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Abstract

European energy crisis has three elements: skyrocketing prices for energy carriers such as natural gas, coal, as well as electricity, reduced nuclear power plant availability in France, and lower hydro power generation in Europe. This paper decomposes the effects of those elements on power markets and the EU ETS. Permanently higher natural gas prices reduce the canceling volume in the MSR by 425 million and prevent gas-CCS from being competitive in the long-run. Electricity prices are almost unaffected because gas-CCS is substituted by similarly competitive nuclear. Half of the 2022 European electricity price increase can be traced back to higher energy prices (from 36 to 143 e/MWh), whereas the other half (from 143 to 247 e/MWh) comes from French nuclear and European hydro problems. The decision to stretch the operation of three German nuclear power plants to counteract against those crises brings down European (German) electricity prices by 0.89% (2.47%) in 2023. Extending them for seven years after stretching, starting from September 2023, brings down electricity prices by 1.88% (4.8%) in 2024.

JEL Code: C61, H21, H23, L94, Q41

Keywords: Electricity prices, natural gas prices, coal prices, nuclear power, hydro power, EU ETS, market stability reserve, power market modeling, intertemporal optimization

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1. Introduction

On August 26, 2022, the natural gas price at the European reference trading hub TTF peaked at 339 €/MWh.[1]. Previously, on February 24, 2022, Russia invaded and started occupying parts of Ukraine. As a consequence, Western countries sanctioned Russia and European countries discussed boycotts of Russian natural gas, oil, and coal. Russian oil and coal are principally well substitutable because there are sufficient global supplies with flexible trading options from shipping. On contrary, natural gas cannot get traded easily without available pipeline infrastructure or sufficient liquefied natural gas (LNG) terminals and ships.[2] This trading characteristic of natural gas is particularly impacting European energy supply because Europe is mainly connected via pipelines that are constructed for the major flow direction from East to West, and LNG capacities exists mainly in countries with own natural gas production (e.g., Netherlands) or those that are actually far away from Russia (e.g., Spain).[3] Moreover, almost 25% of EU27 primary energy use in 2020 is from natural gas and 38% of this natural gas comes from Russia (Holz et al., 2022).

The high natural gas prices are directly passed-through to electricity prices because the merit order principle in power markets design and current technology cost make natural gas-fired power plants often price-setting in most European power markets. Moreover, the other often price-setting technology, coal-fired power plants, experienced four times higher prices (compared to pre-pandemic average), mainly due to the very same reasons as for natural gas. In particular, Russia is the third largest coal exporter, delivering almost one third of its entire export volume to Europe in 2020, which covers more than half of its entire import volume.[4] While European governments still discussed natural gas, oil, and coal boycotts, Russia reduced its deliveries and even stopped them for some European countries supporting Ukraine politically, financially, or militarily.[5] With Russian energy exports either vanishing, getting used to finance the Russo-Ukrainian War, or being highly uncertain, Europe entered a tremendous energy crisis with skyrocketing prices for energy carriers and the fear of natural gas shortages.[6]

The energy crisis triggered by Russia invading Ukraine is not the only crisis hitting Europe in 2022. Natural gas prices increased by four times and coal prices doubled already in 2021 following economic catch-up after the COVID-19 pandemic. Moreover, starting in 2021, French

[1]The historical average is at around 20 €/MWh, see `https://tradingeconomics.com/commodity/eu-natural-gas`.

[2]Oil and coal have considerably higher energy concentrations than natural gas.

[3]The pre-dominant East-West flow pipeline construction prevents that LNG capacities in, e.g., Spain, can sufficiently used for Middle and Eastern European countries.

[4]This is particularly important when considering that the dependency of the EU27 from Russian coal increased from below 5% in 1998 to more than 50% in 2020. EU27 domestic production is 57 Mt and net imports 79 Mt in 2020 (McWilliams et al., 2022). Converting those 156 Mt yields 1,270 TWh, that is, natural gas contributes three times the amount of coal (3,900 TWh) to EU27 primary energy use (15,000 TWh). Note that coal is not lignite, which contributes similar amounts (both are responsible for around 16% of EU27 primary energy use).

[5]From German perspective, the final piece in the escalation history with regard to natural gas is the explosion of three out of four Nordstream pipelines responsible for the major share of German natural gas imports from Russia.

[6]Batlle et al. (2022a) give an overview of the evolution of the energy crisis in Europe.

nuclear power plants experienced problems with some reactors types leading to half of the French nuclear power plant fleet shut down unexpectedly.[7] 2022 was also one of the driest years on record in Europe (Frost, 2023). As a consequence, reservoir levels shrink and run-in-the-river hydro generation dropped as well.[8] In particular, total electricity generation potential of Europe dropped by more than 200 TWh—around 6% of European electricity supply.[9] The German government even decided to extend running German nuclear power plants beyond the end of 2022 in response to those crises.[10]

In this paper, I analyze those multiple crises and decompose effects of higher energy prices, reduced French nuclear availability, and lower European hydro generation on electricity prices, technology mix, as well as CO_2 emissions and prices by using EUREGEN—a multi-region European power market model (EU27 less Cyprus and Malta, plus Norway, Switzerland, and United Kingdom) that optimizes investments, decommissioning, and dispatch of multiple generation, storage, and transmission technologies intertemporally until 2050. I consider three energy price scenarios that reflect pre-pandemic projections, a full price recovery by 2035, and permanently higher natural gas prices. Moreover, I consider multiple variations with regard to French nuclear availability and European hydro generation in 2022 and 2023. I further analyze the role of different German nuclear exit choices (stretching, extension, or extension after stretching). I model unexpected crises and unforeseen German policy choices by accounting for sticky investment behavior and depict EU ETS including market stability reserve (MSR) dynamics by iteratively looping EUREGEN with a simulation model of the EU ETS.

Most political actions, such as stretching operation of nuclear power plants in Germany by 3.5 months until April 15, 2023, aimed to prevent energy (mainly natural gas) scarcity in Winter 2022/23. In Summer 2022, the fear of countries to run out of natural gas, which is actually essential to heat households and balance fluctuating electricity supply as well as periodic demand, was actually real. Milne (2022) argues that tackling such energy scarcity cannot be achieved by

[7] The electricity supply from nuclear power in France and Europe strongly decreased following the discovery of major problems in the French Nuclear power plant fleet. The state-controlled nuclear group Électricité de France called 2022 actually an "annus horribilis" because about half of its 56 reactors sat idle from early May to late October due to repair and maintenance backlog. France even became net importer of electricity in 2022 for the first time since 1980, just when European neighbors needed French nuclear exports more than ever (Beaupuy et al., 2023). Also see (Alderman, 2023, CBS/AFP, 2023, Reuters, 2023).

[8] Hydro power generation depends on seasonal rainfall patterns and climate-related changes in hydrological conditions such as river flows and reservoir fillings. Moreover, extreme weather events like droughts or severe rainfall negatively impact hydro power generation (Osman et al., 2023). The 2022 drought in Europe reduced both hydro generation and also nuclear generation via missing river water flows for cooling nuclear power plants, and thus further increased the demand and prices of natural gas (Milne, 2022).

[9] When referring to electricity generation and prices in Europe, this paper considers EU27 less Cyprus and Malta plus Norway, Switzerland, and United Kingdom.

[10] In Summer 2022, discussion started in Germany to extend the usage of the three remaining nuclear power plants beyond the planned decommissioning date at the end of 2022, and even reactivating the three plants decommissioned at the end of 2021. The German government finally decided to stretch operation by by 3.5 months until April 15, 2023, thereby using existing old fuel rods and not buying new ones (Mier, 2022b).

high prices provided by the markets but indeed need a comprehensive program to manage energy demand reductions in terms of voluntary contributions as well as rationing. Mannhardt et al. (2022) argue in the same direction and compare collaborative and selfish mitigation strategies to prevent natural gas shortages. Also the European Commission suggested how to get thought Winter 2022/23 in terms of managing natural gas supply and demand (Thomas, 2022). Many European governments undertook actions into those directions, but the extreme natural gas prices from August 26, 2022 dropped by 90% and also coal prices archived 2021 levels until May 2023 again, hinting that the natural gas and also coal prices in 2022 were driven by uncertainty, panic, substitution effects for coal, and the target to fill natural gas storage in Europe and, in particular, in Germany (Reed, 2023). However, higher prices hit households and also industry hard, so that many governments introduced subsidizing measures to reduce the energy price burden, which in turn reduces incentives to voluntarily reduce energy consumption.

Households and industry got hit not only by higher natural gas or coal prices, but also electricity prices skyrocketed to unprecedented levels.[11] Note that pre-pandemic European average electricity prices are around 30 to 50 €/MWh, but in August 2022 peak prices partly hit 900 €/MWh as the high natural gas prices are passed-though to electricity prices one to one when natural gas-fired power plants are price setting (Gillespie and Mathis, 2023). As a consequence, focus of policy-makers shifted towards questioning the efficiency of the well-proofed electricity market design (Hogan, 2005, Cramton, 2017, Helm and Mier, 2019, Mier, 2021) with natural gas-fired power plants being price-setting, whereas infra-marginal generators such as nuclear power or renewables earn unexpected profits (Gerlagh et al., 2022, Mier, 2022a,b).[12] In that light, Glachant (2022) discusses motives and potentials of a quick market design change in European electricity markets. Also Schittekatte and Batlle (2023) discuss proposals to change electricity market design with a focus on how to complete long-term markets; which are actually poorly trained in Europe compared to Northern American markets (Cramton, 2017).

This paper builds on Mier (2022a) and Mier (2022b), which are the first two literature contributions that—by using EUREGEN as well—consider the joint effects of higher energy prices, French nuclear problems, lower European hydro generation, and the impact of an adjusted German nuclear exit. The used general model calibration is the same but this paper comes with substantially more detailed and updated calibration with regard to energy prices, French nuclear availability, reduced European hydro generation, and EU ETS modeling.[13] Moreover, Mier (2022a) and Mier

[11]Batlle et al. (2022b) describe the evolution of regional different electricity prices.

[12]There are inefficiencies in European electricity markets but those does not arise from higher natural gas prices but rather from missing long-term or complementing financial markets (Newbery, 2016), price caps (Hogan, 2005, Helm and Mier, 2019), indirect tackling of externalities via subsidies instead of taxes (Helm and Mier, 2021), or not accounting for timing decisions in combination with uncertainty (Borenstein, 2005, Eisenack and Mier, 2019, Mier, 2021).

[13]This paper is also structurally more advanced with regard to hourly resolution. I took several months to calculate final results for all scenarios and variations within the iterative looping given the chosen resolution. Such time was not available in peak crises times, so that Mier (2022a,b) decided to choose a considerably lower hourly resolution.

(2022b) refrain from disentangling the discussed crises effects, but rather focus on analyzing how different German nuclear exit choices actually impact European and German electricity prices. Nevertheless, price effects are comparable to those reported in this paper. Lang et al. (2023) find slightly higher price effects when extending nuclear usage in Germany, which can be traced back to considerably different scenario assumptions and a different modeling framework.[14]

The remainder of this paper is organized as follows: Section 2 introduces the main scenarios and variations. Section 3 introduces the model including the way of modeling unexpected crises as well as how to reflect EU ETS dynamics. Section 4 describes the calibration of the EUREGEN model used for this paper. Section 5 presents results, whereas Section 6 concludes and discusses policy implications.

2. Scenarios and variations

I consider two possible futures, called *recovery* and *high*, that deviate from the business-as-usual (*bau*). Moreover, there are multiple variations of those futures containing different German nuclear exit policies, French nuclear power plant availability, and European hydro generation.

2.1. Main scenarios

There are no unexpected events in *bau*. In particular, the COVID-19 pandemic and related economic shocks were unforeseen as it is the current energy (price) crisis, French nuclear problems, and missing rainfall in 2022. In *recovery*, the price for natural gas drops to *bau* projected levels (20.20 €/MWh) from 2035 onwards. In *high*, the price remains to be 50% higher (30.30 €/MWh). Table 1 shows the *bau* projections and contrast them with the current developments and with the assumptions from *recovery* and *high*. Note that not only natural gas sees a tremendous price increase in 2022 but also coal. Moreover, observe that coal, oil, and uranium reach *bau* projected levels from 2027 onwards. Lignite prices are indeed unaffected because it is not traded. Biomass prices in turn are structurally above *bau* levels because the general demand for biomass (construction, heating, industry, and electricity generation) increased unexpectedly as well.[15]

2.2. German nuclear exit

Germany planned to exit nuclear power by the end of 2022, but the energy (price) crisis brought up political discussions about extending (new fuel rods) or stretching (no new fuel rods) the usage of nuclear power in Germany to reduce electricity prices (and increase grid stability considering the North-South differential). On October 17, 2022, stretching operation of the three still-running German nuclear plants until April 15, 2023 became the official policy. However, an extension of the three still-running German nuclear power after the stretching operation by more than 7 years until 2030 is still under discussion.

[14] Lang et al. (2023) use renewable capacity targets and exogenous capacity planning, whereas investment decisions are endogenous based on EU ETS only in this paper. Moreover, Lang et al. (2023) use myopic optimization, whereas this paper applies intertemporal optimization. Siala et al. (2022) discuss differences arising from the latter.

[15] This biomass price increase is unrelated to the European energy crises.

Table 1: Current and projected fuel prices (in €/MWh thermal) for the different scenarios

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2035	2040	2045	2050
Biomass													
bau	29.1	29.2	29.4	29.5	29.7	29.9	30.0	30.2	30.3	31.5	32.6	33.7	34.9
high/recovery	58.2	52.0	45.7	44.9	44.6	44.8	45.0	45.2	45.5	47.2	48.9	50.6	52.3
Coal													
bau	10.3	10.3	10.2	10.2	10.2	10.1	10.1	10.1	10.1	9.9	9.8	9.7	9.7
high/recovery	44.9	32.8	24.5	16.3	12.2	10.1	10.1	10.1	10.1	9.9	9.8	9.7	9.7
Lignite	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
Natural gas													
bau	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2
recovery	138.9	69.5	69.4	51.8	38.2	34.7	29.8	24.8	22.3	20.2	20.2	20.2	20.2
high	138.9	69.5	69.4	51.8	38.2	34.7	30.3	30.3	30.3	30.3	30.3	30.3	30.3
Oil													
bau	41.1	41.2	41.3	41.3	41.4	41.5	41.5	41.6	41.7	42.2	42.7	43.3	43.9
high/recovery	61.7	57.7	53.7	49.6	45.5	41.5	41.5	41.6	41.7	42.2	42.7	43.3	43.9
Uranium													
bau	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
high/recovery	4.9	4.2	3.7	3.3	2.8	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3

bau values stem from own assumptions in combination with a CGE projection that is used to calibrate EUREGEN consistent with economic development. Past and current *high/recovery* prices come from `https://tradingeconomics.com/`. Future gas prices until 2027 come from urlhttps://www.eex.com/en/. Future bioenergy, coal, oil, and uranium prices per scenario base on own assumptions. Natural gas prices from 2028 onwards base on own assumptions as well. Latest price updates are from February 1, 2023.

Stretching operation. I assume that the three still-running German nuclear power plants face a reduced availability of 75% in January 2023 due to some maintenance works. The availability increases to 80% in February, drops to 70% in March, and to 35% in April—reflecting that the stretching operation runs until April 15, 2023.

Extension. Instead for choosing the stretching operation there was formerly the option to extend operation of German nuclear power plants. In particular, the nuclear availability would be as high as for the average of 2020 and 2021 in 2023 as well, until 2029.[16]

Extension after stretching. German public currently discusses extending the formerly stretched power plants until the end of 2030 to overcome electricity rationing in face of the current situation. When the Winter and Spring turn very cold and the rationing events in Germany increase suddenly, this is a very likely option. Indeed, nuclear availability from September 2023 would be as high as in the average of 2020 and 2021 until the end of 2030. I call this option *stretchtension* in the following.

2.3. European hydro and French nuclear

2022 has been one of the driest years on record, with hydro power generation currently around 13% lower than it was in 2020 or 2021, respectively. Moreover, half of the nuclear power plants

[16] Note that this variation is a what-if variation that cannot get realized anymore.

in France were offline for several month in 2022; mainly due to unexpected technical problems. French nuclear power makes up 70% of French electricity production and accounts for more than half of the entire European nuclear share. *Bau* projections missed this problem as well. I use IEA monthly electricity generation data[17] to calculate real-time hydro generation timeseries and real-time nuclear availability. Both technologies are kind of must-run technologies because variable cost are negligible (hydro) or very low (nuclear). As a consequence, the monthly hydro generation directly matches the respective hydro availability as it is also the case for nuclear all over Europe. For *bau* projections, the average of 2020 and 2021 is used for 2022. For French nuclear power, only 2020 is used because 2021 was already affected by technical problems. For the two energy price crisis scenarios, the monthly availability of those sources is then reduced according to the reduced availability in 2022.[18]

Now turn to the variations. Both French nuclear availability and European hydro generation have indeed a structural impact on the generation mix and electricity prices in Europe in 2022 but both problems still hold in the beginning of 2023. *French nuclear 2022* accounts for the reduced French nuclear availability in 2022, whereas *French nuclear 2023* assumes that French nuclear availability is reduced in 2023 as well. *European hydro 2022* reflects reduced European hydro generation in 2022. *European hydro 2023* assumes that this effect holds for 2023 as well. However, climate change might even yield a permanent hydro damage, so that *European hydro 20XX* considers permanently reduced hydro availability. *Combined 2022* combines the two 2022 effects. *Combined 2023* merges the 2023 effects and *Combined 2023+* additionally assumes that the European hydro generation is permanently lower.

3. Modeling strategy

I use EUREGEN to analyze the main scenarios as well as variations. It is necessary to steer investments under crises scenarios into the right direction because investment planning should base on *pre-pandemic* projections. I therefore describe how to model unexpected crises. Moreover, the underlying regulation of the power sector within the EU ETS and the non-linear dynamics of the MSR indeed have a unique impact on results. I thus describe how to reflect the EU ETS and the non-linear MSR dynamics within a linear power market model in the final subsection.

3.1. Power market model

EUREGEN is a partial equilibrium model of the European power market (EU27 less island states of Cyprus and Malta, plus Norway, Switzerland, and United Kingdom) that optimizes dispatch, investments, and decommissioning of multiple generation, storage, and transmission tech-

[17] `https://www.iea.org/data-and-statistics/data-product/monthly-electricity-statistics`. The update from March 16, 2023 brought the missing December 2022 data. Last update used is indeed from March 16, 2023.

[18] I use this data as well for bioenergy availability because the official statistics often miss providing the correct bioenergy capacity levels, so that availability factors might be above 100% for some countries, such as Sweden.

nologies.[19] The used model version optimizes intertemporarily until 2050 by assuming perfect foresight.[20] On the generation side, I consider bioenergy, bioenergy with carbon-capture and storage (bio-CCS), coal, coal-CCS, lignite, lignite-CCS, nuclear, oil and other generation technologies such as waste burning (oil), geothermal, hydro, wind onshore, wind offshore, open-field solar PV, roof-top solar PV, and four different kinds of power plants burning natural gas: combined-cycle gas turbines (gas-CCGT), open-cycle gas turbines (gas-OCGT), steam turbines (gas-ST), and gas-CCS (on the basis of combined-cycles). Moreover, German combined-heat-and-power (CHP) plants on the basis of biomass, coal, lignite, oil, and natural gas are modeled for the existing power plant fleet. Hydro expansion is restricted to existing capacity. Wind and solar expansion is restricted to resource potentials that are differentiated by quality classes (20% quantiles, see next section). I further differentiate three storage technologies (pumpstorage, batteries, and hydrogen/power-to-gas). Similarly to hydro, expansion of pumpstorage is restricted to existing capacity. Transmission technologies are represented by AC lines as well as DC cables.[21] The used EUREGEN version optimizes years 2020 to 2030 and from 2035 in five-year steps until 2050 intertemporally[22], thereby using a less fine-grained hourly resolution[23] per year. European electricity demand is assumed to

[19]The origins of EUREGEN trace back to Weissbart and Blanford (2019). See Weissbart (2020), Mier and Weissbart (2020), Azarova and Mier (2021), Siala et al. (2022), Mier et al. (2023) for applications of the original model. EUREGEN saw structural advancements with regard to investments cost specifications (Mier and Azarova, 2021a, 2022a,b), spatial and temporal resolution (Mier and Azarova, 2021b), air pollution modeling (Mier et al., 2022), and usage of private as well as social discount rates (Mier and Adelowo, 2022). Mier et al. (2022), Mier and Adelowo (2022) contain the full set of underlying equations.

[20]EUREGEN can also optimize myopically (always only one period ahead on a rolling horizon) and in between (looking ahead only a limited number of years or periods, respectively) (Mier and Azarova, 2021b). Moreover, the optimization horizon can get expanded, calibration-wise, up to 2100, whereas the numerical feasibility of such optimization horizon turns difficult at high hourly resolutions that are necessary to depict intermittent renewables and periodic load.

[21]DC cables mainly apply to connect countries that are divided by water.

[22]This change in periodical resolution was particularly developed to account fur current crisis effects and was already used in (Mier, 2022a,b).

[23]The hourly resolution is the outcome of an hour choice and weighting algorithm that starts with selecting representative hours to depict the extremes (maximum and minimum) of load, wind onshore, wind offshore, rooftop solar PV, and open-field solar PV. In particular, the algorithm first determines the most extreme hour in one- and five-dimensional space for each country (called *corners*), and then calls all hours to be representative that lie within a certain Euclidean distance (determined by different one- and five-dimensional bubble sizes, called *specification*) of those corners (I test bubble sizes from 50% to 0.03125%). Note that an hour might get selected for one country but would not have been selected for another country, because for this other country it is not within the defined Euclidean distance. The mix of extremes of different countries balances quite well that some countries see high load (wind, solar) whereas other countries face medium or even low load (wind, solar) in that hour. Next, the algorithm weights those representative hours to match annual demand as well as full-load hours of the intermittent sources for each country modeled. The best specification (symmetric bubble sizes of 6%) of this algorithm delivers 413 representative hours (total error of 0.083, weighted error of 0.067). Such specification runs for more than a week using 16 cores (32 threads) and 200 GB memory (given 13 optimization periods). Given the number of scenarios and variations (26), as well as the necessity to depict EU ETS and MSR dynamics (times factor 10 yields 260 runs or more than 5 years of running time), I decide to use an efficient specification (symmetric bubble sizes of 11%

keep almost constant until 2025 (at around 3,000 TWh) and then more than doubles until 2050 (to 6,200 TWh) due to electrification (heating, mobility, hydrogen production), intensified cooling, digitization, and economic growth. The driving force of the energy transition is the EU ETS, including the market stability reserve (MSR), that is adjusted to reflect recent ambitions regarding carbon neutrality by 2050.

3.2. Modeling unexpected crises

I model unexpected developments in 2022 and following years by fixing investments into technologies for *recovery* and *high* by *bau* planning. This is necessary because such infrastructure investments are sticky and cannot get changed immediately. In particular, solar PV (wind onshore, wind offshore) investments are fixed for 2022 (until 2023, until 2024). In the three years after this fixing date, countries can expand planned investments by 50% (first year), 100% (second year), or 200% (third year). This, however, does not show much effect because only little investment are going to happen in years 2023 to 2027 within those three technologies. Countries can also expand a certain non-relative amount in those three technologies, which is particularly important because there might be no investments planned. For example, Germany is able to expand solar PV (wind onshore, wind offshore) by 10 (5, 1) GW in the first year, by 20 (10, 2) GW in the second year, and by 30 (15, 3) GW in the third year after the fixing date. Those values are adjusted according to demand shares of the respective country compared to Germany (which is the biggest country in terms of electricity consumption within the modeled area of Europe). Investments into all other generation technologies are fixed until 2030. Moreover, investments into batteries and hydrogen/power-to-gas storages are fixed until 2025, and transmission investments until 2030. However, different crises scenarios are able to decommission non-necessary or too costly capacity and thus installed capacities might differ between scenarios and variations in 2023 already. A planned investment could get, principally, also decommissioned straightaway at full sunk cost.[24]

3.3. EU ETS and MSR

Working. The EU ETS regulates CO_2 emissions of electricity generation, energy-intensive industries, and aviation within a cap-and-trade system.[25] Electricity generators need to buy all their

neglecting dimensions of wind offshore and roof-top solar PV) with 119 representative hours (total error of 0.101, weighted error of 0.086). This specification still performs better than many other specifications with structurally more representative hours. In particular, I tested the *bau* outcome of the best with the chosen efficient specification and differences in total wind and solar output are negligible (below 5% in 2050). However, the total amount of stored electricity is structurally higher for the less fine-grained specifications (1,450 vs. 1,300 TWh in 2050), but the total impact of storage on electricity prices and the technology mix is structurally below that one of transfers between countries. Import and export differences are indeed negligible again (below 5% in 2050).

[24] I do not observe such effect because most planned investment are not so far away from the long-run trend. Moreover, it is generally cost-optimal to decommission oldest vintages instead of the newest power plants because newer ones come with higher burning efficiencies.

[25] Shipping is added to the regulated sectors in 2023. I neither account for additional allowances allocated or auctioned, respectively, nor higher demand of shipping sectors in the used EU ETS calibration.

allowances on the free market or via the auctions, whereas remaining sectors receive almost 90% of their emissions as freely allocated allowances—which can get traded on the free market again. 2008 financial crisis, renewable support policies, and, eventually, a structural oversupply of allowances yield a huge amount of allowances in circulation that are currently not used but banked by companies. This total number of allowances under circulation (TNAC) peaked at 2,554.91 million in 2017 and is still at 1,449.21 million in 2021. To reduce the number of circulating allowances and increase prices for allowances (*CO_2 price* in the following), the EU introduced the market stability reserve (MSR). Until 2022, 24% of the TNAC is deducted from next years auctioning volume and moved into the MSR in the following year when the TNAC is above 833 million.[26] From 2023 onwards, only 12% of the TNAC is moved into the MSR.[27] Moreover, 100 million is actually moved out of the MSR when the TNAC falls below 400 million. At the end of 2021, MSR holdings are at 2,632.68 million. 2023 is the first year of cancellation.[28] The MSR holdings get reduced to the number of previous year's true auctioning volume. Interestingly, when two years ahead the MSR intake is high (due to high TNAC), then the previous year's true auctioning volume is low and the cancellation this year high accordingly.[29]

Modeling. The main problem of modeling the EU ETS is the non-linear behavior of the market stability reserve (MSR). Most models simply assume either a fixed CO_2 price that steers the systems' decarbonization efforts or a residual quantity target as it is imposed by the dynamics of the EU ETS including the MSR. However, such quantity target is only in line with the EU ETS and the MSR when the use of allowances under circulation is exogenously given. Once one decides to allow for endogenous banking decisions within the intertemporal optimization, those decisions have crucial effects on the annual supply of allowances as well as MSR dynamics. In particular, the cancellation of allowances in the MSR tremendously impacts the effect of banking decisions, because the banking decisions show into the opposite direction. For example, firms generally would like to keep their allowances as long as possible (subject to discounting) because their value increases substantially over time. This keeping in turn reduces the long-run supply and increases the price again. Consequently, it is not possible to cover full dynamics when not accounting for the MSR and related banking decisions simultaneously.

Additionally, the MSR imposes sharp event borders, which cannot get handled by a numerical model. For example, allowances are taken out of the MSR when the TNAC is below 400 million.

[26]There are additional allowances in the MSR, e.g., from backloading (900 million in total).

[27]Recent legislative suggestions would keep the 24% after 2022. However, I decided not to reflect recently suggested changes in the legislation, in particular, because firms investment decisions mainly reflect the "old" regulation and changes are not final yet.

[28]There is an open discussion whether it is indeed cancellation or invalidation of allowances. The latter would principally offer the option to validate them again. However, it is a policy-made regulation that could get changed anyhow in every possible way when the political opinion turns that direction.

[29]Recent legislative suggestion would change this dependency from the true auctioning volume and thus tremendously facilitates the underlying modeling problem. Indeed, the cancellation would always reduce the MSR level to 400 million.

When the model optimizes the TNAC to be directly 400 million, it is actually not clear whether or not to take the allowances out of the MSR.[30] Moreover, MSR dynamics require annual modeling, whereas annual modeling for capacity planning comes at high expenses with regard to numerical complexity.[31].

I apply the iterative modeling developed by Azarova and Mier (2021) considering latest updates regarding EU ETS and MSR dynamics. Iterative looping of power market optimization model outcomes with those of a EU ETS/MSR simulation model containing CO_2 emissions of other regulated sectors leads to an equilibrium where both models would not like to deviate anymore. In particular, the simulation model feeds the power market model with outcomes that already translate annual values into periodical ones (for 2035, 2040, 2045, and 2050) to match periodical resolution of the power market model. The power market model then feeds the simulation model with periodical outcomes (of electricity CO_2 emissions) that are translated back into annual values.[32]

Original CO_2 emissions. The starting point of the simulation model are assumptions about CO_2 emissions within the EU ETS. Those are separated into CO_2 emissions from electricity generation (including sizable heat generation in CHP plants) and CO_2 emissions of other EU ETS sectors. I use a CGE calibration of EUREGEN (Siala et al., 2022, Mier et al., 2020, 2022) to determine CO_2 emissions of electricity generation in relation to those of other EU ETS sectors (i.e., energy-intensive industries and aviation). The CGE calibration cannot account for negative emissions or carbon-neutral CCS technologies that might be necessary to reach 2050 carbon neutrality targets of the EU. As a consequence, electricity CO_2 emissions are poorly represented whereas those of other EU ETS sectors are acceptable and in line with literature expectations. I thus take the resulting CO_2 price from the CGE calibration to calculate corresponding electricity CO_2 emissions with the power market model. Indeed, the CGE calibration scenario with highest decarbonization gives a rising CO_2 price, reaching 176 €/ton in 2050 (Mier et al., 2020, 2022). I now take the outcome of the power market model in terms of electricity CO_2 emissions and determine other sectors' CO_2 emissions from the original CGE relation of electricity to other sectors' emissions. However, the power market model gives -144 Mt (-128 Mt in the EU plus Norway and Switzerland, -16 Mt in United Kingdom) in 2050 due to the usage of carbon-negative bio-CCS at a CO_2 price of 176 €/ton (see Table 2). The relation of electricity CO_2 emissions and those of other sectors is thus not working anymore. In particular, the EU ETS should meet carbon-neutrality targets in

[30]The same holds for the upper TNAC threshold of 833 million. Recent suggestions to adjust the EU ETS and MSR would at least resolve the modeling infeasibility at one of the thresholds by implementing a floating mechanism.

[31]Remember that I decide for 119 representative hours already and does not use the best specification with 413 representative ones. Modeling not only 13 optimization periods (2022 to 2030, 2035, 2040, 2045, 2050) but indeed 29 (2022 to 2050) would place an even higher solution time burden when using the 119 representative hours compared to 13 periods and 413 representative hours. As a consequence, it would be necessary to use a less suitable specification with, e.g., 35 hours that comes with huge drawback regarding the presentation of periodic load and intermittent renewables (total error of 0.264, weighted error of 0.241)

[32]Note that the most important horizon until 2030, where all the MSR canceling is actually happening, is modeled annually in the power market model as well.

2050. I thus assume that the entire period 2050 (reflecting years 2046 to 2050) should be indeed carbon-neutral within the EU ETS, meaning that the sum of electricity emissions and those of other EU ETS sectors must be zero. As a consequence, I assume that 128 Mt of CO_2 are hardly to get decarbonized for other EU ETS sectors (e.g., chemistry, aviation), so that the electricity generation must compensate by negative emissions of -128 Mt.

Table 2: CO_2 emissions (in Mt) from electricity generation and other sectors within the EU ETS and in UK

	EU*		UK		Sum
	Electricity	Other sectors	Electricity	Other sectors	
2013	1,046	696	145	22	1,908
2014	966	693	134	21	1,814
2015	957	691	133	21	1,803
2016	918	684	128	21	1,750
2017	913	740	127	23	1,803
2018	855	694	119	21	1,689
2019	741	697	103	22	1,562
2020	631	615	88	19	1,352
2021	654	636	80	19	1,389
2022	657	639	80	19	1,395
2023	620	681	76	20	1,398
2024	588	679	72	20	1,360
2025	558	716	68	21	1,364
2026	573	738	70	22	1,404
2027	582	763	71	23	1,439
2028	609	719	74	22	1,424
2029	626	675	76	20	1,398
2030	631	631	77	19	1,359
2031	521	594	64	18	1,196
2032	446	553	54	17	1,070
2033	372	511	45	15	944
2034	336	464	41	14	855
2035	300	416	37	12	766
2036	267	344	33	10	654
2037	231	300	28	9	568
2038	195	255	24	8	482
2039	183	239	21	7	443
2040	171	223	19	7	404
2041	159	222	21	7	426
2042	147	205	19	6	385
2043	135	187	16	6	344
2044	58	168	7	5	238
2045	-18	148	-2	4	132
2046	-128	128	-16	4	-12
2047	-128	128	-16	4	-12
2048	-128	128	-16	4	-12
2049	-128	128	-16	4	-12
2050	-128	128	-16	4	-12

*EU 2013–2020 values are adjusted by the UK levels for sake of presentability. Norway and Switzerland are almost carbon-neutral and I thus add their marginal share to those of the EU.

Table shows real world values until 2021 and projected values afterwards. Rounding without digits constitutes errors for sum.

There are recent changes in the EU ETS legislation by means of United Kingdom establishing its own (UK) ETS. I thus adjust the CO_2 emissions within the EU by subtracting the respective ones from the UK. For UK emissions of other sectors, I keep the UK share of other sector emissions compared to those of the EU constant at 3.125%, so that other UK sectors end with 4 Mt CO_2 emissions in 2050. The UK is thus indeed carbon-negative in total, because the electricity sector is overcompensating emissions of other sectors. However, the other sectors share in the UK is relative small and hardest decarbonization in UK takes place outside of the currently regulated UK ETS sectors.

The combination of CGE calibration and power market model gives CO_2 emissions for 2021 (real world values), 2025, 2030, ..., 2050, whereas the years 2046 to 2050 are assumed to be constant with regard to electricity and other sectors CO_2 emissions.[33] I now interpolate between periods to obtain annual values. For example, I take the 2035 value as the middle points of the specific 2035 period (2031 to 2035) and thus place it to 2033. I then interpolate between 2033 and 2038 (the middle point of the next period). Such interpolation yields distorted averages over the period. I thus re-weight those values to keep the original 2035 emissions as average for the respective period.

Table 2 shows results of this process. Values until 2021 are real-world observations, and until the end of 2020 UK belonged to the EU. EU values from 2013 to 2020 are thus not comparable to real EU values by the UK share of the respective emissions. However, the underlying CO_2 emissions follow a simple logic: Electricity emissions drop more severe than those of other sectors regulated under the EU ETS (and the UK ETS). EU without UK (plus Norway and Switzerland) obviously applies only until 2020.[34] 2020 values must be seen as outliers due to COVID-19 pandemic. In 2021, there is already some catch-up of CO_2 emissions (in the EU) and also assumed to be the case for 2022. However, emissions then drop slightly again but increase from 2026 onwards due to fundamentally increasing electricity demand. However, the industrial emissions start falling from 2028 onwards, whereas electricity emissions start dropping in 2031.

Auctioning and free allocation. The differentiation between auctioning and free allocation is crucial because the MSR volume is reduced (by canceling) to the level of previous years true auctioning volume. The true auctioning volume in turn depends on the planned one and the MSR flows (MSR intake is indeed subtracted from planned auctioning volume). Recent ambitions seem to hint that free allocation is successively reduced. Currently, other regulated EU ETS sectors obtain almost 90% of their allowances via free allocation. We assume that this share drops by 4% until 2042 and then by 3% in the period 2042-2045, finally reaching 0% free allocation in 2045.

[33] CGE model was calibrated for 2015 and I indeed have real-world observations for 2021 and projections for 2022. I thus adjust the starting point relations. Final 2022 values get published in May 2023.

[34] The placement of Norway and Switzerland is, regulation-wise, not correct but does not impact results because those countries are anyway carbon-neutral until 2045. The final 2050 values from the power market model also account for those countries as well as the CGE model relation of electricity CO_2 emissions to those of other sectors, that is, when Norway and Switzerland turn potentially carbon-negative in 2050, the adjusted modeling of the EU ETS in my model is accounting for that effect already.

Equilibrium of the simulation model. The cap-and-trade system of the EU ETS finally ensures that there is not more CO_2 emitted than allowances supplied to the market. However, recent reforms of the EU ETS and the MSR, as well as some adjustment of the cap in response to UK leaving the EU leaves the EU ETS off-equilibrium when using original CO_2 emissions as in Table 2. I follow the premise of carbon-neutral EU in the average of 2046-2050 and thus does not allow for using banked allowances and MSR outtake in the very last period anymore. Consequently, an equilibrium is given when the MSR is empty by the end of 2045 and simultaneously all allowances are used by the end of 2045 (the TNAC must be zero). The original emissions are indeed to high, yielding a negative TNAC of -162.15 million in 2045 (MSR is indeed empty) at canceling volume of 3,374.55 million allowances. I thus scale 2022 to 2045 electricity emissions by 0.978 (and keep other sectors' emissions fixed, for parsimony), so that the EU ETS is indeed in equilibrium again. The canceling volume increases to 3,409.11 million due to reduced emissions and resulting higher TNAC.

Table 3 gives an exemplary picture of the EU ETS including MSR dynamics after the scaling process that is used as starting point of the iterative looping (for the *bau* scenario). Observe that both allocation and auctioning is zero in 2045, reflecting that only banked allowances can get used in 2045. The distribution between allocated and auctioning depends on the assumed share of freely allocated allowances for other sectors (which turns zero in 2045). The difference between accumulated demand and verified emissions is the canceling volume.[35] Verified emissions accumulate by the amount of electricity CO_2 emissions and those of others. The TNAC follows from the difference of accumulated supply and the sum of accumulated demand and MSR holdings. When the TNAC turns zero and the MSR is empty at the end of 2045, then accumulated supply directly matches accumulated demand. Observe that electricity CO_2 emissions slightly deviate from the values in Table 2, whereas those of other sectors are the same (after UK leaving EU). Moreover, canceling starts in 2023 and 2029 is the last canceling period because the TNAC is below the threshold of 833 million (so that no MSR intake takes place) and the MSR level is above previous years true auctioning volume from 2029 onwards. On contrary, in 2031, 2033, 2039, and 2041 to 2043 the MSR is successively emptied. Note that TNAC, MSR levels, and canceling are changing in response to the iterative looping because electricity CO_2 emissions are changing as well.

4. Calibration

The used calibration of EUREGEN is new to the literature and I thus decide to describe the process of creation and figures in more detail. The old calibration used 2015 as calibration year with adjustments for recent developments (e.g., Azarova and Mier, 2021). The new calibration in turn is able to update automatically for a respective calibration year (here, 2022).

[35] Indeed, there are other but minor cancellation amounts that explain the remaining negligible difference between accumulated demand and the sum of verified emissions and canceling. I account for them in the simulation model but refrain, for parsimony, to depict those negligible details here.

Table 3: CO_2 emissions (in Mt) from electricity generation and other regulated sectors within the EU ETS in Europe

	Allocation	Auctioning	Demand	Verified	Electricity	Others	Canceling	TNAC	In MSR	MSR
2013	1,013	1,037			1,191	717				
2014	939	618			1,100	714				
2015	879	633			1,090	713				
2016	840	715	7,140	7,139	1,045	705		2,594		
2017	802	951	8,943	8,942	1,040	763		2,555		
2018	759	916	10,632	10,632	974	716		2,555	1,297	
2019	688	589	12,194	12,194	844	718		1,385	677	1,297
2020	739	779	13,547	13,546	719	634		1,579	379	1,925
2021	552	583	14,837	14,837	654	636		1,449	348	2,633
2022	575	606	16,083	16,082	607	639		1,384	332	2,980
2023	586	568	20,041	17,334	570	681	2,707	1,286	154	606
2024	557	731	21,452	18,551	538	679	2,900	1,357	163	568
2025	558	678	22,676	19,776	508	716	2,900	1,369	164	730
2026	546	619	24,154	21,037	523	738	3,116	1,273	153	678
2027	534	573	25,661	22,332	532	763	3,328	1,085	130	619
2028	475	585	27,116	23,610	559	719	3,504	866	104	573
2029	419	597	28,458	24,861	576	675	3,596	631	0	585
2030	366	684	29,671	26,074	581	631	3,596	468	0	585
2031	321	659	30,749	27,152	484	594	3,596	369	-100	585
2032	276	733	31,723	28,126	421	553	3,596	405	0	485
2033	235	605	32,592	28,995	358	511	3,596	376	-100	485
2034	195	675	33,387	29,790	331	464	3,596	451	0	385
2035	158	542	34,108	30,510	304	416	3,596	430	0	385
2036	117	513	34,746	31,149	295	344	3,596	421	0	385
2037	90	470	35,312	31,715	267	300	3,596	415	0	385
2038	66	423	35,806	32,209	238	255	3,596	411	0	385
2039	53	367	36,255	32,658	210	239	3,596	382	-100	385
2040	40	410	36,660	33,063	181	223	3,596	427	0	285
2041	31	249	37,063	33,465	181	222	3,596	304	-100	285
2042	20	289	37,420	33,823	152	205	3,596	257	-100	185
2043	11	229	37,731	34,134	124	187	3,596	186	-85	85
2044	5	150	37,948	34,351	49	168	3,596	123	0	0
2045	0	0	38,071	34,474	-26	148	3,596	0	0	0
2046	0	0	38,071	34,474	-128	128	3,596	0	0	0
2047	0	0	38,071	34,474	-128	128	3,596	0	0	0
2048	0	0	38,071	34,474	-128	128	3,596	0	0	0
2049	0	0	38,071	34,474	-128	128	3,596	0	0	0
2050	0	0	38,071	34,474	-128	128	3,596	0	0	0

Allocated and auctioning refer to true (and not planned) values. Demand and verified refer to accumulated demand and verified accumulated CO_2 emissions within the EU ETS. Electricity (electricity CO_2 emissions) and others (other sectors' CO_2 emissions) are EU values that contain the UK share until 2020. The canceling refers only to the cancellation within the MSR.

4.1. Installed capacity

As starting point of optimization, EUREGEN uses installed capacities from generation, storage, and transmission technologies. EUREGEN is forced to avoid adding capacity in 2022, so that 2022 results solely come from handling those existing capacities. Therefore, it is most important to reflect such initial endowment of countries correctly.[36]

Match and merge. EUREGEN optimizes investment, decommissioning, and dispatch decisions based on vintages, that is, considers the age of a specific power plant. Older power plants generally have lower efficiencies and reach the end of their lifetime at specific points in time, which is important to depict the transformation of the entire European electricity system. We obtain data on age (here, commissioning dates) of *conventional* power plants from three main sources. The latest update from Global Power Plant Database from World Resource Institute is from June 2021 (Byers et al., 2021). The database contains power plants for each country in the world (from Afghanistan to Zimbabwe) with name, identification number, latitude, longitude, primary fuel, and capacity installed. Additional fuels are available as well and commissioning dates exists for some of the power plants. The latest update from JRC Open Power Plants Database is from July 2019 (Bocin et al., 2019). It is thus the least recent of the three databases but is structurally more precise with regard to European data and commissioning dates. Finally, OPSD conventional power plant database also provides differentiation for types of gas power plants (open-cycle gas turbine, combined-cycle gas turbine, steam turbine) (Weibezahn et al., 2020).

Power plant specifics also differ with regard to blocks of the very same power plant.[37] One database accumulated the entire capacity of different blocks, others provide block specific commissioning dates. To ensure the highest degree of precision and technological detail, we matched and merged all of three sources by using the location identifier (latitude, longitude) allowing for a maximum distance of 500m between blocks of the same power plant. Additionally, when capacity and year of decommissioning of two power plants from different databases matched, this distance was increased up to 5km. After the three data sets were merged, we obtain vintage-specific capacity data for all 28 countries under investigation.[38]

Biomass and nuclear. The power plant databases are rather imprecise in depicting bioenergy power plants, potentially due to the fact that many of them are too small to be included in such data sets. We, thus, add them manually by searching information for each country separately after the match and merge process. Final bioenergy scaling happens by using bioenergy generation to calculate availability factors that might be above 100% when even the manual search is impacted by the available data quality (see Subsection 2.3). We repeat this process for nuclear capacities as well because deviations with data from other sources are substantial. However, the manual adding of nuclear power plants is not exhausting because the number is comparably low.

[36]The entire paragraph is written from the ”we” perspective because it is not me only who was involved in that process. I gratefully acknowledge the work of Valeriya Azarova, Jacqueline Adelowo, and Adam Drozynski.

[37]Sometimes one power plant has multiple blocks that were build at different points in time. This database accounts for that fact and is thus fundamental to derive the correct age of capacity per country.

[38]In principal, one could expand this task to other countries as well, although data quality drops when moving from industrialized to developing countries. The database as well as the transformed capacity data is available upon request from mier@ifo.de.

ENTSOE adjustments. The power plant databases are not completely up-to-date. In particular, they cannot depict latest developments in added, decommissioned, or re-commissioned capacities. We thus automatically adjust them by comparing the aggregate capacity per technology and country with latest ENTSOE updates.[39] ENTSOE publishes accumulated capacity data per country under investigation and technology. We match ENTSOE technologies with those of the power plant databases and decide to decommission oldest vintages from the databases when ENTSOE values are lower than those of the matched and merged database. We increase capacity from the newest vintage when the ENTSOE values are above the matched and merged database values, which, however, is rarely the case. We always allow for small error margins due to rounding errors and the inconsistent definition of net or gross capacity.

Other technologies. For intermittent renewables sources (hydro, wind onshore, wind offshore, and solar PV), we use IRENA data that traces back to 2000 to obtain vintage specific values for each of the respective technologies. Furthermore, we do final matching with ENTSOE data again to ensure that our overall amount of capacity is correct and latest addings/decommissionings are contained in our dataset. Transmission capacity data reflects net transfer capacities (NTC) between countries. Calibration stems from ENTSOE again and also contains expansion plans according to the Ten-Year-Network-Development-Plan (TYNDP).[40] Finally, data for active pumped hydro storage capacities is taken from Andrey et al. (2022) and complemented with data from the International Hydropower Association [41].

Pipeline investment. As the TYNDP contains plans to expand transmission capacity across countries, there are also power plants under construction (or planned) that would get commissioned in the distant future. For nuclear power plants, I search planned commissioning dates for each power plant under construction or those that are at least officially announced, and use lower investment limits to force those capacities into the model. However, I do not do so for policies intending to increase renewable energy capacities up to a certain amount.

4.2. Cost

Capacity cost. Table 4 shows the specific capacity cost per technology for 2022 to 2050 vintages.[42] The first block contains the dirtiest sources (coal, lignite, and oil). Observe that oil is cheapest and lignite most expensive but oil and lignite have very different generation patterns due to hugely diverging dispatch cost. Moreover, the two CCS technologies cannot get build before 2026 and thus cost occur here only from 2026 onwards. Furthermore, except for oil power plants, capacity cost remain constant as coal and lignite are seen as very mature technologies. However, CCS

[39] `https://www.entsoe.eu/`.
[40] `https://tyndp.entsoe.eu/`.
[41] `https://www.hydropower.org/hydropower-pumped-storage-tool`.
[42] All values are more or less based on `https://data.jrc.ec.europa.eu/collection/id-0089`.

counterparts indeed are not mature but there is still quite some uncertainty about the future cost of those power plants and I thus refrain from decreasing them over time.[43]

Table 4: Capacity cost (in €/kW) for the different generation and storage technologies

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2035	2040	2045	2050
Coal	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600
Coal-CCS					2,550	2,550	2,550	2,550	2,550	2,550	2,550	2,550	2,550
Lignite	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
Lignite-CCS					3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500
Oil	786	786	786	786	779	771	764	757	750	786	786	786	700
Gas-CCGT/ST	850	850	850	850	850	850	850	850	850	850	850	850	850
Gas-CCS					1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500
Gas-OCGT	550	550	550	550	550	550	550	550	550	550	550	550	550
Geothermal	9,650	9,650	9,650	9,650	9,520	9,390	9,260	9,130	9,000	8,800	8,600	8,400	8,200
Nuclear	5,625	5,625	5,625	5,625	5,590	5,555	5,520	5,485	5,450	5,250	5,050	5,025	5,000
Bioenergy	2,570	2,545	2,520	2,495	2,470	2,445	2,420	2,395	2,370	2,260	2,150	2,050	1,950
Bio-CCS					3,870	3,870	3,870	3,870	3,870	3,760	3,650	3,550	3,450
Hydro	1,000												
RoofPV	1,026	1,026	1,026	1,026	1,015	1,004	994	983	972	942	912	888	864
OpenPV	882	873	864	855	846	837	828	819	810	785	760	740	720
WindOn	1,340	1,335	1,330	1,325	1,320	1,315	1,310	1,305	1,300	1,250	1,200	1,150	1,100
WindOff	2,820	2,790	2,760	2,730	2,700	2,670	2,640	2,610	2,580	2,480	2,380	2,330	2,280
Pumpstorage	1,000												
Hydrogen					1,520	1,520	1,520	1,520	1,520	1,520	1,520	1,520	1,520
Batteries	1,440	1,440	1,440	1,440	1,120	1,120	1,120	1,120	1,120	950	780	610	440

Abbreviations: CCS (carbon-capture and storage), CCGT (combined-cycle gas turbine), ST (steam turbine), OCGT (open-cycle gas turbine), RoofPV (roof-top solar PV), OpenPV (open-field solar PV), WindOn (wind onshore), WindOff (wind offshore). Capacity cost for storages contain investment for generation and storage capacity. I assume that 1 GW hydrogen generation capacity comes with 720 GWh of storage capacity and 1 GW battery generation capacity with 4 GWh of storage capacity.

The next block contains gas power plants, which are generally fired by natural gas. The open-cycle version is the cheapest and, again, the CCS version of a combined-cycle power plant (gas-CCS) is most expensive. Observe that gas-CCS capacity cost are structurally below those of coal-CCS and decisive for gas-CCS being present in the long-run technology mix. Also observe that there is some decrease in nuclear cost, as it is the case for bioenergy and bio-CCS. Next, the block of intermittent renewables (hydro to wind offshore) shows substantial cost decreases as well. However, hydro (as also pumpstorage) only shows cost for 2022 because endogenous expansion of this technology is not possible due to scarce natural resources (and public resistance).[44] Finally, the last block shows storage technologies. The uncertainty about the configuration of hydrogen storages leaves me assuming constant cost. However, batteries are quite a mature technology that have seen substantial cost drops already and are expected to reduce capacity cost even further.

[43]Indeed, coal-CCS and lignite-CCS does not play a role for the European technology mix because in no scenario I can observe any expansion of power plants from this kind.

[44]Opening hydro for endogenous investment, would yield hydro only systems because it is indeed the cheapest technology to produce electricity.

Fixed operation and maintenance cost. Table 5 contains the fixed cost of technologies. Observe that CCS counterparts have substantially higher fixed cost due to the equipment that comes with the process of carbon-capture and storage. Moreover, gas power plant have the lowest fixed cost from the conventional sources. Observe that nuclear comes with very high fixed cost. Those cost contain maintenance of power plants to extend lifetimes to up to 60 years. Besides nuclear, also wind offshore bears considerably high fixed cost that are finally decisive for the economic decision not to expand wind offshore.[45]

Table 5: Fixed operation and maintenance cost (in €/kW*a) for the different generation and storage technologies

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2035	2040	2045	2050
Coal	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
Coal-CCS					63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8
Lignite	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Lignite-CCS					87.5	87.5	87.5	87.5	87.5	87.5	87.5	87.5	87.5
Oil	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0
Gas-CCGT/ST	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3
Gas-CCS					37.5	37.5	37.5	37.5	37.5	37.5	37.5	37.5	37.5
Gas-OCGT	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5
Geothermal	178.5	178.5	178.5	178.5	177.0	175.5	174.0	172.5	171.0	167.2	163.4	159.6	155.8
Nuclear	118.1	118.1	118.1	118.1	117.4	116.7	115.9	115.2	114.5	110.3	106.1	105.5	105.0
Bioenergy	56.5	56.0	55.4	54.9	54.3	53.8	53.2	52.7	52.1	49.7	47.3	45.1	42.9
Bio-CCS					96.8	96.8	96.8	96.8	96.8	94.0	91.3	88.8	86.3
Hydro	15.0												
RoofPV	21.4	21.4	21.4	21.4	21.2	20.9	20.7	20.5	20.3	19.6	19.0	18.5	18.0
OpenPV	22.1	21.8	21.6	21.4	21.2	20.9	20.7	20.5	20.3	19.6	19.0	18.5	18.0
WindOn	31.6	31.2	30.9	30.5	30.1	29.7	29.4	29.0	28.6	25.6	22.8	20.7	18.7
WindOff	89.1	87.6	86.1	84.6	83.2	81.7	80.3	78.8	77.4	71.9	66.6	59.4	52.4
Pumpstorage	27												
Hydrogen	33	33	33	33	30	30	30	30	30	29	27	27	26
Batteries	8	8	8	8	6	6	6	6	6	5	5	4	4

Abbreviations: CCS (carbon-capture and storage), CCGT (combined-cycle gas turbine), ST (steam turbine), OCGT (open-cycle gas turbine), RoofPV (roof-top solar PV), OpenPV (open-field solar PV), WindOn (wind onshore), WindOff (wind offshore).

Dispatch cost. Table 6 presents dispatch cost consisting of fuel price (subject to power plant efficiency), variable operation and maintenance cost, and a CCS transport surcharge for CCS power plants (subject to capturing factor). All cost displayed show the respective vintages in the year of installation. For example, a 2022-power plant would have different dispatch cost in 2050

[45] My calibration neglects social resistance against wind onshore and related cost, e.g., from property devaluation (Hoffmann and Mier, 2022), which is one major driver of wind offshore expansion. Assuming similar fixed operation and maintenance cost for wind offshore as for wind onshore (which is not realistic), and reducing capacity linearly by 25% until 2050 actually yields selected countries that deployment wind offshore (offshore still contributes less than 10% to European 2050 wind power output). However, I refrain from manipulating cost to achieve a desired (publicly more accepted) outcome.

than a 2050-power plant. Most probably, the 2050-power plant is cheaper due to lower variable cost and increased efficiency. Non-displayed technologies do not have dispatch cost (hydro, wind, solar). Observe that nuclear is the cheapest technology, followed by lignite, and coal. The CCS counterparts come with doubled dispatch cost. Gas cost are considerable higher than those of coal and lignite. Note that the displayed values are for *bau* scenario assumptions. Adding the 50% natural gas price surcharge from the *high* scenario yields structurally higher gas dispatch cost. However, bioenergy and bio-CCS are the most expensive technologies.

Table 6: Dispatch cost excluding cost for CO_2 allowances (in €/MWh electric) for the different generation technologies under *bau* assumptions

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2035	2040	2045	2050
Coal	25.5	25.4	25.4	25.3	25.2	25.0	24.9	24.7	24.6	24.3	24.1	23.9	23.7
Coal-CCS					49.8	49.7	49.6	49.5	49.5	49.1	48.9	48.6	48.4
Lignite	19.7	19.7	19.7	19.7	19.7	19.6	19.5	19.5	19.4	19.4	19.4	19.4	19.4
Lignite-CCS					44.3	44.3	44.3	44.3	44.3	44.2	44.2	44.1	44.1
Oil	134.4	134.6	134.9	135.1	135.3	135.5	135.7	135.9	136.2	137.9	139.5	141.5	143.2
Gas-CCGT/ST	35.4	35.3	35.2	35.1	35.0	34.9	34.8	34.7	34.6	34.6	34.6	34.3	34.1
Gas-CCS					48.6	48.6	48.6	48.6	48.6	48.6	48.6	48.6	48.5
Gas-OCGT	59.7	59.7	59.7	59.7	59.3	59.0	58.6	58.3	58.0	57.4	56.9	56.4	55.9
Nuclear	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.6	8.6	8.6	8.6	8.6	8.6
Bioenergy	86.1	86.3	86.5	86.7	86.9	87.1	87.3	87.5	87.7	88.5	89.3	92.3	95.3
Bio-CCS					148.4	149.0	149.6	150.2	150.9	150.2	149.6	153.8	158.0

Abbreviations: CCS (carbon-capture and storage), CCGT (combined-cycle gas turbine), ST (steam turbine), OCGT (open-cycle gas turbine).

Note that dispatch cost does not include CO_2 cost because those cost are endogenous to the optimization. An coal emission factor of 0.84 ton/MWh and a CO_2 price 50 €/ton yields CO_2 cost of 42 €/MWh. Coal-CCS comes with an emission factor of 0.095 (4.775 €/MWh). The CCS price advantage is, thus, considerable compared to building a non-CCS power plant. However, gas-CCGT comes with an emission factor of 0.35 ton/MWh (17.5 €/MWh) and gas-CCS even with only 0.048 ton/MWh (2.5 €/MWh). Dispatch cost-wise gas-CCGT thus seems preferable to coal power plants, at least when considering building a new power plant. However, gas-CCS seems to dominate classic gas-CCGT at those cost. Now turn to the special role of bio-CCS that comes with a negative emission factor of -0.9 ton/MWh. A CO_2 price of 100 €/ton (-90 €/MWh) brings bio-CCS into a competitive range. Considerably higher CO_2 prices above 200 €/ton should let bio-CCS dominate the composition of flexible power plants.

4.3. Intermittent renewable timeseries

We apply GRETA to produce availability profiles for wind onshore, wind offshore, roof-top PV, and open-field PV.[46]. Those profiles can be separated by quantiles. For example, q90 is a

[46] `https://github.com/tum-ens/pyGRETA`. This paragraph is written in the "we" perspective again, because I gratefully acknowledge the work of Patrick Hoffmann and Adam Drozynski in generating those timeseries.

representative spot in a country with 10% better and 90% worse wind (solar) spots; and is thus representative for the 20% best spots. I call those classes quantiles and use 20%-quantiles for this paper (q90, q70, q50, q30, and q10). GRETA delivers annual timeseries for wind and solar technologies depending on the selected quantiles. Summing up of those timeseries yields maximum full-load hours (FLH). Table 7 shows results for the best (q90) and worst 20% of spots (q10). A huge difference between those values indicate that the resource quality drops fast. For example, wind offshore FLH in Belgium drop from 3,440 to 3,418, whereas those in Finland drop from 3,368 to 1,679.

Table 7: 2022 full-load hours of intermittent renewable energy technologies by country

	Hydro		RoofPV		OpenPV		WindOn		WindOff	
	Classic	OECD	q90	q10	q90	q10	q90	q10	q90	q10
Austria	4,027	2,817	1,344	1,316	1,366	1,312	1,916	12		
Belgium	3,533	10,088	1,269	1,238	1,248	1,234	2,900	2,082	3,440	3,418
Britain			1,228	911	1,154	892	3,442	1,876	4,195	3,003
Bulgaria	1,351	1,764	1,546	1,523	1,601	1,523	1,444	126	1,690	855
Croatia	2,773	3,161			1,521	1,393	1,461	216	1,835	913
Czech	2,396	3,086	1,336	1,287	1,316	1,275	2,579	1,050		
Denmark	2,606	1,565	1,128	1,089	1,125	1,089	3,644	2,426	4,392	3,244
Estonia	5,878	4,967	1,074	1,037	1,082	1,037	3,238	1,627	3,651	2,602
Finland	4,550	4,732	930	714	966	726	2,558	1,183	3,368	1,679
France	2,588	3,062	1,570	1,389	1,576	1,336	2,708	890	3,589	2,347
Germany	1,757	4,437	1,337	1,236	1,323	1,161	2,827	1,129	4,232	3,369
Greece	1,153	1,654	1,771	1,643	1,774	1,603	1,801	75	2,757	549
Hungary	3,536	3,966	1,392	1,346	1,377	1,333	1,942	1,034		
Ireland	3,117	4,656	1,075	977	1,142	990	3,691	2,404	4,436	3,048
Italy	2,458	2,853	1,700	1,507	1,702	1,461	1,896	103	1,774	748
Latvia	1,236	1,652	1,109	1,045	1,109	1,045	3,107	687	3,675	3,084
Lithuania	3,369	8,099	1,141	1,060	1,141	1,074	2,636	655	3,675	3,322
Luxembourg	3,069	30,136			1,258	1,243	2,597	1,421		
Netherlands	2,787	2,012	1,244	1,244	1,231	1,194	3,083	2,265	4,076	3,552
Norway	4,216	4,398	800	633	929	626	2,430	203	4,363	2,790
Poland	2,793	3,138	1,271	1,158	1,273	1,150	2,777	1,733	3,729	3,100
Portugal	1,944	2,058	1,773	1,773	1,819	1,610	2,210	284	2,801	1,752
Romania	2,826	2,737	1,492	1,381	1,444	1,322	1,442	168	1,871	1,491
Slovakia	2,117	2,500	1,298	1,251	1,325	1,264	2,037	194		
Slovenia	3,603	4,572	1,392	1,380	1,381	1,338	936	15	913	913
Spain	1,387	2,202	2,051	1,697	1,860	1,623	2,222	413	2,923	1,383
Sweden	4,272	4,199	909	778	1,041	773	2,246	484	3,206	1,180
Switzerland	2,885	2,950	1,454	1,315	1,483	1,315	1,671	34		

Classic hydro calibration comes from historical timeseries. OECD hydro values refer to 2021. OECD hydro calibrations stems from updated monthly generation and is more precise because it also covers power plants that are not in every official statistics such as the named power plant databases. All other values refer to state-of-the art technologies from 2022. The quantiles refer to the best (q90) and the worst (q10) 20% of spots.

Hydro values stem from historical data (classic) or real-time adjustments according to monthly hydro generation (see Subsection 2.3). Observe that hydro FLH are above 8,760 hours for Belgium and Luxembourg. This phenomena traces back to bad data for installed capacities of hydro power in those countries. In particular, those countries have only few sources and missing only several small power plants yield those errors. However, fixing total generation potential is the best option here. For countries with more reasonable hydro power capacity data, quality is much better and the values does not differ structurally; although the classic timeseries bases on historical data does not account for latest effects with regard to rainfall.

However, expansion of wind and solar technologies is by far more decisive for the future technology mix. For wind technologies, I thus assume technological progress by means of increasing the average hub height of wind onshore (offshore) turbines from 80m (90m) for existing vintages to 150m (170m) for 2050-vintages. Table 8 shows the outcome of that tasks for Germany and also shows the remaining quantiles. Observe that the effect of rising turbines is more severe for wind onshore than for wind offshore, because the offshore wind quality is better. Moreover, the relative effect is greater for lower quantiles.

Table 8: Full-load hours of wind onshore and offshore over time for Germany

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2035	2040	2045	2050
WindOn (q90)	2,827	2,853	2,880	2,907	2,933	2,959	2,984	3,010	3,036	3,154	3,267	3,369	3,469
WindOn (q70)	2,490	2,515	2,540	2,566	2,589	2,613	2,637	2,661	2,684	2,796	2,898	2,993	3,089
WindOn (q50)	2,151	2,174	2,197	2,220	2,242	2,264	2,286	2,308	2,330	2,434	2,532	2,621	2,711
WindOn (q30)	1,693	1,713	1,732	1,752	1,770	1,788	1,806	1,824	1,842	1,929	2,012	2,087	2,161
WindOn (q10)	1,129	1,144	1,159	1,174	1,188	1,202	1,216	1,230	1,244	1,310	1,372	1,433	1,490
WindOff (q90)	4,232	4,245	4,259	4,272	4,284	4,296	4,309	4,321	4,334	4,391	4,439	4,491	4,574
WindOff (q70)	4,174	4,188	4,202	4,217	4,228	4,240	4,252	4,264	4,276	4,333	4,382	4,433	4,521
WindOff (q50)	4,121	4,135	4,148	4,163	4,175	4,187	4,199	4,212	4,224	4,279	4,329	4,375	4,458
WindOff (q30)	3,933	3,946	3,960	3,973	3,985	3,998	4,010	4,022	4,034	4,087	4,136	4,185	4,265
WindOff (q10)	3,369	3,382	3,395	3,408	3,420	3,432	3,444	3,457	3,469	3,523	3,572	3,620	3,704

The quantiles (q90, q70, q50, q30, q10) refer to the respective quality classes but higher turbines yield higher full-load hours.

However, the worse 80% of spots are rarely deployed because the overall potential of the 20% best spots is already sufficient to cover needs.[47] Table 9 actually summarizes the total resource potential by country as it is calculated by GRETA. Observe that wind offshore potential is small (925 GW) in comparison to open-field solar PV (16,418) but the 925 GW would be sufficient to produce more than 60% of Europe's 2050 electricity demand of 6,200 TWh. Indeed, resource potentials are extremely high compared to the final needs.[48] However, some countries with low potentials and high quality resources (i.e., Denmark and Netherlands) actually face scarce wind onshore spots.

5. Results

I start with showing the outcomes of the three main scenarios in terms of technology mix including storage and export volumes. I also discuss the electricity price development until 2050 as well as CO_2 prices resulting from the EU ETS.[49] In particular, I determine the canceling volume from the MSR to determine the climate impact of the three scenarios under consideration. Next, I

[47]Indeed, Denmark and Netherlands are prominent examples that even use q50 or q30, respectively.

[48]Around 1,500 GW of wind onshore finally deliver around 80% of Europe's electricity generation.

[49]Note that I can only calculate CO_2 prices based on intertemporal banking decisions and mitigation cost of the electricity sector in combination of a well calibrated allowances demand from other EU ETS sectors. I cannot

Table 9: Resource potential of intermittent renewables (in GW)

	RoofPV	OpenPV	WindOn	WindOff
Austria	4.3	219	199	
Belgium	0.2	62	100	5
Britain	8.7	733	688	137
Bulgaria	0.1	159	357	8
Croatia		133	184	16
Czech	3.2	218	290	
Denmark	2.0	40	65	151
Estonia	2.2	124	117	20
Finland	4.7	659	1,014	50
France	10.7	863	1,958	54
Germany	12.3	437	761	75
Greece	0.1	1,298	432	32
Hungary	0.0	64	358	
Ireland	0.8	164	227	24
Italy	0.3	720	1,009	51
Latvia	3.1	205	209	27
Lithuania	2.4	131	209	5
Luxembourg		3	4	
Netherlands	0.5	91	85	120
Norway	52.8	2,314	601	16
Poland	5.1	325	853	20
Portugal	0.0	1,164	387	3
Romania	1.4	127	987	9
Slovakia	0.3	55	152	
Slovenia	0.1	70	54	0.5
Spain	0.1	4,225	2,022	23
Sweden	42.5	1,692	1,084	80
Switzerland	2.4	122	84	
Sum	160	16,418	14,491	925

The values show the total potential of intermittent renewables. Each 20%-quantiles face indeed 20% of those total values.

decompose 2022 price effects to disentangle the effects of (higher) energy prices (*bau*, *recovery*, or *high*), French nuclear availability, and European hydro generation. I then analyze the impact of the three German nuclear exit options (*stretching*, *extension*, or *stretchtension*). Finally, I analyze effects of further reduced French nuclear availability in 2023 and the impact of a potentially permanently lower European hydro generation taking the German nuclear exit option *stretching* as benchmark.

account for arbitrage or speculation effects or even demand for allowances outside EU ETS sectors, e.g., for the use as hedging instrument in relation to the upcoming carbon border adjustment mechanism of the EU. This speculation might have an impact in the mid-run because the MSR thresholds of 400 and 833 million intend to reflect such outside demand for CO_2 allowances. In particular, as long as there is a sufficiently high amount of circulating allowances, results from the model and real world prices might be not directly comparable. Higher real world prices must be seen as the sum of speculation premiums from outside EU ETS sectors, uncertainty premiums from EU ETS sectors, and higher CO_2 prices from non-optimized investment and dispatch behavior from EU ETS sectors. In the long-run, those differences should vanish and CO_2 prices should be driven by mitigation cost of the EU ETS sectors only.

5.1. Scenario outcomes

Figure 1 shows generation (in TWh) with the overall volume of CO_2 emissions (in Mt), stored energy (in TWh), and exports (in TWh) of the European power market from 2022 to 2050.[50] The first bar of each cluster shows the outcome for *bau*, the second one for *recovery*, and the third one for *high*. Each cluster reflects a period with the first cluster presenting 2022 values and the last one 2050 ones. The generation mix is plotted on the left axis with bars presenting the generation level of the respective technologies. CO_2 emissions (gray diamonds), stored energy (yellow squares), and exports (red triangles) are plotted on the right axis. Observe that overall generation more than doubles from around 3,200 TWh in 2022 to 6,800 TWh in 2050 due to assumptions about electricity demand that covers rising electricity demand in general but also electrification trends in industry, heating, and transport, as well as the usage of electricity for hydrogen generation.[51]

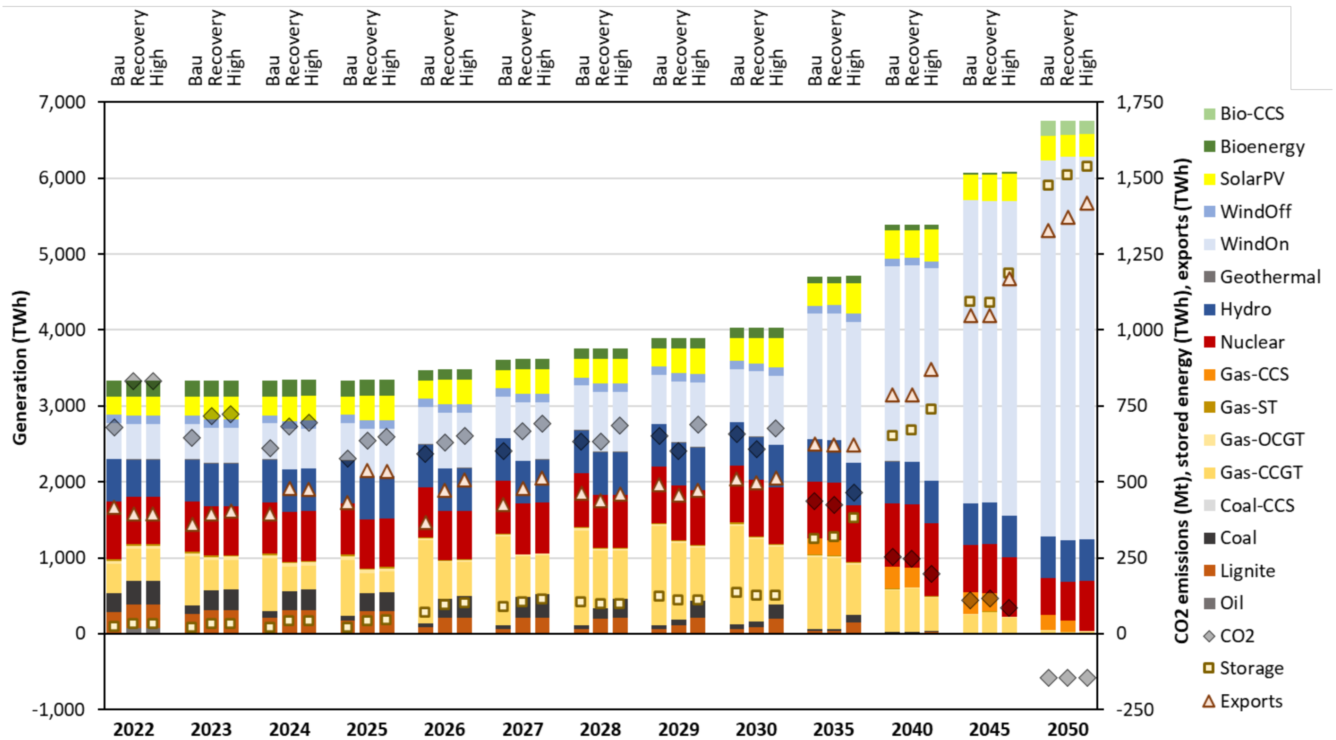
Start with 2022 and remember that *bau* does not account for any crisis impact, whereas the two crises scenarios *recovery* and *high* consider reduced French nuclear availability and reduced European hydro generation in 2022 as well as higher energy prices as shown by Table 1. Observe that *bau* delivers substantially higher nuclear (762 TWh) and hydro generation (557 TWh) compared to the two crises scenarios (both with 623 TWh nuclear and 486 TWh hydro generation). In turn, the amount of lignite, coal, and oil generation is substantially higher for the two crises scenarios (+164 TWh). Also the generation from natural gas fired power plants is still higher (+39 TWh), leading to 832 Mt CO_2 emissions, whereas power plants emit 679 Mt in the *bau* world. The increase in generation from natural gas-fired power plants shows that the French nuclear and European hydro effects are tremendously underestimated in current discussions of the energy (price) crisis. Interestingly, export volumes are considerably lower for the two crises scenarios. Nuclear, as quasi must-run technology, is indeed fostering international electricity exchange because volatile renewable energy cannot kept inside the respective countries when the possible amplitude is reduced by baseload nuclear generation. Moreover, France plays a vital role in nuclear exports. In particular, France exports lots of electricity under *bau* assumptions due to its high nuclear share, which is considerably reduced in the two crises scenario in 2022. Indeed, French nuclear problems reduce nuclear generation in France by 130–145 TWh (depending on the underlying energy price scenario).

Now turn to 2023. In the two main crises scenarios, French nuclear availability and European hydro generation are back to *bau* levels in 2023. Higher energy prices (mainly natural gas and coal, see Table 1) are the only remaining crisis. Observe that natural gas usage is strikingly lower

[50]Exports refer to the bilateral trade volume between the 28 countries under consideration (EU27 less Cyprus and Malta, plus Norway, Switzerland, and United Kingdom). Total European exports equal total European imports (losses are assumed on the exporting side ahead of the border). Country-specific exports and imports might differ.

[51]Generation across scenarios slightly differs—although it is not observable from Figure 1—due to round-trip efficiency losses of storages (charge, automatic discharge, discharge) and transfer losses (assumed on the exporting side). In particular, more stored energy and more exports come with higher losses. However, the impact of storage losses (when comparing scenarios) is almost negligible because it is only batteries that play is fundamental role besides existing pump storage; and batteries come with negligible round-trip efficiency losses.

Figure 1: Generation, CO_2 emissions, stored energy, and exports for main scenarios



for the two crises scenarios (around 460 TWh compared to 715 TWh in *bau*). The difference is mainly compensated by coal (+150 TWh) and lignite (+57 TWh). However, total CO_2 emissions drop in 2023 compared to 2022 but are still considerably higher as it would be the case in *bau*. Interestingly, the higher coal and lignite usages increase exports remarkably (by more than 10% in *high* compared to *bau*). Indeed, the higher generation from medium-dispatchable coal and lignite power plants demands for more exports.

The coal/lignite-gas differential in combination with higher transfer volumes is persistent until 2027. Also CO_2 emissions keep considerably higher until 2027 for the two crises scenarios. In particular, CO_2 emission-wise the natural gas price effect dominates the coal price effect.[52] The system starts observable adjustment processes in 2023 with solar PV expansion (+60 TWh in 2023, +80 TWh in 2024).[53] Wind power adjustments start in 2024 (+50 TWh in 2024, +150 TWh in 2025). Wind differences maintain until 2050, whereas solar differences level out in 2035 (*recovery*)

[52]Higher coal prices foster a shift towards natural gas and thus reduce CO_2 emissions. Higher natural gas prices in turn foster a shift towards coal and yield higher CO_2 emissions.

[53]Remember that those adjustment processes are constrained by sticky investment behavior. Solar PV adjustments are available from 2023 onwards, wind onshore follows in 2024, and wind offshore in 2025. However, those adjustment processes are still constrained by the levels described in Subsection 3.2.

or 2050 (*high*), respectively.

Interestingly, the higher natural gas price in *high* (50% higher compared to *bau* from 2028 onwards and 50% higher compared to *recovery* from 2035 onwards) prevents gas-CCS from being competitive from 2035 onwards.[54] Instead, *high* sees considerable nuclear expansion, so that nuclear contributes 140 (160) TWh more in 2040 (2045) as it would be the case when assuming pre-crisis natural gas prices under *recovery* (*bau*). However, nuclear does not fill the complete CCS gap (165 out of 199 TWh compared to *bau* in 2050); also wind power generation is higher. Compared to *recovery* in turn, nuclear (+154 TWh) overcompensates the CCS gap (-146 TWh) by using more wind power (+10 TWh). Interestingly, the gain of using more nuclear and wind (completely carbon-neutral in operation) compared to almost carbon-neutral gas-CCS leaves space of reducing bio-CCS generation by almost 10% (*high* vs *bau*).[55] In particular, bio-CCS becomes only competitive in 2050 to meet the target of carbon-negative electricity generation (-144 Mt in Europe). Moreover, more nuclear and higher wind generation again increases exports (+88 TWh, +6.6%). Half of this higher export volume traces back to higher nuclear generation because *recovery* comes with comparable wind generation (to *high*) but nuclear generation is comparable to *bau*.[56]

Now turn to Table 10 that shows electricity and CO_2 prices in the three scenarios. It also shows the total canceling volume (of the MSR in the EU ETS) as well as the aggregate CO_2 emissions from electricity generation (without UK). Electricity prices indeed refer to European weighted averages (including UK). Observe that the *bau* price is at 36 €/MWh in 2022 and increases to 55 €/MWh in 2050. The crises scenario *recovery* (*high*) delivers 251 (247) €/MWh in 2022. Prices of crises scenarios halve in 2023 and then slowly drop to reasonable levels again. *Recovery* (*high*) prices converge to *bau* levels from 2029 (2030) onwards. Price differences between scenarios are negligible in the long-run. Observe that *high*, although having the same fuel prices until 2027, has indeed lower electricity prices than *recovery* in the period 2022–2028, because the respective 2022 CO_2 price is only 32 €/ton (compared 40 €/ton). Such 20% difference remains until 2050, where both crises scenarios come with similar CO_2 prices again (233 or 232 €/ton, respectively). Such phenomena can be explained by the higher CO_2 emissions within the EU ETS in the *high* scenario due to non-linear canceling behavior within the MSR. Indeed, the canceling volume is 116 million allowances lower in *high* so that this alleviation of the carbon constraint indeed reduces electricity prices.

[54] CCS expansion is restricted until 2030. There are no official plans to start commercial (in terms of power generation) CCS usage. Moreover, planning, approving, and construction need several years and thus period 2035 (years 2031–2035) is assumed to be the earliest point in time for CCS as a commercially used power generating technology.

[55] Bio-CCS generation is also lower compared to*recovery* (-7 TWh). Remember that all scenarios need to meet the same CO_2 target in 2050.

[56] Note that nuclear power fosters exports in my modeling results even without accounting for ramping times (up, down), corresponding ramping cost, minimum dispatch, necessary down times, start-up times, and corresponding start-up cost. EUREGEN can principally account for those times and cost but, in particular, start-up times and cost in combination with minimum dispatch come at extraordinary computational expenses that would make it necessary to reduce hourly resolution even further. I thus refrain from adding those specifications for this analysis.

Table 10: Electricity prices (in €/MWh), CO_2 prices (in €/ton), canceling (in Mt), and CO_2 emissions

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2035	2040	2045	2050	
Electricity price														
Bau	36	52	53	54	61	62	64	67	89	68	65	65	55	
Recovery	251	124	110	84	77	74	72	68	88	70	65	64	56	
High	247	119	107	80	74	71	69	72	88	72	67	66	56	
CO_2 price														Canceling
Bau	41	43	46	48	50	53	55	58	61	70	90	114	164	3,596
Recovery	40	42	44	46	49	51	54	56	59	68	87	111	233	3,287
High	32	33	35	36	38	40	42	44	47	54	68	87	232	3,171
CO_2 emissions														Sum
Bau	607	570	538	508	523	532	559	576	581	389	228	97	-128	7,925
Recovery	752	641	611	573	569	602	561	526	531	375	222	105	-128	8,235
High	753	647	623	586	593	629	616	618	603	417	174	74	-128	8,350

Electricity price is the weighted average European electricity price. CO_2 price is the price within the EU ETS (excluding UK). Canceling refers to the EU ETS only (in Mt). CO_2 emissions refer to emission from electricity generation within the EU ETS (excluding UK).

CO_2 prices in *bau* are even higher than those of *recovery* until 2045, because the *bau* canceling is at 3,596 million allowances (+309 million compared to *recovery*, +425 million compared to *high*). When looking at CO_2 emissions, one can directly observe the level of higher CO_2 emissions in the two crises scenarios. However, CO_2 emissions of *high* drop below those of *recovery* in 2040 but the CO_2 price remains lower in *high*. The early adjustments processes with regard to wind and solar power indeed yield such distortions. *High* sees more wind power expansion from 2029 onwards and, in particular, the 2040 differences are severe. Also the non-usage of gas-CCS keeps the 2040 CO_2 price under *high* assumptions low. However, there is a massive catch-up effect in 2050, where both *recovery* and *high* see structurally higher CO_2 prices than *bau*. The reasoning lies in missing high quality wind spots (that cannot get used for the newer, more productive turbines anymore) and intertemporally distorted solar expansion in the period 2023–2027. In particular, the aggregate figures hide that local deployment differs across scenarios in response to dirty initial endowments in 2022. Countries with high natural gas usage need to undertake necessary adjustments, whereas countries with considerable amounts of lignite and nuclear power or renewable energies feel less pressure. Moreover, as response to those locally diverging expansion patterns, total export and storage demands are higher and explain parts of the higher 2050 CO_2 price.

5.2. 2022 effects

The prior subsection already started looking into 2022 effects by determining substitution effects in the technology mix caused by lower nuclear and hydro generation. I now have a deeper look into 2022 effects. Table 11 decomposes the effects of reduced French nuclear availability and lower European hydro power generation by showing electricity prices (first and second column), the generation mix (next seven columns), the resulting use of natural gas, CO_2 emissions in Europe, and transfers separated into imports and exports (final four columns). Vertical the table is separated in Europe (first block), Germany (second), and France (third). The first row of each block shows *bau* outcomes. The next three rows add French nuclear, European hydro, and the combined effect of both to the standard *bau* scenario. The fifth row shows *high* outcomes when neglecting French nuclear and European hydro effects, that is, only the energy price effects impact outcomes. The next three rows add French nuclear, European hydro, and the combined effect again. Note that for the *high* scenario the combined effect is assumed to be the standard case as presented in Figure 1 and described in Subsection 5.1.

Table 11: Decomposition of 2022 crises effects

	Price (€/MWh)		Generation (in TWh) Lig	Coa	Gas	Hyd	Nuc	Win	Sol	Gas use (TWh)	CO_2 (Mt)	Transfers Imp	Exp
Europe													
Bau	36		273	248	451	557	762	578	242	876	679	418	418
French nuclear	98	+173%	268	149	682	557	620	579	241	1,293	687	328	328
European hydro	57	+59%	276	208	544	485	774	581	241	1,044	685	404	404
Combined	110	+206%	231	131	801	486	623	580	241	1,507	687	320	320
High	143		355	259	384	551	707	568	237	749	778	435	435
French nuclear	235	+65%	300	299	445	557	620	579	241	870	800	399	399
European hydro	169	+18%	329	267	422	485	732	581	241	820	779	414	414
Combined	247	+73%	306	310	490	486	623	580	241	951	833	396	396
Germany													
Bau	37		95	52	83	45	28	254	75	213	240	45	56
French nuclear	108	+191%	95	41	99	46	29	254	74	242	238	33	52
European hydro	93	+148%	95	43	90	46	29	255	74	226	235	41	51
Combined	124	+232%	80	37	116	47	29	254	75	271	229	35	52
High	102		136	52	77	43	20	245	72	202	275	43	73
French nuclear	199	+96%	110	67	82	46	29	254	74	211	268	38	83
European hydro	152	+49%	120	55	79	46	20	255	74	205	265	37	69
Combined	208	+104%	113	72	83	47	29	254	75	214	274	33	87
France													
Bau	25		0	3	71	68	435	158	21	14	5	9	105
French nuclear	171	+578%	0	4	93	68	290	158	21	47	14	46	22
European hydro	29	+15%	0	2	75	56	445	159	21	18	5	11	105
Combined	194	+669%	0	4	102	56	291	159	21	59	17	46	21
High	98		0	3	69	68	419	157	21	12	9	11	95
French nuclear	326	+232%	0	12	84	68	290	158	21	38	31	45	38
European hydro	106	+8%	0	3	70	56	433	159	21	12	9	9	96
Combined	346	+253%	0	13	86	56	291	159	21	42	32	47	34

Abbreviations: Price (electricity price), Lig (lignite), coa (coal), gas (gas-CCGT/ST/OCGT), nuc (nuclear), hyd (hydro), win (wind onshore and offshore), sol (open-field PV and roof-top PV), imp (imports), exp (exports).

Europe. Start with Europe. Electricity prices would have increased from 36 to 110 €/MWh (+206%) without higher energy prices, solely due to French nuclear and European hydro problems, whereas French nuclear contributes predominantly to that increase. The energy price effect only would have increased prices from 36 to 143 €/MWh. Thus, the energy price effect still dominates but a tripling of prices would have been there even without the increase in fuel prices. However, the addition of French nuclear and European hydro effects on top of the energy price effect brings even more severe price increases (at least absolutely, from 143 to 247 €/MWh, +73%). The three crises thus reinforce themselves.

Observe that nuclear generation is 762 TWh in *bau*. French nuclear reduces this amount by 142 TWh. European hydro in turn would have increased the nuclear generation by 12 TWh. The joint effect is dominated by the reduced availability of French nuclear power plants. Interestingly, the higher energy prices would have reduced nuclear generation already by 55 TWh for sake of lignite generation (+82 TWh). French nuclear in combination with higher energy prices in turn yields same nuclear output as it would be the case without higher energy prices (620 TWh). Generation possibilities immediately become scarce so that nuclear cannot get substituted so easily anymore. Now, interestingly, it is coal and also gas that compensate for reduced nuclear generation. Overlapping effects for reduced European hydro generation are negligible. Indeed, hydro generation is reduced by 91 TWh (-13%) when accounting for hydro effects.

Without higher energy prices, the natural gas use would have increased from 876 to 1,507 TWh when accounting for the combination of both effects. The higher energy prices (without the combined effects) reduce natural gas usage to 749 TWh but the combined effects increase natural gas usage even above the *bau* level (to 951 TWh).[57] Observe that the *bau* variations face very similar CO_2 emissions, but higher energy prices increase CO_2 emissions considerably (from 679 to 778 Mt). The effect of French nuclear on CO_2 emissions is also greater for *high* (22 vs. 8 Mt). However, European hydro has only a superadditive effect in combination with French nuclear, so that final CO_2 emissions in the combined *high* world would be at 833 Mt (+154 Mt compared to *bau*). Most of those increases can be traced back to higher lignite and coal generation.[58]

The decomposition brings also light into transfers between countries. Without higher energy prices (*bau*), French nuclear reduces the transfer volume by 22% (from 418 to 328 TWh) simply because France almost vanishes as nuclear electricity exporting country. The reduction in transfers is smaller for higher energy prices (*high*). In particular, higher energy prices would actually yield more transfers (+17 TWh) but the combination of French nuclear and European hydro effects reduces that amount by 39 TWh again. Table 11 thus supports the finding that nuclear is an exporting technology.

Germany. I now turn to German effects. Germany is more affected by French nuclear and European hydro than the European average. However, higher energy prices indeed have smaller impacts because of Germany's diversified generation portfolio with lignite, coal, and substantial shares of renewable energies. Interestingly, German hydro generation in 2022 is actually not reduced but the European hydro effect is substantial because German usually benefits from hydro generation in neighboring countries (e.g., Austria and Switzerland). Observe that gas generation increases under variations in the *bau* scenario but is almost unaffected when energy prices are higher. Indeed, the higher energy prices increase the export volume of Germany considerably (from 56 to 73 TWh

[57]Note that natural gas usage refers to usage for electricity generation plus combined-heat-and-power generation in Germany.

[58]Some increases go back to increased oil usage that,for parsimony, I refrain from depicting and discussing here.

without additional effects and to 87 TWh with the combined effects), whereas imports even drop (from 45 to 43 to 33 TWh). The substitution effect away from natural gas towards lignite and coal thus fizzles out due to higher overall generation to serve neighboring countries.[59] Interestingly, the CO_2 emissions increase only slightly from 240 to 275 Mt due to higher energy prices. The effects of French nuclear and European hydro even reduce corresponding emissions, mainly because of higher nuclear and lower lignite production. This—lignite generation is reduced by the French nuclear effect—is quite surprising but can be explained by complex dynamics of electricity generation from multiple generation sources (merit order, peak-load pricing). Indeed, reduced nuclear generation in France demands for imports to France during peak hours because the still available plants are serving the French baseload only. The other plants (those in remedial maintenance) are actually missing for the peakload ramp-up. In those peakload hours, it is beneficial to ramp-up gas and coal power plants, whereas lignite power plants actually mainly run on a constant basis as well.[60] The lignite plants in Germany are thus not suitable—from an economic point of view (high fixed cost, low variable cost)—to cover the missing French nuclear generation.

France. Finally, turn to France. The French nuclear problems without higher energy prices increase electricity prices from 25 to 171 €/MWh (+578%). Hydro effects are over-proportional when adding on-top of nuclear issues. Higher electricity prices would have increased prices from 25 to 98 €/MWh. Adding nuclear and hydro problems on-top leads to 346 €/MWh. The nuclear effect comes from a reduction in nuclear generation to 290 or 291 TWh, respectively, whereas maximum generation potential is 50% higher. The substitution of nuclear power is done partly by natural gas, but the gas substitution is reduced given higher energy prices. In particular, coal substitutes considerably amounts of missing nuclear generation for *high* energy prices and French nuclear effects. However, the predominant substitution comes from reduced exports and increased imports. Observe that the *bau* export balance is 105 – 9 = 96 TWh. European hydro has negligible effects here, but French nuclear alone changes this balance to 22 – 46 = –24 TWh, that is, a difference of 120 TWh when accounting for reduced nuclear generation. Higher energy prices in turn reduce that difference to 91 TWh. Such reduction in the balance difference does not come from reduced imports to France but rather increased exports. In particular, it is beneficial for France to serve very expensive peakload hours in neighboring countries by using, e.g., own coal production. Those findings again support the role of nuclear for exports.

5.3. German nuclear exit

One remaining piece is the German response by means of stretching or extending German nuclear power plants beyond their planned decommissioning date at the end of 2022. Table 12 shows electricity price impacts for Europe and Germany.

[59]"Serve" might be misleading because firms earn substantial profits when exporting into neighboring countries that face higher electricity prices than Germany in such times of multiple crises.

[60]Actually, also oil power plants see a tremendous increase in generation and explain the missing 50 TWh in balance under *high* assumptions.

Table 12: European electricity prices (in €/MWh) under different German nuclear exit choices

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2035	2040	2045	2050
Europe													
High*	247	119	107	80	74	71	69	72	88	72	67	66	56
Stretching	247	118	107	80	74	71	69	72	88	72	67	66	56
Extension	247	116	105	79	72	70	69	72	88	72	67	66	56
Stretchtension	247	118	105	79	72	70	69	71	89	72	67	66	56
Germany													
High*	208	108	98	79	77	74	74	78	97	72	71	67	53
Stretching	208	105	98	79	77	74	74	78	97	72	71	67	53
Extension	207	101	94	76	74	74	74	77	96	72	71	67	53
Stretchtension	207	104	94	76	74	74	74	76	96	72	71	67	53

*The benchmark is the *high* scenario with the combined 2022 effect.
Stretching assumes extension of three remaining nuclear power plants by 3.5 month until April 15, 2023. Extension assumes running them seven additional years from January 2023 onwards. Stretchtension assumes running them seven additional years after the stretching from September 2023 onwards.

Europe. The stretching operation reduces European electricity prices by 0.89% in 2023. An extension would have brought price down by 2.4%. The stretchtension option would still accumulate a price effect of 1.21% in 2023 and of 1.88% in 2024. Effects slightly grow until 2025 (2.2%) and then drop towards negligible amounts in the following years. Interestingly, the nuclear extension prevents investments into wind and solar technologies so that the year after the extended nuclear power plants would go off the grid (2030), the prices increase actually by 0.87%. The 2030 effect is even stronger under stretchtension (1.41% increase), although plants are still running until the end of August 2023. However, the European electricity price effect is negligible. Moreover, the canceling volume in the EU ETS increases only by 3 (23, 19) million ton when stretching (extending, stretchtending) German nuclear power plants.[61]

Germany. German electricity prices drop by 2.47% (6.21%, 3.29%) for stretching operation (extension, stretchtension) in 2023. The 2024 price effects for extension and stretchtension are at 4.8% and drop severely from 2027 onwards when wind and solar investment in response to the energy (price) crisis allow for substantial adjustments. However, all nuclear policy options indeed reduce electricity prices, that is, there is no catch-up effect in 2030 as observed for European prices.[62] Moreover, German CO_2 emissions would actually decrease by 3 (43, 45) million ton. Thus, the national reduction in CO_2 under stretching operation directly translates into a true climate impact via the canceling mechanisms of the MSR within the EU ETS. The German mid-run reductions

[61] This canceling volume can be translated directly into the climate impact. Note that the 23 or 19 million are indeed for a period of 9 or 10 years, respectively.

[62] Regarding current discussion in Germany about high electricity prices for industry, observe that German prices are similar to European average and even lower in 2050. Thus, the electricity wholesale price is not the main driver of non-competitively high electricity prices in Germany when optimizing capacity planning harmonized across countries in line with the EU ETS and carbon-neutrality targets of the EU (as well as Germany).

from extension or stretchtension arrive only halfway through in the canceling volume because of the cap-and-trade nature of the EU ETS: CO_2 emissions in other countries actually increase in the mid-run.[63] Note that the potential benefit of substituting lignite generation by nuclear in Germany would be around 30 Mt per year. This, however, neglects electricity market design and the working of the MSR within the EU ETS.

5.4. 2023+ effects

French nuclear problems are still persistent in 2023 as it is the case for reduced European hydro generation. Moreover, climate change brings into discussion whether or not European hydro generation should be assumed to be below historical average even in the long-run. I thus decompose the impact of those effects on electricity prices again. In particular, Table 13 shows European weighted average electricity prices when French nuclear availability is similarly reduced in 2023 as it was the case for 2022 (*French nuclear 2023*), European hydro generation is still reduced in 2023 (*European hydro 2023*), the combination of the prior two effects (*Combined 2023*), European hydro generation is permanently reduced (*European hydro 2023+*), and the combination of the prior two effects again (*Combined 2023+*). The benchmark for this decomposition is the *high* scenario with the combined 2022 effect when Germany stays with the stretching operation.[64]

Table 13: European electricity prices (in €/MWh) under different French nuclear and European hydro variations

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2035	2040	2045	2050
Stretching	247	118	107	80	74	71	69	72	88	72	67	66	56
French nuclear 2023	247	139	107	80	74	71	69	72	88	72	67	66	56
European hydro 2023	247	125	107	80	74	71	69	72	88	72	67	66	56
Combined 2023	247	151	107	80	74	71	69	72	87	72	67	66	56
European hydro 2023+	248	125	112	83	75	72	71	73	93	72	68	66	57
Combined 2023+	248	151	112	83	75	72	71	73	93	72	68	66	56

French nuclear 2023 assumes same availability as in 2022. European hydro 2023 assumes same availability as in 2022. Combined 2023 combines both of those effects. European hydro 2023+ assumes that European hydro generation stays forever at 2022 level. Combined 2023+ combines the French nuclear 2023 effect with permanent European hydro shortfalls.

Start with 2023 values and concentrate on the first three variations (without permanent hydro damages). Remember that French nuclear problems lead to a 2022 price increase from 36 (143) to 98 (235) €/MWh under *bau* (*high*) energy price assumptions due to a drop in French nuclear generation of 145 (129) TWh. System adjustments with regard to solar PV (+60 TWh all over Europe in 2023 compared to *bau*) reduce the 2023 impact of reduced French nuclear generation considerable. Moreover, the 2023 drop in French nuclear generation is less severe (-57 TWh) as the benchmark delivers already substantially lower nuclear generation—344 TWh in 2023 compared to 435 TWh in 2022 under *bau* without any variation effects. Indeed, electricity prices increase from

[63]Note that this is estimation must be seen as the upper bound of additional canceling because reactions of other EU ETS sectors in terms of higher CO_2 emissions in response to lower demand of the (German) electricity sector are ignored.

[64]Note that those values are the same as in the first line of the Europe block in Table 12.

118 to 139 €/MWh only. The hydro effect is again smaller than the nuclear effect (+7 €/MWh) but the combined effect is super-additive (+33 €/MWh); that is, the two crises reinforce themselves.

From 2024 onwards, price difference between the benchmark and the first three variations (with 2023 effects only) are negligible. The permanent hydro damage (-73 TWh, -13%) in turn increases prices by almost 5% in 2024 and by 4% in 2025. The price effect is below 3% until 2030, whereas prices are indeed more than 6% higher given reduced hydro generation. From 2035 onwards, the system can perfectly adjust also its conventional capacity (nuclear, gas-CCS) and thus the price effect almost vanishes in the long-run (+0.33% in 2050). This also explains parts of the higher 2030 effect in general for all scenarios and variations.[65] The impact of reduced European hydro generation also shrinks because the generation share of hydro decreases over time. While generation increases from 3,330 TWh in 2022 to 4,036 TWh in 2030 to 6,757 TWh in 2050, hydro generation is already at its limit and stays at maximum 560 TWh. The generation share thus decreases from 17% in 2022 to 8% (14%) in 2050 (2030). Interestingly, a permanent hydro damage increases the export volume by 1.86% and the amount of stored energy by 0.88%, because hydro is mainly substituted by wind power (+63 TWh in 2050) that requires substantial spatial and temporal balancing across Europe. Those increases are actually small but reflect that countries are differently impacted by the European hydro damage: Those with high damage either expand wind power or increase imports from other regions.

Remember that Germany does not see any impact, whereas French hydro generation drops by 11.81 TWh or 17.33% in 2023, respectively.[66] Moreover, the composition of the hydro damage might change locally, in particular, when considering that shrinking reservoirs levels in Norway, Sweden, and Spain are not directly translated into reduced hydro generation, yet. However, the long-run adjustments of the system in response to the hydro damage reduce the hydro price effect considerably, no matter whether or not the damage is permanent or even more severe than actually observable.

6. Conclusions and policy implications

Current energy crises in Europe has three elements. First, prices for energy carriers skyrocketed in 2022. Second, French nuclear power plant availability is reduced by 33% due to maintenance issues with some reactor types. Third, 2022 was one of the driest years on record and the missing rainfall reduces European hydro generation by 13%. In this paper, I decompose the effects of those elements on electricity prices by using the European power market model EUREGEN, which optimizes investments, decommissioning, and dispatch decisions of multiple generation, storage, and

[65] This phenomena arises from (i) the free capacity expansion of all technologies from 2035 onwards and from (ii) the switch in periodical resolution (from annual to quinquennial modeling).

[66] Other highly impacted countries (more than 10% and significant hydro share above 5%) are Bulgaria (-0.57 TWh, -12.18%), Croatia (-0.88 TWh, -12.89%), Finland (-1.79 TWh, -10.86%), Italy (-17-54 TWh, -36.36%), Portugal (-5.23 TWh, -36.07%), Slovenia (-1.66 TWh, -32.38%), Spain (-12.3 TWh, -34.39%), and Switzerland (-5 TWh, -12.89%). Germany is then indirectly impacted via missing (or more expensive) imports from France and Switzerland.

transmission technologies in 28 countries (EU27 less Cyprus and Malta, plus Norway, Switzerland, and United Kingdom) intertemporally until 2050. I further analyze the role of the adjusted German nuclear exit choice to counteract against higher electricity prices (in Germany). In particular, I analyze three different price scenarios for energy commodities, multiple scenario variations with regard to French nuclear availability and European hydro generation, and the overlapping effect with German nuclear policy (stretching, extension, extension after stretching). I also determine the effect of those elements on the canceling dynamics in the market stability reserve (MSR) of the EU ETS to determine CO_2 prices and the climate impact of the current crises.

I consider three main scenarios. The business-as-usual (*bau*) uses pre-pandemic energy price projections and refrains from reduced French nuclear availability as well as reduced European hydro generation in 2022 as well as succeeding years. Price *recovery* assumes that energy prices recover from 2027 (coal, oil, uranium) or 2035 (natural gas) onwards, whereas biomass prices stay permanently 50% above pre-pandemic projections due to increased biomass demand from other sectors (e.g., construction). *High* assumes the same recovery for oil, coal, and uranium as well as higher biomass, but natural gas prices are 50% above pre-pandemic levels from 2028 onwards. Moreover, *recovery* and *high* consider reduced French nuclear availability and reduced European hydro generation in 2022.

The focus of the modeling is the decomposition of crises effects under the presence of three unexpected crises and an unforeseen policy decision (German nuclear exit) while depicting EU ETS dynamics in detail. In particular, higher natural gas prices lead to a shift towards coal and lignite production, which in turn increases the demand for CO_2 emission allowances within the EU ETS. However, whether or not this yields a CO_2 price increase depends on the canceling dynamics of the market stability reserve (MSR). Unexpected crises are modeled by using sticky investment behavior from the *bau*. EU ETS dynamics are modeled by means of iteratively looping a simulation model of the EU ETS with the power market model EUREGEN.

50% higher natural gas prices compared to pre-pandemic projections keep gas-CCS away from the long-run technology mix. Nuclear is the main substitution choice in countries with nuclear history, which in turn increases export volumes and storage needs. This finding is particularly important for private investment choices and political decision-making in the next years. Investment planning needs to start several years ahead of construction and commissioning. When gas-CCS is a viable option in the future (i.e., from 2035 onwards), planning needs to start now. Current uncertainty about future natural gas prices and also the perception of single countries' governments and societies towards CCS might lead to delays in the deployment of gas-CCS. However, this might be the right decision since gas-CCS is absent in the technology mix when natural gas prices are higher. The problem then moves to the substituting technology, which is often nuclear. Thus, countries and investors face a structural problem now because they do not know whether or not to invest into gas-CCS or nuclear, or concentrate on wind power expansion in combination with transmission grid enhancements and large-scale battery deployment.

In the two crises scenarios (*high–recovery*), 2022 European electricity prices increase from 36 €/MWh to 247–251 €/MWh. 2023 (119–124 €/MWh compared to 52 €/MWh) and 2024 prices (107–110 €/MWh compared to 53 €/MWh) are still substantially higher, but price levels converge to negligible differences in 2050. Interestingly, CO_2 prices are even lower in the two crises scenarios due to substantially lower canceling volumes (3,171–3,287 million compared to 3,596 million in *bau*). In particular, CO_2 emissions from electricity generation in the EU ETS increase from 607 to 753 Mt in 2022, and are more than 70 Mt higher until 2027 in the *high* scenario. The current crises are thus bad news for the climate due to lower canceling volumes. However, the MSR of the EU ETS is particularly constructed for those crises responses. The originally intention was to tackle unexpected and exogenous reductions in the demand for CO_2 emission allowances, but the mechanism works as well the other way around. Those findings actually explain quite stable CO_2 price in the EU ETS throughout the entire year 2022. However, values determined in this paper are not directly transferable to real world prices, which are impacted by speculation and demand outside of the EU ETS, myopic demand behavior, as well as uncertainty.

The decomposition of 2022 price effects shows that the contribution of French nuclear (-145 TWh, -33%) and European hydro generation (-72 TWh, -13%) are tremendously underestimated in current discussion of the energy crisis: The European (German, French) electricity prices would have increased from 36 (37, 25) to 110 (124, 194) €/MWh even without higher energy prices. The absolute rises are even greater with higher energy prices (from 143 (102, 98) to 247 (208, 346) €/MWh). However, the higher energy prices still contribute the major share. European hydro effects in turn are smallest. The focus of policy in evaluating the energy crisis should still lie on energy prices but needs to reflect other crises' contributions as well, in particular, the contribution of French nuclear problems.

The 2022 decomposition shows that reduced nuclear generation has a significant impact on European transfer flows. In particular, France changes from the main exporting country (export balance of 96 TWh) towards one with negative export balance (-13 TWh). The differences mainly stem from nuclear generation, that is, nuclear actually enhances exports (or export needs) across Europe. This finding is quite important in the future evaluation of nuclear. Often nuclear is seen as a stable generating technology (which is true) that increases energy autarky of the using country. This is not completely true when looking at the integrated European electricity market. Nuclear has considerable impact on export capacity needs and also prevents wind power from overtaking greater market shares. In particular, nuclear cost structures (high investment and high fixed cost, low variable cost) make nuclear a quasi must-run technology, which reduces the possible amplitude of intermittent renewables such as wind to fill the gap. This increases storage and transfer needs. Gas-CCS in turn with a different cost structure (lower investment and fixed cost, higher variable cost) is suitable to balance intermittent wind supply (with respect to cost). Those economically-driven effects are even reinforced by technological characteristics of medium-dispatchable nuclear and highly-dispatchable gas power (Mier, 2021).

The impacts of German nuclear exit choices are small. 2023 prices fall from 108 to 105 (101, 104) €/MWh for stretching operation (extension, extension after stretching). Effects are still observable in the period 2024–2026 but level out in succeeding years. The impact on European average prices is even smaller. However, reduced CO_2 emissions of 3 Mt in Germany in 2023 due to stretching operation directly translate into 3 million higher canceling volume in the MSR. The total climate impact of the extension (extension after stretching) choice is 23 (19) million, whereas

German CO_2 emissions drop by 43 (45) Mt. Thus, the discussion of changing the duration of running German nuclear power plants should not be driven by electricity price nor climate change arguments. However, there might be some other reasons to extend nuclear usage in German: grid problems stemming from missing transmission grid expansion between North and South Germany in the past and energy security issues to be slightly more independent from fossil fuel imports. Since natural gas was never scarce in Germany until May 2023, the transmission problem would have occurred without current crises as well, and the energy security motive proofed to be wrong as well.

Reduced French nuclear availability and reduced European hydro generation have smaller impacts on electricity prices in 2023 and succeeding years. In particular, some adjustment processes with regard to solar PV expansion in response to the multiple crises reduce the impact of French nuclear considerably. In particular, prices would increase by 17.7% only. Permanently reduced European hydro generation increases prices by less than 5% in 2024 and the price effect levels out in the long-run. Thus, even when European hydro generation is smaller in the long-run, the overall impact on European electricity prices is small, although single countries with bigger hydro shares see greater effects. However, two of the three analyzed energy crises come with considerably reduced 2023 impacts. What remains are the higher energy prices with their significant and long-lasting impact with regard to technology choices.

My analysis comes with some caveats. First, I use an intertemporal optimization model that considers the EU ETS as only decarbonization policy. Thus, decarbonization is driven only by the cap from the EU ETS and related banking decisions but not by renewables or nuclear subsidies. Moreover, the capacity planning indeed is optimal and all adjustment processes take into account future cost of technologies and also CO_2 prices coming from the EU ETS. In reality, I doubt that systems behave as optimal as an optimization model would do. In particular, the adjustment boundaries assumed to adopt solar PV and wind investment in years 2023–2027 are optimistic and subject to policy decisions with regard to planning and prioritization in every of the 28 modeled countries. Moreover, renewables subsidies, share targets, and capacity expansion targets indeed undermine the efficient working of the EU ETS by fostering renewables expansion for the sake of dirtier technologies (Böhringer and Rosendahl, 2010). Capacity expansion targets even distort efficient technology choices in between wind onshore, wind offshore, and solar PV. My analysis decides to refrain from those distortions and thus does not matches, for example, renewable expansion targets in Germany in 2023 and following years. Second, I decide to steer dispatch decisions solely on the basis of prices for energy carriers. Moreover, prices are assumed to be the same for each country. I further refrain from implementing upper bounds on the usage of coal or lignite to perfectly match real-world 2022 generation. Those frictions might have an additional impact. However, I consider this impact as negligible, and I actually steer generation of nuclear, bioenergy, and hydro facilities in line with empirical observed real-world data. My overall target is to show decomposition and long-run effects, but rather to perfectly match real-world observations. Doing so would require several additional constraints that come with extra cost that should get analyzed in detail again, which, actually, is a useful topic to get addressed in future work.

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