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German nuclear policy reconsidered: Implications for the electricity market[☆]

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Abstract

In the aftermath of the nuclear catastrophe in Fukushima, German nuclear policy has been reconsidered. This paper demonstrates the economic effects of an accelerated nuclear phase-out on the German electricity generation sector. A detailed optimization model for European electricity markets is used to analyze two scenarios with different lifetimes for nuclear plants (phase-out vs. prolongation). Based on political targets, both scenarios assume significant electricity demand reductions and a high share of generation from renewable energy sources in Germany. Our principal findings are: First, nuclear capacities are mainly replaced by longer lifetimes of existing coal-fired plants and the construction of new gas-fired plants. Second, fossil fuel-based generation and power imports increase, while power exports are reduced in response to the lower nuclear generation. Third, despite the increased fossil generation, challenging climate protection goals can still be achieved within the framework of the considered scenarios. Finally, system costs and electricity prices are clearly higher. We conclude that the generation sector can generally cope with an accelerated nuclear phase-out under the given assumptions. Yet, we emphasize that such a policy requires a substantial and costly transformation of the supply and the demand side.

Keywords: Nuclear policy, climate protection, renewable energy, electricity market modeling

JEL classification: Q48, Q58, L94, C61

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[☆]This article presents selected results from a study carried out by the Institute of Energy Economics at the University of Cologne (EWI) in cooperation with Prognos AG and Gesellschaft für Wirtschafts- und Strukturforschung mbH (GWS) for the German Ministry of Economics and Technology.

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1. Introduction

In the aftermath of the nuclear catastrophe in Fukushima in March 2011, nuclear policy has been reconsidered in Germany. Only shortly before, in December 2010, the amendment of the German nuclear law (Atomgesetz, 2010) was passed, including a possible prolongation of nuclear plant lifetimes up to 14 years compared to the nuclear phase-out decision in 2002 (Atomkonsens, 2002). As an immediate reaction to the Fukushima catastrophe, the German government decided on a three-month moratorium which included the temporary shutdown of the seven oldest nuclear power plants and the nuclear plant Krümmel in order to re-evaluate the risks of nuclear power and the associated energy policy. Irrespective of a possibly changing nuclear policy, it was political will that ambitious climate protection targets, as defined in the coalition agreement between CDU/CSU (conservatives) and FDP (liberals) for the 17^{th} legislative period, should still be reached. Most importantly this agreement features the target of a 40% (80%) greenhouse gas emissions reduction until 2020 (2050) compared to 1990 as well as considerable energy efficiency improvements and a significant expansion of renewable energy sources.

This paper presents an analysis of the effects of an accelerated nuclear phase-out on the electricity sector, based on a study commissioned by the German Ministry of Economics and Technology during the time of the nuclear moratorium. We use a detailed investment and dispatch model of European electricity markets and compute two scenarios in order to investigate the impact of a fast nuclear phase-out on electricity capacities, generation, import and export streams, electricity prices and costs, and CO_2-emissions. Scenario A reflects German law before Fukushima, thus possible lifetimes up to the year 2036 for the newest nuclear plants. Prolongations of lifetimes in scenario A are only possible when significant retrofit investments are undertaken. In scenario B all nuclear plants that were shutdown during the moratorium are decommissioned permanently. The remaining nuclear plants have to be shutdown either between 2015 and 2020 (six plants) or before 2025 (three plants). Thus, scenario B corresponds to the political decision reached after the moratorium. In both scenarios, climate protection targets as defined in the coalition agreement are reached – albeit at slightly higher CO_2-prices within the European emissions trading system.

Our analysis extends the findings of Nagl et al. (2011), showing how different possible pathways to a low-carbon German electricity system in 2050 under consideration of different nuclear phase-out times can be reached. Our analysis shows how these climate protection targets can still be reached under a fast nuclear phase-out and illuminates the corresponding consequences for the electricity sector, focussing on the timeframe until 2030. The analysis is structured as follows: Section 2 provides an overview of related literature. Section 3 describes the applied methodological approach, section 4 explains the most important technical and political assumptions. Scenario results are discussed in section 5. Section 6 draws conclusions.

2. Literature overview

A series of studies analyzing the effect of a fast nuclear phase-out have been published after the introduction of the moratorium. These studies can be distinguished by their time horizon (i.e. short term, long term), the applied analytical approach (i.e. model-based, quantitative, qualitative) and their focus on different aspects of the electricity sector.

Matthes et al. (2011b) analyze security of supply as well as price effects in the aftermath of the moratorium screening empirical data on installed power plant capacities, planned installations, potentials of demand side management and historical time series of electricity and carbon emission prices. They show that prices for electricity and carbon emissions rose only slightly after the moratorium and that under certain assumptions security of supply can be guaranteed in a scenario with the last nuclear power plant being shut-down between 2015 and 2020. In a further paper, Matthes et al. (2011a) investigate electricity imports and exports in Germany after the moratorium in view of a public debate concerning possible "nuclear power imports from France". Using empirical data on peak demand, exports and imports and nuclear power plant utilisation in France as well as an analysis of the merit order in Germany, they conclude that additional imports to Germany after the moratorium are not caused by a shortage of capacity and do not come from nuclear power plants in France. Both studies mentioned use empirical data covering a short timeframe in spring after the introduction of the moratorium – e.g. price effects during winter days are not covered by the analysis. Also, possible effects of a phase-out in the mid and long term on installed capacity are not considered.

Kunz et al. (2011) use a dispatch model which was calibrated to represent the network capacities in Central Europe in order to calculate the dispatch in three scenarios (Status quo, Moratorium, Phase-out) on a typical winter day. The analysis focuses on the short-term and does not take into account investment possibilities. The authors observe a rise in imports and a decline in exports combined with a rising electricity price in Germany in the moratorium and phase-out scenarios.

The German regulatory authority Bundesnetzagentur (BNetzA, 2011) focuses on network capacity aspects of security of supply. Several scenarios have been analyzed (using different analytical approaches) based on different assumptions concerning electricity generation from renewable energy sources (RES-E) and electricity demand. The analysis shows that a capacity problem may occur on winter days with little wind. The authors thus advocate network capacity extensions in order to cope with regional differences in demand and generation aggravated by a phase-out from nuclear power.

r2b (2011) apply a model based analysis, covering the timeframe from 2012 to 2020, to calculate a status quo scenario (based on German law before Fukushima) and a phase-out scenario (all nuclear power plants have to be shut-down until 2017). Based on several assumptions concerning RES-E share, fuel prices and electricity demand they observe a decline in net exports and a significant rise in carbon emission and electricity prices in case of a nuclear phase-out. The qualitative effects of this study are in line with the other studies mentioned here, but the magnitude of the price effects is strikingly different (i.e. much more pronounced).

Prognos (2011) analyse two scenario groups covering several moratorium and phase-out scenarios (varying in their shutdown schedule). In this analysis, which covers the timeframe until 2025, imports and exports are treated exogenously. The authors see a rise in electricity production from fossil driven power plants, in particular hard coal until 2020, as well as an increase in prices. They conclude that a phase-out is possible, but stress that investment stimulating incentives have to be investigated.

As we show in the following sections, the results of our analysis are generally in line with the above-mentioned studies, in particular concerning the effects on imports and exports and the rising electricity and CO_2 prices. However, we do observe a different magnitude of the effects which results from differences in methodology and focus. Contrary to (a part of) the before-mentioned studies we model both dispatch and investment decisions, thus including short term effects and long term effects until 2030. In addition, within the nuclear prolongation scenario, we allow for endogenous (cost minimizing) prolongation decisions of each nuclear power plant in Germany based on plant specific retrofit costs. The quantity of nuclear capacity in our scenario representing German law before Fukushima thus varies from other studies, since not all possible nuclear lifetime extensions are realized in an overall cost-minimizing approach, due to high retrofit costs (see section 5). Moreover, by a combined analysis of all carbon emitting sectors our analysis shows that the ambitious carbon emission reduction targets as defined in the coalition agreement for the 17$^{\text{th}}$ legislative period are reached in both scenarios.[1] Our analysis therefore describes a possible pathway to a low-carbon electricity system in Germany under an accelerated nuclear phase-out.

3. Methodical approach

Political intervention in electricity markets, like the one we analyze in this paper, may cause effects (e.g. increasing prices) that influence several sectors of an economy and may eventually feedback on electricity

[1] For more details on this aspect see Schlesinger et al. (2011).

markets (e.g. price elastic electricity demand). An analysis of the economic effects of an accelerated nuclear phase-out therefore requires a simultaneous analysis of all relevant sectors. Reasons are (short and long-term) price responsiveness of electricity consumers, differing CO_2-abatement costs between the sectors as well as the efficient allocation of scarce input factors, such as biomass, between the sectors.[2]

In our study, simulation models were used to analyze the effects in the specific sectors (Schlesinger et al. (2010) and Distekamp et al. (2004)). For the computations of the electricity and cogeneration system, a long-term investment and dispatch model for the European electricity and combined heat markets (DIME) is used.[3] DIME is a dynamic optimization model that calculates the cost-minimal solution to meet electricity demand in Europe. It is applied to simulate an hourly dispatch of conventional power plants leading to investment decisions regarding the supply side of the electricity sector. The objective function minimizes total discounted system costs.

Input parameters can be divided into three groups: demand side parameters, supply side parameters and political parameters. The demand met by conventional generation is called residual demand, which essentially is given by total demand minus RES-E generation.[4]

Important input parameters for the supply side include the costs of generation (investment costs, operation and maintenance costs, fuel prices), technical parameters of conventional generation technologies (including minimum load, net efficiency and ramp-up times) and the amount of conventional capacities already existing within a country. Cross-country electricity transmission is constrained by net transfer capacities (NTC) as exogenous model parameters. Political input parameters include decisions on nuclear policy or the different RES-E regimes in the European countries.

The timeframe of the model is from 2008 to 2030 in five-year steps. (The optimization extends until 2070 in order to derive consistent investment decisions after 2020.) The dispatch in each year is represented by three typical days per season considering load and renewable generation – each day consists of 24 hours. Important model outputs are electricity generation by technology and fuel, investment in power plants and long-run marginal costs of electricity generation.[5]

The interdependencies between the electricity sector and the rest of the economy are taken into account using an iterative approach. In order to find a consistent solution for the electricity and cogeneration system, variables are iterated between the models to estimate sectoral electricity demands (Schlesinger et al., 2010) and the DIME model. In DIME the demand for electricity and (cogenerated) heat are used as input

[2]For example, the transportation sector highly depends on liquid biomass if climate goals are to be achieved.
[3]See Bartels (2009), for applications see e.g. Paulus and Borggrefe (2010) or Nagl et al. (2011).
[4]Electricity generation from waste and small-scale CHP technologies are also treated exogenously.
[5]Marginal costs of electricity generation are estimated on the basis of the dual variables of the equilibrium conditions.

parameters. DIME results including district and process heat generation, the German import and export balance of electricity, and electricity prices are in turn used to model sectoral demand developments. This approach accounts for the interdependency between electricity prices and demand.

4. Assumptions for the electricity sector

The analysis focuses on different nuclear phase-out policies in Germany. Through the comparison of two scenarios, we analyze the effects of an accelerated nuclear phase-out (scenario B) versus a prolongation of lifetimes for nuclear plants according to German law before the Fukushima catastrophe (scenario A).[6] In scenario B all seven nuclear power plants commissioned before 1980 and the Krümmel plant are immediately mothballed. Six other nuclear plants have to be decommissioned between 2015 and 2020. The remaining three plants will have to be decommissioned before 2025.

Contrary, scenario A assumes, that lifetimes of plants commissioned before 1980, may be prolonged by eight years and the lifetimes of the remaining plants may be prolonged by additional 14 years.[7] This implies possible lifetimes up to 2036 for some plants.

Significant retrofit investments are obligatory for nuclear power plants if the lifetime is to be extended. These retrofit investment costs are specific to each power plant and vary between the two scenarios. Retrofit investment costs may hamper the profitability of certain plants and may hence lead to premature decommissions for economic reasons.

In more general terms, both scenarios are embedded in the energy policy framework as defined in the coalition agreement (between CDU, CSU and FDP) for the 17$^{\text{th}}$ legislative period. Most importantly this agreement features the target of a 40% greenhouse gas emissions reduction until 2020 in comparison to the emissions in 1990. The agreement furthermore emphasises the need of energy efficiency improvements and states that renewable energies should be expanded continuously in order to play the predominant role in the future energy mix. Regarding conventional power plants, the usage of carbon capture and storage technologies is encouraged.

4.1. Electricity demand and potential for cogeneration

It is assumed that substantial energy efficiency improvements take place in Germany, leading to a decreasing gross electricity demand in the period regarded. The increasing electricity consumption due to the gradual diffusion of electric mobility is overcompensated by substantial energy efficiency investments of both

[6] See Atomkonsens (2002).

[7] The prolongation times refer to applicable law (Atomkonsens, 2002) before the 2010 amendment to the Atomgesetz (Atomgesetz, 2010).

households and industries. European (net) electricity demand is assumed to further increase in the short run and to reach a peak in 2020 (4% increase compared to 2008). After 2020 European (net) electricity demand is assumed to decrease (2% increase compared to 2008).

Table 1: Net (gross) electricity demand and cogeneration potential in Germany in TWh

	2008	2015	2020	2025	2030
Electricity demand in TWh_{el}					
Scenario A	523.8 (614)	492.7 (574.5)	477.6 (551.4)	468.5 (537.9)	458.7 (516.4)
Scenario B	523.8 (614)	490.8 (571.8)	473.9 (547.7)	465.3 (534.1)	455.5 (514.9)
Heat potential of cogeneration in TWh_{th}					
Scenario A	332.7	320.5	309.5	295.6	281.9
Scenario B	332.7	320.5	309.5	295.6	281.9

German gross electricity demand is reduced by about 16% while net electricity demand is reduced by about 13% until 2030 compared to 2008 (Table 1).[8] The increasing share of RES-E in electricity generation reduces internal power consumption in the system. Furthermore, reduced domestic coal extraction lowers power losses in other conversion sectors. Consequently, gross electricity demand decreases more than net electricity demand. Both, the demand for district heating and process heat in industries decrease in the scenarios. Table 1 reports heating demand (process heat and district heating) which can be served either by combined heat and power (CHP) or pure heating plants. Again, the assumed energy efficiency improvements reduce heat demand in all sectors.

4.2. Fuel and CO_2-allowance prices

Fuel prices for power plants and CO_2 prices are based on international market prices and in the case of fuel prices, transportation costs to the power plants are included. The price path assumed for fuel and CO_2 is shown in Table 2. Prices for hard coal and natural gas are assumed to decrease in the mid term but to increase in the long run up to 3.0 €$_{2008}$/GJ and 7.2 €$_{2008}$/GJ, respectively. For domestic lignite we assume a constant price of 0.4 €$_{2008}$/GJ. The average price for biomass is assumed to increase up to 13.9 €$_{2008}$/GJ in 2030.

Total CO_2 emissions are driven by various factors such as RES-E feed-in, utilization of nuclear power, electricity demand and fossil fuel generation mix. Applied to our scenario framework, with RES-E feed-in held constant between the scenarios, CO_2 emissions vary between the scenarios because of different utilization rates of power plants and different assumptions concerning electricity demand. Because of the accelerated

[8] The development of electricity demand was modelled by Prognos AG using a bottom-up approach as described in Schlesinger et al. (2010).

shutdown of nuclear power plants in scenario B, total CO_2 emissions in scenario B are higher than in scenario A. This consequently leads to slightly higher CO_2 prices in the European ETS market (Table 2).

Table 2: Fuel costs in €$_{2008}$/GJ and CO_2 prices in €$_{2008}$/t CO_2

	2008	2015	2020	2025	2030
Coal	4.8	3.0	2.8	3.0	3.0
Lignite	0.4	0.4	0.4	0.4	0.4
Natural gas	7.0	5.6	6.4	6.8	7.2
Biomass	8.3	10.6	11.9	13.1	13.9
CO_2 price (scenario A)	22.0	17.5	22.5	30.1	39.5
CO_2 price (scenario B)	22.0	18.7	23.9	32.2	41.3

4.3. Technical and economic parameters for power plants

Table 3 depicts the retrofit costs for nuclear power plants based on data provided by the Federal Ministry for the Environment, Nature Conservation and Nuclear Safety (BMU). Due to the longer lifetime of nuclear power plants, retrofit costs are higher in scenario A.

Table 3: Retrofit costs for nuclear power plants for scenario A and B in €$_{2008}$/kW

	Scenario A	Scenario B
Biblis A	600	-
Neckarwestheim 1	600	-
Biblis B	600	-
Brunsbüttel	600	-
Isar 1	600	-
Unterweser	600	-
Philippsburg 1	600	-
Grafenrheinfeld	1,200	100
Krümmel	1,700	-
Philippsburg 2	1,600	600
Grohnde	1,600	600
Gundremmingen B	1,300	100
Gundremmingen C	1,400	600
Brokdorf	1,700	600
Isar 2	1,800	600
Neckarwestheim 2	2000	1,200
Emsland	1,800	600

Investment costs for conventional and renewable technologies are shown in Table 4. Several new or improved conventional technologies are assumed in this study: Coal ”innovative” - 4% higher net efficiency as state of the art power plants; lignite ”innovative” - novel drying process leads to a net efficiency of 48%; and CCS-technologies - available from 2025 with lower net efficiencies than technologies without CCS. Investment costs for renewable technologies, especially wind and solar are assumed to decrease due to learning curve effects until 2030.

Table 4: Development of investment costs for thermal power plants and renewables in $€_{2008}$/kW

	2015	2020	2025	2030
Lignite	1,850	1,850	1,850	1,850
Lignite (innovative)	1,950	1,950	1,950	1,950
Coal	1,300	1,300	1,300	1,300
Coal (innovative)	2,375	2,250	2,025	1,875
CCGT	950	950	950	950
OCGT	400	400	400	400
IGCC-CCS	-	-	2,363	2,039
CCGT-CCS	-	-	1,212	1,173
Coal-CCS	-	-	1,856	1,848
Coal-CCS (innovative)	-	-	2,806	2,423
Lignite-CCS	-	-	2,506	2,498
Wind onshore	1,080	1,030	1,005	985
Wind offshore	2,850	2,400	1,925	1,670
Photovoltaics	2,000	1,375	1,160	1,085
Geothermal	13,500	10,750	10,000	9,500
Biomass	2,400	2,300	2,250	2,200
Hydro	3,500	3,850	4,025	4,128

4.4. Development of RES-E in power generation

Due to the implemented feed-in-tariff system, RES-E capacities have been increased significantly in Germany in recent years. Since the introduction of the promotion system in 2000, the RES-E share of gross electricity consumption has increased from 6.4% to 16.8% in 2010. The development is mainly based on onshore wind turbines, additional biomass plants and especially in the last two years photovoltaics. The further development highly depends on the design of the feed-in tariff system, technological innovation and the technical and economic potential. Table 5 shows the assumed RES-E capacities and the assumed generation by RES-E capacities until 2030.

Table 5: Development of RES-E generation in TWh and (in parentheses) RES-E capacities in GW

	2008	2015	2020	2025	2030
Hydro	20.3 (5.2)	19.0 (5.2)	20.0 (5.2)	24.0 (5.4)	24.0 (5.4)
Wind onshore	40.4 (23.9)	63.9 (33.6)	69.4 (34.0)	75.8 (35.8)	77.4 (35.8)
Wind offshore	0.0 (0.0)	9.1 (3.0)	32.0 (9.4)	44.4 (12.0)	63.5 (16.7)
Photovoltaics	4.4 (6.0)	26.2 (29.1)	32.0 (33.3)	36.0 (37.5)	41.4 (43.1)
Biomass & Waste	27.2 (5.4)	42.1 (7.8)	44.4 (8.2)	49.4 (9.0)	49.5 (9.0)
Geothermal	0.0 (0.0)	0.4 (0.1)	0.9 (0.1)	1.7 (0.2)	2.0 (0.3)
Total	92.3 (40.5)	160.7 (78.8)	198.7 (90.2)	231.3 (99.9)	257.7 (110.3)

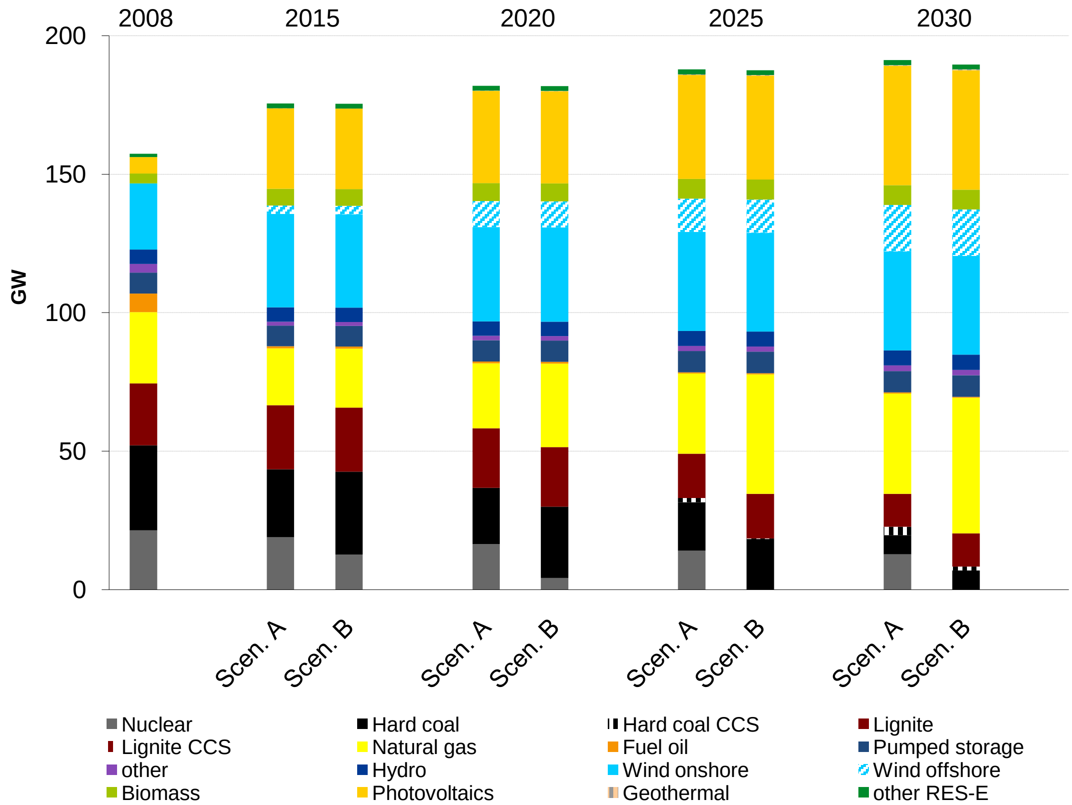
The strong increase of total generation by RES-E capacities (258 TWh in 2030) is mainly driven by additional wind turbines (on- and offshore), photovoltaics and biomass plants. Due to the limited potential of hydro plants in Germany only a small increase in generation is assumed.

5. Scenario results

5.1. Power plant fleet

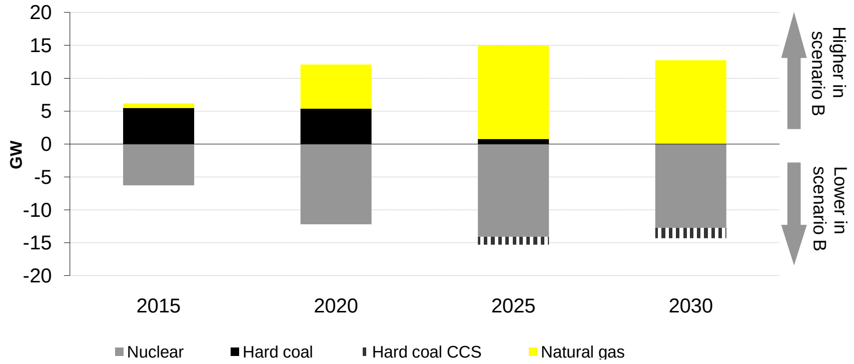
Due to the mothballing of the seven oldest nuclear power plants and Krümmel (together 8.7 GW) in scenario B, total installed nuclear capacity in Germany is reduced to 12.7 GW in 2015 (Figure 1). Further decommissioning of nuclear power plants between 2015 and 2020 reduce installed nuclear capacity to 4.3 GW in 2020. Those remaining plants are mothballed before 2025.

Figure 1: Installed capacity in scenario A (prolongation) and B (nuclear phase-out), in GW



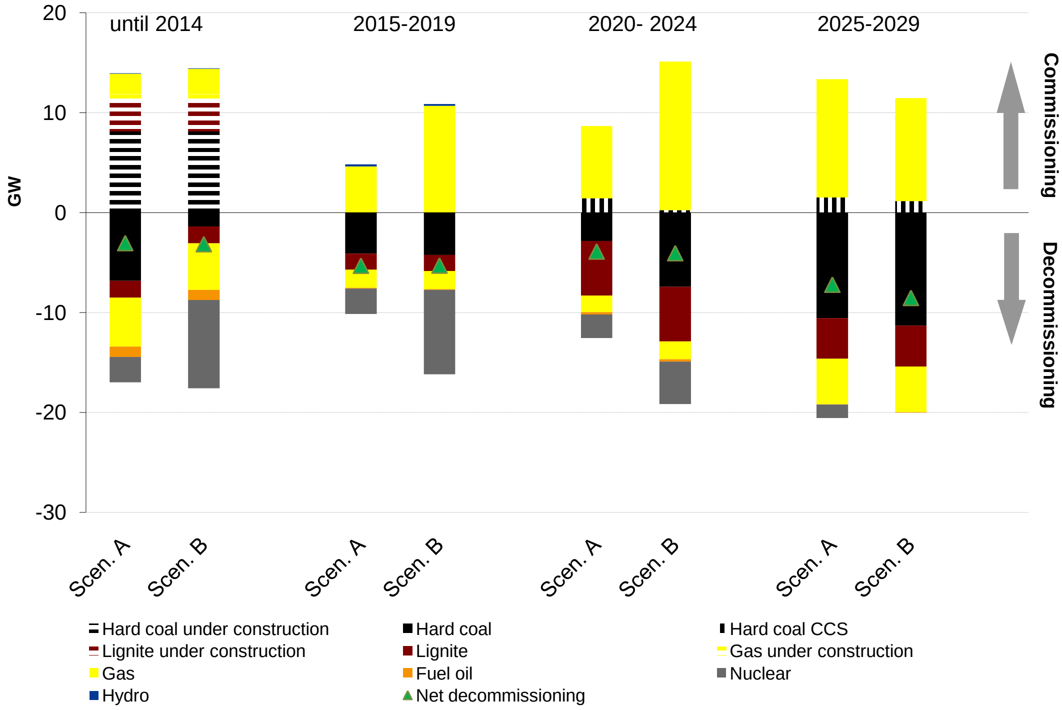
In contrast, 19 GW of nuclear capacity are still installed in 2015 and 16.4 GW in 2020 in scenario A. The difference of 6.4 GW of nuclear capacity between the two scenarios in 2015 is less than the maximum possible difference of 8.7 GW. This is due to the higher retrofit costs for nuclear power plants in scenario A, thus making the prolongation of 2.3 GW unprofitable. The difference in installed nuclear capacity increases over time between the scenarios. In 2020 a difference of 12.1 GW occurs while in 2025 the maximum difference of 14.1 GW is reached. Nuclear power plants are gradually mothballed in scenario A with the last power plants going offline between 2035 and 2040.

Figure 2: Differences in installed capacities between scenario B (nuclear phase-out) and A (prolongation), in GW



The decommissioning of nuclear plants causes an additional need for conventional generation capacity in the German electricity market which is satisfied in a cost-minimal way (Figure 2). Firstly, economic lifetimes of 5.4 GW of old coal-fired plants are extended in scenario B. Secondly, in addition to the power plants currently under construction, significant new-built gas-fired generation capacities come online (Figure 3). The investment dynamics vary between the two scenarios: Due to the additional need for capacity between 2015 und 2025 in scenario B, caused by the fast nuclear phase-out, commissioning of other power plants is accelerated. This mainly affects (open cycle) gas turbines which have relatively short lead times. Yet, under the assumption of a decreasing electricity demand in Germany, total conventional capacity is also decreasing while renewable capacity is increasing over time. Additional RES-E capacity mainly comprises wind power onshore (+11.9 GW until 2030), offshore (+16.7 GW) and photovoltaics (+37.1 GW). Apart from plants currently under construction (+11.5 GW fossil-fired plants, among them 8.7 GW hard coal-based), no additional hard coal or lignite-fired capacities without CCS technology are installed in the scenarios.

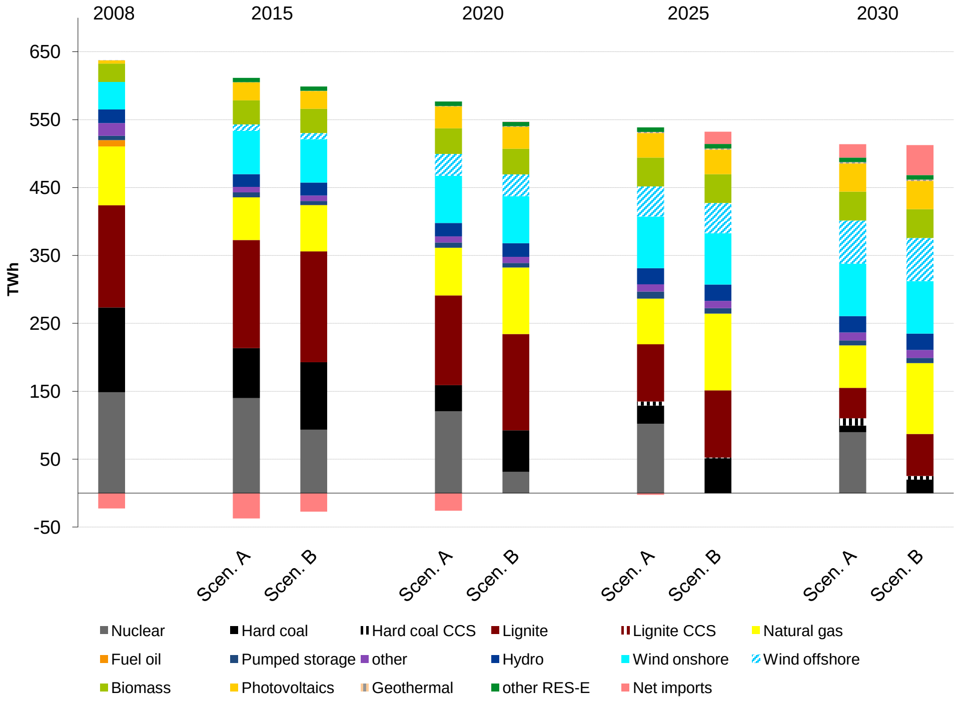
Figure 3: Conventional capacity commissioning and decommissioning in scenario A (prolongation) and B (nuclear phase-out), in GW



5.2. Gross electricity and CHP-heat generation

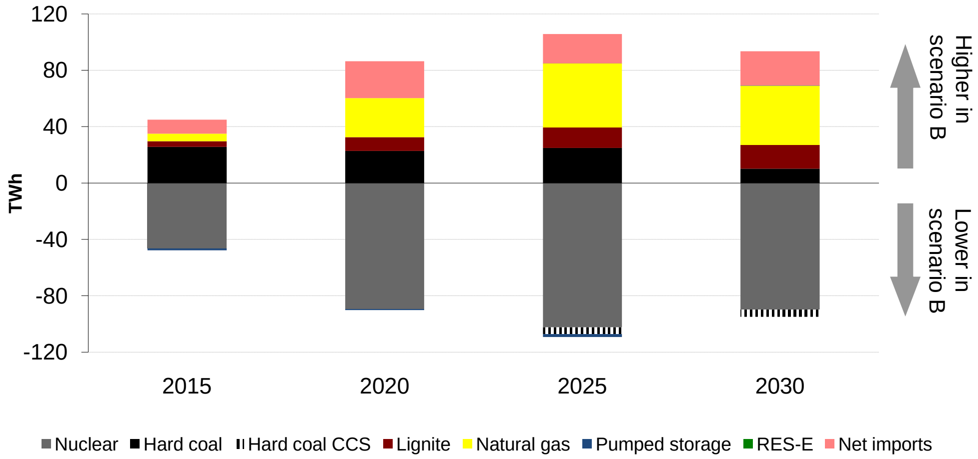
Nuclear power generation in scenario B is in 2015 46.4 TWh lower and in 2020 89.4 TWh lower than in scenario A as a consequence of the fast phase-out (Figure 4). The maximum difference in nuclear power generation occurs in 2025 between the two scenarios. In this year all nuclear plants are decommissioned in scenario B while the remaining nuclear plants generate 102.4 TWh of electricity in scenario A. Nuclear power generation decreases to 89.7 TWh in scenario A in 2030 due to the mothballing of some older plants.

Figure 4: Gross electricity generation in scenario A (prolongation) and B (nuclear phase-out), in TWh



The reduced nuclear power generation in scenario B compared to scenario A is mainly compensated by three effects (Figure 5). Firstly, generation from existing fossil-fuel fired power stations increases. This effect is highlighted by the increased generation from hard coal-fired plants in scenario B compared to scenario A (2015: +25.6 TWh; 2020: +22.8 TWh; 2025: +19.9 TWh; 2030: +4.9 TWh). Secondly, as a consequence of the decommissioning of nuclear plants, additional conventional capacity is installed and utilised. This effect mainly occurs after 2020. In this period additional gas-fired capacities come online and are utilised as long as the clean spark spread (gross profit margin of gas-fired generation taking into account CO_2 costs) is favourable for these plants. Finally, European power trade is influenced. In 2015 Germany is a net electricity exporter in both scenarios. In contrast, Germany becomes a net importer in 2020 due to the fast nuclear phase-out while Germany remains a net exporter in scenario A. In the long run, Germany becomes a net importer of electricity in both scenarios, yet, net imports are higher in scenario B. These effects are a consequence of higher generation from coal and gas-fired plants in Germany due to the fast phase-out which raises marginal costs of generation and hence increases imports and decreases exports. Generally, the direction of international power flows is influenced by the fact that (by assumption) electricity demand is increasing in the rest of Europe while German electricity demand is decreasing. This development is paralleled by an expansion on the supply side. While there are significant fossil generation capacities currently under construction and coming online within the next few years (see Figure 3 above), the increase on the supply side is mainly due to RES-E capacity development which receives strong political support.

Figure 5: Differences in gross electricity generation between scenario B (nuclear phase-out) and A (prolongation), in TWh



Specifically, net imports are 9.9 TWh higher under a fast nuclear phase-out policy in 2015 (Table 6). This is mainly caused by a reduction of power exports from Germany to the Netherlands, Poland and Switzerland while imports increase by 2.7 TWh. In 2020 net imports are 26.3 TWh higher in scenario B. Most of the additional imports are provided by French and Czech generators. In the long run differences in net imports (2025: 20.6 TWh; 2030: 24.2 TWh) are mainly caused by additional imports coming from Poland and the Netherlands.

Table 6: Differences in exports, imports and net imports between scenario B (nuclear phase-out) and A (prolongation), in TWh

	2015	2020	2025	2030
Imports	2.7	5.0	11.3	11.0
Exports	-7.2	-21.3	-9.3	-13.3
Net imports	9.9	26.3	20.6	24.2

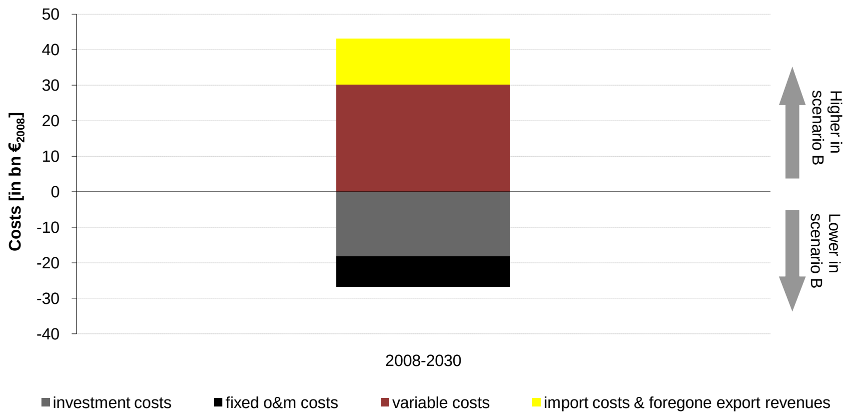
The share of combined heat and power (CHP) generation increases in both scenarios. However, CHP-heat generation is higher under a fast nuclear phase-out regime in comparison to a prolongation policy. This is due to the commissioning of gas-fired power plants with CHP-technology in response to capacity needs caused by the fast phase-out. These plants are utilised to compensate for the reduced nuclear power generation in scenario B and thus are able to efficiently serve heat demand in industry and district heating.

5.3. *Costs of electricity generation and electricity prices*

Comparison of scenario B (nuclear phase-out) to A (prolongation) shows that overall generation cost is increased by the phase-out.[9,10] Accumulating the additional generation costs of scenario B relative to scenario A until 2030, gives a sum of about 16.4 bn €$_{2008}$. The present value of these costs using a discount rate of 3% (10%) amounts to 10.5 bn €$_{2008}$ (4 bn €$_{2008}$).

Taking a more detailed look at the different cost categories, we find that they follow opposing trends, as shown in Figure 6.

Figure 6: Accumulated generation cost differences differentiated by cost categories between scenario B (nuclear phase-out) and A (prolongation), in bn €$_{2008}$



On the one hand, we identify reductions in investment costs as well as in fixed operating and maintenance (O&M) costs in scenario B relative to scenario A. These reductions reflect avoided retrofitting and O&M costs associated with the nuclear power plants, which have been shut down in scenario B. Note that the avoided retrofitting costs for nuclear power plants in scenario B outweigh additional investment costs arising from (additional) capacity commissioning, hence resulting in lower investment costs in scenario B than in scenario A. Adding up the aforementioned cost reductions until 2030, gives an amount of 16.8 bn €$_{2008}$.

On the other hand, as a result of the nuclear phase-out in Germany we find an increase in variable generation costs including the costs associated with the cross-border electricity exchange (costs of additional electricity imports and foregone revenues of exports). This may be explained by the fact that nuclear power

[9]The additional generation costs considered in this section, correspond to the extra costs of conventional electricity generation. This is due to the fact that the costs of RES are assumed to be the same in both scenarios.

[10]There remain risks with every technology - even when adhering to all mandatory security standards -, which in general need to be treated as external costs. As of now, there has not been reached a consensus regarding the correct methodology to quantify those external costs. Therefore, these costs are not taken into consideration in this paper. See the research projects NEEDS (`www.needs-project.org`) and EXTERN-E of the European Commission (`www.externe.info`) for a discussion about external costs.

plants, which were decommissioned because of the moratorium, had to be replaced by generation capacities with higher variable costs, like gas- or coal-fueled power plants. Furthermore, this substitution leads to additional CO_2-emissions in Germany, which in turn causes a rise of the CO_2-price, thus increasing the variable costs of all fossil-fueled power plants. Overall, generation cost increasing effects (about 43.2 bn €$_{2008}$) exceed cost reductions, thus leading to additional generation costs in scenario B which amount to 16.4 bn €$_{2008}$ until 2030.

The phase-out of nuclear power plants leads to higher electricity prices for end-consumers. The impact depends on the consumer type. Table 7 shows the wholesale price, additional costs for renewable energies due to the feed-in tariff system and the resulting end-consumer prices including taxes and grid tariffs.

Table 7: Electricity prices in scenario A (prolongation) and B (nuclear phase-out), in €$_{2008}$/MWh

		Scenario A				Scenario B			
	2008	2015	2020	2025	2030	2015	2020	2025	2030
Wholesale prices	65	39	40	45	46	43	47	54	55
Additional costs for RES-E	12	34	40	38	34	33	37	34	30
End consumer prices									
Households	217	212	221	227	225	216	226	232	230
Trade and commerce	127	143	151	155	154	146	155	160	158
Industries	96	99	107	111	110	102	111	116	114
Electricity intensive industry	71	45	46	52	54	49	53	61	63

Due to higher fuel and CO_2 costs, the wholesale electricity prices increase in both scenarios until 2030. In the short and medium term (until 2030), the decreasing electricity demand, the development of RES-E capacities and the existing and currently-under-construction power plants lead to a comfortable capacity situation in Germany. This leads to a lower wholesale electricity price compared to 2010. In the long run, the wholesale electricity price covers the full costs of conventional power plants but not the costs of RES-E capacities.

The additional costs of RES-E are calculated by extrapolation of the current procedure of sharing these costs. Hence, the additional costs of RES-E sensitively depend on the development of the wholesale electricity price. Due to the strong RES-E expansion with generation costs that exceed wholesale prices, the additional costs increase until 2020. After 2020 the assumed investment costs of RES-E are significantly lower than today and the additional costs for RES-E decrease. The differences in additional costs for RES-E capacities between scenario A and B are due to the different wholesale prices.

The differences of electricity prices for end-consumers between years and scenarios mainly result from the differences in wholesale prices and additional RES-E costs. End-consumer prices increase until 2025/2030.

The electricity price for the electricity intensive industry highly depends on the wholesale electricity price because of exceptional rules considering taxes and additional RES-E costs. The faster phase-out of nuclear power in scenario A leads to a higher electricity price for the energy intensive industry. For the other consumer groups the lower wholesale prices are partly compensated by the burden of the additional costs for RES-E. Therefore the differences between the scenarios are considerably smaller. The burden of a faster phase-out of nuclear power for end-consumers can be determined by the additional expenses for electricity, i.e. the difference in electricity prices weighted by the electricity consumption.

Figure 7: Difference of accumulated financial burden for end-consumers between scenario B (nuclear phase-out) and A (prolongation), in bn €$_{2008}$

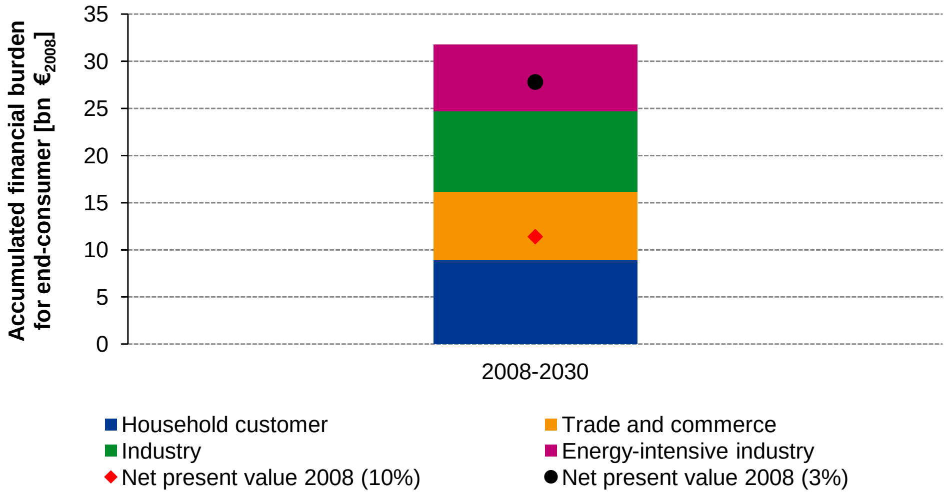


Figure 7 shows the accumulated financial burden for the different end-consumer groups in bn €$_{2008}$ until 2030. Due to higher electricity prices, the faster phase-out of nuclear power leads to an additional accumulated financial burden for all end-consumers of about 32 bn €$_{2008}$ until 2030 (not discounted). The net present value amounts to 27.8 bn €$_{2008}$ (3% discount rate) or 11.4 bn €$_{2008}$ (10% discount rate).

6. Concluding remarks

This paper presented a model-based analysis of two nuclear phase-out energy policy scenarios and their implications for the German electricity market. The analysis shows that the electricity generation sector can cope with an accelerated phase-out. New-built gas-fired capacities, lifetime extensions of existing installations and an increasing share of RES-E substitute the mothballed nuclear plants. Electricity imports increase and exports decrease while domestic generation from fossil-fuelled plants increases during the analysed period in the accelerated phase-out scenario.

Clearly, the analysis shows that an accelerated nuclear phase-out increases both costs and prices of electricity in Germany. Yet, additional costs in the power system are dampened in the case of an accelerated phase-out due to the avoidance of high retrofit costs in the prolongation scenario. Although prices increase for all consumer groups, price increases are more pronounced for industrial consumers than for households. Increasing wholesale electricity prices decrease additional costs for RES-E support and thus partially absorb the price effect for non-industrial consumers.[11]

However, the magnitude of the effects presented in this paper is driven by two very challenging political assumptions: Firstly, the realisation of a 36% RES-E share in 2020. Secondly, energy efficiency improvements and hence substantial electricity demand reductions.

Failure in either of the two will result in additional need for investments in conventional power plants in Germany, additional electricity imports (lower exports) and a higher utilisation rate of high-cost power plants. Generally, these drivers may increase prices, costs and greenhouse gas emissions in a given system. Therefore, to organise the nuclear phase-out both economically and environmentally justifiable, structural transformations on the demand and the supply side are crucial.

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[11] Industrial consumers are widely exempted from sharing the additional costs of German RES-E support mechanisms.

ABOUT EWI

EWI is a so called An-Institute annexed to the University of Cologne. The character of such an institute is determined by a complete freedom of research and teaching and it is solely bound to scientific principles. The EWI is supported by the University of Cologne as well as by a benefactors society whose members are of more than forty organizations, federations and companies. The EWI receives financial means and material support on the part of various sides, among others from the German Federal State North Rhine-Westphalia, from the University of Cologne as well as – with less than half of the budget – from the energy companies E.ON and RWE. These funds are granted to the institute EWI for the period from 2009 to 2013 without any further stipulations. Additional funds are generated through research projects and expert reports. The support by E.ON, RWE and the state of North Rhine-Westphalia, which for a start has been fixed for the period of five years, amounts to twelve Million Euros and was arranged on 11th September, 2008 in a framework agreement with the University of Cologne and the benefactors society. In this agreement, the secured independence and the scientific autonomy of the institute plays a crucial part. The agreement guarantees the primacy of the public authorities and in particular of the scientists active at the EWI, regarding the disposition of funds. This special promotion serves the purpose of increasing scientific quality as well as enhancing internationalization of the institute. The funding by the state of North Rhine-Westphalia, E.ON and RWE is being conducted in an entirely transparent manner.