Large-scale Integration of Renewable Energies and Impact on Storage Demand in a European Renewable Power System of 2050 – Sensitivity Study

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Abstract— **Driven by decreasing prices for photovoltaic (PV) systems and incentive programs of different governments, almost 100 GW of PV and over 100 GW of wind turbines (WT) have been integrated in the European power system by 2014. In some areas, the electricity generation already exceeds the demand, curtailing generation or pushing the existing power transmission infrastructure to its limits in certain hours. In order to reach the European Commission's targets for 2050, the integration of renewable energies will require flexibility sources, independent of conventional generation, in order to provide standard security of supply. Together different flexibility sources will ensure the match between demand and supply at any given time. Energy storage systems can provide this flexibility by shifting the load temporally while transmission grids provide the shift of load spatially. Up to a certain extent, transmission capacity and storage capacity can replace each other, i.e. storage can reduce the load on transmission infrastructure by mitigating local peaks in load and/or generation. For the transition to a fully renewable energy system by 2050, major changes have to be achieved in the structure of the power system. The planning tool GENESYS is a holistic approach that optimises the allocation and size of different generation technologies, storage systems and transnational transmission corridors of a European power system. The source code for the mentioned tool is available free of charge under LGPL license. It can be freely parameterized by the user which allows the study of different power systems under individual assumptions with regard to load, generation potential and cost of the different system components. This publication will give an introduction to the planning methodology, the system model and the optimisation approach. Optimisation results obtained with GENESYS for a fully renewable electricity system for Europe and a cost structure expected for 2050 will be presented together with sensitivity analyses investigating main assumptions. Outcomes show the optimal allocation of PV and WT in a European power system, the resulting demand for storage capacities of different technologies and the capacity of the overlay grid.**

Keywords: strategic planning; power system; energy storage; renewable energy; Europe 2050; optimisation

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The work was sponsored through the German Federal Ministry of Economic Affairs and Energy, BMWi FKZ 0325692)

1. INTRODUCTION

Since the European Commission presented target values for greenhouse gas emissions [1], the evolution of the current power system was characterised by the extensive integration of various renewable energy sources. Until 2013 total installed capacities of 117 GW wind power generators and around 78 GW PV generators have been installed into the current European power system [2]. The integration process is still ongoing, driven by decreasing PV cost, for instance on rooftops. It can be characterised as unplanned and initiated by individual persons and companies, which leads to a strongly decentralised organisation of generation. In addition, the energy feed-in from offshore wind parks and onshore parks in coastal regions cause a major challenge for transmission system operators in periods of strong wind due to high power fluctuations. To counter this, they have developed a ten year development plan [3] for the expansion of the transmission capacities in the European grid.

1.1. PREVIOUS RESEARCH IN POWER SYSTEM MODELLING

The field of power system modelling is addressed by various different approaches, which were compared and analysed in [4], [5] but the total number of existing models can only be estimated to grow constantly. The most general difference is the limit of each model, for example the power sector of the energy system is the limit in the presented work, while other models support multiple sectors and their interactions. Some models focus on market models; those are not in the centre of this work. The second category is motivated to investigate the total generation and its cost without market effects. There are fundamental differences in the investigated geographical scale e.g. island, national, multi-national, continental, and worldwide. The spatial resolution ranges from a 'copper plate' without internal structure to high spatial resolutions of few km² and a detailed grid. To contain the complexity each model has limitations in the spatial or temporal resolution, depending on the investigated subject. Therefore some models only investigate typical days, weeks or months, while others calculate the state of the power system in time series of 15 min, 1 h or 3 h. The simplest approach which is applied in [6] and [7] investigates the necessary balancing energy which results from utilisation of volatile PV/Wind power of different ratios. Other models can be categorized as system "integrated assessment models", "operation models" or "hybrid approaches" [8]. Our model is part of the latter category and incorporates a Greenfield investment approach in 21 interconnected regions with a hierarchical dispatch of system components operating on hourly time series [9], [10].

The presented tool can, amongst others, give an outlook regarding the future needs for grid expansion and integration of storage units in case of high penetration of intermittent renewable generators by 2050. The methodology of this tool is explained in detail in [11], which is briefly summed up in the next section. In this work, the configuration of a future 100% renewable power system considers PV and WT as generation units and batteries, pumped hydro (PH) and hydrogen storage as available short, medium and long term storage systems respectively. Supplementary, a high voltage direct current (HVDC) overlay grid is included for energy transport. The investigated components will become major sources of flexibility, which is a requirement to guarantee system stability.

The fluctuating nature of the non dispatchable generators wind and PV leads to a temporal and spatial mismatch between generation and demand. Spatial flexibility in the power sector can be delivered by transmission grids as stated in the following sub-section. The temporal flexibility can be delivered by various energy storage technologies, which can be divided in the categories mechanical storage, electro-chemical storage and electrical storage. The centre of interest of this analysis is to identify the demand for temporal flexibility on a temporal scale, the technologies are chosen accordingly, which means one technology of each temporal category is selected. We pick batteries for the high frequency fluctuations of few hours, because of high efficiency and relatively high price for energy, but low cost for power. It is intended to balance the day cycle of PV generation. Batteries are used already today for grid support, peak shaving and ancillary services, and are foreseen to become more important e.g. with electric vehicles, and PV solar home system integrations. The same category of services could be delivered by flywheels, super-capacitors or superconducting magnetic energy storage to a certain limit. Historically PH storage plays an important role for power management and compensation of demand fluctuations of the day cycle, for future applications it can have the function of flexibility on a medium time scale of a few days, because of competitive energy cost compared to batteries. An alternative, but less mature technology can be the advanced adiabatic compressed air energy storage (AA-CAES) or vanadium redox flow battery systems. The efficiency in this category needs to be quite high with a medium price for the energy. In systems with no alternative backup capacities the mismatch between generation and demand amounts to about 12-15% [6] and up to 24% [7] annual consumption, which needs large energy reservoirs (TWh scale) with a long time scale in the order of months for discharging. Most promising technology is hydrogen electrolysis, with storage of gas in large caverns or other reservoirs (Power-to-Gas), which would also have an optional connection to gas transmission systems or utilisation in the transport sector. The cycle with re-conversion through hydrogen turbines, or combined cycle gas turbines offers only limited efficiency, but low cost for energy storage. Alternative technologies with similar characteristics can be the methane generation or the rather conceptual hydraulic rock storage.

Another alternative of backup capacities are renewable sources based dispatchable generation from biomass and waste, which is limited in the annual energy amount, and conventional power plants from fossil fuels, in case limited CO_2 emissions are allowed, and nuclear power . The electricity demand in the presented approach is fixed, but also demand flexibility from demand side management (DSM) is imaginable. Whichever alternative is available has results in a reduction of the long term storage demand, which was shown by [12] and [6].

The developed planning tool makes use of the Covariant Matrix Adaption-Evolution Strategy (CMA-ES) developed by N. Hansen [13] in order to optimise the dimensioning and allocation of the above mentioned components of the future European power system. In several works [14], [15], a linear programming (LP) approach is applied to determine the optimal unit commitment and thus the operational costs of a future power system. However, the problem complexity often sets limits for the simulation timeframe, and thus especially long term storages (capable of providing energy at full load for several weeks) can only be run under certain limits. In order to avoid this complexity, in this work the system operation is calculated by a hierarchical management, which is able to efficiently operate generation and storage units of different technologies over periods of several years without perfect foresight of the future situations. The developed methodology will also provide a closer insight into the program's sensitivities concerning the mix of available technologies and technology cost variations.

1.2. PREVIOUS RESULTS RELEVANT TO THE CURRENT WORK

Previous studies confirm that dependent on the system configuration, there exists an optimal mix of wind and PV for renewable electricity generation. The investigation in [16] analyses different ratios of wind and PV generated energy on global scale as share of the total energy demand and find an optimal ratio of 55% wind to 45% PV generated power (TWh), this translates in a power ratio of 45:55. Beside smaller differences in system structure, this is a good match to our own prior result presented in [10] with power ratio of 60% Wind to 40% PV. Other than the work of [16], our tool explicitly does not limit the generated energy to the total demand, but allows excess installation to compensate losses in the storage sector. This was also shown advantageous for the system by the same previously mentioned group in [6].

Different investigated publications show that compared to today's available transfer capacities; the extension of grid is suitable to supply flexibility, which is able to reduce the necessity of backup power in the form of dispatchable generators or storage dischargers. A spanning 'over grid' between Europe and North Africa is identified as cost-effective [17], which is further investigated with our sensitivity analysis presented in the current work. [18] even show, that including MENA with a strong grid (60GW) can be economic and lead to less curtailment smaller requirements of non-dispatchable generators as well as less excess generation. In [7] the authors found that strong transfer capacities of about 11.5x of today's capacity will reduce the balancing energy amount by 9 percent points down to 15% of the annual electricity consumed. The investigation of [14] showed that without strong transmission wind power cannot optimally be integrated to a high extend.

Additional flexibility for the energy system can be supplied if additional sectors are included, like heat and or transportation. The REMix tool was extended to also incorporate heat and traffic applications, which showed two major, successful strategies: a) utilisation of renewable electricity for heat applications and alternative to potentially limited availability of biofuels and b) to reduce RE excess generation to reduce backup capacity utilisation [12]. There are different tools available like [19] or [20], but the most extensive model covering all sectors is made by the International Energy Agency in their world energy model [21].

This work aims to test the different tendencies mentioned beforehand in one consistent model and furthermore present the sensitivities of this model towards changes in certain parameters.

2. Methodology

2.1. Power System Model

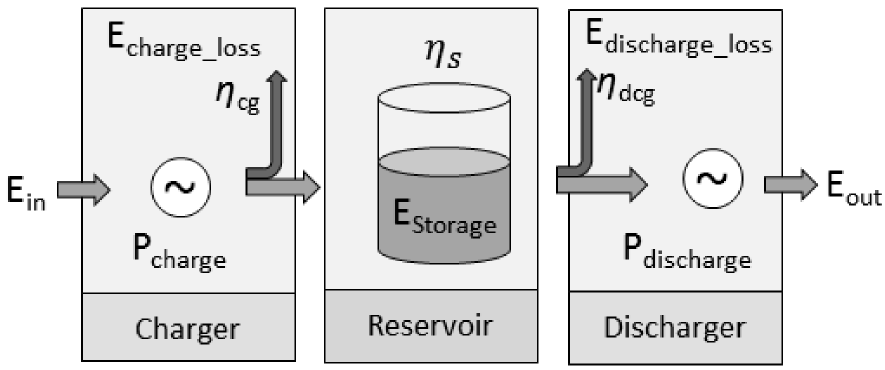

Figure 1: Model of the storage system components

The power system in the GENESYS tool is modelled in the form of interconnected regions with power exchange via variable net transfer capacities (NTC). The respective NTC are part of the optimisation parameters. The standard parametrisation, which is used in this publication, represents the geographical region of Europe, Middle East and North Africa (so-called EUMENA region). There are 21 regions in total which are connected to their neighbours via 49 modelled connection lines. For the power exchange via NTC, the high voltage direct current (HVDC) technology is considered because it allows easy calculation of exchanged power and has efficiency advantages compared to

AC technology, especially for long distances. In each region the model assumes one unit of each available technology, which represents the accumulated power (and respectively storage) capacity of that region. The hourly generation from the renewable generators in the model is calculated as product of the installed power capacity and a normalised time series value for the respective technology (WT or PV). Accordingly, the hourly load demand is obtained by multiplying the respective total annual load of each year with a normalised time series. Each region in the model can access individual generation and load profile time series, which were generated from historic measurements, purchased from MeteoGroup [22], and the ENTSO-E publicly available load records [23].

The model of the storage system components is depicted in Figure 1. There are three different parts: charger, discharger and one reservoir unit. The latter represents the energy capacity $E_{Storage}$. The charger and discharger are represented as power units, which are characterised by the parameters efficiency for the energy conversion (η_{cg}, η_{dcg}) and power capacity rating (P_{charge}, $P_{discharge}$). In the parametrisation the different technologies are distinguished especially by efficiency. The hydrogen (H_2) storage is charged by an electrolyser and discharged by a combined cycle turbine. Therefore, for hydrogen storage the charger and the discharger are separate units, whereas the battery power electronics and water turbines are modelled as one bidirectional unit. For simplification reasons, the reservoir losses are accounted by the charger and discharger. The efficiency of the storage η_s, which is shown in Figure 1, is split up into $\sqrt{\eta_S} * \sqrt{\eta_S}$. As simple average over time, the value from Table 1. , which depicts $\sqrt{\eta_S}$ is, multiplied by the charging losses and discharging losses respectively. The round-trip efficiency is then calculated via

$$\eta_{Roundtrip} = \eta_{cg} \cdot \eta_S \cdot \eta_{dcg} \cdot$$

Table 1. Storage Parameters, authors assumptions for the year 2050 [10]

Unit	Technical storage parameters			
	Parameter	***Battery***	***Pumped Hydro***	***Hydrogen Storage***
€/kW	Investment cost charger/discharger	75	840	300/400
€/kWh$_{netto}$	Storage reservoir	111	20	0.3
%	Efficiency η_{cg}/η_{dcg} charger/discharger	98	90	80/62
years	Lifetime charger/discharger	30	40	15/25
%	Efficiency storage $(\eta_S)^{1/2}$	89.4	100	100
years	Lifetime storage	25	60	40

Table 2. Generation Parameters for the year 2050, authors assumptions [10]

Unit	Technical generation parameters		
	Parameter	***PV***	***WT***
€/kW$_p$	Installation cost	600	1,000
years	Life time	30	18

Table 3. Transmission Parameters, authors assumptions for the year 2050 [10]

Unit	Technical transmission parameters	
	Parameter	***HVDC***
€/kW$_{NTC}$	Installation cost converter stations	130
€/km/kW$_{NTC}$	Installation cost of lines	0.77
years	Life time	40

The cost of power system components is calculated by using the annuity method [24], which allows comparing costs of different components, which have unequal lifetime, based on their economic value during the investigated period. The annuity of the capital expenditure together with the operational expenditures, which are determined by the operation strategy, can be divided by the total consumed electricity, which represents the levelized cost of electricity (LCOE). The assumed parameters for the system components parametrisation are shown in Table 2. -Table 3. For the presented calculations, efficiency for the battery storage is relatively low, because a high temperature technology (NaS) has been assumed, which has additional thermal losses.

2.2. Power system operation strategy

The aim of the authors was to develop a tool which is able to calculate the long term storage operation for a multi annual period. The presented method is therefore able to calculate to operation of one power system for a 5 year period in less than a minute. The scheme of the developed hierarchical system management (HSM) is shown in Figure 2. The residual load within the power system needs to be balanced for all hours through the operation of storage and the use of transmission corridors in a 100% renewable system. The hourly residual load is obtained by subtracting the hourly power output from non-dispatchable generators (WT & PV) from the load. The power generation is

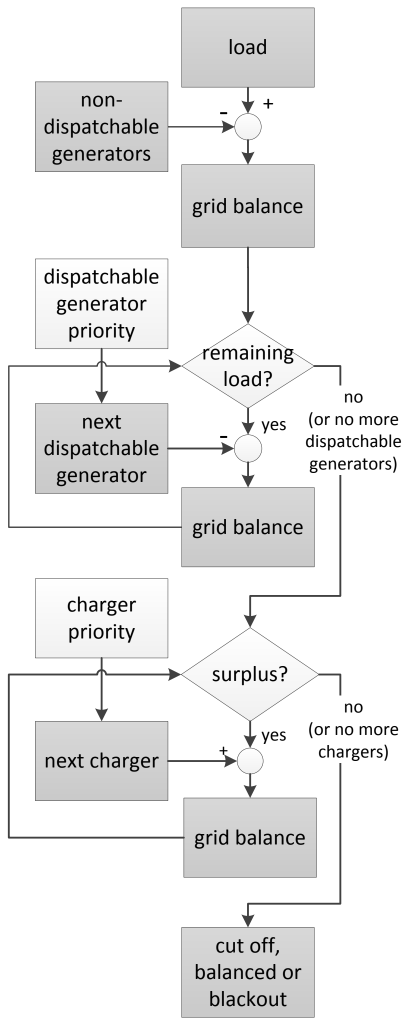

Figure 2: Hierarchical System Management (HSM) Scheme

calculated by using characteristic curves of the generation units and historic measurements of wind speed and solar irradiation multiplied by the installed capacities of WT and PV power generators in the respective system configuration. The optimisation's objective function of the power system operation is the minimisation of the total operation cost, which is strongly influenced by the penalties which are added for hours of remaining positive residual load. To avoid these penalties in hours of insufficient generation, the hierarchical management strategy can utilize the available flexibility options (grid and storage) from the list of dispatchable generators. The strategy is consecutively applied for each hour respecting results of preceding hours and having a perfect foresight horizon of 24 h for the storage operation. By this method, hours of peak load can be identified and adequately supplied by a combination of all available power units of different technologies. The calculation is done for each region within the system, while between the regions the utilisation of existing NTC is calculated between the strategy steps (grid balance). On each step of the strategy the different available power units (charger or discharger), are sorted in a priority list according to the following criteria: 1st efficiency; 2nd future state of charge (SOC) in the connected reservoir of the region, to utilise units with higher SOC more often. The 1st criterion prioritises the high efficient short term technologies like batteries. The grid balance is executed between neighbouring regions in the first step and then remaining NTC is utilised in the subsequent hierarchy steps for each hour.

2.3. POWER SYSTEM OPTIMISATION

An evolutionary strategy (ES), based on the CMA-ES [13], is implemented in the developed planning tool in order to optimise the system composition depending on the investment and operation cost. The power rating or energy capacity of each system component is a degree of freedom for the optimisation. The objective function is subject to different restrictions depending on the scenario. Together, all variables represent a 238-dimensional solution space for the CMA-ES. The algorithm uses a stochastic method to calculate a set of n=151 system compositions (ensemble) for each optimisation loop (called generation). According to the empirical results from the parent generation, it determines the mean value of the distribution of the n/2 best performing systems in the ensemble and generates a new full ensemble around it. This process differs from genetic algorithms, in which a crossover of existing genes is calculated. The CMA-ES uses a set of experience parameters which avoid dependency of high population numbers, yet can avoid local minima and premature convergence.

2.4. DEFINITION OF A BASE SCENARIO

The definition of a base scenario, which is used as reference for the sensitivity analyses, consists of a setup with 21 regions and no limit for the NTCs of the connections. As previously described, there are three storage technologies available, batteries, pumped hydro storage and hydrogen storage. Each region has a lower self-supply boundary of 80%, which means it has to harvest 80% of its consumed energy from own generation units. There are no upper or lower boundaries for the installation of renewable energy generators. This setup allows a free ratio between generation capacities of WT and PV, and calculates no penalties for curtailment. The exemplary results are calculated with technology parameter assumptions for 2050 (Table 1.-3.). The electricity consumption for 2050 is anticipated to amount to 6,250 TWh/a in EUMENA and is based on the authors' assumption by increasing standard of living in today's less developed regions, which is inspired by the documentation in [25]. The difference to today's consumption of about 4,122 TWh [9] is not explained by electrification and demand shift from other sectors.

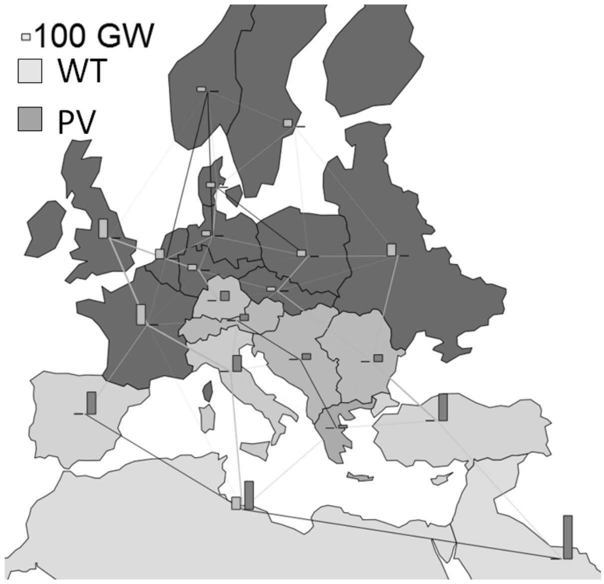

Figure 3: Distribution of generator power units in the standard scenario

2.5. Sensitivity Analyses

Sensitivity analyses have been conducted to evaluate, which impact different technologies or possible restrictions have on the system.

The first sensitivity scenario limits the NTC between the different regions to show the impact of grid as a flexibility source. The variation is conducted by defining upper limits for the NTC of all available connections in steps of 2.5 GW from 15 GW down to 2.5 GW.

The second sensitivity scenario optimises the power system with constrains for single technologies. . Case a) constraints PH as middle term storage option, case b) constraints technologies suitable for short term options (PH and batteries) and case c) constraints long term

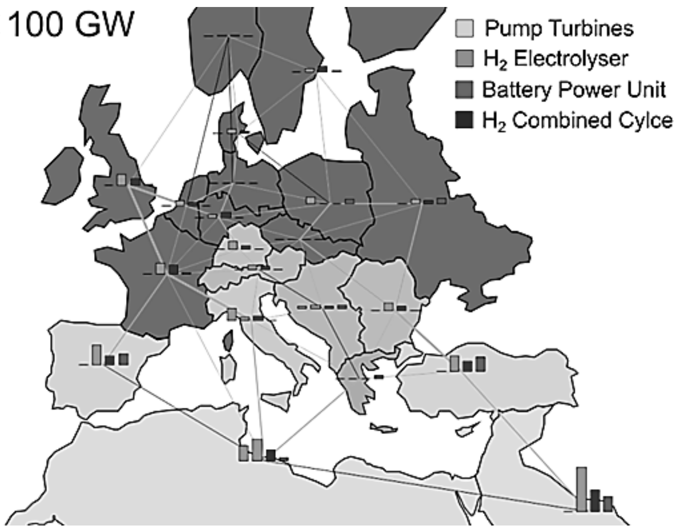

Figure 4: Distribution of storage power units in the standard scenario

gas storages. These sensitivities are investigated via the LCOE. This allows using one indicator for evaluation and comparison of the results.

As third sensitivity analysis, investment cost variations are conducted in order to examine their impact on the power system composition and cost. The system is optimised assuming respectively 30% higher and lower investment cost of the single components compared to the original assumptions from Table 1.-3.

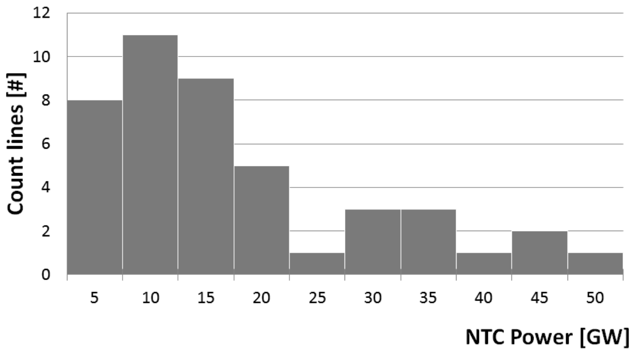

Figure 5: Distribution of NTCs in the base scenario

3. RESULTS

3.1. BASE SCENARIO

The results for the base scenario show a total installed generation capacity of 4,550 GW, which splits up into PV and WT in a ratio of 60:40 on global scale for the EUMENA regions. The allocation in the different regions is depicted in Figure 3. The colouring of dark (WT) and light(PV grey without much mixing indicates that there is usually a certain technology dominating, as typically a significant difference in the LCOE for generation occurs from the different weather potentials. Only the Northern Africa region shows a smaller difference, which results in coexistence of both technologies. The totally generated electricity from PV is 3,900 TWh/a, which equals an average of 1,400 full load hours (FLH), while WT have a significantly higher average value of 2,000 FLH and a total generation of 3,700 TWh/a. The power system requires a significant amount of energy storage systems. The long term capacity of hydrogen storage systems needs to be as high as 800,000 GWh, while for electrolysers an installed capacity of 900 GW and for combined cycle gas turbines a power of 550 GW are required. The demand for middle and short term storage capacity is lower: 2,700 GWh with a power capacity of 190 GW for pumped hydro storage and 1,600 GWh with a power capacity of 320 GW for battery systems are. The

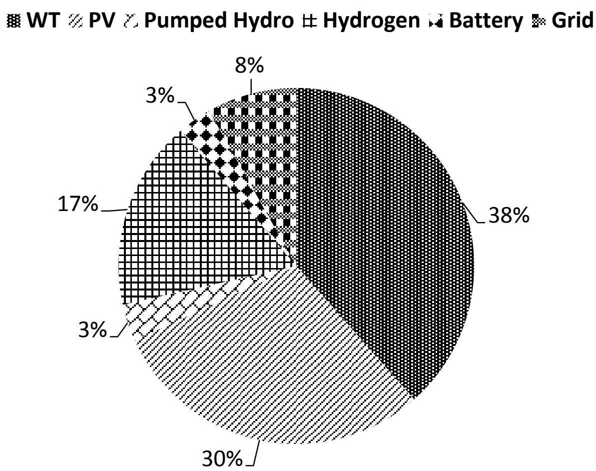

Figure 6: LCOE of 9.67 ct/kWh in the base scenario, shares depicted in [%]

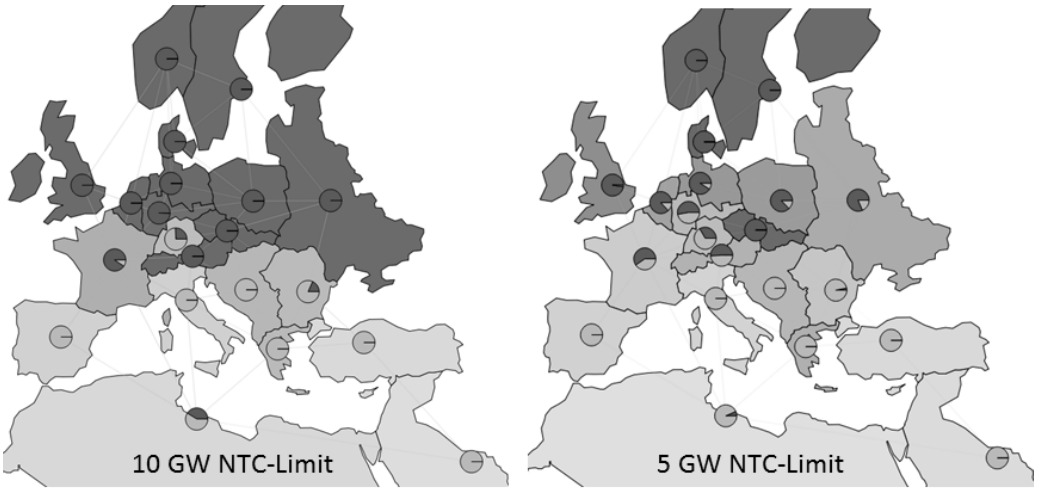

Figure 8: Map of generator ratios per region for NTC-Limit scenarios 10 GW (left) and 5 GW (right).

peak load is about 1,030 GW, which equals the amount of the installed discharge power capacity of all storage units. The distribution of storage units in the system is shown on the map in Figure 4.

The second flexibility source aside from storage is the capacity of transmission corridors. It can be characterised by the grid momentum, which is the capacity of each corridor multiplied by the respective line length calculated in GW·km. For the 46,000 km of HVDC lines represented in the model, the optimisation results in a consideration of 36,000 km which incorporate a grid momentum of 503,000 GW·km. The distribution of transmission corridor capacities, as shown in Figure 5, has a multimodal shape and shows a spread up to 50 GW for one single line. The dominant mode of this distribution indicates that most connections are optimised to have a NTC of 5-10 GW. From this optimisation scenario the LCOE results to 9.67 $ct_{€2014}$/kWh. The pie chart in Figure 6 shows the cost distribution over the different system components. It can be seen that 68% of the toal cost accounts to the investment in renewable generator capacities while storage systems have a share of 24%. The remaining 8% share of the LCOE is required for grid investments as second flexibility source.

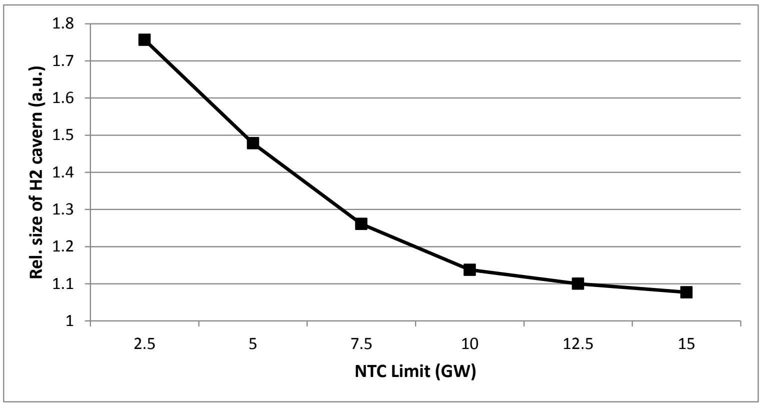

Figure 7: Sensitivity on NTC: Relative long term energy storage capacity compared to base scenario depending on NTC limit

3.2. Sensitivity to NTC Limitations

The results of the single optimisations with varied NTC limits is exemplified in the maps ofFigure 8. The colour of the regions represent the mix of WT in dark and PV light grey. The illustration displays the significant influence of different NTC limitations on the distribution of generator types. Shifting the limitation to smaller transmission capacities results in a stronger mix of PV and Wind generators within the single regions. This effect can be obseverd especially in the central European regions. The impact on storage demand becomes clear when examining Figure 7. The graph depicts the relative change of the long term

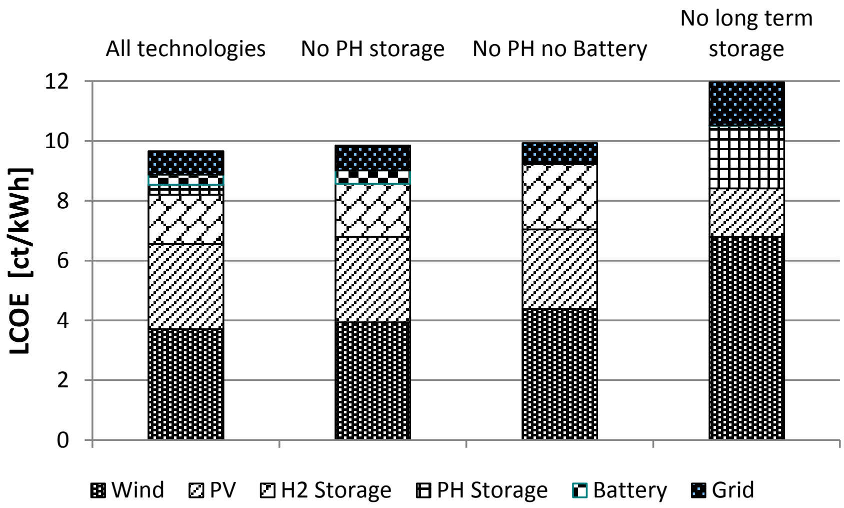

Figure 9: LCOE [ct/kWh] for different technology constraint scenarios

hydrogen storage capacity compared to the base scenario in dependency of the NTC limits. The results show a strong correlation between the available flexibility from the grid represented by the NTC and the additional need for flexiblity from long term storages.

3.3. Sensitivity to technology constraints

The second sensitivity where different cases of constrained storage technologies were investigated is depicted in Figure 9. The LCOE of these three technology constraint scenarios are illustrated in comparison with the base scenario. The base scenario shows the lowest LCOE while constraining long term storage technologies (case c) shows a strong LCOE increase of 24% compared to the full technology mix in the base case. For this case, the only storage technology to be used is the pumed hydro systems, while no batteries are economic. The other two cases (case a) with no pumed hydro storage or (case b) no pumd hydro and no batteries) show only marginal increase of the system cost and slight influence on the ratio between wind generators and PV.

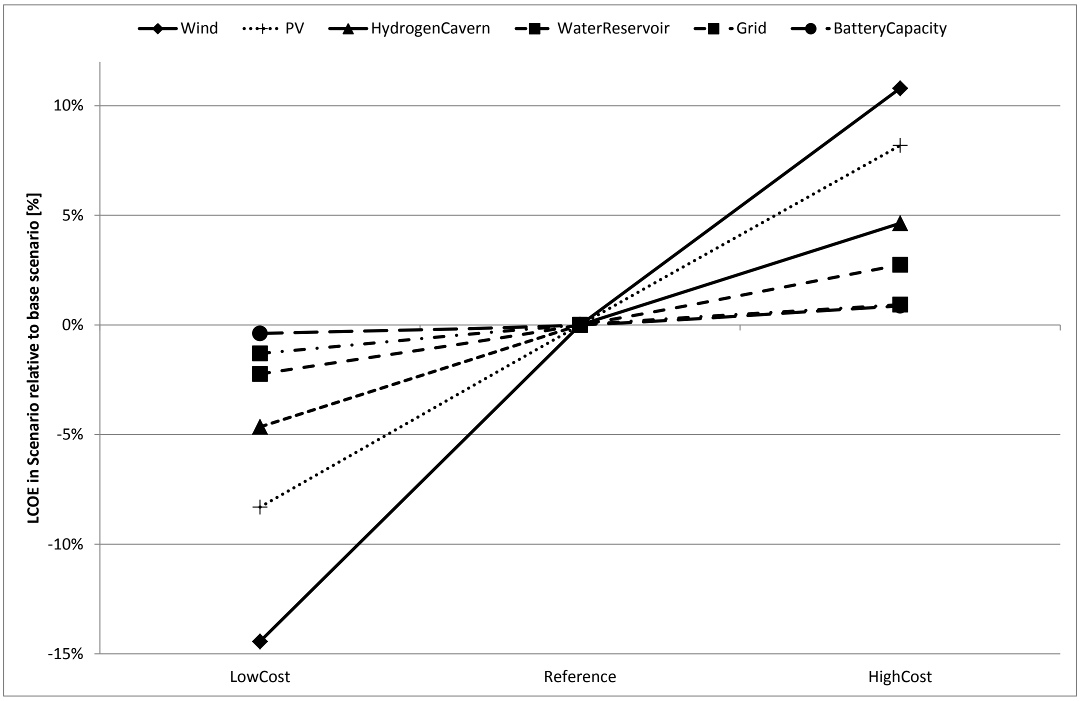

Figure 10: LCOE relative to the standard scenario for different investment cost variations

3.4. Sensitivity to investment costs

The investment costs variations were conducted in ten simulations, two for each technology. The case where investment cost per unit were increased by 30% were named TechnologyX_HighCost, the cases with 30% lower investment cost per unit were named TechnologyX_LowCost. As expected, in all cases the configuration with components of lower cost expose lower LCOE while increased investment cost result in higher LCOE compared to the base case. The highest spread can be found for the variation of wind cost followed by PV, hydrogen-storage, pumped hydro storage, transmision capacity and batteries. The latter two show only a relative low change of LCOE in the range between 0.5-1%.

Figure 11 displays the spread of LCOE ranging from 8.30 ct/kWh absolute in the -Wind_LowCost case to 10.74 ct/kWh absolute in the -Wind_HighCost case on the right ordinate. Moreover, the illustration presents the capacity share of the different technologies for each case on the left ordinate. The impact of the capacity reduction due to increased investment costs in one technology causes various effects in the power system configuration. Three of the cases show installed capacities equal or greater than 7,000 GW in total. This is the case for PV_Low, Wind_High and Battery_Low scenarios. In all of these scenarios the power of wind generators is significantly lower than the average of 1,900 GW, while the capacities of PV generators, battery power and electrolyser power units are increased compared to the average. The standard deviation of

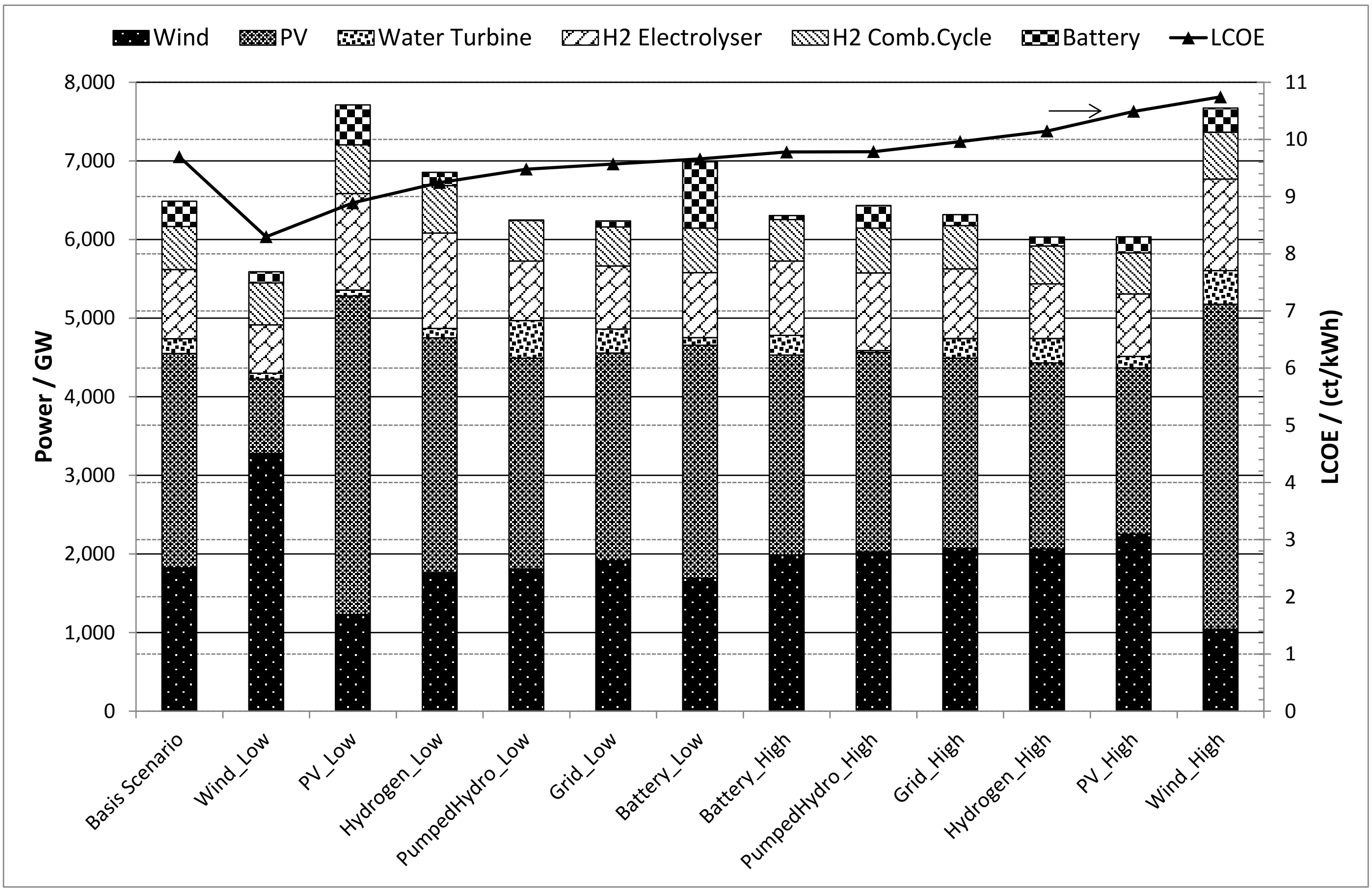

Figure 11: Installed capacities and cost for different Scenarios

Table 4. Storage capacities in Investment Cost Variation Scenarios

	Capacity Water Reservoir (GWh)	Capacity Battery (GWh)	Capacity Hydrogen Cavern (TWh)
Base Scenario	2,725	1,553	802
Wind_Low	1,520	606	479
PV_Low	1,061	2,677	1,054
Hydrogen_Low	1,569	970	952
PumpedHydro_Low	7,610	0	779
Grid_Low	4,423	391	785
Battery_Low	1,164	3,234	841
Battery_High	3,908	331	750
PumpedHydro_High	464	1,894	753
Grid_High	4,140	705	844
Hydrogen_High	5,378	628	654
PV_High	2,780	1,160	735
Wind_High	5,535	881	1,157

H2 combined cycle generation power units within this investigation is less than 8% followed by the electrolyser power units which exhibit a standard deviation of 21%.

The power capacity of water turbines for pumped hydro storage is strongly increased compared to the average in cases of PumpedHydro_Low, Wind_High and Hydrogen_High. In the first and the latter case it coincides with smaller battery power, while the case of Wind_High requires also high battery power.

The energy capacity of the storage systems strongly differs in each case (see Table 4.). While the hydrogen storage capacity only exhibits a standard deviation of 21% leading to small variance between the cases, the installed battery capacity is zero in case of extended water reservoirs (PumpedHydro_Low) and increased by 70% in the PV_Low scenario and even 108% in the Battery_Low scenario compared to base case. The standard deviation of battery storage capacity is in the range of 82%. Pumped Hydro capacity behaves anticorrelated to the battery capacity demand.

4. Discussion

Results of the base scenario verify the possibility to find a combination of system elements for a fully renewable source based future. With a good mix of several technologies for generation and flexibility it is possible to generate electricity at low cost. The allocation of generation technologies is clearly dominated by potentials - which can be extracted from time series - and results in a distinct favourite technology for almost every region. Outcomes regarding transmission corridors show that only few routes exist where an expansion of transmission capacity above 20 GW is economically beneficial. This is the case, for example, for the corridor between Great Britain and France, where high generation capacity of WT is to be found in Great Britain. The calculated sensitivities show that changes in the technology mix lead to increased LCOE. Limiting the possible NTC between the regions leads to increased cost, mainly due to an increased amount of regions where higher and mixed capacities are integrated. The mixed generation synergies of complementing generation characteristics of PV and WT compensate the lack of energy flexibility induced by limited NTC. Furthermore this leads to an increased demand for long term energy storage.

In the scenario cases of storage technologies constraints, only omissions in long term storage technology lead to significant increase in LCOE. In this case a higher share of WT can be found in the power system and more pumped hydro units are installed to compensate temporal fluctuations. Because of a high amount of water turbines in this case, batteries are not economically beneficial.

The variation of investment cost of +/- 30% results in all cases in a change of LCOE lower than +/- 15%. This demonstrates how a variation of system configuration is able to compensate the higher component cost through a change in the resulting optimal configuration of each scenario. As depicted in Figure 5, the LCOE is dominated by the share of generation technologies, wind and solar power, which is confirmed by the variation of their investment costs. Furthermore, Figure 11 illustrates the effect of lower component cost on the economic capacity to reach the minimal LCOE in the respective case. The graphic moreover suggest an anti-correlation between WT capacity and the total capacity in the system. Contrarily, the installation of PV units indicates strong correlations with the overall installed capacity and also demand of energy storage units. The scenarios featuring high share of wind generation and high investment cost for hydrogen storage units exhibit a greater installed power capacity for pumped hydro storage units. The installation of long term energy storage units shows a direct correlation with the amount of installed capacity of WT in the system. A small amount of hydrogen energy storage, on the other hand, is only necessary when the wind power share with high full load hours is significantly greater than PV share.

5. Conclusion

The combination of different flexibility options for spatial and temporal balancing of power fluctuations caused by an entirely renewable energy based power system can lead to economic constellations, which are able to supply energy at low cost. Any constraints of technologies, which characterise the spatial flexibility options, as for example NTC, or especially long term energy storage, will result in a significant increase of electricity cost. However, short term and medium term energy storage technologies do not show strong interdependencies, but mutual exchangeability. The development of the investment cost per capacity will have a great influence in case of the generation technologies. If the power generation share of PV is increased over a certain level, this will cause changing requirements regarding other flexibility components. In consequence that will lead to higher LCOE. The impact of technology investment costs for energy storage systems and transmission plays a minor role compared to generation technologies; only the hydrogen energy storage as only long term storage option is able to noticeably impact the total electricity cost. The utilised tool is not configured to consider other sectors besides the electric power sector. Including the additional demands of the other sectors are nevertheless important to the goal to reach a transsectoral emission reduction. The results presented here are therefore not applicable to an overall 100% RE system, the inclusion of other sectors is however expected to bring additional flexibility to the mathematical optimisation problem with the additional demand characteristics and typical technologies.

Acknowledgment

This work was kindly financed by the Federal Ministry of Economic Affairs and Energy (BMWi) of the Federal Republic of Germany, within the project code FKZ 0325692.

This work was inspired by the collaboration through the HGF Energy Alliance “Stationäre elektrochemische Speicher und Wandler” of the Helmholtz Association.

The authors also want to thank the anonymous reviewers for their valuable input to increase the quality of this publication.

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