Residual Load, Renewable Surplus Generation and Storage Requirements in Germany

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Abstract: We examine the effects of future renewable expansion in Germany on residual load and renewable surplus generation for policy-relevant scenarios for 2022, 2032 and 2050. We also determine the storage capacities required for taking up renewable surpluses for varying levels of accepted curtailment. Making use of extensive sensitivity analyses, our simulations show that the expansion of variable renewables leads to a strong decrease of the right-hand side of the residual load curve. Renewable surpluses generally have high peaks which only occur in very few hours of the year, whereas overall surplus energy is rather low in most scenarios analyzed. Surpluses increase substantially with growing thermal must-run requirements, decreasing biomass flexibility and decreasing load. On average, most surpluses occur around noon and in spring time. Whereas the energy of single surplus hours is often in the range of existing German pumped hydro capacities, the energy of connected surpluses is substantially larger. Using an optimization model, we find that no additional storage is required in the scenarios for 2022 and 2032 in case of free curtailment. Even restricting curtailment to only 1% of the yearly feed-in of non-dispatchable renewables would render storage investments largely obsolete under the assumption of a flexible system. In contrast, further restrictions of curtailment and a less flexible system would strongly increase storage requirements. In a flexible 2050 scenario, 10 GW of additional storage are optimal even in case of free curtailment due to larger surpluses. Importantly, minor renewable curtailment does not impede achieving the German government’s renewable energy targets. We suggest avoiding renewable surpluses in the first place by making thermal generators more flexible. Afterwards, different flexibility options can be used for taking up remaining surpluses, including but not limited to power storage. Curtailment remains as a last resort. Full surplus integration by power storage will never be optimal because of the nature of surpluses shown in this paper. Future research should explore synergies and competition between different flexibility options, while not only covering the wholesale market, but also ancillary services.

JEL codes: Q42; Q47; Q48

Keywords: Renewable energy; Residual load; Storage; Curtailment; Germany

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1 Introduction

In the context of the so-called ‘Energiewende’, the German government has decided to phase out nuclear power completely by 2022. At the same time, renewable power generation is to be expanded substantially. Renewable energy sources (RES) have to account for 35% of German gross electricity consumption by 2020 (BMWi and BMU, 2010). This share was around 23 percent in 2012. The target values for 2030, 2040 and 2050 are 50%, 65% and 80%, respectively. The largest part of renewable power will come from wind and photovoltaics (PV). According to the medium scenario of the network development plan drafted by German transmission system operators (TSOs) in 2012, onshore and offshore wind account for around 45% of gross power demand by 2032, whereas PV contributes around 10% (NEP 2012, scenario 2032B). Afterwards, the shares of wind and solar are projected to grow further until 2050 (cp. DLR et al. 2012)².

Wind power and PV differ from conventional power generators in many respects (cp. Joskow 2011, Hirth 2013). In particular, their production is variable, as the hourly generation capacity strongly depends on weather and season, as well as on the time of the day. Moreover, generation is only weakly correlated with hourly load profiles. Growing shares of these technologies thus have a strong influence on residual load, for example resulting in temporary situations of both power shortage and renewable surplus generation (Denholm and Hand 2011). As a consequence, integrating growing amounts of wind and PV into the power system increasingly requires the application of dedicated integration measures, among them different types of energy storage, demand-side measures, network expansion, flexible thermal back-up plants and renewable curtailment (NREL 2012).³

In this paper, we study the effects of future renewable expansion on residual load in Germany, with a focus on situations of temporary surplus generation. We do not model all potential renewable integration technologies, but focus on storage for taking up excess renewable power.⁴ As an alternative to storage, we also consider temporary curtailment⁵ of renewable generators. We aim to answer two research questions. First, we analyze the future development of German residual load under a range of varying assumptions. We are particularly interested in the right-hand side of the residual load curve, i.e. the power and energy of renewable surplus events.⁶ Second, we investigate which storage capacities of different technologies would be required for taking up temporary renewable surpluses. In doing so, we specifically explore the interrelation of storage and renewable curtailment: how do storage requirements vary different levels of allowed renewable curtailment?

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² For an English summary of DLR et al. (2012) see Pregger et al. (2013).
³ Renewable integration studies that focus on specific flexibility options in the German context are provided by Dena (2011) and VDE (2012a, b and c). Sioshansi et al. (2012) point to technical issues as well as policy-related barriers to actual storage deployment in power markets. Borden and Schill (2013) review policy efforts for storage development in the U.S. and Germany.
⁴ To be more precise, we focus on power-to-power storage, which draws power from the grid and feeds back power to the system in later periods. We do not consider other storage options that transform electric power to other energy carriers, for example power-to-heat or power-to-gas. Beaudin et al. (2010) review the status quo, development potentials and challenges of different electricity storage technologies that can be applied for wind and solar power integration.
⁵ Jacobsen and Schröder (2012) define different categories of renewable curtailment. Drawing on case studies, they show that – contrary to public belief – some level of curtailment of variable renewables is optimal from a system cost perspective, for example by avoiding excessive grid investments.
⁶ The left-hand side of the residual load curve, i.e. situations of supply shortage, is not a major concern in this analysis, as generation capacity is adequate in all scenarios of NEP (2012).
The analysis includes a large number of sensitivities with respect to the development of the conventional and renewable power plant fleet, thermal must-run restrictions, the flexibility of biomass generators, various meteorological wind and PV years, and improvements in energy efficiency. The scenarios used draw on quasi-official projections of the German network development plan (Netzentwicklungsplan, NEP 2012)\(^7\) for the years 2022 and 2032, and on a long-term scenario for 2050, which has been drafted for the federal Ministry for the Environment, Nature Conservation and Nuclear Safety (DLR et al. 2012).

Overall, we carry out 13,104 simulations. Such a large number of sensitivities requires making a range of simplifying assumptions. First, we consider Germany to be both an island and a copper plate. That is, we neglect power exchange with adjacent countries. Likewise, we abstract from network constraints within Germany, i.e., assume perfect network extension within the country. Moreover, we model the power system in a simplified way by abstracting from a detailed representation of flexibility restrictions. Instead, constraints related to the provision of ancillary services or combined heat and power generation are approximated by an aggregated thermal must-run constraint. Regarding storage, we include three stylized power-to-power technologies. We do not model other flexibility options like demand-side management or transmission expansion.

Different aspects of renewable surplus generation, curtailment and related storage requirements have been analyzed in the international literature. Denholm and Sioshansi (2009) quantify how wind power revenues decrease due to curtailment in three transmission-constrained U.S. power systems. Such curtailment losses could be minimized by an appropriate mix of storage and network investments. Denholm and Hand (2011) simulate different scenarios with high shares of wind, PV and solar thermal power in the Texas power system. They show that increasing system flexibility, for example by eliminating thermal must-run generation, substantially reduces renewable surplus generation. For very high renewable penetration, both daily storage and demand-side management are required in order to avoid excessive curtailment. Esteban et al. (2012) determine the storage capacities required in a 100% renewable power scenario for Japan. The system, which is projected to have a peak demand of more than 240 GW by the year 2100, would be largely based on variable wind and solar power. Battery storage with a capacity of 41 TWh would be required, accompanied by around 10 GW of flexible biomass generation and nearly 20 GW of pumped hydro. Mason et al. (2013) develop another fully renewable island scenario for New Zealand and find that wind curtailment can be largely eliminated by pumped hydro storage, which in turn serves peak load. Yet the New Zealand system is hydro-dominated with wind constituting only around a quarter of the energy mix, so it can hardly be compared to systems with high prospective shares of variable renewables like the German one.

Now focusing on Europe, Rasmussen et al. (2012) analyze wind and solar power integration in a largely renewable-based pan European power system, drawing on a parametric time-series analysis of hourly data. They find significant synergies between storage and balancing capacities. Full renewable supply may be possible for overall Europe with a combination of moderate over-capacities of wind and solar, 2.2 TWh of short-term storage and 25 TWh of seasonal storage, assuming adequate transmission capacities. Tuohy and O’Malley (2011) apply a unit commitment model to the

\(^7\) We draw on the 2012 version of this plan which entered into the Bundesbedarfsplangesetz 2013, a federal law that establishes the necessary network expansion projects in Germany.
Irish power system in order to quantify decreases in wind curtailment related to additional pumped storage. They find that building new storage is only economic for very high levels of wind penetration, whereas curtailment is cheaper for moderate shares of wind power. On an even smaller scale, Østergaard (2012) compares different storage options in a 100% renewable energy scenario for a Danish city. He uses an energy system model that covers the power, heat and transportation sectors to show that power storage contributes much more to wind integration compared to biogas storage or heat storage. At the same time, power storage is considered a very costly option.

As for Germany, the much-discussed ‘Energiewende’ has recently increased interest in the development of residual load, renewable surpluses and storage requirements, resulting in a substantial amount of grey literature. Agora (2012) simulate German residual load in the year 2022, drawing on weather data of 2011. Excluding must-run constraints and trade with neighboring countries, they determine around 200 hours of renewable surplus generation. EWI (2013) use a cost-minimizing dispatch model that includes internal transmission constraints and cross-border trade to show that hardly any renewable curtailment should be expected until 2022 in Germany if existing transmission bottlenecks are removed. Without network extensions, curtailment may rise to around 8 TWh by 2022. The authors also show that renewable curtailment increases substantially with additional wind power capacities. BET (2013) determine yearly surplus generation of 2.3 TWh by 2020 and 34.5 TWh by 2030 for Germany, assuming thermal must-run of 10 GW in 2020 and 5 GW in 2030, flexible biomass generation, and neglecting cross-border flows. Maximum and minimum hourly residual load gradients are expected to grow from +14.0/-7.7 GW in 2012 to +13.4/-10.0 GW in 2020, and up to +22.1/-19.0 GW by 2030. If additional demand-side potentials are realized and if thermal power plants, biomass plants and combined heat and power generation are sufficiently flexible, additional storage capacity is required only after 2030. VDE (2012a) analyze renewable curtailment and the demand for additional storage capacity in Germany for scenarios with renewable shares of 40%, 80% and 100% of gross power generation with a cost minimization model (cp. also Beck et al. 2013). Treating Germany as an island and neglecting transmission constraints or restrictions related to combined heat and power, they find 44 hours of negative residual load in the 40% scenario, 2329 hours for 80%, and 4271 hours for 100%. Peak surplus power is 10 GW (40%), 50 GW (80%), and 81 GW (100%), respectively. Accordingly, hardly any additional storage is required in the 40% scenario. With 80% renewables, 14 GW / 70 GWh of short-time storage and 18 GW / 7.5 TWh of seasonal storage are required in an optimized scenario that also makes use of other options like flexibilization of thermal plants and renewable feed-in management. In order to avoid the remaining curtailment, storage capacities would have to double. Storage requirements increase further in the 100% scenario. SRU (2011) also develop a long-term 100% renewable power scenario for Germany. If large-scale power exchange with either Scandinavia or Northern Africa—which is the authors’ preferred option—is not possible, temporary surplus power generation may rise to 209 GW (scenario 1.b), and total yearly surplus energy may exceed 53 TWh (scenario 1.a). Accordingly, up to 37 GW of new

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8 In September 2013, Agora published updated simulations for the years 2023 and 2033 in the form of presentation slides. However, a written report of this analysis, which also includes a spatial component, is not available so far. Importantly, Agora shows renewable and conventional generation in a graphic representation for every subsequent hour of the year. In contrast, we present our simulation results in an aggregated form, for example in the form of load-duration curves, bar charts and histograms.
compressed air storage would be required in order to accommodate a large share of these surpluses.\textsuperscript{9}

This analysis contributes to the existing literature in several ways. First, we aim to further the understanding of renewables’ impacts on residual load in power systems with high shares of variable renewables. Second, we shed light on the interaction of energy storage and renewable curtailment, as well as on the relative advantages of different storage technologies. Finally, extensive sensitivity analyses provide new insights how residual load and storage requirements depend on the development of exogenous key parameters, in particular regarding the flexibility of thermal generators. This allows drawing more general conclusions which are not only relevant for Germany, but also for other countries with thermal power systems that undergo a transformation towards variable renewable power.

2 Methodology

Residual load is calculated by subtracting hourly onshore wind, offshore wind, PV and run-off-river hydro generation from hourly demand data. Must-run requirements of thermal generators are also deducted from hourly demand. The same is true for biomass\textsuperscript{10} plants in the cases in which biomass generation is assumed to be inflexible (compare section 3). Residual load, renewable surplus and load gradients are then sorted in descending order so as to derive load-duration curves. In addition, we evaluate the surplus energy of single hours as well as the energy of ‘connected surpluses’. The latter describes the cumulative energy of all contiguous hours during which residual load is negative. For every surplus event (for example, area A in Figure 1), we check if the cumulative energy of the subsequent period of positive residual load (B) is larger than the previous connected surplus energy. If this is not the case, we add the energy of the next surplus event (C) to the connected surplus, and subtract the positive residual energy in between the two surplus events (connected surplus energy = A-B+C). This approach leads to a lower number of connected surplus events and at the same time to higher surplus energy compared to just looking at isolated surplus events, and is well suited to illustrate the requirements for storage, which is carried out in the next part of the analysis.

\textsuperscript{9} Complementary to the previously mentioned model analyses, Steffen (2012) reviews the current developments and medium-term prospects of pumped hydro storage in Germany and finds that there is now a surge of new projects after around three decades without major developments. Yet the profitability of many of these projects remains questionable.

\textsuperscript{10} In the following, generation from biomass refers not only to the combustion of solid biomass but also biogas and biogenic shares of municipal waste.
In order to determine storage requirements for taking up excess renewable generation, we use a simple linear cost minimization model which simultaneously optimizes storage investments and hourly dispatch of both power plants and storage capacities. Exogenous model parameters include hourly power demand, conventional generation capacities, the hourly availability of renewable generators, and variable generation costs. Storage investment costs and roundtrip-efficiencies are also exogenous. Endogenous variables include storage investments, dispatch of existing and new storage capacities, conventional power plant dispatch, and renewable curtailment. Table 5 in the Appendix provides a list of sets and indices, parameters and variables.

\[
\text{min cost} = \sum_{tech} v_{tech} q_{tech,t} + \sum_{stor} v_{stor} s_{storoust,t} + \sum_{stor} i_{stor} inv_{stor} \quad (1)
\]

subject to

\[
q_{tech,t} - \bar{q}_{tech} \leq 0 \quad \forall tech, t \quad (2)
\]

\[
musrun - \sum_{tech} q_{tech,t} \leq 0 \quad \forall t \quad (3)
\]

\[
bio_t - \bar{bio} \leq 0 \quad \forall t \quad (4)
\]

\[
\sum_t bio_t - \text{yearlybio} \leq 0 \quad (5)
\]

\[
rcurt_t - windon_t - windoff_t - pv_t - hydro_t \leq 0 \quad \forall t \quad (6)
\]

\[
\sum_t rcurt_t - \text{allowrcurt}(windon_t + windoff_t + pv_t + hydro_t) \leq 0 \quad (7)
\]

\[
stor_{in} - stor_{out} - inv_{stor} \leq 0 \quad \forall stor, t \quad (8)
\]

It is important to note that storage investments are optimized in the context of exogenous generation capacities. Peak load supply is not a concern in the scenarios used here. In an optimized system with endogenous generation capacities, storage may contribute to the provision of firm capacity, which is neglected here. In addition, the system value of providing ancillary services by means of storage is not considered (cp. Beck et al. 2013).
Renewables do not appear in the objective function (1) as they are assumed to generate power with zero marginal costs. In contrast, generation $q_{tech,t}$ from thermal generators incurs positive variable costs $v_{tech}$.\textsuperscript{12} Storage output $out_{stor,t}$ may also have positive marginal costs $v_{stor}$.\textsuperscript{13} Furthermore, investment into storage technologies $inv_{stor}$ incurs investment costs $i_{stor}$. These are annualized, using appropriate lifetime and discount factors. Hourly conventional generation faces a capacity constraint $q_{tech}$ (2). Dispatch of thermal generators may be constrained by an aggregated must-run requirement $mustrun$ (3). Flexible generation $bio_t$ from biomass is not only restricted by a capacity constraint $bio$ (4), but also by a yearly energy constraint $yearlybio$ (5). In case of inflexible biomass generation, the variable $bio_t$ is fixed to a yearly average value, such that aggregated generation over the year equals $yearlybio$. Hourly renewable curtailment $rencurt$ has to be smaller than the sum of variable renewable generation from onshore wind ($windon_t$), offshore wind ($windoff_t$), PV ($pv_t$), and run-off-river hydro ($hydro_t$) (6). Overall yearly renewable curtailment may be restricted by a factor of allowed curtailment $allowcurt$ of yearly generation from non-dispatchable renewables (7). Such restrictions of curtailment may not be optimal from a system cost perspective, but can be practically relevant for environmental or political reasons.\textsuperscript{14}

Storage inflows $in_{stor,t}$ and outflows $out_{stor,t}$ are restricted by initial capacities $storinc_{stor}$ and $storout_{stor}$ and additional capacity investments $inv_{stor}$ (8 and 9). The storage level $storlevel_{stor,t}$ follows a law of motion equation, considering storage inflows and outflows as well as losses due to imperfect roundtrip efficiency $\eta_{stor}$ (10). The upper bound for the storage level variable is given by initial storage capacity $storinc_{stor}$ and storage capacity investments (11). As for the latter, we assume a fixed energy-to-power ratio $epratio_{stor}$, which links investments into charging and discharging power $inv_{stor}$ (in MW) to the storage’s energy capacity (in MWh). There is no upper bound for storage investments. An energy balance restriction requires hourly demand $dem_t$ to match supply any time (12).

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\textsuperscript{12} In the application presented in the following, conventional technologies $tech$ are elements of a technology set $TECH$ which includes nuclear, lignite, hard coal, natural gas, oil and other technologies.

\textsuperscript{13} Storage technologies $stor$ are elements of a technology set $STOR$, which includes hourly, daily and seasonal storage. In the numerical application, we abstract from variable storage costs other than roundtrip losses.

\textsuperscript{14} Curtailing power with zero CO\textsubscript{2} emissions may be problematic from a climate policy perspective, in particular if combined with thermal must-run capacity. Moreover, uncompensated curtailment harms the profits of renewable generators. Uncertainty about compensation may increase the financing costs of renewable investments. Compare Jacobsen and Schröder (2012).
3 Model application

3.1 Scenarios for 2022 and 2032

The scenarios for 2022 and 2032 draw on generation capacities of the German network development plan (NEP 2012). This plan has been drafted by the four German TSOs and was approved by the German regulator after a series of public consultation. It is a major component of the so-called Bundesbedarfsplan (Federal Requirements Plan) of 2013 and thus constitutes a quasi-official document. The NEP (2012) includes three scenarios for the year 2022 (A, B, C) with varying assumptions on renewable and conventional capacity developments. Scenario A is designed to achieve the German government’s energy and climate targets. Scenarios B and C are even more ambitious with respect to renewable energy deployment. Scenario B, which is regarded as a reference scenario, is extended to 2032. Table 1 shows installed conventional and renewable capacities for all scenarios. Overall conventional generation capacities are largely the same in all future scenarios, with more lignite and coal in scenario A and more natural gas in scenarios B and C. Nuclear power is phased out completely by 2022 according to German legislation. In contrast, renewable capacities increase strongly, which reflects their comparatively low capacity factor. Among the 2022 scenarios, wind onshore and offshore capacities are largest in scenario C, whereas the largest PV capacity is found in scenario B. Of all scenarios, renewable capacities are largest in B 2032. Overall renewable capacity roughly triples between 2010 and 2032. Around 90% of the renewable capacity in B 2032 is made up of fluctuating wind and solar.

Table 1: Generation capacities in the scenarios for 2022 and 2032 in GW (NEP 2012)

<table>
<thead>
<tr>
<th></th>
<th>2010</th>
<th>A 2022</th>
<th>B 2022</th>
<th>C 2022</th>
<th>B 2032</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nuclear</td>
<td>20.3</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Lignite</td>
<td>20.2</td>
<td>21.2</td>
<td>18.5</td>
<td>18.5</td>
<td>13.8</td>
</tr>
<tr>
<td>Hard coal</td>
<td>25.0</td>
<td>30.6</td>
<td>25.1</td>
<td>25.1</td>
<td>21.2</td>
</tr>
<tr>
<td>Natural gas</td>
<td>24.0</td>
<td>25.1</td>
<td>31.3</td>
<td>31.3</td>
<td>40.1</td>
</tr>
<tr>
<td>Oil</td>
<td>3.0</td>
<td>2.9</td>
<td>2.9</td>
<td>2.9</td>
<td>0.5</td>
</tr>
<tr>
<td>Other</td>
<td>3.0</td>
<td>2.3</td>
<td>2.3</td>
<td>2.3</td>
<td>2.7</td>
</tr>
<tr>
<td>Pumped hydro</td>
<td>6.3</td>
<td>6.3</td>
<td>6.3</td>
<td>6.3</td>
<td>6.3</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>101.8</td>
<td>88.4</td>
<td>86.4</td>
<td>86.4</td>
<td>84.6</td>
</tr>
<tr>
<td>Hydro (run-of-the-river)</td>
<td>4.4</td>
<td>4.5</td>
<td>4.7</td>
<td>4.3</td>
<td>4.9</td>
</tr>
<tr>
<td>Wind onshore</td>
<td>27.1</td>
<td>43.9</td>
<td>47.5</td>
<td>70.7</td>
<td>64.5</td>
</tr>
<tr>
<td>Wind offshore</td>
<td>0.1</td>
<td>9.7</td>
<td>13.0</td>
<td>16.7</td>
<td>28.0</td>
</tr>
<tr>
<td>PV</td>
<td>18.0</td>
<td>48.0</td>
<td>54.0</td>
<td>48.6</td>
<td>65.0</td>
</tr>
<tr>
<td>Bio and other</td>
<td>6.7</td>
<td>9.5</td>
<td>10.6</td>
<td>8.7</td>
<td>12.3</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>56.3</td>
<td>115.6</td>
<td>129.8</td>
<td>149.0</td>
<td>174.7</td>
</tr>
<tr>
<td>Total</td>
<td>158.1</td>
<td>204.0</td>
<td>216.2</td>
<td>235.4</td>
<td>259.3</td>
</tr>
</tbody>
</table>

NEP (2012) includes pumped hydro storage capacities of 6.3 GW in 2010, and 9.0 GW in all other years. In the model analysis, we assume $S_{P_{PHS}} = S_{out_{PHS}} = 6.3$ GW for all years as shown in Table 1, as storage capacity investments are modeled endogenously. We assume an initial energy storage capacity of pumped hydro of 44 GWh, and average roundtrip efficiency of existing pumped hydro storage plants of 75%. We further assume an average availability of 90% for conventional

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15 Natural gas comprises open cycle gas turbines, steam turbines, and combined cycle.
generators, biomass and storage. With respect to hourly dispatch, all thermal generators and storage are assumed to be perfectly flexible.

Must-run requirements of thermal generators take on values of 0 GW, 10 GW or 20 GW. These aggregated must-run levels reflect a combination of economic, technical, system-related and institutional factors. Each block of a thermal power plant generally has to be operated above some minimum load level. Switching off the plant and starting it up again takes time and incurs additional costs. Accordingly, there may be economic and/or technical reasons for power plant operators not to shut down plants for short periods of time. Likewise, combined heat and power generation is usually restricted by heat demand. Most importantly, the provision of ancillary services involves thermal must-run, in particular the provision of frequency control (spinning reserves). The latter is also related to specific institutional arrangements like weekly tendering schedules for primary and secondary control reserves in Germany. It is reasonable to assume that all of these factors may change in the future, for example because of improved power plant flexibility, more flexible operation modes of combined heat and power generation, and the provision of ancillary services by renewable generators and/or the demand side, not least enabled by adjusted market rules.

Table 2 lists fuel prices and variable costs of conventional electricity generation for the NEP scenarios. Variable costs are calculated using own assumptions on average plant efficiencies and CO₂ prices of 20 €/t in 2022 and 30 €/t in 2032. Renewable generation is assumed to be free of variable cost.

Table 2: Assumptions on variable costs of conventional plants for NEP scenarios

<table>
<thead>
<tr>
<th>Fuel prices in Euro/MWh</th>
<th>Variable cost in Euro/MWh</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2022</td>
<td>2032</td>
</tr>
<tr>
<td>Lignite</td>
<td>2</td>
<td>2</td>
</tr>
<tr>
<td>Hard coal</td>
<td>12</td>
<td>13</td>
</tr>
<tr>
<td>Natural gas</td>
<td>25</td>
<td>25</td>
</tr>
<tr>
<td>Oil</td>
<td>53</td>
<td>62</td>
</tr>
<tr>
<td>Other</td>
<td>7</td>
<td>7</td>
</tr>
</tbody>
</table>

Regarding hourly feed-in of onshore wind, offshore wind and PV, we use all existing data provided by the four German TSOs up to the year 2012. Onshore wind data is available since 2006; for offshore wind, the time series starts in 2010. PV data is available only since 2011. For each year for which data is available, we calculate hourly availability factors for onshore and offshore wind and PV by relating the actual hourly feed-in to the installed capacity. To do so, we use official end-of-year installation data and assume linear capacity increase throughout the year. Figure 2 shows sorted

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16 Schröder et al. (2013) provide a literature survey on power plant flexibility and cost parameters, see in particular section 4.1.
17 This is also true for biomass, although biomass generation usually incurs positive fuel costs. This assumption, however, is not critical in the context of this analysis.
18 Offshore wind capacity in Germany is still small. Available data between 2010 and 2012 only reflects power generation from two offshore parks in the North Sea, alpha ventus and Bard Offshore I. alpha ventus became fully operational in spring 2010, whereas the other offshore park has been gradually connected to the grid since late 2010. The data thus represents very specific feed-in situations of two distinctive wind farms.
availability factors for all available yearly time series for onshore wind, offshore wind, and PV in a sorted order, as well as the mean values.

In order to derive renewable generation in the NEP scenarios, we multiply these hourly utilization factors with generation capacities of the respective scenario. Figure 20 in the Appendix shows the resulting load-duration curves for all NEP scenarios (mean load-duration curves for all yearly time-series). Whereas overall onshore wind generation varies substantially both between scenarios and wind years, the shape of the load-duration curve is always similar. Average hourly utilization factors vary between 0.16 in 2010 and 0.21 in 2007. Offshore wind achieves much more full-load hours, with an average hourly utilization factor between 0.39 in 2010 and 0.43 in both 2011 and 2012, although data is not as representative as in the case of onshore wind. The figure also shows respective curves for PV. This technology is characterized by a much steeper load-duration curve with average utilization factors between 0.10 in 2011 and 0.11 in 2012 since power generation is restricted to daytime hours.

Hydro power is assumed to generate at a constant level throughout the year, based on extrapolations of overall generation in 2010. Generation from biomass is assumed to either be perfectly inflexible, i.e. generating at a constant level during all hours of the year, or flexible within the constraints (4) and (5). In doing so, we capture two extreme assumptions on future biomass flexibility. In both cases, overall yearly power generation from biomass is equal. Renewable curtailment is assumed to be either free, restricted to 1% or 0.1% of maximum yearly generation of the non-dispatchable sources wind onshore, wind offshore, PV and hydro, or completely impossible.

As for load, we draw on hourly values provided by ENTSO-E (2013a) for 2010. For statistical reasons, these do not cover total net power consumption, but only a major part of it. We thus scale this hourly profile linearly such that it fits official government data on German net power consumption in the year 2010. We apply the methodology described in NEP (2012), according to which the non-
observed consumption has the same profile as the observed one. The resulting annual power demand of 562 TWh includes 5% network losses on top of net power consumption. These losses, which are again assumed to have the same profile as observed load, are included because these represent real power consumption which has to be provided by generators.\textsuperscript{19} Network load is generally assumed not to change in the NEP scenarios compared to 2010. However, we include sensitivity runs in which load decreases by 10% or 20% (linear decrease in all hours), which is in the range of the German government’s goals (BMWi and BMU, 2010).

There are three types of possible new storage investments, representing three stylized technologies: lithium-ion batteries (hourly storage), new pumped hydro (daily storage), and power-to-gas, or more precisely power-to-gas-to-power, indicating that hydrogen is converted to electricity again (seasonal storage). These technologies vary with respect to energy/power ratios, roundtrip efficiency and investment costs (Table 3). Specific investments are annualized, drawing on specific economic lifetimes and an 8% interest rate. Parameters are derived from Fuchs et al. (2012) and VGB (2012a). We choose to use constant average values for the period 2012-2030, as assumptions on dynamic parameters changes are highly speculative, may distort results, and complicate interpretation.

Table 3: Assumptions on storage technologies

<table>
<thead>
<tr>
<th>Storage Type</th>
<th>Energy/Power Ratio ($e_{pratio_{stor}}$)</th>
<th>Roundtrip Efficiency ($\eta_{stor}$)</th>
<th>Specific Investment in €/kW</th>
<th>Economic Lifetime in Years</th>
<th>Annualized Investment in €/kW ($i_{c_{stor}}$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hourly storage (“Li-ion battery”)</td>
<td>2</td>
<td>0.89</td>
<td>665</td>
<td>15</td>
<td>78</td>
</tr>
<tr>
<td>Daily storage (“Pumped hydro”)</td>
<td>8</td>
<td>0.79</td>
<td>850</td>
<td>30</td>
<td>76</td>
</tr>
<tr>
<td>Seasonal storage (“Power-to-gas-to-power”)</td>
<td>500</td>
<td>0.35</td>
<td>1500</td>
<td>20</td>
<td>153</td>
</tr>
</tbody>
</table>

The parameters represent average values for the period 2012-2030.
Sources: Fuchs et al. (2012), VGB (2012a), own assumptions

Summing up, we vary the following input parameters in the model application:

- Renewable and conventional generation capacities according to the NEP scenarios (A 2022, B 2022, C 2022, B 2032);
- Yearly profiles of wind and PV feed-in (7 for onshore wind, 3 for offshore wind, 2 for PV);\textsuperscript{20}
- Load (100%, 90%, 80%);
- Must-run requirements of thermal generators (0, 10, 20 GW);
- Biomass flexibility (flexible or constant generation);

\textsuperscript{19} As a consequence of including network losses, we calculate a peak load value of 92 GW in 2010. This value is in line with the methodology described by German TSOs in NEP (2012), but higher than in many other analyses that neglect network losses. Interestingly, a study of generation adequacy in Germany, which has also been drafted by the TSOs, neglects network losses and thus contradicts the NEP reasoning (50Hertz et al. 2012). Our sensitivity analyses with decreasing load indicate in which direction results change if network losses are neglected.

\textsuperscript{20} We permute all yearly time series of onshore wind, offshore wind and PV, assuming that there is no correlation between the yearly feed-in patterns of these three technologies.
• Allowed renewable curtailment (no restriction, 1%, 0.1%, or 0% of yearly generation from non-dispatchable renewables)

This results in 12096 distinctive model runs. We are interested in both average outcomes and in extreme cases.

### 3.2 A long-term scenario for 2050

Complementary to the NEP scenarios, we present an outlook on 2050, leaning on scenario ‘2011 A’ of the long-term scenarios published by the German Federal Ministry for the Environment, Nature Conservation and Nuclear Safety (DLR et al. 2012). This scenario assumes a renewable share of 86% in final power consumption by 2050. Conventional generation capacity is largely substituted by renewables (Table 4). Lignite is phased out completely, whereas some hard coal capacity remains (combined heat and power generation). Gas-fired plants make up the major part of remaining thermal capacity. Due to strongly increasing fuel and CO₂ prices, generation costs are assumed to be 136 €/MWh for hard coal and 131 €/MWh for natural gas. As in the NEP scenarios, we assume existing pumped hydro storage to be constant at 2010 levels since additional storage capacities are modeled endogenously.

Installed capacities of hydro power, wind onshore, wind offshore, PV and biomass are in the same order of magnitude as in NEP scenario B 2032. As demand is assumed to be much lower compared to B 2032, these capacities are sufficient to achieve a much higher share of renewables. In addition, there are 3 GW of geothermal power and 10.5 GW of renewable power imported from other countries. We model biomass, geothermal power and imports in an aggregated way. Accordingly, we assume these three technologies to be fully flexible or fully inflexible. In the first case, restrictions (4) and (5) apply for this aggregate, with \( \text{yearlybio} \) consisting of 59 TWh for biomass, 19 TWh for geothermal and 61 TWh for imports, respectively. In the latter, constant average hourly feed-in is assumed. Generation of wind and PV is calculated as described for the NEP scenarios.

| Table 4: Generation capacities in the 2050 scenario in GW (Leit 2011 A of DLR et al. 2012) |
|-----------------------------------|-------|
| **2050**                          |       |
| Hard coal                         | 4.6   |
| Natural gas                       | 33.5  |
| Pumped hydro                      | 6.3   |
| **Total conventional**            | **44.4** |
| Hydro (run-of-the-river)          | 5.2   |
| Wind onshore                      | 50.8  |
| Wind offshore                     | 32.0  |
| PV                               | 67.2  |
| Bio                              | 10.4  |
| Geothermal                       | 3.0   |
| Renewable imports                | 10.5  |
| **Total renewable**               | **179.1** |
| **Total**                         | **223.5** |

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21 An English summary has been published as Pregger et al. (2013).

22 In the 2050 scenario, hard coal includes other solid fuels. The gas plants are fueled not only with natural gas, but also with hydrogen generated from renewables to some extent.
Power demand is much lower in the 2050 scenario compared to the 2022 and 2032 scenarios, as DLR et al. (2012) assume a strong increase in energy efficiency. Accordingly, overall power consumption in 2050 is 413 TWh, a decrease of 27% compared to the NEP scenarios. Peak load accordingly decreases to 67 GW. All other parameters are equal as in the 2022 and 2032 scenarios.

We calculate sensitivity analyses comparable to the NEP scenarios. We again use all available yearly profiles of wind and PV generation (7 onshore, 3 offshore, 2 PV), three different must-run requirements (0, 10, 20 GW), different biomass flexibility, and 4 levels of allowed renewable curtailment (no restriction, 1%, 0.1%, 0% of yearly generation). Yet we abstract from simulating the effects of decreasing load, as overall demand is already very low, and further reductions appear not to be meaningful. Accordingly, we carry out 1008 model runs for the 2050 scenario.

4 Results

4.1 Residual load in NEP scenarios

Due to the limited correlation of variable wind and solar generation with hourly demand, increasing capacities of these technologies do not result in a linear decrease of residual load. The largest effect can be found on the right-hand side of the residual load curve (Figure 3). The decrease becomes stronger with more renewables, and is largest for scenario B 2032. In contrast, peak residual load hardly changes compared to 2010 levels. In other words, variable renewables can substitute a large amount of fossil fuels, but hardly decrease the capacity requirements of the system. Figure 3 also shows the effect of different assumptions on system flexibility on residual load. Compared to a perfectly flexible system with no must-run requirement and flexible generation from biomass, a system-wide thermal must-run requirement of 20 GW combined with inflexible biomass generation substantially decreases residual load. Such inflexibility assumptions would result in negative residual load during 40% of all hours of the year in scenario B 2032. This compares to 5% of all hours under the assumption of flexible generators. In addition, the absolute value of the negative (surplus) peak would be larger than the positive residual load peak. With improving energy efficiency, residual load would decrease further (Figure 21 in the Appendix).

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23 The figure shows mean values for all combinations of yearly availability factors for wind onshore, wind offshore and PV. In the following, this is generally the case, if nothing else is mentioned. Note that the different lines do not represent the same order of single hours.
Figure 3: Residual load (reference load, means)

Figure 4 shows the effects of different flexibility assumptions on positive and negative residual load peaks for all NEP scenarios, as well as the variability of these extreme values over all combinations of yearly availability factors for onshore wind, offshore wind and PV. There are several general observations. First, more renewables always decrease the negative extreme value (from A 2022 to B 2032). Second, the effect of inflexible generation from biomass is a little weaker than the effect of additional 10 GW must-run. This is explained by the fact that average biomass generation is between 5-7 GW in the case of inflexible biomass, depending on the NEP scenario. Third, there is substantial variation in negative peak values, depending on different wind and PV years. In B 2032, the negative peak varies up to 20 GW. The choice of historic feed-in patterns accordingly has a strong effect on the extreme values of residual load and surplus generation, respectively.

Figure 4: Extreme values of residual load depending on wind and PV years, must-run and biomass flexibility (reference load)
Figure 5 shows positive and negative hourly residual load gradients in a sorted order. The largest positive residual load change between two subsequent hours in 2010 was +11.4 GW, and the smallest negative value was -7.2 GW. With increasing capacity of variable renewables, these values become much more extreme: in scenario B 2032, the largest hourly increase of residual load is +21.9 GW, whereas the largest decrease is -26.5 GW.\(^\text{24}\) This corresponds to 24% of the system’s peak load, or 29% respectively. Accordingly, dispatchable power plants, storage, and the demand side have to become more flexible in the future to allow for such large hourly gradients. Notwithstanding the effects on extreme values, the build-up of variable renewables hardly affects load gradients in most hours of the year. Positive gradients in B 2032 are larger than the maximum value in 2010 in only 91 hours, whereas negative extremes are smaller than the negative extreme value of 2010 in 382 hours. Increased flexibility is thus required only during around 5% of all hours of the whole year.

\[\text{Figure 5: Hourly residual load gradients (means)}\]

### 4.2 Renewable surplus generation in NEP scenarios

Now we focus on events of renewable surplus generation, i.e. on the negative part of the residual load curve. Figure 6 shows load-duration curves of surpluses for all NEP cases under the assumption of reference load, no must-run requirements, and flexible bio generation. Curves for the largest and smallest surpluses are provided, depending on wind and PV years used, as well as means for all simulations. In general, the curves have a very steep shape. There are high peaks of surplus generation, but small yearly overall surpluses. In B 2022, there are on average 43 surplus hours;\(^\text{25}\) this number grows to 471 in B 2032. Any measure specifically designed for taking up peak renewable

\[\text{Figure 6: Load-duration curves of surpluses for all NEP cases under the assumption of reference load, no must-run requirements, and flexible bio generation.}\]

\[\text{Figure 6: Load-duration curves of surpluses for all NEP cases under the assumption of reference load, no must-run requirements, and flexible bio generation.}\]

\(^\text{24}\) BET (2013) calculate comparable numbers for 2030, but slightly underestimate the negative extreme value.

\(^\text{25}\) These findings are generally in line with EWI (2013) and VDE (2012a), although the methodology slightly differs. Agora (2012) determine a somewhat higher number of 200 surplus hours because only one specific wind year is used (2011), network losses seem to be neglected, and biomass is assumed to be largely inflexible.
surplus generation would thus achieve only very few full-load hours over the whole year. The growth of the surplus between B 2022 and C 2022 is explained by increasing onshore wind capacity. The further increase between C 2022 and B 2032 is caused by additional PV and offshore wind on top of high onshore wind capacities. Using different wind and PV years has only a moderate effect on peak surplus generation, but a large effect on overall surplus energy. In B 2032, overall surplus varies between 2.5 and 7.5 TWh, depending on the considered yearly availability factors of onshore wind, offshore wind, and PV. This corresponds to around 0.4% or 1.3% of yearly load, respectively. Figure 22 in the Appendix shows corresponding load-duration curves of surplus generation for the case of inflexible generation from biomass, while still assuming no thermal must-run. In this case, surpluses roughly double in all cases, but the shapes of the curves hardly change.

![Figure 6: Load-duration curves of surplus generation (reference load, no must-run, bio flexible)](image)

Overall surplus energy substantially increases with growing must-run requirements and decreasing load, as shown exemplarily for B 2032 in Figure 7. In this case, 10 GW of must-run increase the yearly surplus from 4.5 to 12.1 TWh, corresponding to around 2% of yearly demand; a must-run requirement of 20 GW further increases surplus energy to 28.6 TWh (5%). Decreasing load to 90% or 80% of baseline levels has a similar, but somewhat smaller effect, as 10% of load correspond to a peak load decrease of around 9 GW and an offpeak decrease of only around 4 GW. Combining increasing must-run requirements of 20 GW with decreasing load of 80% results—ceteris paribus—in very large yearly surplus generation of 69.5 TWh, corresponding to around 12% of yearly demand. Accordingly, removing the must-run requirement by making thermal power plants more flexible is
crucial for avoiding large surpluses. This is particular true if the government’s targets on improving energy efficiency are realized.

Figure 7: Surplus for varying assumptions on load and must-run (B 2032, means, bio flexible)

Figure 8 shows the distribution of surpluses over the time of the day for a system with no must-run and flexible biomass (hourly percentages of total surpluses). The largest part of excess generation occurs around noon in all NEP scenarios. This can be explained by PV feed-in. Note that PV capacity factors are low on average, but generally high in the main hours of production (compare section 3.1). Accordingly, we can attribute a major part of surplus generation to PV. A comparison of A 2022 and B 2032 indicates that the distribution gets smoother in case of growing renewable capacities, which generally go along with larger surpluses as shown above. Comparing B 2022 and C 2022 illustrates the effects of increasing wind capacities and decreasing PV capacities: the relative importance of the PV peak around noon decreases, while wind-related off-peak surplus generation becomes more relevant. Figure 23 in the Appendix indicates that the time of day distribution of surpluses becomes even smoother in an inflexible system with a must-run of 20 GW and inflexible biomass. Under such assumptions, not only overall surpluses increase considerably, but also the relative importance of wind-related off-peak surpluses.

Due to daylight saving time, hours are slightly distorted over the course of the year. A part of the surpluses shown in the figure should move one hour to the left. The peak would accordingly be found in the hour between 12:00 and 13:00 in most cases.
Complementary to the time of day distribution discussed above, Figure 9 shows the monthly distribution of surpluses for a flexible system, again as percentages of overall yearly surpluses. In scenario A 2022, in which excess generation is very small, there is a strong concentration on single months, particularly on May. In scenarios with more wind like C 2022 and B 2032, the distribution gets much smoother, while the largest values are still found for the month May. Figure 24 in the Appendix shows that the monthly distribution generally gets smoother with increasing renewables, or with increasing surpluses, respectively.
Figure 9: Monthly distribution of surpluses (reference load, no must-run, bio flexible, means)

The histograms of Figure 10 show the frequency distribution of mean surplus energy in single hours as well as cumulative surplus energy, assuming a flexible system with no must-run and flexible biomass. Given these assumptions, hourly surplus energy is largely in the range of a few gigawatt hours. Even in case B 2032, the energy of nearly 90% of all hourly surpluses is smaller than 30 GWh. For comparison, current German pumped hydro storage capacity is larger than 40 GWh. That is, the surplus of single hours could largely be absorbed with existing storage. As Figure 25 in the Appendix shows, this observation also holds under less favorable assumptions of 20 GW must-run and inflexible biomass: for scenarios A, B and C 2022, surplus energy of most hours is still smaller than 30 GW. Only in scenario B 2032, around 10% of all surplus hours have energies larger than 30 GWh. These make up nearly 30% of the total surplus energy in this scenario.
In addition to the surplus energy of single hours, we calculate the energy of connected surpluses as defined in section 2 (again, means for all wind and PV years). Figure 11 shows that the distribution of connected surplus energies is massively skewed to the right. Most connected surpluses are in the range of existing German pumped hydro storage capacity (around 40 GWh) under the assumption of a flexible system. In scenarios C 2022 and B 2032, which feature large renewable capacities, connected surplus events with cumulative energies of more than 40 GWh nonetheless constitute the majority of total surplus energy. The largest mean connected surplus in B 2032 is 544 GWh, corresponding to 0.1% of yearly demand; for one specific combination of wind and PV years we even find a maximum connected surplus of 1020 GWh (0.2%). Accordingly, the choice of historic wind and PV data has a large effect on the extreme values of connected surpluses.
In an inflexible system with 20 GW must-run and inflexible biomass, connected surplus energy massively increases (Figure 26 in the Appendix). While there are much more connected surplus events, the distribution is even more skewed to the right. Under these assumptions, only a tiny part of the yearly surplus energy could be accommodated by existing pumped hydro capacities. In B 2032, around 90% of yearly surplus energy is made up of connected surpluses larger than 300 GWh. The largest mean connected surplus in B 2032 is larger than 6 TWh (1.1% of yearly demand), the largest single value for a specific combination of wind and PV years is nearly 11 TWh (1.9%). Any technology that is to absorb such surplus energies is thus required to have a very large capacity.

### 4.3 Storage requirements in NEP scenarios

In the following, we show how much storage would be required for taking up the renewable surpluses discussed above, drawing on the outcomes of the optimization model described in section 2. Figure 12 shows optimal storage investments for all NEP scenarios, allowing for different levels of curtailment. We first look at the case of a flexible system without must-run requirements and flexible biomass. No additional storage is needed in any NEP scenario if curtailment is not restricted. Accordingly, integrating surplus energy (on average, between 0.1 TWh in A 2022 and 4.5 TWh in B 2032) by means of storage would be more expensive than generating an according amount of power in thermal plants. In other word, the opportunity costs of investing in storage are

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27 As explained above, optimality only refers to the arbitrage value of storage and its potential for taking up renewable surplus generation in a system with exogenous generation capacities; additional system benefits related to the provision of peak load and/or ancillary services are not considered.

28 VDE (2012a) also find that hardly any storage is required in a scenario with a renewable share of 40%.
prohibitively high. We find a similar result if renewable curtailment is restricted to 1% of the yearly feed-in of wind onshore, wind offshore, PV and hydro power. Under these assumptions, there is only some minor investment in B 2032 into daily storage of 0.8 GW. Allowing a small fraction of curtailment thus renders obsolete virtually all storage investments. If curtailment is further restricted, storage requirements however strongly increase. If only 0.1% of the yearly feed-in of non-dispatchable renewables may be curtailed, mean storage investments increase to more than 9 GW in C 2022 and nearly 22 GW in B 2032. Storage requirements increase to 4, 12, 26 and 41 GW in the four NEP scenarios if no curtailment is allowed. This is because all surplus peaks have to be integrated, even very high and rare ones. Virtually all of these storage capacities are daily storage. The higher roundtrip efficiency of hourly storage cannot compensate its disadvantage in terms of specific costs and energy storage capacity compared to daily storage. Likewise, seasonal storage is hardly required under the flexibility assumptions stated above, as connected surpluses are low.

The right-hand side of Figure 12 shows storage investments in an inflexible system with 20 GW must-run requirement and inflexible generation from biomass. Again, no storage is built in case of unrestricted curtailment. For all other cases of restricted curtailment, however, storage requirements are much larger compared to a flexible system because of larger surpluses. If curtailment is restricted to 1% of the yearly feed-in of non-dispatchable renewables, we determine average storage investments of nearly 4 GW in A 2022 and 38 GW in B 2032. If no curtailment is allowed, these values increase to 32 GW in A 2022 and 74 GW in B 2032. The latter corresponds to 80% of the system’s peak demand. In contrast to the flexible system, a substantial amount of seasonal storage is required in addition to daily storage in the cases with large renewable capacities. For example, 20 GW of seasonal storage is built in B 2032 on top of 54 GW of daily storage in the case with no curtailment. These investments into the more expensive seasonal storage technology are explained by the fact that surpluses are not only more frequent, but also larger in size compared to the flexible system, as shown in section 4.2. Thus, a full integration of surpluses—which are still relatively small compared to yearly load—in an inflexible system by means of power storage requires

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29 Hourly storage technologies like batteries or kinetic storage systems have specific advantages in short-term applications which are not regarded in this analysis. For example, Li-ion batteries are well suited for providing primary frequency control.
very large capacities both in terms of storage loading/discharging and energy capacity. Figure 27 in the Appendix shows the effect of decreasing load on cumulative storage capacities. Not surprisingly, storage investments increase, corresponding to increasing surpluses.

Whereas Figure 12 provides average values, Figure 13 indicates extreme values of storage requirements for different combinations of yearly wind and PV data. We find substantial variations already in the cases in which a flexible system is assumed, and even more so in an inflexible system. Variations are largest in scenario B 2032, which represents the largest capacity of fluctuating renewables. Assuming a flexible system, storage requirements (sum of all technologies) range between 30 GW and 52 GW in B 2032; in an inflexible system, extreme values are 61 GW and 92 GW. These substantial variations in storage investments reflect the underlying variations in surpluses discussed above (compare Figure 4). In all cases, the lower extreme value is much closer to the mean than the upper extreme value, which means that extremely large surpluses only occur very rarely.

We have shown that additional storage is not required in the NEP scenarios if curtailment is not restricted.30 Accordingly, forcing surplus integration by restricting curtailment and instead investing in storage incurs additional costs. Figure 14 shows specific costs of storage investments per avoided curtailment (annualized investment costs divided by amount of electricity not curtailed). Note the logarithmic scale of the second ordinate. In a flexible system, substantial amounts of storage are required in case of no curtailment, but these are rarely used for renewable integration, as surpluses are very small. The specific costs of full surplus integration by means of storage are in the range of several thousand Euros in C 2022 and B 2032, which is prohibitively high. In an inflexible system, not only storage requirements increase, but also storage utilization because of more frequent surplus generation. Accordingly, the specific costs of avoiding curtailment are lower compared to the flexible system, but are still in the range of several hundred Euros in the cases without curtailment. These numbers are way above the costs of generating power with conventional plants, or above market prices respectively. Given our modeling assumptions, curtailing renewables is thus the cheaper option from a system cost perspective compared to investing into new power storage capacities.

30 Curtailment, however, has an effect on renewable energy shares, which is discussed below. An alternative to restricting curtailment would be a constraint on the share of renewable energy in overall electricity demand.
Curtailment, however, decreases the amount of renewable energy used in the power sector. Figure 15 shows how forced surplus integration by means of storage increases the share of renewables in overall power consumption. Assuming a flexible system, renewable shares range between 37% in scenario A 2022 and 58% in B 2032 in case of free curtailment. The storage-related increases in these shares is well below 1 percentage points in all NEP scenarios, as overall surplus generation is low. In contrast, the impact of storage on RES shares is much larger in an inflexible system, as surpluses are higher. This is particularly true for scenarios C 2022 and B 2032, which have the largest renewable surpluses. Assuming 20 GW must-run and inflexible biomass, renewable shares in case of free curtailment are around 45% and 52% in C 2022 and B 2032. Full surplus integration by storage substantially increases these shares by 3 or 7 percentage points, respectively. Accordingly, renewable shares increase to 48% in C 2022 and 59% in B 2032.\(^{31}\) In general, the RES targets of the German government are exceeded in all NEP scenarios, even under the assumption of free curtailment.

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\(^{31}\) The only exception is A 2022, in which the (linearly interpolated) target of 38% is narrowly missed. This finding is in line with the findings of a meta-analysis carried out by Dena (2013), which concludes that power storage is of relatively minor importance for achieving renewable and emission targets in Germany.
4.4 Selected results for the 2050 scenario

Complementary to the previous analyses for the NEP scenarios, we now present selected results for the long-term outlook to 2050. Figure 16 shows load-duration curves of surplus generation for the means of all combinations of wind and PV years as well as for the largest and smallest yearly surpluses.\(^{32}\) In a flexible system, surplus generation now occurs on average during 1707 hours of the year, or 19% of all hours. Mean overall surplus energy is nonetheless rather small with around 18 TWh, corresponding to around 4% of yearly demand. Peak surplus power also increases only slightly compared to B 2032 and reaches 53 GW on average. Under the assumption of 20 GW must-run and inflexible biomass, surpluses would occur in 8004 hours (91% of all hours). Surplus energy would also increase drastically to 195 TWh (47% of yearly demand) with a peak of 89 GW. Accordingly, the scenario 2050 appears utterly inconceivable under the assumption of high must-run requirements and inflexible biomass. Rather, it requires a perfectly flexible system.

![Figure 16: Load-duration curves of surplus generation 2050](image)

Figure 17 shows storage investments for the 2050 scenario, again for the means of all combinations of wind and PV data and for the two extreme combinations. Mean storage investments increase for all levels of curtailment compared to scenario B 2032. What is more, the share of seasonal storage increases because connected surpluses are larger. In a flexible system, around 10 GW of storage are optimal on average even in case of free curtailment. Renewable curtailment accordingly is no longer the least-cost option, and some level of storage investment no longer has to be enforced. The main reason for this finding, aside from increased surpluses compared to the NEP scenarios, is the much higher cost of fossil generation in this scenario.\(^{33}\) In addition to around 3 GW of daily storage, nearly 7 GW of seasonal storage are optimal in case of free curtailment.\(^{34}\) If curtailment is restricted to 1% or 0.1% of the yearly generation of non-dispatchable renewables, average storage requirement increases to 16 GW or 37 GW, respectively. If no curtailment is possible at all, 54 GW of storage are required, of which around 7 GW are seasonal storage.

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\(^{32}\) We select the largest and the smallest surplus in terms of overall energy, not regarding peak surplus. The largest surplus power in a single hour is 64 GW in the flexible case and 100 GW in the inflexible case.

\(^{33}\) Additional simulations show that peak load could also be met without additional storage capacities, but at higher costs.

\(^{34}\) There is nonetheless curtailment of around 40GW in the peak surplus hour.
Figure 17: Storage investment 2050

Storage requirements further increase under the assumptions of 20 GW must-run and inflexible biomass, because these imply extremely large surpluses as shown above. A notable exception is the case of free curtailment, in which we find hardly any investment. The reason for this seemingly counterintuitive result is the low number of remaining hours with positive residual load (756 hours on average, corresponding to 9% of all hours). The full-load hours achievable by additional storage are accordingly strongly restricted, such that investing into storage is no longer optimal from a system cost perspective. In the cases with restricted curtailment, i.e. forced storage investments, storage capacities are very large with 61 GW, 79 GW and 93 GW for curtailment levels of 1%, 0.1% and 0%. These values compare to a system peak load of only 67 GW. Accordingly, the inconceivable surpluses of the inflexible 2050 scenario would go along with absurdly high storage requirements.

Figure 18 shows specific annualized storage investments per avoided curtailment for the mean investments as well as for the maximum and minimum investments of the respective cases.35 These costs are generally lower compared to the NEP scenarios, as surpluses are more frequent and storage utilization is higher. Assuming a flexible system, costs are nonetheless way above the marginal costs of thermal generation in all cases (136 €/MWh for hard coal and 131 €/MWh for natural gas). Storage investments thus occur only if these are forced by restricting curtailment. In an inflexible system, specific costs of avoided curtailment are around 50 €/MWh, which is surprisingly low at first glance. So why is storage only built if it is enforced by restricted curtailment? As shown above, there are only few remaining hours with positive residual load. It is thus impossible to make reasonable use of the stored electricity under model assumptions, as there is no fossil generation left that could be substituted.

35 The figure shows specific costs of avoided curtailment only for the cases in which curtailment is actually restricted. In other words, it shows the specific costs of forced storage investments beyond the level that would be optimal in case of free curtailment.
Figure 18: Investment costs per avoided curtailment 2050

Figure 19 shows storage-related increases in RES shares in overall power consumption. Assuming a flexible system, renewables shares are hardly affected compared to the case of unrestricted curtailment. The mean value in the case of free curtailment is already 95%. It is increased by a little more than 1 percentage point to nearly 97%. The picture completely changes if an inflexible system is assumed. Here, the RES share in the unrestricted case is only 55% because of the high must-run requirement of 20 GW for thermal power plants. In the cases with forced renewable integration by additional power storage, this share increases substantially to around 97%. This is achieved by essentially taking up the thermal must-run generation and not making use of it. This absurd result illustrates the finding that a system with very large shares of variable renewables is not compatible with large thermal must-run requirements.

Figure 19: Storage-related increase of RES share in electricity consumption 2050

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36 Again, only the increase compared to the case of free curtailment is provided, i.e. the increase in the RES share attributable to forced storage investment.
5 Discussion of limitations

The simulations have been carried out under a range of simplified assumptions in order to make room for a large number of sensitivities. In the following, we briefly discuss the effects on simulation outcomes.\textsuperscript{37} We start with a discussion of such assumptions that lead to an underestimation of surpluses and/or storage requirements.

First, we neglect local network constraints within Germany by implicitly assuming that transmission networks (and also distribution networks) will be expanded according to NEP (2012). We thus consider surpluses for the Germany system as a whole and neglect possible local surplus events. In recent years, local curtailment due to network constraints was small, but grew considerably from 74 GWh in 2010 to 126 GWh in 2011 and to 421 GWh in 2012 (Bundesnetzagentur 2012; Bundesnetzagentur and Bundeskartellamt 2013). According to EWI (2013), congestion-related renewable curtailment may increase up to 8 TWh by 2022 if networks are not extended as planned. Second, the linear dispatch model neglects flexibility constraints of thermal generators.\textsuperscript{38} In particular, we consider start-up and ramping to be both costless and perfectly flexible. More realistic assumptions on restricted power plant flexibility may result in slightly higher surpluses as well as larger storage investments. Third, we do not endogenously determine optimal generation capacities, but draw on exogenous capacities from NEP (2012) which prove to be sufficient to satisfy demand in all hours. Accordingly, the potential capacity value of storage for supplying peak load is not captured. A similar interpretation is that storage cannot benefit from scarcity prices. Storage’s capacity value could be captured in a dynamic modeling framework with endogenous capacities, in which storage competes with investments in gas turbines or other technologies. Fourth, we apply varying levels of a stylized, system-wide must-run requirement, which reflects economic, technical, system-related and institutional aspects as discussed above. We assume that this requirement can be decreased to 10 or even 0 GW without specifying, for example, how ancillary services are to be provided. Although the optimal provision of ancillary services in power systems with high shares of fluctuating renewables remains an open question for further research, it appears reasonable to assume that power storage facilities could provide at least a share of these services while still taking up renewable surplus generation. This contributes to a possible underestimation of optimal storage investments in our model. Finally, we do not consider any costs of curtailment related to the institutional framework, for example financial compensation of renewable generators. Including such costs should tend to decrease curtailment and increase optimal storage investments in all cases. Currently, renewable generators in Germany are generally compensated in case of curtailment; however, the future development of the institutional framework for new renewable generators is unclear.

Other simplified assumptions have an opposite effect, i.e. lead to an over-estimation of surpluses and/or storage investments. For example, the linear scaling of historic feed-in patterns of variable renewables neglects adjustments in generator design or site choices, which are expected to align feed-in patterns somewhat better with power demand. Examples are improved orientation of solar PV panels in east-west direction or changed generator design of wind turbines which results in lower

\textsuperscript{37} In addition to the factors discussed below, the permutation of different yearly availability factors of onshore wind, offshore wind and PV may result in exaggerated extreme values of surplus power, connected surpluses and storage requirements. The effect on mean values, however, is unclear.

\textsuperscript{38} To a certain degree, flexibility restrictions are approximated by the system-wide must-run constraint, as explained in section 3.1.
peak generation, but higher full-load hours. Such improvements, which may be triggered by future market integration of RES, should tend to decrease renewable surplus generation. Next, including network fees for storage facilities should tend to reduce storage investments. Currently, existing storage facilities in Germany have to pay network fees for power drawn from the grid. There are several temporary exemptions for new facilities, but the future development of the institutional framework is unclear. A major over-estimation, however, of storage requirements originates from the fact that we neglect other flexibility options, in particular demand-side management, future electric vehicle fleets, the use of electricity in the heat sector (power-to-heat), and the possibility of exchanging power with neighboring countries. In the medium to long run, all of these options are capable of taking up a sizeable share of renewable surpluses and thus reduce power storage requirements. Of these, power-to-heat appears to be particularly promising, as investment costs of electric heating elements are generally very low (VDE 2012a). Moreover, surpluses can be exported to other countries on a large scale. According to ENTSO-E (2013b), the average simultaneous net transfer export capacity (NTC) from Germany to the Netherlands, France and Switzerland is around 8.5 GW (2010 data). In addition, there are interconnections with other neighboring countries. Even if the capacity that can actually be utilized in any given hour may vary substantially from NTC values, there is large room for exports. Furthermore, cross-border capacities should tend to increase in the context of European power market integration.

Considering the combined effects of simplified assumptions, we conclude that the system-wide surpluses determined in this paper should not be systematically disturbed in one direction. Optimal storage investments are on the one hand underestimated, mainly because of their value for providing reliable generation capacity and ancillary services; on the other, these are overestimated in the light of other flexibility options and export possibilities, which are all dismissed here. Overall, we consider the latter factors to dominate the previous ones, such that our analysis should tend to overestimate storage requirements.

6 Summary and conclusions
We have analyzed the effects of future renewable expansion in Germany on residual load and renewable surplus generation for policy-relevant scenarios which cover the years 2022, 2032 and 2050. Moreover, we have determined how much storage would be required for taking up renewable surpluses for varying levels of accepted curtailment. In doing so, we made extensive use of historic renewable feed-in data and carried out numerous sensitivity analyses for varying assumptions, particularly regarding must-run requirements and the flexibility of biomass generators.

We find that the expansion of variable renewables has a very small effect on peak residual load, but leads to a strong decrease on the right-hand side of the residual load curve. There are hours with negative residual load in all scenarios analyzed. In a system without must-run and with flexible generation from biomass, residual load becomes negative during 5% of all hours of the year in scenario B 2032. In a less flexible system with a thermal must-run requirement of 20 GW and inflexible biomass generation, this value increases to 40% of all hours. In the 2050 scenario, surpluses would occur during 19% of all hours assuming a flexible system, and during 91% of all hours assuming an inflexible system. Accordingly, such inflexibility assumptions are implausible for a 2050 scenario with very high shares of renewables. Whereas the residual load curve generally shifts downwards with increasing must-run, decreasing biomass flexibility and decreasing load, there is substantial
variation of extreme values depending on the meteorological wind and PV years used. Maximum and minimum gradients of hourly residual load also become much more extreme.

Focusing on renewable surpluses, we find that their load-duration curves generally have a very steep shape. These correspond to high peaks of surplus generation which occur in very few hours of the year, and low full-load hours, i.e. relatively small overall surpluses. Overall surplus energy varies substantially between different wind and PV years, and increases with growing must-run requirements, less flexible biomass generation and decreasing load. On average, most surpluses occur around noon, i.e. are related to the feed-in of PV. The monthly distribution of surpluses generally has a peak in late spring around the month of May. Both the time of day distribution and the monthly distribution become smoother with increasing capacities of onshore and offshore wind which lead to additional surpluses during night-time and winter months. The energy of single surplus hours is in the range of existing German pumped hydro capacities in most scenarios analyzed. This is generally not the case for connected surpluses, the distribution of which is massively skewed to the right. In the scenarios with sizeable overall surpluses, the connected surplus events with energies larger than 40 GWh constitute the majority of total excess generation. Connected surplus energies greatly increase in case of growing must-run and inflexible biomass generation compared to a flexible system. In addition, there is a strong variation between different combinations of wind and PV years for extreme values of connected surplus energies.

Our analysis of optimal storage investments—which do not include possible values of storage related to the provision of firm capacity and/or ancillary services—shows that no additional storage is required in any NEP scenario if curtailment is not restricted. In contrast, there are around 10 GW of storage investments in 2050 even in case of free curtailment (assuming a flexible system) because of larger surpluses and higher costs of fossil generators. Returning to the NEP scenarios, restricting curtailment to only 1% of the yearly feed-in of non-dispatchable renewables would render storage investments largely obsolete under the assumption of a flexible system. In contrast, full surplus integration would require additional storage capacities of 4, 12, 26 and 41 GW in the four NEP scenarios, as even very large and rare surplus events would have to be integrated. Compared to these results, storage requirements are substantially larger and also comprise significant shares of seasonal storage if thermal generators are assumed to be inflexible, as surpluses also increase strongly under such assumptions. In 2050, mean storage investments increase for all levels of curtailment compared to the NEP scenarios, while the share of seasonal storage is also higher. The maximum values of storage investments vary substantially between different combinations of wind and PV years, reflecting large variation in surplus energies. Forcing surplus integrating by means of storage beyond optimal levels would be more expensive compared to generating the curtailed electricity with thermal plants. Forced surplus integration by restricted curtailment accordingly incurs specific costs of surplus integration which are much larger than variable costs of thermal plants. At the same time, the effect of curtailment on the shares of renewable energy in overall power consumption is negligible under the assumption of a flexible system in all scenarios. If 20 GW must-run and inflexible biomass are assumed, curtailment has an impact on RES shares in the range of a few percentage points in the NEP scenarios; in the 2050 scenario, this effect would be much larger, but an inflexible 2050 scenario appears to be rather meaningless in the context of this analysis. In general, curtailment does not impede achieving the German government’s RES targets in the scenarios analyzed here.
Based on the simulations presented in this paper we draw conclusions that are not only relevant for Germany’s ‘Energiewende’, but also for other countries shifting towards variable renewables. First, we conclude that renewable surpluses can be minimized by flexibilization of thermal generators, in particular by decreasing must-run requirements and by enabling biomass to generate power in a more demand-oriented way. Thermal must-run, which may be caused by economic, technical or system-related factors, can be diminished, for example, by retrofitting existing plants such that lower minimum load levels or faster start-up are enabled. Likewise, combined heat and power generation can become more flexible, for example by coupling such plants with heat storage facilities. Further, must-run can be decreased if ancillary services are provided by renewable generators, storage facilities and/or the demand side, which may also require changes in reserve market rules. Generation from biomass could be flexibilized by increasing the power rating of these installations, coupled with sufficient biogas storage capacities. In the light of growing shares of variable renewable energy, we conclude that increasing system flexibility should become a priority for policy makers. Note that different energy storage technologies can contribute to such flexibilization.

In case of very large RES shares, and if the system is already sufficiently flexible, power storage becomes more relevant. We however conclude that full surplus integration by means of power storage will never be optimal even in a perfectly flexible system because of the nature of surpluses shown in this paper. Taking up total renewable surplus generation, including peaks and the greatest connected surplus events, would require very large storage capacities both in terms of storage loading/discharging and energy. At the same time, storage facilities of such dimensions would achieve only very few full-load hours over the whole year.

While we have only considered curtailment and power storage in this analysis, we infer that there is much room for other flexibility options between these two extreme approaches. In particular, surpluses can be exported, i.e. balanced over a larger geographic area. Moreover, there are large low-cost potentials for using renewable power surpluses in the heat sector. Other flexibility options like demand-side management and grid-connected electric vehicles can also play a role in the medium to long term.

As a guideline for policy makers concerned with excess renewable generation, we suggest (i) avoiding renewable surpluses by making thermal generators more flexible in the first place, (ii) making use of different flexibility options for the remaining surpluses, including but not limited to power storage, and (iii) draw on curtailment as a last resort in case no reasonable use can be made of surpluses. Given these multiple options of handling temporary excess generation, we also conclude that concerns about surpluses should not be regarded as an obstacle to further renewable expansion. As for technology policy, we propose focusing on research and development of energy storage technologies instead of demand-pull measures for the time being, as our analysis indicated that substantial deployment of storage is only required in the long run.

Several questions remain for future research, in particular regarding the optimal mix of storage, curtailment and other competing flexibility options. Examining the interaction of different energy storage technologies with network expansion and power-to-heat appears to be a particularly promising field of research. Moreover, the full system value of storage technologies should be investigated, including their capacity value and the provisions of ancillary surpluses. To do so, sufficiently detailed power sector models are to be applied, which should not only include a realistic representation of the flexibility constraints of thermal power plants, preferably a unit commitment
approach, but also restrictions related to the provision of ancillary services. In any case, the meteorological data for wind and PV generation has to be carefully selected in future research, as this analysis has shown that extreme values of residual load, surplus generation, and in particular connected surplus energies vary substantially.
Literature


Bundesnetzagentur, Bundeskartellamt (2013): Monitoringbericht 2012. Monitoringbericht gemäß § 63 Abs. 3 i.V.m. § 35 EnWG und § 48 Abs. 3 i.V.m. § 53 Abs. 3 GWB. Bundesnetzagentur für Elektrizität, Gas, Telekommunikation, Post und Eisenbahnen und Bundeskartellamt. Bonn, 05.02.2013.


## Appendix

### Table 5: Sets, indices, parameters and variables

<table>
<thead>
<tr>
<th>Sets and indices</th>
<th>Description</th>
<th>Units, allowed values or instances</th>
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<tr>
<td>$t \in T$</td>
<td>Time</td>
<td>Hours</td>
</tr>
<tr>
<td>$tech \in TECH$</td>
<td>Conventional technologies</td>
<td>Nuclear, lignite, hard coal, natural gas, oil, other</td>
</tr>
<tr>
<td>$stor \in STOR$</td>
<td>Storage Technologies</td>
<td>Daily, hourly, seasonal</td>
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**Parameters**

<table>
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<tr>
<th>Parameter</th>
<th>Description</th>
<th>Units, allowed values or instances</th>
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<tbody>
<tr>
<td>allowcurt</td>
<td>Allowed curtailment factor</td>
<td>Between 0 and 1</td>
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<tr>
<td>$bio$</td>
<td>Biomass capacity constraint</td>
<td>MW</td>
</tr>
<tr>
<td>$dem_t$</td>
<td>Hourly demand</td>
<td>MWh</td>
</tr>
<tr>
<td>$epratio_{stor}$</td>
<td>Energy-to-power ratio</td>
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<tr>
<td>$\eta_{stor}$</td>
<td>Roundtrip efficiency</td>
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<td>$hydro_t$</td>
<td>Hourly generation from</td>
<td></td>
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<tr>
<td>$ic_{stor}$</td>
<td>Storage investment costs</td>
<td>€/MW</td>
</tr>
<tr>
<td>$mustrun$</td>
<td>Aggregated must-run requirement</td>
<td>MW</td>
</tr>
<tr>
<td>$pv_t$</td>
<td>Hourly generation from PV</td>
<td>MWh</td>
</tr>
<tr>
<td>$q_{tech}$</td>
<td>Capacity constraint for conventional generation</td>
<td>MW</td>
</tr>
<tr>
<td>$storin_{stor}$</td>
<td>Initial storage charging power</td>
<td>MW</td>
</tr>
<tr>
<td>$storlevel_{stor}$</td>
<td>Initial storage capacity</td>
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</tr>
<tr>
<td>$storout_{stor}$</td>
<td>Initial storage discharging power</td>
<td>MW</td>
</tr>
<tr>
<td>$vc_{tech}$</td>
<td>Variable costs of conventional generation</td>
<td>€/MWh_{el}</td>
</tr>
<tr>
<td>$vstc_{stor}$</td>
<td>Variable costs of storage</td>
<td>€/MWh_{el}</td>
</tr>
<tr>
<td>$windoff_{t}$</td>
<td>Hourly generation wind onshore</td>
<td>MWh</td>
</tr>
<tr>
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<tr>
<td>$yearlybio$</td>
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**Variables**

<table>
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<th>Variable</th>
<th>Description</th>
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</tr>
<tr>
<td>$inv_{stor}$</td>
<td>Storage investment</td>
<td>€/MW</td>
</tr>
<tr>
<td>$q_{tech,t}$</td>
<td>Hourly generation from conventional plants</td>
<td>MWh</td>
</tr>
<tr>
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<td>Renewable curtailment</td>
<td>MWh</td>
</tr>
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<td>MWh</td>
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<tr>
<td>$storlevel_{stor,t}$</td>
<td>Storage level</td>
<td>MWh</td>
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<tr>
<td>$storout_{stor,t}$</td>
<td>Storage discharging</td>
<td>MWh</td>
</tr>
</tbody>
</table>
Figure 20: Load-duration curves for onshore wind, offshore wind and PV for NEP scenarios (means)

Figure 21: Residual load (80% load, means)
Figure 22: Load-duration curves of surplus generation (reference load, no must-run, bio inflexible)
Figure 23: Time of day distribution of surpluses (reference load, 20 GW must-run, bio inflexible, means)

Figure 24: Monthly distribution of surpluses (reference load, 20 GW must-run, bio inflexible, means)
Figure 25: Frequency distribution of surplus energy for single hours (reference load, 20 GW must-run, bio inflexible, means)

Figure 26: Frequency distribution of surplus energy for connected surpluses (reference load, 20 GW must-run, bio inflexible, means)
Figure 27: Effect of load on storage investment (means)