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The reference forecast of the German energy transition—An outlook on electricity markets

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H I G H L I G H T S

- Policy evaluation of the German 'Energiewende'.
- Analysis and modeling of the German electricity sector embedded in an European framework.
- Our results suggest that almost all political targets are not reached.

A R T I C L E   I N F O

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A B S T R A C T

The enactment of the Energy Concept by the German Government in 2010 set ambitious targets for the future energy transition in Germany. The most prominent goals include a greenhouse gas (GHG) emission reduction of the economy and an increase in the share of renewable energy in the whole energy sector. Since the long run effects of these policy measures are hard to assess, science-based policy evaluation methods are needed to identify weak points and areas with a need for action. This paper presents the results of the German Energy Reference Forecast with a focus on the electricity sector. It is based on an investment and dispatch model for the European electricity sector over the planning horizon of the 'Energiewende' up to 2050, with an emphasis on the time period up to 2030. We find that almost all targets of the German 'Energiewende' are not reached, for the case in which no further measures are undertaken. In particular reductions in GHG emissions fall short to the target value. Contrary to the negative results, e.g., regarding GHG-emissions as well as gross electricity consumption, generation from renewable energy sources will exceed the policy's target value.

1. Introduction

The enactment of the Energy Concept by the German Government in 2010 set ambitious targets for the future energy transition in Germany (BMWi,BMU, 2010). The most prominent goals include a greenhouse gas (GHG) emission reduction of the economy and an increase in the share of renewable energy in the whole energy sector. This policy decision was supported by a study defining scenarios for the future energy system up to 2050, applying a consistent modeling framework (Schlesinger et al., 2010). After the Fukushima nuclear disaster in 2011, a part of the Energy Concept was revised as policy makers reached the decision that nuclear power should be phased out by 2022, which gained strong public support. The combination of the nuclear phase out, ambitious CO_2 and renewable energy targets in Germany is commonly referred to as the 'Energiewende' (energy transition). This challenge of an industrialized country seeking to restructure its energy supply is observed with great interest among scientists and politicians worldwide (von Hirschhausen, 2014).

The Energy Concept and its accompanying policies consist of a total of 12 targets that aim to restructure the whole energy sector. These targets address various areas of the energy sector and range from overall targets for emission reduction and efficiency increase to sector-specific targets in the electricity, transportation and

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household sectors. The overall goal of reducing CO_2 emissions in the German energy sector on 40% by 2020 and 80% by 2050 – compared to the level of emissions in 1990 – will have a great impact on the supply structure of the power sector. Furthermore, this national goal has to be achieved under the European Emissions Trading System (EU-ETS). This context makes the implementation of ambitious and effective national policies within a European framework rather complex. Another target of the Energy Concept aims to increase the share of renewables in the energy sector and especially in the power sector, meaning that the share of renewable generation in gross electricity consumption should be 35% by 2020 and 80% by 2050. This is an additional attempt to reduce CO_2 emissions by defining a part of the future technology mix in the power sector. As previously mentioned, these targets are accompanied by the decision of a nuclear phase out by 2022.

In order to achieve these long term goals, an effective policy framework needs to be in place. Since the long run effects of these policy measures are hard to assess, science-based policy evaluation methods are needed to identify areas with a need for action. This is why the Federal Ministry for Economic Affairs assigned a study named “Development of Energy Markets – Energy Reference Forecast” to the consortium of Prognos AG, GWS mbH and the Institute of Energy Economics at the University of Cologne (EWI). EWI's contribution focuses on the analysis and modeling of the German electricity sector embedded in a European framework. In this paper, we present the results of the investment and dispatch model for the European electricity sector in the planning horizon of the ‘Energiewende’ up to 2050, with a focus on the time period to 2030. The modeling approach is able to calculate the development of installed capacities, electricity generation, wholesale prices, end consumer prices and CO_2 emissions for the respective time period, accounting for all policies implemented thus far.

The key element of the paper is the reference forecast up to the year 2030. The reference forecast presents the probable development from the view of the authors. This development is extrapolated in the trend scenario to the year 2050. The results act as a guidance for policy makers to help identify weak points in the policy framework. In order to test for the robustness of the results, sensitivity analyses are performed. Namely, five sensitivity calculations are used to test how different prices for fossil fuels, alternate assumptions about plant cost developments related to renewable energy use as well as higher CO_2 prices would affect key results.

2. Literature review

In accordance with European energy policy, the EU implemented the so-called ‘20-20-20’ goals that focus on environmental sustainability and provide a potential roadmap for the European Union as a whole. These goals specifically mandate a reduction of greenhouse gas emissions by 20%, an improvement of energy efficiency by 20% and a deployment of renewable energy of 20% by 2020 across the EU. Despite the European-wide goals, the authority on how to best reach these goals lies with the national governments. Within this context, Germany plays a major role in the achievement of these targets; however, its chosen path (i.e., increasing deployment of renewables) stands not without critique among the current European discussion. Within the current literature many studies investigate on country specific roles within the EU. The study at hand sheds light on key opportunities and challenges for Germany. Among others, key enablers for a low carbon society are the chosen policy instruments, on a national and supra-national level.

One mutual instrument across member states regarding energy policy is the EU-ETS. It impacts the current and future emission level through emission caps and a yearly reduction rate for total allowances in the European Union. With this instrument in place, the EU emission's landscape is subject to a change eventually leading to renovations of existing power plants and potentially new ‘carbon free’ capacity additions in Europe. Although the EU-ETS remains the major instrument for achieving a reduction in emissions, energy portfolios on a country level are also impacted by access to local resources and policy decisions (i.e., the nuclear phase out decisions). However, most studies have analyzed the impact of the EU-ETS on European energy supply with many of them focusing on the interdependence between prices of emission certificates and electricity prices. Whereas the studies differ in their methodical approach, they consistently emphasize the importance of the EU-ETS as an instrument to a less carbon intense energy system. Lise et al. (2010), for example, analyze the impact of the EU-ETS on electricity prices by using a bottom-up modeling method. They find that a significant part of the costs from buying emission allowances is passed on to consumer prices, resulting in higher electricity prices and additional (‘windfall’) profits for power producers, even in cases of full auctioning. Aatola et al. (2013) use several econometric models with multiple stationary time series and discover a strong relationship between German electricity prices and coal and gas prices with the price of European emission allowances (EUA). Kirat and Ahamada (2011) and Bonenti et al. (2013) come to similar results.

Additionally, the literature provides a full range of studies that model electricity markets on a European and national level. Most of them build on modeling different assumption-driven scenarios for the energy market. Studies based on such scenarios are often quantitative projections of energy consumption, supply, technological development, fuel and certificate prices as well as plenty of other variables that determine the overall future energy trend (see Newell and Iler, 2013). Furthermore, they differ in regional scope (national to global, electricity market to the whole energy system) time horizon (mostly up to 2020 or 2050) and time resolution (hourly, monthly or yearly). However, one key difference lies in the design of scenarios and in the assumptions used, often distinguished between target-oriented, current-policy and reference scenarios. Current-policy scenarios take into account only existing or predetermined energy and environmental policies (see EC, 2013). They therefore avoid judgments on policy proposals that have not yet been decided and provide a useful baseline against which other scenarios can be measured (Newell and Iler, 2013). Target-oriented scenarios focus on specific goals to be reached, however these goals may or may not be reached depending on the approach being used. In that respect, many studies focus on minimizing total system costs in order to reflect cost-efficient technology deployment under a certain set of assumptions. The results of target-oriented scenarios provide substantiated appraisals on the feasibility of reaching a certain (political) goal and often show different possibilities on how to reach these goals. Reference scenarios try to present the most probable trajectory of the future energy system. They also consider measures that have not yet been decided on, but that - according to the authors seem probable to be implemented (see for example UBA, 2013; Newell and Iler, 2013; BP, 2014; Spiecker and Weber, 2014). Our study falls in the latter category.

In addition to the previously mentioned studies that focus on the feasibility of transforming the German economy into a less carbon-intensive economy, Kirsten (2014), Gawel and Hansjürgens (2013) as well as Agora Energiewende (2014) focus, in contrast, on the transition of the German energy system often referred to as ‘Energiewende’ and the interaction between national and international policies. Gawel and Hansjürgens (2013) find that Germany's pioneering attempt to integrate a steadily increasing share of non-dispatchable electricity from renewable sources is jeopardizing the stability of the future European energy system.

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Kirsten (2014) as well as Agora Energiewende (2014) point out the difficulties Germany faces in reaching its ambitious goal of reducing GHG emissions by highlighting the implications of the early nuclear phase-out and the expensive promotion of renewables.

The core of the study at hand is to model the transition of the German energy system and with respect to key aspects of the German 'Energiewende' that – from the authors' perspective – are likely to play a role in the future. In doing so, we provide a projection of the most probable development of the German electricity sector up to 2030.

3. Methodology and assumptions

3.1. Methodology

We apply a linear programming model of the European power system incorporating conventional, thermal, nuclear, storage and renewable technologies. Given certain input parameters and constraints, the model calculates dispatch and investment decisions in such a way that electricity demand is satisfied and total discounted system costs in the European power system are minimized. These costs include investment costs, fixed operation and maintenance (FOM) costs, variable production costs and costs due to ramping thermal power plants. The model considers several techno-economic constraints like a power balance constraint (Eq. (A.4) in the Appendix, ensuring that electricity demand and supply match in each hour and country while accounting for storage and intra-regional trade flows), a capacity constraint (Eq. (A.5) in the Appendix, restricting maximum electricity generation for each technology by the technologies availability[1]), a minimum load constraint for dispatchable power plants (Eq. (A.6) in the Appendix, given by their minimum part-load level) and several ramp-up constraints (Eqs. (A.7) and (A.8) in the Appendix, specifying the maximum ramp up per hour). Further a fuel potential constraint (Eq. (A.9) in the Appendix) restricts the fuel use to a yearly potential in MWh_{th} per country and fuel.

The expansion of renewable generation capacity is treated endogenously in the model and also driven, apart from the cost-minimal dispatch and investment decision, by certain renewable-specific targets on the national and European levels. They are governed by Eqs. (A.13)–(A.15) in the Appendix which specify technology- and region-neutral renewable energy constraints (Eq. (A.13)), technology-specific but region-neutral renewable energy constraints (Eq. (A.14)) and technology- and region-specific renewable energy constraints (Eq. (A.15)).[2]

Generally speaking, the expansion of renewable technologies up to 2020 follows the National Renewable Energy Action Plans (NREAPs) subject to some minor adjustments based on current data. After 2020, and with the slow but steady end of the national renewable support schemes, renewable expansion is increasingly cost driven: From 2020 to 2035 within regional clusters and after 2035 across all European countries.[3]

3.2. Assumptions

The time span of the analysis extends to 2050, with computation extended to 2070 in order to obtain consistent estimates over the whole time horizon. Main input parameters to the model are fuel prices as well as assumptions concerning technical characteristics of power plants. Electricity demand is derived in an iterative procedure with the project partners in order to account for the demand response to electricity price changes (see also the description in Fürsch et al. (2012)). The resulting demand path is depicted in Table 1. As can be seen, electricity demand is slightly decreasing in Germany over the outlook period, while overall demand in Europe is increasing.

Table 1
Net electricity demand assumptions, in TWh_{el}.

Region	2011	2020	2030	2040	2050
Germany	535	510	495	489	496
Europe (incl. Germany)	2976	2932	3083	3247	3480

Table 2
Prices for CO_2 certificates assumptions, in €$_{2011}$/t CO_2.

Certificate	2011	2020	2030	2040	2050
CO_2	13	10	40	65	76

Up until 2020, prices for CO_2 certificates remain at a moderate level due to, among others, surplus allowances as a consequence of the economic and financial crisis. The rise in CO_2 prices after 2020 results from the scarcity of certificates at the European level and, at the same time, the rise is dampened by the merging of European climate protection efforts with those at the international level (Table 2).[4]

Long-term increases in real terms are expected for the market prices for crude oil, natural gas and steam coal. These prices are affected to a significant extent by the growing energy demand in Asian economies. At the global level, the geological availability of fossil energy sources, i.e., crude oil, natural gas, and steam coal, is ensured for the long term. The development of fossil fuel reserves are strongly dependent on future technological progress as well as on market price developments. Global crude oil consumption grows to around 100 mbbl/d by 2030 compared to 87 mbbl/d in 2011. The main reason for this increase is an escalating demand in the transportation sectors of rapidly growing developing and emerging countries. Downward pressure on prices is exerted by the high investment costs in global production capacity and the increasing exploitation of unconventional crude oil deposits. By 2030, political and regulatory efforts towards the reduction of CO_2 and other pollutant emissions lead to a significant rise in the global demand for natural gas. The adjustment of continental European natural gas prices through regional LNG price arbitrage increases prices in the European natural gas marketplace. In Asia, expanding electricity usage coupled with prevalent coal-based electricity sectors leads in many economies – especially in China and India – to heightened demand for steam coal. Currently, low coal prices are expected to trend upwards over time as a consequence of increased demand. Table 3 depicts the resulting assumptions entering the model (for more detailed coverage of the

[1] Availability of wind and solar power plants is given by the maximum possible electricity feed-in per hour.

[2] Note that each considered market region is further divided into renewables regions to account for different renewables conditions and potentials among them.

[3] As we show, renewable potentials will be increasingly used outside of Germany after 2020. Germany contributes to the resulting costs accordingly within the cluster or at the European level.

[4] According to our simulations, the fulfillment of a European emission target of minus 80% by 2050 compared to 1990 levels without any further internationalization of climate policies (i.e., without significant additional imports of emission allowances and corresponding dampening of the European CO_2 certificate price) would lead to European marginal abatement costs of far above 100 €$_{2011}$/t CO_2. Since we consider such high CO_2 certificate prices unlikely due to their potential to undermine the acceptability of climate protection, we assume an internationalization of climate policies consistent with this CO_2 certificate price.

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Table 3
Prices for fossil fuels assumptions, in €$_{2011}$/MWh$_{th}$.

Fuel	2011	2020	2030	2040	2050
Coal	13	13	15	16	17
Natural gas	23	30	31	33	33
Oil	49	54	56	57	57

fuel price assumptions, see Schlesinger et al., 2014).

The power plant characteristics are essentially covered by techno-economic parameters, which can be found in the appendix (see Table B1). Since the existing power plant mix consists of power plants with very different characteristics, we assume a range of parameters for each technology depending on the commission year. In addition, we assume characteristics of new innovative technologies that can be build during the modeling time span. Generally new power plants produce electricity at a higher efficiency, lower FOM-costs, lower start-up time and at a lower minimum load level. The electricity generation of intermittent renewables is based on historic time series that are used to represent the hourly availability.

We assume several new or improved technologies for both conventional and renewable power plants as well as decreasing investment costs over time due to learning curve effects (see Table B2 in the appendix). Innovations for conventional power plants mostly allow for increased flexibility and optimized part-load behavior. Concerning renewable technologies, we expect decreasing costs in particular for wind and PV, mainly due to economies of scale in manufacturing and from larger turbines.

4. Modelling results

4.1. Power plant fleet

4.1.1. Germany

The development of overall installed capacity shows an upward trend driven by an increasing amount of renewable energy capacity in the German energy mix. Overall installed capacity constantly rises over the observed time period, reaching more than 250 GW in 2050. This corresponds to an increase of about 50% compared to the 175 GW capacity in 2011. The 200 GW threshold is reached already between 2020 and 2025. The total installed capacity of conventional power plants barely drops as renewable power plants can only slightly contribute to a required stock of guaranteed capacity. Therefore, a significant amount of conventional power plant capacity is also required in the long run to back weather-dependent electricity generation from renewable energy sources. To guarantee that a sufficient amount of conventional back-up capacities is installed, a non-discriminatory and technologically-neutral mechanism that assures that these power plants can cover their full costs is assumed in the calculations. Such a mechanism can either be a functioning energy-only market with corresponding scarcity rents or a capacity mechanism. As of their flexibility in application and low investment costs, open-cycle gas turbines are expected to play a leading role as back-up capacity in the long term. Lignite and hard coal, on the other hand, will undergo a significant decline up to 2030 followed by a similar but attenuated development (Fig. 1).

Renewable energy resources highly expand their capacity over the observed time span, strongly contributing to the overall development. The model results show a substantial increase in the installed capacity of photovoltaic power plants. Photovoltaic is expected to exceed the enacted promotion ceiling of 52 GW before 2020. Installations slow down after reaching 57 GW in 2020 and reach 78 GW at the end of the observed period in 2050. The continued installment of photovoltaic plants after the expired promotion by the German government is explained by additional photovoltaic plants for own consumption. Such a development should encourage an amendment to the German electricity procurement tariff structure (especially grid charges) to avoid an uncontrolled, and from an overall system perspective, inefficient increase in PV capacity as well as the consequent negative distribution effects.[5]

Wind energy is another strong renewable contributor to the overall development of installed capacity. The model results show a doubling of wind power capacity by 2030 as well as almost a tripling of installed capacity by 2050 compared to the level in 2011. Offshore wind capacity, on the other hand, stays under its political goal of 6.5 GW cumulative installed capacity in 2020, not as result of missing economical or political incentives but rather due to difficulties in required grid expansion. It undergoes a strong surge after 2040, as technology costs are expected to drop and profitable locations for onshore wind power plants become increasingly scarce.

The increasing level of internationalization of the European electricity markets and the assumed cross-border organization of renewable energy expansion in Europe also affect the capacity of renewable power plants in Germany. The cost-efficient expansion of renewable energy outside of Germany contributes to German target attainment via German financing. This effect supports the growth of European renewable energy capacity from 2020 onwards, the growth of renewable capacities within Germany is however slowed because locations in other European countries are more attractive.

4.1.2. Europe

The overall installed capacity in Europe increases to 1400 GW in 2050. Renewable capacities grow strongly until 2020 as the National Renewable Energy Action Plans of the European countries are realized. Between 2020 and 2030 growth of renewable energy capacities slows down because the support of renewable energies is increasingly organized internationally and technology neutral. Additionally repowering of existing onshore wind power plants with modern plants increases electricity generation for a given overall installed capacity. After 2030 growth of renewable capacities accelerates again as the carbon price increases and the European renewable energy targets become more ambitious. In the conventional power plant fleet a significant shift to gas fired power plants can be observed over the analyzed time period. As explained above especially open cycle gas turbines will gain in importance because they can serve as relatively cheap back up capacities for renewable energies. Additionally nuclear energy capacities increase with rising carbon prices while the installed capacity of coal fired power plants decreases significantly (Fig. 2).

4.2. Gross electricity and CHP-heat generation

4.2.1. Germany

In the long term, national gross electricity generation shows a slightly decreasing trend up to 2050. Renewable energy resources significantly gain importance in their contribution to electricity generation in near future. Wind power provides the biggest share of all generating sources already in 2030 and increases its

[5] For a detailed discussion of the interrelations between the current German regulatory system with grid charges calculated based on electricity consumption instead of connection capacity and inefficient expansion of PV capacity see Jägemann et al. (2013).

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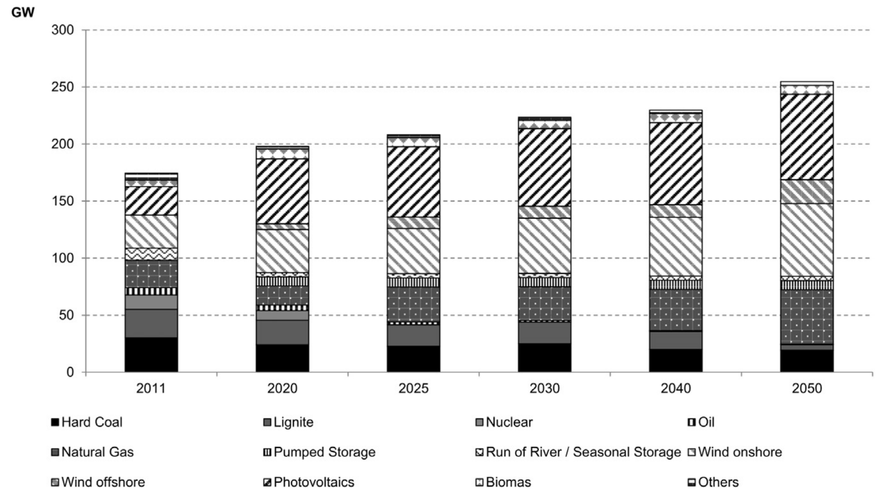

Fig. 1. Installed capacities of German power plant fleet (in GW).

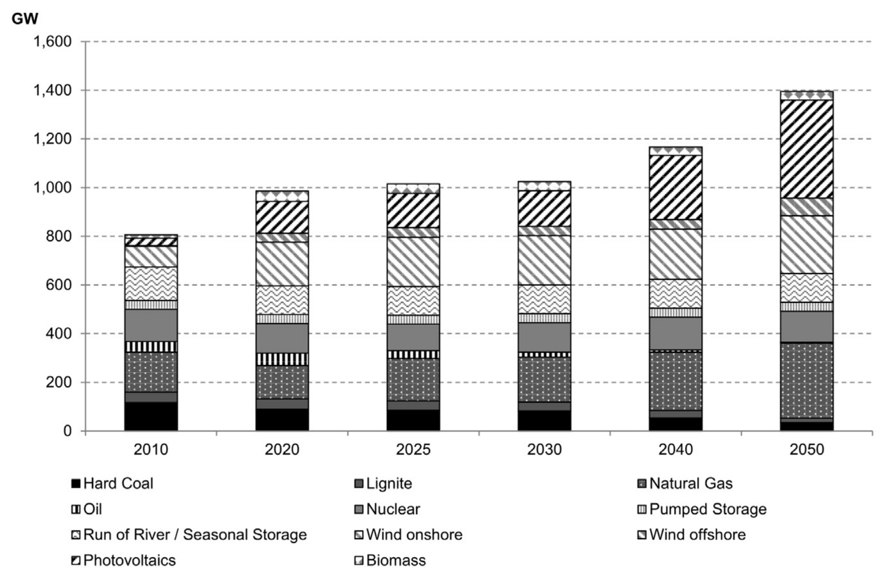

Fig. 2. Installed capacities of European power plant fleet (in GW).

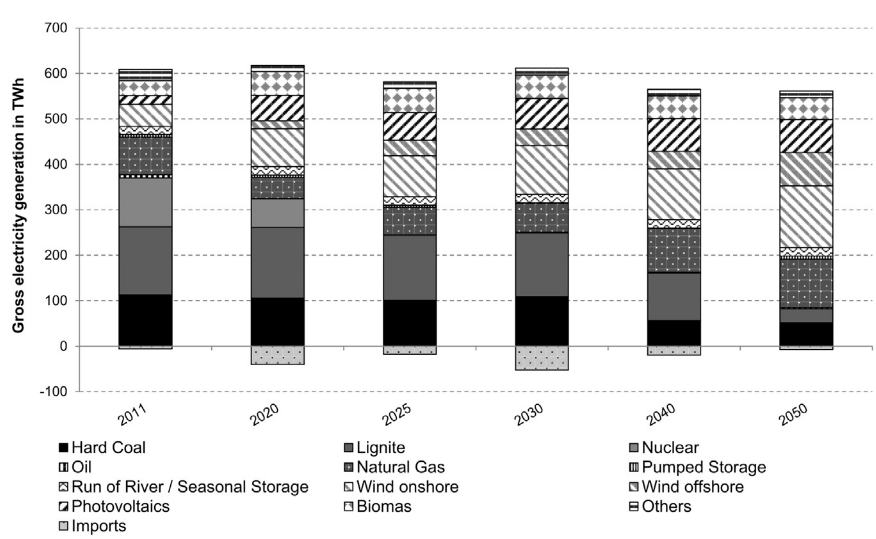

Fig. 3. Gross electricity generation in Germany (in TWh).

contribution from then on, representing the most important energy source in terms of generation. However, there are differences in the course of offshore and onshore wind generation. A similar strong development can be observed for photovoltaic, especially up to 2020 when the constituted promotion limit has already been reached. The ensuing surge of photovoltaic power generation is the result of self-generation and self-consumption.

The power generation from wind and photovoltaic suppresses generation from gas-fired power plants. Gas decreasingly supplies power generation up to 2020. It increases again after 2025 as a result of higher CO_2 certificate prices and therefore increased competitiveness, pushing coal-fired power plants out of the market.

Up to 2030, lignite and hard coal play an important part in German power generation. As CO_2 certificate prices are not expected to rise until 2025, coal-fired power plants stay competitive and compensate the lack of generation caused by the nuclear phase-out. Coal- and lignite-fired power plants that are constructed before 2020 remain especially competitive in the European market. After 2030 generation based on lignite and hard coal drops significantly due to rising CO_2 and commodity prices (Fig. 3).

Pumped storage supplies a steady share in power generation up to 2025. After, it is expected that alternative flexibility options take on greater significance, such as demand side management, flexible conventional power plants, as well as the advanced internalization of the European electricity market and increased cross-border power trade.

Biomass and hydropower are restricted in their potentials to contribute to German gross electricity generation over the observed timespan. Biomass power generation is not expected to expand due to the lack of available cultivation areas and the perpetual competition to other cultivated products. Hydropower generation stays at a constant level as a result of the quick exhaustion of suitable locations.

The development of power generation from CHP power plants is affected by a declining residual demand in the electricity and heating market. The rise in the share of renewable energy resources in generation lowers the amount of electricity generated in fossil-fired CHP plants. At the same time heat demand decreases because of efficiency measures in the heating sector. Consequently the share of CHP in net electricity generation rises only slightly from 15.9% in 2011 to 16.1% in 2020.

The net electricity export is positive for each year considered. However, it exhibits strong fluctuations: While increasing in-feed from renewable energy sources strengthens exports up to 2020 (2011: 6 TWh, 2020: 41 TWh), decommissioning of the last nuclear power plants before 2025 reduces net exports to 18 TWh in 2025. In 2050, Germany remains an electricity exporter, with more export than in 2030, due to increased production from onshore wind plants. By 2050 exports decrease to 7 TWh.

4.2.2. Europe

Total European gross electricity generation increases to roughly 3800 TWh in 2050 because of growing electricity demand in Europe. Because of the increasing prices for CO_2 certificates, the importance of low carbon electricity generation in the European electricity mix increases significantly. The share of renewable energies in total gross electricity generation amounts to over 50% in 2050. Additionally the electricity generation in nuclear power plants increases slightly. Coal based electricity generation on the other hand decreases to less than 200 TWh in 2050. The most important fossil energy source in the European electricity sector in 2050 is natural gas, which has relatively low specific CO_2 emissions and is used in flexible open gas turbines which serve as backup plants for weather dependent and volatile electricity generation from renewable energy sources. Until 2020 gas fired electricity generation is pushed out of the market by electricity generation from renewable energy sources with marginal costs close to zero. After 2020 however the share of gas in the total European electricity mix increases steadily because CO_2 prices increase and the need for flexible back-up plants grows (Fig. 4).

4.3. Full load hours

Average full-load hours of conventional and renewable energy power plants are depicted in Table 4. It can be seen that utilization of hard coal and lignite power plants does not change significantly up to 2030. After 2030, however, full-load hours drop due to rising commodity and CO_2 prices. Full-load hours of gas-powered plants decrease up to 2025 as the increasing generation of renewable energies replaces, in particular, the gas powered electricity generation, which tends to have high marginal costs. After 2025, the increasing CO_2 prices improve competitiveness of gas-fired power plants, which leads to increasing utilization rates. Full-load hours of wind and PV plants remain relatively stable over the observed time span. This is explained by two opposite effects: on the one

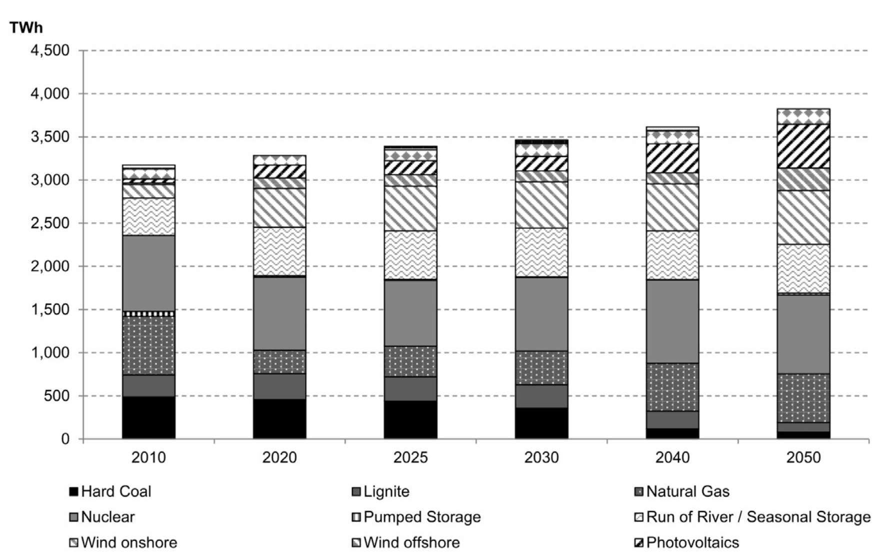

Fig. 4. Gross electricity generation in Europe (in TWh).

Table 4
Average full-load hours.

Generation technology	2020	2025	2030	2040	2050
Hard coal	4423	4466	4346	2840	2679
Lignite	7205	7503	7443	6662	6401
Natural gas	2772	1972	2186	2671	2221
Oil	121	384	777	1938	5619
Nuclear	7404	0	0	0	0
Pumped storage	651	594	114	53	857
Run of river	5031	5031	5031	5031	5031
Wind	2345	2504	2433	2409	2464
PV	988	990	993	999	975
Biomass	5906	6616	7072	6348	6132
Others	6327	5972	5607	4979	4475

Table 5
Endconsumer prices in EUR/MWh.

Endconsumer price	2011	2020	2025	2030	2040	2050
Wholesale - basis	51.1	42.3	60.0	66.8	83.3	86.8
EEG surcharge	35.3	67.5	65.4	36.2	14.6	7.7
Residential	258.8	292.1	312.3	284.3	276.3	267.5
Commercial	188.3	217.6	234.2	210.6	202.7	195.5
Manufacturing	119.2	159.4	177.4	157.2	151.8	146.6
Electricity-intensive manufacturing	55	49.3	68.9	77.8	94.5	100.4

hand, technological progress improves the system efficiency and therefore leads to higher full-load hours. On the other hand, these efficiency gains allow generators to operate wind and PV power plants profitably at new locations with less adequate weather conditions, which may lead to low utilization rates.

4.4. Consumer prices

Electricity prices and the associated electricity tariff elements are illustrated in Table 5. The wholesale base price is a basic indicator of the energy generation mix. Its decline between 2011 and 2020 can be attributed to the strong surge of generation from renewable energies and their merit order effects. The ensuing deceleration of the renewables' growth as well as rising fuel costs and CO_2 certificate prices explain the rise in wholesale electricity prices after 2020. The EEG surcharge goes down an opposing path: Following the annual growth rates from renewable energies, it significantly rises until 2020 and declines subsequently. Based on wholesale electricity prices and the EEG surcharge, endconsumer prices are calculated for residential customers, the commercial sector, as well as the manufacturing and electricity-intensive manufacturing sectors. This distinction accounts for differences in grid charges, consumption profiles as well as different tax burdens and duties such as electricity tax, EEG surcharge, CHP surcharge or concession fees across the mentioned customer groups.

Residential customers electricity rates are closely related to the EEG surcharge, resulting in a considerable price surge between 2011 and 2020 to 292 EUR/MWh. Even as the surcharge begins to decline after 2020, the growth in the wholesale price boosts residential customer prices from 2020 to 2025 to its peak of 312.3 EUR/MWh. The development thereafter shows a higher impact of the sinking EEG surcharge on residential customers prices than the increasing wholesale base price.

The factors responsible for the evolution of commercial and manufacturing customers' electricity prices are identical to those of residential prices. However, their developments occur on a lower level as residential customers face higher charges for specific tariff elements, e.g., concession fees. As residential electricity rates rise up to 2025, so do commercial customers' prices, reaching 234 EUR/MWh. The peak of manufacturing customers' electricity prices is 177 EUR/MWh in 2025. The price of both groups decreases from then on as a result of sinking EEG surcharges. Rates for electricity-intensive manufacturing customers are mainly similar to the wholesale price as they are exempted from most of the mentioned taxes and fees in order to support competitiveness in international markets.

Table 6
CO_2 emissions of the German and European electricity sector in Mt/year.

Emissions	2011	2020	2025	2030	2040	2050
CO_2 emissions in Germany	304	259	245	253	186	110
CO_2 emissions in Europe	1200	722	715	656	465	309

Table 7
German energy policy targets and the results of the reference forecast.

German energy policy target	*Year*	*Target value (%)*	*Reference forecast (%)*
GHG emissions (compared with 1990 levels)	2020	−40	−36
	2050	< −80	−65
Gross electricity consumption (compared with 2008 levels)	2020	−10	−7
	2050	−25	−10
Combined heat and power generation in net electricity generation	2020	25	16
Share of renewable energy sources in gross electricity consumption	2020	>35	41
	2050	>80	64

4.5. CO_2 emissions in the electricity sector

CO_2 emissions from electricity generation and the energy sector take up a large share in overall GHG emissions. Even though policy targets use overall GHG emissions as a reference, the contribution of the electricity sector is of valuable information. Table 6 illustrates the CO_2 emissions of the German electricity sector and the total European electricity sector. It clearly shows that emissions constantly decrease over time in Germany as well as in Europe. Up to 2030 one-sixth of the German emissions level in 2011 is cut, resulting in 253 Mt/year. However, major decarbonization of the German electricity sector occurs after 2030. With 110 Mt/year in 2050, emission levels drop to almost one third of 2011 levels. This result is mainly triggered by reduced output from coal-fired plants after 2030. Total CO_2 emissions of the European electricity sector also drop significantly to 309 Mt/year in 2050 it is evident that Germany stays by far the largest single CO_2 emitter in the European electricity sector.

4.6. Comparison with the German energy policy targets

Our results show that Germany in most cases fails to achieve its energy policy targets (Table 7). The target of a reduction of GHG emissions of 40% by 2020 compared to levels in 1990 is not achieved as GHG emissions are only reduced by 36% within that timeframe. By 2050, reductions of at least 80% are politically proposed; however reductions of only 64% are achieved.[6]

[6] CO_2 emissions from electricity generation only partly contribute to overall GHG emissions. The wedge between CO_2 emissions in the electricity sector and GHG emissions are calculated by iteration with collaborator Prognos AG.

Table 8
Sensitivity framework.

Parameter	Fuel Cost High	Fuel Cost Low	High RES-E costs	Low RES-E costs	Enforced International Climate Protection
Crude Oil (€$_{2011}$/MWh)	2020: +7% 2050: +9%	2020: −7% 2050: −9%	–	–	–
Natural gas (€$_{2011}$/MWh)	2020: +13% 2050: +15%	2020: −13% 2050: −15%	–	–	–
Steam coal (€$_{2011}$/MWh)	2020: +30% 2050: +30%	2020: −30% 2050: −30%	–	–	–
Investment Costs RES-E	–	–	+20%	−20%	–
CO_2 Price (€$_{2011}$/t)	–	–	–	–	+20%

Furthermore, the development of the gross demand for electricity misses its targets. Given reduction targets of 10% by 2020 and 25% by 2050 (compared to 2008 levels), demand decreases by 7% in 2020 and by 10% in 2050 (for a detailed description of the development of energy consumption, see Schlesinger et al., 2014). This result illustrates that general electricity demand targets in a system with a substantial contribution of CO_2-neutral generation are questionable. One reason for this effect, is that a switch from other fuels to electricity often favors energy efficiency. Another is that electricity use and economic growth are positively interrelated (see, for example, Ciarreta and Zarraga, 2010).

The results also show that the target of 25% share of CHP in net electricity generation is not reached by 2020. CHP expansion is not only affected by sinking demand in the electricity and heating market but also by efficiency measures and highly efficient heating technologies such as gas condensing boilers that compete with CHP on the supply side.

Contrary to prior results, the target regarding the share of renewable energy sources in gross electricity consumption is overachieved in 2020. As for 2050, the 80% target is not met within the German borders. It is however assumed that the promotion of renewable energies is gradually organized on a more international level after 2020. Therefore, Germany contributes to the deployment of renewable energies in other European countries and hence meets the national 80% target through additional renewable generation which is financed outside of Germany within a supranational subsidy system for renewables.

5. Robustness checks

Several of the assumptions made within the reference forecast are subject to uncertainty. For instance, prices for most relevant fuels are determined on global markets and, thus, are affected by shocks outside of the scope of this study. Therefore, we conduct several robustness checks by means of altering one single assumption per sensitivity. Hence, we can evaluate the impact of these modified assumptions and determine the robustness of the reference forecast.

We conduct five different sensitivity analyses: We assess the impact of higher and lower fuel prices, respectively. Second, we investigate whether a positive or negative shock in technology costs for renewable energies leads to major deviations from the reference forecast results. And third, we consider enforced climate change abatement activities on a global level by controlling for higher marginal abatement costs for CO_2.

Table 8 presents the differences in the sensitivities compared to the reference forecast assumptions. Table 9 and Fig. 5 illustrate the resulting differences in installed power plant capacities and gross electricity generation. These are discussed in more detail in the following. For reasons of clarity, we restrict our discussion to the years 2020 and 2050 as they are most relevant to the German energy policy targets.

5.1. Higher fuel prices on global energy markets (Fuel Cost High)

The reference forecast clearly illustrates a decreasing contribution of fossil fuels within the German electricity system. However, they still contribute 25% of gross electricity generation in 2050. Thus, uncertainties associated with fuel price developments need to be considered. Taking partial substitution possibilities into account, we assume a long-term equilibrium path with fixed spreads between fuels (incorporating changes in CO_2 certificate prices and transportation costs).[7] Fuel prices are altered upwards and downwards at 30% for steam coal, assuming constant spreads between fuels, 7%–9% for crude oil and 13%–15% for natural gas follow (see Table 8). This framework aims at increasing the competitiveness of energy efficiency measures and renewable energy sources by making their substitutes (i.e., fossil fueled energy conversion plants) more expensive.

Due to longer planning and construction times as well as possible delays within the political system, changes before 2020 are comparably small. However, Table 9 illustrates the increased competitiveness of German lignite-fired power plants within Germany and neighboring countries. For example, an additional 8 GW of lignite-fired power plant capacity is active in 2050.[8] This additional capacity suppresses comparably expensive offshore wind plants and natural gas capacity. These changes in capacities correspond to less generation from natural gas (2020: +2 TWh, 2050: −14 TWh), hard coal (2020: −6 TWh, 2050: −14 TWh) and offshore wind (2020: ±0 TWh, 2050: −31 TWh), whereas lignite-fired plants significantly increase their output (2020: ±0 TWh, 2050: +61 TWh).

With higher output from lignite-fired plants, energy-related GHG emissions in the power sector[9] become significantly higher in 2050: Emissions in 2020 will are approx. 37% lower in comparison to the Kyoto base year 1990 (i.e. +1pp[10]) and around 62% lower (i.e. 3pp more) in 2050. Higher end consumer prices for electricity

[7] While fuel price spreads are assumed to be constant in the Fuel Cost High and Fuel Cost Low sensitivities, changing spreads are implicitly covered in the sensitivity for enforced international climate protection.

[8] However, this does not imply further approvals for opencast lignite mines as the installed capacity is constantly decreasing until 2050.

[9] We restrict our focus to the power sector. However, within the political discussion, the base parameters are overall GHG emissions (i.e., from all sectors).

[10] Changes in percentage points (pp) are given in relation to the target variable of the German energy policy targets. (see, e.g., Table 10). For example with 37% less emission – compared to 1990 – in the first sensitivity and 36% less in the reference forecast, the pp-change is +1pp in emission reduction.

Table 9
Differences in installed power plant capacities between the different scenarios and the reference forecast (in GW).

Generation technology	Fuel cost		RES-E cost		Enforced	Fuel cost		RES-E cost		Enforced
	High 2020	Low 2020	High 2020	Low 2020	2020	High 2050	Low 2050	High 2050	Low 2050	2050
Hard coal	0	0	0	0	0	−1.52	0	0.15	−0.16	−3.51
Lignite	0.55	−0.67	0.03	−0.1	−0.28	7.86	0	0.67	0	0
Natural gas	−0.39	1.43	−0.5	0.56	0.12	−7.56	0.96	−0.53	−0.38	2.43
Oil	0	0	0	0	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0
Pumped storage	0	0	0	0	0	0	0	0	0	0
Run of river/seasonal storage	0	0	0	0	0	0	0	0	0	0
Wind onshore	0	0	0	0	1.35	0	0	−3.19	2.45	0
Wind offshore	0	0	0	0	0	−8.94	2.2	−10.2	2.29	1.08
Photovoltaics	0	0	0	0	1.25	0	0	−4.54	1.54	2.14
Biomass	0	0	0	0	0	0.94	−0.02	−0.13	0.75	0.19

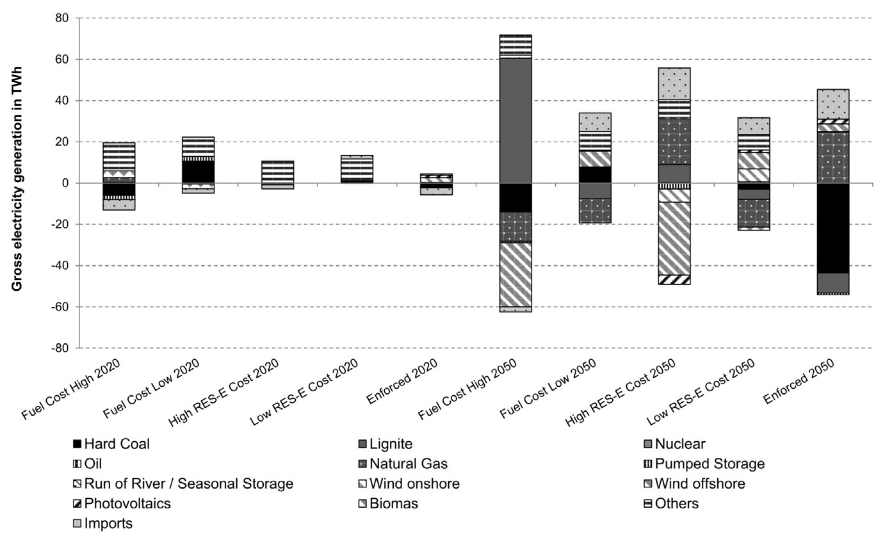

Fig. 5. Differences in gross electricity generation between the different scenarios and the reference forecast.

induced by higher fuel prices result in slightly reduced gross electricity consumption in the short term (2020: −7 TWh/−1pp, 2050: ±0 TWh/±0pp). With less gross electricity consumption up to 2020 and significantly less generation from offshore wind plants in the long run, the share of renewable energy sources in gross electricity consumption barely increases up to 2020 (42%, i.e. +1pp) and decreases significantly in 2050 (59%, i.e., −5pp). Combined heat and power generation in net electricity generation is slightly higher in this sensitivity (i.e., +1pp). These results suggest hardly any changes to the conclusions in the reference forecast regarding energy policy target attainment as again only the target for renewable energy sources in gross electricity consumption is met.

5.2. *Lower fuel prices on global energy markets (Fuel Cost Low)*

Instead of increasing the level of fuel prices, the second sensitivity reduces the price level of globally traded fuels, keeping the spread fixed. Hence, competitiveness of fossil fuels towards energy efficiency measures and renewable energy sources is strengthened, in particular, in the short term as fossil fuel contribution decreases over time.

Whereas higher fuel prices resulted in new investments in lignite-fired capacity, hardly any changes are observable in this sensitivity. As Table 9 shows, only small adjustments in power plant capacity occur, with approx. 1 GW additional capacity for natural gas and approx. 2 GW for wind offshore in 2050. Yet, we find higher utilization of hard coal-fired plants (2020: +10 TWh, 2050: +7 TWh) as well as offshore wind (2020: ±0 TWh, 2050: +8 TWh). While reductions in lignite (2020: ±0 TWh, 2050: −8 TWh) are to be expected, less output from natural gas-fired plants is rather surprising (2020: ±0 TWh, 2050: −12 TWh).

In particular, strong output from hard coal-fired plants increases the CO_2 emissions in the short run, while in the long run results regarding GHG emissions are robust in the reference scenario (2020: +1pp, 2050: ±0pp). Lower market prices correspond with lower end consumer prices. Thus, we find slight increases in gross electricity consumption (2020: +8 TWh/+1pp, 2050: +4 TWh/±0pp). Regarding renewable energy in gross electricity generation, we find slightly less output up to 2020 (40%, i.e. −1pp) and very little increase in 2050 (65%, i.e. +1pp). Combined heat and power generation in net electricity generation slightly increases (2020: +1pp). However, it fails to meet the target. Again, we find hardly any change to the previous results on the attainment of the energy policy targets.

Hence, even though we find several significant deviations (in particular closer to 2050) in power plant dispatch and investment, we find the results regarding attainment of the energy policy target to be robust towards uncertainty in fuel prices.

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5.3. Higher costs for renewable energy sources (High RES-E cost)

The first two sensitivities showed a limited effect of changes in fuel prices on the German electricity generation and power plant fleet. In the following, higher investment costs for renewable energy technologies are assumed. By increasing their costs by 20%, this sensitivity represents the possibility of more gentle learning curves. Furthermore, we assume related upward adjustments in renewable energy support schemes and slightly reduced renewable energy targets in the long term. Adjustments to the support schemes are made such that costs are reimbursed and no further incentives for investments in renewable energies are given. As a consequence, results are driven solely by higher costs in renewable energy and not by changes in the support scheme.

The impact of higher costs for renewable technologies are most predominantly observed in the changes in installed capacities of wind (2020: ±0 GW, 2050: −13 GW) and solar power plants (2020: ±0 GW, 2050: −5 GW). With slightly more lignite-fired and slightly less natural gas-fired capacity, installed capacities of conventional power plants hardly change (see Table 9). Furthermore, we find less output from offshore wind (2020: ±0 TWh, 2050: −35 TWh), onshore wind (2020: ±0 TWh, 2050: −3 TWh) and photovoltaics (2020: ±0 TWh, 2050: −5 TWh). While lignite-fired plants increase their output by 9 TWh in 2050, natural gas-fired plants can substantially increase utilization (2020: ±0 TWh, 2050: +22 TWh). This effect can be explained by lower output from renewable energy sources and, thus, more production opportunities for comparably expensive electricity from natural gas.

The resulting changes in GHG emissions are relevant only in the long-run as natural gas and lignite-fired plants increase their output compared to the reference forecast (2020: ±0pp, 2050: −1pp). Given energy policy goals for the deployment of renewable energy sources, higher technology costs require higher promotion schemes for these technologies. Assuming continuation of the current redistribution scheme (EEG surcharge), end consumer prices are higher under this sensitivity. Thus, we find lower gross electricity consumption (2020: −3 TWh/±0pp, 2050: −2 TWh/−1pp). With a notable reduction in renewable energy output in the long run, the share of renewable energy sources in gross electricity consumption drops (2020: 41%/±0pp, 2050: 56%/−8pp). Again, we find hardly any impact on the utilization of combined heat and power generation (2020: ±0pp).

5.4. Lower costs for renewable energy sources (Low RES-E cost)

Analogous to the third sensitivity, this sensitivity reduces investment costs for renewable energy technologies by 20%. Such developments could result from increased market pressure and steeper learning curves. With lower costs, we assume slightly increased targets for the deployment of renewable energy technologies.[11]

Contrary to the prior sensitivity, we find more installed capacity of wind offshore (2020: ±0 GW, 2050: +2 GW), wind onshore (2020: ±0 GW, 2050: +2 GW), solar power plants (2020: ±0 GW, 2050: +2 GW) and also biomass plants (2020: ±0 GW, 2050: +1 GW). Again, changes are observed mostly in the long-run. Correspondingly, renewable energy sources increase their output in 2050 (wind offshore +8 TWh, wind onshore +6 TWh, photovoltaics +1 TWh, biomass −2 TWh) and production from conventional plants is partly crowded out (hard coal −3 TWh, lignite −5 TWh and natural gas −13 TWh).

The reduction in fossil fuel consumption within the electricity system lowers GHG emissions particularly in the long run (2020: ±0pp, 2050: +1pp). Contrary to the calculations with high costs for renewable energy sources, we find increased gross electricity consumption induced by lower end consumer prices (2020: +3 TWh/+1pp, 2050: +1 TWh/±0pp). As to be expected, the share of renewable energy sources in gross electricity consumption increases in the long run (2020: 40%/−1pp, 2050: 67%/+3pp). Analogous to the previous sensitivity, we find no effect on the share of combined heat and power generation (2020: ±0pp).

Similar to the sensitivities on higher and lower fuel prices, we find the results regarding attainment of the energy policy target in the reference forecast to be robust also to changes in renewable energy technology costs.

5.5. Enforced international climate protection

As discussed within the reference forecast, the linkage of the EU-ETS with international climate protection efforts will play an increasingly important role. This implies a greater value of flexible mechanisms. If, however, the global community enforces climate protection by means of international treaties or national actions, increasing demand for low-cost carbon abatement in other countries would leverage cost containment effects within the European emissions trading scheme. The corresponding higher price level for CO_2 certificates would not only put pressure on emitting industries but also contribute to the achievement of the German energy policy targets.

As one may expect, higher CO_2 certificate prices trigger the fuel switch between hard coal and natural gas-fired plants. As such, we find reduced capacity of hard coal plants (2020: ±0 GW, 2050: −4 GW) and increased capacity of natural gas-fired plants (2020: ±0 GW, 2050: +2 GW). Furthermore, renewable energy sources are increasingly deployed, even in the short run (wind offshore 2020: ±0 GW, 2050: +1 GW; wind onshore 2020: +1 GW, 2050: +0 GW; photovoltaics 2020: +1 GW, 2050: +2 GW). Compared to the minor changes in generation from renewable energy sources, the output of hard coal and lignite-fired plants drops under the pressure of higher CO_2 certificate prices (hard coal 2020: −2 TWh, 2050: −44 TWh; lignite 2020: ±0 TWh, 2050: −10 TWh) and electricity from natural gas gains competitiveness (2020: ±0 TWh, 2050: +25 TWh).

Of course, this framework results in lower GHG emissions (2020: ±0pp, 2050: −4pp). However, at the same time, reduced gross electricity consumption results due to higher cost levels for electricity generation from conventional power plants (2020: −1 TWh/±0pp, 2050: −9 TWh/−2pp). This effect, however, is only small in the short run. The share of renewable energy sources in gross electricity consumption resembles the results of the sensitivity “Low RES-E cost” (2020: 41%/±0pp, 2050: 67%/+3pp). Again, no impact on the combined heat and power generation can be observed (2020: ±0pp).

As illustrated in Table 10, the robustness checks illustrate that the attainment of the German energy policy targets is not influenced by uncertainty in either fuel prices, renewable energy technology costs or global climate change abatement activities. Hence, the reference forecast can be considered relatively robust to such uncertainties.

6. Conclusion and policy implications

The ‘Energiewende’ aims at restructuring supply and demand for energy in Germany. Since 2010, policy makers have implemented ambitious targets for the future energy transition in Germany. With one particular focus of the ‘Energiewende’ centering on the transformation of the power sector. In this paper, we

[11] Again, support scheme adjustments focus on cost reimbursements only.

Table 10
German energy policy target attainment across the sensitivity analyses.

German energy policy target	*Year*	Target value (%)	Reference forecast (%)	Fuel Cost High	Fuel Cost Low	High RES-E Cost	Low RES-E Cost	Enforced
GHG emissions (compared with 1990 levels)	2020	−40	−36	−37%	−35%	−36%	−36%	−36%
	2050	< −80	−65	−62%	−65%	−64%	−66%	−69%
Gross elec. consumption (compared with 2008 levels)	2020	−10	−7	−8%	−5%	−7%	−6%	−7%
	2050	−25	−10	−10%	−9%	−11%	−10%	−12%
Combined heat and power generation in net electricity generation	2020	25	16	17%	17%	16%	16%	16%
Share of renewable energy sources in gross elec. consumption	2020	>35	41	42%	40%	41%	40%	41%
	2050	>80	64	59%	65%	56%	67%	67%

investigate the probable development of the German energy system from the view of the authors, given the current political and industrial conditions and evaluate these development against the policy targets.

We find that output from coal-fired power plants remains almost constant up to 2030. Thus, after 2030, market pressure from renewable energy sources and CO_2 prices reduce coal generation significantly. Up to 2025, gas-fired generation stays under pressure from renewable infeed and further reduces utilization. However, assumed increases in CO_2 prices crowds out gas-fired generation in the long term.

Renewable generation continues its expansion. For example, wind power contributes the largest share to gross electricity generation from 2030 onwards. Cross-border cooperation results in synergies and cost reductions for the deployment of renewable energy sources. Correspondingly, EEG surcharges rise until 2020 and decrease thereafter, yielding an increase in retail prices for almost all consumers except for energy-intensive industries, which are subject to decreasing prices. After 2020 however, prices for residential, commercial and industrial consumers fall, whereas prices for energy-intensive industries rise.

Under these developments, almost all targets are not reached. In particular, reductions in GHG emissions fall short of the target value. Contrary to the negative results regarding GHG emissions as well as gross electricity consumption and combined heat and power generation, deployment and generation from renewable energy sources exceed the policy target value.

In the sensitivity analyses, we find that failure to meet the target is robust with respect to changes in fuel prices, CO_2 prices and technology costs for renewable energy sources. Hence, not only do our results suggest inefficiency of several policy instruments implemented within the ‘Energiewende’, it gives rise to questions whether goals are well coordinated or perhaps rather conflicting. Answering these questions is beyond the scope of this article, but an interesting field for further research.

The policy implications of our results are straightforward. On the one hand, coordination of policy targets of the ‘Energiewende’ should be improved. In that respect, a discussion and re-evaluation of these targets should be initiated. On the other hand, target attainment should be enforced by additional political measures. With reductions in GHG emissions being the most important target to mitigate climate change, reaching the target value requires lowering the output of technologies with high specific CO_2 emissions. From an economic point of view, an efficient measure would have to increase the marginal abatement costs for CO_2 (e.g., by a European or national mark-up on the EU-ETS price). Additional measures to reduce gross electricity consumption such that the target can be reached are hardly to be found. Even though efficiency improvements in electrical appliances make target attainment more likely, increasing electrification (e.g, from electromobility) will counteract the effectiveness of such measures. Regarding the target for combined heat and power generation, policy implications are also complicated. As combined heat and power generation is mostly based on fossil fuels, a simple support scheme would counteract the target for reductions in GHG emissions. Therefore, increasing the share of biomass utilization in the industry and manufacturing sectors would be essential. And finally, efficiently reaching the share of renewable energy sources in gross electricity consumption requires coordination of renewable support schemes among European countries and taking credit for financing renewable energy plants outside of Germany.

Even though we restrict our discussion on the attainment of national energy policy targets, national targets and policies need to be considered in a European context. It is well known that national policies that are not coordinated with European policies may lack an overall positive impact and may also lower efficiency within the system. This holds true for the case of national targets and related policy measures for reductions in GHG emissions that push aside the fact that the EU-ETS is the European measure to address GHG emissions. Putting the policy focus purely on national target attainment and neglecting externalities on European targets and measures may only increase costs without inducing any effect on GHG emissions and, hence, put a burden on the German economy.

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Appendix A. Model appendix

The model description in this section heavily draws on Jägemann (2014) which uses the same base model as used for the analysis at hand. CHP modelling in our analysis is quite detailed as it considers several heat demand cases and involves several additional equations to describe the exact utilization pattern of CHP plants. For brevity and as CHP results and modelling is not the main focus of this paper, we refrain from presenting these equations here. The same applies to the equations governing storage utilization. Both the CHP and storage equations can be found in

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Richter (2011):

$$\min \quad TSC = \sum_{y\in Y}\sum_{c\in C}\sum_{a\in A}\left(disc_y\cdot\left(AD_{y,a,c}\cdot an_a\cdot ic_a + IN_{y,a,c}\cdot fc_a + \sum_{h\in H}\left(GE_{y,h,a,c}\cdot\left(\frac{fu_{y,a}+cp_y * ef_a}{\eta_a}\right) + CU_{y,h,a,c}\cdot\left(\frac{fu_{y,a}+cp_y * ef_a}{\eta_a}+ac_a\right)\right)\right)\right) \tag{A.1}$$

$$disc_y = \frac{1}{(1+dr)^{y-y_{start}}} \tag{A.2}$$

$$an_a = \frac{(1+ir)^{dp_a\cdot ir}}{(1+ir)^{dp_a}-1} \tag{A.3}$$

s.t.

$$\sum_{a\in A} GE_{y,h,a,c} + \sum_{c'\in C} IM_{y,h,c,c'} - \sum_{s\in A} ST_{y,h,s,c} = d_{y,h,c} \tag{A.4}$$

$$GE_{y,h,a,c} \le av_{d,h,a,c}\cdot IN_{y,a,c} \tag{A.5}$$

$$GE_{y,h,a,c} \ge ml_a\cdot av_{h,a,c}\cdot IN_{y,a,c} \tag{A.6}$$

$$CU_{y,h,a,b} \le \frac{IN_{y,a,c}-CR_{y,h,a,c}}{st_a} \tag{A.7}$$

$$CR_{y,h,a,c} \le av_{h,a,c}\cdot IN_{y,a,c} \tag{A.8}$$

$$\sum_{h\in H}\frac{GE_{y,h,a,c}}{\eta_a} \le fp_{y,a,c} \tag{A.9}$$

$$AD_{y,r,c} = \sum_{e\in E} AD_{y,r,c,e} \tag{A.10}$$

$$IN_{y,r,c} = \sum_{e\in E} IN_{y,r,c,e} \tag{A.11}$$

$$GE_{y,h,r,c} = \sum_{e\in E} GE_{y,h,r,c,e} \tag{A.12}$$

$$\sum_{h\in H}\sum_{r\in A}\sum_{e\in E} GE_{y,h,r,c,e} \ge x_{y,c} \tag{A.13}$$

$$\sum_{h\in H}\sum_{e\in E} GE_{y,h,r,c,e} \ge xx_{y,r,c} \tag{A.14}$$

$$\sum_{h\in H} GE_{y,h,r,c,e} \ge xxx_{y,r,c,e} \tag{A.15}$$

See Tables A1 and A2.

Table A1
Sets and parameters of the electricity system optimization model.

Abbreviation	Dimension	Description
Model sets		
a ∈ A		Technologies
s ∈ A	Subset of a	Storage technologies
r ∈ A	Subset of a	RES-E technologies
c ∈ C (alias c')		Market region
e ∈ E		Subregion within a market region (for RES-E technologies)
h ∈ H		Hours
y ∈ Y		Years
y_{start} ∈ Y		Starting year (2011)
Model parameters		
ac_a	(€$_{2011}$/MWh$_{el}$)	Attrition costs for ramp-up operation
an_a		Annuity factor for technology-specific investment costs
$av_{h,a,c}$	(%)	Availability
$d_{y,h,c}$	(MW)	Total demand
$disc_y$		Discount factor
dr	(%)	Discount rate (5%)
dp_a	(years)	depreciation period
ef_a	(t CO_2 /MWh$_{th}$)	CO_2 emissions per fuel consumption
fc_a	(€$_{2011}$/MW)	Fixed operation and maintenance costs
$fu_{y,a}$	(€$_{2011}$/MWh$_{th}$)	Fuel price
cp_y	(€$_{2011}$/t CO_2)	CO_2 price
$fp_{y,a,c}$	(MWh$_{th}$)	Fuel potential
ir	(%)	Interest rate (5%)
ic_a	(€$_{2011}$/MW)	Investment costs
ml_a	(%)	Minimum part load level
$x_{y,c}$	(MWh)	Technology- and region-neutral RES-E target
$xx_{y,r,c}$	(MWh)	Technology-specific but region-neutral RES-E target
$xxx_{y,r,c,e}$	(MWh)	Technology- and region-specific RES-E target
st_a	(h)	Start-up time from cold start
η_a	(%)	Net efficiency (generation)

Table A2
Variables of the electricity system optimization model.

Abbreviation	Dimension	Description
Model variables		
$AD_{y,a,c}$	(MW)	Commissioning of new power plants
$AD_{y,r,c,e}$	(MW)	Commissioning of a new RES-E technology r in subregion e
$CU_{y,h,a,c}$	(MW)	Capacity that is ramped up within one hour
$CR_{y,h,a,c}$	(MW)	Capacity that is ready to operate
$GE_{y,h,a,c}$	(MW$_{el}$)	Electricity generation
$GE_{y,h,r,c,e}$	(MW$_{el}$)	Electricity generation of a RES-E technology r in subregion e
$IM_{y,h,c,c'}$	(MW)	Net imports
$IN_{y,a,c}$	(MW)	Installed capacity
$IN_{y,r,c,e}$	(MW)	Installed capacity of a RES-E technology r in sub-region e
$ST_{y,h,s,c}$	(MW)	Consumption in storage operation
TSC	(€$_{2011}$)	Accumulated and discounted total system costs

Appendix B. Data appendix

See Tables B1–B14.

Table B1
Techno-economic parameters for conventional power plants.

Generation technology	Net efficiency (%)	Technical lifetime (a)	FOM-costs (EUR/kW/a)	Availability (%)	Start-up time (h)	Minimum part-load (%)
Coal	37–46	45	36–54	84	5–7	27–40
Coal (innovative)	50	45	36	84	4	27
Lignite	32–43	45	43–65	86	10–11	35–60
Lignite (innovative)	47	45	43	86	7	30
CCGT	40–60	30	28	86	2–3	40–70
OCGT	28–40	25	17	86	0.25	40–50
IGCC	46	30	40	84	4	35
Nuclear	33	60	97	92	24	45
Biomass (solid)	30	30	165	85	1	30

Table B2
Specific investment costs for thermal and renewable power plants in €$_{2011}$/kW.

Generation technology	2020	2030	2040	2050
Coal	1200	1200	1200	1200
Coal (innovative)	2025	1800	1700	1650
Lignite	1500	1500	1500	1500
Lignite (innovative)	1600	1600	1600	1600
CCGT	711	711	711	711
OCGT	400	400	400	400
IGCC	1700	1700	1625	1575
PV (roof)	1260	935	800	734
PV (base)	1110	785	650	584
Wind Onshore	1253	1188	1128	1073
Wind Offshore (>20 m depth)	3080	2585	2420	2310
Wind Offshore (<20 m depth)	2800	2350	2200	2100
Biomass (solid)	3297	3293	3290	3287

Table B3
Gross domestic generation reference scenario.

Gross generation (TWh)	2011	2020	2025	2030	2040	2050
Hard coal	112.4	105.7	101.1	108.7	56.6	51.6
Lignite	150.1	155.8	143.0	140.5	104.3	31.2
Natural gas	82.5	46.7	60.5	64.5	96.6	106.3
Oil	6.8	0.6	0.9	1.2	1.8	2.4
Nuclear	108.0	62.8	0.0	0.0	0.0	0.0
Pumped storage	5.8	5.2	4.8	0.9	0.4	6.9
Run of river/seasonal storage	17.7	18.7	18.7	18.7	18.7	18.7
Wind	48.9	100.3	124.3	143.4	150.5	208.6
Wind onshore	48.3	82.9	89.6	106.9	111.9	136.0
Wind offshore	0.6	17.3	34.7	36.4	38.6	72.6
Photovoltaics	19.3	56.1	61.1	67.3	71.8	72.9
Biomass	32.8	52.1	52.8	51.9	50.1	48.4
Others	24.5	13.9	14.8	14.7	14.5	14.4
Total	608.9	617.8	581.8	611.7	565.2	561.3
Imports (TWh)	−6.3	−40.6	−17.6	−52.6	−19.3	−7.2
Share of renewable energy sources in gross electricity consumption (%)	20.5	40.6	46.9	51.7	54.7	64.3

Table B4
Gross domestic generation Fuel Cost High.

Gross generation (TWh)	2011	2020	2025	2030	2040	2050
Hard coal	112.4	99.7	94.0	78.7	32.8	37.6
Lignite	150.1	156.2	147.2	165.7	162.4	91.8
Natural gas	82.5	48.9	61.6	51.8	93.9	92.0
Oil	6.8	0.6	0.9	1.2	1.8	2.4
Nuclear	108.0	62.8	0.0	0.0	0.0	0.0
Pumped storage	5.8	3.1	4.7	0.9	1.1	6.1
Run of river/seasonal storage	17.7	18.7	18.7	18.7	18.7	18.7
Wind	48.9	100.3	124.9	144.3	151.4	177.6
Wind onshore	48.3	82.9	90.2	107.9	112.8	136.0
Wind offshore	0.6	17.3	34.7	36.4	38.6	41.6
Photovoltaics	19.3	56.1	61.1	67.3	71.8	72.9
Biomass	32.8	55.5	53.7	52.0	50.1	49.9
Others	24.5	13.9	14.8	14.7	14.5	14.4
Total	608.9	615.7	581.5	595.3	598.4	563.3
Imports (TWh)	−6.3	−45.6	−20.9	−40.1	−51.8	−9.6
Share of renewable energy sources in gross electricity consumption (%)		41.7	47.5	52.2	54.8	59.0

Table B5
Gross domestic generation Fuel Cost Low.

Gross generation (TWh)	2011	2020	2025	2030	2040	2050
Hard coal	112.4	116.2	117.1	123.9	77.3	59.0
Lignite	150.1	155.3	138.2	134.1	77.4	23.5
Natural gas	82.5	46.9	59.8	58.6	97.8	94.6
Oil	6.8	0.6	0.9	1.2	1.8	2.4
Nuclear	108.0	62.8	0.0	0.0	0.0	0.0
Pumped storage	5.8	7.4	5.0	1.5	0.3	7.3
Run of river/seasonal storage	17.7	18.7	18.7	18.7	18.7	18.7
Wind	48.9	100.3	124.3	145.2	152.4	216.3
Wind onshore	48.3	82.9	89.6	108.8	113.8	136.0
Wind offshore	0.6	17.3	34.7	36.4	38.6	80.3
Photovoltaics	19.3	56.1	61.1	67.3	71.8	72.9
Biomass	32.8	49.9	49.7	51.5	47.2	48.9
Others	24.5	13.9	14.8	14.7	14.5	14.4
Total	608.9	628.0	589.5	616.7	559.2	557.9
Imports (TWh)	−6.3	−42.8	−20.2	−52.4	−7.9	1.8
Share of renewable energy sources in gross electricity consumption (%)		39.7	45.9	51.5	54.0	65.1

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Table B6
Gross domestic generation high EE costs.

Gross generation (TWh)	2011	2020	2025	2030	2040	2050
Hard coal	112.4	105.8	104.3	111.7	57.8	51.8
Lignite	150.1	155.8	143.2	146.5	113.0	39.9
Natural gas	82.5	46.4	60.8	62.1	97.2	128.4
Oil	6.8	0.6	0.9	1.2	1.8	2.4
Nuclear	108.0	62.8	0.0	0.0	0.0	0.0
Pumped storage	5.8	5.2	3.8	0.7	0.3	4.0
Run of river/seasonal storage	17.7	18.7	18.7	18.7	18.7	18.7
Wind	48.9	100.3	121.7	129.6	131.4	166.9
Wind onshore	48.3	82.9	87.1	94.1	95.0	129.6
Wind offshore	0.6	17.3	34.7	35.4	36.4	37.3
Photovoltaics	19.3	56.1	59.8	66.0	68.0	68.5
Biomass	32.8	51.6	52.4	51.8	50.7	49.1
Others	24.5	13.9	14.8	14.7	14.5	14.4
Total	608.9	617.1	580.3	602.9	553.3	544.1
Imports (TWh)	−6.3	−42.6	−20.8	−46.6	−7.8	8.2
Share of renewable energy sources in gross electricity consumption (%)		40.7	46.5	49.2	50.7	56.3

Table B7
Gross domestic generation low EE costs.

Gross generation (TWh)	2011	2020	2025	2030	2040	2050
Hard coal	112.4	105.9	95.1	101.2	53.4	48.6
Lignite	150.1	155.7	141.2	138.0	99.1	26.2
Natural gas	82.5	47.1	56.4	53.2	95.5	92.9
Oil	6.8	0.6	0.9	1.2	1.8	2.4
Nuclear	108.0	62.8	0.0	0.0	0.0	0.0
Pumped storage	5.8	5.3	4.9	3.6	0.9	7.5
Run of river/seasonal storage	17.7	18.7	18.7	18.7	18.7	18.7
Wind	48.9	100.3	148.8	163.0	171.2	222.8
Wind onshore	48.3	82.9	114.2	126.6	132.6	142.3
Wind offshore	0.6	17.3	34.7	36.4	38.6	80.6
Photovoltaics	19.3	56.1	62.3	68.6	73.2	74.2
Biomass	32.8	52.5	52.9	51.1	48.7	46.9
Others	24.5	13.9	14.8	14.7	14.5	14.4
Total	608.9	618.8	596.0	613.4	576.9	554.5
Imports (TWh)	−6.3	−38.9	−29.5	−48.7	−29.7	0.9
Share of renewable energy sources in gross electricity consumption (%)		40.5	51.3	54.7	58.4	66.7

Table B8
Gross domestic generation enforced scenario.

Gross generation (TWh)	2011	2020	2025	2030	2040	2050
Hard coal	112.4	103.8	97.9	79.2	24.7	7.9
Lignite	150.1	155.6	140.8	133.4	76.6	21.5
Natural gas	82.5	47.0	62.2	86.9	107.2	131.0
Oil	6.8	0.6	0.9	1.2	1.8	2.4
Nuclear	108.0	62.8	0.0	0.0	0.0	0.0
Pumped storage	5.8	5.0	4.3	0.3	0.3	6.0
Run of river/seasonal storage	17.7	18.7	18.7	18.7	18.7	18.7
Wind	48.9	102.5	128.0	143.6	152.5	212.7
Wind onshore	48.3	85.2	93.4	107.1	113.7	136.3
Wind offshore	0.6	17.3	34.7	36.5	38.8	76.4
Photovoltaics	19.3	57.4	61.1	67.3	73.0	75.1
Biomass	32.8	52.6	53.6	52.1	50.5	48.6
Others	24.5	13.9	14.8	14.7	14.5	14.4
Total	608.9	619.8	582.2	597.4	519.7	538.3
Imports (TWh)	−6.3	−43.9	−20.5	−43.3	18.5	7.1
Share of renewable energy sources in gross electricity consumption (%)		41.4	47.9	52.2	56.2	66.5

Table B9
Installed capacity reference scenario.

Gross capacity (TWh)	2011	2020	2025	2030	2040	2050
Hard coal	30.2	23.9	22.6	25.0	19.9	19.2
Lignite	24.9	21.6	19.1	18.9	15.7	4.9
Natural gas	23.9	16.8	30.7	29.5	36.2	47.8
Oil	6.4	4.9	2.3	1.5	0.9	0.4
Nuclear	12.7	8.5	0.0	0.0	0.0	0.0
Pumped storage		8.0	8.0	8.0	8.0	8.0
Run of river/seasonal storage	10.6	3.7	3.7	3.7	3.7	3.7
Wind	29.1	42.8	49.6	58.9	62.5	84.7
Wind onshore		37.8	39.6	48.4	51.3	63.7
Wind offshore		5.0	10.0	10.5	11.1	20.9
Photovoltaics	25.0	56.8	61.7	67.8	71.9	74.8
Biomass	5.4	8.8	8.0	7.3	7.9	7.9
Others	6.4	2.2	2.5	2.6	2.9	3.2
Total	174.5	198.0	208.2	223.3	229.5	254.7
Share of renewable energy sources (%)		56.7	59.1	61.7	63.6	67.2

Table B10
Installed capacity Fuel Cost High.

Gross capacity (TWh)	2011	2020	2025	2030	2040	2050
Hard coal	30.2	23.9	22.6	23.5	18.4	17.7
Lignite	24.9	22.2	19.6	23.3	22.9	12.7
Natural gas	23.9	16.4	29.6	26.0	29.8	40.3
Oil	6.4	4.9	2.3	1.5	0.9	0.4
Nuclear	12.7	8.5	0.0	0.0	0.0	0.0
Pumped storage		8.0	8.0	8.0	8.0	8.0
Run of river/seasonal storage	10.6	3.7	3.7	3.7	3.7	3.7
Wind	29.1	42.8	50.0	59.5	63.0	75.7
Wind onshore		37.8	40.0	49.0	51.9	63.7
Wind offshore		5.0	10.0	10.5	11.1	12.0
Photovoltaics	25.0	56.8	61.7	67.8	71.9	74.8
Biomass	5.4	8.8	8.0	7.4	8.3	8.8
Others	6.4	2.2	2.5	2.6	2.9	3.2
Total	174.5	198.2	208.0	223.4	229.9	245.5
Share of renewable energy sources (%)		56.6	59.4	62.0	64.0	66.5

Table B11
Installed capacity Fuel Cost Low.

Gross capacity (TWh)	2011	2020	2025	2030	2040	2050
Hard coal	30.2	23.9	22.6	25.0	19.9	19.2
Lignite	24.9	21.0	18.4	18.2	15.7	4.9
Natural gas	23.9	18.3	31.9	30.8	37.3	48.8
Oil	6.4	4.9	2.3	1.5	0.9	0.4
Nuclear	12.7	8.5	0.0	0.0	0.0	0.0
Pumped storage		8.0	8.0	8.0	8.0	8.0
Run of river/seasonal storage	10.6	3.7	3.7	3.7	3.7	3.7
Wind	29.1	42.8	49.6	60.0	63.6	86.9
Wind onshore		37.8	39.6	49.5	52.5	63.7
Wind offshore		5.0	10.0	10.5	11.1	23.1
Photovoltaics	25.0	56.8	61.7	67.8	71.9	74.8
Biomass	5.4	8.8	7.9	7.2	7.2	7.9
Others	6.4	2.2	2.5	2.6	2.9	3.2
Total	174.5	198.8	208.7	224.9	231.2	257.8
Share of renewable energy sources (%)		56.4	59.0	61.7	63.4	67.2

Table B12
Installed capacity high EE cost.

Gross capacity (TWh)	2011	2020	2025	2030	2040	2050
Hard coal	30.2	23.9	22.6	25.0	20.1	19.4
Lignite	24.9	21.7	19.1	19.6	16.3	5.5
Natural gas	23.9	16.3	30.1	28.4	35.5	47.3
Oil	6.4	4.9	2.3	1.5	0.9	0.4
Nuclear	12.7	8.5	0.0	0.0	0.0	0.0
Pumped storage		8.0	8.0	8.0	8.0	8.0
Run of river/seasonal storage	10.6	3.7	3.7	3.7	3.7	3.7
Wind	29.1	42.8	48.1	51.0	51.9	71.3
Wind onshore		37.8	38.1	40.8	41.4	60.6
Wind offshore		5.0	10.0	10.2	10.5	10.7
Photovoltaics	25.0	56.8	60.4	66.5	67.9	70.2
Biomass	5.4	8.8	7.9	7.3	7.7	7.8
Others	6.4	2.2	2.5	2.6	2.9	3.2
Total	174.5	197.5	204.8	213.7	214.9	236.9
Share of renewable energy sources (%)		56.8	58.7	60.2	61.1	64.6

Table B13
Installed capacity low EE cost.

Gross capacity (TWh)	2011	2020	2025	2030	2040	2050
Hard coal	30.2	23.9	22.6	24.8	19.8	19.1
Lignite	24.9	21.5	19.0	18.8	15.7	4.9
Natural gas	23.9	17.4	30.7	29.7	35.2	47.5
Oil	6.4	4.9	2.3	1.5	0.9	0.4
Nuclear	12.7	8.5	0.0	0.0	0.0	0.0
Pumped storage		8.0	8.0	8.0	8.0	8.0
Run of river/seasonal storage	10.6	3.7	3.7	3.7	3.7	3.7
Wind	29.1	42.8	64.2	70.6	74.9	89.4
Wind onshore		37.8	54.2	60.1	63.7	66.2
Wind offshore		5.0	10.0	10.5	11.1	23.2
Photovoltaics	25.0	56.8	62.9	69.2	73.4	76.3
Biomass	5.4	8.8	8.0	7.4	8.6	8.6
Others	6.4	2.2	2.5	2.6	2.9	3.2
Total	174.5	198.5	223.9	236.5	243.1	261.2
Share of renewable energy sources (%)		56.5	62.1	63.9	66.1	68.2

Table B14
Installed capacity enforced scenario.

Gross capacity (TWh)	2011	2020	2025	2030	2040	2050
Hard coal	30.2	23.9	22.6	21.5	16.4	15.7
Lignite	24.9	21.3	18.8	18.6	15.7	4.9
Natural gas	23.9	17.0	30.7	32.7	38.8	50.3
Oil	6.4	4.9	2.3	1.5	0.9	0.4
Nuclear	12.7	8.5	0.0	0.0	0.0	0.0
Pumped storage		8.0	8.0	8.0	8.0	8.0
Run of river/seasonal storage	10.6	3.7	3.7	3.7	3.7	3.7
Wind	29.1	44.1	51.8	59.1	63.6	85.8
Wind onshore		39.1	41.8	48.5	52.4	63.7
Wind offshore		5.0	10.0	10.5	11.2	22.0
Photovoltaics	25.0	58.1	61.7	67.8	73.2	76.9
Biomass	5.4	8.8	8.0	7.4	8.0	8.1
Others	6.4	2.2	2.5	2.6	2.9	3.2
Total	174.5	200.4	210.2	222.9	231.3	257.0
Share of renewable energy sources (%)		57.3	59.7	61.9	64.3	67.9

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