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Power System Transformation toward Renewables:

Investment Scenarios for Germany

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Abstract

We analyze distinctive investment scenarios for the integration of fluctuating renewables in the German power system. Using a combined model for dispatch, transmission, and investment, three different investment options are considered, including gas-fired power plants, pumped hydro storage, and transmission lines. We find that geographically optimized power plant investments dominate in the reference scenarios for 2024 and 2034. In scenarios with decreased renewable curtailment, storage and transmission requirements significantly increase. In an alternative scenario with larger investments into storage, system costs are only slightly higher compared to the reference; thus, considering potential system values of pumped hydro storage facilities that are not included in the optimization, a moderate expansion of storage capacities appears to be a no-regret strategy from a system perspective. Additional transmission and storage investments may not only foster renewable integration, but also increase the utilization of emission-intensive plants. A comparison of results for 2024 and 2034 indicates that this is only a temporary effect. In the long run, infrastructure investments gain importance in the context of an ongoing energy transition from coal to renewables. Because of long lead times, planning and administrative procedures for large-scale projects should start early.

Keywords: German energy transformation, integrated planning, renewable integration, transmission, storage.

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1 Introduction

Germany is experiencing substantial growth in renewable energy. According to the Federal German Energy Concept, which is a cornerstone of Germany's *Energiewende*, renewables should account for at least 35% of gross power demand supplied by 2020, 50% by 2030 and 80% by 2050 (BMWi and BMU, 2010). Due to limited potentials of hydro power and biomass in Germany, this implies substantial growth of renewable electricity generation from wind and solar power. These sources are characterized by fluctuating feed-in patterns, an uneven geographical distribution of potentials, and a low capacity credit. Supply from wind and solar power has to be balanced with demand at all network nodes at all times. This poses challenges for the overall power system. Several strategies are under discussion, including flexible thermal power plants, power storage, and transmission grid expansion (Denholm and Hand, 2011; NREL, 2012).

The requirements of such investments are studied for different countries, but largely focus on individual options and rarely analyze the interactions of combined implementations. Sioshansi et al. (2012) discuss technical issues as well as policy-related barriers to actual storage deployment in power markets. Pérez-Arriaga and Batlle (2012) provide a general review of the challenges of integrating fluctuating renewables into power systems and identify necessary regulatory adjustments. While generation and transmission capacity expansion were centrally coordinated in the formerly vertically integrated industry, decisions are now made by multiple agents driven by market forces. Van der Weijde and Hobbs (2012) propose a two-stage stochastic optimization model for network planning, which they apply to Great Britain. They show that stochastic approaches may enable lower-cost planning decisions than deterministic methods do when considering uncertainty. Munoz et al. (2012) build upon this approach and apply an extended model, which also respects Kirchhoff's voltage law, to a stylized Californian system. Denholm and Hand (2011) simulate different scenarios with high shares of variable renewables in the Texas power system. For very high renewable penetrations, substantial capacities of both daily storage and demand-side management are required in order to avoid excessive curtailment. The analysis, however, excludes transmission constraints.

EWI and energynautics (2011) carry out a long-term study on the European power system, iterating a dynamic power plant investment and dispatch optimization model with a transmission investment model described by Fürsch et al. (2013). For example, they find that transmission upgrades bring benefits by substituting for costly storage investments. Nagl et al. (2013) determine European power plant mixes for different shares of renewables, applying a dynamic stochastic optimization model. The stochastic approach results in higher overall system costs compared to a deterministic model, such as the one used in this analysis. While stochastic models have distinctive advantages, their temporal and spatial resolution has to be much lower compared to the one presented in this paper in order to ensure solvability. In addition, internal transmission grids are rarely modeled explicitly, instead approximated by assumed net transfer capacities or aggregated transmission systems between regions.

For the specific German situation, there are several policy-oriented studies on infrastructure requirements for renewable integration. Dietrich et al. (2010) optimize the location of power plant investments in the German system with a fixed transmission network on a nodal level. Weigt et al. (2010) analyze wind power integration in Germany in 2015 with a network and dispatch model that neglects investments into power plants and storage. They find that high-voltage direct current lines as connections to major load centers in Western and Southern Germany are promising for wind integration. In a study commissioned by the German government, Prognos et al. (2010) simulate the future German power plant fleet, using a

European dispatch and investment model. The German transmission network, however, is not considered in the analysis. In contrast, the Grid Development Plan (NEP)[1] focuses on expansion requirements of the German transmission system. This plan, which is drafted on a yearly basis by German transmission system operators for a time horizon of 10 and 20 years, is based on a European market dispatch model, the results of which feed into a technical transmission model (50Hertz et al., 2013). Investments into power plants and storage, however, are not determined endogenously, but enter as exogenous parameters into the dispatch model.

We contribute to the literature by carrying out a techno-economic model analysis to determine investment scenarios for a power system with increasing shares of renewables. Investments into thermal power plants, pumped hydro storage, and the transmission grid are optimized simultaneously from the perspective of a central planner. As for the spatial resolution, we model the German high-voltage transmission network on a nodal level. We look at the year 2024, in which the remaining nuclear capacity in Germany will be completely phased out, and also at 2034, which represents a longer-term system transformation toward fluctuating renewables. We base our calculations on scenarios of the German NEP but do not primarily aim to confirm or disconfirm its outcomes. Rather, we are interested in the intricate interaction of investments into power plants, storage, and transmission. Although the modeling exercise reflects the specific German situation, both our approach and the general

[1] The abbreviation NEP stands for the German name: *Netzentwicklungsplan*.

findings are also relevant for other countries with thermal power plant fleets that shift toward fluctuating renewables.

2 Methodology

We use an integrated optimization model[2] for dispatch, transmission, and investments that includes a nodal disaggregation of the high-voltage transmission network and applies the “DC load flow” approach (Schweppe et al., 1988; Leuthold et al., 2012). Endogenous investments in generation, storage, and transmission infrastructure are characterized by integer variables. The model decides simultaneously on all investment option considering endogenously the tradeoffs between them. The objective value is total system costs, which consist of annualized fixed costs for new investments and variable generation costs (fuel and CO_2) of existing and new conventional power plants, scaled to one year. The model thus determines an investment mix that minimizes overall system costs for one static year.

The model includes capacity constraints for the generation of conventional power plants and for hourly renewable generation. Operation of pumped hydro storage plants faces constraints on the generation and pumping capacity, the upper limit of the storage level, and an inter-temporal storage level equation. Electricity flows are constrained by the maximum thermal line rating and their distribution in the network approximated by the “DC load flow” linearization. Additional new high-voltage DC lines are modelled as point-to-point transport flows. An energy balance ensures that generation of existing and new power plants together

[2] The full model formulation is in Egerer and Schill (2014).

with the network inflows minus network outflows is equal to (inelastic) demand in every node at every hour.

In order to ensure solvability of the model, we make some simplifying assumptions. First, we neglect ramping constraints of thermal power plants, and abstract from restrictions related to the combined provision of heat and power. Accordingly, the utilization of flexible generators and pumped hydro storage may be underestimated, whereas generation of inflexible base-load power plants is overrated. In turn, the optimal level of investments in flexible assets such as gas-fired power plants and – in particular – pumped hydro storage may be underestimated in our model. We also disregard the provision of reserves and other ancillary services, which should have a similar effect. Furthermore, the topology of the AC network is fixed to 2012, such that no new lines between previously unconnected nodes are possible. However, all existing AC connections may be expanded. Likewise, the physical flow distribution on existing connections is fixed to the initial flow pattern in the topology in order to prevent non-convexity. We also disregard exchange with neighboring countries and accordingly assume fully domestic balancing of supply and demand. We thus abstract from existing low-cost renewable integration potentials in neighboring countries. This should in general lead to an overestimation of domestic infrastructure requirements, especially regarding power plants and storage. Nonetheless, the domestic perspective chosen here is highly relevant to German policy makers, as the *Energiewende* is mainly carried out as a national project.[3]

[3] A more general disclaimer refers to optimality gaps of mixed-integer optimization models. In our application, relative optimality gaps are always below 1% but vary between scenarios. The corresponding absolute gaps are

3 Input Data and Scenarios

The model is applied to different scenarios for 2024 and 2034, corresponding to the planning horizon of the German NEP 2014. Because of numerical restrictions, it is impossible to model all subsequent hours of the respective year. Instead, we consider every second hour of four representative weeks covering all seasons, including the peak load hour.[4] Exogenous assumptions on generation capacities, fuel prices, and power demand are derived from the NEP 2014 scenario framework. The NEP is drafted on a yearly basis by the German transmission system operators in a multistage process. After a series of public consultation, the German regulator approves a final version of the NEP, which is translated into federal legislation. We draw on the "scenario framework" for the NEP 2014 (50Hertz et al., 2013; BNetzA, 2013), more specifically on the medium scenarios B 2024 and B 2034. Table 1 depicts the development of generation capacities in these scenarios compared to the reference year of 2012. Nuclear power is already phased out completely by 2022;[5] lignite and oil capacities are lower in 2024, while hard coal capacity only starts decreasing after 2024 due to the construction of several hard coal power plants that will come online between 2012 and 2024. The plan foresees additional natural gas and pumped hydro storage capacities in B 2024

often in the same order of magnitude as infrastructure investments into single power plant blocks, storage facilities, or transmission lines. Accordingly, we cannot make definitive statements about the advantageousness or disadvantageousness of individual power plants, storage facilities, or transmission lines. Readers should focus on general insights of the analysis, not on the specific numbers.

[4] Assessing the effects of this simplification on model results is challenging. Extreme situations of demand and renewable feed-in may be slightly overestimated. Drawing on other hours may, for example, slightly alter the level and the regional distribution of optimal infrastructure investments. Likewise, scaling historic feed-in patterns of wind and PV of the reference year 2012 to 2024 and 2034 levels neglects expectable smoothing effects related to changes both in the geographical distribution of generators and in generator design. This may lead to a slight overestimation of renewable surpluses and respective investments in storage and transmission lines (see Schill, 2014).

[5] For a discussion on the nuclear phase-out in Germany see Kunz and Weigt (2014) in this issue.

and/or B 2034, the construction of which has not started as of March 2014 (“planned”). These are not considered in our analysis as investments in new power plants are determined endogenously. Where thermal capacities decrease through 2034, there is a disproportionately high increase in renewable generation capacities, which reflects their comparatively low capacity factors. By 2034, onshore wind power remains the technology with the largest capacity installed followed by photovoltaic; offshore wind has the largest growth rate.

Table 1: Generation capacities of the scenario framework 2014

	2012 Status quo	2024 B	2034 B
Nuclear	12.1	-	-
Lignite	21.3	15.4	11.3
Hard coal	25.5	25.8	18.3
Oil and other	8.3	5.6	3.9
Natural gas	26.9	22.4	22.0
Pumped hydro storage	6.4	6.3	6.3
Natural gas (planned)	-	5.9	15.7
Pumped hydro storage (planned)	-	3.7	3.7
Wind onshore	31.0	55.0	72.0
Wind offshore	0.3	12.7	25.3
Photovoltaic	33.1	56.0	59.5
Biomass and other	6.5	10.2	11.5
Hydropower	4.4	4.7	5.0

Source: BNetzA (2013).

In addition, for parameters not included in the NEP scenario framework, we draw on data collected from several public sources including, for example, time series for electricity demand, seasonal availability factors for power plants, regional hourly availability factors for wind and photovoltaic, as well as a regional distribution of renewable generation capacity and load. The topology of the German high voltage network reflects the state of the year 2012. Transmission line capacity constraints include a reliability margin of 20% in order to approximate n-1 security (Egerer et al., 2014). In order to reduce numerical complexity, the topology is aggregated such that only meshed elements are included. We also abstract from cross-border lines. Overall, the model includes 326 nodes and 743 lines.

Drawing on these parameters, we examine five scenarios (Table 2) that include different assumptions on the available infrastructure options and the costs of renewable curtailment: a “Reference scenario” without additional constraints; two “Decreased curtailment” scenarios, in which curtailed renewable generation is penalized with 100 EUR/MWh and 1000 EUR/MWh, respectively, in the objective function; a “No network extension” scenario that does not allow any investments in transmission lines; and an “Exogenous storage” scenario that assumes that pumped hydro storage capacity will be built according to the NEP 2014 scenario framework.

Depending on the respective scenario, the following investments options are available (Figure 1):

- Existing AC transmission lines can be extended by additional 380 kV circuits with capacities of 1.7 GW;
- six new DC point-to-point connections are possible (dashed lines) in steps of 1 GW;
- generation capacity can be built in steps of 500 MW at ten important network nodes in the transmission systems, which are distributed all over Germany (grey dots). Investment options are combined cycle gas turbines (CCGT) and open gas turbines;

- a list of pumped hydro storage projects is considered with specific capacities and locations (dark diamonds).[6]

We do not consider thermal investments in technologies other than gas-fired power plants. Nuclear power is not an option in Germany according to the law, lignite is not compatible with the German government's emission targets, and hard coal cannot compete with natural gas in the medium term given NEP's CO_2 price assumptions. Moreover, we abstract from including demand-side measures such as load shifting and load shedding as endogenous variables. While such measures may become more relevant in the future, a solid parameterization of costs and technical characteristics is challenging. The NEP scenario framework, which we also draw on, already assumes some level of peak shaving by reducing peak load from 87 GW in 2012 to 84 GW in 2024 and 2034. We implicitly assume that additional demand-side measures cannot compete with pumped hydro storage in terms of specific investments and operational costs.

Annualized fixed costs for investments are calculated from specific investments and assumptions on the technical life time of the installation (Table 3). Pumped hydro storage plants have a fixed energy to power rating of seven hours. A four percent discount rate is applied. The mixed-integer character of the model allows for the lumpy investment character for transmission lines and the specific pumped hydro storage projects to be represented.

[6] We include 13 specific pumped hydro projects that are actually planned with a total capacity of nearly 6 GW, see Egerer and Schill (2014).

Figure 1: Endogenous options for infrastructure investments

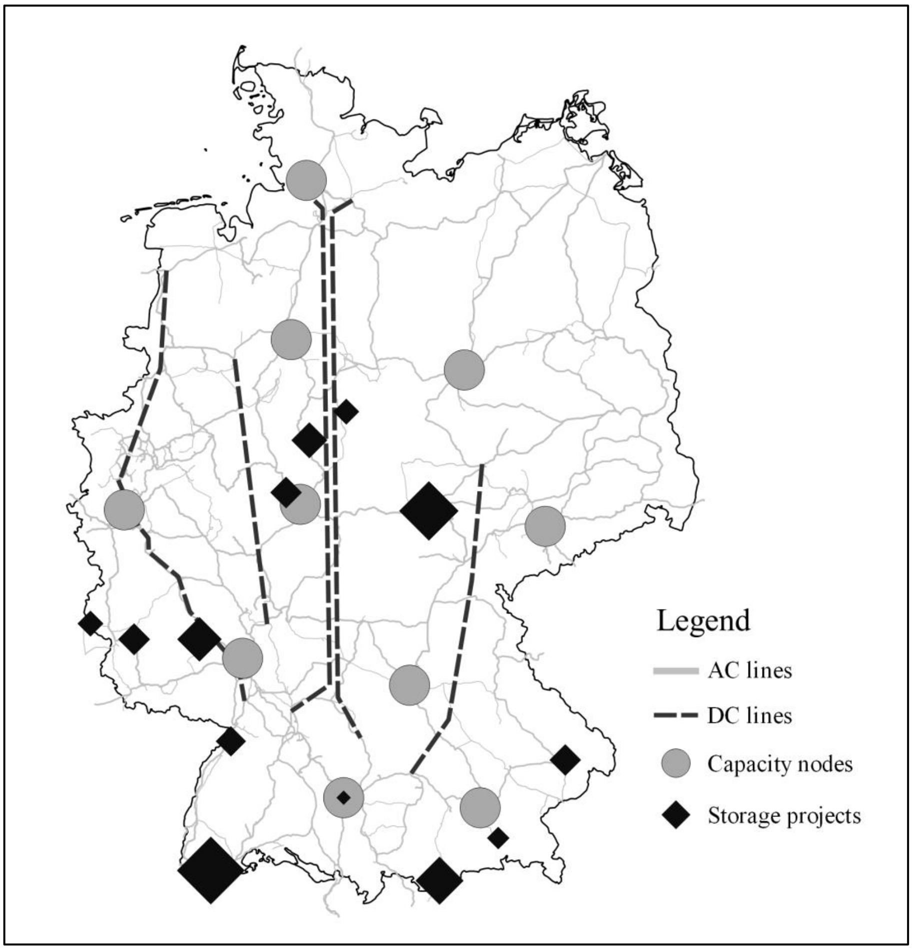


Table 2: Investment options in the different scenarios

Scenario	Investments in *Gas power plants*	*Transmission lines*	*Pumped hydro storage*	**Costs of RES curtailment**
Reference scenario	✓	✓	✓	0
Decreased curtailment 100	✓	✓	✓	100 EUR/MWh
Decreased curtailment 1000	✓	✓	✓	1000 EUR/MWh
No network extension	✓	-	✓	0
Exogenous storage	✓	✓	Exogenous	0

Table 3: Investment parameters

	Specific investments	**Life time in years**	**Efficiency in percent**
	(mn EUR/km)		
AC transmission lines	1.4	40	
DC transmission lines	1.4	40	
	(mn EUR)		
AC transformer	4	40	
DC converter	338	40	
	(mn EUR/GW)		
CCGT power plants	800	35	60
OCGT power plants	400	30	45
Pumped hydro storage power stations	1200	40	80

Source: BNetzA (2013).

4 Results

4.1 Reference scenarios 2024 and 2034

In the 2024 "Reference scenario," we determine investments into new gas-fired power plants and transmission lines, but no investments into pumped hydro storage. Eight GW of CCGT generation capacities are added.[7] This number is close to the overall level of capacity

[7] We do not find investments into open cycle gas turbines in any scenario. This result is probably driven by the nature of the analysis, which neglects the flexibility constraints of thermal power plants. System flexibility is not valued in the model which abstracts from ramping constraints and market uncertainty. The higher flexibility requirements with increasing renewable shares favor additional storage and open gas cycle turbine capacity and reduce the level of less flexible CCGT investments.

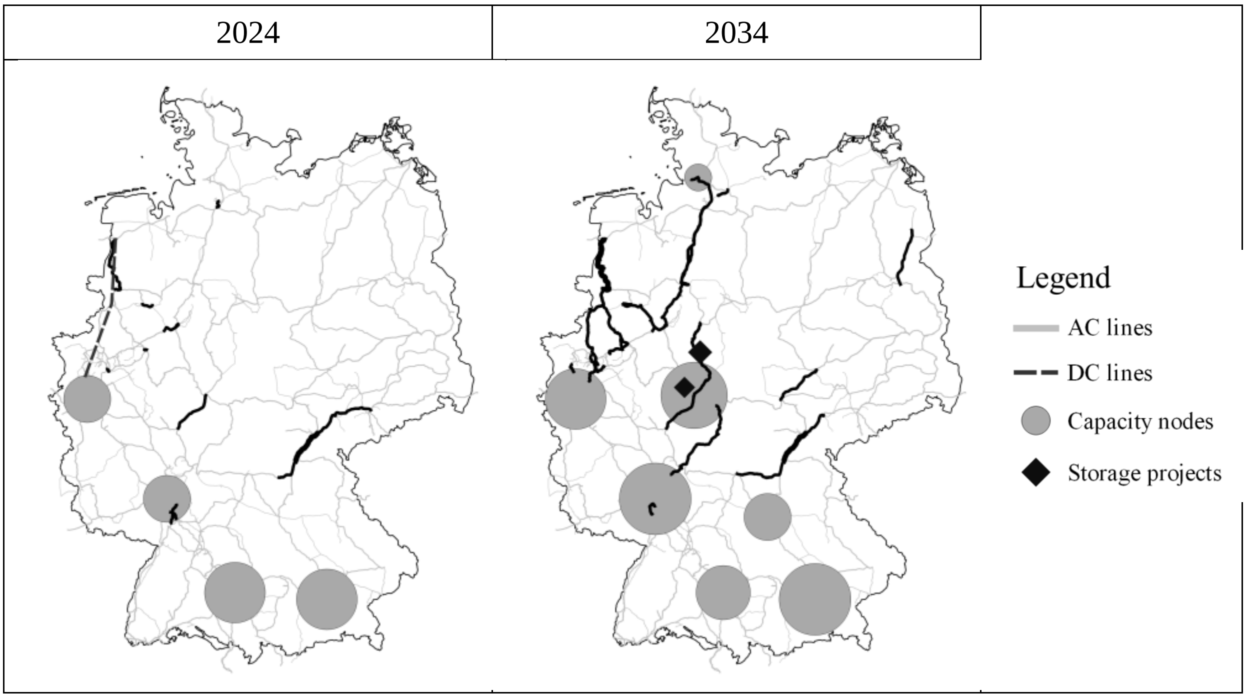
additions assumed in the scenario framework of the NEP 2014. The regional focus of these investments is in southern and western Germany, namely in Bavaria, Hesse, North Rhine-Westphalia and Baden-Wuerttemberg (Figure 2). The observed lack of pumped hydro investments can be explained by relatively high specific investments. In addition, opportunities for arbitrage are limited due to small hourly price differentials caused by a flat merit order of conventional power plants and by the large feed-in of photovoltaics during daytime. Additional AC lines sum up to more than 700 km, with a focus on connections between Saxony/Thuringia and northern Bavaria as well as between Lower Saxony and North Rhine-Westphalia. In addition, there are minor investments into a DC line of around 200 km, connecting large wind capacities located at the North Sea coast to North Rhine-Westphalia. Renewable energy has a share of nearly 48% of overall power generation, compared to lignite and hard coal with around 19% and 18%, respectively. Old and new gas-fired power plants account for nearly 12%. Renewable power generation is curtailed by around 1.3 TWh due to network constraints, corresponding to 0.5% of the maximum yearly feed-in. Avoiding such curtailment by means of additional network or storage capacity would be more expensive in the 2024 scenario compared to generating an equivalent amount of electricity in conventional power plants.[8] Yearly CO_2 emissions by the German power sector are around 230 million tons, or 427 g/kWh, respectively.

The optimization for 2034 is carried out without rolling planning. That is, the model does not enforce investments of a 2024 run to be present in the respective 2034 scenario. The results of

[8] A similar point is made by Schill (2014) regarding renewable surpluses in Germany.

the 2034 reference scenario, however, do largely include the nodal power plant and storage investments of the 2024 reference. The same also holds for regional network enforcements, though the choice between AC and DC lines slightly changes in western Germany. Compared to 2024 results, we find much larger infrastructure investments in the 2034 “Reference scenario.” This result is driven by an exogenously decreasing thermal power plant fleet and an increasing penetration of variable renewables. CCGT capacity additions sum up to 16.5 GW, which is twice the level of 2024. Again, this magnitude is in line with the scenario framework of the NEP 2014. As in the 2024 reference scenario, the regional focus of these investments is southern and western Germany. In contrast to 2024, there are also two small additional pumped hydro storage projects in North Rhine-Westphalia and Hesse, in total around 0.7 GW. AC line extensions sum up to around 2800 km, which is around four times the amount of the 2024 reference scenario. AC investments again focus on connections between Saxony/Thuringia and northern Bavaria and between Lower Saxony and North Rhine-Westphalia. Renewables’ share in overall power generation increases to 60% by 2034, while the shares of lignite and hard coal decrease to about 12 and 6 percent, respectively. The share of old and new gas-fired power plants grows to 18%. Renewable curtailment increases to 5.7 TWh (1.7%). CO_2 emissions decrease substantially to 140 million tons, or 259 g/kWh, respectively.

Figure 2: Investments in the reference scenarios



4.2 Alternative scenarios

Investments in the other scenarios differ substantially from the reference scenarios (Table 4). In the “Decreased curtailment” scenarios, additional investments into storage and transmission lines are required in order to reduce renewable curtailment. These are particularly high in the scenarios where renewable curtailment is penalized with 1000 EUR/MWh: in 2024, more than 4700 km of AC lines and 2.5 GW of storage are required. By 2034, AC and DC investments of nearly 1800 km and 7900 km, respectively, are built by the model. Additional DC lines directly connect northern and southern German regions. These investments are triggered by large onshore and offshore wind capacities in the north and high electricity demand in the south and the west. Note that AC investments are smaller in 2034 compared to 2024, as these are largely substituted with DC lines.[9] Accordingly the additional AC lines in the "Decreased curtailment 1000" scenario of 2024 have the characteristic of stranded investments. At the same time, 4.5 and 5.1 GW of pumped hydro storage are added in the 2034 scenarios of "Decreased curtailment," which constitute most of the investment potential available to the model. Investments into gas-fired power plants are slightly lower compared to the respective reference scenarios as these are partly substituted by the additional storage and transmission capacities.

In the "No network extension" scenarios, somewhat higher power plant investments are required compared to the reference scenario, as transmission bottlenecks during hours of peak residual load cannot be relieved. The geographic distribution of the additional plants also shifts toward northern Bavaria in 2024 and toward western Germany in 2034 (Figure 3). However, there are no investments into pumped hydro storage in 2024 and only small investments in 2034. This may be explained by the specific locations of the storage facilities, because these cannot fully be utilized without additional integration into the transmission system. In the "Exogenous storage" scenarios, the assumed storage expansion of 3.7 GW, which corresponds to the NEP scenario framework 2014,[10] partly substitutes for investments in gas-fired power plants compared to the reference scenario. Moreover, the geographic

[9] We assume higher investment costs for DC than for AC technology, motivated by the higher converter costs. However, flows on point-to-point DC lines bridge long distances from north to south and reduce loop-flows in the AC network. We do not make strong statements on the choice of technology as model decisions on AC and DC investments are very sensitive to the scenario assumptions.

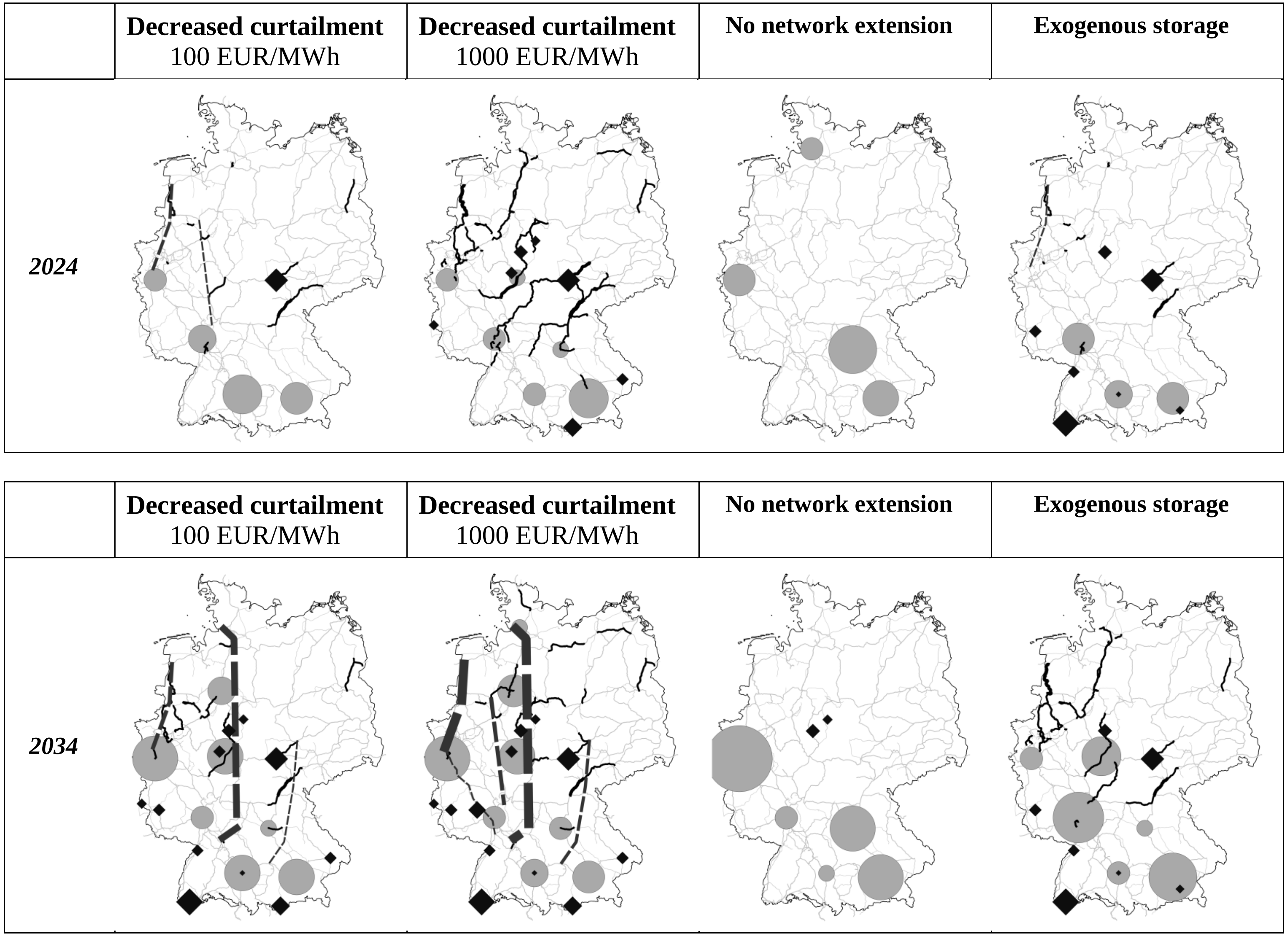
[10] The Grid Development Plan foresees additional pumped hydro capacities of around 3.7 GW by 2024 and 4.4 GW by 2034. In the numerical application, we have used a value of 3.7 GW for both 2024 and 2034 in order to make the scenarios comparable.

distribution of new power plants further shifts toward Southern Germany in both 2024 and 2034. Network investments do not change much compared to the reference scenario.

Table 4: Investments in different scenarios

	Reference scenario	Decreased curtailment 100	Decreased curtailment 1000	No network extension	Exogenous storage
		2024			
		(GW)			
CCGT	8.0	7.5	7.0	10.0	5.5
Storage	0.0	1.1	2.5	0.0	3.7
		(km)			
AC lines	708	876	4737	0	563
DC lines	220	690	0	0	220
		2034			
CCGT	16.5	14.5	14.5	18.0	15.0
Storage	0.7	4.5	5.1	0.6	3.7
		(km)			
AC lines	2787	1836	1751	0	2917
DC lines	0	4010	7880	0	0

Figure 3: Investments in the different scenarios

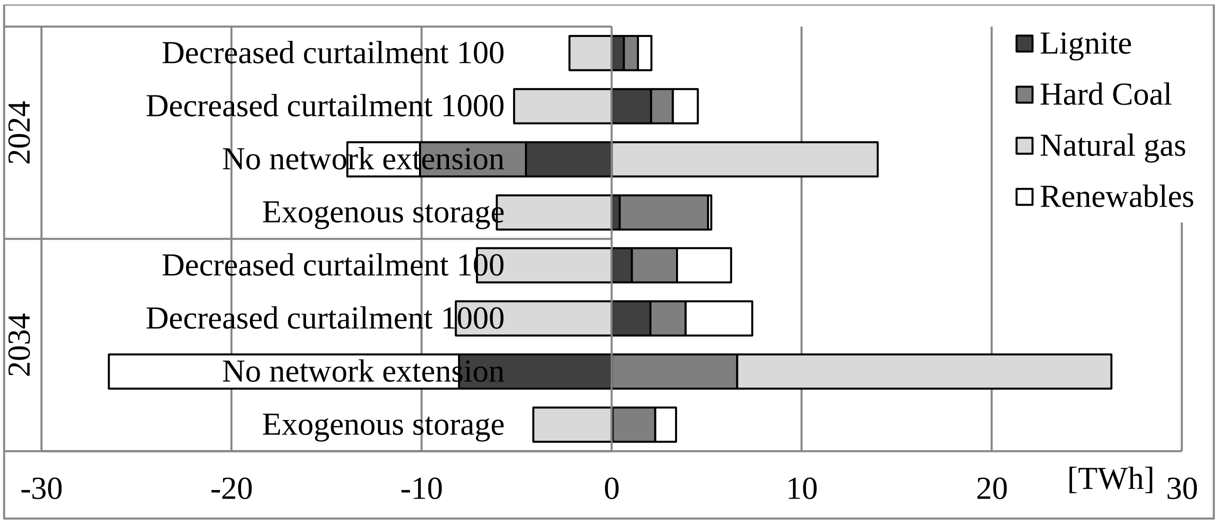


5 Discussion

5.1 Renewable and conventional generation affected

Model results indicate that additional network and storage capacities may not just foster the system integration of renewable power, but also of existing coal power stations, as the utilization of technologies with low variable costs increases during hours of low demand and high availability of renewables. By 2024, network and storage capacity expansion in the "Decreased curtailment" scenarios allow for the additional utilization of around 0.7 TWh (100 EUR/MWh) of renewable power compared to the reference scenario, or 1.3 TWh (1000 EUR/MWh). By 2034, 2.8 TWh (100 EUR/MWh) or 3.5 TWh (1000 EUR/MWh) of renewable energy can be integrated through additional infrastructure investments compared to the reference scenario. At the same time, power generation from base-load lignite-fired plants and mid-load hard coal plants increases at the cost of gas-fired generation (Figure 4). In the "Exogenous storage" scenarios we find corresponding effects on the dispatch. Compared to the reference scenarios, additional pumped hydro capacities allow for the additional utilization of around 0.2 TWh of renewable power by 2024, and 1.1 TWh by 2034. At the same time, additional storage allows hard coal plants to increase their production by 4.6 and 2.2 TWh, respectively. In contrast, renewable curtailment in the "No network extension" scenario is 4.0 TWh higher compared to the reference in 2024, and even 18.4 TWh higher in 2034. In this case, no storage is built by 2024 and only 0.6 GW are added by 2034. This lack of storage can be explained by the projects' specific geographic locations in the context of unrelieved transmission bottlenecks. At the same time, the utilization of the new gas-fired plants is high, while power generation from lignite decreases.

Figure 4: Changes in power generation compared to the reference scenario



5.2 CO_2-intensity

The different levels of power generation from renewables and coal-fired plants are reflected by respective CO_2 emissions. Compared to the reference scenarios, yearly emissions barely change in the "Decreased curtailment" cases because the increased utilization of lignite and hard coal plants compensates for emission reductions related to improved renewable integration. In the "No network extension" scenarios, CO_2 emission effects are more pronounced: in 2024, emissions are around 6 million tons lower compared to the reference scenario because of decreasing power generation from lignite and hard coal; by 2034, this effect reverses because of substantially increasing curtailment of renewable generation, such that emissions increase by nearly 2 million tons compared to the reference. Assuming "Exogenous storage", emissions increase by around 3 million tons by 2024, as the additional storage facilities – together with network extensions allow a high utilization of lignite and coal plants. By 2034, this effect vanishes. Accordingly, relaxing regional network restrictions and providing additional storage capacities may not just foster renewable integration but could also cause a temporary increase in CO_2 emissions, depending on the power plant fleet.[11]

5.3 Power system costs

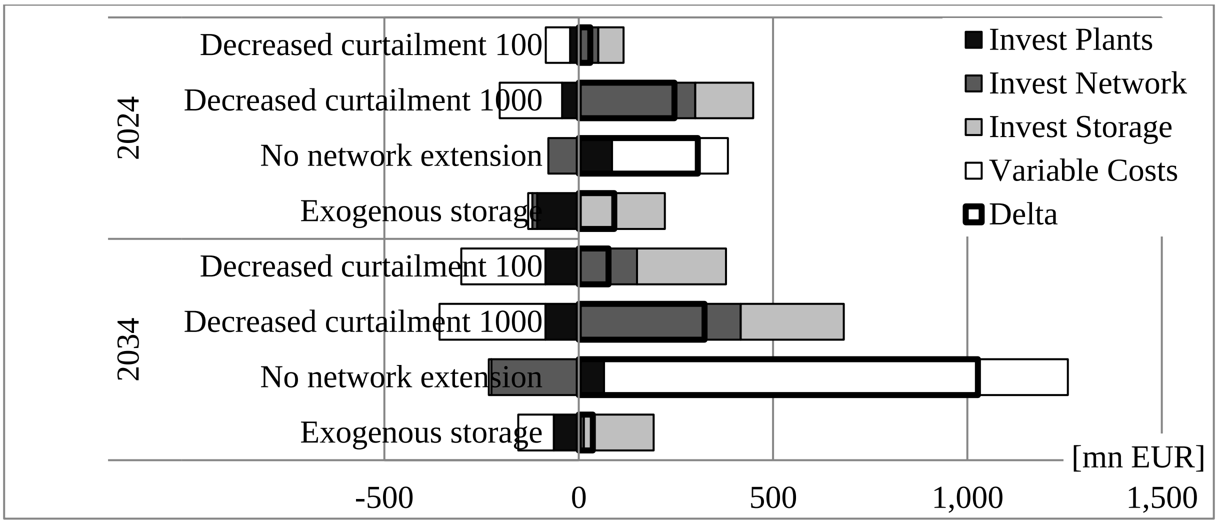
Yearly power system costs – consisting of variable costs and annualized fixed costs of new investments – differ only slightly between the scenarios (Figure 5). The most expensive cases are the “No network extension” scenarios, as the investment option with the best ratio between reducing variable system costs and annualized fixed costs is not available here. Yearly systems costs are around 300 million EUR higher compared to the reference in 2024, and around 1 billion higher in 2034. In contrast, the “Decreased curtailment 100” scenario is only slightly more expensive than the reference (around 30 million EUR in 2024 and 80 million in 2034). The “Decreased curtailment 1000” scenarios have considerably higher system costs – although not as high as in the “No network extension” case – as more infrastructure options have to be applied in order to further reduce curtailment. System costs of the “Exogenous storage” scenarios, which exogenously assume storage investments of 3.7 GW, are only slightly higher than the reference case, especially by 2034 (around 40 million EUR higher).

Importantly, pumped hydro storage not only has an arbitrage value and a capacity value in the power system, but may also provide ancillary services such as operating reserves (Denholm et al., 2010). Such additional system benefits are not included in the model. Likewise, ramping-

[11] A similar effect is shown for the case of increasing demand-side flexibility (Holland and Mansur, 2008).

related flexibility requirements will continue to increase in Germany in the course of ongoing expansion of variable renewables. Accordingly, moderate investments into pumped hydro storage appear to be beneficial from a system perspective, even if such investments are small in the reference scenarios.

Figure 5: Changes in system costs compared to the reference scenario



6 Conclusions

We examine different investment scenarios for the German power system with increasing shares of renewables for 2024 and 2034, using an integrated dispatch, transmission, and investment model with a high spatial resolution. In particular, we study the interdependencies between investments in generation capacity, pumped hydro storage, and transmission as well as their impact on power plant operation and system costs.

Based on the numerical results discussed above, we suggest several conclusions. First, the requirement for investments into generation, storage, and transmission increases through 2024 within the context of an aging thermal power plant fleet and a strong capacity build-up of fluctuating renewable generators. To some extent, investments into CCGT plants, pumped hydro storage, as well as AC and DC transmission lines may be substituted against each other. In a cost-minimizing system, however, a mix of all investment options is required in the longer run. Considerable investments into CCGT plants are found in all scenarios. Importantly, these generation capacities have to be placed in specific regions. In 2024 most new CCGTs are located particularly in southern Germany, where nuclear capacities are phased out. 2034 results indicate that additional CCGTs in western Germany replace hard coal and lignite capacities. In reality, the current German market design provides little incentives for system-optimal power plant placement, and policy makers should work toward proper regional investment incentives.

As for pumped hydro storage, our model determines rather small capacity requirements by 2024, and moderate investments by 2034. Nonetheless, pumped hydro storage appears to be a no-regret option from a system perspective: overall system costs of the scenarios with more or less storage differ only slightly, while pumped hydro storage facilities at the same time have additional system values related to the provision of reserves and other ancillary services, which are not included in the optimization. Such additional benefits may outweigh the slightly higher system costs of the exogenous storage scenarios; a detailed analysis of this issue is left for future research.[12] In any case, given that our longer-term scenarios indicate growing storage requirements–even without considering additional system values–early planning for new pumped hydro storage facilities appears to be favorable.

[12] Gas-fired power plants may also contribute to the provision of ancillary services. The relative importance of ancillary services revenues, however, is larger for pumped hydro facilities.

Regarding transmission investments, we identify several AC lines that are to be expanded in virtually every scenario. It may be favorable to make developing these projects a priority. Making definitive statements on the requirement or the advantageousness of individual AC or DC connections, however, is beyond the scope of this analysis; moreover, line investments strongly depend on future power plant and storage deployments, both of which are uncertain in the context of a competitive power market. In any case, some network extensions are required in most cases analyzed here.

In general, most investment options analyzed here face long lead times, especially storage and transmission investments. With the perspective of a long-term transition toward a largely renewable-based system, it appears to be reasonable to administratively prepare such infrastructure projects early on. This argument is even more valid if there is a political intention to reduce renewable curtailment, which may, among other reasons, be motivated by climate policy concerns. With the perspective of further increasing renewable shares after 2034, early planning with priority for renewable integration as in the decreased curtailment scenarios may thus be beneficial.

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