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Long-run power storage requirements for high shares of renewables: Results and sensitivities

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A R T I C L E I N F O

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A B S T R A C T

We use the model DIETER, introduced in a companion paper, to analyze the role of power storage in systems with high shares of variable renewable energy sources. The model captures multiple system values of power storage related to arbitrage, capacity, and reserve provision. We apply the model to a greenfield setting that is loosely calibrated to the German power system, but may be considered as a more generic case of a thermal power system with increasing shares of variable renewables. In a baseline scenario, we find that power storage requirements remain moderate up to a renewable share of around 80%, as other options on both the supply and demand side may also offer flexibility at low cost. Yet storage plays an important role in the provision of reserves. If the renewable share further increases to 100%, the need for power storage grows substantially. As long-run parameter assumptions are highly uncertain, we carry out a range of sensitivity analyses. As a general finding, storage requirements strongly depend on the costs and availabilities of other flexibility options, particularly regarding flexible power generation from biomass. We conclude that power storage becomes an increasingly important element of a transition toward a fully renewable-based power system, and gains further relevance if other potential sources of flexibility are limited.

1. Introduction

In [1], we introduce a new open-source model, DIETER, the Dispatch and Investment Evaluation Tool with Endogenous Renewables. This model minimizes total system costs and addresses important domains, derived from a dedicated literature review, of power storage requirements in systems with high shares of variable renewable energy sources (RES): an hourly resolution, a consideration of all contiguous hours of a full year, a representation of balancing reserves, and detailed constraints with respect to demand-side management. The model captures multiple system values of power storage related to arbitrage, capacity, and reserve provision. Nonetheless, the model is computationally efficient, which allows for carrying out numerous sensitivity analyses.

In this article, we use DIETER to analyze the role of power storage in systems with high shares of variable renewable energy sources. We abstract from path dependencies by simultaneously optimizing the full power system with all capacities being endogenous variables. We apply the model to a long-term greenfield setting that is loosely calibrated to the German power system. In Germany, the share of renewable sources in gross power demand has increased from around 3% in the early 1990s to nearly 32% in 2016. In the context of the *Energiewende*, Germany's ambitious long-term energy transition, the German government is aiming for a renewables share of at least 80% by 2050.[1] In the long run, comparable or even higher shares of renewable energy sources may also be required in many other countries in the context of tighter carbon constraints. Although our analysis focuses on the German case, it can be considered as a generic example of a thermal power system with increasing shares of variable renewable energy sources. In order to guarantee complete traceability and transparency of our analysis, both the model and all input parameters are provided under dedicated open-source licenses.[2]

The remainder of this paper is structured as follows: Section 2 introduces all relevant input parameters and the scenarios studied. Results of the baseline scenario and numerous sensitivities are presented in Section 3. Limitations of the model application and

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[1] This target is stated in numerous government documents and is also included in the 2012, 2014, and 2017 versions of the German Renewable Energy Sources Act (*Erneuerbare-Energien-Gesetz*, EEG).

[2] DIETER may be freely used and modified by anyone. The code is licensed under the MIT License. Input data is licensed under the Creative Commons Attribution-ShareAlike 4.0 International Public License. To view a copy of these licenses, visit http://opensource.org/licenses/MIT and http://creativecommons.org/licenses/by-sa/4.0/. This article refers to model version 1.0.2. Different model versions and further information are provided at http://www.diw.de/dieter.

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potential impacts on results are discussed in Section 4. The final Section 5 concludes.

2. Input data and scenarios

2.1. Input data

The model is loosely calibrated to the German power system with regard to demand, hourly availabilities of variable renewable energy sources, as well as constraints for offshore wind power, biomass, pumped-hydro storage, and demand-side management (DSM).[3] Hourly load values are taken from ENTSO-E [2] for the year 2013. For the fraction of reserves called, we divide the mean hourly reserves actually activated, provided by the German TSOs [3], by the contracted capacities at that point [4].

Aside from time-related input data, which is based on the year 2013 under baseline assumptions, all technology-specific input parameters reflect a 2050 perspective. Tables B.1–B.5 in Appendix B contain a detailed representation of all technology-specific assumptions of the baseline, including respective units and data sources. Annualized fixed costs are generally calculated by drawinging on overnight investment costs, fixed costs not related to power generation (where applicable), specific technical lifetimes, and an assumed interest rate of 4%. Monetary values are generally stated in real prices of 2010.

Regarding thermal generation technologies, we include hard coal, combined cycle natural gas (CCGT) and two types of open cycle natural gas turbines (OCGT)—an "efficient" one with lower marginal but higher investment costs and an "inefficient" type for which the opposite is true. By assumption, investments into nuclear, lignite, and run-of-river hydro power are not possible. In case of nuclear, this reflects the legal situation in Germany. Lignite plants, which have high specific CO_2 emissions, are assumed not to be compatible with a long-term, low-emission, renewable-based system.[4] Run-of-river is excluded because, on the one hand, potentials in Germany are small; and on the other, it is a non-dispatchable low-cost technology, such that unlimited investment opportunities would render model results trivial.

The major source for cost parameters for conventional generators and biomass plants is the DIW Data Documentation [5], of which medium projections for 2050 are used. Supplementary information stems from VGB PowerTech [6], and VDE [7] for load change flexibility. Marginal production costs of conventional plants are calculated based on the carbon content of the fuel [8], an assumed CO_2 price of 100 Euro per tonne, and specific efficiency and fuel costs. Fuel prices follow the "medium" price path within [9], except for lignite [10].

Regarding variable renewable technologies, we include onshore and offshore wind power as well as solar photovoltaics. In addition, investments in dispatchable biomass generators—which are treated like conventional thermal plants in the model formulation—are possible. Cost data for renewables also comes from the DIW Data Documentation [5]. Under baseline assumptions, a cap on offshore wind power installations of 32 GW is assumed [9]. We further assume a yearly biomass budget of 60 TWh in the baseline [11]. We calculate hourly renewable availability factors by dividing the 2013 hourly in-feed of onshore wind [12–15], offshore wind [14], and solar photovoltaics (PV) [16–19], provided by the German TSOs, by the installed capacity in the same year [20].[5]

Building on the "Roadmap Storage" [21], we consider seven distinct storage technologies that vary with respect to specific investments into power and energy as well as roundtrip efficiency. In most scenarios, investment choices are restricted to three of these technologies: lithium-ion batteries (Li-ion, as an example for a short-term storage technology), pumped-hydro storage (PHS, medium-term), and power-to-gas (P2G, long-term).[6] The remaining four technologies are included only in a sensitivity analysis. These are considered to be either risky with respect to environmental or security concerns, such as lead acid batteries and sodium-sulfur (NaS) batteries, or not to be cost-competitive with the other storage options like redox flow batteries and advanced adiabatic compressed air energy storage (AA-CAES). For DSM potentials and costs, we largely draw upon [23] who assemble evidence from numerous academic and applied studies, as well as on [24–26].

2.2. Scenario definition

The model is implemented in the General Algebraic Modeling System (GAMS) and solved with the commercial solver CPLEX.[7] We apply the model to a baseline scenario and to numerous sensitivities, while always varying the requirement for the minimum renewable share between 60%, 70%, 80%, 90%, and 100%. In order to study the effects of deviating parameter assumptions, we carry out various sensitivity analyses (Table 1).

A first group of sensitivities deals with different assumptions on the costs and availabilities of power storage technologies: availability of additional storage technologies, deviations of specific investment costs, and a tighter energy cap for pumped-hydro storage. Next, we consider two extreme variations of the assumed DSM potentials, zero or double compared to the baseline. Another group of sensitivities relates to costs and availabilities of renewables. This includes alternative assumptions on offshore wind power costs and potentials—a very important sensitivity for transferring results to other countries with higher or lower offshore wind potentials compared to Germany—smoother onshore wind profiles,[8] and alternative specific investments for PV. Moreover, we include a sensitivity on the availability of biomass and a worst case with respect to variable renewable feed-in by assuming a week of "dark winter-no wind", during which electricity demand is high, but no power generation from onshore wind, offshore wind, or PV is possible. Moreover, we vary the level of required reserves, which may be considered both as a sensitivity with respect to a distinctive model feature or a parameter assumption.

In Appendix A.2, we also provide capacity outcomes for sensitivity analyses with respect to alternative base years. While the patterns of renewable feed-in and load are based on 2013 German data in all aforementioned model runs, we test the effect of alternatively drawing on 2011 or 2012 data. Yet the results are not fully comparable to 2013, as offshore wind feed-in data is less reliable, being based on very few single wind turbines, such that results may be distorted with respect to one decisive variable, that is, offshore wind power deployment.

3. Results

3.1. Baseline scenario

Under baseline assumptions, we determine a renewable share of around 76.4% in the unrestricted case.[9] Photovoltaics and onshore wind power have the largest capacities installed (Fig. 1). If the minimum renewable share approaches 100%, overall capacities in-

[3] All input data is freely available under a Creative Commons Attribution-ShareAlike 4.0 International Public License under http://www.diw.de/dieter.

[4] This assumption appears not to be critical. Additional model runs that include a lignite option parametrized according to Table B.1 show that no such investments take place under the assumed baseline CO_2 price of 100 Euro per tonne, as lignite plants incur both high investments and high variable costs.

[5] For convenience, we impose a linear expansion path on the installed capacities between the beginning and the end of 2013.

[6] Here, "power-to-gas" involves the use of electricity to generate hydrogen and later reconversion to electricity. A more precise, but rather lengthy term would be "power-to-hydrogen-to-power".

[7] Whereas the source code and all input parameters are available under open-source licenses, GAMS and CPLEX are proprietary software.

[8] Profiles are taken from [27].

[9] As the model restriction on the minimal renewable share is not binding for minimum shares of both 60% and 70%, these can be interpreted as "unrestricted" cases. The same reasoning applies in the following. For the sake of consistency, we always show results for 60%, 70%, 80%, 90%, and 100%, respectively.

Table 1
Assumptions for sensitivities.

Availability of storage technologies								
		Li-ion	Lead acid	NaS	Redox flow	PHS	AA-CAES	P2G
Baseline		✓	–	–	–	✓	–	✓
Seven technologies		✓	✓	✓	✓	✓	✓	✓
Annualized specific investment costs of storage in EUR/kWh, EUR/kW								
		Li-ion	Lead acid	NaS	Redox flow	PHS	AA-CAES	P2G
Baseline, c_{sto}^{iE}		14	–	–	–	<1	–	<1
Baseline, c_{sto}^{iP}		3	–	–	–	46	–	68
Double, c_{sto}^{iE}		28	–	–	–	1	–	<1
Double, c_{sto}^{iP}		5	–	–	–	92	–	136
Half, c_{sto}^{iE}		7	–	–	–	<1	–	<1
Half, c_{sto}^{iP}		1	–	–	–	23	–	34
Storage energy restriction in GWh								
		Li-ion	Lead acid	NaS	Redox flow	PHS	AA-CAES	P2G
Baseline		∞	–	–	–	300	–	∞
Tight restriction		∞	–	–	–	75	–	∞
DSM potentials in MW								
			Load shifting				Load curtailment	
	1 h	2 h	3 h	4 h	12 h	cheap	medium	expensive
Baseline	793	2535	1385	1451	1050	3300	1600	5400
No potential	0	0	0	0	0	0	0	0
Double potential	1585	5088	2770	2902	2100	6600	3200	10,800
Offshore wind power costs and potentials								
Baseline	32 GW							
No offshore	0 GW							
Breakthrough	53 GW, and half specific investment costs							
Onshore wind profiles								
Baseline	Derived from German feed-in time series of 2013							
Smooth	Smoothed pan-European pattern based on wind speed data of 2011							
Specific annualized investment costs of PV in EUR/kW								
Baseline	27							
Double costs	54							
Half costs	14							
Dark winter-no wind								
Baseline	Wind and PV availability according to German patterns of 2013							
Dark winter-no wind	No wind and PV feed-in in week 45							
Energy restriction on biomass in TWh								
Baseline	60							
No biomass	0							
Reserve requirements								
	int_+^r		slp_+^r		int_-^r		slp_-^r	
Baseline, wind	1.912		0.031		3.242		0.026	
Baseline, PV	1.912		0.005		3.242		0.018	
Zero, wind	0		0		0		0	
Zero, PV	0		0		0		0	
Double, wind	1.912		0.062		3.242		0.052	
Double, PV	1.912		0.010		3.242		0.036	

Note: numbers generally rounded to integers, and to three decimals for reserve parameters. For reserve requirements, subscript + indicates relevance for positive reserves, subscript - for negative reserves.

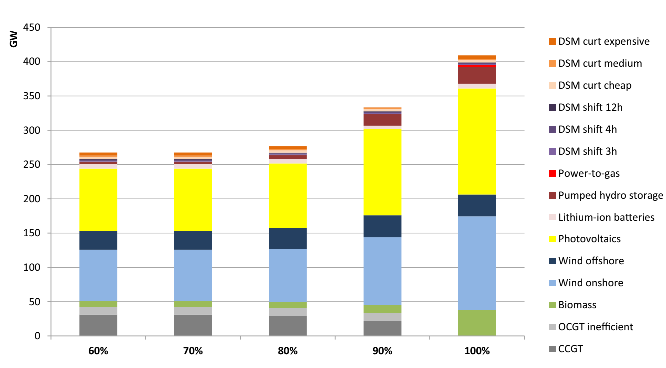

Fig. 1. Baseline scenario: installed capacities.
Source: own calculations.

crease strongly. Gas-fired power plants are substituted by a mix of other flexibility options in the 100% case. First, the capacity of dispatchable biomass increases strongly, while its energy limit stays constant. Biomass full-load hours accordingly decrease strongly. Second, the capacities of variable renewables increase disproportionately. Offshore wind power already reaches its installation limit in the 90% case. At the same time, renewable curtailment increases from 1.2% in the unrestricted case to more than 7% in the 100% case. Third, storage capacities are expanded.

The requirements for short-term flexibility options (lithium-ion batteries and DSM) barely change between the cases.[10] These technologies are already required in the unrestricted case. In contrast, pumped-hydro storage increases strongly beyond a share of 80%. In a 100% renewable setting, pumped hydro reaches a capacity of around 24 GW, corresponding to 32% of the system peak load, and also reaches its energy cap. Long-term-storage is required only to a small extent and only in the 100% case under baseline assumptions (around 3 GW). Yet its E/P ratio is much larger compared to pumped-hydro

[10] DSM shift 3h, DSM shift 4h, DSM shift 12h, DSM curt cheap, and DSM curt medium are always at their capacity limits. This is also true for most of the sensitivities.

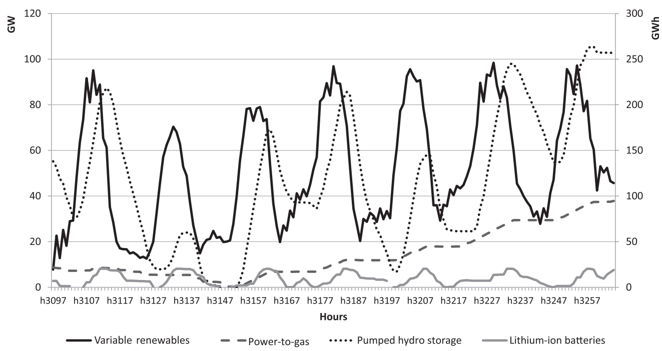

Fig. 2. Baseline scenario: exemplary patterns of variable renewable power generation (left axis) and storage energy levels (right axis).
Source: own calculations.

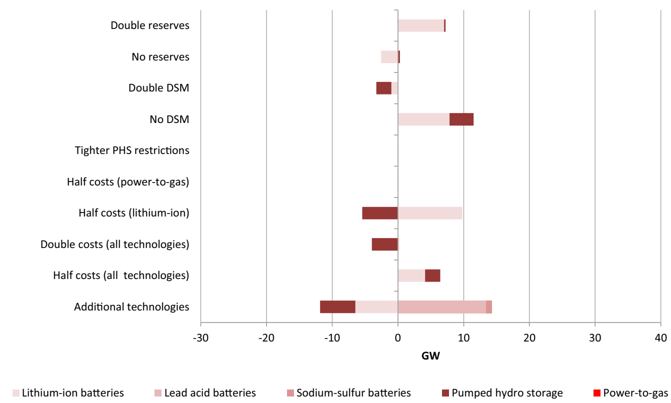

Fig. 3. Sensitivities on storage, DSM, and reserves: changes in installed storage power for 80% renewables.
Source: own calculations.

storage (42 compared to 12 h for PHS and 3 for lithium-ion batteries). Overall, the storage requirement nearly triples from around 12 GW in the 80% renewables case to 34 GW in the fully renewable case.

As regards overall yearly energy provision, the shares of combined cycle gas turbines, biomass, and offshore wind power are larger compared to the respective shares of installed capacities (Fig. A.1 in Appendix A.1). These technologies achieve higher full-load hours compared to onshore wind power and PV. In contrast, open cycle gas turbines and load curtailment have disproportionately small energy shares, as these technologies have high variable costs and are, thus, hardly used.

Fig. 2 shows the patterns of variable renewable power generation and storage energy levels for an exemplary week in spring. Variations in renewable generation are dominated by daily PV patterns. The energy level of pumped-hydro storage closely tracks these PV fluctuations. In this respect, pumped-hydro storage may be referred to as "daily storage" or even as "PV storage". Lithium-ion batteries are operated in similar cycles, but have lower E/P ratios and thus reach their upper and lower capacity limit virtually every day. In contrast, power-to-gas storage follows a much longer-term cycle.

Compared to its shares in overall capacity or yearly energy, power storage plays a much larger role in the provision and activation of control reserves. This is particularly the case for short-term lithium-ion batteries. Figs. A.4–A.7 in Appendix A.3 show the shares of technologies in both reserve provision and activation for overall renewable shares of 80% and 100%. It can be seen that power storage particularly contributes to primary reserves, and its relevance for the other reserve segments also increases in the 100% case.

3.2. Sensitivities on storage costs and availabilities

3.2.1. Availability of additional storage technologies

We now assume that additional storage technologies are available. These are parametrized according to Table B.3, leaning on [21]. The results of this sensitivity—as well as several others—are shown in Figs. 3 and 4, which indicate the changes in installed storage power compared to the baseline for the cases with 80% and 100% renewables.

In case additional storage technologies are available, we observe a massive deployment of lead acid batteries, which causes a full substitution of lithium-ion batteries as well as—in the 100% case—long-term storage. Moreover, pumped-hydro storage capacities are partly replaced. Overall, storage capacity slightly increases compared to the baseline. Because of their favorable investment costs, lead acid batteries become the dominant short- and medium-term technology in this scenario with E/P ratios of 4 (unrestricted case) to nearly 6 (100% renewables). Pumped hydro, conversely, turns into some kind of long-term storage in the 100% case with an E/P ratio of 33 h. Sodium-sulfur batteries are installed to a small extent with E/P ratios between 2 and 3. Overall system costs decrease by around 1% as a consequence of the assumed availability of the comparatively cheap lead acid technology. Redox flow batteries and adiabatic compressed air energy storage are never installed because of higher costs and lower round-trip efficiencies.[11]

3.2.2. Half or double specific investment costs of all storage technologies

If investment costs of the three storage options considered in the baseline are assumed to halve, for example because of technological breakthroughs, more short- and medium-term storage capacities are installed for a renewable share of 80% (Fig. 3). The same is true for the 90% case (not depicted here). In the fully renewable case, lithium batteries increase by nearly 13 GW to a total level around 20 GW, corresponding to 26% of the system peak load (Fig. 4). At the same time, both medium-term and long-term storage decrease slightly in the 100% case. Pumped-hydro storage, nevertheless, reaches its energy cap, going along with a slightly increased E/P ratio. Overall, the assumed change in investment costs is relatively more favorable for lithium-ion batteries. These changes in the storage portfolio go along with slight deviations in the renewable mix: onshore and offshore wind power are used a little less, whereas PV generation slightly increases. System costs decrease by 2.2% due to cheaper storage options. Likewise, the renewable share in the unrestricted case increases from 76.4% to 78.1%.

Under the assumption of double investment costs of all storage technologies, for example because of lower research activities or a more challenging investment environment, we generally find opposite effects, but less pronounced. In particular, hardly any long-term storage is installed (around 1 GW). Instead, onshore wind power installations as well as renewable curtailment increase slightly. Installed PV capacity, which requires daily storage, also decreases. Overall costs increase by 3% in the fully renewable system.

3.2.3. Half specific investment costs of particular storage options

We now test the sensitivity of results with respect to cost breakthroughs of single storage technologies. In doing so, we focus on lithium-ion batteries and power-to-gas, as these are less developed than pumped-hydro storage.

If specific investment costs of lithium-ion batteries decrease by 50%, we observe a major shift toward this technology (Figs. 3 and 4). The E/P ratio of lithium-ion batteries increases to around 4–6 h,

[11] In an additional sensitivity run not shown here, we include all storage technologies except for lead acid batteries and find very similar but slightly less pronounced effects. In this case, lead acid capacities are almost entirely substituted by the slightly more expensive sodium-sulfur batteries that become the dominant short- and medium-term storage option. System costs savings compared to the baseline are accordingly slightly lower.

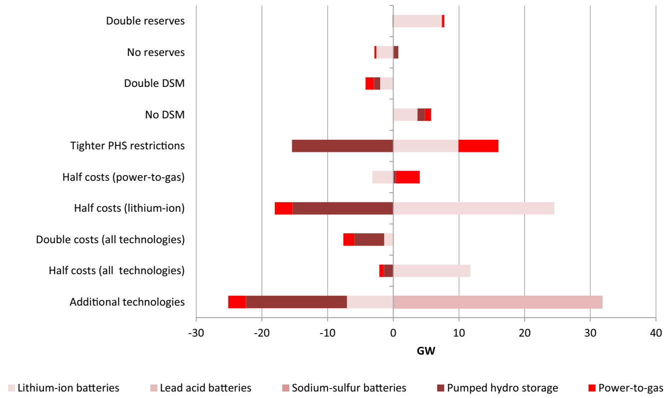

Fig. 4. Sensitivities on storage, DSM, and reserves: changes in installed storage power for 100% renewables.
Source: own calculations.

depending on the required renewable share, such that they evolve into some kind of medium-term storage option. Accordingly, pumped hydro requirements decrease. Yet pumped hydro still reaches its energy cap in the 100% because of an increased E/P ratio (nearly 33 h). Overall costs decrease by 1.4%.

In contrast, a 50% cost reduction of long-term storage has smaller effects. Even under these optimistic cost assumptions, power-to-gas is never built except for the 100% case, and even then investments increase by a mere 4 GW. Accordingly, cost breakthroughs in long-term storage appear not to be a game changer in the setting analyzed here. The sluggish uptake of the long-term storage option in the model is mainly caused by its comparatively low round-trip efficiency, which is far below the other options. If long-term storage is to become viable, cost reductions thus have to be accompanied by efficiency improvements.

3.2.4. Tighter energy restriction on pumped-hydro storage

Under baseline assumptions, pumped hydro is the dominant medium-term storage option. We test the robustness of results with respect to a tighter cap on the maximum installable energy capacity, i.e., 75 GWh as compared to 300 GWh. 75 GWh are a little higher than the cumulative energy capacity of current pumped-hydro storage facilities that are directly connected to the German transmission grid. This is meant to reflect less optimistic prospects for constructing upper and/or lower reservoirs, for example because of limited topographic potentials, public resistance or environmental restrictions.

Due to the tighter energy cap, the E/P ratio of pumped-hydro storage remains around 8 h for all renewable shares, compared to up to 12 h in the baseline. Accordingly, the installed power of pumped hydro facilities changes less than its energy cap. Investments into storage power change compared to the baseline only in the 90% and 100% cases (for the latter, see Fig. 4). Pumped-hydro storage now reaches its energy cap already in the 90% case, such that capacity is around 8 GW lower. Yet this decrease is partly compensated by a 6 GW increase in lithium-ion batteries. In the 100% case, pumped hydro decreases by nearly 16 GW, but is substituted by the more expensive short-term (+10 GW) and long-term (+6 GW) storage options. Overall system costs therefore increase by 1.7% in the fully renewable case.

3.3. Sensitivities on DSM potentials

Under the assumption that demand-side options cannot be developed, required power storage capacities increase. In particular, DSM is substituted by lithium-ion batteries. In case of double DSM potentials, we find corresponding effects in the opposite direction, but less pronounced. For example, double DSM potentials decrease overall storage requirements by less than 4 GW compared to the baseline in the 80% case (Fig. 3), whereas the corresponding opposite effect of zero DSM is much larger. Accordingly, the marginal rate of substitution between DSM and storage decreases strongly. This may be due to time-related restrictions of load shifting and comparatively high costs of several DSM segments.

3.4. Sensitivities on reserve requirements

The future demand for reserves is generally uncertain, as it depends, among other factors, on the size of the balancing area as well as tender and delivery periods. We carry out two sensitivities with zero and double reserve requirements related to variable renewables. The sensitivity without any reserves also serves as a test of the importance of including reserves at all in the model.

If reserve requirements are set to zero, the capacities of both short-term storage and DSM decrease in all runs, irrespective of the minimum renewable share. In particular, the expensive load curtailment technology is no longer deployed. Likewise, lithium-ion battery capacity is 2–3 GW lower than in the baseline. Neglecting reserves in power system models may thus lead to a systematic underestimation of short-term storage and DSM capacities.

If reserve requirements are assumed to be twice as high as in the baseline, we find a corresponding effect in the opposite direction. Yet the impact on short-term storage is much stronger with a capacity increase of some 6–7 GW, see Figs. 3 and 4. Load curtailment capacity also increases, but is less pronounced, as many DSM segments are already at their capacity limit in the baseline. Overall, our findings suggest that considering reserves in power system modeling is particularly important for a proper assessment of short-term power storage requirements.

3.5. Sensitivities on renewable costs and availabilities

Storage requirements also change under alternative assumptions regarding the costs and availabilities of renewable energy sources. The changes of installed storage power, compared to the baseline, are shown in Figs. 5 and 6, for the cases with 80% and 100% renewables.

3.5.1. Alternative costs and potentials of offshore wind power

Given the parameter assumptions used in this study, offshore wind power is a cost-efficient renewable energy source. Under an alternative assumption that offshore wind power potentials cannot be developed, model results substantially change. The share of renewables in the unrestricted case decreases to 65.6%, compared to 76.4% in the baseline. In order to reach minimum shares of 70% or more, significant capacity additions of onshore wind power and PV are necessary. Because of their comparatively lower full-load hours, overall installed capacity of all technologies increases by nearly 130 GW, and reaches an absolute level of 538 GW in the 100% case, which is more than seven

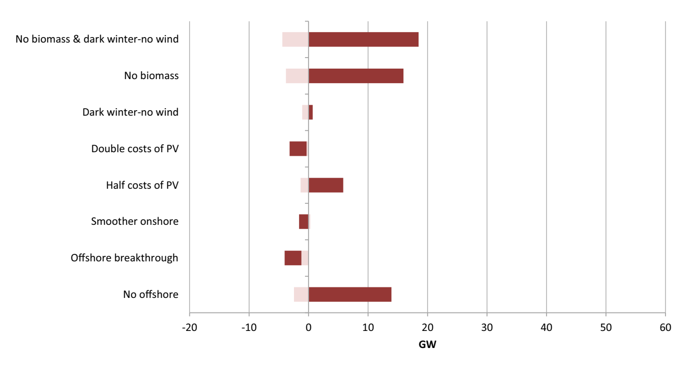

Fig. 5. Sensitivities on renewable costs and availabilities: changes in installed storage power for 80% renewables.
Source: own calculations.

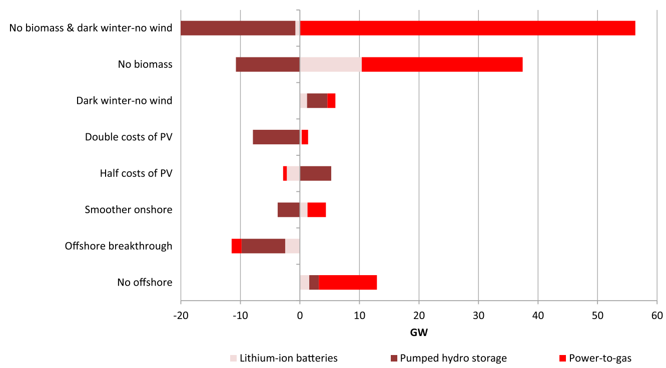

Fig. 6. Sensitivities on renewable costs and availabilities: changes in installed storage power for 100% renewables.
Source: own calculations.

times higher than the system peak load. At the same time, renewable curtailment increases to 14% in the 100% renewable scenario (7% in the baseline). In such an environment, power storage requirements also increase. In the 80% and 90% cases, around 14–17 GW additional pumped-hydro storage capacity is needed, whereas in the 100% case additional 10 GW of power-to-gas are installed compared to the baseline. System costs are accordingly 13.7% higher than in the baseline in the fully renewable setting.

Figs. 5 and 6 also indicate the effects of deviating assumptions in the opposite direction, i.e., an offshore wind power breakthrough. Extending the installation cap for offshore wind power to 53 GW and, at the same time, halving specific investment costs increases the renewable share to 81.3% in the unrestricted case. At the same time, lower capacities of onshore wind power and PV are required in all cases. As offshore wind power fluctuates less than onshore wind and PV, the overall storage requirement also decreases by around 11 GW (largely pumped hydro) in the fully renewable setting. System costs substantially decrease by 11.4% in the 100% case compared to the baseline. Accordingly, the availability and the costs of offshore wind power not only play an important role for future power systems with high shares of renewables, but also have a strong impact on the requirement of mid- and long-term storage technologies.

3.5.2. Alternative projections for onshore wind profiles

With alternative projections for onshore wind profiles, we aim to capture the effects of both widespread geographical[12] balancing, which makes the profiles smoother, and future changes in generator configuration, which increases full-load hours. Under these assumptions, onshore wind power gains ground in the competition with other renewable technologies. We accordingly observe a massive shift toward onshore wind power, which substitutes both offshore wind and PV capacity. At the same time, storage requirements barely change compared to the baseline. In the 100% case (Fig. 6), there is a minor shift from pumped hydro (−4 GW) to lithium-ion batteries (+1 GW) and power-to-gas (+3 GW). This may be due to the fact that onshore wind substitutes technologies which fluctuate both more (PV) and less heavily (offshore wind), such that the net effect on storage largely cancels out.

3.5.3. Half or double specific investment costs of photovoltaics

As regards PV, we carry out model runs with respect to different developments of specific investment costs, as these appear to be especially relevant sensitivities, given the wide range of long-term cost projections [5]. Under the assumption that specific PV investment costs halve compared to the baseline, PV capacity increases by around 40 GW in all cases, substituting either offshore or onshore wind power. At the same time, pumped-hydro storage requirements increase on the order of 5–6 GW (Figs. 5 and 6).

Under the assumption that specific PV investment costs are twice as high as in the baseline, we find corresponding effects in the opposite direction. Lower PV capacities go along with decreases in pumped-hydro storage requirements between 3 and 8 GW, depending on the renewable share. Thus, these outcomes support the previously discussed finding that pumped hydro may be interpreted as “PV storage” in this setting.

3.5.4. Dark winter-no wind

All model calculations presented so far draw on hourly renewable availability factors derived from historic time series. Under baseline assumptions, the sum of hourly availabilities of PV, onshore wind power, and offshore wind power drops to very low levels only during a few subsequent hours. We now examine a kind of worst case scenario with respect to security of supply by assuming that PV, onshore wind power and offshore wind power are completely unavailable over a full winter week in which power demand is high (“dark winter-no wind”).

Up to a renewable share of 90%, some 11–13 GW of additional gas-fired power plants (largely open cycle gas turbines) are sufficient to serve power demand during the dark winter week. These partly substitute installations of the expensive load curtailment category, as gas turbines have comparatively lower variable costs and thus displace load curtailment in both the reserve and wholesale markets. Only in the 100% renewable case, in which no gas-fired generators can be built, do we observe substantial capacity additions of biomass as well as moderate increases in all three power storage technologies (nearly 2 GW lithium-ion batteries, 3 GW pumped hydro, and 1 GW power-to-gas; see Fig. 6). Thus, it is biomass, and not power storage, that serves as the main source of flexibility in this setting. Note that the energy cap on biomass does not change, such that full-load hours of biomass decrease substantially.[13] In order to offset lower power generation from biomass in the remaining hours of the year, additional PV installations are required in the 100% case, which also contribute to increased storage requirements.

3.5.5. No biomass

In all scenarios, flexible power generation from biomass plays an important role. Under the alternative assumption that no biomass is available for power generation, model results change substantially. In the cases with renewable shares of 80% and 90%, substantial capacity additions of onshore wind power and PV are required—as offshore wind power is already at the assumed capacity limit. As a consequence of increased supply-side variability, storage requirements (largely pumped hydro) also rise (Fig. 5). At the same time, renewable curtailment increases to 4.7% (80%) and 8.3% (90%), compared to 1.6% and 3.7% in the baseline, respectively. In the 100% case, however, the picture changes (Fig. 6). Here, excessive additional onshore wind power capacity is deployed combined with power-to-gas storage (additional 27 GW compared to the baseline) in order to achieve full renewable supply without flexible biomass. At the same time, both renewable curtailment and system costs significantly increase. In other words, substantial capacity of seasonal storage is required only under the assumption of both very high renewable shares and restricted availability of biomass in our model setup.

In an additional model run, we combine the assumptions of “dark winter-no wind” and complete non-availability of biomass. In such a

[12] The profiles are based on interpolated European wind speed time series from 2011. Based on this, hourly availabilities for many wind farm locations over Europe are derived. For further details, see [27].

[13] We implicitly assume that it is possible to shift a substantial fraction of the yearly biomass energy budget to one specific winter week. In practice, this would require additional storage capacity of either biomass or biogas, the costs of which are not taken into account here.

setting, power-to-gas is used as seasonal storage and becomes a main source of flexibility in the 100% renewable case with an absolute power rating of 59 GW, and an energy capacity of nearly 17 TWh (Fig. 6). The corresponding E/P ratio is 286 h, i.e., around 12 days. The case for seasonal storage discussed above thus increases further, if high RES shares and non-availability of biomass are combined with simultaneous non-availabilities of variable renewables for longer periods.

4. Discussion of limitations

In the following, we briefly discuss important limitations of our model and how these may affect results.

We deliberately abstract from a real power system and instead adopt a long-term, greenfield perspective. This necessarily restricts the potential to draw policy conclusions that are immediately relevant for today's power systems or questions of optimal transformation paths toward renewable-dominated systems. Rather, we aim to provide on the one hand long-run benchmarks for power storage in an optimized future power system, and, on the other, qualitative insights into interdependencies of power storage and various other flexibility options. Consequently, our analysis may not be used to draw conclusions on today's power systems, but rather to guide longer-term research and development policy on power storage and other technologies as well as the regulatory framework. Because of the greenfield perspective, we also do not address questions of path-dependency or intermediate development stages of the power system on the way toward high renewable shares. Accordingly, results should not be interpreted as a forecast, but rather as a benchmark for an optimized future system.

Despite adopting a greenfield perspective, it is necessary to loosely calibrate the model to a specific power system. For example, the capacities of dispatchable renewables such as hydro power or biomass have to be restricted in order not to generate trivial results. Our choice of Germany is obvious because of its ambitious and legally binding long-term renewable targets; this choice none the less involves a range of issues. For example, we abstract from power exchange with neighboring countries, thus neglecting the possibilities of smoothing both renewable variability and power demand by balancing over larger geographical areas.[14] This may result in exaggerated variability of renewable generators, which in turn leads to an overestimation of the need for flexibility and power storage.

Another limitation that may distort results in a similar direction is the linear scaling of historic renewable feed-in time series. This approach neglects future changes in generator design as well as changes in the geographical distribution, which would lead to smoother feed-in profiles. Likewise, the demand profile may become smoother in the future because of demand-side innovations and behavioral changes. Our analysis, however, already includes such developments, at least to some degree, as we assume substantial DSM capacities of both load shifting and load curtailment.

We are aware of further limitations of the model framework with respect to long-term, high-RES, low-carbon energy system modeling. Probably the most important one is the exclusive focus on the electricity sector, as both new flexibility options and new flexibility requirements may arise from the interaction with other sectors, such as heat or mobility.[15] Likewise, we abstract from solar prosumage, which may lead to an increasing deployment of decentral batteries used for the optimization of PV self-consumption [36]. Next, we make a range of simplifications with respect to the level of technical detail of the generation portfolio. Not least, the focus on a stylized power system, loosely calibrated to German data, does not take into account spatial flexibility from cross-border interconnections. For a further discussion of the capabilities and limitations of the model formulation, see also [1].

We are, however, convinced that, in order to soundly assess long-term power system configurations with very high shares of variable renewable energy sources, both a tractable and comprehensive analysis with respect to highly uncertain future developments of costs and availabilities of technologies is of paramount importance. In our application, we aimed to tackle both challenges.

5. Conclusions

Based on a review of model-based analyses on power storage requirements in systems with high shares of variable renewable energy sources, the dispatch and investment model DIETER was developed. We apply the model to study the role of power storage and other flexibility options in a greenfield setting with high shares of renewables. In contrast to many other analyses, our model not only captures the arbitrage value of storage, but also system values related to capacity and reserve provision.[16]

In a baseline scenario, we find that power storage requirements remain moderate up to a renewable share of around 80%, as other options on both the supply and demand side also offer flexibility at low cost. These findings connect to other model-based studies reviewed in the companion paper [1]. If the renewable share increases further to 100%, power storage requirements increase strongly and nearly triple compared to the 80% case. Yet even in a completely renewable-based system, not much long-term storage is needed under baseline assumptions, connecting to the lower end of the findings from the literature. Compared to the wholesale market, power storage generally plays a larger role in the provision and activation of control reserves.

As long-run parameter assumptions are highly uncertain, we carry out a range of sensitivity analyses with respect to costs and availabilities of storage and renewable energy sources. We also vary assumptions on DSM potentials and reserve requirements. A common finding of these sensitivities is that—under very high renewable shares—storage requirements strongly depend on the costs and availabilities of other flexibility options. Aside from demand-side options, the availability of flexibly dispatchable biomass generators appears to be a key determinant for power storage requirements. Further, storage needs strongly depend on the costs and the potentials of offshore wind power, which has relatively smooth generation profiles compared to onshore wind power and PV. Low-cost demand-side measures, both load shifting and curtailment, turn out to be dominant options. In particular, load shifting potentials with 3, 4, and 12 h are installed up to their assumed capacity limits in most scenarios; the same is true for low- and medium-cost load curtailment technologies.

As regards single storage technologies, we conclude that pumped-hydro storage would continue to play a dominant role under the cost assumptions made here. Pumped hydro is deployed with such energy to power ratios that it serves as daily storage for balancing out PV-related variability. Lithium-ion (and other) batteries may increasingly contribute not only to reserve provision, but also to wholesale balancing, in particular if their costs decrease further. In contrast, long-term storage only plays a major role in rather extreme scenarios of the model analysis - for example, if no biomass is available in a 100% renewable setting, and even more so if this assumption is combined with a winter week without any variable renewable feed-in. When it comes to specific technologies, it should also be noted that flexible sector coupling

[14] One exception to this approach is the sensitivity with smoother onshore wind power profiles derived from historic European wind speed data.

[15] For an overview of sector coupling approaches, see [28]. A DIETER extension that includes electric vehicles is already available (from version 1.1.0 on). It has been used to study the potential role of vehicle-to-grid and reserve provision by electric vehicles in Germany [29].

[16] Network-related values of power storage, such as the contribution to congestion management, are not considered here, as assumptions on network constraints would be rather arbitrary in our stylized, long-term greenfield setting.

options are likely to play an important role in a largely renewable-based system. Analyzing their potential impacts on power storage requirements is beyond the scope of the analysis presented here and is left for future research.

While our model is loosely parameterized to the German power system, many of the findings of this greenfield analysis are also relevant for other countries moving toward high shares of variable renewables. In particular, the sensitivities should be of interest to international readers, as other countries may, for example, have higher or lower offshore wind power potentials or lower biomass availability compared to Germany.

Based on both the literature review [1] and the model results presented here, we conclude that power storage is becoming an increasingly important element of a transition toward a fully renewable-based power system. Power storage gains further relevance if other potential sources of flexibility are limited. Thus, supporting the development of power storage should be considered a useful component of policies designed to safeguard a transition towards renewable energy sources. Policy-makers should aim for technological progress and cost reduction in different power storage technologies, primarily by means of broad-based support for research and development. At the same time, they should enable a level playing field for competition among flexibility options in the various areas of application. This also applies to flexible sector coupling options not considered here.

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Appendix A: additional results

A.1. Shares of energy provision in the baseline scenario

Fig. A.1 shows energy shares in the baseline scenario.

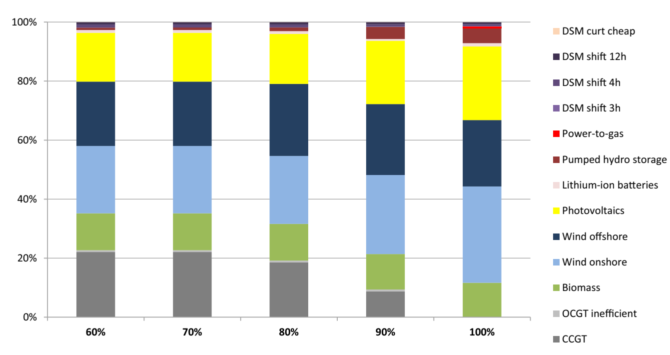

Fig. A.1. Baseline scenario: energy shares.
Source: own calculations.

A.2. Sensitivities with respect to alternative base years

The baseline draws on 2013 data regarding load, renewable feed-in, and control reserves. To test the robustness of results with respect to alternative base years, we use the years 2011 or 2012. Yet results are not fully comparable, as offshore wind power feed-in time series of the years 2011 and 2012 are based on very few single wind turbines, the feed-in of which is very synchronous, and which were also simultaneously maintained at times. Results may thus be distorted with respect to offshore wind power deployment, which proves to be a decisive variable (compare Section 3.5.1).

Because of these distortions, offshore wind power capacities are lower for all renewable shares in both the 2011 and the 2012 sensitivities, whereas PV and – except for the 100% case in the 2011 sensitivity – onshore wind power capacities are higher. Because of increased renewable variability, storage requirements also increase. In the 100% case based on 2012 data (Fig. A.2), overall storage capacity increases by 20 GW compared to the baseline, of which 10 GW are short-term storage. Drawing on 2011 data, the storage requirement increases further in the 100% case—by 31 GW compared to the baseline, of which the largest share (21 GW) is again short-term storage (Fig. A.3). This is driven by large capacity additions of solar PV, as 2012 was a relatively good PV year in Germany. Note that pumped hydro, which turns out to be the prime option for PV storage in other model runs, already reaches its energy cap in the 90% cases of both the 2011 and the 2012 sensitivities. Instead, additional short-term battery storage is applied in the fully renewable setting.

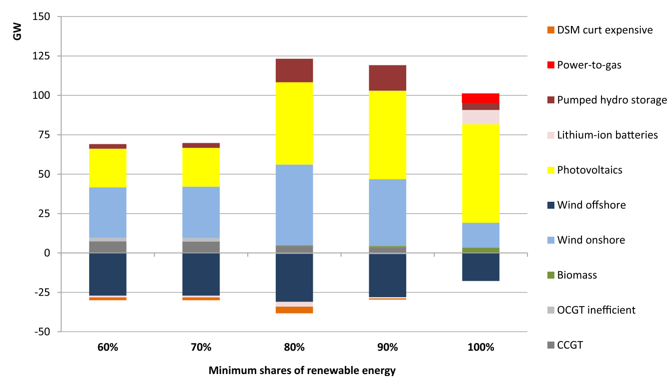

Fig. A.2. Base year 2012: energy shares.
Source: own calculations.

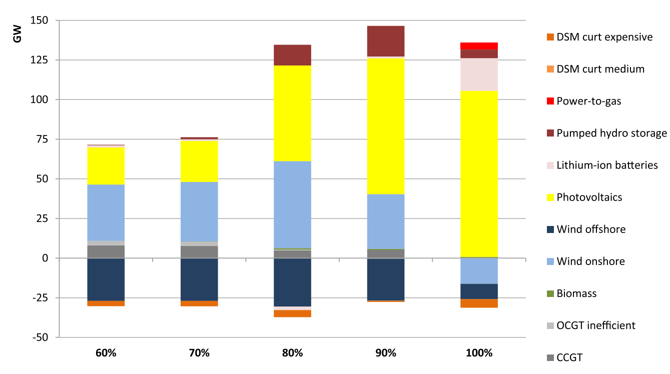

Fig. A.3. Base year 2011: energy shares.
Source: own calculations.

A.3. Reserve provision and activation

Model outcomes on reserves differ between reserve provision (capacity) and activation (energy). Fig. A.4 shows how different technologies contribute to reserve provision over the whole year for a renewable share of 80%. Short- and medium-term power storage both substantially contribute to primary reserve (PR) provision and, less pronounced, to secondary (SR) and minute (MR) reserve provision. These large shares are caused by storage's high flexibility, high availability, and low variable costs. CCGT plants have disproportionately high shares compared to overall energy provision because of their dispatchability. CCGT shares are particularly high for negative SR and MR provision, as a respective activation incurs relatively high savings of variable costs in the objective function. In addition, the demand side is a relevant provider of short-term flexibility. The respective energy shares (Fig. A.5) show a rather similar picture.

Corresponding figures on the shares of reserve provision and activation for a renewable share of 100% are provided in Figs. A.6 and A.7. It can be seen that power storage technologies gain further importance with respect to reserves in a fully renewable scenario. An even more pronounced effect can be observed for biomass, which largely substitutes dispatchable gas-fired plants. Accordingly, both storage and flexible biomass are not only vital for residual load balancing, but also for reserve provision in a 100% renewable setting.

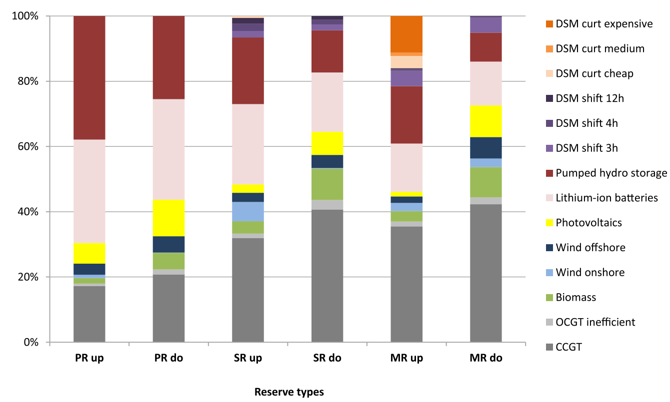

Fig. A.4. Baseline scenario: shares of reserve provision for a renewable share of 80%.
Source: own calculations.

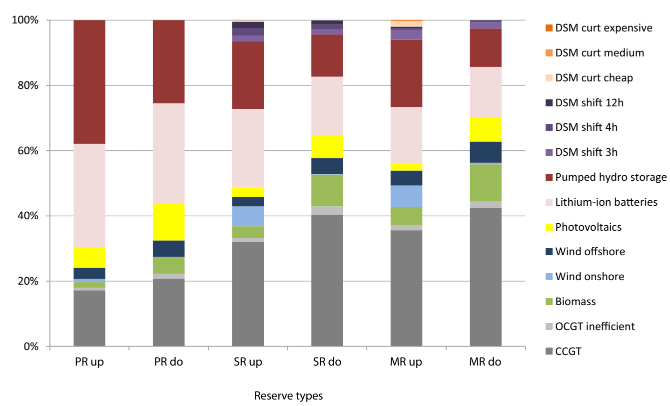

Fig. A.5. Baseline scenario: shares of reserve activation for a renewable share of 80%.
Source: own calculations.

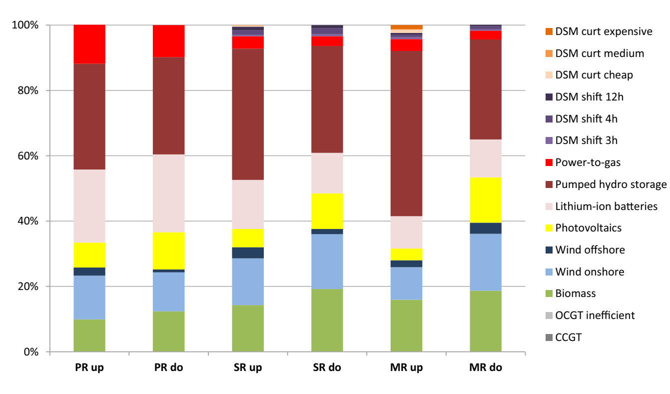

Fig. A.6. Baseline scenario: shares of reserve provision for a renewable share of 100%.
Source: own calculations.

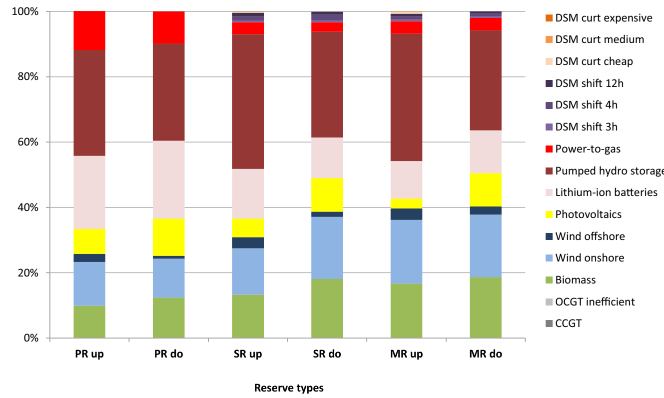

Fig. A.7. Baseline scenario: shares of reserve activation for a renewable share of 100%.
Source: own calculations.

Appendix B: numerical assumptions on input parameters

Table B.1
Technical assumptions on conventional power plants.

	Parameter	Value	Unit	Source
Lignite				
Efficiency		0.466	–	[5]
Carbon content		0.364	$tons/MWh_{th}$	[8]
Fuel price		4.90	EUR/MWh_{th}	[10]
Marginal generation costs	c^m_{con}	88.54	EUR/MWh	
Overnight investment costs		1,500	EUR/kW	[5]
Technical lifetime		35	$years$	[5]
Annualized investment costs	c^i_{con}	80	EUR/kW	
Annual fixed costs	c^{fix}_{con}	30	EUR/kW	[5]
Load change costs up and down	c^+/c^-	30	EUR/MW	Own assumption
Maximum load change for reserves	$\phi^\pm$	4	$\%of\ capacity\ per\ minute$	[7]
Hard Coal				
Efficiency		0.467	–	[5]
Carbon content		0.354	$tons/MWh_{th}$	[8]
Fuel price		23.04	EUR/MWh_{th}	[9][a]
Marginal generation costs	c^m_{con}	125.12	EUR/MWh	
Overnight investment costs		1,300	EUR/kW	[5]
Technical lifetime		35	$years$	[5]
Annualized investment costs	c^i_{con}	70	EUR/kW	
Annual fixed costs	c^{fix}_{con}	30	EUR/kW	[5]
Load change costs up and down	c^+/c^-	30	EUR/MW	Own assumption
Maximum load change for reserves	$\phi^\pm$	6	$\%\ of\ capacity\ per\ minute$	[7]
CCGT				
Efficiency		0.619	–	[5]
Carbon content		0.202	$tons/MWh_{th}$	[8]
Fuel price		38.16	EUR/MWh_{th}	[9][a]
Marginal generation costs	c^m_{con}	94.28	EUR/MWh	
Overnight investment costs		800	EUR/kW	[5]
Technical lifetime		25	$years$	[5]
Annualized investment costs	c^i_{con}	51	EUR/kW	
Annual fixed costs	c^{fix}_{con}	20	EUR/kW	[5]
Load change costs up and down	c^+/c^-	20	EUR/MW	Own assumption
Maximum load change for reserves	$\phi^\pm$	8	$\%\ of\ capacity\ per\ minute$	[7]
OCGT inefficient				
Efficiency		0.396	–	[6]
Carbon content		0.202	$tons/MWh_{th}$	[8]
Fuel price		38.16	EUR/MWh_{th}	[9][a]
Marginal generation costs	c^m_{con}	147.37	EUR/MWh	
Overnight investment costs		400	EUR/kW	[5]
Technical lifetime		25	$years$	[5]
Annualized investment costs	c^i_{con}	26	EUR/kW	
Annual fixed costs	c^{fix}_{con}	15	EUR/kW	[5]

(continued on next page)

Table B.1 *(continued)*

	Parameter	Value	Unit	Source
Load change costs up and down	c^{+}/c^{-}	15	EUR/MW	Own assumption
Maximum load change for reserves	$\phi^{\pm}$	15	$\%\ of\ capacity\ per\ minute$	[7]
OCGT efficient				
Efficiency		0.457	–	[5]
Carbon content		0.202	$tons/MWh_{th}$	[8]
Fuel price		38.16	EUR/MWh_{th}	[9][a]
Marginal generation costs	c^{m}_{con}	127.72	EUR/MWh	
Overnight investment costs		650	EUR/kW	[5]
Technical lifetime		25	$years$	[5]
Annualized investment costs	c^{i}_{con}	42	EUR/kW	
Annual fixed costs	c^{fix}_{con}	15	EUR/kW	[5]
Load change costs up and down	c^{+}/c^{-}	15	EUR/MW	Own assumption
Maximum load change for reserves	$\phi^{\pm}$	15	$\%\ of\ capacity\ per\ minute$	[7]

[a] Medium price path.

Table B.2
Technical assumptions on renewable power plants (baseline).

	Parameter	Value	Unit	Source
Wind onshore				
Overnight investment costs		1,075	EUR/kW	[5]
Technical lifetime		25	$years$	[5]
Annualized investment costs	c^{i}_{res}	69	EUR/kW	
Annual fixed costs	c^{fix}_{res}	35	EUR/kW	[5]
Maximum capacity or energy		–	–	
Wind offshore				
Overnight investment costs		3,522[a]	EUR/kW	[5]
Technical lifetime		25	$years$	[5]
Annualized investment costs	c^{i}_{res}	225	EUR/kW	
Annual fixed costs	c^{fix}_{res}	80	EUR/kW	[5]
Maximum capacity or energy	m_{res}	32	GW	[9]
Photovoltaics				
Overnight investment costs		425	EUR/kW	[5]
Technical lifetime		25	$years$	[5]
Annualized investment costs	c^{i}_{res}	27	EUR/kW	
Annual fixed costs	c^{fix}_{res}	25	EUR/kW	[5]
Maximum capacity or energy		–	–	
Biomass				
Efficiency		0.487	–	[5]
Carbon content		0.00	$tons/MWh_{th}$	[8]
Fuel price		23.04	EUR/MWh_{th}	Own assumption
Marginal generation costs	c^{m}_{con}	47.31	EUR/MWh	
Overnight investment costs		1,951	EUR/kW	[5]
Technical lifetime		30	$years$	[5]
Annualized investment costs	c^{i}_{con}	113	EUR/kW	
Annual fixed costs	c^{fix}_{con}	100	EUR/kW	[5]
Load change costs up and down	c^{+}/c^{-}	25	EUR/MW	Own assumption
Maximum load change for reserves	$\phi^{\pm}$	15	$\%\ of\ capacity\ per\ minute$	[7]
Maximum capacity or energy	m^{E}_{bio}	60	TWh/a	[9]

[a] The number includes additional investments for offshore grids. These are 1429 EUR/kW according to calculations based on [30].

Table B.3
Technical assumptions on power storage (baseline).

	Parameter	Assumption	Unit	Source
Lithium-ion batteries				
Efficiency	η_{sto}	0.92	–	[21]
Marginal costs of storage operation		1	*EUR/MWh*	Own assumption
Overnight investment costs power		35	*EUR/kW*	[21]
Overnight investment costs in energy		187	*EUR/kWh*	[21]
Technical lifetime		20	*years*	[22]
Annualized investment costs capacity	c_{sto}^{iP}	3	*EUR/kW*	
Annualized investment costs energy	c_{sto}^{iE}	14	*EUR/kWh*	
Annual fixed costs	c_{sto}^{fix}	10	$EUR/kW(h)$	Own assumption
Maximum power or energy capacity		–	–	
Lead acid batteries				
Efficiency	η_{sto}	0.84	–	[21]
Marginal costs of storage operation		1	*EUR/MWh*	Own assumption
Overnight investment costs power		35	*EUR/kW*	[21]
Overnight investment costs in energy		67	*EUR/kWh*	[21]
Technical lifetime		15	*years*	[21]
Annualized investment costs power	c_{sto}^{iP}	3	*EUR/kW*	
Annualized investment costs energy	c_{sto}^{iE}	6	*EUR/kWh*	
Annual fixed costs	c_{sto}^{fix}	10	$EUR/kW(h)$	Own assumption
Maximum power or energy capacity	m_{sto}^{P}	0	*MW*	Own assumption
Sodium-sulfur batteries				
Efficiency	η_{sto}	0.88	–	[21]
Marginal costs of storage operation		1	*EUR/MWh*	Own assumption
Overnight investment costs power		35	*EUR/kW*	[21]
Overnight investment costs in energy		89	*EUR/kWh*	[21]
Technical lifetime		15	*years*	[21]
Annualized investment costs power	c_{sto}^{iP}	3	*EUR/kW*	
Annualized investment costs energy	c_{sto}^{iE}	8	*EUR/kWh*	
Annual fixed costs	c_{sto}^{fix}	10	$EUR/kW(h)$	Own assumption
Maximum power or energy capacity	m_{sto}^{P}	0	*MW*	Own assumption
Redox flow batteries				
Efficiency	η_{sto}	0.8	–	[21]
Marginal costs of storage operation		1	*EUR/MWh*	Own assumption
Overnight investment costs power		600	*EUR/kW*	[21]
Overnight investment costs in energy		70	*EUR/kWh*	[21]
Technical lifetime		25	*years*	[21]
Annualized investment costs power	c_{sto}^{iP}	38	*EUR/kW*	
Annualized investment costs energy	c_{sto}^{iE}	4	*EUR/kWh*	
Annual fixed costs	c_{sto}^{fix}	10	$EUR/MW(h)$	Own assumption
Maximum power or energy capacity	m_{sto}^{P}	0	*MW*	Own assumption
Pumped-hydro storage				
Efficiency	η_{sto}	0.8	–	[21]
Marginal costs of storage operation		1	*EUR/MWh*	Own assumption
Overnight investment costs power		1,100	*EUR/kW*	[21]
Overnight investment costs in energy		10	*EUR/kWh*	[21]
Technical lifetime		80	*years*	[21]
Annualized investment costs power	c_{sto}^{iP}	46	*EUR/kW*	
Annualized investment costs energy	c_{sto}^{iE}	<1	*EUR/kWh*	
Annual fixed costs	c_{sto}^{fix}	10	$EUR/kW(h)$	Own assumption
Maximum power or energy capacity	m_{sto}^{E}	300	*GWh*	Various sources[a]
Adiabatic compressed air energy storage				
Efficiency	η_{sto}	0.73	–	[21]
Marginal costs of storage operation		1	*EUR/MWh*	Own assumption
Overnight investment costs power		750	*EUR/kW*	[21]
Overnight investment costs in energy		40	*EUR/kWh*	[21]
Technical lifetime		30	*years*	[21]
Annualized investment costs power	c_{sto}^{iP}	43	*EUR/kW*	
Annualized investment costs energy	c_{sto}^{iE}	2	*EUR/kWh*	
Annual fixed costs	c_{sto}^{fix}	10	$EUR/kW(h)$	Own assumption
Maximum power or energy capacity	m_{sto}^{P}	0	*MW*	Own assumption

(continued on next page)

Table B.3 *(continued)*

	Parameter	Assumption	Unit	Source
Power-to-gas				
Efficiency	η_{sto}	0.46	–	[21]
Marginal costs of storage operation		1	*EUR/MWh*	Own assumption
Overnight investment costs power		1,000	*EUR/kW*	[22]
Overnight investment costs in energy		0.2	*EUR/kWh*	[21]
Technical lifetime		22.5[b]	*years*	[21]
Annualized investment costs power	c_{sto}^{iP}	68	*EUR/kW*	
Annualized investment costs energy	c_{sto}^{iE}	<1	*EUR/kWh*	
Annual fixed costs	c_{sto}^{fix}	10	*EUR/kW(h)*	Own assumption
Maximum power or energy capacity		–	–	

[a] Based on [31–34].

Table B.4
Technical assumptions on load curtailment (baseline).

	Parameter	Assumption	Unit	Source
DSM curt cheap (industry)				
Load curtailment costs	c_{lc}^{m}	500	*EUR/MWh*	[23]
Overnight investment costs		10	*EUR/kW*	[23]
Technical lifetime		10	*years*	Own assumption
Annualized investment costs	c_{lc}^{i}	1	*EUR/kW*	
Annual fixed costs	c_{lc}^{fix}	1	*EUR/kW*	[23]
Maximum duration	t_{lc}^{dur}	4	*h*	[24]
Recovery time	t_{lc}^{off}	24	*h*	Own assumption
Maximum installable capacity	m_{lc}	3,300	*MW*	[23]
DSM curt medium (industry)				
Load curtailment costs	c_{lc}^{m}	1,500	*EUR/MWh*	[23]
Overnight investment costs		10	*EUR/kW*	[23]
Technical lifetime		10	*years*	Own assumption
Annualized investment costs	c_{lc}^{i}	1	*EUR/kW*	
Annual fixed costs	c_{lc}^{fix}	1	*EUR/kW*	[23]
Maximum duration	t_{lc}^{dur}	4	*h*	[24]
Recovery time	t_{lc}^{off}	24	*h*	Own assumption
Maximum installable capacity	m_{lc}	1,600	*MW*	[23]
DSM curt expensive (industry)				
Load curtailment costs	c_{lc}^{m}	8,000	*EUR/MWh*	[23]
Overnight investment costs		10	*EUR/kW*	[23]
Technical lifetime		10	*years*	Own assumption
Annualized investment costs	c_{lc}^{i}	1	*EUR/kW*	
Annual fixed costs	c_{lc}^{fix}	1	*EUR/kW*	[23]
Maximum duration	t_{lc}^{dur}	4	*h*	[24]
Recovery time	t_{lc}^{off}	24	*h*	Own assumption
Maximum installable capacity	m_{lc}	5,400	*MW*	[23]

Table B.5
Technical assumptions on load shifting (baseline).

	Parameter	Assumption	Unit	Source
DSM shift 1h (climatization, process heat/cold)				
Load shifting costs	c_{ls}^{m}	1	EUR/MWh	[23]
Overnight investment costs		745	EUR/kW	[23]
Technical lifetime		10	$years$	Own assumption
Annualized investment costs	c_{ls}^{i}	92	EUR/kW	
Annual fixed costs	c_{ls}^{fix}	–	EUR/kW	
Maximum duration	t_{ls}^{dur}	1	h	[26]
Recovery time	t_{ls}^{off}	1[a]	h	Own assumption
Maximum installable capacity	m_{ls}	793	MW	[23]
DSM shift 2h (circulation pumps, heat pumps, ventilation)				
Load shifting costs	c_{ls}^{m}	1	EUR/MWh	[23]
Overnight investment costs		1,517	EUR/kW	[23]
Technical lifetime		10	$years$	Own assumption
Annualized investment costs	c_{ls}^{i}	187	EUR/kW	
Annual fixed costs	c_{ls}^{fix}	–	EUR/kW	
Maximum duration	t_{ls}^{dur}	2	h	[35,26]
Recovery time	t_{ls}^{off}	1[a]	h	Own assumption
Maximum installable capacity	m_{ls}	2,535	MW	[23]
DSM shift 3h (industry)				
Load shifting costs	c_{ls}^{m}	100	EUR/MWh	Own assumption
Overnight investment costs		10	EUR/kW	[23]
Technical lifetime		10	$years$	Own assumption
Annualized investment costs	c_{ls}^{i}	1	EUR/kW	
Annual fixed costs	c_{ls}^{fix}	–	EUR/kW	
Maximum duration	t_{ls}^{dur}	3	h	[25]
Recovery time	t_{ls}^{off}	1[a]	h	Own assumption
Maximum installable capacity	m_{ls}	1,385	MW	[25]
DSM shift 4h (white goods, ventilation)				
Load shifting costs	c_{ls}^{m}	1	EUR/MWh	[23]
Overnight investment costs		835	EUR/kW	[23]
Technical lifetime		10	$years$	Own assumption
Annualized investment costs	c_{ls}^{i}	103	EUR/kW	
Annual fixed costs	c_{ls}^{fix}	–	EUR/kW	
Maximum duration	t_{ls}^{dur}	4	h	Own assumption
Recovery time	t_{ls}^{off}	1[a]	h	Own assumption
Maximum installable capacity	m_{ls}	1,451	MW	[23]
DSM shift 12h (storage heaters)				
Load shifting costs	c_{ls}^{m}	1	EUR/MWh	[23]
Overnight investment costs		30	EUR/kW	[23]
Technical lifetime		10	$years$	Own assumption
Annualized investment costs	c_{ls}^{i}	4	EUR/kW	
Annual fixed costs	c_{ls}^{fix}	–	EUR/kW	
Maximum duration	t_{ls}^{dur}	12	h	[26]
Recovery time	t_{ls}^{off}	1[a]	h	Own assumption
Maximum installable capacity	m_{ls}	1,050	MW	[23]

[a] This means that recovery time is not restricted for shifting processes.

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