



POTSDAM-INSTITUT FÜR
KLIMAFOLGENFORSCHUNG

Originally published as:

Schmid, E., Knopf, B. (2015): Quantifying the long-term economic benefits of European electricity system integration. - Energy Policy, 87, 260-269

DOI: [10.1016/j.enpol.2015.09.026](https://doi.org/10.1016/j.enpol.2015.09.026)

Quantifying the long-term economic benefits of European electricity system integration

Eva Schmid ^{1(a)}, Brigitte Knopf ^(a,b)

^a Potsdam-Institut für Klimafolgenforschung, Postfach 60 12 03, 14412 Potsdam, Germany,
eva.schmid@pik-potsdam.de

^b Mercator Research Institute on Global Commons and Climate Change, Torgauer Str. 12, 10829
Berlin, Germany, Knopf@mcc-berlin.net

Abstract

This paper aims to quantify the long-term economic benefits that arise from an increasing integration of the pan-European electricity system by means of comparing model-based decarbonization scenarios developed with the model LIMES-EU+. It explicitly accounts for the interplay between transmission infrastructure and renewable generation capacity expansion. We confirm earlier findings that, on aggregate, pan-European transmission capacity expansion constitutes a no-regret option for integrating increasing shares of variable renewables. It leads to positive social returns on investment in all mitigation scenarios under analysis. However, the reduction in total discounted system costs stemming from transmission capacity expansion is modest in magnitude. Over the period 2010-2050 it reaches a maximum of 3.5% for a case with massive expansion compared to one in which the status quo remains. In technical terms this means that the optimum is rather flat and taking into account regional and local benefits and distributional aspects could alter the evaluation of the economic benefits. A crucial finding is that the configuration of pan-European transmission infrastructure and the importance of specific country-connections, i.e. a “Southern” versus a “Northern” solution, hinges on the relative development of specific investment costs for solar and wind technologies over the next decades.

Keywords: mitigation; transmission infrastructure planning; renewable integration; energy system modeling; European energy policy targets; Energy Union

¹ Corresponding author. E-mail: eva.schmid@pik-potsdam.de, Address: P.O. Box 601203, 14412 Potsdam, Telephone: +49 331 288 2674, Fax: +49 331 288 2570.

1. Introduction

The integration of the European electricity system by means of expanding pan-European transmission infrastructure capacities is argued to be an economically beneficial means for achieving four key long-term energy and climate policy targets (European Parliament and the European Council, 2009; 2015; European Commission, 2010; European Council, 2011). It constitutes a pivotal option to (i) integrate high shares of renewables, leading to a reduction in greenhouse gas emissions by substituting fossil-based electricity generation. Also, it (ii) increases competition in the internal market for electricity, leading to lower prices. Further, it (iii) increases security of supply in the European Union through integrating remote areas in the European periphery, enabling a more diversified energy mix and reduced congestion. And, finally, progress in attaining these three climate and energy policy ends jointly contributes to the long-term European policy target of (iv) transitioning to a competitive low carbon economy. “Energy infrastructure” and its development is also a key term in the 2030 framework for climate and energy policies (European Commission, 2014) and the Energy Union (European Council, 2015). Despite these bold political statements, the respective arguments are given without any quantification, so the question is: How great are the long-term economic benefits of European electricity system integration and what are crucial variables influencing the result?

In order to quantify the economic benefits in the context of the political targets discussed above, one ideally had a numerical model accounting for the full sets of system effects inherent to the future development of the European electricity system. However, two greater challenges apply. First, models are by definition only capable of representing a reduced set of effects and one has to select which ones to include. Second, computational power limits the possible complexity of the analysis, e.g. in terms of geographical, temporal and technological resolution and interactions between system effects. Depending on the research question individual model studies pursue distinct choices with regard to these two challenges, resulting in a variety of numerical models. To date, the majority of modelling studies for the European electricity system focuses on grid-related, technical aspects; only few are designed to report dedicated results on the economic effects of system integration through transmission grid expansion. Interestingly, all of them indicate that pan-European grid expansion is a no-regret option.

A literature review by Booz & Company (2013) finds that the benefits from improved electricity system integration are broadly in the range of 1-10% of system costs, with the majority of the studies lying in the lower area of this range. Confirming this finding, Fürsch et al. (2013) find that average system costs can be reduced by 1.9% in 2030 and 3.4% in 2050 if pan-European transmission capacity expansion is pursued optimally from a system cost perspective as opposed to a restricted scenario, i.e. one that does not allow for those transmission lines that are being significantly delayed as specified in the ten-year network development plan (TYNDP) (ENTSO-E, 2012). The main cost drivers in the restricted scenario are the use of less favorable wind and solar potentials and the need for storage technologies. Using a refined version of the model applied in Fürsch et al. (2013), Hagspiel et al. (2014) find higher costs in a scenario with optimal pan-European transmission grid expansion compared with one that strictly avoids any line extension. Over the period 2011-2050 total discounted system costs are 20.9% higher in the restricted scenario. The main cost drivers are again the need to exploit sites with comparatively less

favorable resource availabilities, much higher curtailment rates of wind and solar as well as investments in the more costly renewable technologies biomass and geothermal power. Both studies apply an iteratively coupled European energy market model and a line-sharp infrastructure model.

By means of a line-sharp model of the European transmission grid Tröster et al. (2011) calculate that, if the grid is configured in an optimal manner given a specific feed-in structure of renewables that provide a share of 97%, curtailment can be cut by two thirds from 12% to 4%. This reduces the need for investments into renewable generation capacities. Schaber et al. (2012b) find in a parametric study with high temporal and spatial resolution that for a European electricity system with 60% renewables, an optimal grid configuration in combination with an optimal mix between wind and solar capacities can even reduce curtailment to less than 1% as well as dampen the need for additional back-up capacities. These system effects lower the average European cost of electricity by 7% as compared to a scenario with no grid extensions; and by 11% in a variant that assumes lower specific investment costs for the renewable technologies solar photovoltaic, wind onshore and offshore.

We contribute to the current literature by providing a range of quantitative estimates of the economic benefits of European electricity system integration applying the European electricity system LIMESEU+ (Haller et al., 2012). In particular, we expand the focus of previous work by further investigating the magnitude and the structural pattern of system effects that result from the interplay between the expansion of transmission infrastructure and renewable generation capacity. This is enabled by a distinct feature of LIMESEU+, namely that both transmission and generation capacity expansion are an endogenous decision of the model. We compare model results from a set of scenarios that are characterized by different assumptions on the expansion rate of pan-European net transfer capacity (NTC) and the development of specific investment costs for the variable renewable (vRES) technologies wind onshore and offshore, solar photovoltaic and concentrated solar power. If not explicitly stated otherwise the analysis rests on assumptions regarding the future development of system drivers and exogenously enforced CO₂ emission reductions in the electricity sector that are in line with the “Roadmap for moving to a competitive low carbon economy in 2050” (European Commission, 2011a) as well as the scenario 80%DEF of the model intercomparison exercise EMF28 (Knopf et al., 2013b).

The outline is as follows. Section 2 briefly introduces the electricity system model LIMESEU+ (Haller et al., 2012) and outlines important scenario assumptions. Section 3 presents the model results. Section 3.1 focuses on the impact of transmission capacity expansion on total system costs. Sections 3.2 and 3.3 analyze structural patterns emerging in the configuration of pan-European transmission infrastructure and the technology mix. Section 3.4 explores the distribution of electricity prices resulting in the different scenarios. The model results are presented in aggregate over the European model regions due to the European scope of the analysis and in order to be comparable to previous work and in particular the scenarios of the European Commission. Departing from the model results, Section 4 goes further to discuss the question of how large the expected gains from European electricity system integrations really are and identifies arising policy implications. Section 5 concludes.

2. Method: Model and Scenarios

The partial electricity system model LIMES-EU+ (Haller et al., 2012) is designed to generate quantitative scenarios that represent a consistent, system-cost optimal transition towards a decarbonized European electricity system in 2050. Endowed with perfect foresight, LIMES-EU+ yields a social planner solution that specifies in time steps of 5 years for each model region the optimal (i) dispatch and curtailment of installed electricity generation technologies, (ii) electricity import balance from neighboring model regions, (iii) investments into installed capacities of electricity generation technologies² and (iv) investments into net-transfer capacities³ (NTCs) between model regions. Model regions are defined as individual countries or country groups in some instances, implicitly assuming that there are no bottlenecks within the countries (copper plate assumption). Electricity transmission is represented as a transport problem by specifying NTCs between all neighboring model regions. For the calibration year 2010 each model region is endowed with initial installed transmission (ENTSO-E, 2010) and generation⁴ capacities.

The use of the NTC approach has specific limitations, in particular it cannot take into account loop flows and the root cause for NTC congestions remains open – they could be either caused by domestic congestions in the hinterland or by actual congestions in the cross-country connection. Also, due to this conflation of root causes it is challenging to put an unambiguous price tag on NTC capacity expansion. However, at the same time the NTC approach is a frequently applied simplification that reduces the numerical complexity of the model sufficiently to allow for a simultaneous, endogenous optimization of transmission and generation capacities – a feature that is as such not covered in other models.

The model is calibrated⁵ to the ENTSO-E region and additionally covers the Middle East and North Africa (MENA). However, the focus of this analysis is the ENTSO-E region and the possibility to import electricity from the MENA regions is disabled in all scenarios. Specified as a linear optimization model, the objective function of LIMES-EU+ is to minimize the total sum of discounted⁶ electricity system costs (comprised of fuel, investment, fixed and variable operation and maintenance costs) jointly for all model regions between 2010 and 2050, given a number of boundary conditions. Climate policy is simulated by constraining annual CO₂ emissions as suggested by the “Roadmap for moving to a competitive low carbon economy in 2050”⁹, leading to a near decarbonization of the electricity system in 2050. In order to represent fluctuating feed-in of vRES and differences in electricity demand occurring on sub-annual time scales, LIMES-EU+ uses a time-slice approach (for details see Ludig et al., 2011). A total of 48 six-

² To prevent excessive annual capacity additions that are not reconcilable with likely developments, they are restricted for wind onshore, offshore and biomass to 3, 1.5 and 1 GW, respectively.

³ Investment costs for NTC expansions are set to 0.38€/kW km, for more details consult Haller et al. (2012).

⁴ Installed capacities are derived from Kjærstad and Johnsson (2007) and IEA Energy Balances for Non-OECD Countries (2010 edition) as well as IEA Energy Balances for OECD Countries (2010 edition).

⁵ For details on the model calibration consult Haller et al. (2012), particularly the supplementary material.

⁶ We apply a social discount rate of 5%.

hourly time slices represent three representative vRES feed-in days with corresponding demand levels⁷ for each season of the year and each model region individually.

The scenarios for this analysis are specified so as to represent both different conceivable degrees of European electricity system integration and developments of vRES technologies' specific investment costs. Other influential system drivers, e.g. electricity demand, CO₂ emission reduction targets, primary energy prices and the like are kept constant across scenarios and are either retrieved from literature estimates or based on the definition of the scenario 80%DEF defined in the European Stanford Energy Modeling Forum (EMF) model intercomparison exercise EMF28 (Knopf et al., 2013b). The scenario 80%DEF is characterized by 80% greenhouse gas emission reduction by 2050 relative to 1990, leading to 93% CO₂ emission reduction in the electricity sector, the availability of the carbon capture and storage (CCS) technology and a reference development for energy efficiency, nuclear energy and renewable energies. It is constructed in a similar way than the scenarios in the "Energy Roadmap 2050" (European Commission, 2011b).

Different degrees of European electricity system integration are implemented in the model via restricting NTC expansion between neighboring model regions from one five-year time step to the following one (Δ NTC). As a reference case we set Δ NTC = 0 GW/a, i.e. as a lower extreme in the scenario "no" current transfer capacities between countries persist. In order to proxy different speeds of integration of the European electricity system, we consider three scenarios with Δ NTC \leq 0.25, 0.5 and 1 GW/a, referred to as "low", "mod" and "high". Considering that currently 40 GW of NTC are installed between the ENTSO-E regions (ENTSO-E, 2010a) in 33 country-connections, the "high" scenarios could theoretically exhibit almost a doubling of European NTC per year, serving as an upper extreme.

The second scenario dimension in this analysis regards the development of specific investment costs of vRES technologies; an uncertain but at the same time very decisive parameter that directly influences the technology mix in optimization models (Nemet, 2009; Junginger et al., 2010). In energy system modeling, it is common practice to assume substantial long-term reductions in specific investment costs for vRES technologies (Schmid et al., 2013). They are generally justified by technology learning and more specifically by the empirically derived concept of learning-by-doing, which postulates a negative log-linear relationship between cumulative installed capacities and specific investment costs: the learning or experience curve (Junginger et al., 2010). It especially holds for modular technologies that allow for large economies of scale, e.g. solar photovoltaic (Junginger et al., 2010). Complementary to such top-down econometric approaches, bottom-up engineering-type of estimates examine cost reduction potentials for each step in the manufacturing and deployment chain of immature technologies. They generally confirm the trends postulated by top-down estimates (Neij, 2008).

However, it is not a universal law that specific investment costs have to decrease log-linearly with cumulative installed capacities. There is a growing strand of literature that identifies significant uncertainties regarding the specification and identification of the log-linear learning curve model

⁷ Demand projections are based on Capros et al. (2010) and IEA (2010a, 2010b)

(Nemet, 2009; Nordhaus, 2009; Yeh and Rubin, 2012). Particularly for wind technologies, specific investment costs did increase in the recent years – despite continuously increasing installed capacities (Heptonstall et al., 2012). Rising steel and concrete prices had a significant effect on wind technologies’ investment costs in the recent years (Panzer, 2012), and may do so in the future. Based on a data documentation of recent literature (Schröder et al., 2013), Figures 1 and 2 plot the range of bottom-up estimations compiled in for the development of specific investment costs of the vRES technologies solar photovoltaic (SPV) and concentrated solar power (CSP) with storage as well as onshore and offshore wind (Wind-ON, Wind-OFF). Interpreting the band of projections as a conceivable range for future developments, we consider four combinations of vRES investment cost developments: In three scenarios all four technologies develop similarly (“pessimistic”, “middle” and “optimistic”); a fourth one considers the solar technologies to be on the optimistic trajectory and the wind technologies on the pessimistic one (“solarOpt/windPes”).

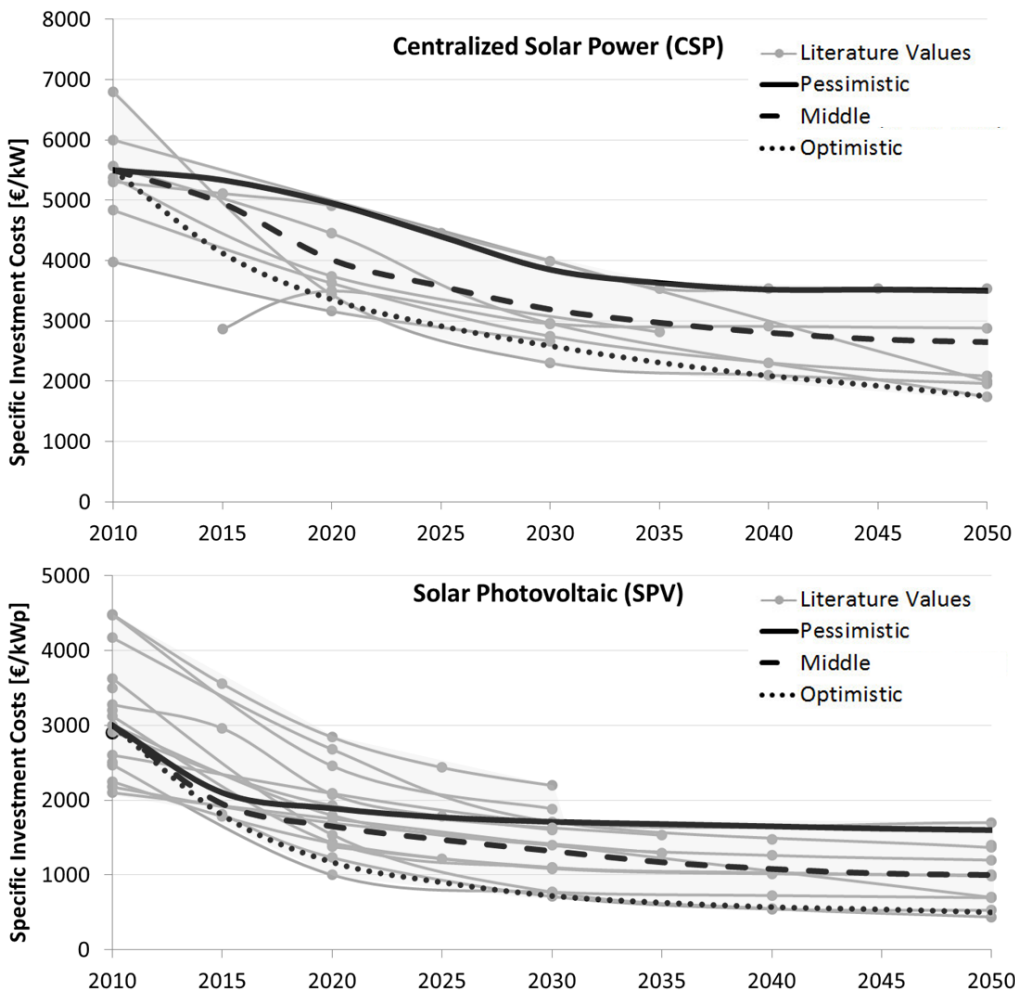


Figure 1 Specific investment costs in €/kW for solar technologies from the literature in grey and the Pessimistic, Moderate and Optimistic trajectory chosen for this analysis in black. Literature data is retrieved from Schröder et al. (2013).

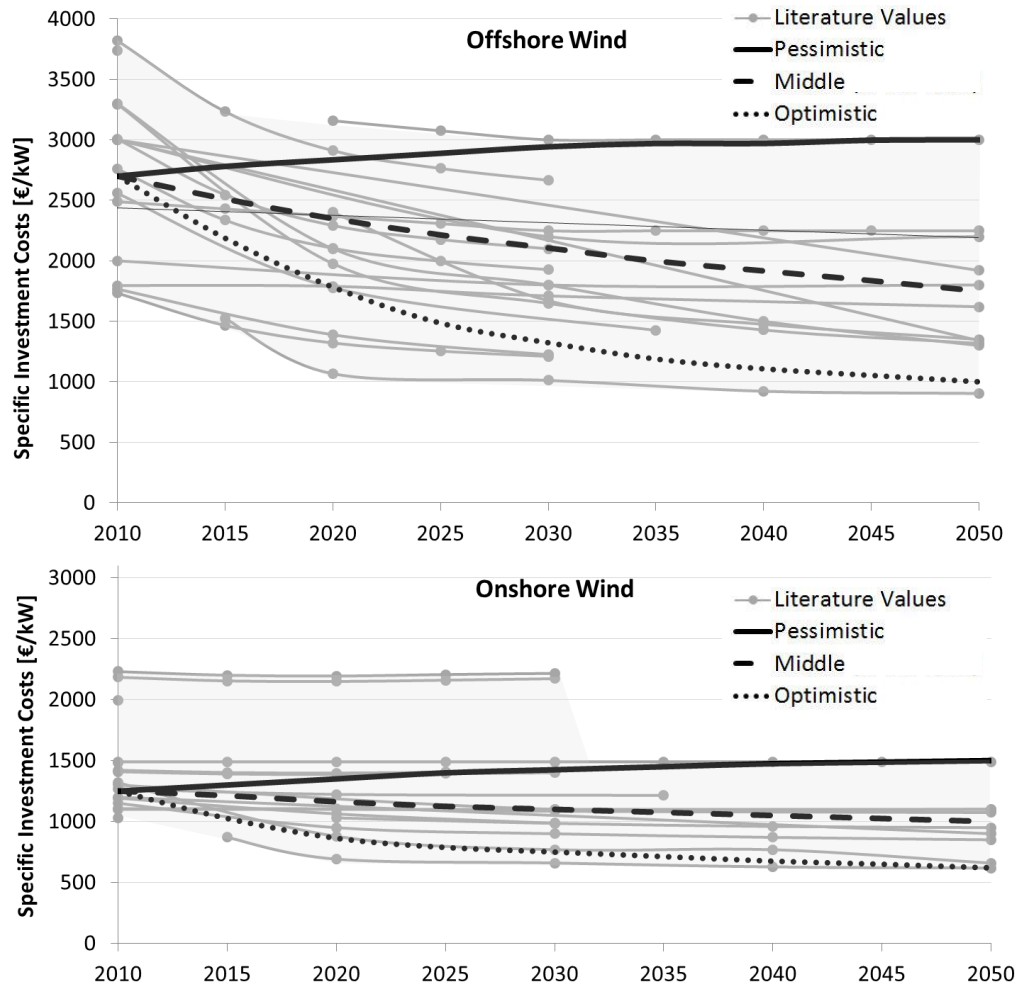


Figure 2. Specific investment costs in €/kW for wind technologies from the literature in grey and the Pessimistic, Moderate and Optimistic trajectory chosen for this analysis in black. Literature data is retrieved from Schröder et al. (2013).

3. Results

In order to quantify economic benefits of European electricity system integration and drivers thereof, this Section analyzes selected model results computed with LIMES-EU+. Conceptually, benefits are determined by comparing model results between scenarios that allow for an expansion of NTCs with respective reference scenarios that are bound to a pan-European transmission infrastructure as is today (keeping all other parameters constant).

3.1. Total Discounted Electricity System Costs

An obvious indicator to analyze is the total discounted electricity system costs over the time horizon 2010-2050, the minimization of which is the objective function of LIMES-EU+. Comparatively lower total system costs incurred by the European electricity system are economically beneficial as the cost

differential may be directed to value-creating activities in other sectors of the economy. On the left axis, Figure 3 displays the savings in terms of this indicator for the different NTC expansion scenarios, relative to the respective reference vRES investment cost scenario in which NTCs remain at today's level. On the right axis, the dots indicate the social return of investment in NTC capacity expansion beyond the reference level in terms of system cost savings as percentage of investments in NTC.

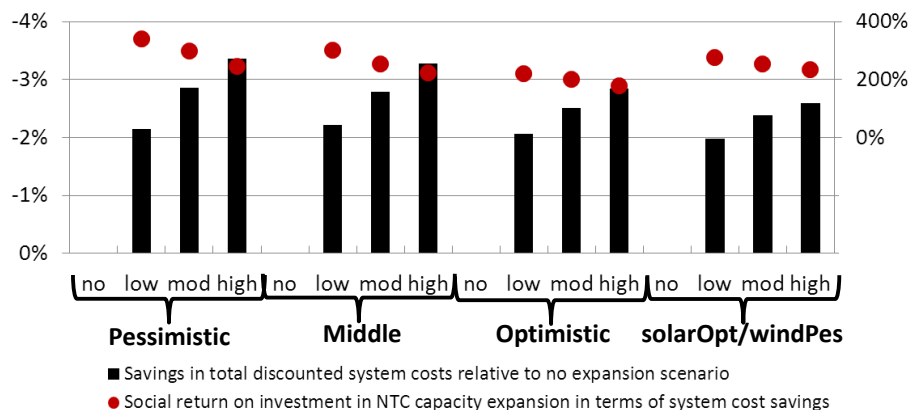


Figure 3. Two indicators measuring economic benefits of pan-European electricity system integration - savings in total discounted system costs (left axis) and social return on investment in NTC capacity (right axis) for all scenarios under analysis (for abbreviations see Section 2).

A first finding is that total system costs decrease upon allowing for NTC capacity expansion under all settings of specific investment costs for vRES technologies. Social returns on investments in NTC capacity expansion beyond the respective reference levels amount to 180-340%. Hence, pan-European transmission capacity expansion presents itself as a means to increase the cost-efficiency of decarbonizing the European electricity sector. This confirms the conclusion of previous work that it constitutes a no-regret option. Moving from the low to high NTC expansion scenarios, the effect becomes less pronounced, revealing decreasing returns to incremental NTC deployment. Also, both indicators decrease when moving from the pessimistic over the middle to the optimistic scenarios, revealing that the added value of NTC expansion is higher if vRES technologies remain more capital-intensive to deploy. In the latter case vRES generation sites with better potential in the European periphery are comparatively more valuable to connect to central Europe, leading to higher social returns on NTC investment.

A second finding that is robust across all scenarios is that the percentage change by which total system costs decrease as NTC expansion increases from low to high rates is quite modest in magnitude. It ranges between 2-3.5% in all cases. This is also valid for other combinations of vRES investment costs not illustrated in this paper but analyzed by the authors. In technical language this implies a flat optimum of the objective function with respect to the parameter “transmission capacity expansion rate” (Δ NTC). This result is broadly in line with the quantitative estimates mentioned in the Introduction, except for Hagspiel et al. (2014). They find a significantly higher advantage of European transmission capacity expansion amounting to 20.9% lower total discounted system costs over the period 2011-2050. The potential reasons for this difference are manifold and could arise from the different model

structures, taking into account distinct set of system effects, as much as from different assumptions on e.g. investment costs; a more elaborate discussion is postponed to Section 4.

3.2. Structural Pattern and Bottlenecks of Pan-European Transmission

Having found that the optimum is not very much affected in absolute terms and on aggregate does not yet imply that the scenarios are similar with respect to the configuration of NTC and generation capacities across Europe. Moving from the reference case with NTCs restricted to today's values to the high expansion scenario, LIMES-EU+ deploys more and more NTC capacities in order to transport electricity between model regions to achieve a system-cost-optimal solution (Figure 4). All displayed scenarios have the investment costs of vRES set to the middle trajectory. In the low transmission expansion scenarios the constraint on Δ NTC is binding (illustrated in dotted lines) for four transmission corridors: (1) the east-west connection between the islands of Ireland and Great Britain with the mainland in France and Benelux, (2) the north-south connection between Sweden, Norway, Denmark and Germany, (3) the west-east connection between the Baltic states, Poland and Germany, and (4) the south-north connection between the Iberian Peninsula and France. All these transmission corridors connect the European periphery to central Europe. They serve to transport electricity produced by vRES capacities in the northern, western and eastern (and southern) European periphery, endowed with comparatively more favorable wind (solar) potential, to agglomerations in central Europe. In the moderate transmission expansion scenario only corridors (1)-(3) are subject to restrictions. In the high expansion scenario the constraint is non-binding for all country connections except for Great Britain and Benelux and between Denmark and Germany.

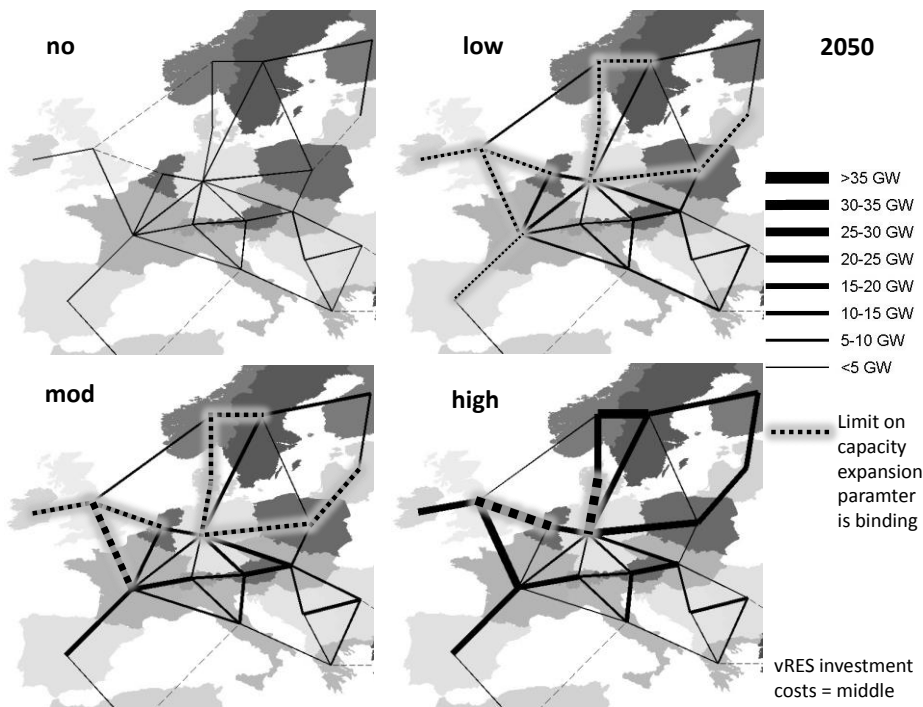


Figure 4 Net transfer capacities (NTC) between ENTSO-E model regions in 2050 for the different transmission capacity expansion scenarios (vRES investment costs are set to the middle trajectory).

In general terms, this implies that the possibility of a faster transmission capacity expansion is important particularly for those country connections that serve to transport electricity generated by variable renewables from the European periphery to central Europe. A more specific finding the model results indicate is that, in the long-term, a pan-European transmission capacity expansion focusing on the integration of high-quality wind sites in Northern Europe, the Baltic countries, Ireland and Great Britain is the system-cost-optimal strategy. Are these findings robust?

In fact, in the pessimistic and optimistic scenarios the deployment of NTC capacities follows a very similar pattern to that in the middle scenarios. Likewise, the integration of wind sites in the northern periphery is the dominant driver, confirming both the general and the more specific finding. However, the picture changes in the scenario that assumes solar technologies to follow the optimistic trajectory and wind technologies the pessimistic one. Figure 5 illustrates the average annual power flows in 2050 for two scenarios with high transmission capacity expansion ($\Delta\text{NTC}=1\text{GW/a}$), the one with middle assumptions on vRES investment costs on the left and the mixed scenario solarOpt/windPes on the right. In the latter, LIMES-EU+ taps into the abundant solar potential of Southern Europe, particularly on the Iberian Peninsula. NTC capacity expansion primarily occurs in the south-north corridor between the Iberian Peninsula, France and Benelux countries. Also the transmission corridor South-Eastern Europe to Central Europe is strengthened, drawing on the solar resources in these regions. In this case the high-quality wind sites on and around Ireland and Great Britain are only exploited for domestic supply, and not for exports to central Europe. The high-quality wind resources of northern Europe and the Baltic states are still relied upon, but to a much lower extent.

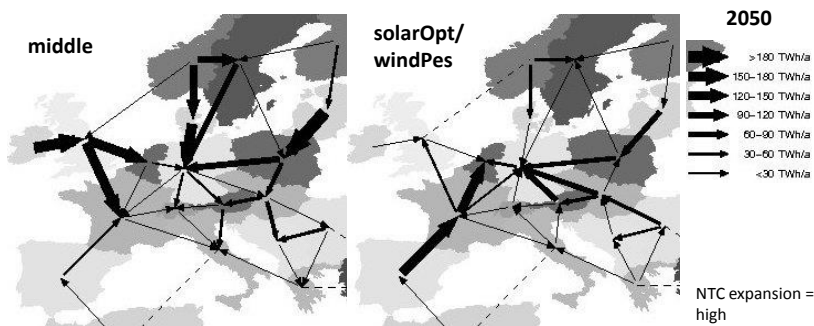


Figure 5. Average annual net electricity flows between ENTSO-E model regions in 2050 for the middle and solarOpt/windPes scenario (with high NTC expansion rates).

Hence, the general finding identified above is robust for the different vRES investment cost scenarios, i.e. the cost-optimal configuration of the pan-European transmission infrastructure is driven by the integration of high-quality renewable resource sites in the periphery. However, answering the question of which country-connections are especially important crucially hinges on the relative development of specific investment costs of vRES technologies. If solar PV will continue its strong price decreasing trend of the past decades, CSP starts to exploit its learning-by-doing potential and wind technologies specific investment costs stagnate or even increase, then the cost-optimal strategy would be a “Southern solution”. It is in its implications quite different from the wind-based “Northern solution” identified in the pessimistic, middle and optimistic scenarios.

The importance of individual country-connections depends on the respective overall system configuration. Additional model runs indicate that prohibitions of expanding individual country connections, e.g. for political reasons, generally lead to a circumvention of that specific country connection and a slight adaptation in national energy mixes of neighboring countries. Total system costs are visibly affected only in cases in which the country-connection is highly relevant to the system and circumvention is not possible, which applies to the connection France-Spain in the abovementioned “Southern solution”.

3.3. Implications for the Electricity Mix

Figure 6 illustrates for the ENTSO-E region the aggregate installed generation capacities as well as intra-day storage⁸ for all scenarios in the year 2040 (left axis) and the corresponding share of vRES in total net electricity production (right axis). It is not surprising that the share of vRES is substantially higher in the optimistic scenarios, with 56-60%, as compared to the solarOpt/windPes, middle and the pessimistic scenarios, accruing to 46-48%, 43-49% and 31-41%, respectively. As can be expected, in the solarOpt/windPes scenarios the installed capacity of solar PV is substantially higher. It delivers around 40% of annual electricity production in all four transmission expansion scenarios; interestingly offshore wind capacities are not deployed at all. Due to the aggregate scope of the analysis the technology mix is depicted for the model regions as a whole. However, domestic portfolios are diverse both from the outset and over the course of the coming decades in the different scenarios. A more detailed analysis of dynamics on the country-level is pursued in Knopf et al. (2015); the issue is picked up again in Section 4.

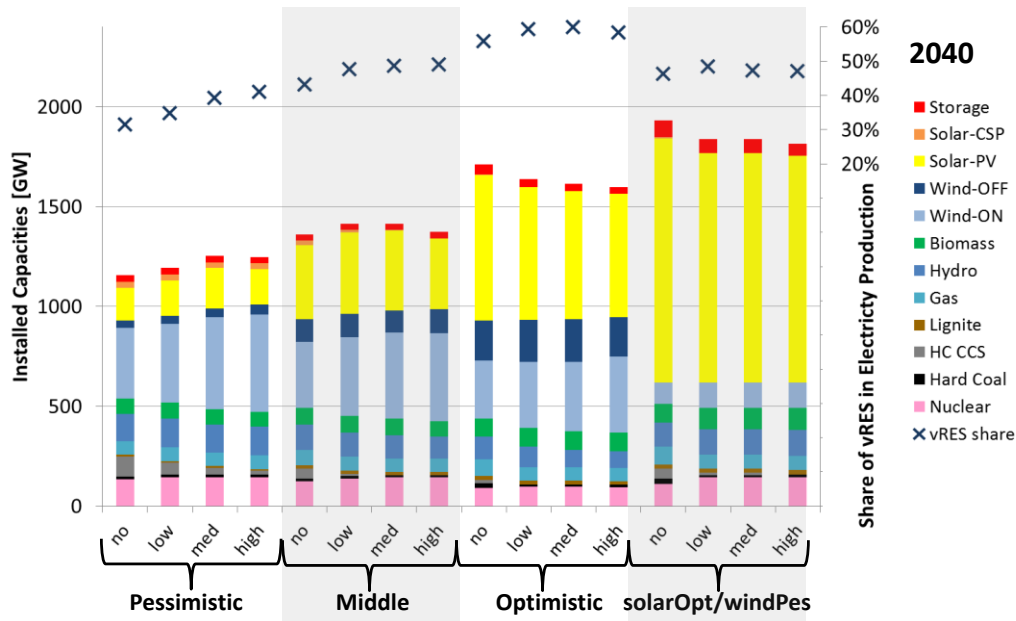


Figure 6. Aggregate installed electricity generation and storage capacities in the ENTSO-E region (left axis) and corresponding shares of vRES generation in net electricity production (right axis) for the year 2040.

⁸ Calibrated to pumped hydro storage with region-specific potential. Generic day-to-day and inter-seasonal storage technologies exist in LIMES-EU+ (see Haller et al., 2012); however, they are not deployed in the scenarios.

The influence of the different constraints on the speed of transmission capacity expansion on the aggregate technology mix is visible, but not very pronounced. With increasing NTC expansion, there is a tendency for (i) absolute installed capacities to decrease, (iii) solar PV capacities to decrease and (iii) onshore wind capacities to increase. Particularly in the no NTC expansion scenarios, more solar PV capacities along with slightly higher intra-day storage capacities are deployed. As an option to increase the temporal flexibility of vRES production storage is not the preferred option in LIMES-EU+. Rather, flexible back-up capacities are used for balancing fluctuations. One needs to acknowledge, however, that across scenarios the allocation of capacities to model regions differs as it is an endogenous model decision. Particularly in the no expansions scenario each region has to be almost self-sufficient in its supply of electricity.

In a more integrated European electricity system one expects that comparatively less back-up capacities are required to accommodate rising shares of variable renewables due to the effect of large-area pooling of anti-correlated feed-in. Also, curtailment of vRES feed-in is expected to be lower. Both these effects are observed in the model results, particularly when the absolute share of variable renewables is high. In 2040 and on aggregate, the effect of NTC capacity expansion (high expansion compared to no expansion) leads to a reduction in the required gas turbine capacities of 22%, 20% and 12% for the solarOpt/windPes, the optimistic and middle case, respectively. There is no change in natural gas turbine capacities in the pessimistic case. In the optimal scenarios curtailment is reduced from 34% of annual electricity generation without grid expansion to 19% in the case of high expansion. In the solarOpt/windPes scenarios these values amount to 24% in the no expansion and 13% in the high expansion case. In the middle and pessimistic scenarios they are comparatively lower with 11% and 5% as well as 6% and 4%, respectively. Due to the the varying total shares of variable renewables a meaningful comparison across scenarios and studies is difficult. The relative impact of grid expansion on curtailment amounts to a reduction ranges from 33% to 55% in our scenario, which is somewhat lower than the 66% found by Tröster et al. (2011) – who analyze a case with a much higher share of renewables, though.

Regarding thermal capacities, in the scenarios following a pessimistic trajectory for investment costs for vRES technologies, nuclear and especially CCS capacities are cost-optimal to deploy. The share of nuclear power in electricity production accrues to 20-25% in the pessimistic and middle scenarios, but reaches only 15% in the optimistic ones. Likewise, CCS plays a visible role mainly in the pessimistic scenarios with the highest share of 18% of electricity production in the no grid expansion scenario. It is also deployed in the no grid expansion scenarios facing middle and optimistic developments of vRES investment costs, but in these cases contributes less than 2%.

3.4. Electricity Price Distributions

In order to investigate the argument that pan-European transmission capacity expansion is economically beneficial through lowering electricity prices, Figure 7 presents box plots of their distributions in the

year 2040 for the ENTSO-E region. Electricity prices are a model result⁹ and differ for each region and time slice, leading to a sample of 600 prices per time step (48 time slices in 15 ENTSO-E model regions). The price-dampening effect of NTC expansion postulated in the introduction is present in these model results through a reduced spread of the electricity price distributions. When moving from the no expansion to the high expansion scenarios there is a tendency for the interquartile ranges to become narrower and the length of the top whisker to decrease in all four vRES investment cost cases. In the middle and optimistic scenarios the latter is only the case for the moderate and high expansion scenarios. This effect can be explained the following way.

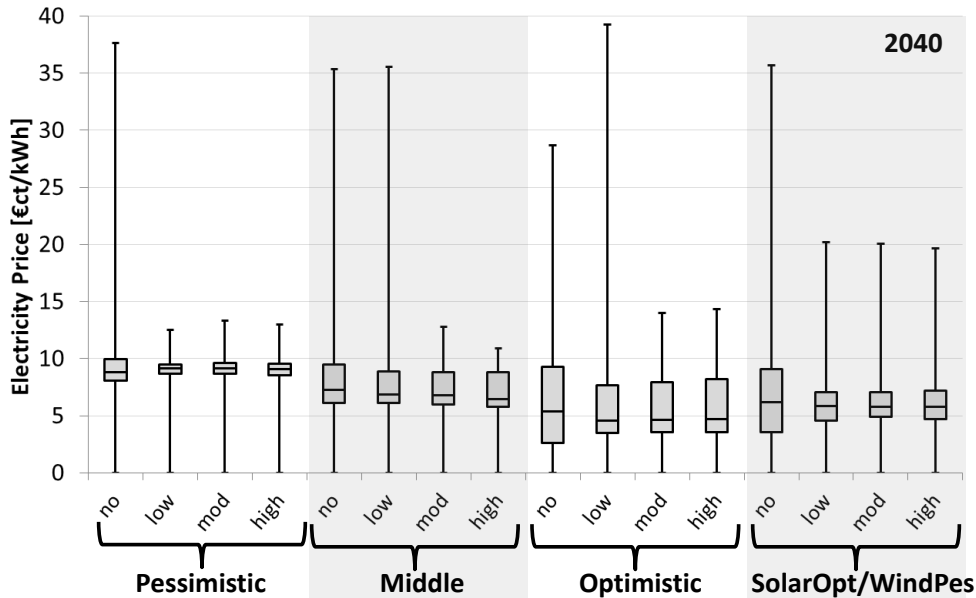


Figure 7. Box plots of the electricity price distributions for the year 2040, based on 600 individual shadow prices for 48 time slices and 15 model regions.

In all scenarios with $\Delta NTC=0$, fluctuations in vRES feed-in need to be balanced within each region, individually. This requires some back-up capacities that have very low full-load hours, since they are only dispatched during the few time periods that are characterized by very low vRES feed-in and high demand (which mainly occur during winter). During these times, electricity prices are high. If NTC expansion is permitted, model regions can balance their fluctuations through exchanging electricity with other countries or share back-up capacities in case vRES feed-in is low in the respective moment in all regions. In the pessimistic scenarios, in which the share of vRES in electricity production stays below 40% (cp. Figure 6), this effect reduces the spread of the distribution already significantly in the low transmission capacity expansion scenarios. Due to the dominance of dispatchable generation technologies in the pessimistic scenarios' technology mix, the added value of NTC expansion is low beyond that threshold (dispatchable capacities generate electricity within individual model regions and do not require the transport of electricity between regions). However, in the middle and optimistic

⁹ Electricity prices in LIMES-EU+ are shadow prices, i.e. the marginal value of the electricity balance equation which specifies that electricity demand must equal supply in all time-slices and model regions.

scenarios, the share of vRES in electricity production amounts to 50-60%. Here, relatively more NTC expansion is required to induce the effect described above and the variance decreases only in scenarios with $\Delta NTC \leq 0.5$ and 1. Schaber et al. (2012a) also find that the standard deviation of electricity prices across the European region increases with increasing vRES capacity and can be lowered with grid extensions.

4. Discussion

Departing from the above insights based on quantitative model results, the following discusses the overarching question of how large the expected gains from European electricity system integrations really are. We proceed along the lines of three issues: First, coming back to the question raised in Section 3.1, we elaborate on possible reasons for the large difference in estimated system cost savings between the results reported in Hagspiel et al. (2014) and in this paper. Second, we touch upon the topic of heterogeneity in de facto investment costs for renewables across Member States, an issue that is genuinely neglected in energy system modeling. Finally, we highlight the importance of regional differences in the assessment of the expected gains from electricity grid integration. For each issue we deduce policy implications.

Why are the reported system cost savings over the period 2011-2050 much higher in Hagspiel et al. (2014), amounting to 20.9%, as compared to our results, reaching a maximum of 3.5%? Conclusive answers to this question can only be delivered by a structured model comparison exercise with harmonized input assumptions. Nevertheless, some valuable insights can already be gained by means of an unstructured comparison. In absolute terms Hagspiel et al. (2014) find total system costs of 2833 bn€ in the scenario with grid expansion and 3424 bn€ in the restrictive scenario, leading to a difference of 591 bn€. For the optimistic (pessimistic) scenarios we calculate total system costs of 3748 (4545) bn€ with high grid expansion and 3637 (4386) bn€ with low grid expansion, reaching a difference of 111 (159) bn€.

Three insights arise: First, the order of magnitude of total system costs is similar between Hagspiel et al. (2014) and our calculations, making a comparison worthwhile. Also, the applied social discount rates are the same with 5%. Second, pessimistic assumptions on investment costs for renewable generation technologies lead to higher total system costs and hence a different base for relative cost reductions. Their investment cost assumptions for solar (wind) correspond roughly to our optimistic (middle) trajectory. Third, the total cost savings from grid expansion are several times higher in Hagspiel et al. (2014) as compared to our results. A possible reason for this is the much higher geographical and temporal resolution of their grid modeling, which is done by a line-sharp model. It is coupled to an electricity market model by means of flow-based market coupling based on power transfer distribution factors (PTDFs). This method is more accurate in terms of power flow dynamics than net transfer capacities (NTC), which are used in Fürsch et al. (2013) as well as our analysis. However, it required dedicated analysis to manifest this speculative conclusion – a multitude of other cost drivers could in principle also be responsible. In any case the policy implications of all model results are unambiguous: more electricity system integration is on aggregate economically beneficial for Europe, only the extent is yet unclear and requires further research.

One assumption that is the case in all cited modeling studies as well as our analysis is that investment costs for installed capacities of renewable generation technologies are the same in all modeled regions. Hence the only root source for differences in regional generation costs is the quality of the resource potential. The results have shown that an important driver for system cost savings from grid integration is that it enables the exploitation of high-quality solar and wind potentials in the European periphery. If, however, it was the case that in reality investment costs were comparatively higher in these high-quality regions, then the total system cost savings from grid integration were lower. There are indications that this might actually be the case.

There is to date no systematic account on the components of regional installation costs across Europe. IRENA (2012) illustrate that the range for installed solar PV system prices in France, Italy, Spain and Portugal is substantially higher than in Germany, reducing the competitive advantage of their favorable solar resource potential. Klessmann et al. (2013) identify that project developing costs are an important cost driver for renewables deployment. They estimate that removing administrative barriers and the cost of capital through reduced policy, revenue and technology risks could decrease the levelised cost of renewable generation by more than 40% in some European countries. Brückmann (2015) illustrate that the cost of capital for RES projects are heterogeneous and particularly high in Southern and Eastern European countries. An important policy implication is that such institutional factors can directly or indirectly be affected by national policy action (Dinica, 2011; Rathmann et al., 2011), e.g. through measures such as one-stop-shop permitting procedures as well as transparent and stable support frameworks.

Finally, we turn to the importance of regional differences in the assessment of the expected gains from electricity grid integration. The aim of this paper was to quantify the economic benefits of European electricity system integration on aggregate; so far we excluded the distributional aspect across countries and the questions of *who* actually incurs the economic benefits and costs of European electricity system integration. Knopf et al. (2015) apply LIMES-EU to analyze this aspect in more detail, showing for the period 2010-2030 that the transition effort is highly heterogeneous across countries. Both the change in the share of renewable electricity generation and the average annual investments in relation to GDP differ significantly with a tendency for peripheral countries, in particular Eastern and South-Eastern states to bear the highest economic burden. Creutzig et al. (2014) argue that a European energy transition featuring substantial renewable capacity deployment in the periphery can be interpreted as a chance through acting as economic stimulus, decreasing trade deficits, and possibly positive employment effects. Such local and regional co-benefits could play an important role, however, at the same time negative externalities (e.g. locally unacceptable changes in land-use, devaluation of property, higher regional electricity prices) could occur (see Edenhofer et al., 2013a; 2013b). If the distributions of economic costs and benefits are highly skewed across the European, national and local level, the resistance by those who bear the costs but do not harvest the benefits of electricity system integration could prove to be a significant impediment for reaching the overall economically beneficial solution.

In order to reap the full benefits of European electricity system integration it deems that a governance framework foreseeing institutional arrangements that balance costs and benefits across jurisdictions both vertically and horizontally is in need. As this is not the case in the current policy framework, careful

reforms are necessary. In the context of the European renewables target for 2030 it has been decided to install a new governance system (European Council, 2014), but its design is yet unclear. In order to accommodate the regional differences in costs and benefits a European-wide effort-sharing mechanism including financial transfers could be part of the solution (cp. Knopf et al., 2015). Doing so requires taking into account both vertical and horizontal interactions between the different governance levels, i.e. the European Union, federal Governments, state Governments and local authorities (cp. Knopf et al., 2013a). Also the interplay between grid and generation capacity expansion deserves more explicit consideration. Hence the already established process to formulate a European-wide ten-year network development plan by ENTSO-E should be intertwined with the governance mechanism for renewables deployment. On a final note, it is by no means clear that the most efficient way of designing this governance mechanism is a full centralization and homogenization of policy at the EU-level (Strunz et al., 2015) – also bottom-up processes can lead to more integrated policies and hence cooperation of sovereign Member States.

5. Conclusion and Policy Implications

In order to quantify the long-term economic benefits that arise from an increasing integration of the pan-European electricity system, this paper analyzed a set of decarbonization scenarios calculated with the European electricity system model LINES-EU+ (Haller et al., 2012). We confirm earlier findings that, on aggregate, pan-European transmission capacity expansions constitute a no-regret option with positive social returns on investment. More NTC capacities lead to economically beneficial effects in terms of total discounted system costs - albeit the magnitude of the effect is rather modest. With high pan-European NTC capacity expansion, total system costs decrease by not more than 3.5% over the period 2010-2050, as compared to a scenario without NTC expansion. It turns out that this result is robust across decarbonization scenarios with varying vRES investment cost pathways. In technical terms, this can be interpreted as a flat optimum of total energy system costs with respect to NTC capacity expansion.

A crucial finding is that conclusion that long-term infrastructure planning should carefully evaluate the interplay between the relative cost developments for wind and solar technologies and the choice of which transmission corridors to expand. Establishing the right balance is crucial for reaping the full economic benefits of pan-European electricity system integration. In this respect we expand the focus of previous work. If installation costs of solar PV will continue its strong decreasing trend of the past decades, CSP starts to exploit its learning-by-doing potential and wind technologies specific investment costs stagnate or even increase, - then the cost-optimal strategy would be a “Southern solution” that taps into the abundant solar potential of Southern Europe, particularly on the Iberian Peninsula and South-Eastern Europe. This would require a strengthening of the transmission corridors from these areas to central Europe. However, in case wind technologies’ specific investment costs develop comparatively favorably, a “Northern solution” focusing on the integration of high-quality wind sites in Northern Europe, the Baltic countries and the islands of Ireland and Great Britain is the system-cost-optimal strategy. In both cases the capacity of the European transmission grid would need to be expanded substantially; by factor 3 to 5 – which constitutes an immense infrastructure investment requirement and in places also to visible altering of the natural landscape.

Discussing the overarching question regarding how large the expected gains from European electricity system integration really are revealed three major insights and corresponding policy implications. First, a higher geographical and temporal resolution of the modeling tool might lead towards an even higher quantitative assessment of economic benefits on aggregate. In any case, policies that lead towards a higher level of integration are beneficial to the European electricity system. Second, the theoretically derived economic benefits of integration can only be reaped if project development costs for renewables in peripheral, high-quality resource regions are not unnecessarily inflated by institutional factors like administrative barriers and high costs of capital. An important policy implication is that these costs can directly or indirectly be affected by national policy action. Third, ultimately it is crucial to identify *who* incurs the economic benefits and costs from integrating more renewable electricity generated in the European periphery into the European electricity system as a whole. A suitable framework to govern a European energy transition ideally featured an effort-sharing mechanism that leads to a fair distribution of benefits and costs and adequately intertwines the deployment of generation and transmission infrastructure on the local, national and regional scale.

An important implication of the finding that pan-European transmission capacity expansion is both a no-regret option and crucial for integrating high-quality renewable potential in the European periphery is that the speed of transmission capacity expansion needs to accelerate. Research on the determinants of social acceptance of infrastructure projects identifies transparency of the planning process and fair participation opportunities as important success factors (Schweizer-Ries, 2008). In case of transmission infrastructure particularly the discussion whether individual transmission lines are really needed and for what purpose is a controversial issue between TSOs, non-governmental organizations and local residents. A transparent assessment that quantifies the economic benefits of transmission capacity expansion could play an important facilitating role in justifying grid development at the local level, and could also be a basis for determining eventual financial remunerations for those that experience local negative externalities of grid expansion. Such measures could help to accelerate pan-European transmission capacity deployment and open the window of opportunity for reaping the economic benefits thereof.

Acknowledgments

The authors would like to thank Ottmar Edenhofer, Michael Pahle, Lion Hirth, Paul Nahmmacher, Sylvie Ludig, Oliver Tietjen, Robert Pietzcker, Jan-Christoph Goldschmidt, Christian von Hirschhausen and Franziska Holz for fruitful discussions and helpful comments. Also we would like to thank three anonymous referees.

References

- Booz & Company, D. Newbery, G. Strbac, D. Pudjianto, P. Noël and Leigh Fisher (2013). Benefits of an integrated European energy market.
https://ec.europa.eu/energy/sites/ener/files/documents/20130902_energy_integration_benefits.pdf (Accessed on August 3, 2015)
- Brückmann, R. (2015). Financing Renewables: Comparison of cost of capital in 28 MS. Presentation on DIACORE-CEPS Policy Workshop, Brussels. http://diacore.eu/images/eventsPDF/3rd%20DIACORE%20Policy%20Workshop/DIACORE_WS_Brussels_20150521_Robert_Bruckmann_eclareon.pdf (Accessed on August 6, 2015)
- Creutzig, F., J.C. Goldschmidt, P. Lehmann, E. Schmid, F. von Blücher, C. Breyer, B. Fernandez, M. Jakob, B. Knopf, S. Lohey, T. Susca and K. Wiegandt (2014). "Catching two European birds with one renewable stone." *Renewable and Sustainable Energy Reviews* 38: 1015-1028.
- Dinica, V. (2011). "Renewable electricity production costs - A framework to assist policy-makers' decisions on price support." *Energy Policy* 39(7): 4153-4167.
- Edenhofer, O., L. Hirth, B. Knopf, M. Pahle, S. Schlömer, E. Schmid and F. Ueckerdt (2013a). "On the economics of renewable energy sources." *Energy Economics* 40 (Supplement 1): S12–S23
- Edenhofer, O., B. Knopf and G. Luderer (2013b). "Reaping the benefits of renewables in a nonoptimal world." *PNAS* 110(29): 11666–11667.
- ENTSO-E (2010). NTC Summer Values 2009.
https://www.entsoe.eu/fileadmin/user_upload/library/ntc/archive/NTC_Values_Summer_2009.pdf (Accessed on May 5, 2015)
- ENTSO-E (2012). 10-Year Network Development Plan 2012. <https://www.entsoe.eu/major-projects/ten-year-network-development-plan/tyndp-2012/> (Accessed on May 5, 2015)
- European Commission (2010). Energy infrastructure priorities for 2020 and beyond - A Blueprint for an integrated European energy network.
https://ec.europa.eu/energy/sites/ener/files/documents/2011_energy_infrastructure_en.pdf (Accessed on May 5, 2015)
- European Commission (2011a). A Roadmap for moving towards a competitive low carbon economy in 2050. http://eur-lex.europa.eu/resource.html?uri=cellar:5db26ecc-ba4e-4de2-ae08-dba649109d18.0002.03/DOC_1&format=PDF (Accessed on May 5, 2015)
- European Commission (2011b). Energy Roadmap. <http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=COM:2011:0885:FIN:EN:PDF> (Accessed on May 5, 2015)
- European Commission (2014). A policy framework for climate and energy in the period from 2020 to 2030. <http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52014DC0015&from=EN> (Accessed on May 5, 2015)
- European Council (2011). Conclusions of 4 February 2011.
http://www.consilium.europa.eu/uedocs/cms_data/docs/pressdata/en/ec/119175.pdf (Accessed on May 5, 2015)

- European Council (2014). Conclusions of 24 October 2014.
http://www.consilium.europa.eu/uedocs/cms_data/docs/pressdata/en/ec/145397.pdf
 (Accessed on August 6, 2015)
- European Council (2015). Conclusions of 19 March 2015.
<http://www.consilium.europa.eu/en/press/press-releases/2015/03/20-conclusions-european-council/> (Accessed on May 5, 2015)
- European Parliament and the European Council (2009). DIRECTIVE 2009/28/EC, Official Journal of the European Union. **L 140/16**.
- Fürsch, M., S. Hagspiel, C. Jägemann, S. Nagl, D. Lindenberger and E. Tröster (2013). "The role of grid extensions in a cost-efficient transformation of the European electricity system until 2050." *Applied Energy* 104: 642-652.
- Hagspiel, S., C. Jägemann, D. Lindenberger, T. Brown, S. Cherevatskiy and E. Tröster (2014). "Cost-optimal power system extension under flow-based market coupling." *Energy* 66: 654–666.
- Haller, M., S. Ludig and N. Bauer (2012). "Decarbonization scenarios for the EU and MENA power system: Considering spatial distribution and short term dynamics of renewable generation." *Energy Policy* 47(0): 282-290.
- Heptonstall, P., R. Gross, P. Greenacre and T. Cockerill (2012). "The cost of offshore wind: Understanding the past and projecting the future." *Energy Policy* 41: 815–821.
- IRENA (2012) Renewable energy technologies: Cost analysis series. Volume 1: Power Sector, Issue 4/5 Solar Photovoltaics.
http://www.irena.org/DocumentDownloads/Publications/RE_Technologies_Cost_Analysis-SOLAR_PV.pdf (Accessed on August 4, 2015)
- Junginger, M., W. van Sark and A. Faaij, Eds. (2010). *Technological Learning In The Energy Sector. Lessons for Policy, Industry and Science*. Cheltenham, Edward Elgar.
- Kjärstad, J. and F. Johnsson (2007). "The European power plant infrastructure - Presentation of the Chalmers energy infrastructure database with applications." *Energy Policy* 35(7): 3643-3664.
- Klessmann, C., M. Rathmann, D. de Jager, A. Gazzo, G. Resch, S. Busch, and M. Ragwitz (2013). "Policy options for reducing the costs of reaching the European renewables target." *Renewable Energy* 57: 390–403.
- Knopf, B., B. Bakken, S. Carrara, A. Kanudia, I. Keppo, T. Koljonen, S. Mima, E. Schmid and D. van Vuuren (2013a). "Transforming the European energy system: Member States' prospects within the EU framework." *Climate Change Economics* 4(3).
- Knopf, B., H.-Y. Chen, E. De Cian, H. Förster, A. Kanudia, I. Karkatsouli, I. Keppo, T. Koljonen, K. Schumacher and D. P. van Vuuren (2013b). "Beyond 2020 - Strategies and costs for transforming the European energy system." *Climate Change Economics* 4(4).
- Knopf, B., P. Nahmmacher and E. Schmid (2015). "The European renewable energy target for 2030 – An impact assessment of the electricity sector." *Energy Policy* 85 (Oct 2015): 50–60.
- Ludig, S., M. Haller, E. Schmid and N. Bauer (2011). "Fluctuating renewables in a long-term climate change mitigation strategy." *Energy* 36(11): 6674-6685.
- Neij, L. (2008). "Cost development of future technologies for power generation—A study based on experiencecurves and complementary bottom-up assessments." *Energy Policy* 36(6): 2200–2211.

- Nemet, G. F. (2009). "Interim monitoring of cost dynamics for publicly supported energy technologies." *Energy Policy* 37(3): 825-835.
- Nordhaus, W. D. (2009). "The Perils of the Learning Model For Modeling Endogenous Technological Change." National Bureau of Economic Research Working Paper Series No. 14638. <http://www.nber.org/papers/w14638.pdf> (Accessed on July 28, 2015)
- Panzer, C. (2012). Investment costs of renewable energy technologies under consideration of volatile raw material prices. PhD Thesis. Vienna University of Technology. <http://www.ub.tuwien.ac.at/diss/AC07813238.pdf> (Accessed on July 28, 2015)
- Rathmann, M., D. De Jager, I. de Lovinfosse, B. Breitschopf, J. Burgers and B. Weöres (2011). Towards triple-A policies: More renewable energy at lower cost. RE-Shaping Project Report D16. http://www.reshaping-res-policy.eu/downloads/Towards-triple-A-policies_RE-ShapingD16.pdf (Accessed on August 6, 2015)
- Schaber, K., F. Steinke and T. Hamacher (2012a). "Transmission grid extensions for the integration of variable renewable energies in Europe: Who benefits where?" *Energy Policy* 43: 123-135.
- Schaber, K., F. Steinke, P. Mühlich and T. Hamacher (2012b). "Parametric study of variable renewable energy integration in Europe: Advantages and costs of transmission grid extensions." *Energy Policy* 42(0): 498-508.
- Schweizer-Ries, P. (2008). "Energy sustainable communities: Environmental psychological investigations." *Energy Policy*. 36(11): 4126–4135.
- Schmid, E., M. Pahle and B. Knopf (2013). "Renewable electricity generation in Germany: A meta-analysis of mitigation scenarios." *Energy Policy* 61: 1151-1163.
- Schröder, A., F. Kunz, J. Meiss, R. Mendelevitch and C. von Hirschhausen (2013). "Current and Prospective Costs for Electricity Generation until 2050." DIW Data Documentation 68. http://www.diw.de/documents/publikationen/73/diw_01.c.424566.de/diw_datadoc_2013-068.pdf (Accessed on July 28, 2015)
- Strunz, S., E. Gawel, P. Lehmann (2015). "Towards a general "Europeanization" of EU Member States' energy policies?" *Economics of Energy & Environmental Policy* 4(2).
- Tröster, E., R. Kuwahata and T. Ackermann (2011). European Grid Study 2030/3050. http://www.energynautics.com/downloads/competences/energynautics_EUROPEAN-GRID-STUDY-2030-2050.pdf (Accessed on July 28, 2015)
- Yeh, S. and E. S. Rubin (2012). "A review of uncertainties in technology experience curves." *Energy Economics* 34(3): 762-771.