate that free riding occurs.

Yet, negative spill over effects of CRMs are also possible, as illustrated at the examples of Denmark and the Netherlands, where ENS volumes increase driven by the market design changes in their neighbouring countries. Both of these countries have less own capacity available under the national CRM policies than in the European EOM and are only interconnected with other market areas (Germany, Belgium) confronted with the same issues, therefore aggravating the access to sufficient capacities at all times.

4.2 High-RES Decentralized Scenario

4.2.1 Development of Conventional Generation and Storage Capacities

In Figure 9, the development of the total conventional generation and storage capacities throughout the simulation period of 2020 up to 2050 is presented for the High-RES decentralized scenario. Again, some general trends across the modelled countries can be identified. Firstly, similarly as in the Mod-RES scenario, a strong fuel switch towards gas-fired technologies is noticeable. Although the CO_2-prices are assumed to grow stronger in High-RES decentralized than in Mod-RES, some coal-fired generation remains in the market even in 2050. This is due to the fact that decommissioning of power plants is exogenously defined based on their respective age, while model-endogenous decommissioning is not considered. Secondly, as a result of the higher CO_2-prices than in Mod-RES, substantial investments in gas-fired power plants equipped with CCS technology are carried out towards the end of the simulation period. Thirdly, no storage units are built in any of the market areas. Against the background of the strong increase in electricity demand and the proportionally small increase of electricity generation from RES (see Figure 4), investments in gas turbines remain more profitable than storage investments even in the long run. Furthermore, the residual load curves have again been smoothed by demand-side management measures prior to their use in PowerACE (for details see Zöphel *et al.*, 2019), reducing storage profitability.

Comparing the European EOM with the national CRM policies, similarly to Mod-RES, slightly lower total capacities develop in Germany in the long run. The French CRM successfully incentivizes investments in additional generation capacity (mainly open cycle gas turbines), while investment incentives in the Netherlands are reduced. Yet, contrary to Mod-RES, the Netherlands are much less affected by cross-border effects of the CRMs. The background to this finding is that the strongly increasing demand across all countries in High-RES decentralized often leads to combined cycle power plants being the more profitable investment option than additional peak-load capacity. Since CRMs mainly affect the allocation of peak-load capacity, the amount of investments in countries without CRM is less affected by cross-border effects of the national CRM policies in High-RES decentralized than in Mod-RES.

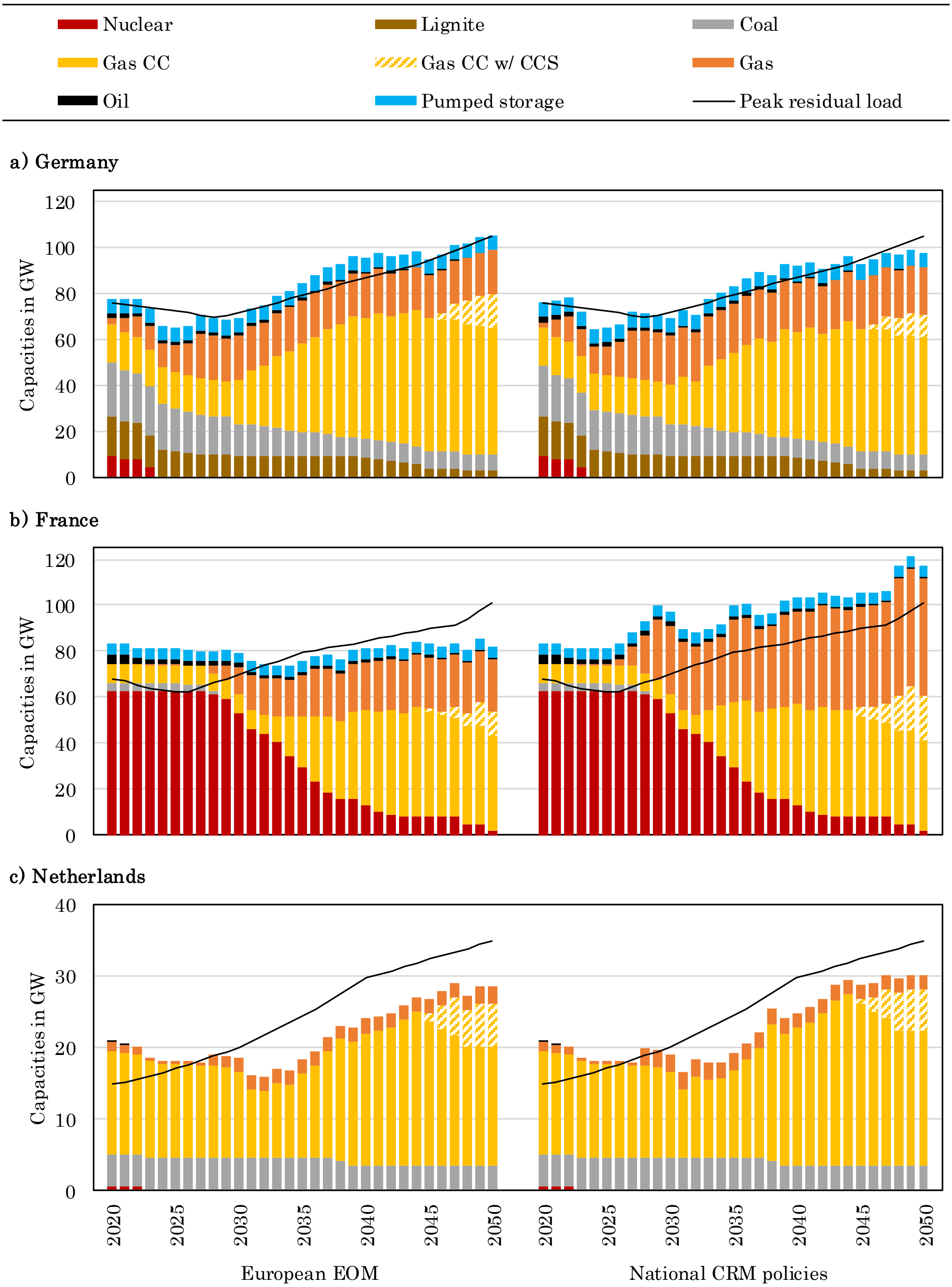

Figure 9: Total generation and storage capacities in the High-RES decentralized scenario for three exemplary countries. A strong fuel switch towards gas-fired technologies with some share of CCS technology towards 2050 can be observed, while no investments in storage technologies are realised. Total capacities in Germany drop slightly under national CRM policies, while the Netherlands build slightly more and France significantly more due to their CRM.

4.2.2 Wholesale Electricity Prices

In the same fashion as before for the Mod-RES scenario, Figure 10 presents the impact of national CRM policies on average wholesale electricity prices as compared to a European EOM in the High-RES decentralized scenario. Again, the average prices are somewhat lower almost throughout the simulation period in France (mean −6%) and Italy (mean −5%) resulting from the introduction of their respective CRMs. These findings stand in line with the Mod-RES scenario, yet are more pronounced. As compared to Mod-RES, the Polish CRM has a greater impact on additional investments in Poland, leading to a marginally positive effect on average prices (mean −1%). The introduction of the national CRM policies results in moderately higher prices in the Netherlands and Belgium (mean +3%, respectively) as well as to a lesser extent in the remaining countries (mean between +1% and +2%). The smaller increases in average prices as compared to Mod-RES are again related to the differences in the respective technology mixes as described previously.

For the three exemplary countries, Figure 10 shows the yearly development of the relative price differences and the respective linear trend curves. Since the investment decisions in Germany and the Netherlands are much less affected by the national CRM policies than in Mod-RES, both countries benefit from the additional capacity in France due to their CRM. In the long run, a small downward trend of the average prices under national CRM policies can be observed in both Germany and the Netherlands. In France, the price-dampening effect of their CRM is stronger than in Mod-RES, since the additional French capacity reduces capacity in the surrounding countries only to a small extent. Therefore, the overall capacity across all countries is much higher under the national CRM policies than in the European EOM, from which also France benefits strongly.

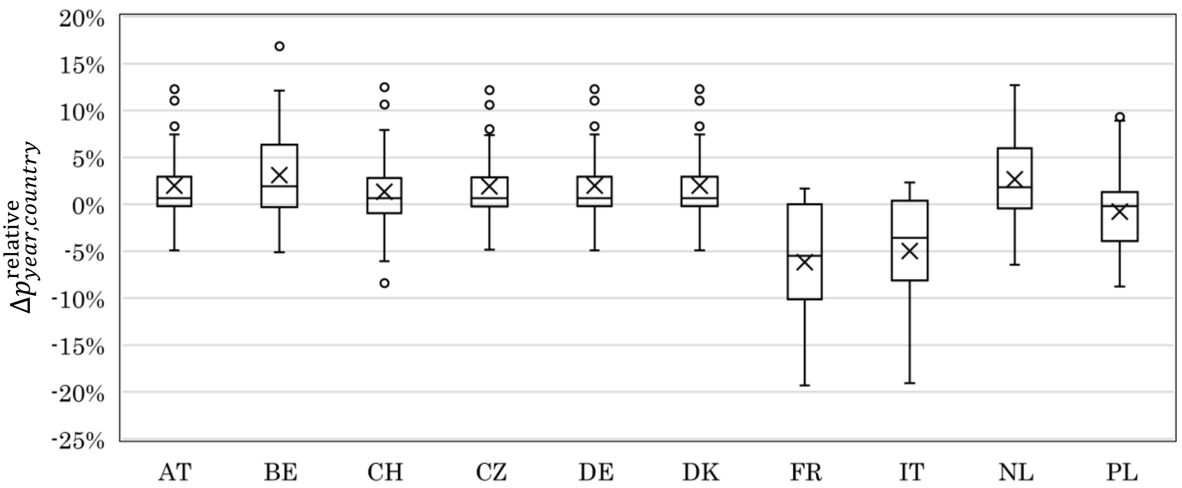

Figure 10: Relative difference between the yearly mean wholesale electricity price under national CRM policies and under a European EOM in the High-RES decentralized scenario. The box plots present the range of the yearly differences for all years between 2020 and 2050. France, Italy and to a lesser extent also Poland generally seem to benefit from the introduction of their respective CRMs and therefore face lower average wholesale prices, while prices in most other countries show a moderate increase on average.

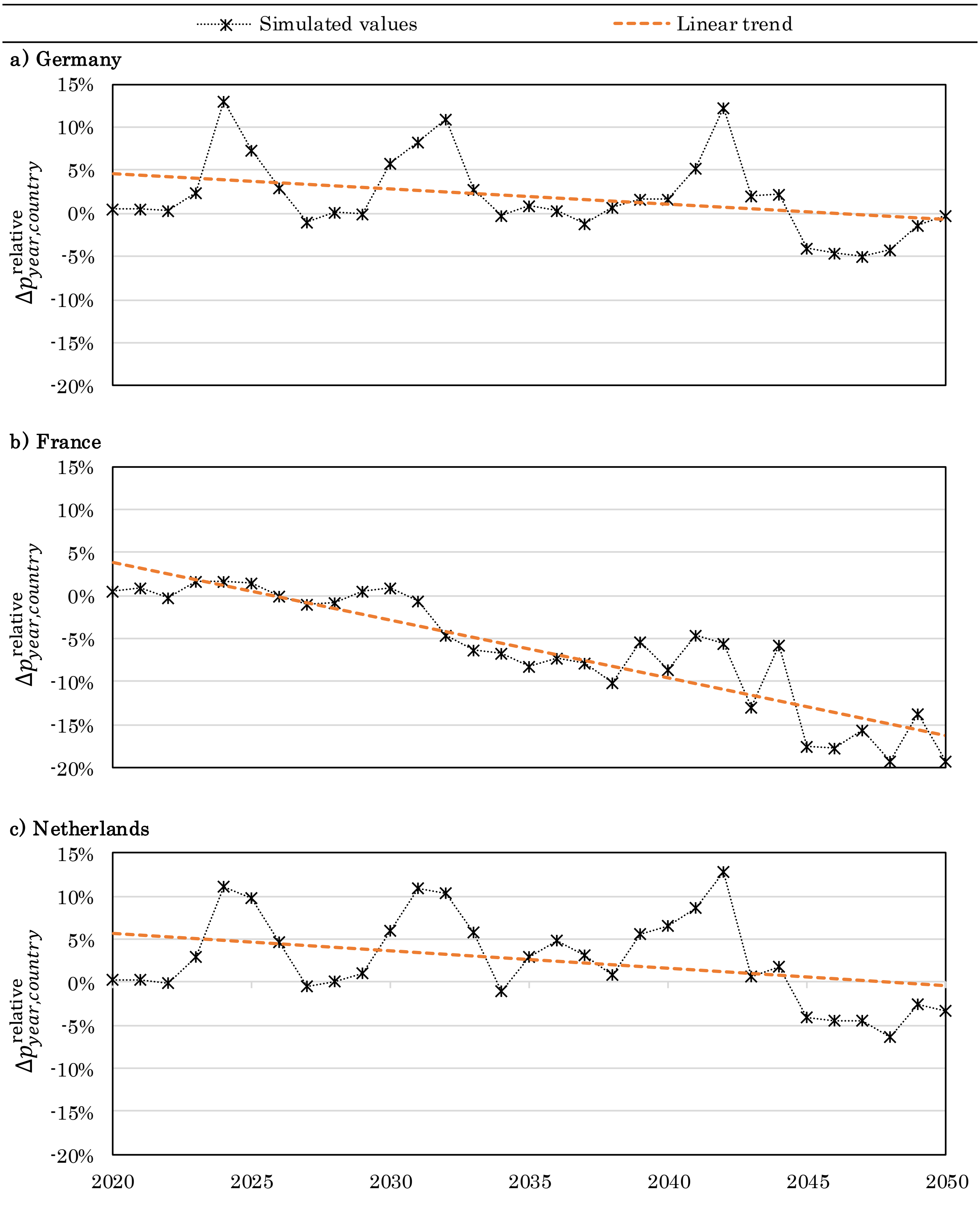

Figure 11: Development of the relative price differences between the yearly averages of the wholesale electricity prices under national CRM policies as compared to a European EOM in the High-RES decentralized scenario. Three exemplary countries are shown: in the long run, Germany and the Netherlands benefit from slightly lower average prices under the national CRM policies. However, this positive effect is much more pronounced in France due to the introduction of their CRM.

4.2.3 Impact on Generation Adequacy

Table 5 presents the average yearly hours with no successful clearing of the day-ahead market for the High-RES decentralized scenario. Contrary to Mod-RES, the average amount of these hours decreases more strongly by almost 100% in France and Italy as a result of implementing their respective CRMs under the national CRM policies. Again, all other market areas, even the ones not using any kind of CRM, benefit from the national CRM policies, leading to substantial reductions of the hours without successful day-ahead market clearing (more than 50% for all market areas).

The picture is completed by Table 6, showing the corresponding ENS volumes. As in Mod-RES, France and Italy achieve a reduction of their volumes by 100%. Yet, also Poland, Belgium and Switzerland only have minor ENS volumes remaining under the national CRM policies. While this is less surprising for Poland, due to the introduction of their CRM, and Belgium, due to their strategic reserve, Switzerland seems to strongly benefit from free riding, using the additional capacity provided by their neighbouring countries. This positive spill over effect of CRMs is further illustrated by the fact that all market areas manage to reduce their ENS volumes significantly in High-RES decentralized. Even Denmark and the Netherlands, that are negatively affected by the market design changes in the Mod-RES scenario, now benefit from the CRMs in their neighbouring countries in this specific setting.

Table 5: Mean yearly hours with no successful clearing of the day-ahead market, i.e. the maximum day-ahead market price of 3000 EUR/MWh due to a shortage of generation and storage capacity, in the High-RES decentralized scenario. The different colours represent the respective market designs as introduced in Section 3.2. All values are averaged over the years 2020 to 2050. All modelled market areas are positively affected by the national CRM policies with reductions of the hours without day-ahead market clearing reaching more than 50%.

Scenario	Unit	AT	BE	CH	CZ	DE	DK	FR	IT	NL	PL
European EOM	[h/a]	38	34	37	38	38	38	29	25	37	37
National CRM policies	[h/a]	18	14	17	18	18	18	0	0	18	12
Change	[-]	−52%	−60%	−55%	−52%	−52%	−52%	−99%	−100%	−51%	−68%

Table 6: **Mean yearly ENS volumes, i.e. demand that is curtailed due to a shortage of generation and storage capacity, in the High-RES decentralized scenario. The different colours represent the respective market designs as introduced in Section 3.2. All values are averaged over the years 2020 to 2050. France and Italy both manage to reduce their ENS volumes by 100% as a consequence of introducing their CRMs. All remaining countries, whether with or without an own CRM, also strongly benefit from the market design changes in their neighbouring countries.**

Scenario	Unit	AT	BE	CH	CZ	DE	DK	FR	IT	NL	PL
European EOM	[GWh/a]	24	15	15	1	58	11	15	9	70	13
National CRM policies	[GWh/a]	7	0	0	0	27	6	0	0	7	0
Change	[-]	−70%	−99%	−97%	−79%	−53%	−48%	−100%	−100%	−90%	−98%

4.3 High-RES Centralized Scenario

4.3.1 Development of Conventional Generation and Storage Capacities

Figure 12 shows the development of the total conventional generation and storage capacities throughout the simulation period of 2020 up to 2050 for the High-RES centralized scenario. The general trends that are identified in the High-RES decentralized scenario partly apply also in this specific setting. Firstly, a strong fuel switch towards gas-fired technologies is noticeable. Secondly, resulting from the same high CO_2-price development as in High-RES decentralized, investments in gas-fired power plants equipped with CCS technology are carried out towards the end of the simulation period. However, due to the lower peak residual loads, fewer such power plants are being built than in High-RES decentralized, because the capacity need is lower towards the end of the simulation period and substantial investments have already been carried out in the years before. Thirdly, for the same reasons as in High-RES decentralized, no storage units are built in any of the market areas.

Much like in the two scenarios presented before, additional open cycle gas turbines are built in France due to their CRM. Yet, also investments in combined cycle gas turbines with CCS technology increase. In Germany, capacity developments are quite similar in both market design settings without substantial differences observable. Contrary, the Netherlands are again affected by the market design changes of their neighbouring countries. While fewer combined cycle and open cycle gas turbines without CCS are built, the capacity of combined cycle gas turbines with CCS is higher under the national CRM policies. This is likely related to the fact that investments in the Netherlands are generally shifted to later periods, where power plants equipped with CCS become the most profitable option.

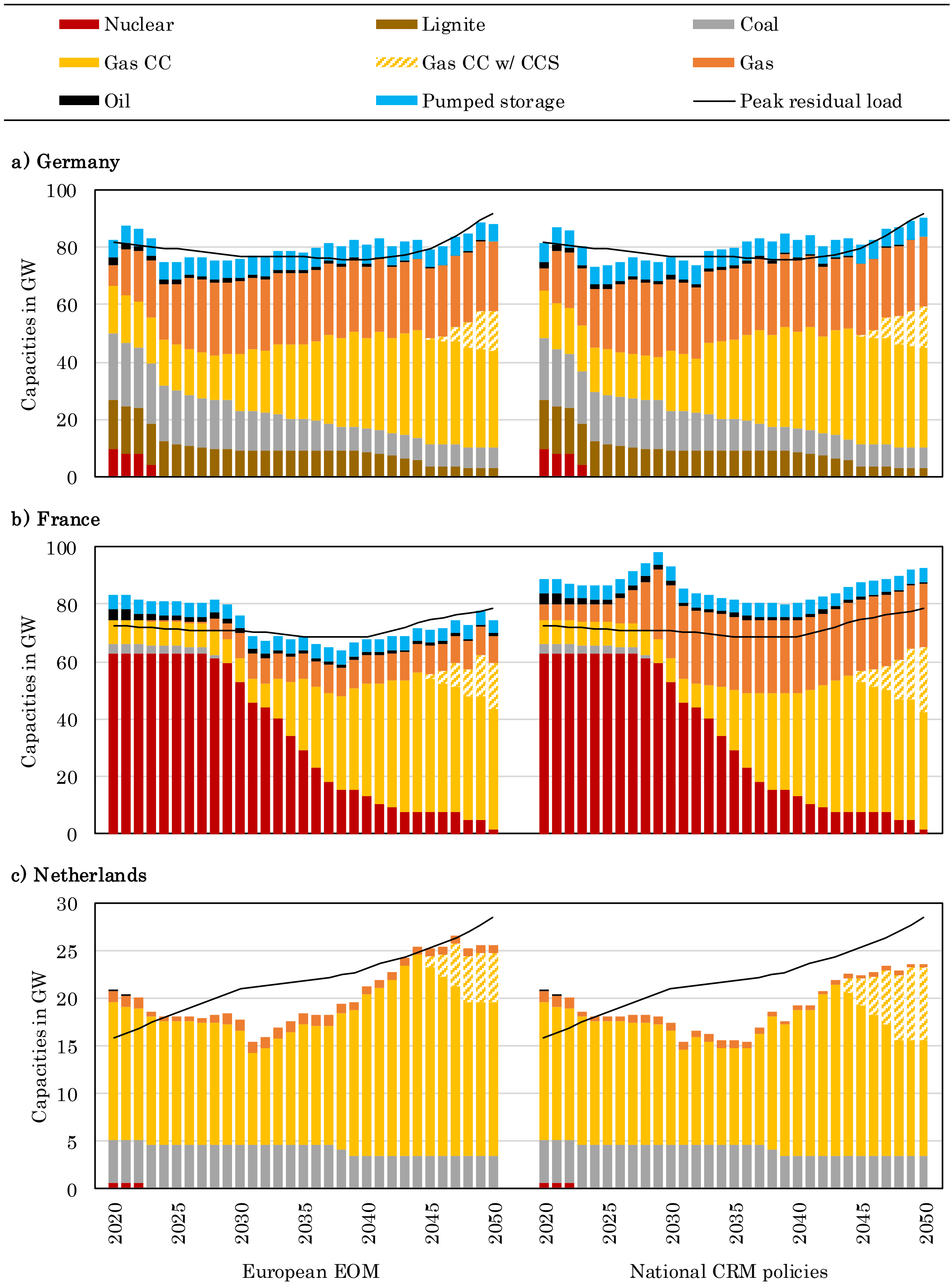

Figure 12: Total generation and storage capacities in the High-RES centralized scenario for three exemplary countries. A strong fuel switch towards gas-fired technologies with some share of CCS technology towards 2050 can be observed, while no investments in storage technologies are realised. Total capacities in Germany remain relatively stable under national CRM policies, while the Netherlands invest less and France builds significantly more gas turbines as a result of the market design changes.

4.3.2 Wholesale Electricity Prices

Figure 13 presents the impact of national CRM policies on average wholesale electricity prices as compared to a European EOM in the High-RES centralized scenario. Similarly to High-RES decentralized, the average prices are lower in France, Italy and Poland as a consequence of introducing their CRMs. While the magnitude of this effect as compared to High-RES decentralized is similar for Italy (mean −6%), France (mean −8%) and Poland (mean −3%) both face a stronger price decrease in this specific setting.

Average prices in Belgium rise slightly (mean +1%) after the introduction of the national CRM policies, which stands in line with both the Mod-RES and High-RES decentralized scenarios. Moreover, stable prices in the Netherlands (mean close to 0%) and even small decreases of average prices (mean between −1% and −3%) in the remaining countries can be observed. These findings may partly be attributed to the higher share of CCS under national CRM policies than in the European EOM, which is beneficial towards the end of the simulation period. This effect in turn results from investments in countries without CRM being shifted to later years, where CO_2-prices are sufficiently high for CCS technologies to be economically viable.

For the three exemplary countries, Figure 14 shows the yearly development of the relative price differences and the respective linear trend curves. Although in the first part of the simulation period (2020–2035), Germany and the Netherlands face higher average prices under the national CRM policies, in the long run, both of these countries benefit from lower average prices. This may again be an outcome of the higher share of CCS technologies under national CRM policies. France also benefits from this effect, but additionally from the introduction of their CRM, which leads to substantially lower average prices under the national CRM policies throughout the simulation period.

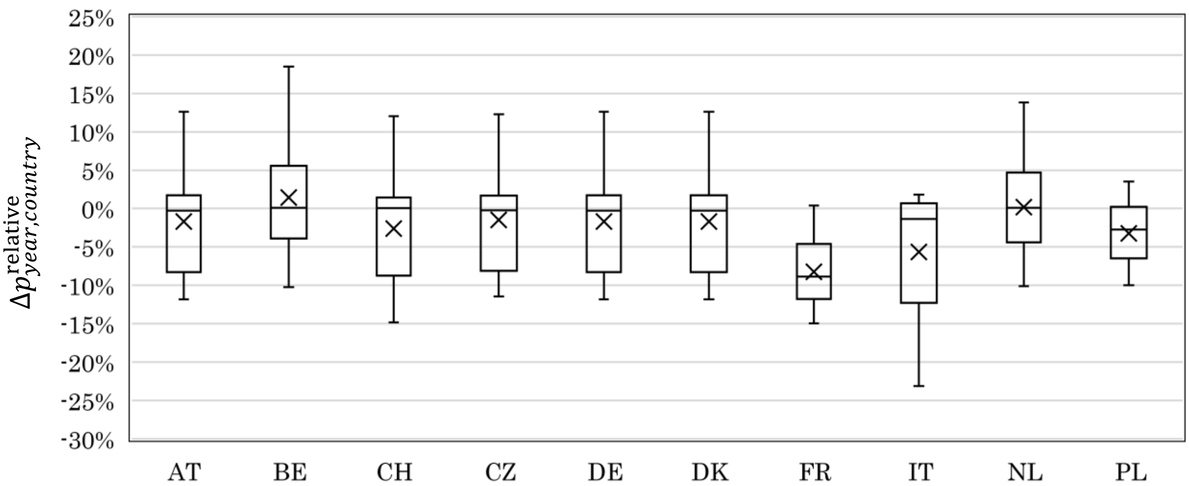

Figure 13: Relative difference between the yearly mean wholesale electricity price under national CRM policies and under a European EOM in the High-RES centralized scenario. The box plots present the range of the yearly differences for all years between 2020 and 2050. France, Italy and Poland generally seem to benefit from the introduction of their respective CRMs and therefore face lower average wholesale prices. Apart from Belgium, small decreases of the average prices can also be observed in all other countries.

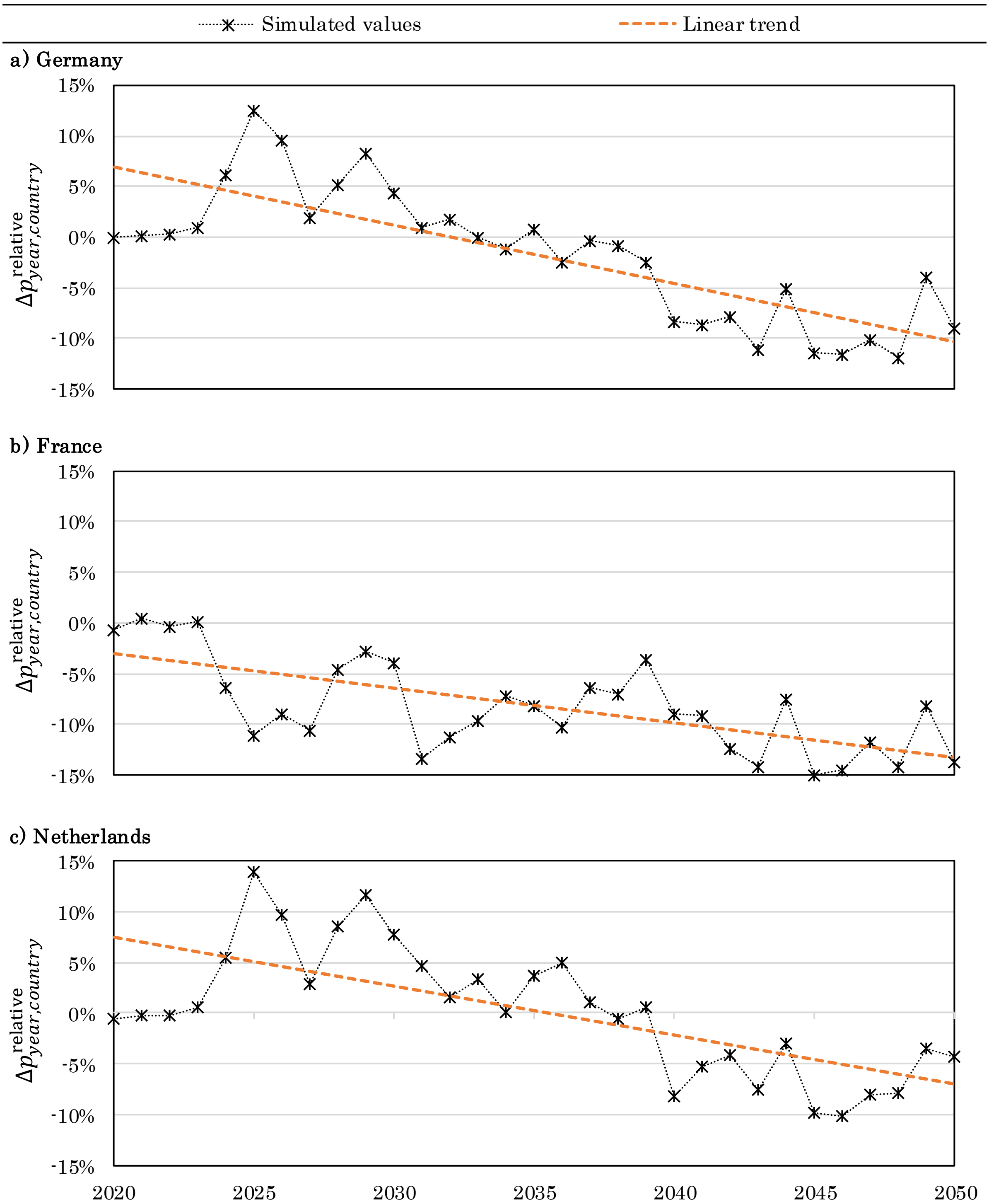

Figure 14: Development of the relative price differences between the yearly averages of the wholesale electricity prices under national CRM policies as compared to a European EOM in the High-RES centralized scenario. Three exemplary countries are shown: in the first part of the simulation period (2020–2035), Germany and the Netherlands face higher average prices under the national CRM policies. Yet, in the long run, both of these countries as well as France benefit from lower prices, amongst others driven by the introduction of the French CRM.

4.3.3 Impact on Generation Adequacy

Table 7 summarizes the average yearly hours with no successful clearing of the day-ahead market for the High-RES centralized scenario. Similarly to Mod-RES and High-RES decentralized, all market areas, whether using a CRM or not, benefit from the national CRM policies. This is reflected in substantial reductions of the hours without successful day-ahead market clearing (more than 60% in all market areas). As a result from the introduction of their respective CRMs, France and Italy even manage to reduce these hours by more than 90%.

Additionally, Table 8 presents the corresponding ENS volumes. France, Italy, Poland and Austria all achieve reductions of their volumes by almost 100% under the national CRM policies. Apart from Denmark, all further countries again benefit from the market design changes under national CRM policies and can significantly reduce their ENS volumes. In Denmark, the volumes rise slightly, yet starting from a base of almost 0 GWh/a under the European EOM.

Table 7: Mean yearly hours with no successful clearing of the day-ahead market, i.e. the maximum day-ahead market price of 3000 EUR/MWh due to a shortage of generation and storage capacity, in the High-RES centralized scenario. The different colours represent the respective market designs as introduced in Section 3.2. All values are averaged over the years 2020 to 2050 and given in h/a, unless stated otherwise. While all modelled market areas are positively affected by the national CRM policies, even the countries introducing a CRM still face some hours with "imported" scarcity situations.

Scenario	Unit	AT	BE	CH	CZ	DE	DK	FR	IT	NL	PL
European EOM	[h/a]	37	31	38	36	37	37	31	31	34	33
National CRM policies	[h/a]	11	10	11	11	11	11	2	2	11	7
Change	[-]	−70%	−68%	−72%	−69%	−70%	−70%	−93%	−95%	−67%	−80%

Table 8: Mean yearly ENS volumes, i.e. demand that is curtailed due to a shortage of generation and storage capacity, in the High-RES centralized scenario. The different colours represent the respective market designs as introduced in Section 3.2. All values are averaged over the years 2020 to 2050 and given in GWh/a, unless stated otherwise. France, Italy, Poland and Austria manage to reduce their ENS volumes by almost 100% under the national CRM policies. Apart from Denmark, all remaining countries are also positively affected by the market design changes in their neighbouring countries.

Scenario	Unit	AT	BE	CH	CZ	DE	DK	FR	IT	NL	PL
European EOM	[GWh/a]	17	3	2	1	58	0	84	52	15	12
National CRM policies	[GWh/a]	0	2	1	1	21	0	0	0	8	0
Change	[-]	−99%	−38%	−59%	−48%	−64%	+85%	−100%	−100%	−44%	−99%

5 Summary and Conclusions

In this report, the electricity market model PowerACE was applied to a region covering multiple interconnected European market areas with different electricity market designs. Several long-term scenario analyses up to 2050 were carried out in order to quantitatively assess the long-term cross-border effects of CRMs in the European electricity system. By comparing "European EOM" settings to "National CRM policies" settings, valuable insights regarding the impact of national CRM policies on amount and location of new investments, the resulting technology mixes in the electricity sector as well as generation adequacy could be derived.

Across all investigated scenarios and market areas, a strong fuel switch towards gas-fired power plants can be observed as a result of the assumed CO_2 price development. Due to the more extreme assumptions with regard to CO_2 prices in the High-RES scenarios, CCS technologies turn out to be profitable towards 2050, while this is not the case in the Mod-RES scenario. Furthermore, in all scenarios, storage technologies only play a minor role under the assumptions made. This finding is related to the proportionally low shares of renewable electricity generation due to strongly increasing electricity demand. Besides, the applied electricity load curves are already smoothed by demand-side management measures prior to their implementation in PowerACE. In future work, additional sensitivity calculations will therefore be carried out, focusing on higher shares of electricity generation from RES as well as the assumed learning rates and cost developments for storage technologies.

With regard to generation adequacy, the introduction of CRMs proves to be an effective measure substantially shifting investment incentives towards the countries implementing the mechanism. The additional generation capacity in these countries in turn reduces both the average wholesale electricity prices and the amount of scarcity situations. Depending on the specific setting, neighbouring countries of those implementing a CRM may face both positive and negative cross-border impacts.

In the Mod-RES scenario, which is characterised by a moderate growth of electricity demand, peak-load power plants often prove to be the most profitable investment option. However, building more peak-load capacity in countries with an active CRM, drastically reduces investment incentives in neighbouring countries without an own CRM, leading to increasing wholesale electricity prices in these countries.

Contrary, in the High-RES scenarios, where the electricity demand grows stronger over time, investments in combined cycle gas turbines are often economically preferable over peak-load capacity. In contrast to peak-load power plants, the profitability of combined cycle gas turbines in countries without an own CRM is less affected by additional investments in neighbouring countries with CRM. Consequently, in the long run, the average wholesale electricity prices may decrease also in countries without an own CRM.

Across all scenarios, CRMs generally increase generation adequacy not only in the country implementing the mechanism, but also in the neighbouring countries, indicating that free riding occurs. Yet, also negative spill over effects can be observed for Denmark and the

Netherlands in the Mod-RES scenario. The reduced investment incentives in these countries lead to a decrease of the generation adequacy level. However, Denmark might be less negatively affected in reality as compared to the simulations carried out, since interconnections to the Nordic countries are not considered, but provide additional flexibility.

Summing up, whether positive or negative cross-border effects of CRMs prevail, depends on a variety of factors, including the future development of electricity demand and renewable electricity generation as well as the geographical location of a given country. The European Commission should therefore continue to assess potential CRMs carefully prior to allowing their real-world implementation. Further insights on this issue might be derived testing the impact of a coordinated European CRM. This alternative market design solution potentially stands better in line with the goals of creating an internal electricity market in Europe.

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