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Results

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Impact of the German nuclear phase-out
- model results

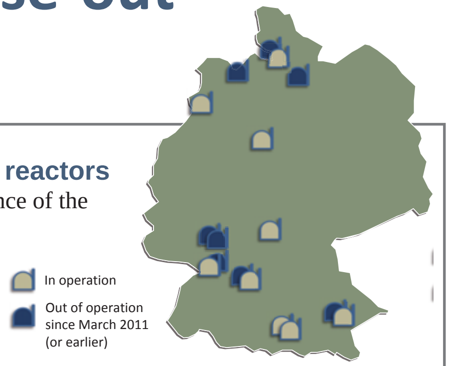
This study applies techno-economic energy systems modeling to analyze consequences of the recent German governmental decision on the future of nuclear power in Germany, i.e. to phase out all 17 reactors by 2023 and the immediate shutting down of 8 of the 17 today operational nuclear reactors. The analysis considers both short-term and the long-term perspectives.

Our analysis indicate that as a consequence of taking eight reactors out of operation (corresponding to 60 TWh reduction in supply), the increase in short-run marginal electricity cost generally remains below 4 €/MWh in the German electricity market during a calendar year. At certain points in time, e.g. during certain peak-load situations, the marginal electricity cost increase may, however, become significantly larger. Unbundled and interconnected electricity markets across Europe lead to cost increases also in Germany's neighboring countries. On the other hand, such cost increases become less significant outside Germany. In the Nordic market, the corresponding price increase rarely exceeds 3 €/MWh during a year compared to a case where all 17 reactors are in operation. The electricity production in the eight reactors is mainly replaced by gas and coal fired power as well as by an annual increase in German net electricity import of approximately 20 TWh.

Compared to a reference case where all 17 reactors remain in operation beyond 2030 (through lifetime extensions), the phasing out by 2023 implies that Germany moves from a significant net exporter of electricity in the long run to instead become a net importer of considerable size. This assumes, however, that no sudden and/or significant capacity deficits occur in Germany's neighboring countries.

German nuclear reactors

As a direct consequence of the Fukushima nuclear reactor accident in Japan, the German government agreed in June 2011 on a decision to finalize a complete nuclear phase out by the end of 2022. Furthermore, the eight of the today 17 operational nuclear reactors that were closed down as an immediate response to the Fukushima accident in March are not to be brought back on line again. These eight reactors include the seven oldest facilities (commissioned prior to 1981) and one additional unit that has been out of operation since 2009 (the Krümmel plant commissioned in 1983), together corresponding to about 8.5 GW. The aggregated capacity of the remaining 9 reactors is about 12 GW. The figure shows the location of the German nuclear reactors.



The location of the 17 German nuclear reactors, divided into those in operation (9) and those out of operation (8).

Impact on short-run marginal electricity generation costs

Figure 1 (left panel) presents the increase in short-run marginal electricity generation cost in Germany, i.e. the difference from comparing the reference case including all 17 German nuclear reactors to the case where the eight reactors are excluded. In the figure, the increase in marginal cost during 730 days and nights, i.e. a whole year (model year 2010), is depicted according to decreasing order. It can be seen that the increase in marginal cost typically stays below 5 €/MWh. More specifically, more than 80 percent of the model year the increase in marginal electricity generation cost remains below 4 €/MWh. However, at certain points in time it may reach 10 €/MWh (and, occasionally, higher than that). This increase in generation cost becomes less significant in the neighboring countries due to interconnector bottlenecks. In the Nordic market, represented here by Denmark, the increase in generation cost is below 3 €/MWh during 90 percent of the modeled year (see Figure 1 to the right). When looking at Sweden, model results indicate that this cost increase is somewhat lower.

Limited impact on long-run marginal costs

Even though all nuclear reactors in Germany are taken out of operation by 2023, the model-estimated increase in long-run marginal costs of electricity is relatively small, 2-3 €/MWh in Germany after 2020. One of the explanations is that CCS sets the long-term marginal cost for new power post 2020. A withdrawal of other capacity, in this case nuclear, is, thus, replaced by additional CCS implying a limited impact on the long-run marginal costs of electricity. Prior to 2020, the nuclear phase-out is, as indicated above, mainly covered by an increase in gas power (and a reduction in coal power in order to meet the given CO_2-emission reduction target). In a short-to-mid term

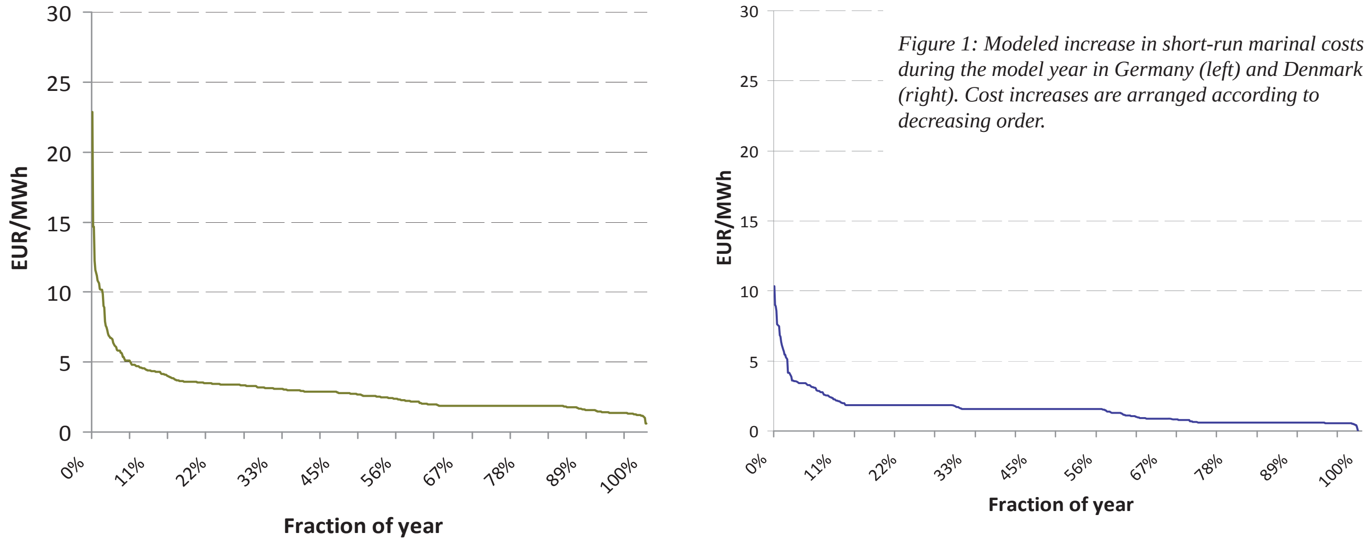


Figure 1: Modeled increase in short-run marinal costs during the model year in Germany (left) and Denmark (right). Cost increases are arranged according to decreasing order.

perspective there is considerate "idle" capacity of gas power in the EU-27 that may supply a large part of the gradually phased-out nuclear capacity in Germany. Furthermore, new interconnectors may be built endogenously in the model as a response to the German nuclear phase-out, which further integrates the European electricity markets. Thereby, the increase in German long-run marginal cost of electricity is spread across Europe and becomes "diluted". In the context of an integrated European electricity market, the total German operational nuclear generation capacity is relatively small, roughly five percent of the total European electricity generation.

The corresponding increase in marginal CO_2-reduction cost, a proxy for the price of European tradable emission rights, obtained in the model runs is approximately 1-3 €/t CO_2. Estimates on wholesale-electricity price increases due to a complete nuclear phase-out differ significantly between different studies. For instance, the Umweltbundesamt (2011) estimates the price increase to around 6-8 €/MWh for electricity and 2-4 €/t for the EU ETS while R2B Energy consulting GmbH (2011) makes corresponding estimates at around 11-16 €/MWh electricity and 5-10 €/t CO_2. Both these studies assume a completed nuclear phase out in 2017 which is a tougher goal than 2023 as assumed here. Thus, if the same phase out year would have been applied in the present analysis, this should generate somewhat higher price increases, all else being identical.

Future impact on the German electricity-trade balance

The nuclear phase out results in a significant change in the German electricity-trade balance with its neighbors. In Figure 2, net electricity import to Germany is shown for both cases investigated, the reference case and the "Rapid phase-out" case. In the reference case, Germany becomes a significant net exporter, typically 25 TWh around 2020-2025. This is due to a continued expansion in the field of renewables, investments (and comparative advantages) in CCS schemes and, not the least, the full utilization of the 17 nuclear reactors. At the same time, domestic demand is stagnating. In the "Rapid phase-out" case, on the other hand, Germany instead becomes a significant net importer of electricity, typically 20 TWh around 2020-2025. Thus, the short-fall of around 150 TWh of domestic production is met by an almost 50 TWh increase in German net import. The rest is supplied domestically.

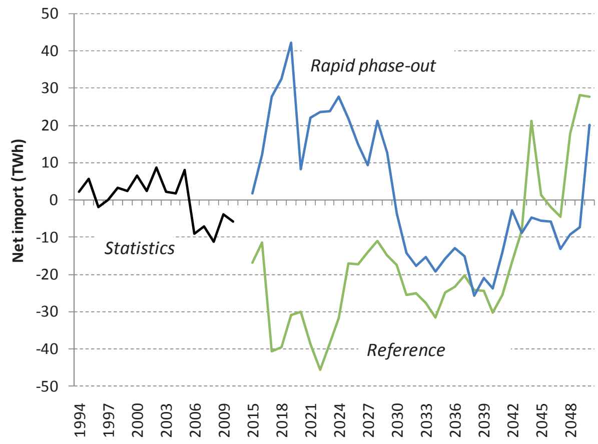


Figure 2: Long-run impact on German net electricity import (trade with Switzerland excluded) as obtained from the modeling in this work.

Final remarks

The analysis presented here makes a number of important assumptions which may underestimate the impact of the German nuclear phase out. One of these important considerations is that CCS becomes commercially available from 2020 and onwards. Thereby, nuclear baseload power may be replaced by another means of generating low-emitting baseload power. If CCS fails in becoming commercially available, or is substantially delayed, other types of baseload power must be used, e.g. conventional fossil power which most probably would lead to a more significant impact on EU ETS prices than estimated here. Furthermore, the model approach used here permits unlimited interconnector investments. Thus, the impact on the German electricity market becomes geographically spread and diluted. Limiting the analysis to existing interconnectors is likely to increase the impact in the German electricity market (and probably reduce impact on neighboring markets) compared to what has been reported here. A supplementary model run indicates that such limitations (new interconnectors and a later commercialization of CCS) have an impact especially on the marginal CO_2-reduction cost. In such a case, a cost increase of around 7 EUR/t was obtained as compared to the 1-3 EUR/t in the reference case. Accordingly, the marginal electricity cost increase was roughly one EUR/MWh above the outcome in the reference case.

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