Analyzing the future role of power transmission in the European energy system

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Abstract

To integrate renewable energy generation, our energy systems need to become more flexible than they are today. While many studies on planning flexibility options have emerged in the last years, the literature still lacks of a better understanding of investments into power transmission infrastructures. Here, our study makes three contributions. We aim to re-understand the role of power transmission in the context of, first, the many available and competing flexibility options; second, the major uncertainties in societal preferences on energy technologies; and third, different ways of modeling power flows in energy system optimization models.

Our methods base on the energy system optimization model (REMix) for planning the transition of Europe's energy system. We also consider interactions with the heating and transport sectors. A broad set of scenarios explores how investments in transmission are affected by certain strategies regarding grid expansion, solar power imports and hydrogen generation. The power flows in the transmission grid are modeled in three different ways, once as transport model, as direct current power flow and with profiles of power transfer distribution factors.

In all scenarios explored, deploying transmission systems contributes significantly to system adequacy. Storage technologies are needed, but investments in transmission are at least two times higher. Imports from concentrated solar power plants in North Africa call for larger transmission systems. Combined with hydrogen systems the need for transmission culminates. If investments in new power transmission infrastructure are restricted (for example as a consequence of social opposition), grid expansion can be replaced by additional power generation and storage technologies for slightly higher system costs. The different ways of modeling the power flows within REMix caused only minor changes on the investments in load balancing technologies. At least with a spatial resolution of mostly one node per country, it does not seem to matter how the power flow distribution is modeled.

As next steps, we recommend improving the spatial distribution to avoid underestimating the need for flexibility due to aggregation of spatially explicit information. Our results are relevant for energy policy makers as well as energy modelers.

1 Introduction

Decarbonizing energy systems requires structural changes in the energy sector. To cope with high shares of renewable power generation, flexibility is needed, which can be provided by sector coupling, flexible demand and generation, energy storage, or transmission grids (to be referred to as flexibility options or load balancing technologies). Model-based analysis of long-term energy scenarios is a well-developed and widely used approach to investigate the complex interactions of energy technologies, including flexibility options, with the purpose of advising policymakers and stakeholders. Major challenges of such modeling approaches are uncertainties stemming from assumptions on future developments (e.g. cost inputs) or from modeling techniques each with different levels of abstraction. The interactions of technologies for spatial and temporal load balancing are not sufficiently investigated, especially when a wide perspective is required such as in the case of the European energy system. In addition, the realization of large-scale infrastructure projects is facing great challenges already today (e.g. due to resistance of local stakeholders). For this reason, it is even more important to gain more knowledge about the interchangeability of flexibility options and the associated costs.

Identifying flexibility requirements has been the objective of many studies, especially in the last decade. For example, the review of (Haas et al. 2017) systemized the advances in planning energy storage technologies. They found, for example, that most studies considered less than three technologies for load balancing, and that sector-coupling has been treated only incipiently. An overview on more general flexibility options is given by (Zerrahn and Schill 2017), who conclude that requirements on especially storage depend on a variety of parameter assumptions and model features.

Previous model-based scenarios evidenced the importance of grid expansion for the long-term transformation of the European energy system. (Steinke, Wolfrum, and Hoffmann 2013) stress the role of transmission to reduce the demand on backup generation capacities in 100% renewable energy supplies. The analyses of (Schlachtberger et al. 2017) underline the contribution of unconstrained power transmission to the energy system's affordability. Nevertheless, according to the findings of (Marinakis et al. 2018), power transmission stands not only in competition but also in complementarity with energy storage. (Cebulla et al. 2018) compared modelling results for over 500 energy scenarios and showed that electricity storage can reduce system costs especially in systems with a high share of photovoltaics and that grid expansion is especially important when wind power generation is dominant. These analyses, although helpful, are usually plagued by the assumptions about future cost developments, differences in technology representation and abstractions for model building (see e.g. (Gils et al. 2019)). Sensitivities of model results that focus on the role of power transmission have not sufficiently been investigated, especially for the European energy system while taking into account a broad spectrum of different flexibility options as well as sector coupling.

Gaining more knowledge about the interaction and interchangeability of flexibility options and the associated system costs is not only relevant from the perspective of established technologies but also in the light of new technologies. Besides intensified sector-coupling, there are two factors that may strongly influence future infrastructure needs in the European electricity system. These are the possibility of importing large quantities of electricity from North Africa and the generation of hydrogen (H_2) or other synthetic fuels from renewable electricity. Both cases may require an expansion of transmission grids to different extents. If properly planned, these infrastructures could offer a high degree of flexibility and thus reduce the need for installing other load balancing technologies within Europe. Such interactions have already been investigated in the literature. (Benasla et al. 2019) demonstrate the potential of electricity imports generated by concentrated solar power (CSP) plants in North Africa. (Michalski et al. 2017) particularly focus on stronger coupling of the power and gas sector by hydrogen generation for reducing transformation costs. However, such options need to be examined much more closely, taking into account their interactions and in particular their grid integration. In addition, public acceptance plays an important role in all transformation pathways with concrete implications on the future energy system. There are already considerable acceptance problems with the implementation of the large transmission lines planned to date, for example, from Germany's wind-rich areas in the north to the demand centers in the south (Neukirch 2016). Besides reducing the need for -or completely replacing- unpopular technologies, solar power imports or a hydrogen economy offer also opportunities to reduce societal risks from planning the energy system transformation. In this sense, a more detailed scenario analysis is still missing in order to assess possible consequence of constrained grid expansions for the overall energy system.

The way of modeling power flows in a high voltage alternating current (HVAC) transmission network in the context of expansion planning tools varies widely. In general, the most accurate modeling approach is known as AC power flow. It is typically used in the field of power flow analysis, where infrastructure is fully modeled which is –from an overall energy system's perspective- a rich spatial resolution (Singh et al. 2014). To cope with the associated computational cost the temporal dimension is reduced to snapshots (e.g. worst-case situations (Quintero et al. 2014)). Energy system optimization models (ESOMs), on the other hand, aim to represent the full planning year for the whole energy system. The computational burden of solving the related non-linear equations, render AC power flow impracticable for overall system planning (Zhang et al. 2012). Existing ESOMs and their case studies on Europe reveal that the Ac power flow equations are usually simplified to linear DC power flow equations (Leuthold, Weigt, and Von Hirschhausen 2008) or economic transport models (Hitchcock 1941) even though such systems are much more complex (Schaber, Steinke, and Hamacher 2012).

To better account for power transmission when designing future energy systems, two general approaches have emerged. One is integrated modeling (Babrowski, Jochem, and Fichtner 2016), (Hörsch et al. 2018) which is characterized by increasing spatial resolutions in ESOMs. This implies explicitly modeling of nodes and transmission lines in the HVAC grid. A detailed compilation of the associated modeling constraints to be considered is provided by (Schönfelder et al. 2012). The other general approach involves model coupling, meaning that a power flow simulation is iterated with an ESOM (Hagspiel et al. 2014). However, these studies focus on electricity transmission and oversimplify or neglect further sectors (such as heat or fuels). To conclude, with the exception of few isolated efforts, power flow modeling approaches within large-scale ESOMs are limited to transport and DC power flow models whereas the usefulness of the particular approaches is not fully understood.

The literature reveals gaps in ESOMs on how investments of power transmission infrastructures are assessed when planning future energy systems. Especially, the existence of many competing flexibility options, further conceivable but not yet implemented technological concepts, major uncertainties in societal preferences on energy technologies and strong simplifications on transmission modeling call for a more careful examination. This is where our study aims to contribute. We strive to consider the main flexibility options available, and in that context, to re-evaluate the role of power transmission for transitioning towards a low-carbon energy system in Europe. Concretely, we contribute by answering:

1. What is the role of power transmission in the transition of the European energy system in relation to emerging flexibility technologies, including sector-coupling, on system costs and adequacy?
2. There are strong uncertainties with respect to societal preferences on future supply strategies, such as electricity imports from solar power plants in Africa and large-scale implementation of hydrogen technologies that both impact the need for transmission, as well as the acceptance of transmission systems themselves. What is the impact of these uncertainties on future grid investments?
3. Power transmission is a highly complex phenomenon, yet energy system planning tools commonly reduce it tosimplistic models. How do different modeling approaches impact the final recommendations on transmission investments?

The questions above are relevant because power transmission is one key technology of the transformation towards low-carbon energy systems, albeit to be discussed in the context of a manifold of conceivable load balancing measures. In order to assess the contribution of power transmission and its expansion for the decarbonization of the European energy system, model-based analyses are required to explore a wide range of scenarios.

In the following, the methodology of this model-based scenario analysis is detailed. The outcome is presented in section 0, and discussed in section 4 together with the outline of future work.

2 Materials and Methods

To find answers to our research questions, we recur to established methods from energy systems analysis. More precisely, we use an advanced ESOM – REMix (Renewable Energy Mix for a sustainable energy supply) – for planning energy systems. Today's applications range from country specific cross-sectoral energy system analyses (Gils, Simon, and Soria 2017) to multi-regional and spatially highly resolved power system analyses (Cao, Metzdorf, and Birbalta 2018). The methodological approach and the essential functionalities of the model are described in (Gils et al. 2017). Figure 1 provides an overview of our methodological approach which is described in the following subsections (each of these subsections is denoted in brackets behind the box captions). An extended overview of our methodological approach including all types of input and output data can be found in the Supplementary Material.

In our current work, the ESOM REMix is improved by integrating a more accurate representation of the power transmission system, with respect to power flow modeling, related constraints and investment costs. Subsequently, it is applied systematically to analyze to which extent power transmission competes with or complements other flexibility options. Section 2.1 provides further details on the modelling approach.

In terms of scope, spatially we focus on Europe, and technologically we focus on the power system including the demand for heating and energy for individual transport (including power-to-gas applications) as sector coupling. Section 2.2 elaborates on the scope and inputs.

To re-understand the role of transmission systems as one of many flexibility options in low-carbon energy systems, we define three sets of scenarios to answer our research questions. In general, these are characterized by different demand and supply structures that affect the transmission infrastructure. The first set refers to different emission targets and sensitivity to the generation mix. For treating uncertainties with regard to modeling and parameter assumptions on power transmission modeling, we will vary both model inputs and modeling techniques. Therefore, the second group defines narratives on technology acceptance and availability of large infrastructures (including generation, storage, and transmission) which, as a whole, affect the need for spatial load balancing. Finally, the third set corresponds to different approaches for modeling power flows in energy system optimization models. Section 2.3 details these scenarios.

2.1 Modeling approach (REMix)

Based on a cost minimization, REMix decides on the optimal system configuration and operation of the energy system to satisfy the demand. The tool is setup to model a whole year with sequential hourly time steps, i.e. 8760 steps. The main outputs refer to quantified investments in technologies from a given set and dispatch time series. Technologies considered cover fossil and renewable power generators, load balancing options (i.e. energy storage, demand-side management, power-to-gas, power-to-heat), electricity transmission, and hydrogen storage, reconversion and transport via gas transmission infrastructures. Table 1 of the Supplementary Material shows the exhaustive list of technologies considered in our study. Note that the inputs and scope will be discussed in section 2.2.

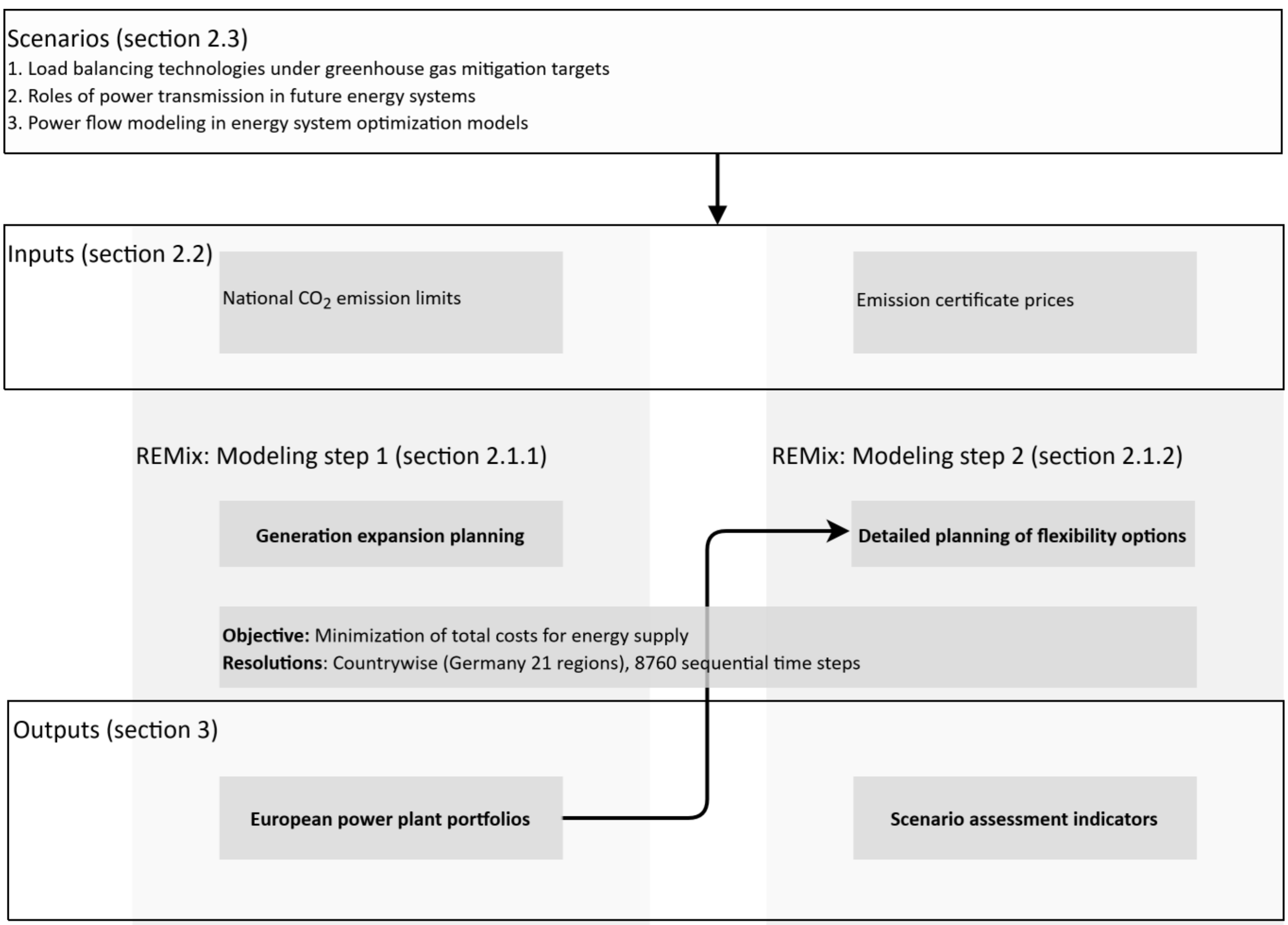

Figure 1: Overview of methods, including inputs, scenarios, and outputs. Our modeling approach has two steps: step one performs a classical expansion plan and step two a detailed planning of many flexibility options.

As can be seen in Figure 1, we perform a two-level optimization. The first level plans the investments in generation, (in a simplified manner) transmission and (one kind of) storage systems starting from an initial European power plant portfolio that considers current generation capacities as well as a phase-out of coal. Only the resulting power generation mix is passed on as inputs to the second level, which in turn decides in detail on the different flexibility technologies. (Note that this is different from a *bilevel* optimization, in which one problem is nested within another (Fan and Cheng 2009)) We opted for this two-level approach to be able to benchmark in each scenario the resulting flexibility options against each other, rather than competing with expansions from all kinds of generation technologies. The final outputs for our considered scenarios are described with several key indicators, including total system costs, investments in each of the flexibility technologies, backup capacities, emissions, and capacity factors.

2.1.1 Level 1: Generation expansion planning with limited flexibility

The first modeling step aims to find intentionally stressed European power plant portfolios to serve as baseline (starting point) for the many scenarios of this study. This rationale is inspired by how in real power market the core of the system already exists. From that baseline, gradual changes are evaluated in response to the emergence of new flexibility options, changes in societal acceptance, and improvement of energy models (with each of these three elements relating to the three research questions).

Sector-coupling is modeled as inflexible electricity demand time series of the transport and heat sectors, while the operation of combined heat and power plants (CHP) are determined by must-run factors that stem from preliminary analyses where we observed only a little impact of these factors on the resulting system configuration. The stressed system results from running the optimization for different times series of historical weather years from 2006 to 2012 (seven times), and picking the one with the smallest generation capacities (lowest adequacy). With this intentionally undersized system, we run the second modeling step.

The modeling is restricted by a series of boundary conditions, so that the results appear plausible from today's perspective. One constraint relates to the overall emissions of energy-related carbon dioxide (CO_2) from power generation applied to each country taking into account current discussions on burden sharing and equity principles. Another one distributes the power generation capacities across Europe by setting country-specific self-sufficiency thresholds of 80% in terms of annual demands. As additional adequacy constraint, 80% of the annual peak load is enforced as firm capacities per country. Taking 80% for both the self-sufficiency ratio and the firm capacities is based on expert's judgements deduced in an internal workshop from preliminary model runs performed for thresholds of 0%, 50%, 80% and 100%.

2.1.2 Level 2: Detailed planning of flexibility options

The second modeling step focuses on the deployment of a broad spectrum of flexibility options to balance power generation with demand. This means that the prescribed generation capacities are fixed (using the values from the first level). However, investments into additional gas turbines as backup capacity remain possible (this can be interpreted as an indicator of security of supply).

Considered energy storage systems are pumped hydro, adiabatic compressed air, lithium-ion and vanadium-redox-flow battery systems. Demand-side management of industrial consumers and controlled charging of electric vehicles are further flexibility options in the second level.

Compared to modeling step 1, sector-coupling is now modeled in much more detail. Using the modeling concepts from (Gils 2015), heat demand can be covered by conventional technologies (gas burners or district heating networks) or electrical technologies (electric boilers and heat pumps). Capacities of these technologies, including their heat storage, are determined by the model.

Expansion planning for hydrogen generation and storage is enabled in some scenarios. Large electrolyzers produce hydrogen to be stored in salt caverns. Later it can either be used directly as fuel for transportation or indirectly by reconversion to electricity. Direct use is allowed in fuel stations within a radius of 100 km to the caverns. We assumed that gas stations further away would have their own small electrolyzers for on-site hydrogen production and storage in tanks. Reconversion to electricity is enabled by co-firing hydrogen to (renewable) methane in all open and combined cycle gas turbines in the vicinity of the caverns (Noack et al. 2014).

2.2 Scope and inputs

The scope of our analysis is the energy system of Europe (ENTSO-E members), with the exception of Turkey, Island and Cyprus. The used spatial resolution and representation of the power transmission grid is as illustrated in Figure 2. The higher spatial resolution for Germany is due to the history of model development and the availability of data for model parameterization. In the analysis carried out here with a focus on the whole of Europe, it enables a more precise consideration of the power flows in the central part of Europe. Note that candidate-lines, for example for importing solar energy from Africa, are not depicted. The power system is fully considered, whereas the heat and transport sectors are modeled as explained in subsection 2.1.2.

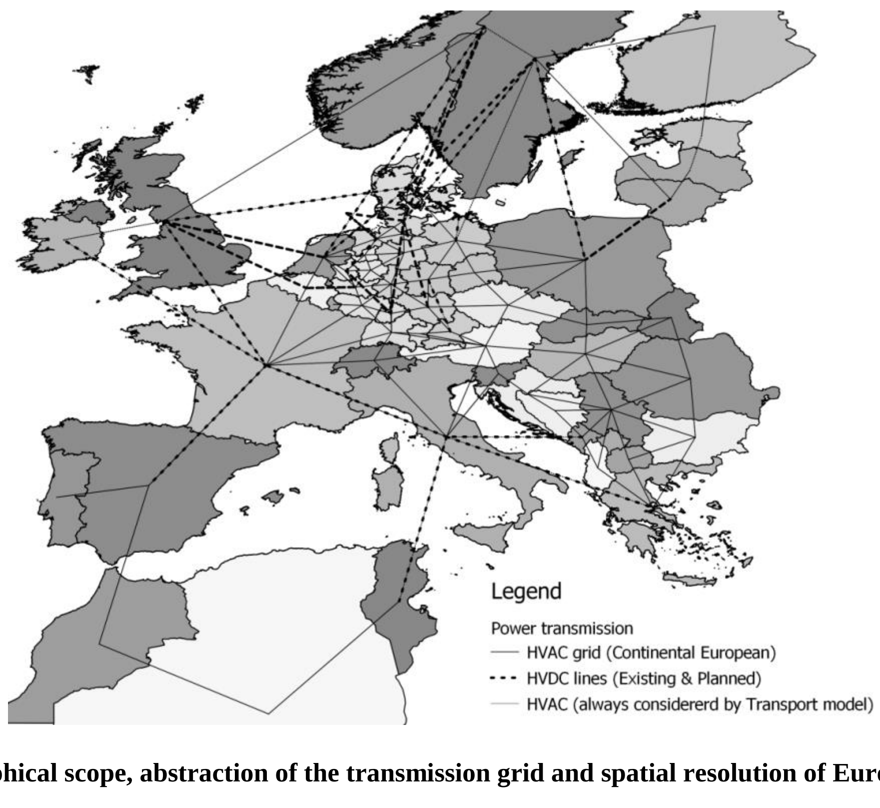

Figure 2: Geographical scope, abstraction of the transmission grid and spatial resolution of Europe.

The resulting systems from REMix are evaluated in terms of the energy supply trilemma –i.e. affordability, security and sustainability– based on a set of defined indicators. The first aspect of the trilemma, affordability, is given by the objective function of the applied model. The second aspect, system security, is assessed from the perspective of adequacy, a common indicator for long-term planning (ENTSO-E 2018). In this sense, adequacy refers to the existence of facilities within the system that ensure load balancing with respect to operational constraints (Billinton and Allan 1988). When using an ESOM with a power balance constraint applied to all hours of the year, system adequacy is intrinsically ensured either by building a cheap power generation technology (power-related adequacy) or by producing very expensive electricity from an artificial (slack) generator (energy-related adequacy). The latter is the common approach in ESOMs if only a given power plant portfolio should be operated (without the possibility to expand generation capacities) but could lead to inappropriate high markups on system costs and would complicate a cost-based comparison of scenarios. Therefore, we measure system adequacy as the flexibility options' capability to avoid the installation of gas turbines. Finally, the third aspect, sustainability, is evaluated in terms of energy related CO_2 emissions.

The main inputs to REMix include five large groups: technology data, weather data, energy demand, emission budgets, and other technical assumptions. These will be summarized as follows.

2.2.1 Technology data

Technology inputs include conversion efficiencies, investment and operation cost projections as well as the installed capacities and related phase outs (i.e. limited lifetime).

The costs and conversion efficiencies of fossil-fired power plants are based on the work of (Gils 2015) and have been validated through earlier studies (Scholz et al. 2014a), (Scholz, Gils, and Pietzcker 2017). Updated techno-economic data of energy storage is taken from (Cebulla, Naegler, and Pohl 2017), while costs for expansion and maintenance of transmission lines are derived from (TSOs 2012) and (Seidl and Heuke 2014). New technologies in the current study involve electrolyzers, hydrogen storage tanks and hydrogen caverns as initially used in (Michalski et al. 2017). The corresponding costs were estimated in (Noack et al. 2014) and can be consulted in (Cao et al. 2019).

For thermal power plants, we use the installed capacities given in (Platts 2015) and assume technology-specific life-times for their phase-outs. Political plans for phase-out of coal are additionally superimposed (and no new coal power plants can be built by the model). For existing renewable technologies, we used the capacities from (ENTSO-E 2015b). In terms of grid expansion, we prescribed all or only a selection of projects of the "Ten-Year Network Development Plan 2016" (ENTSO-E 2015a), depending on the grid scenario (see 2.3.2).

2.2.2 Weather data

The weather inputs are based on resource-potentials processed as described in (Scholz 2012), using different weather data sets from 2006 until 2012 for power generation from photovoltaics (PV) and wind, relying on technology data (e.g. performance curves of wind energy converters) collected from 2010. Hydro power plants are modeled as feed-in time series (i.e. run-of river reservoirs) based on data from the year 2010.

Our model runs, unless otherwise indicated, are done with weather inputs from 2006 as that year presents average capacity factors (in comparison with the available years).

2.2.3 Energy demand

The projection of the annual electricity demand primarily relies on data published in the e-Highway2050 study (Bruninx et al. 2014). Existing conventional consumers are based on the scenario "Small & Local" which assumes low economic and population growth in Europe. This results in a long-term decline from around 3200 TWh in 2014 to 2700 TWh in 2050, after an intermediate increase to 3480 TWh in 2030 according to scenario Vision 4 of (ENTSO-E 2016a). Future energy systems will additionally be impacted by new electricity consumers. Assumptions on the overall heat demand and the electricity use for heat pumps and electric heaters are based on (Scholz et al. 2014a). The annual energy demand of electric vehicles is taken from the e-Highway scenario "100% RES" with the exception of Germany, where scenario C from (Nitsch et al. 2012) is used. For all countries, hydrogen demand for transport is derived with a similar methodology as for Germany in (Nitsch et al. 2012). As a result, the additional electricity consumption in 2050 for heat is assumed to be 185 TWh and for electric vehicles maximum 529 TWh for all European countries. In the case of a scenario with hydrogen use, the electricity consumption for electric vehicles is 263 TWh and the complementary electricity consumption for hydrogen in transport is about 570 TWh.

The final inputs for REMix are hourly time series of electricity, heat, and hydrogen consumption. These time series are determined by multiplying the sector-specific energy demands with pre-defined load profiles taken from or similarly derived as in (ENTSO-E 2016a), (Pregger et al. 2012), (Gils 2015) and (Michalski et al. 2017).

2.2.4 Emission budgets and emission costs

CO_2 emissions in REMix can either be treated as fixed annual budget or as certificate costs. While we use the first variant in level 1, we apply the latter in level 2, in order to observe an additional indicator for the comparison of scenarios.

To ensure that each country contributes to the achievement of greenhouse gas mitigation targets applied on a European level, we define country-specific CO_2 budgets. The budgets are determined based on annual energy balances from 2010 (IEA 2014) to 2050 and fuel-specific CO_2 emission factors (Intergovernmental Panel on Climate Change 2006). Based on a reduction target of 90% in the power sector of Germany and by assuming equal emissions per capita in Europe in 2050, a total reduction between 55% and 85% (compared to 1990) seems achievable and is imposed in the model across all EU-28 countries. The resulting CO_2 budgets are presented in Table 1. For North African countries, a maximum in emissions is set as upper bound (167% and 116% relative to 1990).

Table 1: Cumulated greenhouse gas emissions budgets and certificate costs

CO_2 mitigation target (relative to 1990)	**Emission budget for EU28* for modeling step 1**	**Emission certificate costs for modeling step 2** (Scholz et al. 2014a)
55%	656 Mio.t	45 €/t
85%	213 Mio.t	75 €/t

* without Malta

From the results of modeling step 1 we can derive emission certificate prices that would lead to similar emissions. These are based on the marginal values of the corresponding decision variables.

As in modeling step 1 these prices are country-specific, we assumed comparable average values according to (Scholz et al. 2014b) as shown in the right column of Table 1.

2.2.5 Power transfer distribution factors

One of the goals of the work presented is to use a more detailed transmission grid model in the ESOM REMix. The highest level of detail is reached with AC power flow models that fully model active and reactive power flows for each line. However, due to their nonlinear characteristics, it is not possible to use the AC power flow equations in the context of an optimization, as in an ESOM. By linearizing the trigonometric functions involved and assuming constant voltage amplitudes of 1 p.u. at every node, the AC power flow equations become linear in the variables. The active power flow on the line l connecting node n and node n' is then given as $P_f(l) = b(l)(\vartheta(n) - \vartheta(n'))$, where $\vartheta(n)$ and $\vartheta(n')$ are the voltage angles at nodes n and n', respectively, and $b(l)$ is the susceptance of the corresponding line. Note that, due to the fact that the equation has the same structure as Ohm's laws for a DC network, this simplification is called "DC power flow", even though it refers to the power flow in an AC network.

However, DC power flow equations correspond to a linearization around a constant, artificial operating point, which may result in significant errors if the real operating point is significantly different. Moreover, it requires either a representation of all nodes in the grid or, when considering aggregated regions, the definition of equivalent, virtual lines between regions. For ESOMs, the former usually does not match the spatial resolution of the rest of the model, while the latter is nontrivial and may cause additional inaccuracy. In order to overcome these shortcomings, a numerical linearization of a full AC power flow model can be performed. Consider the power flows $P_{f,\mathrm{AC}}(l_{\mathrm{AC}})$ for every line l_{AC} obtained by an AC power flow computation for given active power balances $P_{\mathrm{AC}}(n_{\mathrm{AC}})$ at every node n_{AC}. For an ESOM with aggregated spatial resolution, as REMix, all lines in $\mathcal{L}_{\mathrm{AC}}(n, n')$ (the set of lines that connect regions n and n') can be aggregated to a so-called flow gate l with the load flow

$$P_f(l) = \sum_{l_{\mathrm{AC}} \in \mathcal{L}_{\mathrm{AC}}(n,n')} P_{f,\mathrm{AC}}(l_{\mathrm{AC}}). \qquad \textbf{Equation 1}$$

The corresponding active power balance of region n is given as

$$P(n) = \sum_{n_{\mathrm{AC}} \in \mathcal{N}_{\mathrm{AC}}(n)} P_{\mathrm{AC}}(n_{\mathrm{AC}}), \qquad \textbf{Equation 2}$$

where $\mathcal{N}_{\mathrm{AC}}(n)$ is the set of nodes in the AC model that belong to region n. Then, it is possible to linearize around an operating point $P_0(n)$, $P_{f0}(l)$ by (numerical) computation of the Jacobi matrix $M_{\mathrm{PTDF}} = \left.\frac{\partial P_f}{\partial P}\right|_{P_0}$ such that

$$P_f \approx P_{f0} + M_{\mathrm{PTDF}}(P - P_0), \qquad \textbf{Equation 3}$$

with $\sum_n P - P_0 = 0$, meaning that power is shifted from one region to another without affecting system balance. The element ln of M_{PTDF} denotes by how much the power flow through flow gate l changes in relation to a change in the power balance of region n. Hence, the factors in M_{PTDF} reflect how a change in power flow due to a shift of power from one region to another is distributed among the flow gates. For this reason, they are called "Power Transfer Distribution Factors" (PTDF).

In the context of the coupling between REMix and the transmission system model presented in this paper, we have determined six characteristic PTDF matrices based on a full AC transmission system model at six different operating points. In order to determine characteristic operating points, publicly available time series have been obtained from the Open Power System Data platform (Open Power System Data 2017), which is based on data from European TSOs. These time series cover, among others, electrical load and feed-in from wind and solar power per country. From the time series of 2015, six representative combinations of load and wind feed-in have been selected: low, medium and high load combined with low and high wind feed-in. For each of these time instances, a suitable AC power flow model has been set up and used to compute six different PTDF matrices M_{PTDF} as described above. The grid model used is based on the current grid extended by the expansion projects until 2030 listed in the TYNDP (ENTSO-E 2016b) that apply for the regions considered. Then, for each hour, one of these PTDF matrices is selected to be applied in REMix based on a similarity metric between the load and wind feed-in data in REMix for that hour and the corresponding data used for the PTDF computations.

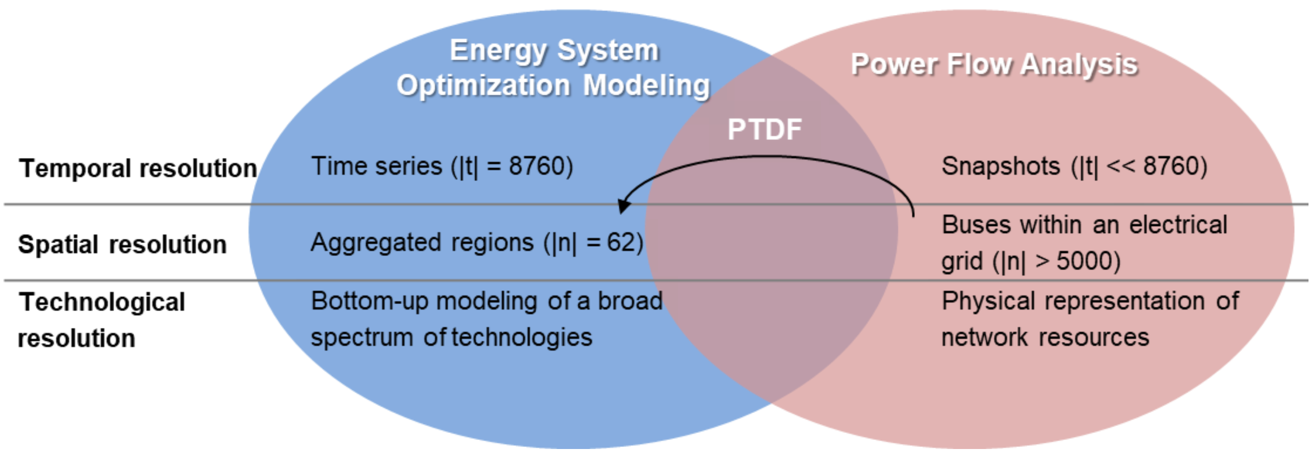

Figure 3: Modeling approaches for the application of Power Flow Distribution Factors

2.2.6 Costs for expanding cross-border transmission lines

Apart from power flow in an existing AC transmission grid, REMix also considers AC grid expansion in order to increase interconnection capacities between regions. This can be considered as a flexibility option to balance load and demand in competition with other flexibility options within regions. Note that HVDC connections are also considered in REMix but treated differently, as the power flow over these can be controlled independently.

In order to consider AC grid expansion, it is necessary to estimate the related cost. We consider both adding capacity to existing connections as well as the construction of new connections. For adding capacity to existing connections, we use cost assumptions from (Feix et al. 2015) and (Dena 2010). For new connections, a common assumption is to assume a fixed cost per length and capacity. However, a further decisive factor is the kind of terrain to be overcome. Taking this factor into account leads to different specific costs for each interconnection. To obtain these, an altitude model has been developed covering the complete area of the transmission system model which is based on satellite data from the Shuttle Radar Topography Mission (Deutsches Zentrum fuer Luft- und Raumfahrt e. V. (DLR) 2017). The topography data are classified into four clusters in order to obtain a sufficiently exact categorization of the terrain type between regions. Based on a meta-study on (estimated) costs for grid expansion projects, specific costs for each terrain type have been derived. Finally, the grid expansion measures are factorized with a terrain dependent detour factor due to the fact that the length of a line is longer than the linear distance between both ends. For each pair of neighboring regions, two transmission grid substations that are suitable for interconnection are selected. The direct line between the geo-coordinates of these substations then is used to determine the distance for each terrain type, allowing for a computation of the total cost of the new interconnection. Table 2 lists those total costs for a standard overhead line type (562-AL1/49-ST1A) with a maximum capacity of about 5.5 GW.(Open Power System Data 2017)

Table 2: Topography dependent specific grid expansion costs for an additional interconnection capacity of 5.5 GW

Terrain type	Height above sea level in m	Specific cost in €/km	Detour factor
High mountains	$h \geq 1.200$	1 432·10^3	1.4
Hills and low mountains	$600 \leq h < 1.200$	1 037·10^3	1.4
Plains	$0 < h < 600$	833.5·10^3	1.4
Sea	$h < 0$	5.000·10^3	1.3

2.3 Scenarios

In order to answer our three research questions, we define three groups of scenarios. The first group aims to find the transmission system investments within a multitude of other flexibility options under the assumption of different CO_2 caps. The second group focuses on societal acceptance on different energy technologies, also including transmission. Finally, the third group consists of different ways of modeling power flows in the grid. Table 3 provides a qualitative overview of the key assumptions applied to each element of the scenario groups. The scenarios are based on consistent assumptions and thus, can be compared easily. They have the following in common. They couple the heat and power sector (i.e. boilers and heat pumps), they allow for curtailment of renewable electricity generation, and they plan for open cycle gas turbines as backup. The full list of examined scenarios and the corresponding quantifiable differences are compiled in Table 5 and are explained in the following.

Table 3: Qualitative specification of scenarios and model parameterization

Type	Label	Qualitative definition
Group 1: Flexibility and CO_2 emission caps	*Ref*	Reference case: no flexibility options considered except open cycle gas turbines and curtailment of renewable power generation.
	Base	Equal to *Ref*, but with a broad variety of load balancing options (grid and storage expansion, controlled charging of EVs, demand-side management).
	55%	Reduction of 55% of CO_2 emissions in the power sector compared to 1990.
	85%	Reduction of 85% of CO_2 emissions in the power sector compared to 1990.
Group 1s:	*eHighway*	Sensitivity power generators: Equal to *85%*, but with significant differences in the installed generation mix.
Group 2a: Technology acceptance	*CSP*	Equal to *Base-85%*, but with electricity imports from CSP plants in North Africa (including HVDC point-to-point transmission lines).
	H_2	Equal to *Base-85%*, but with H_2 generation and additional power demand.
	CSP&H_2	Equal to *Base-85%*, but with H_2 generation and additional power demand and with electricity imports from North Africa (including HVDC point-to-point

		transmission lines).
Group 2b: Transmission acceptance	*Trend*	All major TYNDP projects implemented. Current structure of transmission and distribution grids is kept, new expansion in high- and extra-high-voltage network.
	Smart	Increased self-sufficiency in all countries: Capacity expansion is allowed to meet local demand. Smart grids are widely implemented while transmission projects are limited (projects with the status "under consideration" from TYNDP 2016 are excluded). Transmission expansion is exclusively realized with underground cables.
	Protest	Transmission expansion is limited due to low public acceptance and only realized with underground cables. Other large-scale technologies (e.g. cavern storage) cannot be implemented either.
Group 2s:	*2007-2012*	Sensitivity weather: Equal to *H_2:Smart*, but with different weather years and load profiles (years 2007 to 2012).
Group 3: Modeling of transmission system	*Transport model*	Power transmission is modeled as economic transport.
	DC power flow	DC power flow modeling: equal to *Transport model*, but with additional power flow distribution constraints depending on effective transmission line susceptances.
	PTDF	Modelling with Power Transfer Distribution Factors derived from a preceding AC power flow simulations: equal to DC power flow, but with profiles of PTDFs.
Group 3s:	*PTDF_LC*	Sensitivity grid expansion costs: Equal to *PTDF*, but transmission line costs consider the topography for the interconnections of cross-border substations.

*****TYNDP: Ten-Year Network Development Plan 2016

2.3.1 Scenario group 1: Load balancing technologies under greenhouse gas mitigation targets

In order to respond to the question of the role of power transmission in the context of several other available flexibility technologies, we define a "Base" case scenario for each of the two GHG mitigation targets determined in subsection 2.2.4. In addition, an equivalent scenario, "Ref" is set up for gaining the maximum demand on backup generation capacities for each GHG emission target. This backup demand is to be reduced by deploying load balancing technologies. In other words, this scenario (in which system adequacy is achieved solely by gas turbines) is designed as benchmark to be compared to all other scenarios. The scenario *eHighway* is a sensitivity with respect to the distribution and composition of the European power plant portfolio. In contrast to all other scenarios, the installed capacities used as a starting point in modeling step 1 stem from the scenario "Small and Local" of the e-Highway 2050 project (Vafeas, Pagano, and Peirano 2014).

2.3.2 Scenario group 2: Roles of power transmission in future energy systems

The second group of scenarios captures narratives on technological preferences of large-scale energy projects, including CSP, H_2, and transmission. These narratives are all characterized by the generation mix determined in level 1. The first narrative, "CSP", allows power imports from CSP plants in Africa. It extends the *Base-85%* scenario by optimizing CSP capacities in Morocco, Tunisia and Algeria including candidate transmission lines (high voltage direct current, HVDC) to Europe. The second narrative, *H_2* allows hydrogen technologies (electrolyzers and hydrogen storage) to be widely deployed. Note that compared to battery electric vehicles, synthetic fuels have worse well-to-wheel efficiencies which increases the electricity demand significantly in the case of hydrogen use. *CSP&H_2* combines both solar power imports and hydrogen infrastructures.

In terms of preferences on the transmission system, we define three grid scenarios: *Trend*, *Protest*, *Smart*. These make different assumptions on permissible capacity expansion and on the type of lines to be deployed (overhead or underground) (see Table 3 and Table 5). The "Protest" scenario is extreme in the sense that it assumes that any large-scale technology is also to be avoided. Finally, to account for different weather years, we defined an additional set of scenarios varying the renewable power generation and demand profiles. These are labeled by the year of the underlying empirical data.

2.3.3 Scenario group 3: Power flow modeling in energy system optimization models

In order to investigate the impact of different power flow modeling approaches on the final recommendations on transmission investments and on the mix of load balancing technologies, we define four scenarios. The first, *Transport model*, relies on an economic transport model. Here, the power flows in the grid, resulting from surpluses and deficits of nodal power injections are only restricted by the transfer capabilities of the transmission lines. The second, *DC power flow*, adds voltage angles to the model to restrict the distribution of power flows according to the physical parameters of the transmission lines (distance-depended line susceptances). The scenario *PTDF* denotes lineareized power flow computation approach for which the power transfer distribution factors (PTDFs) are determined in preceding AC power flow simulations of the fully-resolved transmission network. Based on the PTDF matrices of the six analyzed grid situations (see section 2.2.5) we determine hourly PTDF profiles as additional input for REMix. The fourth and last, *PTDF_LC* uses the same constraints as the previous one, but computes more specific costs for all cross-border transmission lines (as described in subsection 2.2.6) instead of using coarse distance-estimates based on the aggregated model.

Table 4: Implementation of power flow approaches in REMix: transport model, DC power flow and PTDF.

Transport model	$\boldsymbol{P}(t,n) = \sum_{l \in \mathcal{L}} K^T(n,l) \cdot \boldsymbol{P_f}(t,l),$	$\forall t \in \mathcal{T}, \forall n \in \mathcal{N}$	**Equation 4**
DC power flow	$\boldsymbol{P_f}(t,l) = \sum_{l' \in \mathcal{L}} B_{\mathrm{diag}}(l,l') \cdot \sum_{n \in \mathcal{N}} K(l',n) \cdot \boldsymbol{\vartheta}(t,n),$	$\forall t \in \mathcal{T}, \forall l \in \mathcal{L}$	**Equation 5**
	$\boldsymbol{P}(t,n) = \sum_{n' \in \mathcal{N}} B(n,n') \cdot \boldsymbol{\vartheta}(t,n'),$	$\forall t \in \mathcal{T}, \forall n \in \mathcal{N}$	**Equation 6**
	$\sum_{n \in \mathcal{N}} \boldsymbol{P}(t,n) = 0,$	$\forall t \in \mathcal{T}$	**Equation 7**
PTDF	$\boldsymbol{P}_f(t,l) = P_{f0}(t,l) + \sum_{n \in \mathcal{N}} M_{\mathrm{PTDF}}(t,l,n) \cdot [P_0(t,n) + \boldsymbol{P}(t,n)],$	$\forall t \in \mathcal{T}, \forall l \in \mathcal{L}$	**Equation 8**

With sets: $\mathcal{T}$: time steps, $\mathcal{N}$: regions, $\mathcal{L}$: transmission lines; variables: $\boldsymbol{P_f}(t,l)$: power flow, $\boldsymbol{P}(t,n)$: nodal power balance, $\boldsymbol{\vartheta}(t,n)$: voltage angle; parameters: $K(l,n)$: incidence matrix, $B_{\mathrm{diag}}(l,l')$: diagonal matrix of line susceptances, $B(n,n')$: nodal susceptance matrix (imaginary part of nodal admittance matrix), $P_{f0}(l,n)$: power flow offset, $M_{\mathrm{PTDF}}(t,l,n)$: matrix of power transfer distribution factors

The first three scenarios result in the equations provided in Table 4. For the sake of clarity we simplified the notation (e.g. planning year or transmission technology sets are neglected) compared to the one implemented in REMix.

Table 5: Specification of scenarios and model parameterization

Scenario label	CO_2 cap in million tons	Annual energy demand in PWh	Set of load balancing measures[1]	Expansion of large-scale storage (Pumped hydro, Compressed air)	Expansion of CSP in North Africa	H_2 vehicles, power reconversion, capacity expansion of electrolyzers and H_2 storage	Expansion of H_2 caverns	Specific grid expansion costs for HVAC in €/km/GW	Specific grid expansion costs for HVDC in k€/km/GW	Upper bound (2 GW) on additional transmission capacity	Full implementation of TYNDP 2016	Expansion of wind onshore and PV
55%-Ref	268	4.04	×	×	×	×	×	-	-	×	✓	×
85%-Ref	736	4.06	×	×	×	×	×	-	-	×	✓	×
eHighway-Ref	736	4.11	×	×	×	×	×	-	-	×	✓	×
55%-Base:Trend	268	4.04	✓	✓	×	×	×	346	375	×	✓	×
55%-Base:PTDF	268	4.04	✓	✓	×	×	×	346	375	×	✓	×
55%-Base:PTDF_LC	268	4.04	✓	✓	×	×	×	346	375	×	✓	×
55%-Base:Transport model	268	4.04	✓	✓	×	×	×	346	375	×	✓	×
85%-Base:Trend	736	4.06	✓	✓	×	×	×	346	375	×	✓	×
85%-Base:Protest	736	4.06	✓	✓	×	×	×	3460	2000	✓	✓	×
85%-Base:Smart	736	4.06	✓	×	×	×	×	3460	2000	✓	×	✓
eHighway	736	4.11	✓	✓	×	×	×	346	375	×	✓	×
85%-Base:PTDF	736	4.06	✓	✓	×	×	×	346	375	×	✓	×
85%-Base:PTDF_LC	736	4.06	✓	✓	×	×	×	346	375	×	✓	×
85%-Base:Transport model	736	4.06	✓	✓	×	×	×	346	375	×	✓	×
CSP:Trend	736	4.06	✓	✓	✓	×	×	346	375	×	✓	×
CSP:Protest	736	4.06	✓	✓	✓	×	×	3460	2000	✓	✓	×
CSP:Smart	736	4.06	✓	×	✓	×	×	3460	2000	✓	×	✓
CSP&H_2:Trend	736	4.50	✓	✓	✓	✓	✓	346	375	×	✓	×
CSP&H_2:Protest	736	4.50	✓	✓	✓	✓	×	3460	2000	✓	✓	×
CSP&H_2:Smart	736	4.50	✓	×	✓	✓	✓	3460	2000	✓	×	✓
H_2:Trend	736	4.49	✓	✓	×	✓	✓	346	375	×	✓	×
H_2:Protest	736	4.49	✓	✓	×	✓	×	3460	2000	✓	✓	✓
H_2:Smart2006	736	4.49	✓	×	×	✓	✓	3460	2000	✓	×	✓
H_2:Smart2007	736	4.49	✓	×	×	✓	✓	3460	2000	✓	×	✓
H_2:Smart2008	736	4.49	✓	×	×	✓	✓	3460	2000	✓	×	✓
H_2:Smart2009	736	4.49	✓	×	×	✓	✓	3460	2000	✓	×	✓
H_2:Smart2010	736	4.49	✓	×	×	✓	✓	3460	2000	✓	×	✓
H_2:Smart2011	736	4.49	✓	×	×	✓	✓	3460	2000	✓	×	✓
H_2:Smart2012	736	4.49	✓	×	×	✓	✓	3460	2000	✓	×	✓

[1]General load balancing measures: capacity expansion of grid transfer capabilities (HVAC & HVDC), capacity expansion of battery (lithium-ion, vanadium-redox-flow) & heat storage, demand-side management, controlled charging of electric vehicles

3 Results

This section is divided in three parts. The first part presents the contribution of power transmission under CO_2 emission constraints and in the context of other load balancing technologies to cost-efficiency and system adequacy. The second provides details on this contribution with a special focus on a broader set of scenarios. The third one shows the implications of different power flow modeling approaches on the final investment recommendations of transmission infrastructure. Note that all figures shown have their corresponding data tables in the Supplementary Material.

Before getting into these subsections, we provide the necessary background to understand the main trends that will be laid out. Recall that we optimized in two steps, in which the found generation capacities of the first step serve as basis for the second step which plans the flexibility options with more detail. Figure 4 shows these generation mixes (resulting from the first level) for the different narratives. Scenarios *55%-Ref*, *85%-Ref* and *eHighway-Ref* are not depicted because their capacities are identical to the corresponding *Base* scenarios.

When inspecting the capacities of Figure 4, the following aspects become clear. One is that the installed capacities in the *85%* scenarios are significantly higher than in the *55%* scenario (at least 1600 versus 1500 GW). Another is that in H_2 scenarios the capacities are up to 13% larger (compared to *Base* or *CSP*) given the correspondingly higher energy demand. And, finally, the *eHighway* scenario shows even larger capacities. This is a direct result of the prescribed power plant portfolio that is even larger than in the other scenarios where the majority of generation capacities are optimized. For further insights into the outcome of modeling step 1, the country-specific power generation mixes can be consulted in the Supplementary Material.

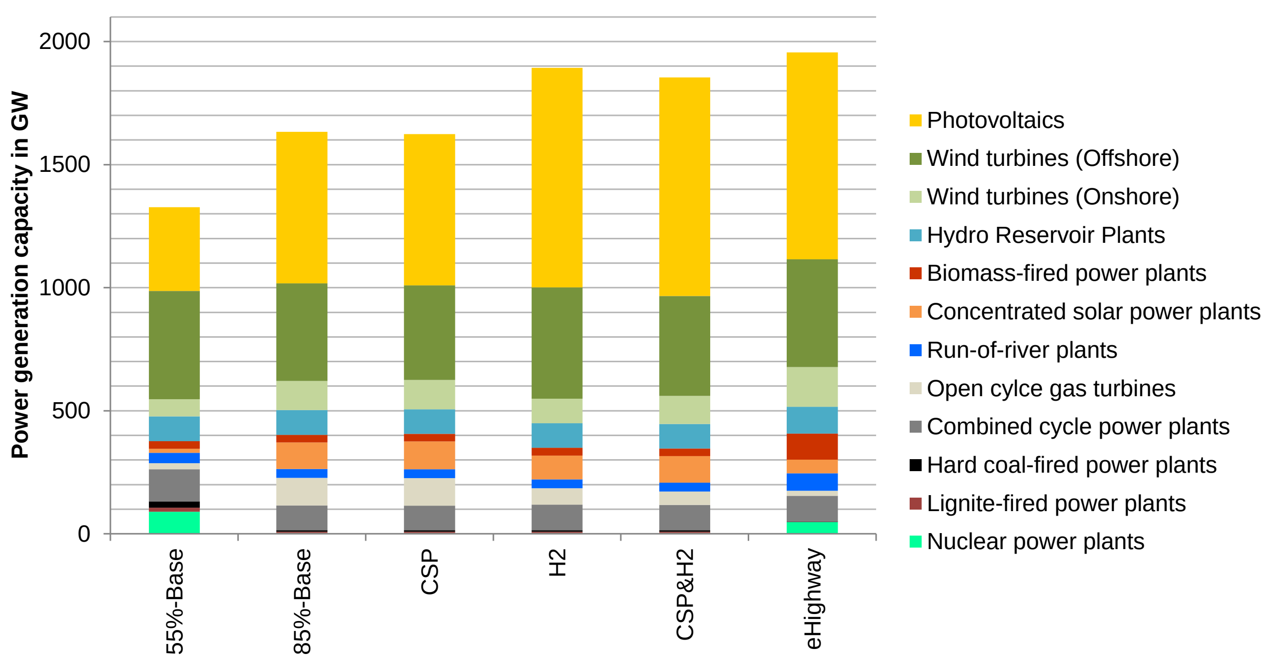

Figure 4: Power generation mix of different European scenario narratives

3.1 Contribution of power transmission and other flexibility options to system cost and adequacy

Here, we will analyze how transmission in the context of many other flexibility options available contributes to system adequacy and costs. Two kinds of scenarios are distinguished: the reference cases (where additional flexibility is only provided by backup capacities) and those where almost all conceivable technologies for load balancing are available (the simplest of those being “Base”).

Recall that we measure system adequacy as the reduction in backup capacity (which here is gas turbine capacity). In other words, the lower the gas turbine capacity (compared to a *Ref* scenario), the higher the contribution of all flexibility options to system adequacy. In terms of costs, we measure the cost difference between a given scenario and the *Ref-85%* scenario. They are composed of all costs for supply of fossil fuels, emission allowances, variable and fixed costs for operation and maintenance as well as annuities of both model-exogenously and model-endogenously installed capacities.

Figure 5 compares the backup capacity (x-axis) with cost difference (y-axis) for all scenarios that differ in their generation mix resulting from modeling step 1. *85%-Ref* has, per design, the highest backup capacity. These 242 GW serve as benchmark for all other scenarios. In contrast, *85%-Base*, for example, has a backup capacity of 161 GW, which implies a contribution to system adequacy of 81 GW. Such contributions are also observed in all other scenario-pairs: 75 GW (in *55%-Ref* vs. *55%-Base*), and 165 GW (in *eHighway-Ref* vs. *eHighway*). Hence, it can be concluded that, the presence of flexibility options systematically contributes to adequacy.

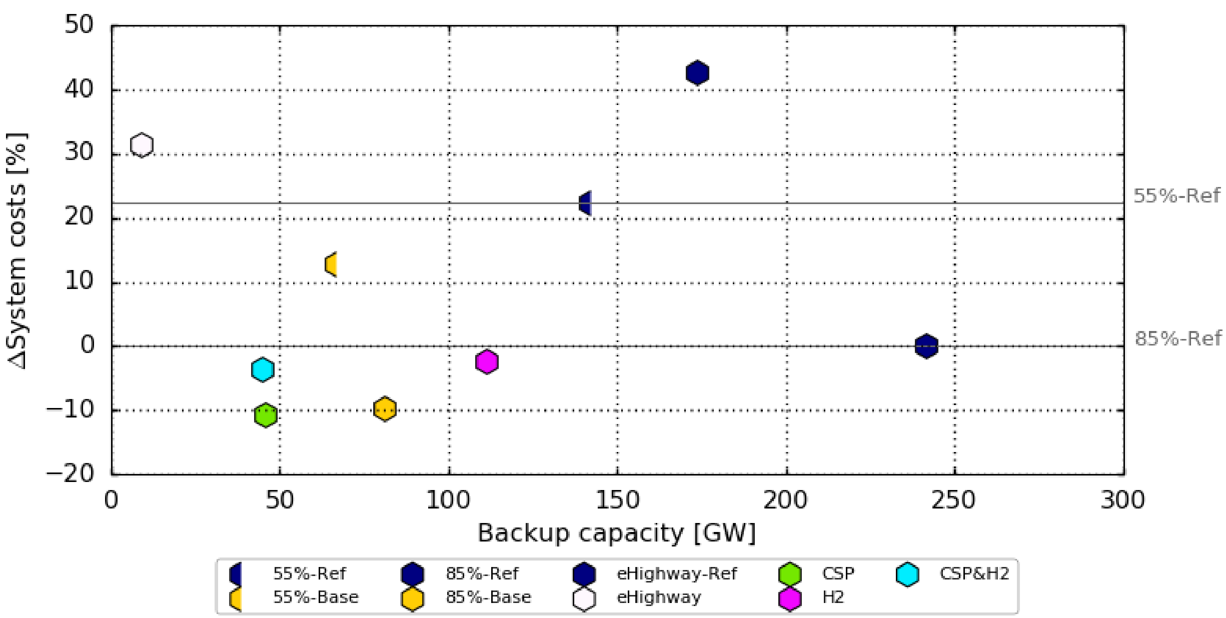

Figure 5: Energy costs reduction (relative to *85%-Ref*, with system costs of 390 Bn. €) and system adequacy for different European scenario narratives.

In terms of cost[1] reduction, the differences between the scenario-pairs (e.g. *55%-Ref* versus *55%-Base*) are significant. The observed system cost decreases are about 10% for each of the pairs *55%*, *85%* and *eHighway*. Such high numbers confirm the relevance of sector coupling, as well as directing modeling efforts towards a better understanding of its role in future energy systems.

Although the assumed hydrogen infrastructure provides significant flexibility to the system, resulting in low backup capacities, scenario H_2 shows a relatively small cost reduction, less than 2.5%. This effect can be traced back to the higher annual electricity demand of a hydrogen consuming transport sector. Both scenarios considering solar power imports from North Africa (*CSP* and *CSP&*H_2) show a strong substitution of backup capacities. This is due to their capability to provide additional power generation capacity. Scenario *CSP* achieves the lowest system costs of 348 Bn. €. Again, such positive findings motivate to focus on more CSP studies.

As comment on consistency, note that eHighway scenarios show to be more expensive (than our reference case, *85%-Ref*). This relates to the prescription of a power plant portfolio that is simply more expensive than the one resulting from our cost minimization. Something similar happens for the 55% scenarios (*Ref* and *Base*). Here, the annuities from the existing (fossil-based) park are suboptimal in contrast to the alternative of investing in optimally sited renewable power generators as it happens in the other scenarios.

Next we will take a closer look on grid expansion. Figure 6 shows the investments made for energy storage (x-axis) and power transmission (y-axis) for the scenarios from group 1 and group 2 (recall Table 3). In this regard, note that all scenarios labelled as *Trend* in Figure 6 are equivalent to those shown in Figure 5. In Figure 6, the value next to each marker shows the ratio of grid to storage investments. It is striking that this ratio is always greater than one, which means that in all scenarios investment in grid expansion is greater than in storage expansion. The minimum ratio is approximately two, and occurs in scenarios with limited and more expensive grids (*Smart* and *Protest*). The highest ratio is 18 and is observed in *CSP&*H_2*:Protest* with grid investments of 18.2 Bn. €. Here, two factors come together. First, the massive solar power imports from Africa require the corresponding lengthy HVDC transmission lines. And second, large storage facilities are inadmissible in *Protest* scenarios which limits storage investments and favor transmission as a direct consequence.

[1] Note that in our results evaluation the total costs for energy supply are different from the objective value of optimization problem. They are composed of all costs for supply of fossil fuels, emission allowances, variable and fixed costs for operation and maintenance as well as annuities of both model-exogenously and model-endogenously installed capacities.

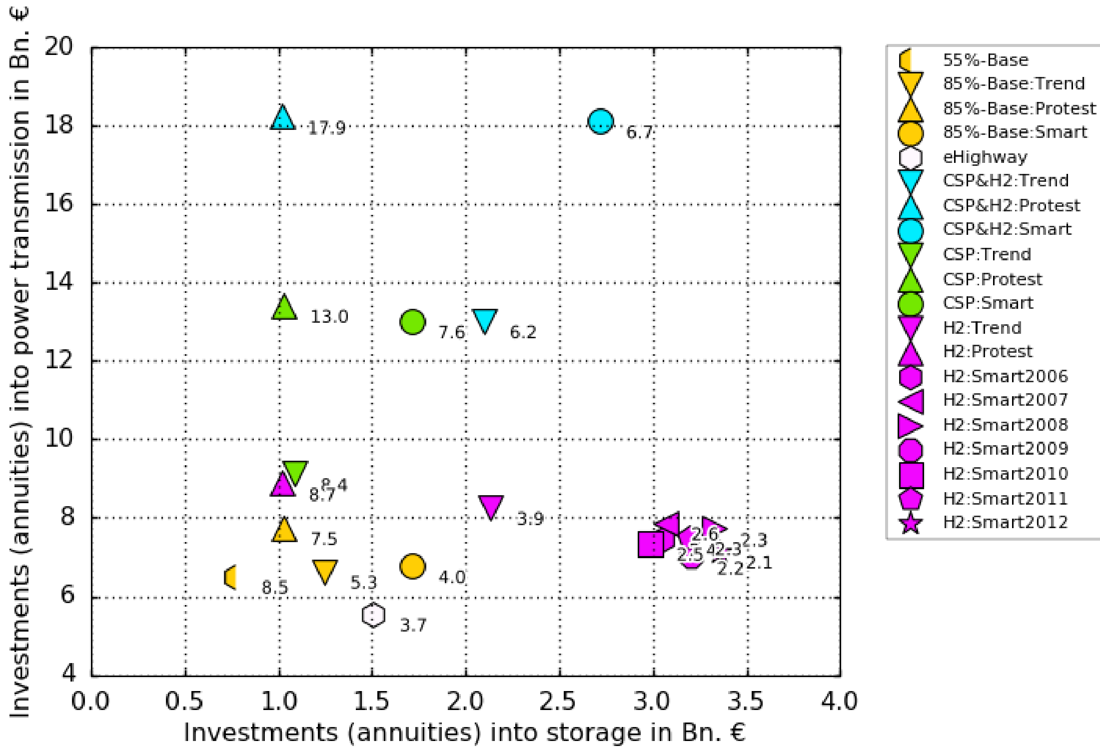

Figure 6: Investments for expanding power transmission (y-axes) versus storage (x-axes) and ratio between these investments (labels next to the markers). Storage in CSP plants is neglected.

The smallest grid investments occur in scenarios that consider neither solar imports nor a hydrogen system, *eHighway* shows the smallest value of 5.6 Bn. €. However, recalling Figure 5, this scenario presents the highest system costs. Here, a more extensive power generation park provides the flexibility. The lowest investments in storage are observed for the *Protest* scenarios, (all of about 1 Bn. €) where only heat storage (e.g. in CHP plants) is deployed.

In general, storage requirements relate to the need of matching renewable generation with demand (fluctuations of the residual load), both highly dependent on weather. To further underpin the statement that grid investments dominate storage investments, we took the scenarios with the largest storage investments (*H_2:Smart*) and subjected them to different weather years. The results are the pink markers in Figure 6. They all consistently show grid to storage ratios around two, with absolute investments between 3 and 3.5 Bn. €.

In short, the many available flexibility options (including sector coupling and transmission) contribute strongly (from about 80 to 160 GW) to system adequacy in all scenarios. In terms of cost, they achieve a significant reduction of ten percent points. Both findings underline the relevance of those flexibility options on the road towards highly renewable systems. Finally, even in the context of many available flexibility options, investments in transmission are significantly higher (at least by a factor of two) than in storage.

3.2 Power transmission in future energy systems with different technological preferences

This section shows how different scenarios of technological preferences impact the resulting investment recommendations. We will first focus on the scenarios of CSP imports and H_2 generation (scenario set 2a), followed by scenarios of grid acceptance (scenario set 2b). The following indicators are used to assess the scenarios:

- Normalized capacity factor of a given technology [CF%]
- Installed power capacity [GW] /energy storage capacity [GWh]
- Curtailment of wind and PV energy relative to the annual potential [%]
- Grid expansion [TW km]
- CO_2 emissions from power and heat sector[2] [Mio. t]
- Total installed wind and PV capacity [GW][3].

These indicators are plotted in form of a radar (or spider) diagram in Figure 7. Scenarios with preferences for CSP imports and H_2 generation are plotted on the left compared to *Base* (Figure 7-a) and those related to grid preferences (*Trend*, *Smart*, *Protest*) are compared on the right (Figure 7-b). Note that these grid scenarios were computed for all *CSP* and H_2 scenarios but the final results were very similar. For this reason, the grid scenarios are only shown for *CSP&H₂*.We will start by analyzing the implications of each technology, under the scenarios considered, to then derive the implications for transmission.

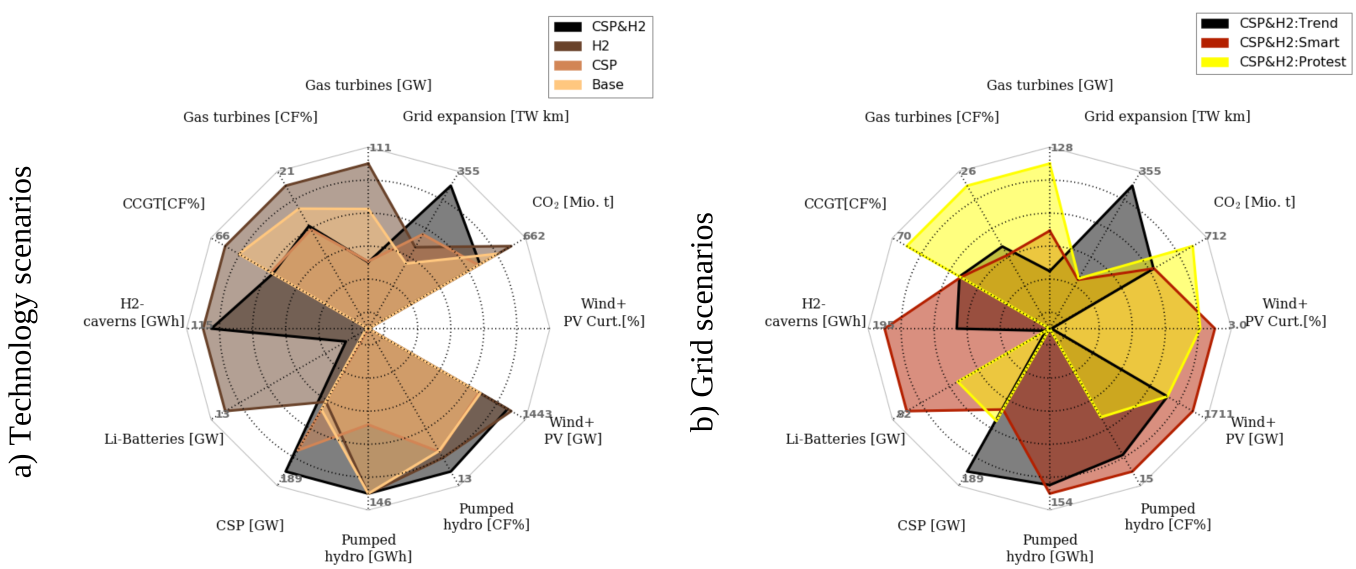

Figure 7: Key indicators for technology scenarios (left) and grid scenarios (right) for 85% CO_2 reduction targets.

In terms of storage, vanadium-redox-flow batteries and adiabatic compressed air storage do not show investments in any of the scenarios, which is why they are absent in Figure 7. By definition, only H_2

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[2] CO_2GHG emissions of the transport sector are not considered in the applied modeling approach and thus not explicitly provided.

[3] Recall that opposed to all other outputs, the wind and PV capacities are fixed results from modeling step 1 (and can only be increased in the scenario *Smart*)

scenarios can deploy hydrogen caverns. The obtained 175 GWh across Europe are of the same order of magnitude as pumped hydro plants (146 GWh). Lithium-ion batteries only occur for scenarios with hydrogen infrastructure. Their absence in other scenarios might relate to the availability of other short-term low-cost flexibility (e.g. controlled charging of electric vehicles or demand-side management). Nevertheless, in the H_2 scenario, investments into lithium-ion batteries are also surprising: Instead of to-be-expected hydrogen storage tanks, lithium-ion batteries appear as attractive short-term option to complement the long-term hydrogen technologies.

Clearly, the most significant investments into CSP plants happen for *CSP* and *CSP&*H_2 scenarios. Here, CSP power is imported from North Africa. However, CSP is also present in the other scenarios (H_2 and *Base*) where it serves for covering local electricity demand in South Europe and North Africa (as result from modeling step 1).

With regard to CO_2 emissions, H_2 scenarios shows higher emissions reaching 662 Mio.t. This effect is due to the additional electricity demand from hydrogen technologies, which cannot be fully covered by emission-free power generation under the assumptions of the scenario. Hydrogen is rather produced from "grey electricity" (high utilization of gas power plants). In contrast to the H_2 scenario, solar power imports reduce emissions by 15 and 22% for scenarios *CSP* and H_2*&CSP*, respectively.

The required grid investments are lowest in the base case and gradually grow in the scenarios H_2, CSP, and H_2*&CSP*. The H_2 scenario triggers 15% more transmission infrastructure to connect the spatially distributed caverns across Europe. In the CSP scenario, the 30% higher demand of transmission is directly related to enabling solar power imports from North Africa. Finally, the massive deployment of H_2*&CSP* combines both balancing requirements, climaxing in 80% of more transmission systems as compared to the base case.

In terms of grid preference scenarios, the right part of Figure 7 shows that there are three alternative configurations for load balancing:

1. *Trend* (black): Unrestricted grid expansion allows for full integration of power generation from wind and PV, while the need for gas power plants and cavern storage is comparably low. Lithium-ion battries and curtailment are absent. The CO_2 emissions are in the desired range.
2. *Smart* (yellow): Restrictions on grid expansion are compensated by a broad spectrum of additional measures – more capacities from wind turbines and PV as well as caverns, lithium-ion batteries and pumped hydro plants across all scenarios. Curtailed renewable energy is high (3%). CO_2 emissions are as in Trend but at 1.5 to 2.5% higher total system costs (see Table 13 of the Supplementary Material).
3. *Protest* (red): Restrictions on grid expansion as well as the exclusion of large-scale storage lead to more gas power plants. Consequently, emissions miss the -85% target.

Besides for *CSP&*H_2, these characteristic relations of the different indicators can be also observed for the grid scenarios (*Trend*, *Smart*, *Protest*), if combined with the other narratives (*Base*, *CSP or* H_2). For this reason the appropriate plots are not reported.

To summarize this subsection, we observed that transmission expansion is a significant constituent of all scenarios. If new transmission is realized by underground cables (*Smart*), less transmission is deployed. This is compensated by deploying other alternative flexibility technologies –especially all types of storage–, leading to higher costs and curtailments. If other large-scale projects, including caverns, are also to be avoided (*Protest*), the amount of transmission remains constant, with the flexibility provided only by gas technologies. Massively deploying CSP and H_2 calls for larger transmission systems. If the system evolves towards H_2 only, higher system costs and additional CO_2 emissions (for renewable shares below 100%) are to be expected. For combined CSP and H_2 futures, those emissions can be reduced, while the need for grid expansion climaxes.

3.3 Implications of power flow modeling approaches on system configuration and operation

This subsection evaluates how three different approaches for power flow modeling (*Transport model*, *DC power flow*, *PTDF*) impact the investment decisions and system operation of a spatially aggregated ESOM. In addition, a fourth scenario (*PTDF_LC*) tests the influence of widely differing cost estimations for the expansion of grid transfer capabilities (as described in subsection 2.2.6**Fehler! Verweisquelle konnte nicht gefunden werden.**).

In Figure 8, the resulting key indicators (as presented in section 3.2) are shown for the different grid modelling approaches (using *85%-Base* as underlying scenario). It is striking that with the exception of investments in grid expansion and in pumped hydro, all curves show an almost congruent shape. Grid investments change by around 5% when using constant length specific investment costs (as in *Transport model*, *DC-Power-Flow* and *PTDF*), whereas the impact on the other indicators is negligible (deviations below 1%). These findings also hold when solving for scenarios with a *55%* reduction target (not shown here). That grid investments would be affected was expected but that most other technologies are indifferent is surprising.

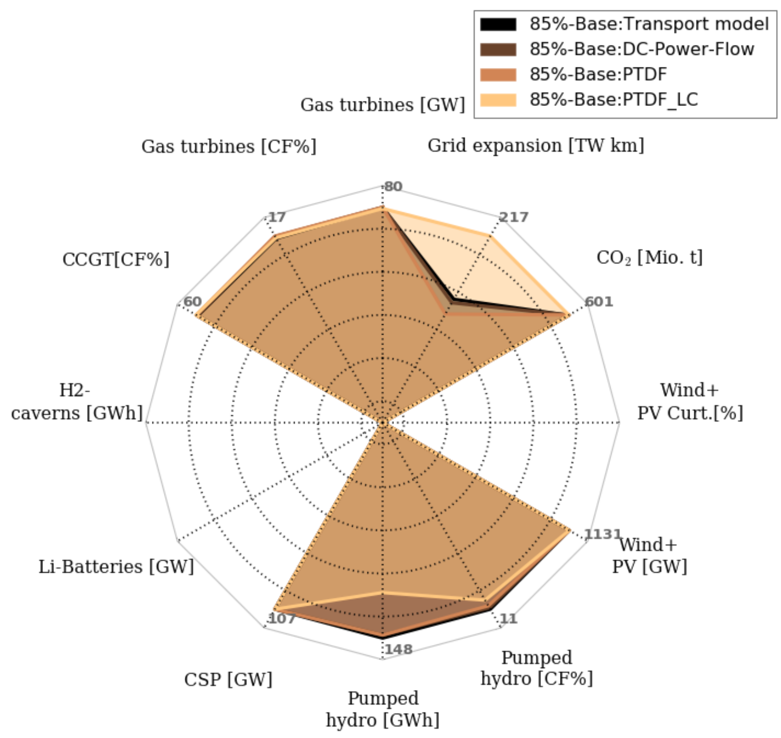

Figure 8: Key indicators comparing *85%-Base* scenarios using different approaches for modeling power flows.

The most significant differences are observed for *PTDF_LC*. Recall that here we switch from simple length-specific to line-specific investment costs. For most of the candidate transmission lines, this leads to a decrease of costs which explains the additional grid expansion. This is due to the fact that only the costs of upgrading the transmission link between the two nearest substations of cross-border transmission lines are taken into account while any follow-up costs for upgrading feeder lines are completely ignored. Opposed to that, in the case of length-specific costs (applied to all other scenarios shown in Figure 8), this aspect is approximated by estimating distances between the region centers as lengths of modeled transmission lines.

Remarkably, the significant grid expansion in *PTDF_LC* displaces only 30 GWh of pumped hydro power plants in Spain (nor that the location cannot be read from the figure).

Based on the observations above, most system-wide indicators are not impacted by the way power flows are modeled. In addition, Figure 9 provides additional insight into the spatial distribution of grid expansion. It details the grid investments for the majority of analyzed scenarios (x-axes) and countries (y-axes). The marker size corresponds to the grid investments relative to system costs for the different scenario sets. The left refers to the different grid modelling approaches. The right group shows the scenarios related the technology preference scenarios (scenario set 2a and 2b).

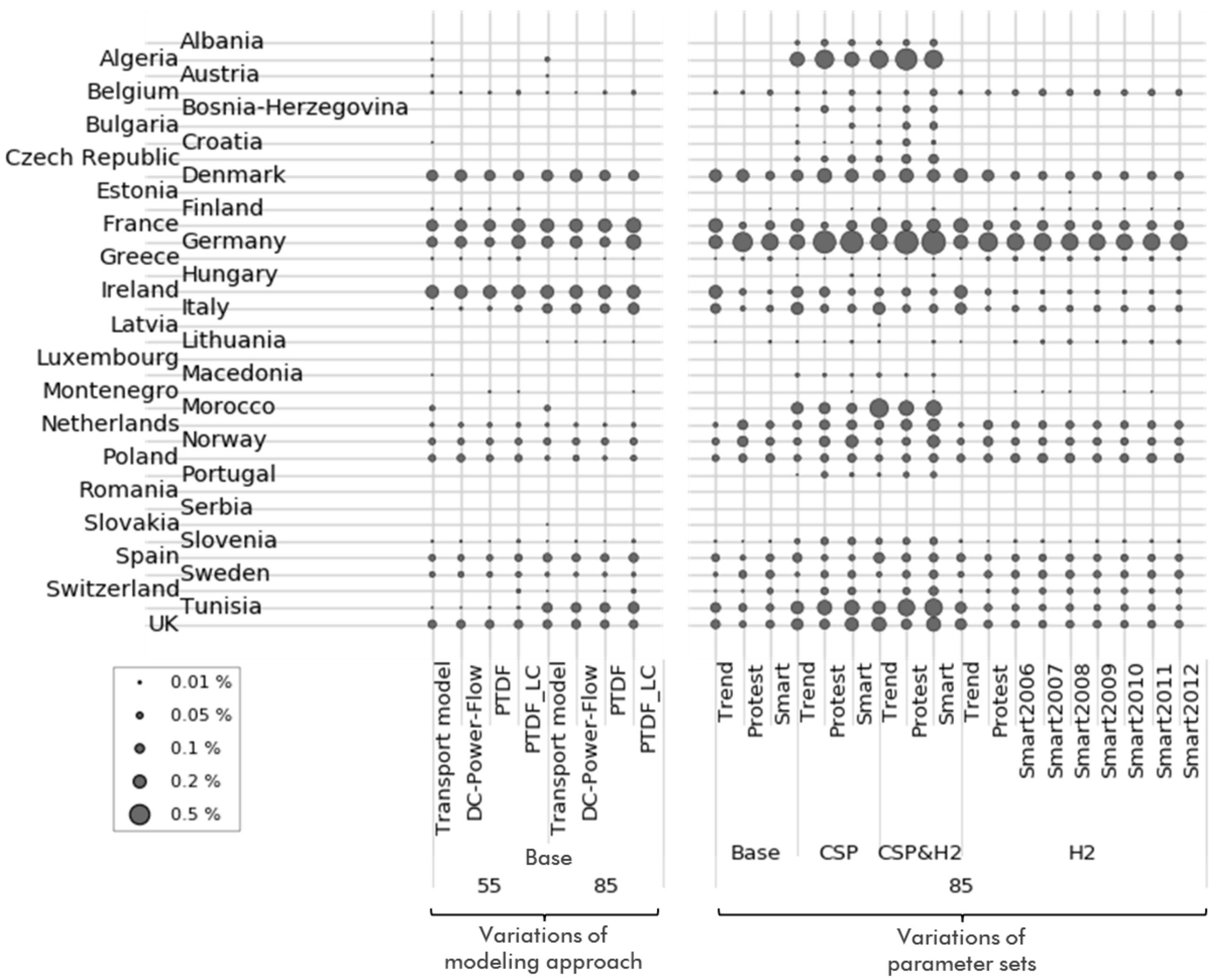

Figure 9: Investments into transmission infrastructures relative to total system costs across all considered scenarios and countries.

Taking a look at the left group of Figure 9, we see how grid investments are virtually constant for all ways of grid-modelling (*Transport model*, *DC-Power-Flow*, *PTDF)* also at different cost assumptions (*PTDF_LC*). There are only small differences when using the transport model, compared to the more complex (and restrictive) counterparts. This confirms what we found earlier:

the approach for modeling power flows has only a minor effect on the final recommendations derivable from an spatially aggregated ESOM. This holds for both *55%* and *85%* emission targets.

These deviations are even more insignificant, when compared to the scenarios to the right of Figure 9 that show larger impacts for the technology scenarios. . Here, especially differences in regional grid investments occur due to considering solar power imports as these are directly related to new HVDC lines for point-to-point power transmission lines from North Africa to Europe. Furthermore, the variation across different weather input data from 2006 to 2012 (*H_2:Smart*) also results in no differences in grid investments. In other words, these are . This indicates that grid investments are comparably robust against varying the availability of power generation form VRES among several annual periods.

In short, we found that the three different methodologies of how to determine the distribution of power flows (*Transport model*, *DC-Power-Flow*, *PTDF*) result in negligibly differences of most evaluated key indicators. However, investment into power transmission does change if line-specific as opposed to length-specific costs are used. In contrast, the impact from different technology-preference scenarios on the spatial distribution of transmission investments is much more significant.

4 Discussion

This study examines the role of power transmission in the future energy system of Europe. We further investigated the modeling of power flows within an advanced energy system optimization model (REMix) and applied it to a broad range of scenarios. First, we discuss the optimal sizes of new transmission lines, among a wide range of other flexibility options. Second, in different scenarios, we evaluate how preferences of certain energy technologies (hydrogen (H_2), concentrated solar power (CSP) imports, and power transmission) impact the investment decisions related to transmission grid expansion. And third, we assess how different ways of power flow modeling affect these decisions.

4.1 Power transmission contributes significantly to cost efficiency and system adequacy

New transmission infrastructure significantly contributes to system adequacy which is measured as the reduction of required back-up capacity. Transmission investments at least double storage investments. Nevertheless, storage is still needed in all scenarios, which confirms the complementarity of these two technologies. But even in the context of other flexibility technologies (including sector coupling), investing in transmission is more cost-efficient for all scenarios evaluated. These findings are in line with (Brown et al. 2018) who also conclude that electricity transmission is a robust measure for cost-efficient energy supply across many scenarios. Nevertheless, in practice, transmission faces non-economic challenges such as social opposition that impede reaching the cost-optimal solution.

4.2 Technological preferences strongly impact the need for flexibilities

If grid expansion is restricted the demand for both additional power generators and alternative load balancing technologies grows strongly. This also leads to an increase of 9% (see Supplementary Material) in system costs and of 3% in curtailment. The load balancing capabilities are mainly provided by a combination of additional renewable power generation and short-term (lithium-ion batteries), mid-term (pumped hydro plants), and long-term (salt caverns) storage facilities. If other large-scale projects are also to be avoided (*Protest* scenarios), flexibility is only provided by gas turbines and combined cycle power plants.

A successful deployment of CSP systems in North Africa calls for larger transmission systems but reduces the need for flexibility in the European power system. Significant grid expansion is also observed when building large-scale H_2 infrastructures. These are associated with high additional electricity demand, higher system costs and additional CO_2 emissions (for renewable shares below 100%). For combined CSP import and H_2 futures, those emissions can be reduced, while the need for grid expansion climaxes.

4.3 Differences in linear power flow modeling provide no further insights at low spatial resolution

When using different approaches for power flow modeling (i.e. transport model, DC power flow, or power transfer distribution factors gathered from preceding AC power flow simulations) within our energy system optimization model, which models interconnected regions that mostly represent countries, the investment results in transmission infrastructure are quite robust. The corresponding mix of load balancing technologies also showed minimal changes only. In consequence, it does not matter how the power flow distribution is modelled, at least for the used regional scope (Europe) and spatial resolution (one node per country).

4.4 Limitations and outlook

A limitation of spatially aggregated energy system optimization tools is that transmission bottlenecks cannot be fully captured. This averages the variability from renewables, leading to an underestimation of the real balancing needs. The spatial resolution of the ESOM applied to our study is low next to models dedicated to power flow analysis. In other words, our approach has a significant higher degree of abstraction. This abstraction impacts the distribution of power flows and so the capability of capturing the real need for exchanging power surpluses and deficits.

To overcome this issue, planning tools with increasing spatial resolutions are being developed (Hörsch et al. 2018) but with the associated drawback of requiring tremendous amounts of spatially-explicit inputs and large computational effort. While the trend to publishing more openly available data sets offers a solution to the former of these challenges, recent efforts on the development of open source solvers for high performance computers (e.g. PIPS-IPM++ (Breuer et al. 2018)) are a promising solution for the latter. Finally, we recommend evaluating scenarios with more stringent greenhouse gas mitigation targets, and considering sustainability indicators beyond emissions.

5 Conflict of Interest

The authors declare that the research was conducted in the absence of any commercial or financial relationships that could be construed as a potential conflict of interest.

6 Author Contributions

TP was responsible for the conceptualization, funding acquisition and project administration. KKC contributed to the conceptualization and design, model application, and software development, conducted the formal analysis and visualization. JH contributed to the formal analysis. KKC and TP prepared the model input data and were responsible for data curation. HL was responsible for the AC grid modeling and PTDF methodology. KKC, TP, JH and HL wrote the original draft. All authors contributed to manuscript revision, read and approved the submitted version.

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10 Data Availability Statement

The raw data supporting the conclusions of this manuscript will be made available by the authors, without undue reservation, to any qualified researcher.