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Representing node-internal transmission and distribution grids in energy system models

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Today's energy system models calculate power flows between simplified nodes representing transmission and distribution grid of a region or a country – so called copper plates. Such nodes are often restricted to a few tens thus the grid is not well represented or totally neglected in the whole energy system analysis due to limited computational performance using such models. Here we introduce our new methodology of node-internal grid calculation representing the electricity grid in cost values based on strong correlations between peak load, grid cost and feed-in share of wind and photovoltaic capacity. We validate in our case study this approach using a 491 node model for Germany. This examination area is modelled as enclosed energy system to calculate the grid in a 100% renewable energy system in 2050 enabling maximum grid expansion. Our grid model facilitates grid expansion cost and reduces computational effort. The quantification of the German electricity grid show that the grid makes up to 12% of total system cost equivalent up to 12 billion € per year.

Keywords: grid expansion, copper plate, energy system model, balanced energy mix, fluctuating and dispatchable renewable energy shares, CSP-HVDC

1 Introduction

Energy system models are todays methods to calculate and optimize future energy systems often with the target function of minimal system cost (REMix, PLEXOS, TIMES, ReEDS, etc. [1]). One major barrier of such numerical calculation methods is the complexity of the model. A higher spatial granularity often increases the computing capacity and calculation time exponentially. However, reducing spatial resolution does not lead to more robust results when neglecting effects like grid expansion especially with high shares of fluctuating renewable energies like photovoltaics (PV) and wind turbines. Neglecting grid cost means that in a model node (continent, country or region) an ideal exchange of power flows is possible without any transmission constraint – the so called copper plate. This obviously leads to wrong system cost and a distorted power plant structure. Interconnecting model nodes using transmission links is a first step to solve the problem but computing capacity quickly reaches its limit when spatial resolution and the number of

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interconnection paths rise. Such transmission models are used e.g. in renewable energy-based power supply scenarios for Europe [2]. The logical solution quantifying the grid would be a simplified grid model which considers basic grid expansion effects inside a model node – a node-internal grid model. The paper is part of the dissertation "The Value of Concentrating Solar Power for a Sustainable Electricity Supply in Europe, Middle East and North Africa" http://elib.dlr.de/114683/.

1.1 State of science

Besides that mentioned characteristic of unlimited transmission in a copper plate – a copper plate has also spatial modelling restrictions regarding the power plant structure. For example a one node model means that the whole energy system with its production and demand is concentrated to one point. For renewable energies this characteristic is approached by weather data based time series consider the spatial expansion of the model geographical examination area. This raises of course the problem of calculating with spatial average time series which may overestimate the capability of renewable energies due to their often fluctuating resource even when calculating with hourly resolution. Effects on spatial and temporal resolution like clustering possibilities or cost differences, have already been analysed in [3], [4] by aggregating grid nodes or load profiles and in [5] with different time slices. The authors found out that a clustering can represent the grid and that higher temporal resolution leads to higher system cost. Effects on spatial resolution with high renewable energy supply up to 100% are rather rare and therefore grid effects are not well quantified.

Existing grid studies are focused on system integration costs for wind turbines. The assumed technological grid cost for wind turbines according to their capacity show huge bandwidths (0 to 1500$/MW) [6]. However, these cost assumptions do often not consider technologies integrated in the energy system but try to quantify separately additional cost for technologies. The essential point is getting to know how much grid is needed in a cost efficient interplay of technologies. This means that such studies do not relate the grid to the simultaneous feed-in power of the energy mix. Therefore it is necessary to calculate the grid as one technological element in concurrence with other technologies in a temporal and spatial dissolved energy system optimisation model. Schaber et al. [7] analysed transmission grid integration cost for wind turbines and PV over Europe in this manner, however in a relative low spatial resolution. They found out that the right wind/PV share reduces cost, power plant capacity and curtailment. Boie et al. [8] quantified grid expansion over Europe and North Africa using three different modelling tools with different temporal and spatial resolution. With new grid data [9], [10] it is now possible to quantify the transmission and distribution grid in a high spatial resolution using one energy system model.

1.2 Novelty and scientific contribution

1.2.1 *Grid*

Here we introduce our node-internal grid model and validate expansion cost assumptions in relation to wind and PV for Germany with an energy system model. This novel approach allows a quantification of grid cost as a function of feed-in power of wind and PV in a single copper plate integrating spatial transmission and distribution of the electricity grid. With this novelty it is possible to calculate a fictitious grid in a single model node reducing the number of model nodes and transmission paths and therefore computing resources. The methodological approach and the validation of the node-internal grid model is the core of the present paper. Other novel frame conditions of modelling constraints are discussed in the following but are not the nub of the matter because the investigation at hand is part of a broad system analysis.

1.2.2 *Energy system modelling*

The energy system analysis is based on the scenario year 2050 for Germany with a 100% renewable energy supply. A 100% renewable energy share is used to quantify the grid expansion in a large expansion potential. With an energy share variation of **fluctuating renewable** energies like *photovoltaics and wind turbines (and run-of-river)* and **dispatchable renewable** energies such as *biomass, geothermal power, gas turbines using renewable fuel and concentrated solar power (CSP) with thermal storage and co-firing* it is possible to examine grid expansion as a function of fluctuating energy share. Fluctuating renewable energy are assessed to be the dominant grid expansion drivers due to their potentially high surpluses. Cost sensitivity analysis (max, mean and min) show the scope of the grid cost range with overhead lines (OHL) and underground cables (UGC). A broad bandwidth of grid expansion configurations lead to a more general examination of grid cost as well of the examination of cost uncertainty. The used modelling constraints thus allow an assessment of the grid using high shares of fluctuating renewable energies.

2 Methodology and key assumptions

2.0 Energy system model REMix

As numerical energy system model we use REMix (sustainable Renewable Energy Mix) [2]. This bottom-up model has the target function of minimizing system cost using linear programming under perfect foresight. System cost includes the annuities of investment and the cost of operation and maintenance for energy relevant technologies (power plants, storage and transmission). The model can optimize capacities and dispatch based on the cost of technologies starting from a greenfield (model endogenous optimization), a partial greenfield (model endogenous optimization under exogenously given capacities). Furthermore a sole dispatch optimization with only exogenously given capacities is possible. REMix is built in the algebraic language GAMS using the CPLEX solver. As input data REMix uses weather data which are calculated by EnDaT (Energy Data Tool) to potentials and technological time series for renewable energies. With the least-cost optimization REMix produces as output data: cost, capacity and energy balance as well as emission data. A detail overview of the model methods is available in the references [11], [2], [12].

2.1 Grid modelling

This chapter deals with the question of how to model the grid in a simplified way considering the major grid expansion effects (hypothesis). Secondly we show the validation methods of the modelling assumption.

2.1.1 *Hypothesis*

The fundamental idea of the model is that fluctuating renewable energy generates surpluses which lead to grid expansion. We illustrate in Figure 1 and in Eq. (1) - (5) the general functionality of our new node-internal grid model with a simplified power dispatch. Variables are listed in bold. Eq. (1) describes the generated power $\boldsymbol{P}_{gen}(t)$ and curtailed power $\boldsymbol{P}_{curt}(t)$ dependent on the existing and added capacity $P_{existCap}$ and $\boldsymbol{P}_{addedCap}$ multiplied with a normalized time series s_{gen}(t) from REMix-EnDaT [2].

$$\boldsymbol{P}_{gen}(t) + \boldsymbol{P}_{curtail}(t) \stackrel{!}{=} \left(\boldsymbol{P}_{addedCap} + P_{existCap}\right) \cdot s_{gen}(t) \qquad \forall t \text{ [2]} \tag{1}$$

$$\boldsymbol{P}_{gen}(t) \leq \boldsymbol{P}_{fluc\ feed-in,max} \qquad \forall t \tag{2}$$

While the existing grid is able to handle with a certain amount of PV and Wind, a starting point of grid expansion arise in Eq. (3).

$$\boldsymbol{P}_{fluc\ feed-in,max} \geq P_{demand,peak} \cdot f_{grid\ exp} \tag{3}$$

The question of this starting point is a major uncertainty and thus variated and calibrated subsequently. The model uses a feed-in power of PV and wind $\boldsymbol{P}_{fluc\ feed-in}$ into the grid and a starting point of grid expansion which is in relation to peak load. The starting point is the product of peak load $P_{demand,peak}$ and a grid expansion factor $f_{grid\ exp}$. When the start point is passed by feed-in power, grid is expanded according to the difference of highest feed-in power $\boldsymbol{P}_{fluc\ feed-in,max}$ and the start point of grid expansion in relation to peak load Eq. (4).

$$\boldsymbol{P}_{grid\ exp} = \boldsymbol{P}_{fluc\ feed-in,max} - P_{demand,peak} \cdot f_{grid\ exp} \tag{4}$$

The resulting maximum delta $\boldsymbol{P}_{grid\ exp}$ in the examined year is multiplied with a grid specfic cost $c_{grid\ cost}$ value, respectively Eq. (5).

$$\boldsymbol{C}_{grid\ exp\ cost} = \boldsymbol{P}_{grid\ exp} \cdot c_{grid\ cost} \tag{5}$$

Grid specific cost values mean cost for transmission and distribution grid. These grid specific cost $c_{grid\ cost}$ can also be interpreted as additional cost of fluctuating feed-in power $c_{fluc,\ feed-in}$ (6).

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$$c_{grid\ cost} = c_{fluc,feed-in} \tag{6}$$

Distribution and transmission grid distinguish not only in cost but also in the feed-in power of PV and Wind Onshore (in distribution grid) and PV, Wind Onshore and Wind Offshore (in transmission grid) and in the start point of grid expansion. When grid expansion is too expensive, the model can decide to use other available technologies or curtail the feed-in power $\boldsymbol{P}_{curtail}$. We assume a linear expansion of the grid in relation to fluctuating feed-in power.

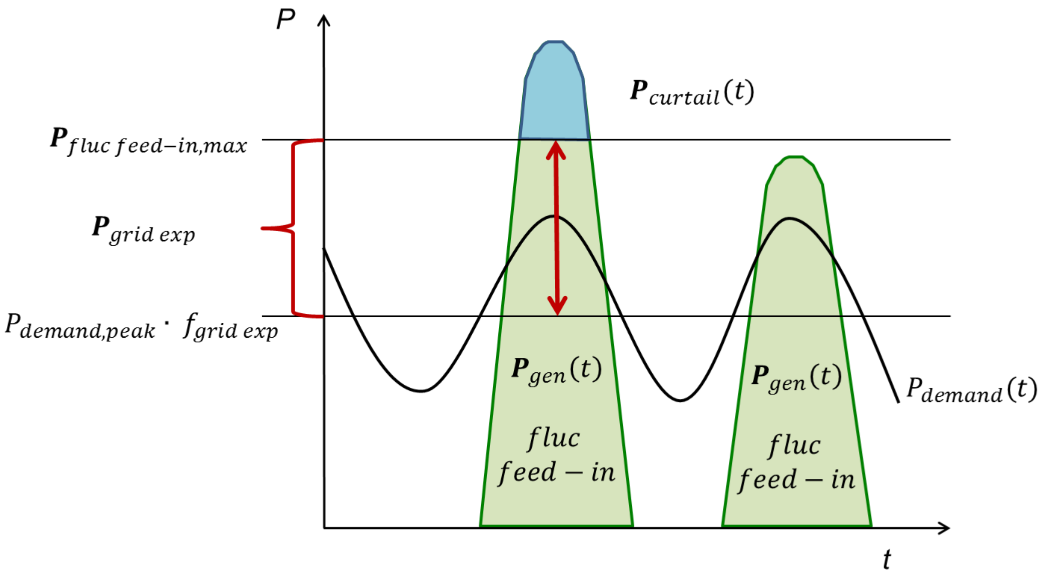

Figure 1: Principle of the node-internal grid calculation model. Grid extension is related to feed-in power of fluctuating energies depending on a starting point in relation to peak load.

2.2 Methodological overview and validation approaches

For an evaluation and validation of this hypothesis we use four steps approximating the cost of the electricity grid shown in Figure 2. The first approach calculates cost of existing alternating current (AC) transmission grid. The second one approximates distribution grid cost and its expansion starting points with a meta-analysis of two existing studies [10], [13]. The third one is an energy system analysis with the energy system model REMix under a low (3a Figure 2) and high (3b Figure 2) spatial resolution of the transmission grid in Germany which calibrates cost of AC and DC transmission and approximates the start of grid expansion. The fourth one shows new (4 Figure 2) node-internal transmission grid model for REMix which is based on the previous approaches showing the novelty of the paper: the grid cost induced by fluctuating feed-in power. Finally we compare the results with the state of research using no grid model in our case study for Germany.

All approaches focus on minimal necessary cost of grid expansion. In the analysis we compare the state of research, preliminary examination and the new model. This comparison is based on grid cost, system cost, curtailment and power plant capacities.

Due to computational limits a preliminary examination is necessary to vary temporal and spatial resolution for good approximation of grid cost. In the preliminary examination the first and second approach leads in approach 3a Figure 2 to a first approximation of the node-internal grid model. The power plant capacities of 3a Figure 2 are implemented in 3b Figure 2. This leads to a fit function of grid cost for our new node-internal grid model in 4. Thus step 4 is calibrated using approach 3b.

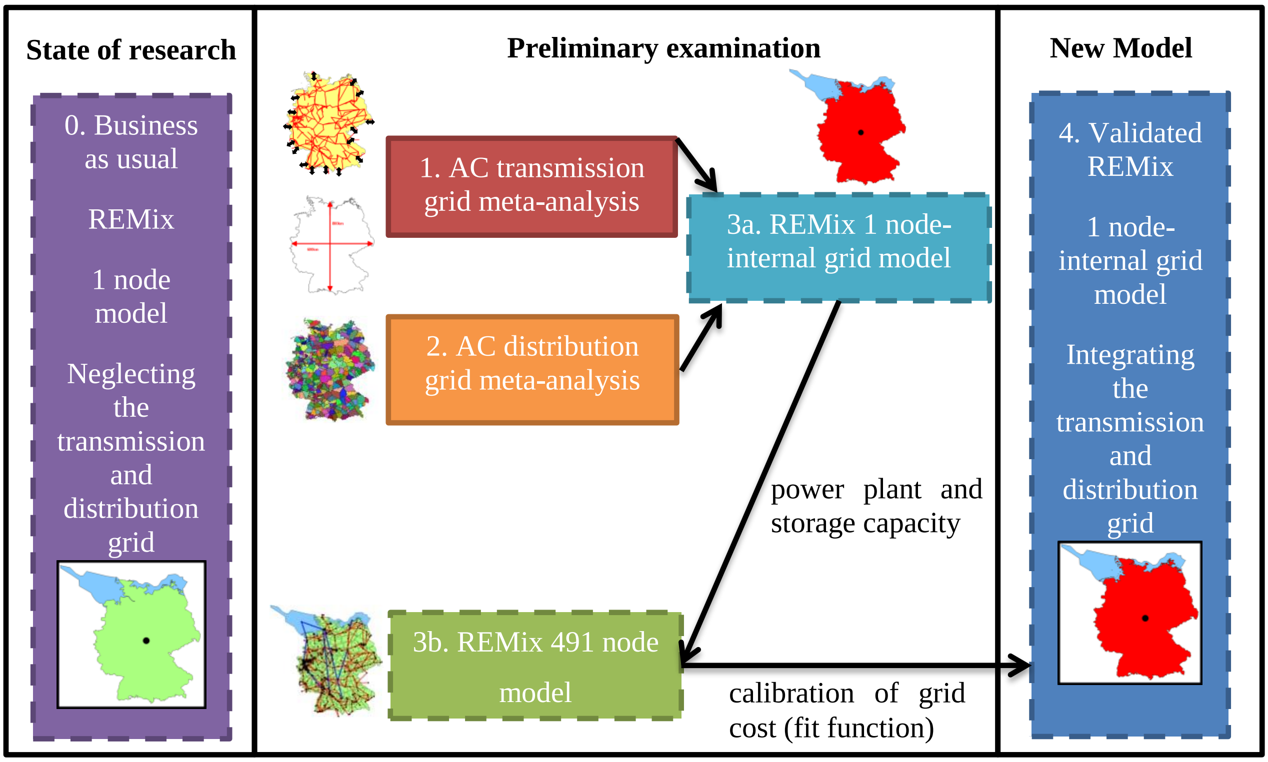

Figure 2: Methodological approaches for the new node-internal grid model

REMix calculations are executed in the dashed boxes. These calculations optimize the entire energy system in hourly resolution.

3 Input data

Grid specific cost $c_{grid\ cost}$ assumptions in the first step are based on existing grid cost per grid power of the transmission grid and later calibrated with a high resolution model. For the distribution grid we use specific cost from literature. For the transmission grid we consider in a first pre-analysis the grid cost and the NTC relation to quantify the specific grid cost. Substantiating this approach we have a look on the grid cost and peak load of central ENTSO-e countries. Having the specific grid cost the next step is to find out the starting point of grid expansion and calibrating the model and the input data within a case study using a high spatial resolution transmission grid model.

3.1 Specific cost for grid expansion

Cost of the existing grid is calculated with the circuit lengths from ENTSO-e and a specific cost value per km (400.000 $€_{\mathbf{2015}}$/km (220 kV), 500.000 $€_{\mathbf{2015}}$/km (380kV)). Cost of the existing German transmission grid in 2013 are thus 15.85 bn $€_{2015}$. To measure roughly the internal grid capacity we use the sum of the border transfer capacities from Germany with about 17 GW [14]. This is nearly in the same range when calculating the quotient of existing power kilometres with about 28 TWkm in Germany and the average grid length 1400km (North-South and East-West spatial extent) which leads to max. about 20 GW. Thus 17 $GW_{AC\ trans}$ seem reasonable as min. capacity value for the German transmission grid. According to Eq. (7) the grid cost per grid capacity in Germany for overhead line configuration are thus assumed min. about 916 €/ $kW_{AC\ trans}$ for OHL and 1758 €/ $kW_{AC\ trans}$ for UGC (UGC = 1.92 x OHL [15]). For the distribution grid we use data from literature [10] and [13] with 375 to 500 €/$kW_{grid\ distr}$ which we describe later in Table 1.

$$c_{AC\ trans} = \frac{Cost\ of\ grid\ in\ Germany}{Maximum\ export\ capacity} \tag{7}$$

$$Germany{:}\quad c_{AC\ trans} = \frac{\sim 15.85\ bn\ €}{\sim 17\ GW_{\mathrm{AC\ trans}}} \approx 916\ \frac{€}{kW_{\mathrm{AC\ trans}}}$$

3.2 Comparison with European countries and annual basic grid cost

For a view beyond the horizon of the German electricity grid, we compare on European level grid cost, peak load and the comparability to our approach in Germany. As shown in Figure 3 the coefficient of determination of peak load and grid cost is with 85.88 % relatively high and thus shows a high correlation. Grid cost is calculated with a typical cost value per transmission circuit length, thus this determination can be also interpreted as peak load to grid length determination. Assuming that the grid capacity is built in other European countries like in Germany, the above mentioned correlation enables using country specific grid cost with the same peak load to grid capacity ratio like in Germany (83$GW_{peak\ load}$ /~17$GW_{AC\ trans}$ of about 5). Cost for reaching this grid status like in Germany is neglected in the analysis. Under these assumptions France has a grid capacity of about 18.5 $GW_{AC\ trans}$ (92.9 $GW_{peak\ load}$ / 5) and Spain of 8 $GW_{AC\ trans}$ (39.6 $GW_{peak\ load}$ / 5). Especially Spain has with 17.6 bn. € relative high grid cost in relation to its 40 GW peak load and thus relative high cost of grid to grid capacity (~2200 €/$kW_{AC\ trans}$) which indicates a confirmation of our approach due to its relative low assumed grid capacity. The majority of central ENTSO-e countries have a peak load of less than 10 GW in the year 2013.

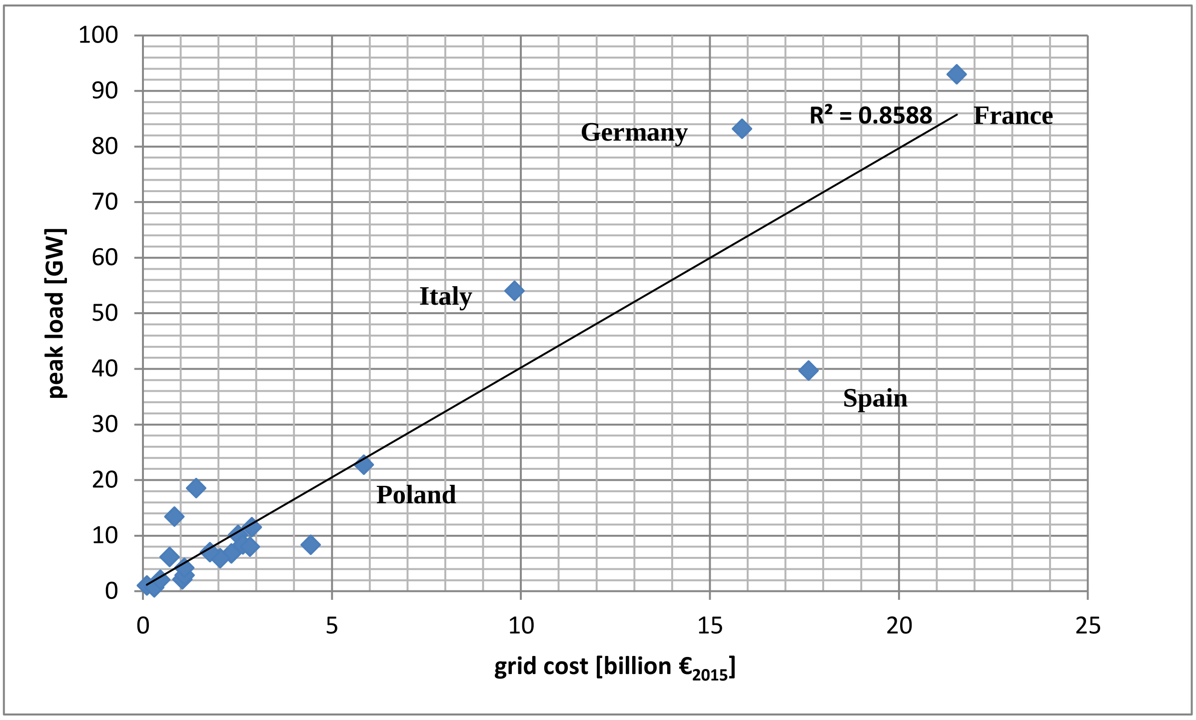

Figure 3: Coefficient of determination (R^2) of grid cost to peak load with countries in central ENTSO-e of the year 2013.

Annual basic grid cost in relation to peak load:

Since grid expansion with a rising demand can be assumed as linear (high correlation of peak load to grid cost in Figure 3) we determine in Eq. (8) basic grid cost values for Germany. For our subsequently calculation of cost using the annuity method, we consider annual cost of transmission grid in Germany which can be calculated according the existing annual grid expenditures (average of the years 2007-2013) [16]:

$$C_{basic\ grid\ cost} = \frac{Annual\ grid\ expenditures}{peak\ load} \left[\frac{€/y}{GW_{peak\ load}}\right] \tag{8}$$

Transmission grid: 0.95 bn €/y /91 $GW_{peak\ load}$ = 10.4 mio €/y /$GW_{peak\ load}$

Distribution grid: 5.96 bn €/y /91 $GW_{peak\ load}$ = 65.5 mio €/y /$GW_{peak\ load}$

With the used scenario peak load of Germany in the year 2050 of 111 $GW_{peak\ load}$ (705 TWh/y electricity demand) the annual cost of the transmission grid is 1.15 bn. €/y and for the distribution grid 7.27 bn. €/y.

3.3 Starting point of grid expansion based on Wind and PV feed-in capacity

The starting point of the grid expansion indicates the grid expansion after a certain point. This point is achieved when the existing grid is no more able to handle with additional fluctuating feed-in capacity. As input data we use literature values of the distribution grid and assume that the starting point of grid expansion is the same for the transmission grid due to their interdependent load flows. Figure **4** shows the extrapolation of literature values (dots), the resulting starting point (intersection with the x-axis) and its shift (due to higher assumed peak load in the study compared to literature values).

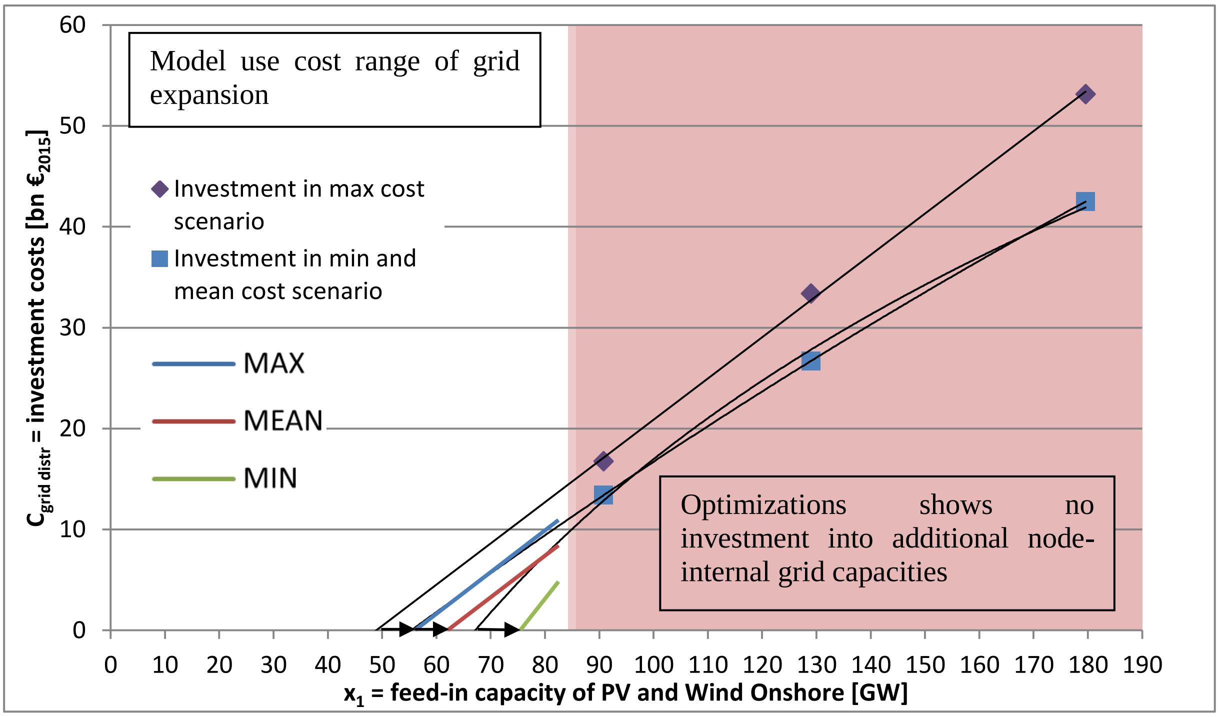

Figure 4: Cost sensitivities MIN, MEAN and MAX investment costs of distribution grid expansion. Investment [bn €] based on **[10]**, **[13]**, trend curves based on **[17]**.

For an extrapolation of distribution grid expansion cost of former studies [10], [13] (dots in Figure 4), we use a logarithmic (min), a polynomial (mean) and a linear (max) trend line curve which is based on reference [17]. Grid expansion in the distribution grid starts at 67.15 GW (min), at 55.31 GW (mean) and at 48.90 GW (max) of PV and wind onshore capacity. This equates to a $f_{grid\ exp}$ with 73.4% (min), 60.5% (mean) and 53.5% (max) of peak load. While peak load here is assumed higher (111 GW) than in the used studies (~91 GW) the coloured lines (max, mean and min) are shifted to the right in Figure 4. The rose area in Figure 4 shows that the distribution grid in Germany is maximal expanded until less than 82 GW feed-in power of PV and Wind Onshore, thus the model does not need a consideration of cost above these capacities. Thus the linearization of the non-linear cost curves Figure 4 can be assumed. We show in Table 1 this linear approximation in Eq. (12), (13) and (14) of the non-linear Eq. (9), (10) and (11). However, the used distribution grid studies [10], [13] are based on a more detailed analysis thus the distribution grid costs may be undervalued in the present analysis due to uncertain distribution of Wind and PV power plants.

Table 1: Distribution grid expansion cost sensitivity with different grid expansion starting points

Cost sensitivity	$C_{grid\ distr,\ \mathrm{max}}$:		$C_{grid\ distr,\ \mathrm{mean}}$:		$C_{grid\ distr,\ \mathrm{min}}$:	
Function from [17] adjusted to cost values of [10], [13]	0.4086_{x1}- 19.983 [mio. €] (with UGC in the 110kV level)	(9)	$-0.0004x^2_1+ 0.4371x_1 - 22.951$ [mio. €]	(10)	$42.625\ln(x_1)-179.28$ [mio. €]	(11)
Linearized function in relation to fluctuating feed-in power (x_1) used in the model	$0.4086x_1$	(12)	$0.375x_1$	(13)	$0.500x_1$	(14)
Start point of grid expansion in relation to peak load	$f_{grid\ exp}= 0.535$		$f_{grid\ exp}= 0.605$		$f_{grid\ exp}= 0.734$	
Specific grid cost	➔ $c_{grid\ distr,max} = 408.6$ €/$kW_{grid\ distr}$		➔ $c_{grid\ distr,mean} = 375$ €/$kW_{grid\ distr}$		➔ $c_{grid\ distr,min} = 500$ €/$kW_{grid\ distr}$	

4 Energy system modelling framework

Analysing the 100% renewable energy system as a whole, we include todays available technologies such as photovoltaics, wind turbines, run-off-river power plants as fluctuating energies and biomass, geothermal energy and CSP as dispatchable renewable energies and short-term, medium-term and long-term storages. A detailed description of used technologies is available in Table 2.

Table 2: Classification of used technologies for electricity generation based on [11]

Technology class of electricity generating power plants		Characteristics	Range of validity
Fluctuating renewable energies	Photovoltaics	Silicon cells with a module efficiency of 18%	Standard test conditions: 25 °C module temperature, 1000 W/m^2 irradiance
	Wind Onshore	Rotor diameter: 130 m Hub height: 132 m	Start-up wind speed: 2 m/s, nominal power output is reached at 12 m/s. Cut-off was set to start at 25 m/s and to end at 35 m/s.
	Wind Offshore	Rotor diameter: 140 m Hub height: 192 m	
	Hydro run-of-river (here fluctuating because of fluctuating water level and no co-firing option)	No power plant model – analysis is based on empirical time series	Power plants in operation, annual generation and generation potentials in Germany
Dispatchable renewable energies (with co-firing option)	Biomass	Power plant with steam turbine - 35% electric efficiency - using forest wood, waste wood, straw and energy crops	Domestic share of net primary production potential, yields and competing use scenarios per country for forestry, agriculture and other sectors - agricultural statistics.
	Geothermal power	Enhanced geothermal system (EGS)	Depth range 2000 - 5000 m
	Concentrating Solar power	Parabolic trough power plant with molten salt storage - 37% power block efficiency and 95% storage efficiency -	Reference irradiance - direct normal irradiance (DNI) - with 800 W/m^2, tracking the sun along the north south axis

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Compared to fluctuating renewable energies, dispatchable renewable energies have the option of co-firing to guarantee supply of energy at any time. While grid cost are analysed in relation to fluctuating energy share, we make a variation of the fluctuating and dispatchable energy share (combination of 10% to 90% share) referred to gross electricity production.

As novelty in the energy system model we use dispatchable solar thermal electricity of CSP from MENA for Germany, due to the fact that dispatchable renewable energies like biomass and geothermal energy are strongly limited in Europe and Germany. We include therefore CSP power plants from MENA by point-to-point DC transmission lines (Figure 5) for a higher possible renewable dispatchable share in Germany. The blue transmission lines illustrate selected paths from CSP plants in MENA to Germany (see Figure 5a), other HVDC lines may provide CSP from MENA also for other countries. This concept was published with TRANS-CSP in 2006 [18] and [19]. Point-to-point transmission lines already exist for example from the water power plant in Itaipu to São Paulo or from the Xiangjiaba Dam to Shanghai.

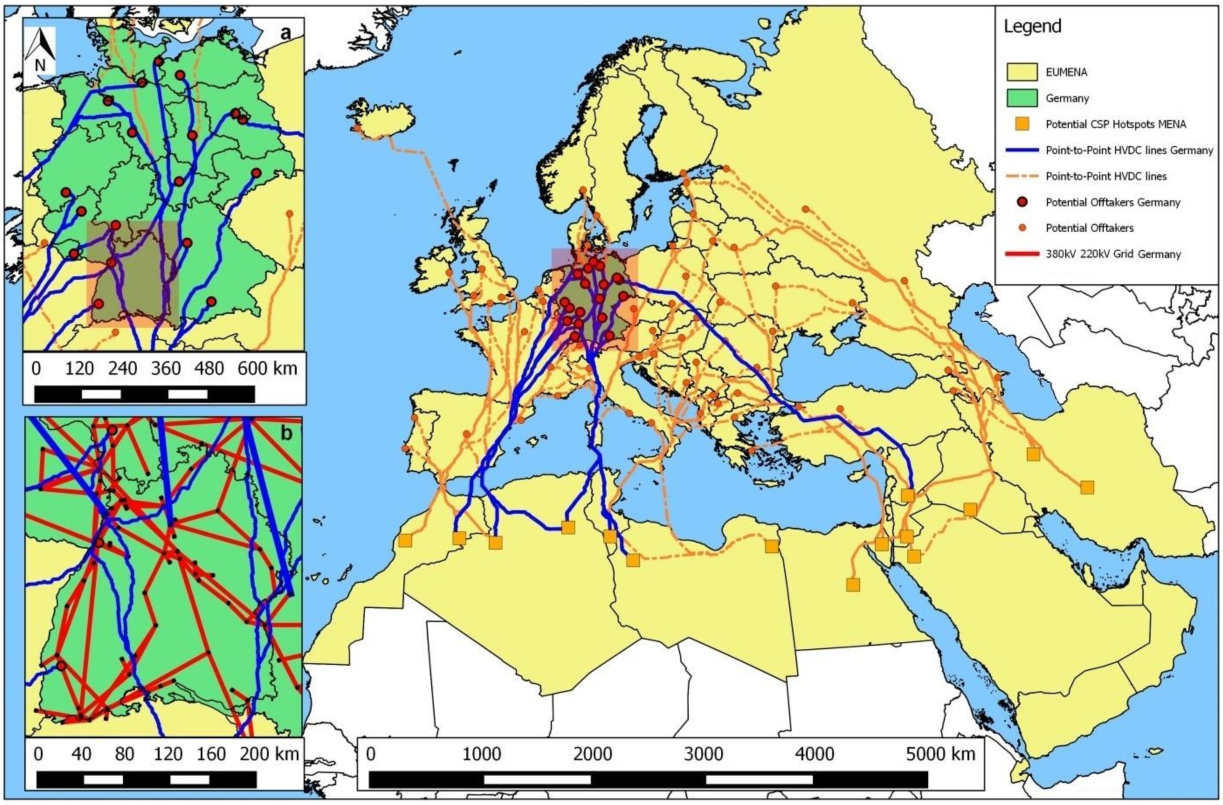

Figure 5: CSP-HVDC point-to-point transmission line model (based on [19]) bringing dispatchable energy to centres of demand – This concept distinguishes itself from a capacity intensive meshed intercontinental overlay grid.

Blue lines show selected HVDC 600kV (OHL and sea cable) transmission paths from CSP plants in MENA to centres of demand in Germany and country internal HVDC in north-south direction. Each federal state in Germany **a**) has at least one centre of demand in the model. Baden-Württemberg (BW) **b)** is modelled with two exemplary off-taker points near Karlsruhe and Freiburg which have also feed-in points into the regional transmission grid (red lines). Orange lines are illustrative showing potential paths to other countries which are not analysed in the paper.

The analysis is based on the examination year 2050. This approach enables assessing cost of one year with the annuity method. Allowing meaningful results of future cost, cost sensitivities (all max, all mean and all min cost values based on international expert assumptions shown in Table 7 and Table 8) for the used technologies are made. The paper focuses on the grid cost and the new grid model and does not present all detailed results.

Germany is modelled isolated without exchange of electricity with other ENTSO-e regions because the power exchange is assumed to be balanced within Germany avoiding high imbalance of the country. Future work can analyse the whole energy system of Europe, Middle East and North Africa (EUMENA) Figure 5 with the results of the present analysis.

5 Case study of the German energy system in 2050 and model calibration

To calibrate the input data assumptions and the model itself, we calculate the transmission grid in a high resolution grid model (491 regions) inside Germany with a model endogenous power plant park and a determined grid topology in a 100% renewable energy scenario (reaching maximum grid expansion). For the grid expansion quantification we use different shares of fluctuating and dispatchable energy (combination of 10% to 90% share) related to gross electricity consumption.

5.1 Case study input values and modelling framework

For a computational feasible determination of the power plant park we use at first a one node model for Germany and optimize all capacities endogenously (with cost sensitivities, OHL/UGC configuration and fluctuating/dispatchable energy share combination). Secondly we distribute the achieved capacities and demand according potentials to the 491 regions (appendix Figure 8). We include AC and DC technologies in REMix (see Table 3). The transmission grid is represented with 491 model nodes in Figure 6. The transmission line topology with the modelled transmission connections are based on today’s AC connection and the planed DC

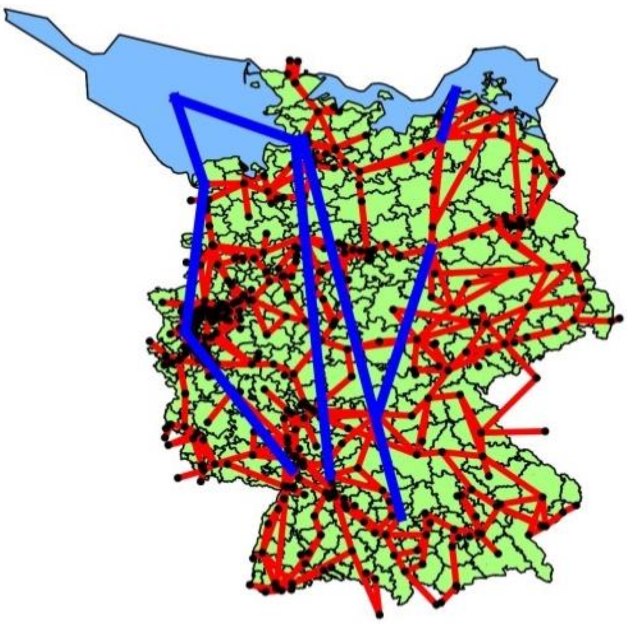

Figure 6: Grid model in Germany with 491 nodes and AC (red) and DC (blue) transmission lines

connections [9], [20]. The 491 node model includes all details in lengths and nodes of the existing transmission grid in Germany. The areas around the 491 grid nodes are made by an aggregation of postal codes which surround the nearest grid node [21]. Thus one model node represents an agglomeration of postal code areas.

In the case study nuclear, gas, coal and CCS are excluded due to their non-renewable characteristic.

Table 3: Techno-economic values of AC and DC in the case study

	AC	**AC substation**	**DC**	**DC converter**
Specific Cost OHL	500.000 €/km	24.790.000 € per station	786.000 €/km	148.730.000 € per station
Specific Cost UGC	962.000 €/km	24.790.000 € per station	2.271.350 €/km	148.730.000 € per station
Specific Capacity	1005 MW	1005 MW	1500 MW	1500 MW
Specific Voltage	380 kV		600 kV	

Sources: [22], [19], [15], [20]

In the following we calibrate our assumptions of Eq. (7) for the transmission grid. Since the calculation of a 491 node model in hourly resolution over one year would be more exact but is still computationally intractable. We use in Table 4 an approach of average hours (24h over one year) and critical hours (one hour in a year) to determine grid cost. With this approach the power plant park capacity of the pre-optimization in a one node model of Germany is exogenously given and distributed to the 491 regions. The grid capacity is endogenously optimized in the predefined link connection structure – no optimization of topology.

Fluctuating energy causes energy supply peaks. Therefore critical grid hours show relevant grid cost in high shares of fluctuating energy. In low fluctuating energy shares a 24h time resolution over one year determines the grid expansion because low peaks of fluctuating energy do not cause high grid expansion. This is shown in Table 4 with the combination of the used time resolutions. Higher grid cost with higher share of fluctuating energy confirms the assumption that grid is more expanded with more share of fluctuating energy.

Table 4: Annual transmission grid cost in the 491 node model under different time resolutions

Scenario [bn. €] energy share	24h average one year		High load with high feed-in of Wind one hour (7963)		Low load with high feed-in of Wind one hour (8706)	
fluctuating_dispatchable	Max UGC	Min OHL	Max UGC	Min OHL	Max UGC	Min OHL
10_90	**1.93**	**0.80**	0.01	0.3	0.24	0.50
30_70	**4.63**	**1.58**	3.10	1.01	3.73	1.22
50_50	**6.30**	**1.74**	5.13	1.64	5.80	1.55
70_30	7.58	2.12	8.05	2.10	**9.14**	**2.48**
90_10	8.07	2.70	**11.57**	**3.28**	8.31	2.69

Values in bold are considered. Critical grid hours are 7963 and 8706 out of 8760 hours.

The critical grid hours show following characteristic: high load is 102 GW and relative low load 89 GW. High feed-in of Wind is in hour 7963 (% of installed capacity): 31.6% wind onshore and 85.0% wind offshore. High feed-in of Wind is in hour 8706 (% of installed capacity): 37.4% wind onshore and 82.5% wind offshore.

To prove that grid critical hours (7963 and 8706) are met, we look at the curtailment in these hours and compare them with the same hours of the calibrated grid model. In these hours no (in the 491 node model) or infinitesimal (in the 1 node model) curtailment accrues. Thus it seems provable that the grid is maximum expanded in these hours when all occurring electricity is transmitted or used. Also other selected hours in high-low combination of load, wind and photovoltaic feed-in did not show higher grid cost in the 491 node model (not listed in the analysis).

5.2 Model validation

The model assumption is that a rising share of fluctuating energy leads to a rising grid expansion in a cost optimized framework. The use of the 491 node model with different power plant parks has proven this hypothesis. Thus, the model can represent a grid expansion according to fluctuating energy share and is therefore considered as valid.

5.3 Derivation of specific grid expansion cost and starting point

Based on the results in Table 4 with the 491 node model, it is clear that transmission grid expansion does not start relative late like in the distribution grid, but early with about 20-30% of fluctuating feed-in power. This starting point (compared to grid expansion and todays fluctuating energy share in Germany) occurs when comparing the annual grid cost of the model with the current annual grid cost in reality. The resulting grid expansion cost of $c_{cb,grid\ trans}$ with 585 €/$kW_{grid\ trans}$ (OHL) and 900 €/$kW_{grid\ trans}$ (UGC) is cheaper than the former assumed cost $c_{grid\ trans}$ in section 3.1. Thus a cost reduction takes place in the OHL case with 35%

(from 916 €/kW$_{grid\ trans}$ to 585 €/kW$_{grid\ trans}$) and in the UGC case with 52% (from 1728 €/kW$_{grid\ trans}$ to 900 €/kW$_{grid\ trans}$). Consequently we calculate with the cheaper grid expansion cost and earlier grid expansion starting point.

5.4 Quality of calibration values, model results

As shown in Table 4, annual grid investment cost rise in a linear manner with a rising share of Wind and PV. This linear correlation is visible also in Figure 7 with the coefficient of determination of 99.52% (UGC max) and 96.73% (OHL min). The cost bandwidth of Table 4 can be met by our new node-internal grid model with the typical cost of the grid in relation to fluctuating feed-in power ($c_{cb,grid\ trans}$) in Figure 7. Comparing the results of cost bandwidths in of the 491 node model (results and linear interpolation - dots) and the calibrated one node model, we determine a medium deviation of 4.53%. However, the model is calibrated in a 100% renewable energy mix with fluctuating and dispatchable energy shares. While renewable dispatchable energies might have different cost characteristics than coal, gas or nuclear power plants, our grid model assumptions could be also different in low renewable energy share scenarios – but probably quite similar due to fundamental grid expansion corresponding to increasing shares of fluctuating energy.

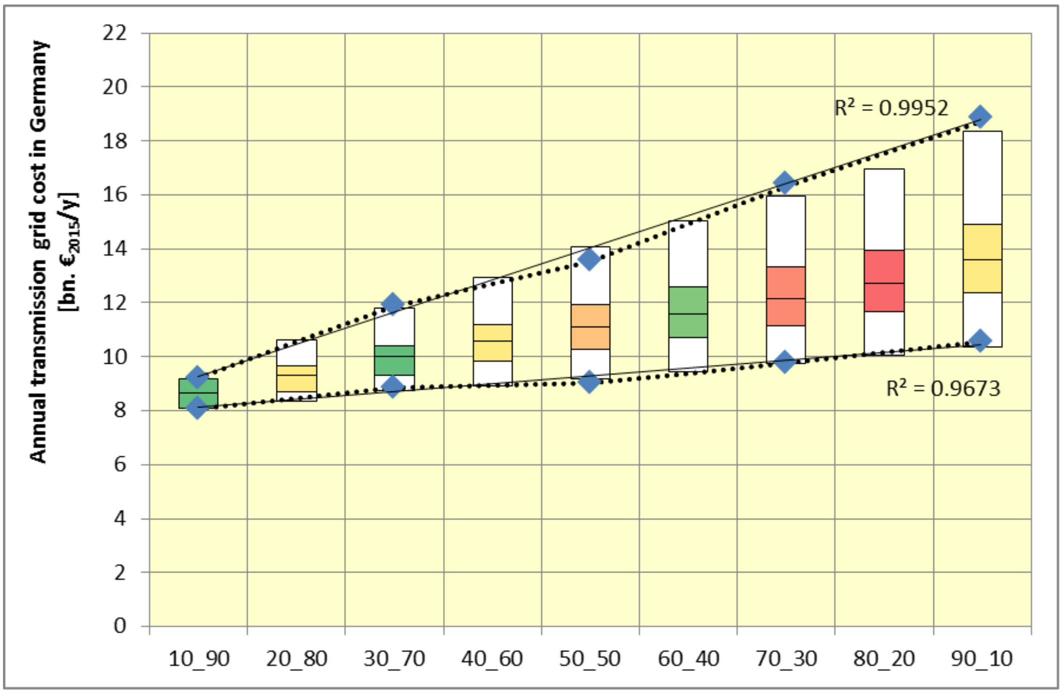

Figure 7: Grid cost of the 491 node model (blue dots from Table 4 and $C_{basic\ grid\ cost}$) meeting cost bandwidths of the calibrated node-internal grid model (boxes). Green to red colours show the min to max cost deviation. The x-axis shows the shares of fluctuating_dispatchable energy share (related to gross electricity consumption).

As assumed in section 3.1, $c_{grid\ trans}$ can also be calculated for other countries like in Germany based on the calibrated results and cost reductions for Germany (see appendix Table 9). Detailed grid analysis should prove the cost ranges of the different national grids in future analysis when more computational performance and more detailed data are available. Table 5 shows exemplarily detailed results of the 491 node model representing the German transmission grid. The used transmission line topology shows the installed link capacities in a case specific grid. These case specific grid configurations show the maximum cost of the grid. Thus the grid is not totally represented with each needed maximum transmission line capacity but with the entire maximum transmission capacity of the whole transmission grid. This is obvious due to missing expanded transmission lines (light blue) especially in the OHL min 90_10 case. Thus the grid may be still undervalued due to today's impossibility of calculating this model over an entire year in hourly resolution. Additionally we calculate with Equation (15) the power kilometres in Germany to quantify the grid besides than just cost. Power kilometres can show how much power is transmitted over distance. In Table 5 they triple to quadruple from the 10_90 to 90_10 scenario while the major impact arises with the HVDC North-South transmission lines.

$$TWkm := \sum_{transmission\ line} TW \cdot km \tag{15}$$

For calculation of TWkm by cost values of scenarios we use 1.01 k€/MWkm for transmission grid and 5.21 k€/MWkm for distribution grid [10], [13].

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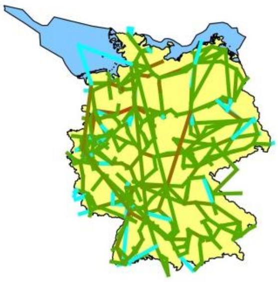
Table 5: Transmission line capacities, power kilometres under different shares of fluctuating and dispatchable energies

fluctuating_ dispatchable	10_90	50_50	90_10
time resolution	24h over a year	24h over a year	1h in the year
Legend installed capacity [GW] 0.0 - 0.0 0.0 - 0.1 0.1 - 0.4 0.4 - 0.8 0.8 - 1.6 1.6 - 2.8 2.8 - 4.8 4.8 - 6.0 6.0 - 8.3 8.3 - 13.9 13.9 - 27.3 27.3 - <37.8			
UGC max			
TWkm	17	39	63
Legend installed capacity [GW] 0.0 - 0.0 0.0 - 0.1 0.1 - 0.4 0.4 - 0.8 0.8 - 1.6 1.6 - 2.8 2.8 - 4.8 4.8 - 6.0 6.0 - 8.3 8.3 - 13.9 13.9 - 27.3 27.3 - <37.8			
OHL min			
TWkm	22	36	57

5.5 Case study results of the German energy system

This chapter discusses the used case study of Germany with the REMix calculations of the approaches without the grid (business as usual) and with the calibrated grid model. The research question of the case study is: How is the energy system influenced by neglecting and including the transmission and distribution grid?

The results in Table 6 show the resulting bandwidths (uncertainties) as output data of grid cost, system cost, capacity and curtailment. The range of 'fluctuating_dispatchable' in the figures of Table 6 is from a high dispatchable energy share (left) to a high fluctuating energy share (right) showing in green the smallest system cost bandwidth and in red its largest.

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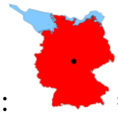
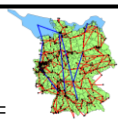
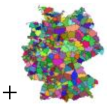
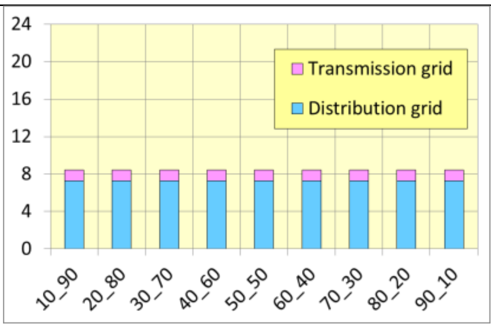
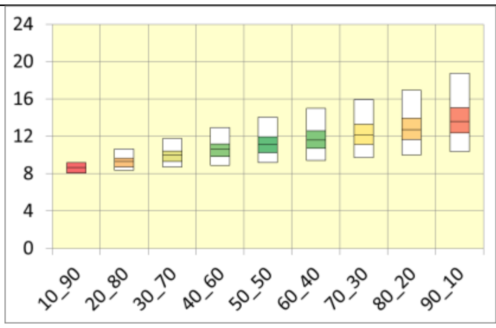
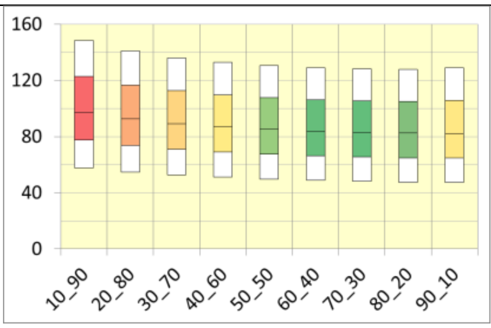
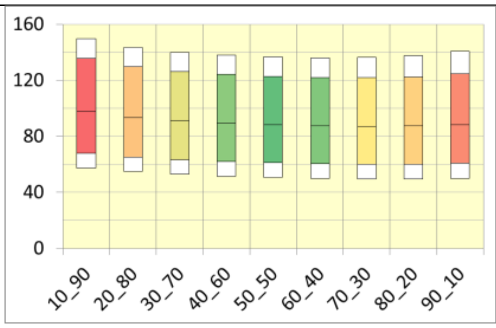
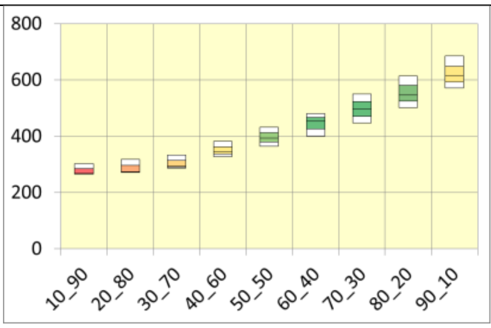
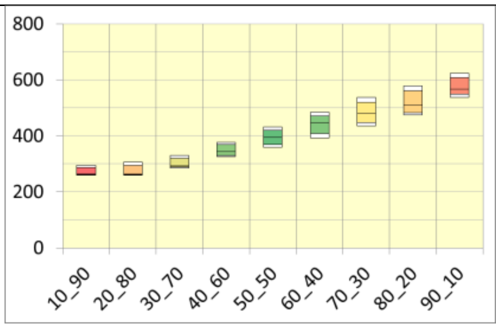
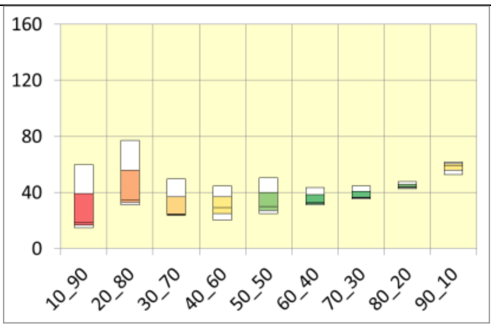
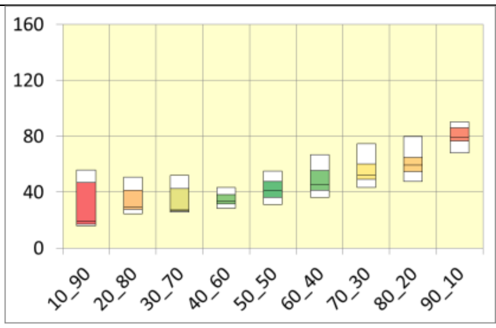
Table 6: Bandwidths as results of sensitivity analysis in the REMix model

Methodological approach	REMix – business as usual	REMix – new node-internal grid model
Model nodes	1: 	1:  =  + 
Grid Cost	no grid expansion – cost of statistical data (existing)	transmission + distribution grid (existing + expansion)
Annual Grid Cost [bn. €$_{2015}$/y]		
Annual System Cost [bn. €$_{2015}$/y]		
Total Capacity [GW]		
Curtailment [TWh/y]		

5.5.1 *Grid cost*

Annual grid cost are separated to grid expansion cost and base grid cost (in relation to peak load) including transmission and distribution grid. While the business as usual case includes only the base grid cost of about 8.4 bn. €/y, the grid expansion cost in our case study with 491 grid nodes are about 1-12 bn. € (up to 11.7% of system cost) per year. Grid expansion cost has also an effect on the expanded capacity and the curtailment. Thus such cost can’t be neglected in a robust energy system analysis that claims to consider a broad spectrum of technological characteristics.

Considering the grid cost ranges it is obvious that uncertainty of grid cost rises with a rising share of fluctuating renewable of almost up to a low double-digit annual bn. € amount.

5.5.2 *System cost*

Annual system cost show all cost of annual operation and maintenance (O&M), fuel cost and annuity capital expenditures. In the business as usual case the minimal system cost uncertainty (green) is in a higher fluctuating share (60_40) while the absolute minimum is in the highest fluctuating share (90_10). This relation is shifted to a more dispatchable share (50_50) when calculating with the grid expansion cost. However system cost minimum does not differ much and system cost bandwidth overlap in all scenarios. Thus outgoing from these bandwidths, system cost doesn’t play a major role regarding grid expansion or in deciding between more fluctuating or more dispatchable energy share (not considering curtailment compensation payments for fluctuating energy). However, when calculating with known determined and well known cost (no bandwidths), the right mixture of fluctuating and dispatchable share might save up to double-digit billions of € per year.

5.5.3 *Curtailment*

Curtailment accrues depending predominantly on: the model endogenous optimized capacities, the variable O&M cost and the share of fluctuating and dispatchable energy. All approaches show the trend of rising curtailment (up to 13% of annual demand) with rising share of fluctuating energy.

Handling with high curtailment is a major challenge regarding also the effect of new build capacities of Wind and PV. These capacities could be more stressed by higher curtailment due to possible conservation of the status quo of former operating Wind and PV capacities which still may have a prior feed in possibility. This can cause missing incentives in building power plants due to a lower or missing profit. Thus the question arises: Who will build such capacities when these are predominant curtailed? How much money is needed to compensate curtailed capacity? – Cost of curtailment compensation (EinsMan – feed-in management) has been in the first quarter of the year 2015 in Germany around 100 mio. €/$TWh_{curtailed}$ [23].

Such cost of curtailment would raise the system cost of the scenarios with high fluctuating energy share up to billions.

5.5.4 *Power plant and storage capacity*

Total capacity include all capacities of power plant, electrical storage charge and electrical storage discharge unit. A higher share of fluctuating energy leads to higher installed capacity. In the highest fluctuating energy share, capacity expansion is up to 6 times of peak load (up to 700 GW). In the highest dispatchable energy share, capacity expansion is about 3 times of peak load (300 GW).

6 Conclusion and suggestion for improvements

Neglecting the grid would mean that no grid related effects of capacity expansion of power plants and storages, curtailment and cost would be considered. This would mean in our case study for Germany that curtailment and grid expansion would be undervalued. Up to 12 bn. €/y grid cost, around 20 TWh/y curtailment and about 10% less needed power plant capacities would be neglected excluding the node-internal electricity grids. This remarkable difference of capacity expansion, curtailment and system cost compared is still a conservative assumption due to the computational limit of calculating not an entire year in hourly resolution for the validation of the model. Further research is necessary to improve the model validating the model in more spatio-temporal accuracy. The new grid model facilitates the consideration of the transmission and distribution grid with two parameters: feed-in capacity of wind and PV and the starting point of grid expansion. Here we use a calibration approach with a 491 node model looking at critical grid hours. The major achievement of the model is that it can represent the grid in cost and TWkm and power system interdependencies such as the use of fluctuating and dispatchable power plants and also a simplified curtailment behaviour reducing complexity in energy system models.

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Symbols

Parameter

$c_{cb,grid\ trans}$	[€/kW]	Calibrated specific transmission grid cost
$c_{AC\ trans}$	[€/kW]	Specific grid cost in AC configuration
$C_{basic\ grid\ cost}$	[mio. €]	Cost of existing or basic grid
$c_{fluc,\ feed\text{-}in}$	[€/kW]	specific cost of fluctuating feed-in capacity
$c_{grid\ cost}$	[€/kW]	Specific grid cost
$c_{grid\ distr}$	[€/kW]	Specific distribution grid cost
$c_{grid\ trans}$	[€/kW]	Specific transmission grid cost
$f_{grid\ exp}$	[-]	Grid expansion factor
$P_{demand,peak}$	[GW]	Peak load
$P_{existCap}$	[MW]	Capacity of existing power plants
R^2	[-]	Coefficient of determination
$s_{gen}(t)$	[-]	Generation time series
x_1	[$\mathrm{kW_{fluc\ feed\text{-}in}}$]	feed-in power of PV and Wind Onshore

Variables

$\boldsymbol{C}_{grid\ distr}$	[mio. €]	Investment cost of distribution grid expansion
$\boldsymbol{P}_{addedCap}$	[$\mathrm{GW_{el}}$]	Capacity of additional power plants
$\boldsymbol{P}_{curt}(t)$	[$\mathrm{GW_{el}}$]	Curtailed power generation
$\boldsymbol{P}_{gen}(t)$	[$\mathrm{GW_{el}}$]	Power generation
$\boldsymbol{P}_{grid}$	[$\mathrm{GW_{el}}$]	Power of grid [kW]
$\boldsymbol{P}_{grid\ distr}$	[$\mathrm{GW_{el}}$]	Power of distribution grid [kW]
$\boldsymbol{P}_{grid\ trans}$	[$\mathrm{GW_{el}}$]	Power of transmission grid [kW]

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Abbreviations

AC	Alternating Current
CSP	Concentrating Solar Power
CSP-HVDC	Concentrating solar power with point-to-point high voltage direct current line
DC	Direct Current
EEZ	Exclusive Economic Zone
EnDaT	Energy Data Tool
EUMENA	Europe, Middle East and North Africa
F_D	share of F% fluctuating and D% dispatchable as total share of gross energy demand
max, mean, min	Cost sensitivities
O&M	Operation and maintenance cost
OHL	Overhead Line
PV	Photovoltaic
REMix	Renewable Energy Mix
TWkm	Power kilometres
UGC	Underground Cable

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9 Appendix

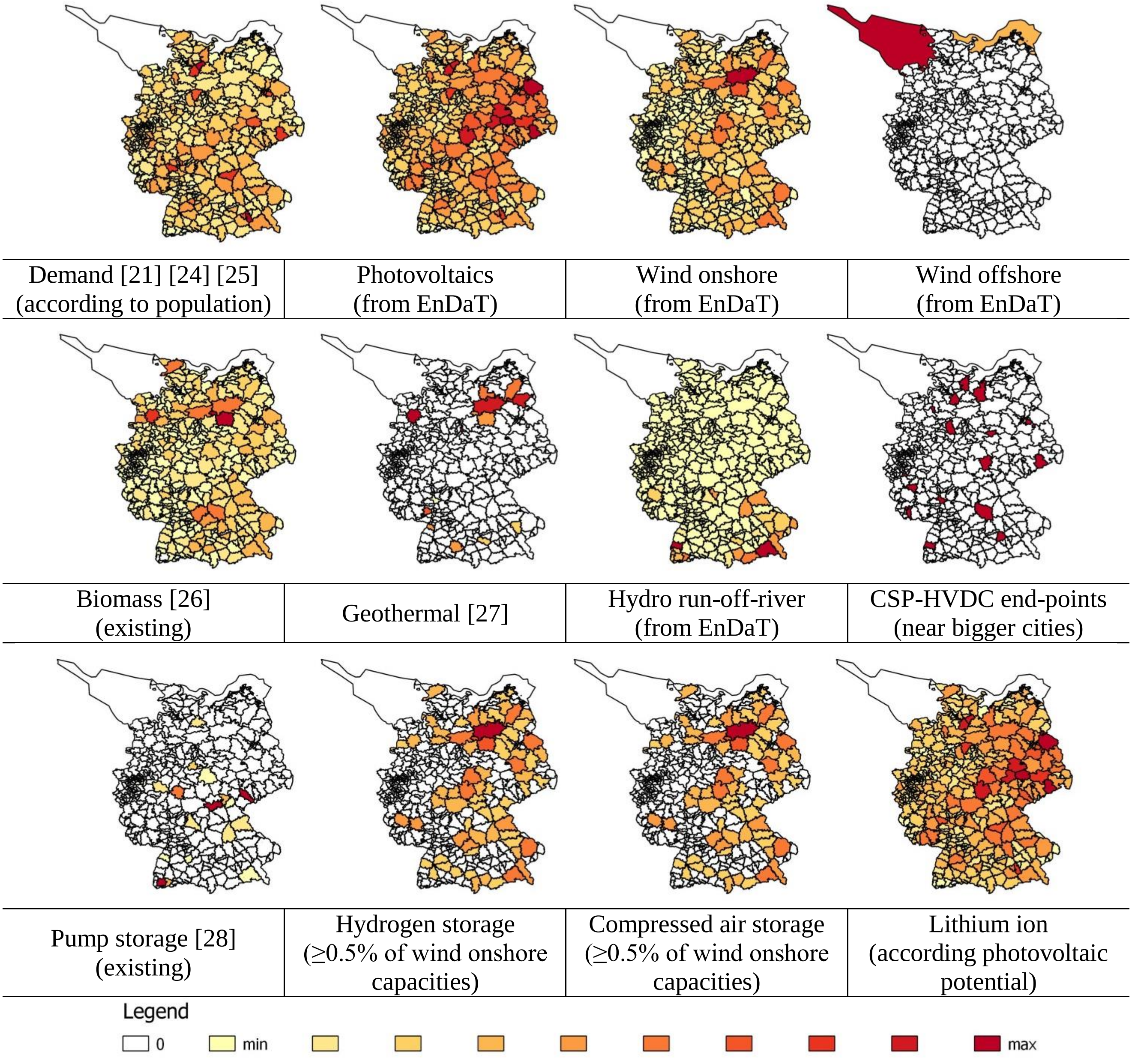

Figure 8: Distribution factors of demand and capacities according their potentials [% of total capacity].

On the technological side, hydrogen, adiabatic compressed air and lithium ion are distributed according to renewable potentials due to their high charging and operational correlation [29].

Table 7: Cost and technology parameters for power plants in the year 2050 based on expert assumptions

Technology	Cost sensi-tivity	Specific investment [k€/MWel]	O&M Fix [%/y] of investment	O&M Variable [€/MWh]	Fuel cost [€/MWh]	Amortisation Time [y]	Interest Rate	Efficiency [-] net	Availability	Capacity Credit [-]
Photovoltaics	max	1150	0.04	0.00		20	9%	1	98%	0
	min	597	1.10	0.00		40	3%			
Wind Onshore	max	1272	2.10	4.33		18	9%	1	95%	0
	min	769	1.61	2.44		24	3%			
Wind Offshore	max	2275	3.64	13.87		16	9%	1	95%	0
	min	1052	3.49	9.55		22	3%			
Run-Of-River	max	5541	5.50	4.84		40	9%	1	95%	0
	min	5541	2.75	2.44		60	3%			
Hydro Reservoir	max	2113	5.00	1.00		40	9%	1	98%	0
	min	1017	5.00	1.00		30	3%			
Solid Biomass	max	3833	1.98	3.20	40.0	20	9%	0.35	90%	0.9
	min	1647	5.60	2.90	25.0	30	3%			
Geothermal	max	6797	3.00	0.10		20	9%	1	90%	0.9
	min	3826	3.00	0.10		30	3%			
CSP power block	max	1098	2.50	2.22		35	9%	0.37	95%	modelled with 0, however 0.9 is possible accepting firm capacity abroad
	min	857	2.50	2.22		45	3%			
CSP solar field	max	356 k€/$MW_{thermal}$	2.50			20	9%		95%	-
	min	166 k€/$MW_{thermal}$	2.50			30	3%			
CSP thermal storage	max	18 k€/MWh	2.50			20	9%	0.95 and 0.05%/h self-discharge rate	95%	-
	min	11 k€/MWh	2.50			30	3%			

Sources: [30], [31], [32], [33], [34], [35], [36], [37], [38], own assumptions

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Table 8: Cost and technology parameters for storages in the year 2050

Technology	Cost sensitivity	Specific investment [k€/MWel]	O&M Fix [%/y] of investment	O&M Variable [€/MWh]	Amortisation Time [y]	Interest Rate	Efficiency [-] net	Availability	Capacity Credit [-]
Pump Storage storage	max	40 k€/MWh	2.80	-	30	9%	0%/h self-discharge rate		-
	min	5 k€/MWh	1.86	-	40	3%			
Pump Storage charge	max	400	2.80	3.80	20	9%	0.89	95%	-
	min	180	1.86	3.80	30	3%			
Pump Storage discharge	max	400	2.80	-	20	9%	0.90		0
	min	170	1.86	-	30	3%			
Power-to-Gas-to-Power (P2G2P) Storage	max	0.20 k€/MWh	3.00	-	25	9%	0%/h self-discharge rate		-
	min	0.20 k€/MWh	2.42	-	35	3%			
Power-to-Gas-to-Power (P2G2P) charge	max	1206 = 606 (alkali electrolysis) +600 (methanation)	3.00	2.30	15	9%	0.70 = 0.79 (methanation) x 0.89 (compression)	95%	-
	min	922 = 322 (PEM electrolysis) +600 (methanation)	2.42	1.64	20	3%			
Power-to-Gas-to-Power (P2G2P) discharge (gas turbine)	max	713	3.00	-	25	9%	0.465		0.95
	min	417	2.42	-	40	3%			
Compressed Air Storage storage	max	60 k€/MWh	1.30	-	25	9%	0.125%/h self-discharge rate		-
	min	38 k€/MWh	1.30	-	35	3%			
Compressed Air Storage charge	max	310	1.30	2.70	20	9%	0.88	95%	-
	min	200	1.30	0.10	30	3%			
Compressed Air Storage discharge	max	400	1.30	-	25	9%	0.70		0
	min	260	1.30	-	35	3%			
Lithium Ion storage	max	220 k€/MWh	2.00	-	15	9%	0.001%/h self-discharge rate		-
	min	150 k€/MWh	2.00	-	25	3%			
Lithium Ion charge	max	25	2.00	0.22	15	9%	0.97	95%	-
	min	12.5	2.00	0.22	25	3%			
Lithium Ion discharge	max	25	2.00	-	15	9%	0.97		0
	min	12.5	2.00	-	25	3%			

Sources: [30], [39], [40], [41], own assumptions

Table 9: Country specific grid values, peak load and cost of fluctuating feed-in power

country	220 kV [km]	≥380 kV [km]	Today's grid cost [bn. €$_{2015}$]	Power kilometres [TWkm]	Peak Load [GW]	Assumed grid capacity [GW]	$c_{cb,grid\ trans,\ OHL}$ per fluc feed-in [€$_{2015}$/kW]	$c_{cb,grid\ trans,\ UGC}$ per fluc feed-in [€$_{2015}$/kW]
Central ENTSO-e								
Austria	3667 [42]	2838 [42]	2.89	4.99	11.44 [43]	2.39	772	1188
Belgium	432 [42]	1326 [42]	0.84	1.58	13.35 [43]	2.78	192	295
Bosnia-Herzegovina	1525 [42]	865 [42]	1.04	1.76	2.07 [43]	0.43	1540	2370
Bulgaria	2837 [42]	2419 [42]	2.34	4.08	6.74 [43]	1.41	1065	1639
Croatia	1210 [42]	1248 [42]	1.11	1.96	2.81 [43]	0.59	1206	1857
Czech Republic	1909 [42]	3510 [42]	2.52	4.64	10.09 [43]	2.10	764	1177
France	26640 [42]	21752 [42]	21.53	37.37	92.90 [43]	19.35	710	1093
Germany	14053 [42]	20455 [42]	15.85	28.74	83.10 [43]	17.30 [44]	585	900
Hungary	1394 [42]	2978 [42]	2.05	3.8	5.86 [43]	1.22	1069	1645
Italy	11149 [42]	10746 [42]	9.83	17.29	53.98 [43]	11.25	558	858
Luxemburg	259 [42]	0 [42]	0.10	0.15	0.99 [43]	0.21	319	491
Montenegro	400 [42]	280 [42]	0.30	0.51	0.62 [43]	0.13	1478	2275
Netherlands	740 [42]	2234 [42]	1.41	2.68	18.46 [43]	3.85	234	361
Poland	7923 [42]	5354 [42]	5.85	9.99	22.68 [43]	4.73	789	1215
Portugal	3565 [42]	2434 [42]	2.64	4.52	8.32 [43]	1.74	972	1496
Romania	4796 [42]	5050 [42]	4.44	7.87	8.31 [43]	1.73	1639	2522
Serbia	2284 [42]	1713 [42]	1.77	3.05	6.93 [43]	1.44	782	1204
Slovakia	688 [42]	1644 [42]	1.10	2.05	4.13 [43]	0.86	814	1253
Slovenia	328 [42]	669 [42]	0.47	0.86	1.98 [43]	0.41	719	1107
Spain	18239 [42]	20639 [42]	17.62	31.36	39.64 [43]	8.25	1362	2097
Switzerland	4915 [42]	1737 [42]	2.83	4.61	7.94 [43]	1.66	1093	1682
Other European countries								
Albania	1128 [45]	120 [45]	0.51	0.78	1.20 [45]	0.25	1305	2009
Armenia	164 [46]	1320 [46]	0.73	1.42	1.20 [47]	0.25	1852	2850
Azerbaijan	1226 [48]	1655 [48]	1.32	2.38	1.05 [49]	0.22	3833	5900
Belarus	2281 [50]	4502 [50]	3.16	5.85	6.78 [50]	1.41	1428	2199

Cyprus	7678 [51]	7678 [51]	6.91	12.19	0.81 [51]	0.17	26256*	40416*
Denmark	3400 [52]	3400 [52]	3.06	5.4	6.20 [53]	1.29	1511	2327
Estonia	158 [54]	1702 [54]	0.91	1.8	1.59 [54]	0.33	1764	2716
Finland	2300 [55]	4500 [55]	3.17	5.86	14.80 [55]	3.08	656	1010
Georgia	1596 [56]	303 [56]	0.79	1.23	1.85 [57]	0.39	1305	2009
Great Britain	6342 [58]	12122 [58]	8.60	15.87	56.00 [58]	11.67	470	724
Greece	8393 [59]	2785 [59]	4.75	7.68	9.89 [60]	2.06	1470	2263
Iceland	859 [61]	0 [61]	0.34	0.5	2.33 [61]	0.49	452	695
Ireland	2000 [62]	450 [62]	1.03	1.62	5.09 [62]	1.06	617	949
Kosovo	353 [63]	181 [63]	0.23	0.39	0.89 [64]	0.18	801	1233
Latvia	0 [65]	1381 [65]	0.69	1.39	1.37 [66]	0.29	1546	2380
Liechtenstein	NA	NA	NA	NA	NA	NA	NA	NA
Lithuania	0 [67]	1761 [67]	0.88	1.77	1.69 [68]	0.35	1599	2462
Macedonia	0 [69]	529 [69]	0.26	0.53	1.51 [69]	0.31	537	827
Malta	8 [70]	0 [70]	0.00	0	0.44 [71]	0.09	22	34
Moldova	532 [72]	203 [72]	0.31	0.51	0.95 [72]	0.20	1017	1566
Norway	4850 [73]	2810 [73]	3.35	5.65	24.18 [73]	5.04	424	652
Russia until Ural mountains	0 [74]	72324 [74]	36.16	72.69	80.32# [75]	16.73	1379	2122
Sweden	4000 [76]	11000 [76]	7.10	13.38	23.40 [76]	4.88	929	1430
Turkey	85 [77]	17747 [77]	8.91	17.89	41.00 [77]	8.54	665	1024
Ukraine	3976 [78]	4934 [78]	4.06	7.27	31.86 [78]	6.64	390	600
Middle East								
Bahrain	350 [79]	0 [79]	0.14	0.2	2.88 [79]	0.60	149	229
Djibouti	NA	NA	NA	NA	NA	NA	NA	NA
Iran	28478 [80]	17438 [80]	20.11	34.1	50.18 [81]	10.45	1227	1889
Iraq	13746 [82]	3723 [82]	7.36	11.74	11.00 [82]	2.29	2049	3154
Israel	4579 [83]	741 [83]	2.20	3.41	11.50 [83]	2.40	586	903
Jordan	3522 [84]	924 [84]	1.87	2.98	2.98 [84]	0.62	1926	2964
Kuwait	4014 [85]	854 [85]	2.03	3.19	9.00 [86]	1.88	692	1065
Lebanon	290 [87]	0 [87]	0.12	0.17	1.94 [88]	0.40	183	282
Oman	2837 [89]	686 [89]	1.48	2.34	2.77 [89]	0.58	1632	2512
Palestine	NA	NA	NA	NA	NA	NA	NA	NA
Qatar	550 [90]	287 [90]	0.36	0.61	6.80 [91]	1.42	164	252
Saudi Arabia	13489 [92]	13489 [92]	12.14	21.41	62.26 [92]	12.97	597	919
Syria	5785 [93]	1409 [93]	3.02	4.78	7.22 [93]	1.50	1280	1970
United Arab Emirates	437 [94]	875 [94]	0.61	1.13	17.74 [95]	3.70	106	163

Yemen	1161 [96]	0 [96]	0.46	0.68	0.68 [97]	0.14	2098	3229
North Africa								
Algeria	13390 [98]	2872 [98]	6.79	10.68	11.19 [98]	2.33	1859	2862
Egypt	17570 [99]	3060 [99]	8.56	13.3	28.02 [99]	5.84	935	1440
Libya	13677 [100]	442 [100]	5.69	8.4	4.76 [100]	0.99	3665	5642
Morocco	9220 [101]	1753 [101]	4.56	7.13	5.60 [102]	1.17	2496	3842
Tunisia	0 [103]	2792 [103]	1.40	2.81	3.35 [104]	0.70	1275	1963

Costs: 400000 €$_{2015}$/km (220 kV), 500000 €$_{2015}$/km (380kV); Assumed capacity for power kilometres: 0.582 GW/km (220 kV), 1.005 GW/km (380 kV). This is based on the assumption of using a double bundle 240/40 (Al/St) with a load of 60%.

$c_{cb,grid\ trans}$ OHL is a result of the reduction of $c_{grid\ trans}$ OHL of 35% and for $c_{cb,grid\ trans}$ UGC a reduction of 52% of $c_{grid\ trans}$ UGC (calibration result of the case study in Germany).

*Very high, due to much installed transmission lines and relative low load. Grid expansion cost may be 10 times lower in Cyprus reaching the scale of other countries. # Estimated from the country values with 56.6% of whole country electricity production [75].