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Decarbonization scenarios for the EU and MENA power system: Considering spatial distribution and short term dynamics of renewable generation

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HIGHLIGHTS

- ► We present an EU+MENA power system model that considers long term investments and integration of renewables.
- ► For low emission targets, renewable integration issues lead to escalating electricity prices.
- ► The feasibility frontier can be pushed by adequate transmission and storage investments.
- ► The transformation from wind/fossil to wind/solar regime changes integration requirements.
- ► Low emission targets can be reached without significant interconnections between EU and MENA regions.

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ABSTRACT

We use the multi-scale power system model LIMES-EU$^+$ to explore coordinated long term expansion pathways for Renewable Energy (RE) generation, long distance transmission and storage capacities for the power sector of the Europe and Middle East/North Africa (MENA) regions that lead to a low emission power system. We show that ambitious emission reduction targets can be achieved at moderate costs by a nearly complete switch to RE sources until 2050, if transmission and storage capacities are expanded adequately. Limiting transmission capacities to current levels leads to higher storage requirements, higher curtailments, and to an increase in temporal and spatial electricity price variations. Results show an escalation of electricity prices if emission reductions exceed a critical value. Adequate expansion of transmission and storage capacities shift this threshold from 70% to 90% emission reductions in 2050 relative to 2010.

1. Introduction

The necessity to reduce greenhouse gas (GHG) emissions to limit anthropogenic climate change has been widely confirmed (IPCC, 2007; UNEP, 2010). The European Union has defined ambitious emission reduction targets for the near and long term future: to reduce domestic GHG emissions by 20% until 2020, and by 80–90% until 2050 (relative to 1990 emissions). The "Roadmap for moving to a competitive low carbon economy in 2050" (EC, 2011) states that domestic emission reductions of 80% would imply overproportional emission reductions of 93–99% in the power sector, owing to the large number of low emission power generation technologies available: fuel switch from coal to gas, power-heat cogeneration (CHP), nuclear power, carbon capture and sequestration (CCS), and a large portfolio of renewable energy (RE) options. But fuel switching and expansion of CHP capacities will not be sufficient to reach ambitious mitigation targets, nuclear power suffers from low public acceptance (especially after the Fukushima accident), and it is uncertain when CCS technology will be ready for large scale deployment. Renewable generation capacities, on the other hand, increased dramatically over the last years. A number of recent studies explore the possibilities for decarbonization of the European power sector, and RE generation dominates many of these scenarios (EWEA, 2011; WWF, 2011; EREC, 2010; ECF, 2010; PWC, 2010).

1.1. A challenge to power system design

The large scale integration of RE technologies into power systems, however, is a demanding task. In its "Special Report on Renewable and Energy Sources and Climate Change Mitigation" IPCC (2011) states that – although RE expansion will not be limited by global technical potentials or fundamental technological barriers – the costs and challenges related to system integration of RE generation may be significant. Due to the uneven spatial distribution and the seasonal, daily, and short

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term variability of RE resources, balancing demand and supply requires a combination of dispatchable backup capacities, storage capacities, and the expansion of long distance transmission infrastructure. In Europe and MENA regions, wind onshore and especially offshore potentials are largest in northern and northwestern areas, while solar resources are high in the countries surrounding the Mediterranean Sea. Power demand is highest in Central European countries—although demand is projected to increase significantly in the MENA region (Trieb, 2005). The European Commission pushes the establishment of an integrated Trans-European power grid (EC, 2010), however, as power grids have been developed from a purely national perspective, crossborder interconnections are still limited. ENTSO-E (2010) identifies 42 100 km of power lines to be built or refurbished between 2010 and 2020, and claims that integration of RE generation in the Northern and Southern parts of Europe is one of the main drivers. Still, grid expansion is progressing at a limited pace, mostly due to regulatory constraints and long lead times (MVV Consulting, 2007).

But the massive expansion of long distance transmission infrastructure is not be the only possible scenario. If generation capacities are clustered in few regions with high resource endowments, the dependency on electricity imports increases for regions with lower resource availability. This raises energy security concerns in the case that exporting countries are not able – or willing – to deliver the required power. Lilliestam and Ellenbeck (2011) discuss the concerns about European import dependency in the context of the DESERTEC project (Club of Rome, 2008) which promotes large scale power imports of solar generated power from MENA countries. This issue is also important on a national scale: for example, a study commissioned by the German government (SRU, 2010) analyzes the feasibility of a completely renewable based German power system that does not require power imports.

1.2. A challenge to power system modeling

Investment decisions regarding RE generation, transmission and storage capacities are tightly interconnected. It can be expected that coordinated long term planning for these assets, while taking seasonal, daily and short term dynamics of supply and demand into account, would significantly ease the large scale integration of RE generation. Most model-based studies, however, do not take up such a systemic view. The various model approaches that are used to analyze long term scenarios for power systems can be categorized as follows:

Integrated assessment models. These models usually cover multiple sectors, have long time horizons, coarse spatial resolution, and represent variability and spatial distribution of RE sources by using highly aggregated parameterizations. Examples are REMIND (Leimbach et al., 2010), WITCH (Bosetti et al., 2006), MESSAGE-MACRO (Messner and Schrattenholzer, 2000) and POLES (Russ and Criqui, 2007) on a global scale, and PRIMES (Capros et al., 2010) on the European level.

System operation models. These models represent technical characteristics of the power system in great detail. Although they do not consider long term changes of capacities endogenously, they can be used for analyzing the technical feasibility and cost effective operation of power system scenarios. Examples on a European scale are ELMOD (Leuthold et al., 2008), representing the European transmission infrastructure with great detail, and ReMIX (SRU, 2010), which calculates hourly dispatch and transmission flows for a complete year.

Hybrid approaches. These approaches aim at representing long term investment and short term operation decisions in a single framework. The ReEDS (Short et al., 2009) and the US-REGEN (Blanford and Niemeyer, 2011) models follow this approach. Both represent the United States' power system. Hybrid approaches for the Europe and MENA region are scarce: Möst and Fichtner (2010) calculate long term scenarios with the investment model PERSEUS-RET and validate them with the dispatch model AEOLIUS, but there is no hard link between the two models. TIMES-PET (Kypreos et al., 2008) is an European power system model that takes transmission requirements and system operation into account, but it does not include the MENA region and has only 12 time slices to represent short term dynamics. Pina et al. (2011) present another TIMES application with a better representation of short term fluctuations, but the model is calibrated to an isolated island system and does not consider transmission requirements.

So far, there is a lack of multi-scale models that could deliver coordinated long term scenarios for the EU and MENA power systems by considering spatial distribution and short term dynamics of supply and demand endogenously. The LIMES-EU$^+$ model, which is presented in this paper, fills this gap. We use it to analyze how the power sector of the European and MENA regions can be decarbonized by relying on RE resources. The following research questions are explored:

- What reduction levels of power system emission reductions are technically and economically feasible by expanding RE generation—without relying on CCS or building new nuclear power plants?
- What role does an interconnected European and Mediterranean transmission grid play, and how does its availability effect feasible RE penetration levels?
- What are cost effective investment pathways that, in the long term, lead to a decarbonized power system?

The paper is structured as follows: Section 2 introduces the structure of the LIMES-EU$^+$ model and gives an overview of the parameterization. In Section 3.1 we analyze the transition process that leads to a low carbon power system. Section 3.2 takes a closer look at the system in 2050—we investigate the structure of an adequate overlay grid and show how the cost effective choice of RE technologies depends on the availability of grid expansion beyond current levels. In Section 3.3, we perform a sensitivity analysis and show how CO_2 and electricity prices depend on the emission reduction target. Section 4 summarizes the paper and draws some final conclusions.

A detailed documentation of the model formulation and model parameters is provided in the supplementary material.

2. Methodology

2.1. Model structure

LIMES is a partial, multi-regional electricity sector modeling framework. It minimizes total discounted power system costs (investments, fuel, fixed and variable operation and maintenance) over a long time horizon. The model regions differ with respect to their power demand profiles and renewable potential endowments. Regions are interconnected by long distance transmission lines. Build-up and technical depreciation of generation and storage capacities in each region, as well as of transmission capacities between the regions, are modeled explicitly. Short term fluctuation of power demand and RE supply is represented by characteristic time slices. In each time step and region, supply and demand (which is price inelastic) need to be balanced for each time slice, given the available generation, transmission and storage capacities. By determining investment decisions and dispatch of capacities

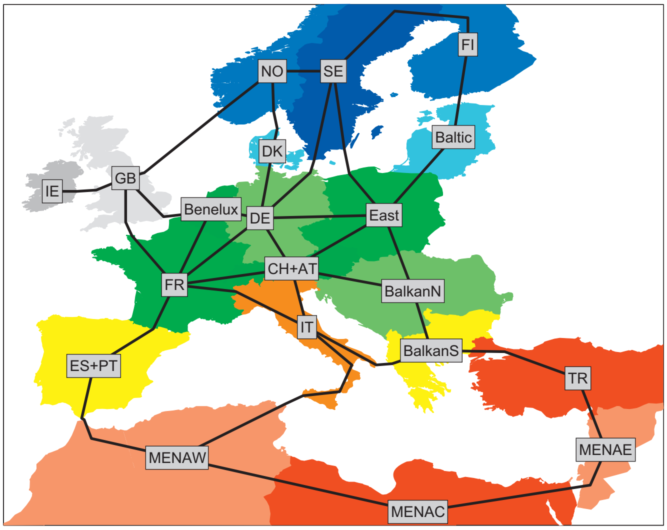

Fig. 1. Regional layout of the LIMES-EU$^+$ model.

Table 1
Aggregation of model regions to region groups (for data visualization only).

Region group	Model regions
EUNorth	NO, SE, FI, Baltic
EUCentral	DE, FR, Benelux, East, BalkanN, CH+AT
GB+IE	GB, IE
EUSouth	ES+PT, IT, BalkanS
MENA	MENAE, MENAC, MENAW, TR

endogenously, it is ensured that all investments are refinanced by the rents that are generated over time. The model takes on a social planner perspective, implying perfect foresight and perfect information. LIMES is formulated as a linear programming (LP) problem. It is implemented in GAMS (2010) and solved with the CPLEX solver.

The LIMES-EU$^+$ model represents the power system of the EU-27 member countries, Norway, Switzerland, and the Middle Eastern and North African countries surrounding the Mediterranean Sea (MENA region). It has 20 geographical regions that are connected by 32 transmission corridors (Fig. 1). To simplify the visualization of results in this paper, these regions are aggregated to region groups (see Table 1).

Long term investment decisions are modeled in 5 year time steps from 2010 to 2050. Short term fluctuation patterns are represented by 49 time slices. There are four seasons, each with three characteristic days that cover low, medium and high RE supply regimes. Each day is represented by four time slices, each one with a length of 6 h. An additional super peak time slice represents high demand and low RE supply. A selection algorithm ensures that the 12 characteristic days adequately represent temporal and spatial fluctuation patterns.[1]

2.2. Parameterization

Nine generation technologies are available: coal, gas and nuclear power plants, biomass IGCC, large hydropower, wind onshore/offshore, photovoltaic (PV) and concentrating solar power (CSP). Carbon capture and storage (CCS) is not taken into account, and it is assumed that no nuclear power plants will be built, although existing plants remain in operation until the end of their technical lifetime.[2] We assume decreasing specific investment costs for solar and wind generation technologies.[3] High voltage AC lines are used as transmission technology. Investment costs for overland lines and sea cables are differentiated. Transmission losses are assumed to be linearly correlated with transmission distance. Two generic storage technologies allow for day/night storage and intra-seasonal storage. CSP is modeled with integrated day/night storage. Tables 2–4 give an overview of the technoeconomical parameters of generation, storage and transmission technologies.

Wind onshore/offshore, PV and CSP resources and fluctuation patterns have been derived from gridded meteorological data (Kalnay et al., 1996). Model input consists of installable generation capacities per region as well as maximum capacity factors per region and time slice. The method for calculating these parameters is based on EEA (2009) and Hoogwijk (2004).[4] Each region features

Table 2
Parameters of generation technologies. For technologies with decreasing investment costs the costs in 2010 and 2050 are given. The availability factor of hydropower is subject to seasonal variations. Availability of fluctuating RE (⁎) depends on region, resource grade and time slice. Monetary units are given in 2008 present values.

Technology	Investment costs (€/kW)	Fixed O&M (%/a)	Variable O&M (ct/kW)	Availability factor (%/a)	Life time (a)	Build time (a)
Nuclear PP	3200	3	0.28	80	60	3.1
Coal PP	1100	2	0.68	80	50	2.2
Gas CC PP	500	6	0.05	80	40	1.3
Hydropower	3000	2	0.00	33–41	80	1.8
Biomass IGCC	1500	4	0.29	80	40	1.3
Wind onshore	970→750	3	0.00	⁎	30	0.8
Wind offshore	2170→1680	5	0.00	⁎	30	0.8
Solar PV	2820→865	1	0.00	⁎	30	0.5
CSP	6480→3640	3	0.00	⁎	35	1.0

Table 3
Parameters of storage technologies.

Technology	Investment costs (€/kW)	Fixed O&M (%/a)	Variable O&M (ct/kW)	Round trip efficiency (%)	Life time (a)	Build time (a)
Day/night storage	1500	0.5	0.24	80	80	1.8
Day to day storage	2500	1	0.00	70	10	0.8

Table 4
Parameters of transmission technologies.

Technology	Investment costs (€/kW km)	Fixed O&M (%/a)	Variable O&M (ct/kW km)	Losses (%/1000 km)	Life time (a)	Build time (a)
Overland line	0.38	0	0	7	50	5
Sea cable	3.8	0	0	7	50	5

[1] Details are provided in the supplementary material.

[2] For the sake of simplicity, reactors already under construction (e.g. France, Finland) are neglected, as well as national plans for phasing out existing reactors (Germany).

[3] The supplementary material provides details on cost curves.

[4] Details are provided in the supplementary material.

three resource grades with decreasing maximum capacity factors to represent generation sites of different qualities.

For each region and grade, maximum full load hours per year can be calculated by aggregating maximum capacity factors across all time slices. If sorted by resource quality, these can be used to construct regional renewable supply curves. Fig. 2 shows these supply curves for aggregated model regions.

Biomass based power generation is assumed to be fully dispatchable. Region constraints on biomass consumption are taken from EEA (2007).

Initial generation capacities are based on the Chalmers Energy Infrastructure database Kjärstad and Johnsson (2007) and IEA (2010a,b). Initial transmission capacities are based on net transfer capacities (NTCs) published by ENTSO-E. Demand profiles are based on ENTSO-E load data. Demand projections until 2050 are taken from Capros et al. (2010) and IEA (2010a,b). We assume a maximum transmission expansion rate of 1 GW/a per cross border interconnection. Price developments for coal natural gas and uranium are based on BMU (2008). For biomass we assume a constant price of 2.5 €/GJ.

Climate policy targets are represented by applying annual emission caps. In this paper we refer to emission reduction targets in 2050 relative to emissions in 2010. Emission caps decrease linearly from 2010 to 2050. There are no regionally differentiated emission targets; the cost effective allocation of reductions across regions is determined endogenously.

2.3. Limitations and scope

The strength of the LIMES-EU$^+$ model lies in its integrated, multi-scale perspective. It is important, however, to keep in mind the limitations of this approach. In terms of short term dynamics, the selection of characteristical days and the low temporal resolution of 6 h per time slice leads to a loss of information regarding extreme events and fluctuations on very short time scales (as shown in Haydt et al., 2011). Fluctuations on very large time scales ("good" and "bad" wind years) and forecast uncertainty are not taken into account.[5] In terms of grid representation, the model does not consider power flow distribution effects.[6] All these simplifications may lead to an underestimation of system integration challenges.

On the other hand, there are model characteristics and assumptions that may lead to an overestimation of these challenges: as power demand is assumed to be price inelastic, system integration cannot be facilitated by adapting demand profiles to match fluctuating supply. Considering the scenario design, the efforts of reaching ambitious mitigation targets may be overestimated by excluding other mitigation options besides RE generation. A mixture of nuclear power, CCS and RE generation may well be cost effective from a system point of view. In this study, nuclear power and CCS are excluded ex ante in order to evaluate the feasibility of high RE scenarios. An economic comparison of these alternatives is beyond the scope of this paper.

Lastly, it should be noted that, while social acceptance hampers the current deployment of nuclear power and CCS, it may also become an important issue in high RE share scenarios (e.g. public opposition regarding wind turbine installations and transmission lines). These aspects are not considered in this study.

[5] It should be noted that the super peak time slice, which is characterized by high demand and low renewable supply in all model regions, ensures that sufficient backup capacities are built to guarantee system adequacy in extreme events.

[6] Haller et al. (2012) show in a conceptual framework considering power flow constraints, while significantly increasing numerical costs, have little effect on long term system development.

3. Results and discussion

Table 5 shows the four scenarios that are presented.

To explore the role of an interconnected trans-European and Mediterranean grid, we compare scenarios where power transfers between regions are allowed, but transmission capacities are limited to current levels, with scenarios allowing for grid expansion. Both grid scenarios are shown for a 90% emission reduction target and for a Business as Usual (BAU) scenario without climate policy constraints.

Section 3.1 discusses — in aggregated the long term transformation process that is required to reach the desired target system in 2050. Section 3.2 takes a closer look at the power system in 2050 — we show regional generation mixes, grid structures and generation dispatch across the year. In Section 3.3 a sensitivity analysis with respect to emission caps is performed, and the effect of large RE shares on CO_2 prices and electricity prices is analyzed.

3.1. Long term system development

Fig. 3 shows the generation mix over time (aggregated across all regions) for the `PolGrid` scenario. Existing nuclear power plants are phased out according to their remaining technical lifetime. Coal based generation also decreases to meet emission caps. There are no investments in new coal power plants; however, there is a partial switch from gas to coal in 2015 by changing the dispatch of existing overcapacities. This does not conflict with the imposed emission targets due to the aggressive expansion of onshore wind turbines. An expansion of offshore wind does not take place before 2030. Solar based generation enters the system in 2035, with PV being the dominant technology. The share of dispatchable technologies (gas, hydropower and biomass) remains at about 25% to provide balancing services. The share of gas generation increases after 2030 (which coincides with the expansion of wind offshore and solar based generation), but is limited by the emission constraint.

Fig. 4 summarizes the development of several power system characteristics over time. The generation share of fluctuating RE increases to 75% for both policy scenarios, and it increases to about 40% in the absence of emission caps. This shows that a substantial expansion of RE generation is economically competitive without applying climate policy constraints, but that policy is required to reach ambitious targets. In the absence of emission caps, gas power plants are almost completely replaced by coal power plants. This leads to a coal/RE mix scenario, where emissions in 2050 are 20–40% higher than in 2010, despite the increased RE shares.[7] Foregoing the option of transmission expansion leads only to a small reduction of RE shares in the BAU case—this shows that the incentive to expand transmission capacities is significantly smaller if no climate policy is applied. For the policy scenarios the import share of consumption[8] increases from 4% in 2010 to 20% in 2050. In the BAU scenario, transmission plays a minor role, and the import share levels out at about 8% in 2050. Storage plays only a minor role until 2030, but in the `PolGrid` and `PolNoGrid` scenarios it is expanded significantly afterwards—this coincides with the expansion of solar based generation. The storage charge to total generation ratio increases to 10% if transmission is allowed. Foregoing the option to expand transmission capacities leads to an increase of this parameter to 15%. Despite these increased investments in storage capacities curtailments increase to 14% if transmission is not available.

[7] See Section 3.3 for a sensitivity analysis regarding different emission caps, and the resulting CO_2 prices in 2050.

[8] The import share of consumption is defined as demand which is not met by domestic resources, divided by total demand. It is determined individually for each model region and aggregated afterwards.

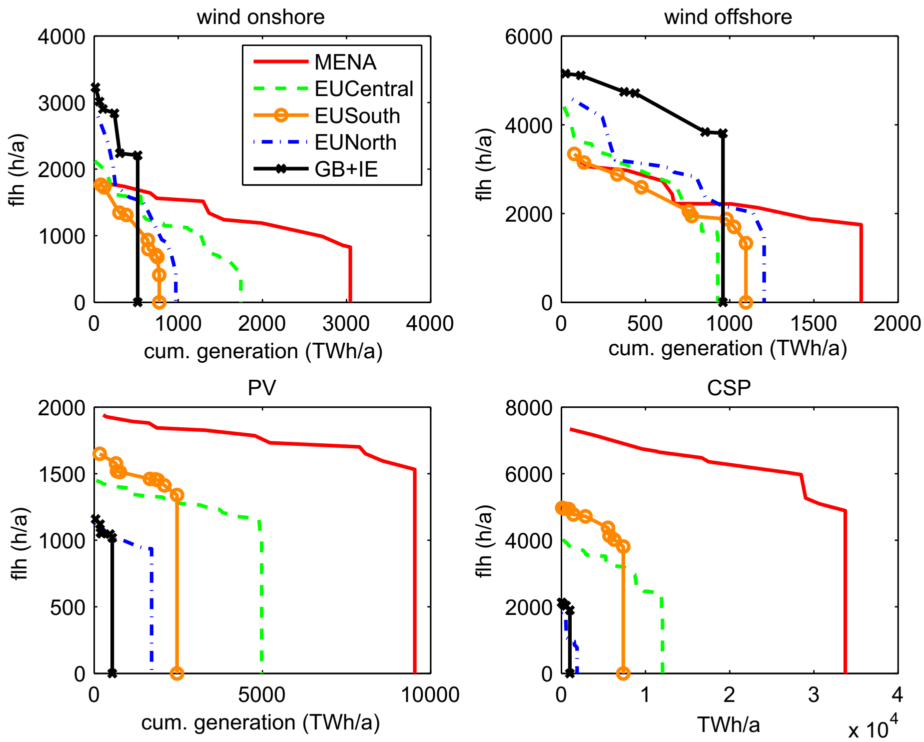

Fig. 2. RE potentials (marginal annual full load hours over total generated power) for aggregated region groups.

Table 5
List of scenarios.

Scenario	Emission reduction until 2050 (rel. to 2010)	Transmission expansion beyond 2010 levels
`PolGrid`	90%	Yes
`PolNoGrid`	90%	No
`BAUGrid`	None	Yes
`BAUNoGrid`	None	No

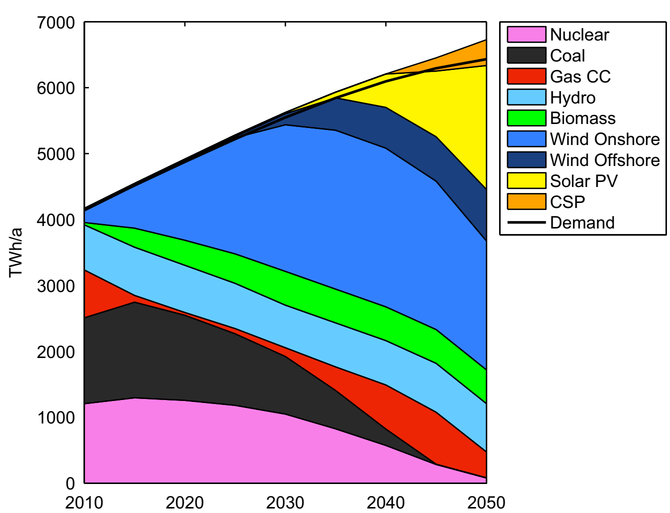

Fig. 3. Generation mix over time for the `PolGrid` scenario, aggregated across all regions.

3.2. *The power system in 2050*

This section takes a closer look at the power system in 2050 for the two policy scenarios.

Fig. 5 shows regional generation mixes in 2050 for the `PolGrid` and `PolNoGrid` scenarios. If transmission expansion is allowed, it plays an important role—although all regions exploit their domestic RE resources to a certain extent. Central European regions are net importers (mainly Germany, Eastern Europe and the Benelux countries), with import shares of 30–60% of total consumption. The main exporters are the Scandinavian countries (hydro and wind), Great Britain and Ireland (wind), and southern European and north African regions (PV and CSP). CSP, while making only a small contribution to overall generation, reaches large shares in the eastern and western MENA regions. In the `PolNoGrid` scenario, the lack of imports in Central European countries is mainly compensated by an expansion of domestic PV capacities, which displace wind onshore and offshore generation capacities in Norway and GB.

Fig. 6 shows installed transmission capacities and net flows in 2050 for the `PolGrid` scenario. The major transmission corridors are from Scandinavia, Great Britain and Spain to central European countries. Connections between MENA regions and Europe do exist, but they play a minor role. Turkey imports power from central and eastern MENA regions.

Fig. 7 shows net transmission over time across the major transmission corridors that have been identified above (see Table 1 for a definition of region groups). Net flows increase rapidly from 2010 onwards. Flow patterns show a shift between two regimes: until 2030, Northern European countries and the British Islands export electricity not only to central Europe, but also to the southern regions. After 2030, coinciding with the expansion of solar based generation, exports to the southern regions decrease, and MENA and southern European countries become net exporters in 2035 and 2040, respectively.

Fig. 8 shows generation across time slices in 2050 for Germany, which is the largest net importer in the `PolGrid` scenario. In this scenario, wind onshore and offshore dominate the generation mix, and supply and demand fluctuations are almost completely balanced by imports. Additional generation by gas power plants

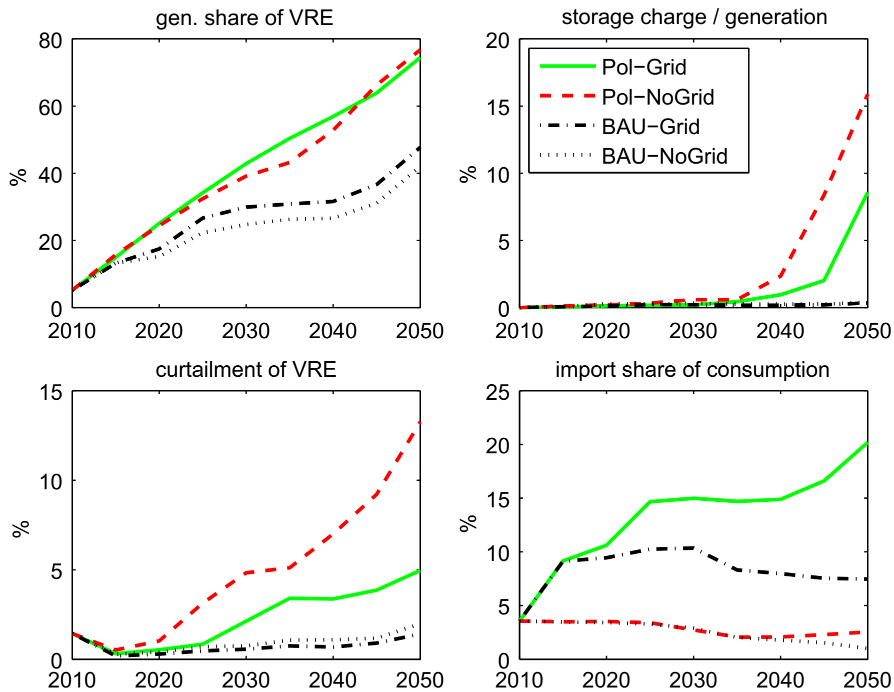

Fig. 4. Long term system development for all scenarios. The panels show generation share of fluctuating RE, storage charge to total generation ratio, import to total consumption ratio, and curtailments of fluctuating RE.

mainly occurs on winter days with low wind supply. Storage capacities are very small. In the PolNoGrid scenario, PV capacities are expanded significantly, which leads to large generation surplus during daytime. This is compensated by large day/night storage capacities to shift this surplus to the night time slices.

3.3. CO_2 and electricity prices

Fig. 9 shows endogenously calculated CO_2 prices and electricity prices in 2050 that result from applying different emission caps. It shows results for the Grid and NoGrid configurations analyzed above, and additionally for a configuration where neither transmission nor storage expansion is allowed. CO_2 prices are larger than zero for 2050 emission levels of 120–140% rel. to 2010. Thus, emissions would increase by 20–40% (depending on the availability to expand transmission capacities) if no emission caps were applied. This is caused by an expansion of coal generation which replaces gas (due to lower fuel prices) and nuclear (because we assume that no new nuclear power plants will be built), an effect that overcompensates the increase of RE generation shares to 40% (see Fig. 4). Prices increase moderately up to emission reductions of 60%. For more ambitious targets, the results show a nonlinear increase. This indicates that there is a feasibility frontier where the increasing share of RE generation leads to serious integration issues.

The increase of average electricity prices is less pronounced than the increase of CO_2 prices. Marginal costs for every additional ton of CO_2 are high, but due to the low level of residual emissions, this leads to a decreasing cost mark-up for the average electricity price.[9]

Allowing for the expansion of transmission and storage capacities has two effects: firstly, it leads to a general reduction of CO_2 prices and electricity prices. For moderate emission caps (less than 60% reductions), these price differences amount to 70−120 €/tCO_2 and 0.8–1.2 ct/kW h, respectively. Secondly, it shifts the frontier where prices increase above tolerable levels to more ambitious emission targets. The threshold after which electricity price increases escalate lies between 70% and 90%, depending on the availability of transmission and storage.

The increasing share of fluctuating RE has an additional effect: it leads to an increase in temporal and spatial price variations. Fig. 10 shows cumulative distribution functions of electricity prices in 2050 for all regions and time slices.[10] In the absence of emission caps (BAUGrid and BAUNoGrid scenarios) price variations are very moderate, and the availability of transmission expansion has only a small effect. In the PolGrid and PolNoGrid scenarios, however, price variations are much more pronounced, and foregoing the option to expand transmission capacities leads to a significant increase of price variations. About 24% and 35% of all prices are zero (for PolGrid and PolNoGrid scenarios, respectively), indicating that supply exceeds demand in the respective time slices and regions—a situation that would pose severe problems for a market that relies on marginal pricing methods, as it is currently the case in the EU.

4. Conclusions

We explore long term decarbonization strategies for the power sector of the European and MENA regions. Analyses have been performed using the LIMES-EU$^+$ model, a multi-scale power system model that integrates long term investment decisions in generation, transmission and storage capacities as well as the effects of short term fluctuation of renewable supply. We show that – if transmission and storage capacities are expanded well

[9] Both CO_2 price and electricity price are marginals (of emission and energy balance constraint, respectively) determined endogenously during the optimization process. Thus, the CO_2 price is included in the electricity price.

[10] Prices for the super peak time slice are not shown, as they increase well above 100 ct/kW h.

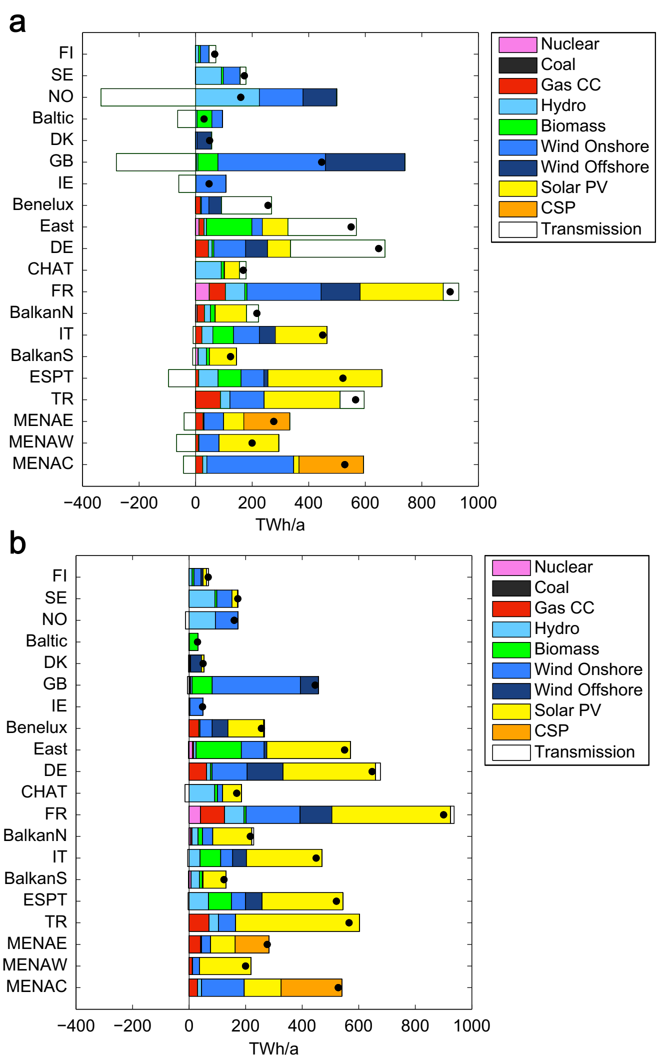

Fig. 5. Regional generation mix in 2050 for the `PolGrid` and `PolNoGrid` scenarios. The dots mark domestic demand. (a) `PolGrid` scenario and (b) `PolNoGrid` scenario.

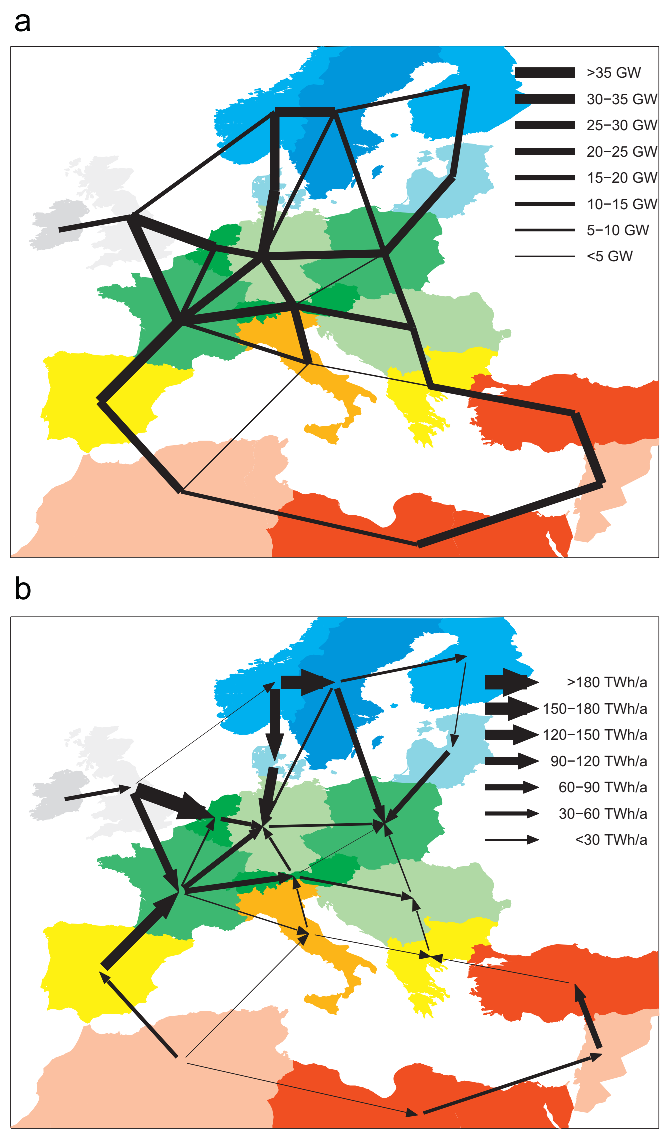

Fig. 6. Transmission capacities and net transmission flows in 2050 (`PolGrid` scenario). (a) Transmission capacities and (b) net transmission flows.

above their current levels – a near complete decarbonization of the power sector can be achieved at moderate costs. Although every region exploits its domestic RE resources to some extent, long distance transmission plays an important role. Up to 2030 transmission capacities are expanded to transfer power generated by wind onshore and offshore from Scandinavia and the British Islands to central and southern European regions. After 2030 PV and CSP capacities are expanded, and southern European countries become net exporters as well. In 2050, central European countries import 30–60% of their domestic demand. These results show that creating an interconnected power system for the EU and MENA regions does not only require significant transmission capacity expansions; it also strongly increases import dependency of central European regions. This may raise concerns regarding energy security—although in this study, the major share of power exchanges occurs within the EU region. Power exports from MENA to European countries increase after 2040, but they play a minor role.

The study also shows that emission reductions of up to 90% are still feasible without expanding transmission capacities. This leads to a fragmented system without major long distance power transfers, where each region is able to meet its domestic demand

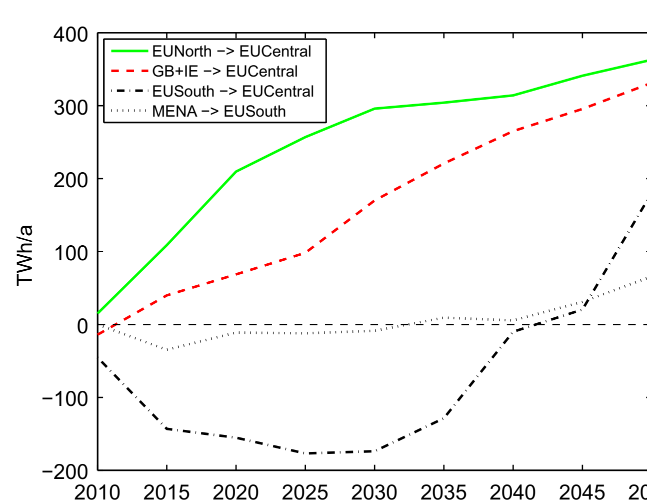

Fig. 7. Net transmission flows over time across the four major transmission corridors (`PolGrid` scenario).

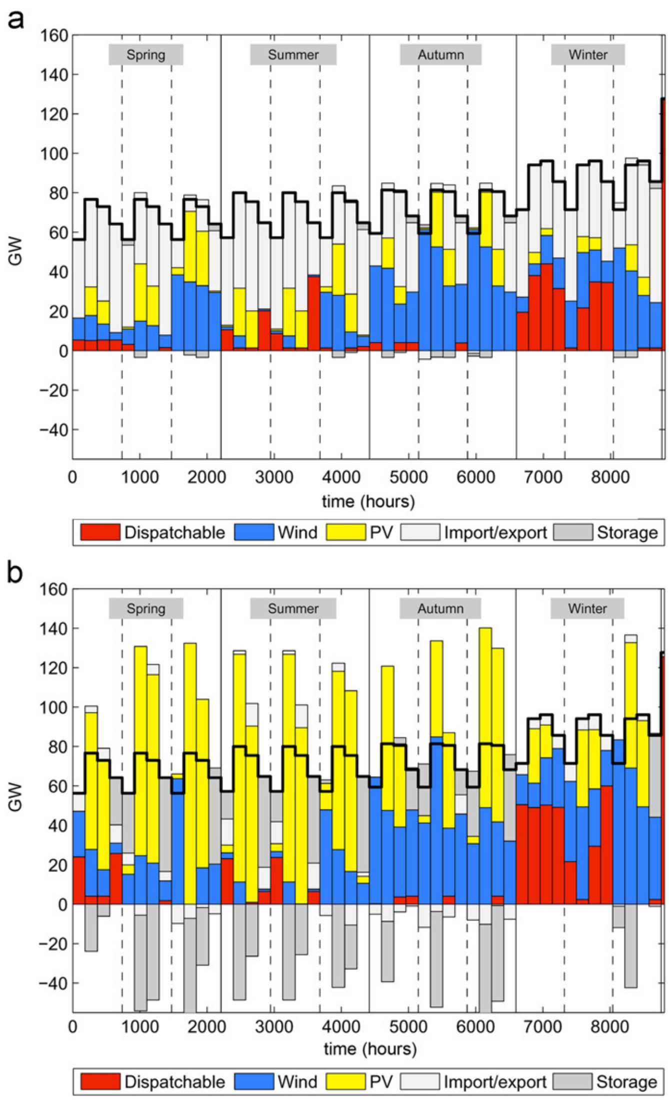

Fig. 8. Generation mix across time slices in 2050, for Germany (`PolGrid` and `PolNoGrid` scenarios). The black line represents domestic demand. To improve readability, technologies have been aggregated to groups (dispatchable: coal, gas, hydropower, biomass, nuclear; wind: wind onshore/offshore; storage: day/night and intra-day storage). (a) `PolGrid` scenario and (b) `PolNoGrid` scenario.

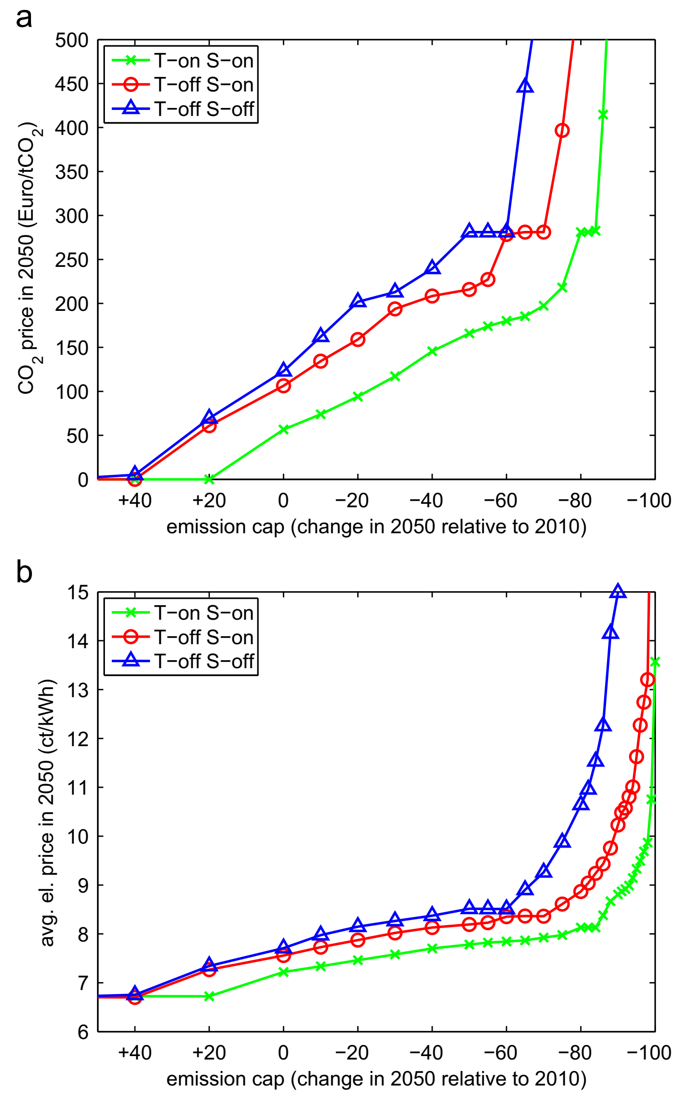

Fig. 9. CO_2 prices and electricity prices in 2050 depend on the emission cap and the availability of transmission and storage expansion. (a) CO_2 prices in 2050 and (b) electricity prices in 2050.

without relying on imports. In this case, solar PV is used to a much greater extent in central European regions, which requires large storage capacities to account for diurnal supply fluctuations.

We identify a threshold for emission reductions where CO_2 prices and electricity prices escalate. By expanding transmission and storage capacities beyond their current levels, this threshold can be shifted from 70% to 90% reductions up to 2050.

High shares of fluctuating RE lead to a significant increase in temporal and spatial price variations. Marginal pricing methods, as they are currently used on the European power markets, are likely to fail under these conditions. This indicates that the development of adequate market designs (e.g. capacity markets) is an important requirement for managing the transition to a renewable based power system.

The LIMES-EU$^+$ approach fills a gap in the current literature by delivering long term power system scenarios that take RE integration issues explicitly into account. It does not intend to replace bottom-up models with higher technological, temporal and spatial resolution—these are very well suited to analyze the technical and economical feasibility of a desired target system. Its strength lies

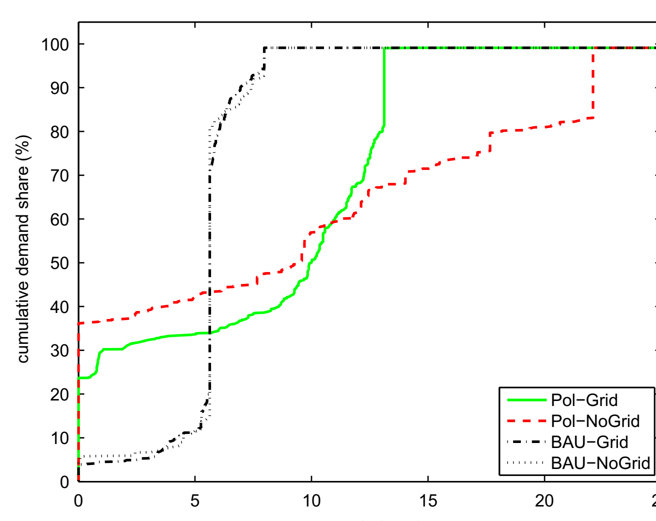

Fig. 10. Cumulative distribution function of electricity prices in 2050 (prices for all regions and time slices).

in the ability to analyze pathways which can be taken to reach a long term target.

There are many opportunities for future work. An important issue is to validate the presented scenarios with a detailed bottom-up model. Inside the LIMES-EU$^+$ model, there is still some room (in terms of numerical cost) to increase short term temporal resolution—this may be especially important to represent fluctuations of wind supply. Acquiring higher resolution meteorological is very demanding and was out of the scope of this paper. An interesting issue is to explore different regional or national climate policies—the model would be well suited to examine which harmonized or fragmented climate policy measures are required to incentivize RE expansion and to reach emission targets. Another important topic is the feasibility of scenarios with combined expansion of RE and other low carbon generation options (nuclear and CCS).

Appendix A. Supplementary data

Supplementary data associated with this article can be found in the online version at http://dx.doi.org/10.1016/j.enpol.2012.04.069.

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