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Tightening EU ETS targets in line with the European Green Deal: Impacts on the decarbonization of the EU power sector

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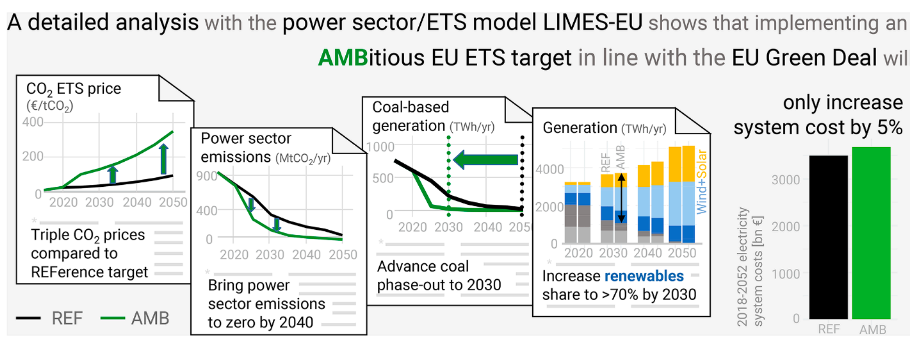
HIGHLIGHTS

- Tighter EU ETS target (−63% instead of −43% in 2030) speeds up transformation by 3–17 years.
- Renewable share >74% in 2030, EU-wide coal phase-out almost completed by 2030.
- Tighter target decreases cumulative emissions by 54%, increases costs by only 5%.
- Carbon prices increase to 129EUR/tCO_2 in 2030 under ambitious ETS target.
- Unavailability of fossil CCS and/or nuclear does not affect results.

GRAPHICAL ABSTRACT



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ABSTRACT

The EU Green Deal calls for climate neutrality by 2050 and emission reductions of 50–55% in 2030 in comparison to 1990. Achieving these reductions requires a substantial tightening of the regulations of the EU emissions trading system (EU ETS). This paper explores how the power sector would have to change in reaction to a tighter EU ETS target, and analyses the technological and economic implications. To cover the major ETS sectors, we combine a detailed power sector model with a marginal-abatement cost curve representation of industry emission abatement. We find that tightening the target would speed up the transformation by 3–17 years for different parts of the electricity system, with renewables contributing 74% of the electricity in 2030, EU-wide coal use almost completely phased-out by 2030 instead of 2045, and zero electricity generation emissions reached by 2040. Carbon prices within the EU ETS would more than triple to 129€/tCO_2 in 2030, reducing cumulated power sector emissions from 2017 to 2057 by 54% compared to a scenario with the current target. This transformation would come at limited costs: total discounted power system costs would only increase by 5%. We test our findings against a number of sensitivities: an increased electricity demand, which might arise from sector coupling, increases deployment of wind and solar and prolongs gas usage. Not allowing transmission expansion beyond 2020 levels shifts investments from wind to PV, hydrogen and batteries, and increases total

Abbreviations: BECCS, Bioenergy with carbon capture and storage; CCS, Carbon capture and storage; CT, Combustion turbine; EU ETS, European Union emission trading system; EUA, EU ETS allowances (for the stationary sector); LIMES-EU, Long-term investment model for the EU electricity sector; LRF, Linear reduction factor (for the EU ETS cap); MSR, Market stability reserve; NTC, Net transfer capacity; PSP, Pumped storage power plants; PV, photovoltaic; TNAC, total number of allowances in circulation; RES, Renewable energies; vRES, variable renewable energies (i.e., wind & solar).

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system costs by 3%. Finally, the unavailability of fossil carbon capture and storage (CCS) or further nuclear investments does not impact results. Unavailability of bioenergy-based CCS (BECCS) has a visible impact (18% increase) on cumulated power sector emissions, thus shifting more of the mitigation burden to the industry sector, but does not increase electricity prices or total system costs (<1% increase).

1. Introduction

While current EU climate mitigation targets of a 40% reduction of greenhouse gas emissions in 2030 and a 80–95% reduction in 2050 are a relevant contribution towards slowing down climate change, stronger efforts are needed in order to achieve the Paris agreement goal of keeping global warming to well below 2 °C [1].

Accordingly, the EU has called for further actions, namely to set the target of achieving climate neutrality by 2050 at the latest, as stated in the "European Green Deal" unveiled by EU Commission President, Ursula von der Leyen. In December 2019, leaders of all EU Member States except Poland agreed to carbon neutrality by 2050 [73] and in January 2020 the European Parliament also endorsed the objective in its resolution on the European Green Deal [2]. Furthermore, the European Green Deal calls for increasing the 2030 EU emission reduction target from 40% to 50–55% [3], which implies a tightening of the EU Emissions Trading System (EU ETS, or ETS) and EU Effort Sharing Regulation (EU ESR) targets. As the EU ETS is the key climate policy to drive the decarbonization of the EU electricity system and the EU heavy industry sector, such a tightening will have substantial implications for utilities across Europe, fundamentally influencing the investment into new technologies.

Studies so far have mostly focused on individual parts of the picture: on the one hand econometric analyses of short-term drivers of EU ETS prices (e.g., [4,5]), on the other hand the analysis of electricity systems with a high renewable share.

Examples of the latter are e.g. [6], who analyse the system adequacy of various 100% renewable power system setups for Europe in 2050; [7], who focus on a greenfield analysis of combinations of variable renewable energy shares and CO_2 prices to achieve a given level of CO_2 emission reductions for a single year; [8], who analyse two pathways to a 100% renewable system due to the externally-prescribed constraint that after 2015 no nuclear and no fossil power plant can be installed in Europe; [9], who estimate the value of transmission system expansion for a highly decarbonized EU power system by analysing cost-optimal greenfield investment and dispatch for a single year; [10], who explore the trade-off between storage and curtailment for cost-optimization of highly renewable power systems; [11], who integrate a reliability indicator related to kinetic reserves into a power sector model to analyse the system adequacy of future French power systems with externally enforced renewable shares of up to 100%.

Except for [8,11], these studies all focus only on analysing a single year (usually 2050) under greenfield assumptions, not on the transformation pathway from today's system to that target point. The two transformation pathway studies implement exogenously-prescribed 100% renewable energy (RE) scenarios without analysing the drivers needed to realize this transformation.

An older study [12] provides a full analysis of the transformation of the EU electricity system under CO_2 emission constraints until 2050, but their study was performed before the substantial reduction of RES technology costs and the maturing of integration options such as batteries or hydrogen electrolysis, and under less ambitious EU climate targets. Furthermore, the model used in Jägemann et al. [12] represents neither the intertemporal trading that the ETS allows and which influences the temporal profile of emissions, nor the interaction between decarbonization in the electricity system and in energy-intensive industry through their combined coverage in the EU ETS.

Thus, a comprehensive, up-to-date analysis that assesses the impact of tighter EU ETS targets on the transformation of the electricity system from today until 2050 is missing.

The current study intends to fill this literature gap by extending a detailed power sector model – LIMES-EU [13] – with representations of the EU ETS dynamics, including emissions and marginal abatement costs in the ETS-covered heavy industry and public heating sectors as well as intertemporal certificate trading, in order to explore what such a tightening of the ETS targets would mean for the power sector transformation: What would the resulting carbon prices be, how would this change the deployment of novel technologies, and how would electricity prices and total system costs be impacted? This does not only contribute crucial new knowledge for utilities and regulators about how the EU ETS targets drive investment decisions, but could be instrumental for the discussion on the EU Green Deal, and more specifically for the decision about adopting more ambitious EU ETS targets in 2021.

We furthermore explore how our results depend on three key aspects: *i*) the increase of electricity demand as can be expected from higher electrification and sector coupling, *ii*) potential restrictions in expanding transmission grids, and *iii*) the potential unavailability of carbon capture and storage (CCS) and/or nuclear power. Sector coupling is expected to play a key role in deep decarbonization pathways, mostly via direct electrification of the transport and heating sectors [14,15], but potentially also through the production of e-fuels [16,17]. This would lead to an increasing electricity demand and thus augment the decarbonization pressure within the EU ETS, as the direct emissions from transport and heating are regulated in the EU ESR and thus outside the EU ETS. Regarding transmission grid expansion, the last decade has shown substantial delays in the realization of grid expansion projects, e.g. in Germany due to local protests, and it is possible that future deployments will face similar opposition. Finally, public acceptance issues for CCS and nuclear power, cost overruns for nuclear and missing technology readiness for CCS could potentially result in these technologies not being available for the decarbonization of the power sector.

2. Method

Our analysis of ETS-driven power sector decarbonization in the EU uses a new version (v2.37) of the Long-term Investment Model for the Electricity Sector of EUrope (LIMES-EU) that was updated and developed further in order to include the relevant EU-ETS dynamics [13]. We use this model to perform a scenario analysis where we study variations of the following four dimensions: the emission reduction target, the electricity demand, the investments in transmission capacity, and the availability of CCS and nuclear technologies.

We extend the system operation and investment model of the European power sector to correctly represent intertemporal allowances trading; improve the current emission markets and technology trends parametrization; and include the interaction via the shared emission cap between decarbonization in the electricity system and other sectors covered by the EU ETS. This allows our analysis to partially internalize the advantages of full energy system models regarding the sector interrelation and broader scenario analyses aspects, without giving up the detailed analysis present in detailed power sector models.

2.1. Modelling framework

The core of LIMES-EU is an investments and dispatch European electricity sector linear optimization model. It computes optimal transmission and generation capacities under emission constraints for the time period 2010–2070. The model contains a detailed representation of

Table 1
Techno-economic characteristics of power plants. When efficiency ranges are given, they refer to plants installed from 1970 to 2015, with plants installed after 2010 having the value at the upper end of the range.

	Investment costs (€/kW)	Efficiency (%)	Autocons. (%)	Fixed O&M (%/yr)	Variable O&M (e/MWh)	Min load (%)	Lifetime (yr)
Nuclear	7000	33	5	3	5	40	60
Hard Coal	1800	38–50	8	2	6	30	45
Hard Coal CCS	see Table 2	43	8	2	29	30	45
Lignite	2100	36–47	8	2	9	50	55
Lignite CCS	see Table 2	42	8	2	34	50	55
Gas CC	900	54–60	3	3	4	40	45
Gas CC CCS	see Table 2	52	3	3	18	40	45
Gas CT	400	41	3	3	3	0	45
Oil	400	42	9	4	3	0	40
Hydrogen CC	945	57	3	3	4	40	40
Hydrogen CT	420	39	3	4	3	0	40
Hydrogen FC	see Table 2	45	3	2	3	0	40
Waste	2000	22	2	4	3	0	40
Other gases	900	76	8	3	3	40	40
Biomass	2000	42	5	4	6	0	40
BECCS	see Table 2	42	30	2	6	0	40
Hydro	2500	100	2	2	0	0	80
Wind Onshore	see Table 2	100	0	3	0	0	25
Wind Offshore	see Table 2	100	0	3	0	0	25
PV	see Table 2	100	0	1	0	0	25
CSP	see Table 2	100	0	3	0	0	30

Source: Haller et al. [53], Markewitz et al. [54], Bundesnetzagentur [55], UBA [56], IEA [57], BMWi [31], Agora [58], own assumptions.

Table 2
Default assumptions for technologies with time-dependent investment costs (€/kW). Investments costs after 2050 are assumed to remain constant at the 2050 value.

	Hard Coal CCS	Lignite CCS	Gas CC CCS	Hydrogen FC	BECCS	Wind Onshore	Wind Offshore	PV	CSP
2010	3748	3748	2113	2000	3800	1764	4750	2500	6250
2015	3748	3748	2113	1800	3800	1605	4412	1100	5100
2020	3475	3475	1942	1600	3800	1257	2736	703	4750
2025	3200	3200	1800	1400	3625	1197	2419	488	4750
2030	3000	3000	1700	1200	3450	1137	2102	395	4750
2035	2900	2900	1600	1000	3270	1062	2000	357	4600
2040	2800	2800	1550	900	3090	987	1900	340	4450
2045	2700	2700	1500	800	3045	955	1800	332	4000
2050	2600	2600	1450	700	3000	923	1700	326	3560

Source: REMIND, IEA [57],Capros et al. [59], IEA [60], IEA [61], Strefler et al. [62], IEA PVPS [63] and own assumptions.

the electricity sector, comprising 35 technologies, including different vintages for lignite, hard coal and gas plants. Three storage technologies are considered: pumped storage power plants (PSP), batteries and hydrogen electrolysis. The first two only provide intra-day storage, while the latter could provide seasonal storage. In order to capture both variation and correlation between demand, wind and solar power while keeping the computational cost manageable, each 5-year time step is modelled through a set of representative days, which are computed using a clustering algorithm [18]. In this paper, we use 10 representative days with 3-hour bins for a total of 80 time slices. Capturing such intra-day and seasonal variation is essential to assess the economics of investments into generation plants, transmission and storage. The model includes all EU countries except for Malta and Cyprus, but additionally contains Switzerland, UK, Norway and an aggregated region covering the Balkan countries. Each country is represented as a single node, i.e., cross-border transmission is considered using the net transfer capacities (NTCs), but not the internal network.

To allow analysing the impact of ETS emission caps on the power sector and the interaction among sectors, the model was extended so that it covers all stationary EU ETS emission sources. To that end, emissions from energy intensive industries were added to the model based on our estimation (637 $MtCO_2$ in 2015, see Appendix A for calculation details), and marginal abatement cost curves for energy-intensive industries were derived on the basis of Gerbert et al. [19]

Table 3
Fuel prices.

	Fuel prices (€/GJ)												
	2010	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060	2065	2070
Hard Coal	2.9	2.3	3.0	3.0	3.0	3.1	3.2	3.4	3.6	3.6	3.6	3.6	3.6
Lignite	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Natural Gas	5.7	5.3	6.2	6.8	7.1	7.8	8.3	8.4	8.9	8.9	8.9	8.9	8.9
Uranium	0.5	0.6	0.7	0.8	1.0	1.2	1.4	1.7	2.0	2.0	2.0	2.0	2.0
Biomass	5.9	5.9	6.0	6.0	6.0	8.0	12.0	16.0	20.0	23.0	25.0	26.0	28.0
Oil	10.7	8.0	11.9	13.2	14.3	16.4	16.0	17.6	19.3	19.3	19.3	19.3	19.3
Waste	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Other gases	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1

Source: fuel prices taken from respective REMIND runs, Strefler et al. [62]; own assumptions.

Table 4
Emission factors.

	CO_2 intensity	
	tCO_2/TJ	tCO_2/kWh_{th}
Hard Coal	96	347
Lignite	107	387
Natural Gas	56	200
Biomass*	100	360
Oil	81	290
Waste	154	554
Other gases	203	730

Source: BMWi [31] and Gomez et al. [52]; own assumptions.
* Biomass emissions are not counted towards the ETS cap.

model parameters.

A full description of the employed model setup and all parameter values for the LIMES-EU version 2.37 used in this study can be found in the model description [13].

2.2. Emission trading system representation

The EU ETS target is modelled through the provision of annual emission allowances. These can be either used for emissions in that year or banked for future years, thus leading to intertemporal trade. The number of allowances provided is calculated via the linear reduction factor (LRF). The LRF is the rate at which the EU ETS cap decreases each year. It was 1.74% for the 2013–2020 period, equaling 38 $MtCO_{2e}$. It is set at 2.2% for the 2021–2030 period. As a reference case (*REF* scenario family), we assume that the current LRF of 2.2% will be kept and continued after 2030. This implies an emission reduction of 43% in 2030 and 85% by 2050 with respect to the 2005 values, with a zero allowance provision reached in 2057. We also assume the EU ETS to end in 2057, i.e., allowances cannot be banked beyond this date.

Table 5
Characteristics of storage technologies.

	Power Inv. Costs (€/kW)	Reservoir Inv. Costs (€/kWh)	Fixed O&M (%/a)	Variable O&M (€/MWh)	Efficiency (%)	Lifetime (yr)
Pumped storage	1129	80	1	0	80	80
Batteries	see Table 6	see Table 6	1	0	80	20
Hydrogen electrolysis	see Table 6	0.1	2	3	70	20

Source: Schmidt et al. [64], Reuß et al. [65] and own assumptions.

Table 6
Storage technologies with time-dependent investment costs. Investments costs after 2050 are assumed to remain constant at the 2050 value.

Technology	Type of cost	2010	2015	2020	2025	2030	2035	2040	2045	2050–2070
Batteries	Power (€/kW)	678	678	373	231	156	122	108	102	95
	Reservoir (€/kWh)	802	802	441	273	184	144	128	120	112
Hydrogen Electrolysis	Power (€/kW)	1595	1595	1282	973	662	629	596	563	530

Source: Schmidt et al. [64],Saba et al. [66] and own assumptions.

and Enerdata [20]. Similarly, heating-related emissions covered by the EU ETS (district heat provision) and a marginal cost curve for their abatement were included in the model. Emissions in 2015 amounted to 212 $MtCO_2$, and baseline emissions for heating are assumed to increase linearly to 120% in 2050 [21].

Further changes from version 2.26 of the LIMES-EU model used in Osorio et al. [22] include the representation of negative emission technologies (BECCS); updated technology parameters (e.g., PV, wind and hydrogen costs, hydrogen conversion efficiencies) (see Table 1 and Table 2 in Appendix B); updated fuel costs (Table 3 in Appendix B); adjustment of variable renewable energies (vRES) availability factors based on historical data and expected improvements in technologies[2]; adjustment of hourly patterns based on historic peak demand [23] as changes in peak demand in certain countries in the last decade are larger than changes in annual demand, e.g., UK.; updated benchmarks for transmission capacity (see Section 2.33); storage costs split into power and reservoir costs (Table 5 and Table 6 in Appendix B); updated demand forecast scaling country-level data from the European Commission [25] using the most recent EU-data from the “Strategic long-term vision for a prosperous, modern, competitive and climate-neutral economy by 2050“ [1] (Table 7 in Appendix B); possibility of decommissioned capacity to be used as reserves for up to 10 years; proxy for hydrogen storage capacity (only technology capable of providing seasonal storage) assuming one storage cycle; and updated installable capacity for hydropower [26]. For the sake of completeness we reproduce some tables from the model documentation [13] in Appendix B to show the main

In our ambitious (*AMB*) scenario family, we assume that the EU pushes for faster decarbonization, setting a target of 55% total emission reduction by 2030 in comparison to 1990. To calculate an ETS target consistent with the overall target, we assume a continuation of the current split of reduction shares between ETS and ESR, which are as follows: EU ETS emissions should be reduced by 43% (i.e., 1018 $MtCO_{2e}$) and ESR emissions by 30% (i.e., 857 $MtCO_{2e}$) with respect to the 2005 values [27]. This implies that the ETS is expected to contribute 54% of the total emissions reductions by 2030. If the EU-wide target is to increase by 15%-points from 40% to 55% with respect to 1990 levels, then 859 $MtCO_{2e}$ additional reductions are required in 2030. Assuming the contribution shares remain unchanged (54% for EU ETS and 46% for ESR), emissions in the EU ETS would need to be reduced further by 467 $MtCO_{2e}$, i.e., by 1485 $MtCO_{2e}$ in total. Such a volume implies a 63% reduction compared to the 2005 value, or an increase of the LRF to 4.26% from 2021 onwards. Assuming that this LRF is continued after 2030, the last EU allowances (EUA) would be allocated and auctioned already by 2040. Our calculations are very similar to the values in the most recent EU Impact assessment (see p. 99 in European Commission [28]), where the stylised examples of how to update the ETS stationary cap suggest that under the 55% EU-wide reduction scenario, the LRF would be modified so that the ETS cap reaches 825 MtCO2 in 2030, i.e., 65% lower than emissions in 2005. Since the European Commission [28] considers the new LRF (6.79%) only after 2026, the cap decrease is much steeper than our assumption, so the last certificates would be issued in 2035.

We assume in both REF and AMB scenario families that 5.1 $GtCO_{2e}$

[2] For capacity installed until 2020 we use the average annual availability factors between 2010 and 2015 for each technology and country [34]. For capacity built after 2030, we consider derived capacity factors from NREL [77] for wind onshore and offshore and Pietzcker et al. [78] for photovoltaic (PV). For 2025, we assume an average of historical data and those for 2030–2050.

Table 7
Default assumptions for final electricity demand (in TWh).

Region	2010	2015	2020	2025	2030	2035	2040	2045	2050–2070
BE	83.4	82.5	84.7	88.3	93.9	98.7	105.4	114.7	124.2
BG	27.2	28.3	29.3	31.2	32.8	34.0	35.5	37.9	40.9
CZ	56.2	56.8	61.5	66.3	69.8	74.0	77.8	84.4	90.9
DK	32.1	30.7	33.1	35.7	37.7	40.6	43.1	47.0	51.1
DE	532.4	514.7	534.6	563.9	590.0	603.4	613.4	639.0	666.2
EE	6.9	6.9	7.7	8.1	8.8	9.2	9.6	10.5	11.3
IE	25.3	25.5	26.4	28.2	29.7	31.5	33.2	35.8	39.0
GR	53.1	50.8	53.7	53.8	53.3	56.8	58.8	61.5	64.8
ES	245.4	232.1	248.6	257.8	271.0	282.7	292.9	311.3	334.3
FR	443.7	421.6	455.9	473.7	495.4	525.3	550.9	587.5	629.1
HR	15.9	15.3	16.3	16.8	17.3	18.4	19.4	21.3	23.6
IT	299.3	287.5	306.8	316.8	331.1	360.7	389.2	420.8	453.8
LV	6.2	6.5	7.3	7.9	8.5	9.0	9.8	10.6	11.4
LT	8.3	9.3	10.4	10.8	10.8	11.1	11.4	12.5	13.4
LU	6.6	6.2	7.0	7.8	8.8	10.0	11.3	12.6	13.8
HU	34.2	37	36.2	39.5	41.3	43.6	46.5	50.8	54.2
NL	107.4	103.6	111.4	118.3	122.8	127.4	133.4	142.1	152.6
AT	60.3	60.8	67.7	72.1	76.5	80.2	84.2	90.3	95.1
PL	118.7	127.8	143.2	161.3	177.6	190.2	201.4	216.8	232.5
PT	49.9	45.8	47.5	49.3	50.5	52.0	53.7	56.3	58.6
RO	41.5	43.1	47.6	50.9	53.9	57.2	61.0	66.2	71.6
SI	11.9	12.8	13.6	15.2	15.9	16.5	17.3	18.5	19.8
SK	24.1	24.4	27.3	30.4	32.8	34.6	35.8	37.6	39.3
FI	83.4	78.4	80.4	85.2	88.6	92.7	96.2	103.1	110.4
SE	131.2	124.9	136.6	144.3	152.2	159.1	165.3	177.9	190.5
GB	329	302.9	324.9	341.4	359.4	381.6	414.5	450.3	471.5
NO	113.5	110.8	120.2	123.8	128.0	131.4	135.4	141.6	147.1
CH	59.8	58.2	58.6	58.3	58.1	57.8	58.8	59.8	60.8
Balkan	57.7	57.7	60.0	61.5	62.2	64.6	67.6	70.4	73.4

Source: European Commission [25], EUROSTAT [67], BFE [68], BFE [69]; own assumptions.

EUA will be cancelled by the market stability reserve (MSR[3]) until the end of the EU ETS [29], and constant emissions (covered by the EU ETS) of 60 $MtCO_2$/yr for the aviation sector (see Appendix A for details of these estimations). This results in an emission budget for the stationary sector of 35 and 19 $GtCO_2e$ for the reference and ambitious cases, respectively, during the 2018–2057 period[4].

2.3. Calibration and validation

We calibrate the model for the base year 2015. While a calibration to 2020 data would be desirable, this is not possible due to the incompleteness of data. Accordingly, we fix generation and transmission capacities and carbon prices (8 EUR/tCO_2) in 2015, i.e., only the dispatch of generation, storage and transmission technologies is optimized by LIMES-EU. Generation capacities are taken from a range of sources: Open Power System Data [30], BMWi [31], EUROSTAT [32]. The cross-border transmission capacities in 2015 correspond to the average value of NTCs in both directions, according to data from the ACER/CEER [33] report. For those links for which 2015 NTCs are not reported (countries with market coupling, e.g., FR-BE), the values from 2010 are used. The resulting dispatch and emissions for 2015 highlight that the electricity mix at country level and for the aggregated EU28 is well reproduced by the model[5]. Biases in results can be explained by model assumptions and potential differences in fuel prices across EU countries that are not captured in LIMES.

Although we do not fully calibrate the model to 2020, we bound the capacities for that year, and fix ETS prices to 25 EUR/tCO_2. We assume conventional technologies to vary $\pm$ 5% from 2019 capacities, while vRES are fixed to estimated capacities. Due to the lack of data we assume that biomass capacity cannot grow by more than 20% in 2020 with respect to its level in 2015. In addition, we assume that the share of combined-cycle and open-cycle gas plants of 2015 remains in 2020, and concentrating solar power capacities correspond to those installed by 2018. We use public sources for the values in our estimations: dispatchable technologies and PSP capacities are derived from the Winter Outlook 2019/2020 [23], vRES capacities are interpolated between the current capacities [34] and the expected capacities from WindEurope [35] and SolarPower Europe [36] outlooks. The cross-border transmission capacities in 2020 are also fixed. We derive them from the 2018 Ten Year Network Development Plan – TYNDP [37]. The official data for emissions in 2020 are not available yet, but a rough estimation results in $\sim$750 $MtCO_2$ in 2019 (Details are described in Appendix A). Our modelled emissions are in the range of 747 to 763 $MtCO_2$. Please note that there might be some variations as not all the capacities are fixed. These results suggest that a calibration to 2015 allows us to appropriately represent the electricity sector in 2020.

In order to include the real-world restrictions on near-term technology deployment due to long planning times or limited technology availability, we consider additional constraints for certain technologies in the medium-term. For instance, we bound transmission in 2025 and 2030 given the long-term planning involved. While NTCs for 2025 are available from ENTSO-E [24], those for 2030 are estimated averaging the expected values for 2020 [37] and 2040 [38]. On the generation side, we also assume some constraints on the CCS deployment, namely no large-scale CCS before 2028, maximum deployment of 1 GW per technology type until 2030, and maximum deployment of 2 GW per technology type until 2035 in each country except UK and Germany. The assumption that no commercial-scale post-combustion or oxy-fuel CCS power plant will start commercial operation before 2028 is based on the fact that the Global CCS Institute lists no CCS power plants in Europe as "advanced development" or "construction" [39] and the long realization

[3] The EU decided to reform the ETS in 2015, the MSR being one of the main elements of this reform (it was amended in 2018). The MSR is aimed at strengthening the EU ETS by absorbing the surplus of certificates, blamed to be one of the main reasons for the low ETS prices seen until 2018 [80]. Likewise, when scarcity arises it is set to release certificates to the market.

[4] This number includes an initial total number of allowances in circulation (TNAC) of 1.65 GtCO2 [50].

[5] Please refer to the model documentation, Section 8 for more details on the comparison between historical and modelled data for generation and emissions.

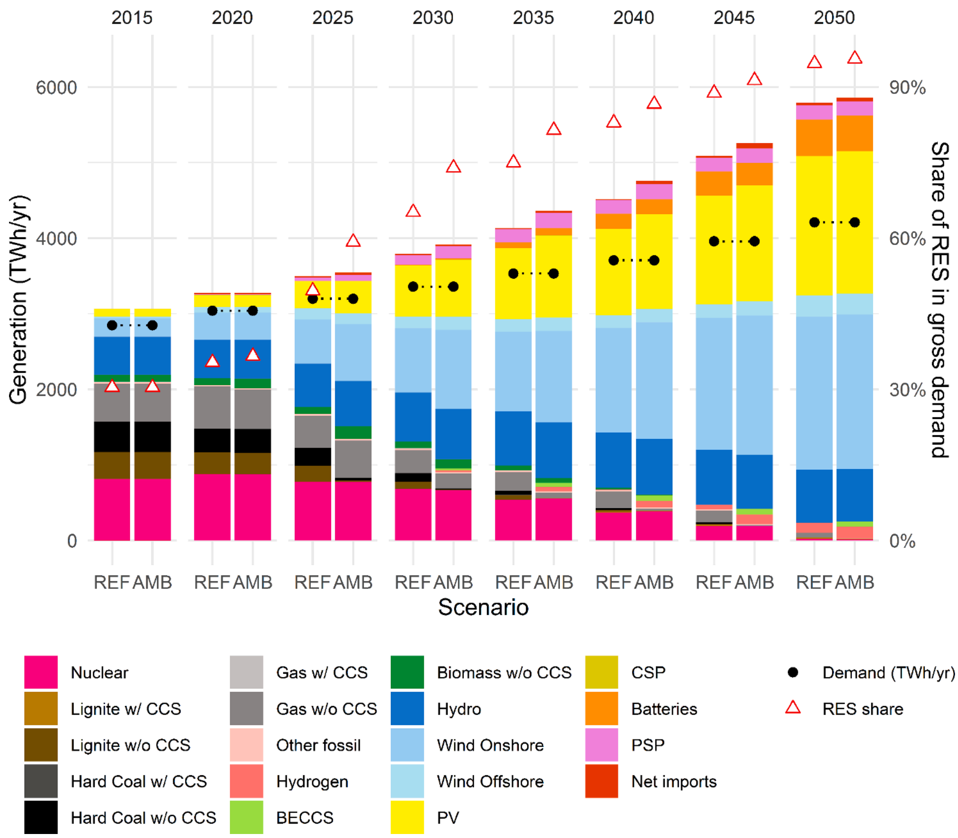

Fig. 1. Generation-mix in REF and AMB (assuming default demand and default transmission expansion) between 2020 and 2050 in the EU ETS.

times for CCS plants due to the complexity of CCS power plants and the surrounding regulation. The UK, one of the most ambitious CCS-proponents in Europe, has a target of achieving 10 $MtCO_2$ CCS sequestration by 2030 [40] – which would roughly translate into the emissions from 2 GW of coal power plants. Given that the target of 10 $MtCO_2$ includes CCS projects in industry and natural-gas to hydrogen conversion, our limit of 1 GW per technology type (gas w/ CCS, coal w/ CCS, biomass w/ CCS) for all countries except for UK and Germany seems to be quite optimistic for CCS.

To account for the larger number of CCS power plant projects in an early development phase in the UK (Drax BECCS, Net Zero Teesside, Caledonia Clean Energy), we implement higher upper bounds in the UK of a maximum of 2 GW per technology type operational in 2030 and 4 GW per technology type in 2035. Due to substantial public opposition against CCS that led to the failure of previous attempts at passing legislation that would create the necessary regulatory framework for building CCS plants, we preclude investments into CCS in 2030 in Germany, and implement a 1 GW per technology type limit in 2035 and 2 GW limits in 2040.

Phase-out plans to date (i.e., nuclear power in Germany, Belgium and Switzerland and no-CCS coal in 15 Member States[6]) are considered through upper bounds in capacity. In 2025, only nuclear power investments[7] are exogenously fixed given their long-term planning and construction periods, while investments into all other technologies are left to the model.

2.4. Scenario variations to test more challenging conditions for the decarbonisation

The impacts of increasing the climate target ambition of the ETS are analysed under different boundary conditions. More precisely, we perform a scenario analysis with variations of three dimensions: the electricity demand, the investments in transmission capacity, and the availability of CCS and nuclear technologies.

For each level of ambition, i.e., in each scenario family, two alternatives are analysed: default vs. As the model cannot endogenously capture the additional electricity demand from sector coupling and electrification in the various demand sectors, we have to implement the "high electricity demand due to sector coupling" scenario via an exogenously prescribed higher final energy demand pathway. In the high demand scenario we assume that final electricity demand grows linearly until 2050 to 6880 TWh/yr, which is 169% of the 2050 demand in the default scenarios of 4060 TWh/yr, and 250% of the demand in 2015. This value was derived from the largest scenario ensemble for European energy scenarios that we know of, the DEEDS scenario explorer (https://data.ene.iiasa.ac.at/deeds-explorer) containing 190 EU energy scenarios developed by a variety of research groups. We took the 85% quantile of electricity demand to abstract from extreme outliers when deriving our "high demand" scenario.

In the unrestricted transmission expansion scenarios, we assume that investments in transmission capacity are bounded until 2030. Investments into transmission expansion remain unrestricted afterwards. In the limited transmission expansion scenarios we assume that transmission expansion remains constant at 2020 values.

Additionally, we analyse the impact of the unavailability of certain technologies. Most climate change scenarios use negative emissions

[6] According to Europe Beyond Coal [71], 14 EU members have agreed on phasing-out coal before 2030 (or in the case of Belgium have already done it), one (Germany) will do it by 2038, 7 do not have coal in their electricity-mix and two are discussing it. No coal phase-out is under discussion in Poland, Slovenia, Croatia, Romania and Bulgaria.

[7] Olkiluoto 3 (1600 MW, Finland) in 2020; Flamanville 3 (1750 MW, France), Mochovce 3 & 4 (471 MW each, Slovakia) and Hinkley Point C (1750 MW, UK) in 2025. The years correspond to those in LIMES-EU, and are based on commissioning dates provided by the World Nuclear Association [81].

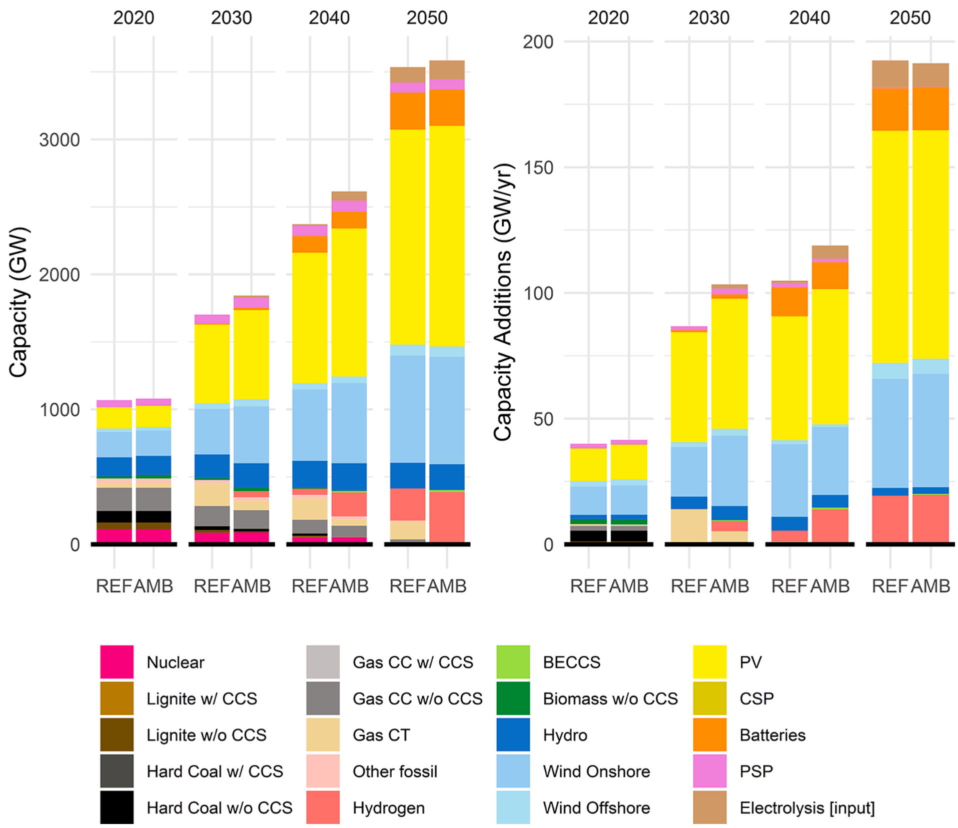

Fig. 2. Capacities (left) and capacity additions (right) in REF and AMB (assuming default demand and default transmission expansion) between 2020 and 2050 in the EU ETS.

technologies to draw CO_2 from the atmosphere. Of these, some form of bioenergy with carbon capture and storage (BECCS) is fundamental to achieving the 1.5 °C goal as set by the 2015 Paris agreement [41]. However, is it also important for decarbonizing the power sector?

In the scenarios evaluated by the European Commission [1] achieving even only 80% emission reduction at the EU level, BECCS is deployed, and those aiming at net zero emissions by 2050 have a non-neglibible use of negative emissions (up to 600 $MtCO_2$/yr are captured by BECCS and direct air capture by 2050). However, there are currently no large-scale power plants (even fossil-based) with integrated CCS in Europe[8]. In the European Commission [1] scenarios, nuclear power also plays a role, despite the increasingly difficult outlook for nuclear expansion in the EU: nuclear power faces not only increasing opposition in the form of moratoriums to new plants, cancellations[9] and phase-out plans, but also cost overruns [42,43,44] and abandoning of projects under development. We thus evaluate the impact that the reduced availability of CCS and/or nuclear power would have on the decarbonization pathways by running five additional scenario variants of the *REF* and *AMB* scenarios in which individual technologies cannot be deployed in the electricity sector by the model after 2020: no fossil CCS, no BECCS, no CCS at all (neither fossil nor biomass-based), no new nuclear (all constructions to be commissioned in 2025 are stopped, and no additional ones are allowed), and neither nuclear nor CCS power plants.

3. Results

3.1. Effects of increasing the target stringency

We analyse the impact of increasing the climate mitigation ambition on the power sector. Our results show that even under the current target, the electricity sector changes fundamentally over the next decades, with the share of renewable energy sources (RES) in gross demand increasing from 30% in 2015 to 65% in 2030, and 95% in 2050. Tightening the target does not fundamentally change the power sector transformation in the long-term, but speeds it up, with renewables contributing more than half the generation already in 2025 and zero emissions reached by 2040. In the following, we discuss the detailed impacts on technology deployment, emissions and costs.

3.1.1. Technology investment and dispatch

Fig. 1 shows the evolution of the generation mix in the EU ETS between 2015 and 2050 in the two core scenarios with default demand and unrestricted transmission expansion. To illustrate the impact of the different ETS targets on investments into novel technologies, Fig. 3 shows the yearly capacity additions and total standing capacities for the same scenarios. The main impacts of the ambitious target are a fast phase-out of coal, a faster expansion of wind and solar power, a gradual phaseout and replacement of gas-based power plants by hydrogen-based power plants, and, in the long-term, some deployment of BECCS.

When the ETS target is tightened, fossil-based generation decreases

[8] All CCS power plant projects in Europe are at an early development stage [39]. The European Commission [72] reported that all assessments of carbon capture, transport and storage projects (29 from seven countries) turned out to be economically infeasible. In countries like Germany there is also strong public opposition toward CCS [76]. Recently, five German federal states have prepared decisions or have passed laws limiting or banning underground storage of CO_2 [72].

[9] Between 1970 and mid-2019, under construction projects accounting for 94 units (12%) were abandoned or suspended in the world, of which 25 in EU member states[79].

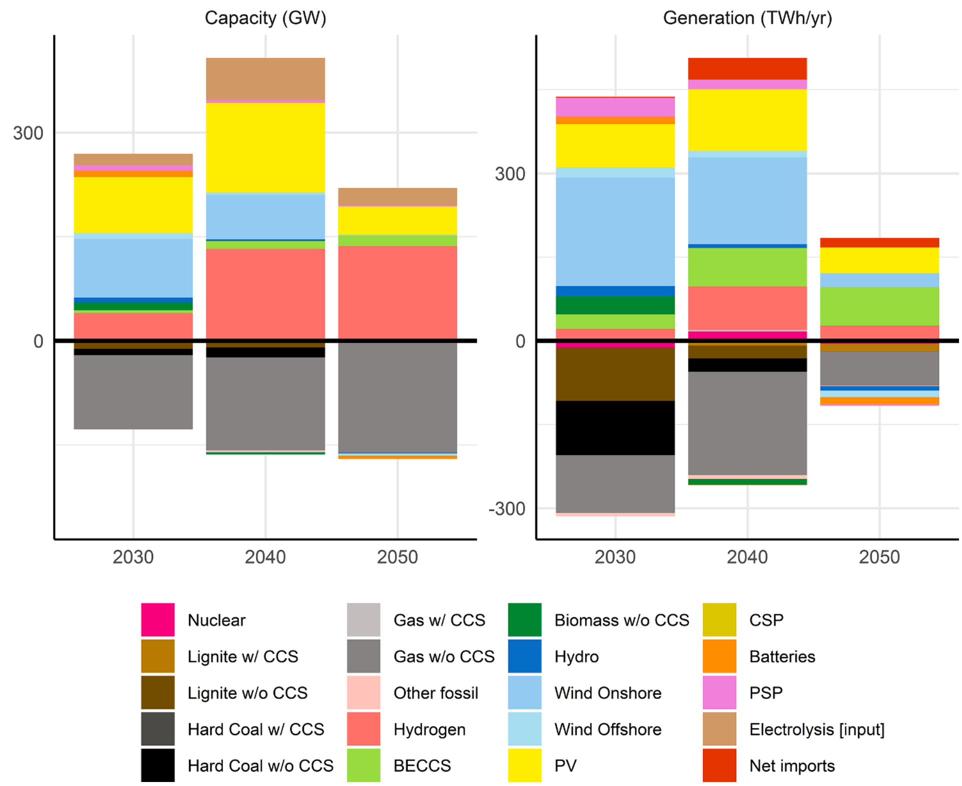

Fig. 3. Difference in capacity- and generation-mix between AMB and REF in the EU ETS. Positive values mean higher capacity/generation in AMB.

more rapidly: coal-based generation is reduced to 17 TWh[10] (less than 3% of its 2015 usage) and coal is thus almost completely phased out already by 2030 in *AMB*, while in *REF* the same reduction level is only reached after 2045. Reduction in gas-based generation happens later, suggesting that gas still plays a transition role in *AMB*, but only for a short period: In *AMB*, gas-based generation starts to decrease visibly after 2025, going down to 74 TWh (15% of 2015 use) until 2035. The phase-out is substantially faster than in REF, where gas-based generation only slowly decreases after 2025, staying above 74 TWh until 2045.

The continuous decline of gas generation hides a fundamental shift and substantial new construction: as vRES shares increase, gas takes on a new role and only dispatches in hours with low vRES generation, leading to low capacity factors. Accordingly, REF shows a strong deployment of cheaper open-cycle gas turbines (10 GW added each year) between 2020 and 2030 (see Fig. 2). In AMB, deployment of open-cycle gas turbines is also strong in the first part of the decade, but with rising CO_2 prices open-cycle hydrogen turbines take over at the end of the decade.

Complementing the reduced fossil fuel use in *AMB*, wind and solar deployment is further accelerated in the short-to-medium-term: RES share in gross demand increases from 65% in 2030 for *REF* to 74% in *AMB*, with vRES supplying 45% (*REF*) and 52% (*AMB*). In both scenarios RES increase further until 2050, reaching shares of 95%. In *AMB* vRES is deployed earlier than in REF, although by 2050 the vRES installed capacity is almost identical in both scenarios. A closer look at Figs. 1 and 2 shows that going from *REF* to *AMB* is similar to speeding up the deployment by 2–7 years (~2 yr for PV and ~7 yr for wind). Deployment rates in AMB over the decade 2020–2030 are ~30GW/yr for wind and ~50GW/yr for PV, a substantial increase from the 14GW of PV and 12GW of wind added from 2018 to 2019. Still, this increase would only require an annual growth rate of 17% for wind, which is similar to the observed annual growth from 2005 to 2010, and of 23% for PV, which is much lower than the observed growth of 45%/year from 2005 to 2015 [34].

While no BECCS is deployed in REF, the ambitious target leads to 70 TWh/yr of BECCS in 2050. Fossil-based generation coupled with CCS is also present from 2035 onwards, but remains marginal in both scenarios (<20 TWh/yr). Nuclear power generation decreases in both scenarios from 880 TWh in 2020 to 20 TWh/yr in 2050 due to the decommissioning of old capacity and commissioning only of plants currently under construction (exogenous to the model). Due to the high costs of building new nuclear power plants in Europe (the model sees turn-key costs including financing costs of 8200 EUR/kW, equivalent to overnight capital costs of 7000 EUR/kW[11]), the model does not choose to endogenously invest in the construction pf any new nuclear power plants.

To illustrate more explicitly the impact of the ambitious target, Fig. 3 show the differences in capacity and generation between *AMB* and *REF*. The composition of the capacity differences is qualitatively similar over time, namely more vRES, BECCS, electrolysis and hydrogen capacity, and less gas capacity in AMB than in REF. There are 170–200 GW more of vRES in AMB in 2030 and 2040, but the difference shrinks to just 40 GW in 2050 (all PV). Unlike vRES, hydrogen differs mainly in the long-term: while there are 40 GW more in 2030, the difference increases to 130 GW in 2040 and remains at that level until 2050. As mentioned above, this reciprocates the development of gas capacity, with AMB having 110 GW and 160 GW less gas capacity in 2030 and 2050, respectively.

For coal, the differences in generation are much larger than the differences in capacities: in AMB there are 200 TWh less of coal-based electricity in 2030, while capacity is only reduced by 21GW. This highlights the much lower load factors of coal in AMB, where coal plants remain in the system mostly for adequacy purposes.

[10] All values are stated for all countries in or associated to the EU-ETS, namely EU27+UK+Norway

[11] For comparison, EDF (Electricite de France) cost estimates for Hinkley Point C had risen from 6200 €/kW in 2015 to ~7600 €/kW by 2019 [70,74].

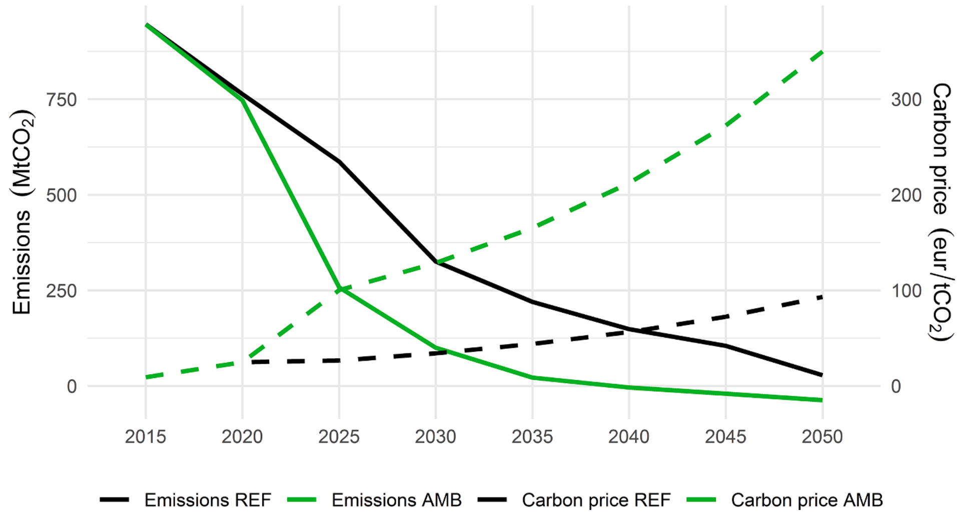

Fig. 4. EU ETS-wide emissions from electricity generation (continuous lines – left axis) and carbon prices (dotted lines – right axis) in REF and AMB.

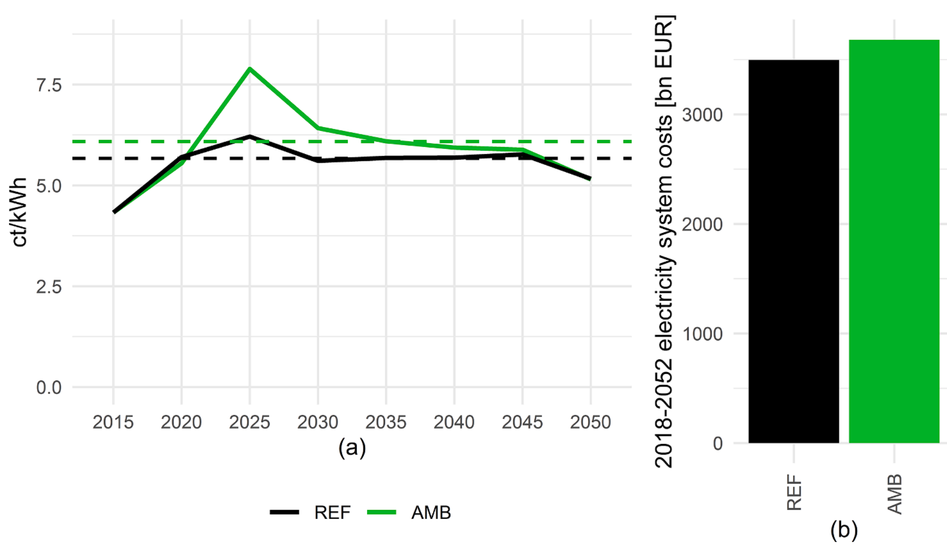

Fig. 5. Comparison of (a) full electricity prices (weighted average over 2018–2052 shown as dotted horizontal lines) and (b) discounted full electricity system costs under the reference and more ambitious EU ETS target.

3.1.2. Impacts on emissions and emissions pricing

The more ambitious target results – as expected – in substantially lower emissions, as can be seen in Fig. 4. The resulting 2018–2057 cumulated emissions from electricity generation are 10.9 $GtCO_2$ and 5.1 $GtCO_2$ in *REF* and *AMB,* respectively[12]. To achieve deeper decarbonization, higher carbon prices are required: in *AMB* they are more than three times as high as in *REF*, reaching 350 EUR/tCO_2 in 2050.

The additional emission reductions in *AMB* mainly arise from three sources: lower coal use between 2020 and 2040, lower gas use after 2025, and deployment of BECCS from 2030 on. Tightening the ambition pulls forward the almost complete phase-out of coal[13] by almost 20 years, from after 2045 in *REF* to 2030 in *AMB*. Similarly, gas use is reduced after 2025 in *AMB*, leading to a much stronger decline than in *REF,* and phase-out by 2045.

Finally, as carbon prices rise above 100 EUR/tCO_2, the model invests into the deployment of BECCS. Although the electricity generation from this technology is not a large contribution (1.3% of gross demand in 2050), it plays a role in the deep-decarbonization scenario as it is the only technology in the LIMES-EU model able to provide negative emissions. BECCS provides 40 $MtCO_2$/yr of negative emissions in 2050, which brings total electricity sector emissions down to a similar level, thereby freeing up allowances for the hard-to-decarbonize parts of the

[12] Note that these volumes represent 31% (*REF*) and 27% (*AMB*) of the total ETS emission budget for the stationary sector. This implies that under a more stringent EU ETS cap, the power sector needs to decarbonise more with respect to the heating and industry sectors.

[13] We here use as phase-out criterion that coal supplies less than 1% of the total generation. Full technology phase-out is rarely observed in LIMES, as the model does not explicitly represent the economies of scale for the supply chain. At very low usage of a technology, the costs for keeping the supply chain working (e.g. open cast mines, dedicated coal ports and coal railway connections) might overcompensate the revenues from the low power sales, thus leading to earlier closure of the power plants.

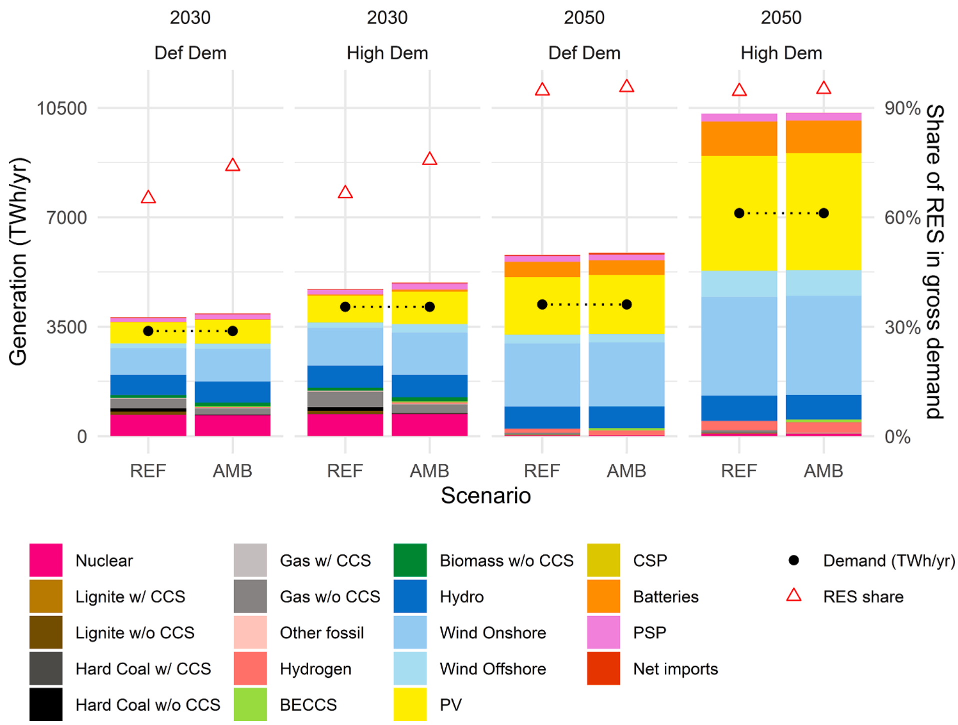

Fig. 6. Generation-mix in the EU ETS in 2030 and 2050 for the scenarios with default and high demand (assuming unrestricted transmission expansion) in the EU ETS.

industry sector.

3.1.3. *Impacts on electricity price and total electricity system costs*

Increasing the stringency of the climate target leads to a limited increase of full electricity prices[14] by around 7% (0.4 ct/kWh) averaged over 2018–2052 (5.7 ct/kWh in *REF* and 6.1 ct/kWh in *AMB*, see dotted lines in Fig. 5(a)), with the maximum increase observed in 2025 at 1.7 ct/kWh. This short-term increase can be explained by the need to shut down fossil power plants before the end of their lifetime, and the earlier scale-up of wind and solar power in 2020–2030. After 2025, prices decrease in *AMB* until converging with *REF* prices in 2045, reaching an average of 5.5ct/kWh, the lowest level after 2020 due to cheap vRES. Finally, tightening the cap results in an increase of total discounted power system costs by 5% (3680 vs 3500 bn EUR) for the period 2018–2052.

3.2. *Impact of higher electricity demand on power sector transformation*

Sector coupling, based mainly on further electrification of the heating and transport sectors, is expected to play a key role in the transition pathway to a low- (or even net zero) emissions economy. However, higher electricity demand creates additional pressure on the electricity sector.

In the scenarios with demand increasing to 169% of the value in the default scenarios, we do not find a strong interaction between demand and cap stringency, as the features of each high demand scenario are very similar to those of its corresponding default demand scenario (see Fig. 6). The shares of RES when demand increases are very similar to those of the corresponding default demand scenarios, which implies that the increase of demand leads to an absolute increase of investments in RES: in 2030 in the *REF* (*AMB*) case additional 350 (300) TWh/yr are generated from wind onshore, and 180 (280) TWh/yr from PV. Furthermore, additional ~50 TWh/yrof hydropower are required in both scenarios, and in the case of *AMB*, wind offshore provides additional 100 TWh/yr.

At the same time, the higher electricity demand creates an incentive to keep more fossil-based generation in the mix. When demand is higher, gas-based generation in 2030 in *REF* (*AMB*) is ~190 (90) TWh/yr higher than in the default scenarios. In the case of *REF*, this implies that gas generation remains at the 2015 level (510 TWh) instead of decreasing to 310 TWh/yr. Coal generation is not strongly influenced by the increase in electricity demand, it only slightly increases by 20 TWh/yr in *REF* and remains unchanged in *AMB* in 2030. Of the overall increase of electricity consumption of 780 TWh/yr in 2030, roughly 75% is thus supplied by additional RES and the remaining 25% by gas-fired plants in *REF*. RES shares are even larger in *AMB*, where these technologies account for more than 85% of the final demand increase.

With increased demand, the vRES share reaches ~85% in both reference and ambitious scenarios. PV and wind onshore generation thus increase between 2015 and 2050 by a factor of ~40 and ~13, respectively, in high demand scenarios, compared to ~20 and ~8, respectively, in default demand scenarios. With such high output from vRES, storage requirements increase due to further balancing requirements. Accordingly, batteries output increases by ~600 TWh/yr, hydrogen-based electricity by ~170 TWh/yr and PSP by 60 TWh/yr.

To sum up, the additional 2100 TWh/yr of electricity consumption in 2050 are supplied almost completely by vRES. Only a small share (50 TWh/yr) is covered by a slower shutdown of nuclear power. As a result of the interim higher fossil-based generation in the high demand scenarios, cumulative emissions from the electricity sector are 12.4 (5.4) $GtCO_2$, i.e., 13% (6%) higher than the emissions in *REF* (*AMB*) with default demand. This implies that higher electricity demand requires deeper decarbonization in the industry sector covered by the EU ETS.

3.3. *What if the transmission expansion does not go as planned?*

As Fig. 7 shows, the transmission capacity in 2030 and 2050 across

[14] Full electricity prices cover investment, fuel, operation and maintenance, CO_2 certificates as well as additional investments needed to ensure capacity adequacy.

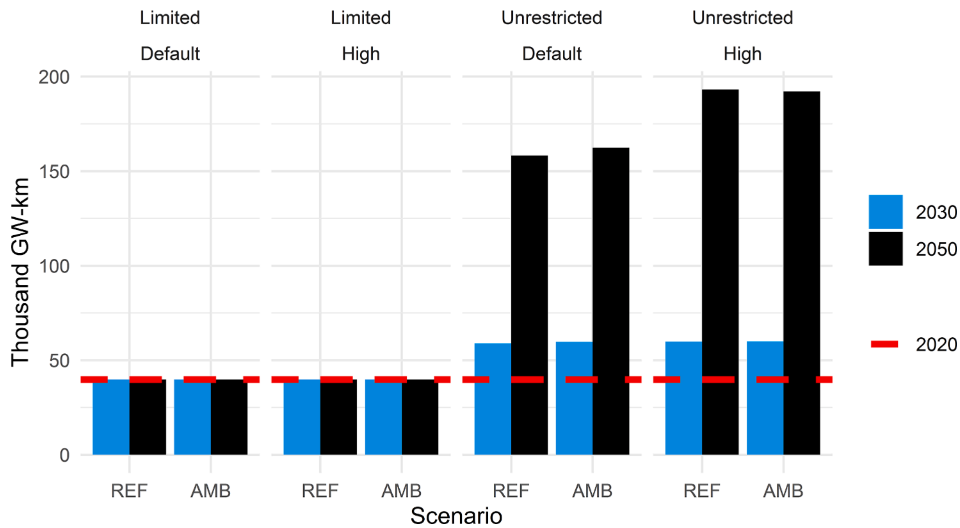

Fig. 7. Aggregate transmission capacity at the EU ETS level in 2030 and 2050.

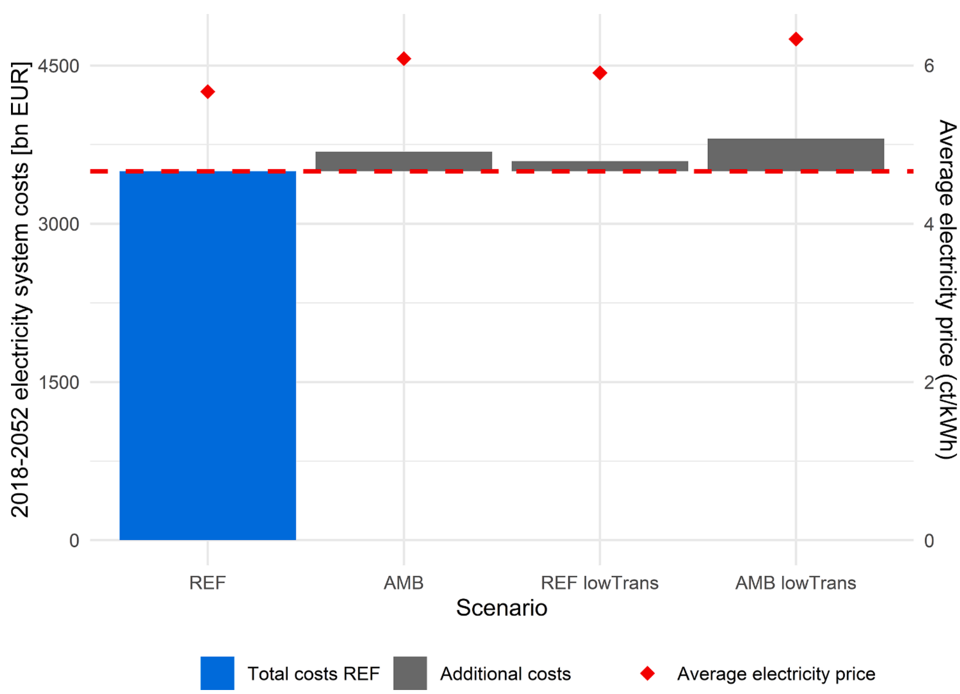

Fig. 8. Total discounted cost of the electricity sector 2018–2052 and average electricity price in REF and AMB (assuming default demand), with the impact of low transmission in the EU ETS.

scenarios with unrestricted transmission expansion is ∼50% and >300%, respectively, higher than the actual 2020 capacity. The EU ETS cap stringency does not appear to have a significant impact on transmission investment decisions. The level of demand does have a small impact on transmission expansion by 2050 when transmission is unrestricted: further expansion is carried out, aggregated transmission capacity being ∼20% higher when demand is high.

3.3.1. *Aggregate effects of limited transmission expansion*

Limited expansion leads to more expensive decarbonization because of technology lock-ins. This effect is three-fold: (*i*) fossil-based generation in countries where such technologies are dominant remains more competitive due to the limitation to import (cleaner) electricity; (*ii*) countries with high RES potential are discouraged to invest beyond their own needs because demand remains limited as export potential is constrained; (*iii*) less pooling over larger areas implies higher balancing requirements within the confines of a country. Hence, transmission expansion allows for a more efficient use of resource endowments, e.g., investing in RES with high availability and transporting them instead of relying on local RES with lower availability factors.

Fig. 8 shows the total discounted power sector costs aggregated from 2020 to 2050 in *REF* and *AMB* with default demand, highlighting the additional costs posed by limited transmission. The total costs amount to 3500 bn EUR in *REF* and to 3680 bn EUR in *AMB*. In both *REF* and *AMB*, limited transmission expansion increases total system costs by 3%, more than half of the 5% cost increase that comes from tightening the target[15].

[15] The relative differences between the total costs in default demand scenarios hold also for the high demand scenarios, the total costs of high demand *REF* being 4690 bn EUR.

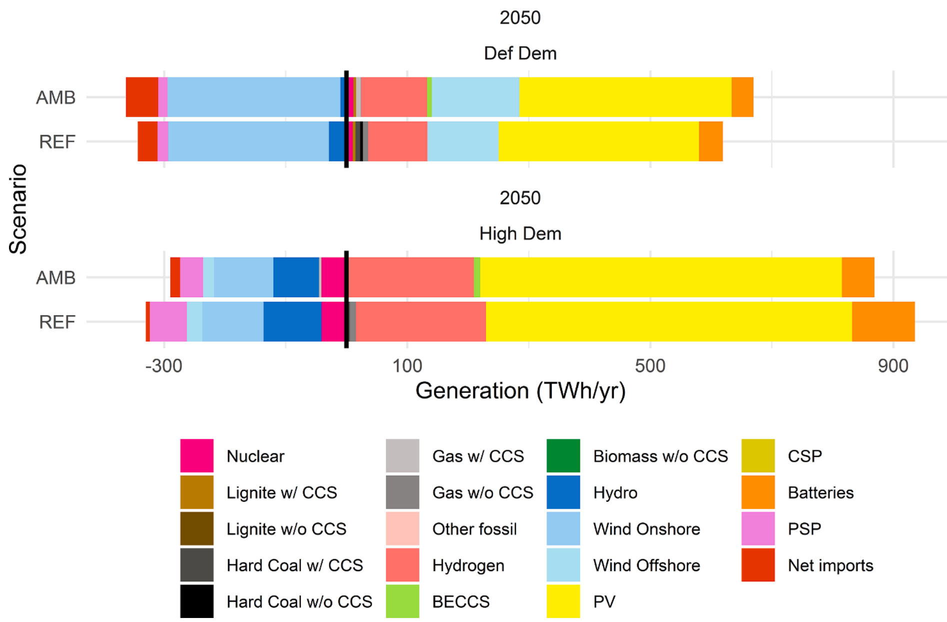

Fig. 9. Change in generation when going from unrestricted to limited transmission scenarios in 2050 in the EU ETS. A positive value implies that generation for a given technology is higher in the restricted scenario.

This implies that putting strong political will behind realizing the optimal transmission expansions could – to a large extent – offset the additional costs from tightening the emission target. Put differently, not managing the transmission expansion would make tightening the emission cap almost twice as expensive as it would be with well-managed transmission expansion. This reconfirms earlier findings about the relevance of transmission grid expansion [45].

To illustrate the impact of restricted transmission expansion on the long-term technology choice, Fig. 9 shows the difference in generation between the scenarios with unrestricted and limited transmission. With limited transmission expansion it becomes more difficult to accommodate large shares of wind output, thus encouraging generation from PV, hydrogen and batteries. The additions in PV generation offset entirely the drop in wind output, i.e., vRES generation is always higher when transmission expansion is limited. Restricted transmission expansion also limits imports from non-EU ETS members and PSP operation. There is an overall higher generation when transmission is limited, highlighting the increased storage requirements and the resulting higher storage losses.

3.3.2. *Transmission and technologies deployment at the national level*

The impact of transmission expansion on the generation-mix is not evenly distributed across countries. To illustrate such changes we compare the two ambitious scenarios with and without transmission expansion. Fig. 10 shows the change in gross demand shares of solar, wind, batteries and hydrogen generation when going from unrestricted to no transmission expansion.

Limited transmission expansion leads to more solar generation except in southern countries like Spain and Greece, i.e., those with best resource quality. Wind share decreases in most of the countries where the solar share increases. Like for solar, wind decreases in countries with largest resource endowment such as Denmark, Norway, Austria, Switzerland, UK and Ireland. These countries account for almost the entire reduction in wind output.

To balance supply and demand in the restricted transmission scenario, investment into batteries and hydrogen increases. As can be expected from the strong day-night variation in PV output, battery shares increase in most countries where PV increases (except for Italy). Hydrogen-based generation increases almost across all EU members[16], appearing to further cope with the increasing balance requirements from vRES, i.e., a role mainly played by gas in *REF*.

3.4. *Decarbonizing electricity under restricted technology choice – CCS and nuclear*

Do our results change when limiting CCS or nuclear availability? We find that not being able to deploy CCS or new nuclear plants, either because of technological or political reasons, would have little impact in the *REF* scenario (less than 1% change in any of the variables of interest), as investments in CCS technologies are negligible even if CCS is allowed (3 GW of hard coal CCS and 3 GW of lignite CCS is installed EU-wide in 2050), and no new nuclear plant constructions are cost-efficient after 2025.

Tightening the emissions target in the *AMB* scenario increases the effects, but they stay at a low level (see Fig. 11). There is still no impact from not having fossil CCS power or nuclear power – at the currently expected costs and technological parameters, these technologies do not seem very relevant for a low-carbon power system. However, the negative emissions from BECCS matter to a certain extent: Not using BECCS would increase carbon prices by 8% in the EU ETS due to missing negative emissions, but it would have little impact on total system costs and electricity prices, as both would increase by less than 1%. Emissions appear to be more sensitive to the unavailability of BECCS: not having the 1079 $MtCO_2$ negative emissions from BECCS in the period 2030–2057 increases the total power sector emissions by 923 $MtCO_2$, an increase of 18%. This means that the 8% increase in CO_2 prices reduces the non-BECCS emissions from the power sector by 156 $MtCO_2$, or 3%. As the EU-ETS cap is fixed, the missing negative emissions from BECCS for the power sector imply that some of the decarbonization burden is shifted to the industry sector.

[16] In those countries where hydrogen decreases due to restricted transmission, namely Norway, Denmark, Austria and Portugal, the change is marginal (lower than 2 TWh/yr, i.e., less than 2% change in share).

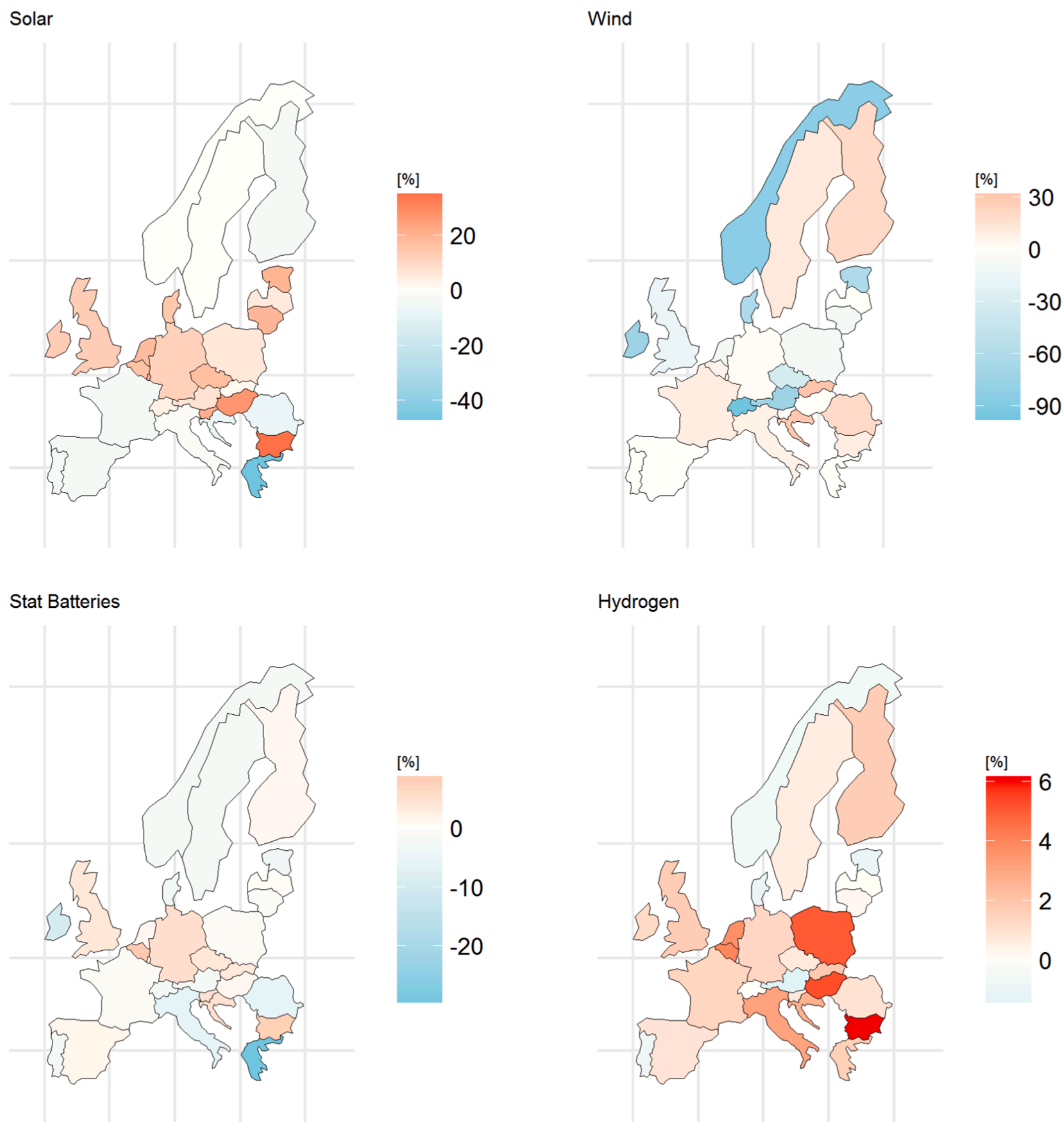

Fig. 10. Impact of transmission grid expansion on the generation-mix. The colour legend indicates the change in the 2050 share of this technology's output in gross demand when going from AMB with default transmission expansion to AMB with no transmission expansion. A positive value implies that the share of the technology is higher in the scenario with limited transmission expansion than in the one with unrestricted transmission expansion.

Although our results show that BECCS availability has limited impact on prices under default assumptions, BECCS deployment would depend on the net negative emissions intensity of these plants (see Appendix C), a very uncertain parameter due to land-use change and processing emissions [46,47] which is also challenging to account for. So far there is no clear regulation for accounting negative emissions from BECCS in the EU ETS [48] and the treatment of biomass in the '2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories' did not change substantially with respect to the 2006 guidelines.

4. Conclusion

In this study we explore the impacts of tightening the EU climate target from a 40% to a 55% reduction in 2030 – which we translate into an increase of the EU ETS linear reduction factor from 2.2 to 4.26%, thus strengthening the 2030 EU ETS emission reduction target from –43% to −63% and pulling forward the year of zero allowances from 2057 to 2040. We find that tightening the target speeds up the transformation by 3–17 years for different parts of the electricity system, with renewables contributing two thirds of gross demand already in 2030 instead of 2034, EU-wide coal use almost completely phased-out by 2030 instead of 2045, and zero power sector emissions reached by 2040. As a result, cumulated power sector emissions from 2018 to 2057 decrease by 54%, from 11.0 $GtCO_2$ to 5.1 $GtCO_2$. Carbon prices within the EU ETS more than triple, increasing to 129 EUR/tCO_2 in 2030 and 212 EUR/tCO_2 in 2040. However, total discounted power system costs only increase by 5%, and the average electricity price rises by 0.4ct/kWh – but with a short peak in 2025 when the electricity price difference increases to 1.7ct/kWh. This short-term increase in electricity prices highlights that the key challenges from tightening the target will likely be felt in the current decade, when the system is in the middle of the transformation with still substantial fossil capacities in the market.

We furthermore find that a potentially increased electricity demand from sector coupling would not fundamentally change the picture. A 69% higher demand in 2050 mostly leads to a faster and larger expansion of wind and solar in combination with batteries, a longer reliance on gas, and increased deployment of hydrogen. In case the transmission expansion cannot be realized and transmission grids stay at their 2020 extent, the technology mix would shift towards more PV, hydrogen, gas and batteries, and costs would increase by 3% – half the costs associated

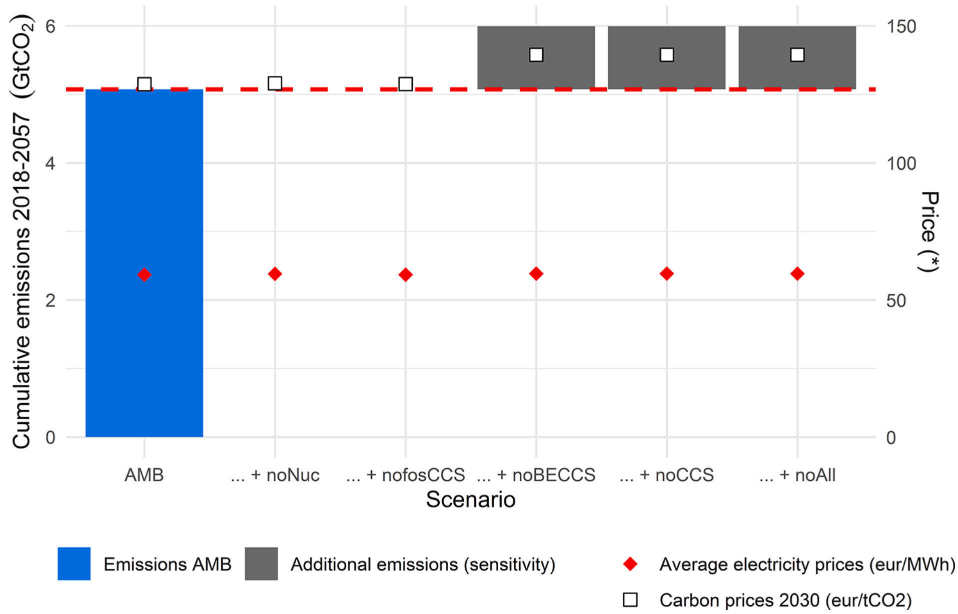

Fig. 11. Impact of unavailability of CCS and/or new nuclear power plants on cumulative emissions from power sector (left axis), carbon prices in 2030 and average 2018–2052 electricity prices (right axis) in the EU ETS in the more ambitious AMB scenario (assuming default demand and unrestricted transmission expansion).

with tightening the target. This implies that putting strong political will behind implementing transmission expansions could to a sizable extent offset the additional costs from tightening the emission target.

Finally, we analyse the impact of limited availability of fossil CCS, BECCS, or additional nuclear power, be it due to public acceptance issues or due to technological barriers to up-scaling and deployment. We find that the unavailability of fossil CCS or nuclear power has no relevant effect on decarbonization costs, CO_2 prices or emissions for the EU. This finding is quite different from older results by Jägemann et al. [12], who found substantial cost increases when refraining from using nuclear and or fossil-CCS in the process of decarbonizing the EU power system. Their differing results can probably be explained by the technological progress over the last 7 years since their paper was published: substantial cost reductions have been realized for renewable technologies, and integration options such as battery storage and hydrogen electrolysis have today entered the market, while a decade ago they were less mature and thus not considered in the older study. The only CCS technology whose unavailability has a small but visible impact in our study is BECCS – not using BECCS increases CO_2 prices by 8% and cumulated power sector emissions by 18%, thereby shifting more of the decarbonization burden to the industry sector. At the same time, electricity prices and total system costs are only marginally affected even if BECCS is unavailable – they increase by less than 1%. This illustrates that the negative emissions from BECCS can facilitate achieving deep decarbonization targets, but they are not a sine qua non for power sector decarbonization. Refraining from using fossil-based CCS has no discernible effect on carbon emissions and prices. It thus seems sensible to focus CCS-related research and demonstration projects on BECCS and

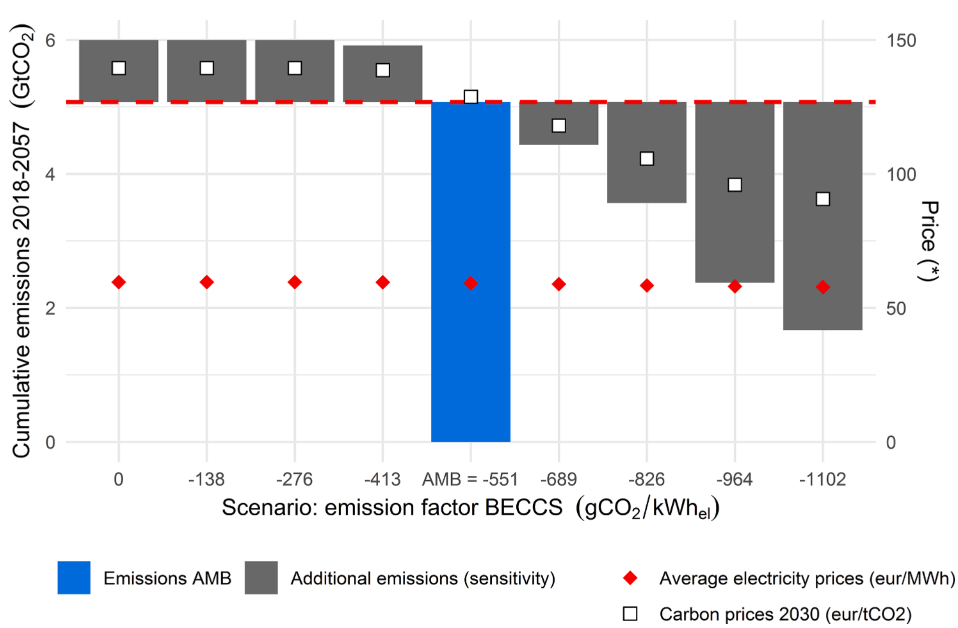

Fig. 12. Impact of the BECCS emission factor on power sector emissions (left axis), carbon prices in 2030 and average electricity prices (right axis) in the ambitious scenario (assuming a default demand and unrestricted transmission expansion) in the EU ETS.

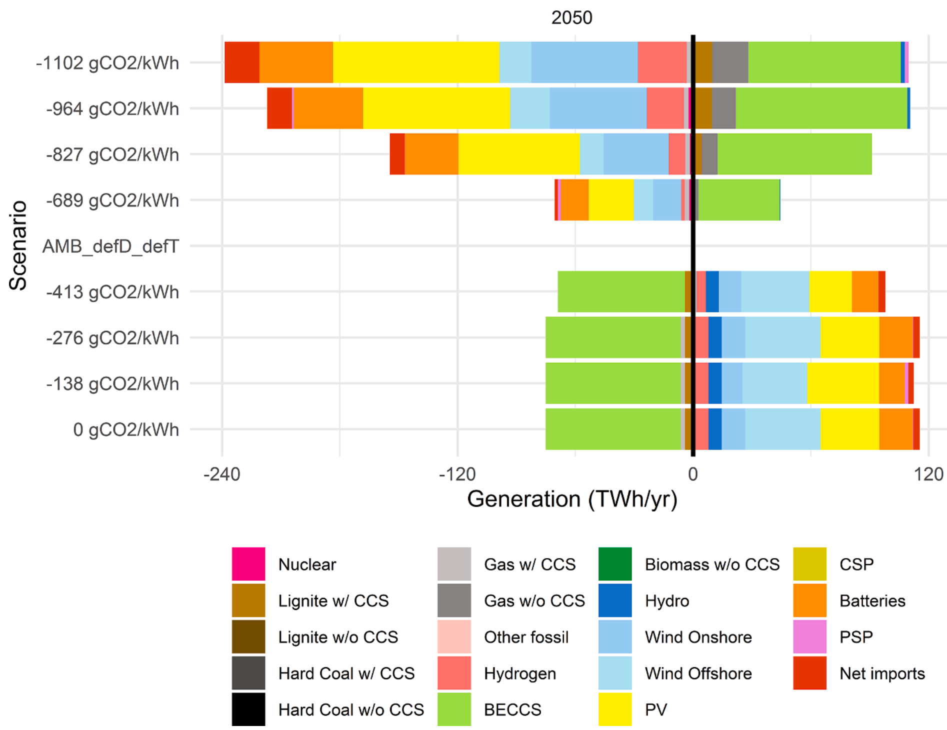

Fig. 13. Change in generation in 2050 between BECCS emission factor scenarios and default AMB scenario (-551 gCO_2/kWh_{el}) in the EU ETS. A positive value means there is higher generation in the corresponding scenario.

CCS for industry process emissions instead of CCS for fossil power plants.

While this study provides new insights on ETS-driven power sector decarbonization pathways for the EU, further research is needed to test the robustness of these findings and to better represent the deep interconnectedness of future decarbonized energy systems. One important step would be to increase the detail of the representation of industry and heating plant abatement costs and options. Furthermore, sector-coupling effects on electricity demand and short-term flexibility options as well as the competition for scarce resources like biomass or CO_2 storage sites from the different sectors should be either explicitly represented, or at least dynamically linked to the climate target stringency.

In summary, tightening the EU ETS target for 2030 from −43% to −63% reductions compared to 2005 could achieve a substantial reduction of aggregated 2018–2057 power sector emissions – minus 54% compared to the current target – at limited additional costs: total electricity system costs would increase by roughly 5%. Tightening the target would be an efficient measure to bring the EU power sector closer to the Paris agreement ambition of keeping global warming to well below 2 °C [49].

CRediT authorship contribution statement

Robert C. Pietzcker: Conceptualization, Methodology, Writing - review & editing, Supervision. **Sebastian Osorio:** Formal analysis, Investigation, Methodology, Software, Writing - original draft, Visualization. **Renato Rodrigues:** Software, Visualization.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix A. Calculation of emission values

Estimation of emissions from the ETS-covered energy-intensive sector

Estimating the emissions from energy-intensive industry covered by the EU ETS is not straightforward due to the fact that different sources only report (differently) aggregated values, thus we have to make assumptions on how to allocate and back-calculate sectoral emissions. Combustion of fuels, representing mainly for power and centralized heat provision, accounted for 1213 $MtCO_2$, while other stationary emitted 590 $MtCO_2$ [50]. Since Mantzos et al. [21] report 1166 $MtCO_2$ for power and district heating in 2015, we assume that the difference between the 'combustion of fuels' and "power and district heating" values (47 $MtCO_2$) is also part of the energy-intensive industries. Hence, we estimate emissions from energy-intensive industries to be 637 $MtCO_2$ in 2015.

Estimation of electricity-related emissions in 2019

Electricity-related emissions in 2015, i.e., emissions from electricity-only plants plus electricity-related emissions from CHP plants, amounted to 954 $MtCO_2$ [21] in the EU28. This volume equals 79% of emissions accounted within the 'combustion of fuels' category in the EU ETS (1213 $MtCO_2$) [50]. Emissions in the same category amounted to 955 $MtCO_2$ in 2019. Assuming the share of electricity-related emissions remains unchanged, we estimate electricity-related emissions to be 751

$MtCO_2$ in 2019.

Estimation of amount of certificate cancellations from the MSR

We assume in both REF and AMB scenario families that 5.1 $GtCO_2e$ EUA will be cancelled by the market stability reserve (MSR) until the end of the EU ETS [29]. From these cancellations, 1.55 $GtCO_2$ correspond to certificates backloaded (900 $MtCO_2$) and non-auctioned before 2020 (650 $MtCO_2$) [51]. More specifically, among the 650 $MtCO_2$ non-auctioned, 350 $MtCO_2$ correspond to EUA non-auctioned in 2017. Since each variable in LIMES represents the 5 years around the specified time (e.g., the '2020′ cap represents the cap for 2018–2022), only 3.85 GtCO2 are actually subtracted from our cap.

Estimation of aviation sector emissions:

The aviation sector has its own cap (on average 38 $MtCO_2$ between 2013 and 2019), which so far has been below the actual emissions covered (between 53 and 68 $MtCO_2$). This sector thus has to cover this gap buying certificates from the stationary sector (EUA). Stationary firms are not allowed to buy allowances from the aviation ETS (EUAA). From 2020 this cap is set to decrease at the same pace of the stationary sector, thus the aviation cap and the resulting EUA bought from the stationary sector depend on the expected LRF. Accordingly, the EUA used by aviation companies amount to 1.6 and 1.9 $GtCO_2$ in the reference and more ambitious scenario, respectively.

Appendix B. Model parameters

See Tables 1–7.

Appendix C. The impact of BECCS emission factors

According to the European Commission [1] scenarios, BECCS is fundamental to achieving the 1.5 °C goal. However, how important is it for decarbonizing the power sector? In our results, we found that this technology only played a minor role in electricity-sector decarbonization in the AMB scenario. We show that this depends on the actual ability to 'generate' negative emissions, i.e., to ensure that emissions captured largely offset indirect emissions generated during the biomass supply chain.

Owing to carbon emissions associated with the initial land use change and the subsequent emissions from treating and transporting the biomass as well as emissions from incomplete capture in the power plant, the actual amount of emissions removed through a BECCS plant can actually vary in sign depending on the choices made throughout the supply chain, making BECCS either a negative or a positive emissions technology [46,47]. For instance, according to Fajardy and Dowell's estimations [46], total carbon intensity would vary between −1100 and +1000 gCO_2/kWh_{el} for short rotation cropping willow burned for power generation – mostly due to indirect land use changes and processing emissions.

In all the scenarios in the paper we consider an emission factor of −551 gCO_2/kWh_{el} for BECCS. This is consistent with an emission factor of 100 tCO_2/TJ for biomass [52], a net plant efficiency of 30%, a capture rate of 90% and an offset factor of 50%[17].

As pointed out in Hanssen et al. [47], the emission factors will be (among others) a function of demand. In a future where the EU aims for GHG neutrality within a global context of achieving the Paris Agreement, most full-system analyses show a substantial demand for biomass from other sectors, such as aviation and shipping, but potentially also heavy-duty freight, heating and industry. In the database for the IPCC "Special Report on Global Warming of 1.5 °C" (https://data.ene.iiasa.ac.at/iamc-1.5c-explorer), the global modern bioenergy demand in 2050 is ~100EJ/yr or 28000TWh (median of the 141 scenarios with median temperature increase of 2 °C or less that report "modern biomass use"), a substantial increase over today.

Hanssen et al. [47] find only limited supply (<10EJ_electricity) at emission factors below 150kgCO2/GJ, or 540kgCO2/MWh. Given that in the database for the IPCC Special Report on 1.5 °C, the median of modern bioenergy use in 2050 is ~100EJ/yr (equivalent to 30–40EJ_{elec}/yr), our default seems rather on the optimistic side for BECCS in the context of global climate change mitigation.

Still, given the uncertainty of the land use change and processing emissions (here implemented via an "offset factor"), we evaluate values between 0 and 100% in a sensitivity analysis, i.e., we consider variations of our two core scenarios (*REF* and *AMB* with default demand and unrestricted transmission expansion) featuring a BECCS emission factor between −0 and –1102 gCO_2/kWh_{el}.

BECCS emission factor has no impact on *REF* as BECCS is not deployed even if biomass offset the maximum (i.e., when emission factor is −1102 gCO_2/kWh_{el}). Unlike *REF*, there is a large impact on the AMB scenario: Fig. 12 shows that BECCS use quickly declines when using emission factors closer to zero than our default value of −551gCO2/kWh_el, reducing BECCS use to almost zero at −413gCO2/kW_el. This leads to almost 1 GtCO2 additional emissions and a CO2 price 8% higher than in the default scenario – very similar to the scenario result where BECCS use is excluded. Runs with emission factors of −276gCO2/kWh show no BECCS use at all. A higher (absolute) BECCS emission factor has a strong impact on emissions and carbon prices. As BECCS turns more profitable, lower carbon prices are required to achieve deep decarbonisation of the EU ETS. Cumulative emissions and carbon prices for the highest (absolute) emission factor of 1102 gCO_2/kWh_{el} – equivalent to assuming no land-use change and process emissions at all – are respectively 67% and 30% lower than in the default *AMB* scenario.

Very low emissions in the power sector are possible due to the higher investments in BECCS when the emissions offset is maximum. These reach up to 39 GW in 2050, compared to the 15 GW installed in the default *AMB*. If BECCS offsets 1102 gCO_2/kWh, BECCS generation in 2050 increases by 80 TWh/yr with respect to default *AMB*, displacing vRES (85 TWh/yr solar and 70 TWh/yr wind) and its corresponding storage-related requirements, namely batteries (35 TWh/yr) and hydrogen (25 TWh/yr) (see Fig. 13). Interestingly, the resulting lower carbon prices due to lower costs to decarbonise the power sector, encourage non-CCS fossil generation (20 TWh/yr gas and 20 TWh/yr lignite). Despite the increase of non-CCS fossil generation, the volume of negative emissions still allows reducing the overall emissions in the power sector, as shown in Fig. 12. In 2050 negative emissions account for −160 $MtCO_2$, overall power emissions reaching −150 $MtCO_2$.

[17] Different estimations about the negative emissions potential are found in literature. For instance, Fajardy and Dowell [46] estimate this between 46% and 62% of the carbon intensity, depending on whether LUC and ILUC are accounted. Heck et al. [75] estimate also negative emissions potentials accounting for ~50% of the total captured by BECCS.

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