CO_2 Mitigation and Power System Integration of Fluctuating Renewable Energy Sources: A Multi-Scale Modeling Approach

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Summary

Decarbonizing the electricity sector is of vital importance for mitigating greenhouse gas emissions due to increasing power demand, but also because of the broad portfolio of low carbon power generation options. Emission reduction policies are likely to incentivise an expansion of renewable power generation capacities far beyond current levels.

This thesis investigates the question of how renewable power generation can contribute to mitigate CO_2 emissions. It analyzes the system integration challenges that result from large shares of variable and spatially dispersed renewable power generation, how an expansion of long distance transmission and storage capacities can facilitate system integration, and how system integration issues – and the availability of integration options – affect long term strategies for power system decarbonization. More specific, it investigates if (and how) Europe can reach its ambitious power sector decarbonization targets by expanding renewable generation capacities. These questions are addressed in a series of model-based studies.

Results show that power system decarbonization in general and expansion of renewable power generation in specific play a crucial role for economy-wide mitigation efforts. They also demonstrate that investment decisions in transmission, storage and generation capacities are tightly interrelated. Adequate expansion of transmission and storage facilitates the integration of renewable supply, and limiting the availability of these options affects deployment and spatial allocation of renewable generation capacities.

It is shown that until 2050, Europe and the Middle East / North African (MENA) regions can achieve power system CO_2 emission reductions of 90% (relative to 2010) by expanding renewable power generation – without relying on CCS or building new nuclear power plants. This target can be met without large-scale electricity transfers between Europe and MENA regions, but inside Europe, a clear pattern of importing and exporting countries emerges. Meeting the 90% emission reduction target leads to an increase of average electricity prices to 8.7 ct/kWh, if transmission and storage capacities are adequately expanded (compared to 6.8 ct/kWh in the baseline scenario). If transmission capacities are limited to current levels, electricity prices increase to 10.1 ct/kWh, and the requirements for storage capacities increase significantly.

Cost-efficient expansion pathways until 2050 are far from linear: Until 2030, the system is characterized by a mixture of wind and fossil generation, followed by a switch to a wind and solar based generation mix. This transition on the generation side results in different integration challenges, and it changes the interregional patterns of power transfer and the way the existing transmission infrastructure is used.

Feasible mitigation levels that can be achieved by renewable generation capacities are shown not to be limited by their technical potential, but by system integration issues. Electricity prices escalate if emission caps exceed a certain limit. In the presented scenarios, this threshold varies between 70% and 95% CO_2 reductions, depending on the availability of transmission and storage expansion. This shows that a coordinated expansion of renewable generation capacities and system integration options is crucial for achieving ambitious decarbonization targets.

Zusammenfassung

Die Dekarbonisierung des Elektrizitätssektors ist von elementarer Bedeutung für die Vermeidung von Treibhausgasemissionen, zum Einen wegen steigender Stromnachfrage, zum Anderen bedingt durch die große Auswahl an Optionen zur emissionsarmen Stromerzeugung. Politische Initiativen zur Vermeidung von Emissionen werden mit großer Wahrscheinlichkeit Anreize für eine Erweiterung der Erneuerbaren Stromerzeugungskapazitäten weit über den gegenwärtigen Stand hinaus schaffen.

Diese Arbeit beschäftigt sich mit der Frage, welchen Beitrag Erneuerbare Stromerzeugung zur Vermeidung von CO_2-Emissionen leisten kann. Sie erkundet die Herausforderungen, die durch die Systemintegration großer Anteile variabler und räumlich verteilter Stromerzeugung aus Erneuerbaren Energiequellen entstehen, wie ein Ausbau von Stromnetzen und Speicherkapazitäten zur Systemintegration beitragen kann, und inwiefern langfristige Strategien zur Dekarbonisierung des Elektrizitätssektors durch Probleme der Systemintegration – und die Verfügbarkeit von Integrationsoptionen – beeinflusst werden. Im Speziellen untersucht diese Arbeit, ob (und wie) die ehrgeizigen Emissionsminderungsziele der EU im Stromsektor durch einen Ausbau Erneuerbarer Energien erreicht werden können. Diese Fragen werden in einer Reihe modellbasierter Studien beantwortet.

Die Ergebnisse unterstreichen, dass die Dekarbonisierung des Elektrizitätssektors im Allgemeinen und der Ausbau Erneuerbarer Stormerzeugung im Speziellen für das Erreichen gesamtwirtschaftlicher Emissionsvermeidungsziele eine entscheidende Rolle spielen. Weiterhin wird dargelegt, dass Investitionsentscheidungen in Netz-, Speicher- und Erzeugungskapazitäten in engem Zusammenhang stehen. Ein bedarfsgerechter Ausbau von Netz- und Speicherkapazitäten erleichtert die Integration Erneuerbarer Stromerzeugung, und eine eingeschränkte Verfügbarkeit dieser Optionen beeinflusst Ausbauraten und Standortentscheidungen Erneuerbarer Erzeugungskapazitäten.

Es wird gezeigt, dass durch einen Ausbau Erneuerbarer Energien die CO_2-Emissionen in den Stromsektoren Europas und der Länder des Nahen Ostens / Nordafrikas (MENA) bis 2050 um 90% (relativ zu 2010) reduziert werden können – ohne auf die Option der CO_2-Abscheidung (CCS) zurückzugreifen oder neue Kernkraftwerke zu bauen. Dieses Ziel kann ohne großskalige Stromtransfers zwischen Europa und der MENA-Region erreicht werden; innerhalb Europas tritt sich jedoch ein klares Muster aus importierenden und exportierenden Ländern zu Tage. Eine Reduktion der CO_2-Emissionen um 90% führt zu einem Anstieg der durchschnittlichen Strompreise auf 8.7 ct/kWh (gegenüber 6.8 ct/kWh im Referenzszenario), falls Netz- und Speicherkapazitäten in angemessenem Maße ausgebaut werden. Eine Beschränkung der Übertragungskapazitäten auf den heutigen Stand führt zu einem Anstieg der Strompreise auf 10.1 ct/kWh und zu einem deutlich höheren

Bedarf an Speicherkapazitäten.

Kosteneffiziente Ausbaupfade bis 2050 verlaufen nicht linear: Bis 2030 ist das System durch eine Mischung aus Windenergie und fossiler Stromerzeugung geprägt; erst danach erfolgt der Übergang zu einem auf Wind- und Solarenergie basierend Strommix. Dieser erzeugungsseitige 'Systemwechsel' führt zu veränderten Anforderungen seitens der Systemintegration sowie der sich ausprägenden Lastflüsse im existierenden Stromnetz.

Die Emissionsminderungsziele, die durch einen Ausbau der Erneuerbaren Erzeugungskapazitäten erreicht werden können, sind nicht durch ihr technisches Potenzial, sondern durch Anforderungen an die Systemintegration limitiert. Das Überschreiten eines kritischen Wertes seitens der Emissionsbeschränkungen führt zu einem nichtlinearen Anstieg der Strompreise. In den vorgelegten Szenarien liegt dieser Grenzwert – abhängig von der Verfügbarkeit von Netz- und Speicherausbau – zwischen 70% und 95% CO_2-Reduktionen. Dies zeigt, dass ein koordinierter Ausbau von Erneuerbaren Erzeugungskapazitäten in Kombination mit Maßnahmen zur Systemintegration für das Erreichen ambitionierter Dekarbonisierungsziele von entscheidender Bedeutung ist.

Chapter 1

Introduction

The importance of reducing greenhouse gas (GHG) emissions to limit anthropogenic climate change has been widely confirmed by the scientific community (IPCC, 2007). This awareness is also being reflected in international efforts to implement ambitious climate policies – although current pledges are still deemed insufficient to reach emission targets that would avoid an escalation of climate damages (UNEP, 2010). There exists a broad portfolio of options to reduce emissions (Bruckner et al., 2010; Bauer et al., 2009). However, reducing anthropogenic emissions to acceptable levels is a demanding task, and reaching this objective requires a profound transformation of energy systems.

In its *Special Report on Renewable Energy Energy Sources and Climate Change Mitigation* (IPCC, 2011) the IPCC draws the conclusion that renewable energy sources can play an important role in this transformation process. Fig. 1.1 shows global primary energy supply from renewable sources for a large number of long-term scenarios provided by different modeling groups. Although variations across scenarios are large, it is apparent that, under ambitious climate constraints, the deployment of renewable energy technologies has to increase dramatically compared to current levels.

Due to the large number of low carbon power generation technologies that are either emerging or already available at market scale, the power sector will play an important role in emission mitigation efforts (Leimbach et al., 2010). In addition to that, power demand is most likely to increase in many world regions - firstly, because of the growing energy demand of developing economies, and secondly, because of the trend of electrification in different end-use sectors (e.g. electro-mobility). Chances are high that future electricity systems will face large penetration levels of renewable power generation.

1.1 The European case

The European Union (EU) is currently taking a leading role in international climate negotiations and has proposed ambitious medium and long-term emission reduction targets for its member countries: to reduce GHG emissions by 20% until 2020 and by 80%-95% by 2050 (compared to 1990 emissions, under the condition that other countries participate in efforts to reduce global GHG emissions). The feasibility of reaching these long-term targets are discussed in the "Roadmap for moving to a competitive low carbon economy in 2050" (EC, 2011a). The roadmap states that GHG emissions from the power sector need

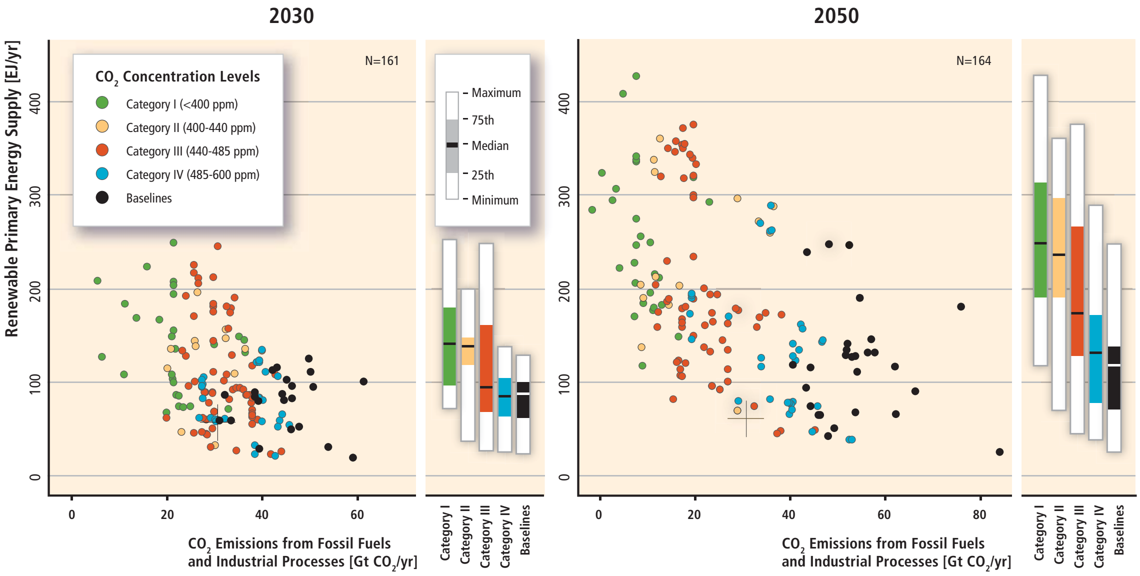

Figure 1.1: Global RE primary energy supply (direct equivalent) from 164 long-term scenarios as a function of fossil and industrial CO_2 emissions in 2030 and 2050 (IPCC, 2011). The colors represent categories of atmospheric CO_2 concentration level in 2100. The blue cross marks 2007 data. Although variations across scenarios are large, ambitious emission reduction targets imply a vast expansion of RE deployment.

to be reduced by 93%-99% (relative to emissions in 1990) as a prerequisite for reaching a system wide GHG reduction target of 80% (see Fig. 1.2). An "Energy Roadmap 2050" is expected to be put forward by the EU in the second half of 2011 to elaborate on these long-term targets in more detail.[1]

At the same time the EU defined the target of the renewable share of total energy supply to 20% in 2020 (EC, 2010), which entails an increase of renewable power generation share of the electricity mix to 37% (EC, 2011b). Managing this transition until 2020 and beyond poses a huge challenge, and especially the integration of increasing renewable generation capacity requires careful long-term planning. European renewable resources are large and diverse, but they are spatially highly unevenly distributed, with solar resources in the southern regions, large wind offshore potentials in the Northwest and hydro power resources in Norway and the alpine regions in Central Europe. Large-scale expansion of transmission infrastructure would be required to connect these regions to major demand centers.

The European Commission fosters the establishment of an integrated trans-European power grid (EC, 2010), however, as power grids have been developed from a purely national perspective, cross-border interconnections are still limited. In its recent "Ten Year Network Development Plan" (ENTSO-E, 2010) the European Network of Transmission System Operators for Electricity (ENTSO-E) identifies 42100km of power lines[2] 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. ENTSO-E also emphasizes that beyond 2020, profound changes of supply and demand patterns will

[1] http://ec.europa.eu/energy/strategies/consultations/20110307_roadmap_2050_en.htm

[2] This figure considers cross-border as well as domestic connections.

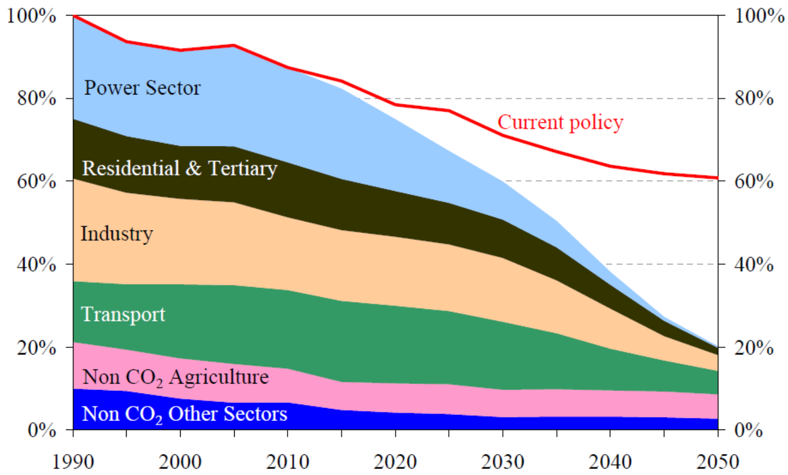

Figure 1.2: GHG emission trajectories for Europe in order to achieve 80% emission reductions in 2050, as proposed by the European Commission (EC, 2011a).

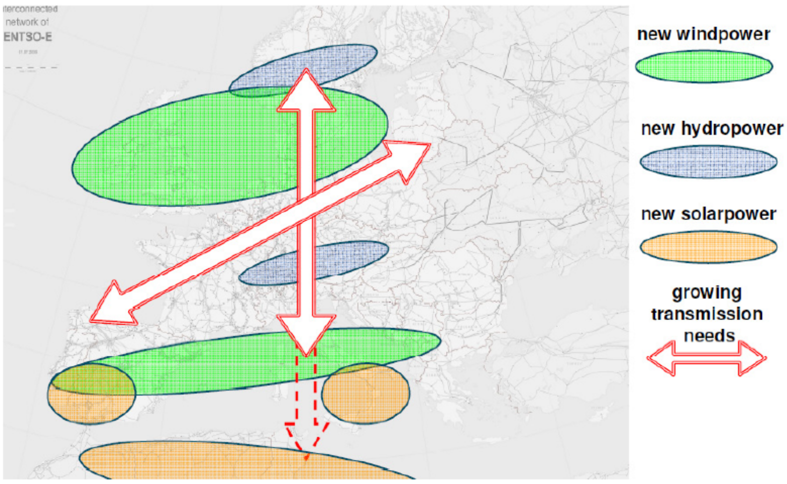

Figure 1.3: Long-term transmission requirements for the European power sector (ENTSO-E, 2010).

create further transmission needs (see Fig. 1.3).

Another issue is the possible interconnection of power systems in Europe and Middle East / North Africa (MENA) regions. The MENA region is endowed with abundant potentials for solar power generation. The DESERTEC project (Club of Rome, 2008) proposes the large scale expansion of concentrating solar power (CSP) capacities in this region, complemented by an integrated electricity grid for EU and MENA regions and considerable power imports into the EU. This, however, raises concerns about increasing import dependency (Lilliestam and Ellenbeck, 2011). The discussion about whether to distribute generation capacities on an international scale (to make use of the best resource locations) or to rely on domestic resources (to decrease the dependency on power imports) has also been raised on a national scale (e.g. SRU (2010) in Germany).

1.2 System integration of fluctuating renewable energy

The integration of renewable generation poses a challenge to power system design and operation. Renewable energy (RE) generation technologies have special characteristics that set them apart from conventional (fossil and nuclear) generation technologies. IPCC (2011) gives an overview on these technology and resource specific features, the resulting challenges for system integration, and the options that are available to ease the integration process.

Firstly, renewable energy resources are geographically unevenly distributed. The efficiency and unit cost of RE generation depends on the availability and intensity of the used resource, and is therefore site dependent. Conventional generation capacities consume consume fuel that can be transported across large distances (although within certain limits) and are usually located close to demand centers. In contrast, in a power system that relies heavily on renewable generation technologies, sites are primarily chosen according to resource potential and thus are not necessarily located close to demand. This increases the requirements for transmission infrastructure that connects supply and demand sites.

Secondly, the output of renewable energy generation depends on the magnitude of natural energy flows (i.e. wind speed and solar irradiation), and these flows fluctuate in time. These fluctuation patterns have deterministic[3] as well as stochastic[4] elements, and they occur on a large range of temporal scales, ranging from interannual, seasonal and diurnal patterns down to hours, minutes and seconds. This poses a challenge to power system design and operation as supply and demand need to be balanced at all times to prevent frequency variations and system failures.

Thirdly, the transition towards a power system with large shares of renewable generation is most unlikely to be achieved quickly, but will occur gradually over a time span of several decades. Power system assets have long build and depreciation times, and investments need to be refinanced over their lifetimes. This creates considerable inertia. During this transition process, the boundary conditions of the system change, i.e. CO_2 prices, technological progress and changing fuel prices. These long-term dynamics need to be taken into account when making investment decisions at any given point in time.

These three problem dimensions – the long-term transition process of the overall system, the short-term dynamics that govern system operations, and the spatial characteristics of supply, demand and the transmission infrastructure – are represented in Figure 1.4. They jointly affect the design of cost-efficient renewable integration pathways. The integration issues that arise along these dimensions, and the technical options to alleviate them, are discussed below.

Spatial system characteristics The dependence on site specific resources is a characteristic feature that distinguishes renewable energy technologies from (most of) their conventional counterparts. The spatial distribution of resources varies across a broad range of scales. In general, the magnitude of solar irradiation, as well as its deterministic seasonal and diurnal cycles, are a function of latitude. Wind speeds are generally higher in coastal

[3]E.g. diurnal solar irradiation cycles.

[4]E.g. wind speed variations.

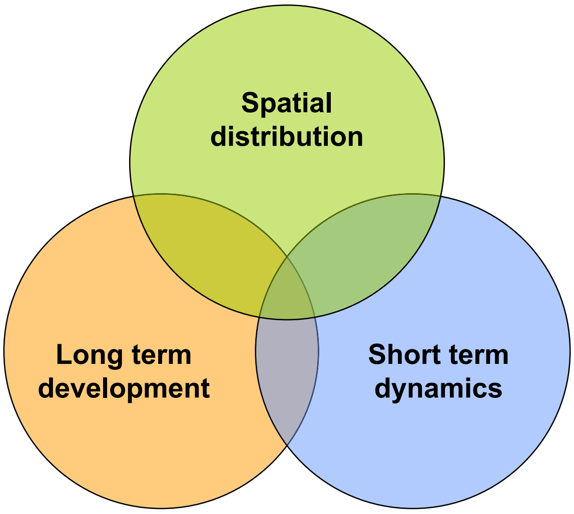

Figure 1.4: System integration of fluctuating renewable energy: the three problem dimensions.

areas or large plains. Actual resource quality, however, is highly region specific.

Transmission infrastructure is required to transfer electricity between supply and demand locations. But there are other advantages of an interconnected grid: The overall variability of supply and demand is smoothed by pooling together large numbers of fluctuating sources and sinks – provided that their fluctuation patterns are not strongly and positively correlated. An interconnected grid also enables the pooling of generation reserves, which reduces the total amount of reserves required to maintain system reliability (Holttinen et al., 2009; Katzenstein et al., 2010). All these three functions become increasingly important for higher penetration rates of renewable generation.

Short-term dynamics Certain renewable generation technologies are subject to fluctuations across a wide range of time scales, with considerable technology specific differences. Fluctuations are especially important for wind turbines and photovoltaic solar power (PV). Wind speeds show large fluctuations at small time scales with a strong stochastic element (Holttinen et al., 2009). Solar irradiation patterns are characterized by pronounced seasonal and diurnal cycles (Curtright and Apt, 2008). For concentrating solar power (CSP) plants, short-term fluctuations of irradiation are dampened to a certain extent by the thermal to electrical energy conversion process, and they can be associated with thermal energy storage to level out diurnal cycles (DLR, 2009; GE Energy, 2010).

Balancing power supply and load at all times is a prerequisite for maintaining system stability. In power systems that rely on conventional generation, power plants must provide a certain degree of flexibility to follow demand fluctuations and to provide backup in case of planned and unplanned outages. With increasing shares of renewable power generation, the supply-side variability adds to the flexibility requirements. System flexibility can be increased by adding power plants with good ramping abilities that are designed to operate at low full load hours (e.g. gas turbines) or by increasing storage capacities. The degree of dispatchability, i.e. the availability to adjust power output to follow balancing requirements, differs significantly between different types of renewable power generation. Whereas the dispatchability of biopower plants, hydro power plants, and CSP plants is comparable to that of fossil fuel based technologies, the maximum output of wind and

PV plants is at each point in time limited by the actual resource availability. These technologies can still to some extent contribute to system balancing by reducing output, or by operating them at suboptimal levels to increase ramping capacities, and are therefore considered to be partially dispatchable (IPCC, 2011). From an economic point of view, however, these power curtailments are not desirable.

Power system reliability, i.e. the availability of a power system to operate without failures, is determined by system adequacy and system stability. System adequacy[5] measures the ability of a power system to balance load and supply in all possible steady states that may exist under standard conditions, i.e. that generation matches consumption, and that the transmission system can accommodate the resulting flows. For the UCTE grid, system adequacy is determined at an hourly resolution. System stability describes the ability of the power system to deal with disturbances of the steady state on a sub-hourly basis, i.e. the ability to control frequency and voltage. Different control mechanisms are applied on different time scales: inertial response to frequency changes of synchronous generators smoothens fluctuations on very small time scales. Primary and secondary reserves are provided within seconds to minutes, e.g. by changing the operation parameters of thermal plants in part load operation. Tertiary reserve is activated manually within hours, e.g. by rapidly starting gas power plants.

Long-term system development The long-term perspective is important when designing power systems – and there are two main reasons for that. The first one is that, although changes in the power sector can happen very fast,[6] investment decisions have long-lasting effects. Power plants, transmission lines and many other assets in the power sector have life times of up to 60 years, and also the commissioning, licensing and construction process can span several years. There are strong incentives to avoid stranded investments - i.e. by decommissioning power plants before they reach the end of their life time. New renewable generation technologies compete with existing capacities, and their integration will be much easier if they replace retiring assets. The second reason is that power systems will face a continuous state of change for the next decades, and with it the economic, technological and institutional context in which power plants are operated. Climate policy constraints will become more stringent over time, being reflected in increasing CO_2 prices, taxes, or technology portfolios. Costs of new technologies will decrease by technological progress, and prices of fossil fuels and uranium may increase due to the limited availability of their resources. All this affects the ranking of competitiveness across generation technologies.

1.3 Modeling system integration of renewables generation – the current state of science

This section discusses how the integration of fluctuating RE generation is treated in electricity sector modeling tools. Special regard is given to model based studies that analyze

[5]See UCTE (2009) for the UCTE methodology to define system adequacy.

[6]E.g. the market growth rates of over 30% per year that have been achieved by the wind turbine and PV industry between 1998 and 2008 (EPIA, 2008; Sawyer, 2009).

the European power system and thus have a similar scope as the LIMES-EU$^+$ model.

1.3.1 An overview on modeling approaches

Pina et al. (2011) suggest to divide energy modeling tools into two generic groups. The tools from the first group are typically used to analyze how energy systems are affected by long-term economic or technical transition processes. They operate on large time scales, and assess changes of system characteristics with a temporal resolution of several years. These models often cover several sectors of the energy system and either do not consider integration of fluctuating RE generation at all, or they use highly aggregated parametrization. Integrated Assessment Models (IAMs) typically fall into this category. 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.

The second group consists of models that are more focused on representing technological details of the power system in detail. They usually treat the system infrastructure as static, or consider capacity changes in a simplified manner, and analyze system operation and reliability on small temporal and spatial scales. 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.

Recent publications show that a third group of hybrid models, combining features of the first two categories, are becoming more relevant. Integrating short-term system dynamics and transmission requirements into long-term investment models has become an increasingly important issue in the IAM community. 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. ReEDS has a time horizon of 50 years and a high spatial resolution. It follows a recursive dynamic approach to determine capacity expansions. US-REGEN determines capacity expansion and system operation in an inter-temporal optimization framework. To date, the only renewable generation option considered is wind energy. The model is currently under construction. Pina et al. (2011) present a TIMES application with a better representation of short-term fluctuations, but the model is calibrated to an isolated island system and has a time horizon of only four years.

The LIMES model, which has been developed for this thesis, and which will be described in detail in Section 1.4, belongs to this group of models.

1.3.2 System integration studies for Europe

There are hardly any studies in peer reviewed literature that deal with large scale system integration of RE generation in the specific European context: 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 a European power system model that takes transmission requirements and system operation into account, but it does not include the

MENA region and has only twelve characteristic load segments to represent short-term dynamics.

However, a large number of studies on renewable generation expansion scenarios have been published by independent research institutes, consulting agencies and NGOs, mostly commissioned by the European Union or national governments. In the following section, three of these studies will be presented to reflect the current state of knowledge, and to highlight how this thesis can add to this knowledge base. They were selected based upon the following criteria:

- They focus on the system integration challenges that result from large scale renewable power expansion.
- They use detailed power system models, covering a wide range of modeling approaches.
- The applied modeling approach is well documented, and this documentation is publicly available.

TradeWind study The 'TradeWind' study (EWEA, 2009) was commissioned by the EU and prepared by a consortium led by the European Wind Energy Association (EWEA). It analyzes the effects of increased wind generation shares in the European power system and, amongst other results, makes recommendations on how the transmission grid should be reinforced to facilitate system integration. The study uses a power system model that represents the high voltage transmission grid of the EU-25 region at a high level of detail and determines cost-efficient capacity dispatch at an hourly resolution. Wind onshore and offshore capacity additions and their regional allocation are defined exogenously. The TradeWind study assumes overall installed wind generation capacities of 300 GW in 2035, which corresponds to a 28% share of total demand. Performance and reliability of the power system are analyzed at different periods between 2010 and 2030. The study also recommends a number of grid connections that are most severely congested (by using the electricity price gradient across each line as a sensitivity measure). It is shown that overall system costs decrease significantly if these grid expansions are actually implemented.

The strength of the TradeWind study is its accurate representation of the transmission grid infrastructure, combined with a thorough and spatially highly resolved parametrization of wind supply. However, it has some limitations: The spatial allocation of wind capacities is determined exogenously. Furthermore, the study is limited in scope: It does not look beyond 2030, it does not consider other renewable generation technologies besides wind turbines, and it does not assess penetration levels above 28% of total demand. Of all renewable generation options, wind energy is to date the most economic one, and it will doubtlessly play an important role during the next two decades. But to achieve the objective of decarbonizing the power sector in the long-term, wind generation will need to be complemented with other energy sources, and these will pose different challenges to system integration.

ECF Roadmap 2050 study The 'Roadmap 2050' study (ECF, 2010) analyzes how the EU objective of reducing GHG emissions by 80% until 2050 can be reached. The study covers the complete European economy, but puts a heavy focus on the electricity sector. A multi-sector macro-economic model is used to allocate emission reductions across sectors and to assess economic effects of changing costs of energy. The authors claim that the economy wide 80% GHG reduction target can only be achieved if emissions in the electricity sector are reduced by 95%-100%. A multi-region generation dispatch and investment model is used to create detailed decarbonization scenarios for the power sector. A back casting approach is used to develop these scenarios: First, a target system in 2050 is defined by setting a suitable generation mix and allocating these capacities across model regions. Production shares are then back-casted in 10 year time steps from 2050 to 2010 following a linear build-up. For each of these time steps, the power sector model determines cost-efficient generation, transmission and storage capacities that are required to meet the predefined power mix and reliability constraints. It calculates dispatch across one year with an hourly resolution and takes investment costs into account by using an Levelized Costs of Electricity (LCOE) approach. The study analyzes different scenarios with varying shares of RE generation, nuclear energy and CCS, with RE generation shares ranging from 40% to 80%. An additional 100% RE scenario, which also assumes (exogenously defined) electricity imports from North Africa, is presented separately.

The rationale behind this approach is to define many characteristics of the target power system ex-ante (i.e. power mixes at the end of the time horizon, their development over time, and the spatial distribution of generation capacities), and to optimize the optimal dispatch of these capacities, as well as investments in required transmission, backup and storage capacities, with high detail. This has the advantage that the operation and reliability of the designed system can be evaluated with good accuracy. The downside of this approach is that it cannot be guaranteed that the defined investment choices (timing and siting of generation capacities) are cost-efficient. Integration measures are determined endogenously by the model to complement the changes on the generation capacity side, but the effects that varying availability of integration measures may have on generation choices are not considered.

SRU study 'Pathways towards a 100%renewable electricity system' A report commissioned by the German government (SRU, 2010) analyzes possibilities and limitations of achieving a 100% renewable power mix in Germany until 2050. Although the study puts a heavy focus on the German system, it analyzes different levels of interconnection with neighbouring countries and uses a model that covers Europe and the North African region. The study compares three degrees of cross-border interconnection: an extreme scenario in which no cross border flows are allowed, a scenario in which Germany, Denmark and Norway can exchange power, and a scenario that allows for power exchange across all European and North African countries. In all scenarios, net imports of countries are limited to 15% of domestic demand. The study uses the ReMIX model which has the objective function of minimizing total system costs in a given year. It has 36 regions and optimizes capacity dispatch at an hourly resolution. Investments in generation, transmission and storage capacities are determined endogenously; annualized investment costs are part of the objective function. This is a significant difference to ECF (2010) and EWEA (2009) where capacity mix and siting of generation capacities are defined exogenously. The study shows that the cost-efficient choice of generation technology and location depends heavily on whether cross border power exchanges are possible or not.

However, although the study describes in detail the configuration and operation of the power system in 2050, it gives no account of how to get there. As the model does not optimize investments across several time periods, it cannot specify how capacities develop between now and the desired target system in 2050.

It is apparent that each of these studies has its unique strengths. But, to conclude this review: Only very few model based studies exist that develop system integration scenarios for renewable energy generation and reconcile long-term developments and short-term operation requirements. For the European and MENA region, this type of study has not been performed so far. Existing studies are either limited in scope (in terms of technology portfolio or time horizon) or focus on a detailed assessment of the long-term target while neglecting the possible pathways that will lead to this target. The power system model LIMES, which is presented in this thesis, fills this gap by integrating long distance transmission requirements and short term dynamics into a long term inter-temporal optimization framework.

1.4 The LIMES modeling framework

LIMES (Long-Term Investment Model of the Power Sector) is a power sector model that uses a multi-scale optimization approach. 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. Renewable resources are differentiated by discrete grades that limit maximum installable capacity (based on geo-referenced meteorological data). Regions are interconnected by long-distance transmission corridors. 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 time slices which represent characteristic combinations of demand and renewable resource availability. In each time step and region, supply and demand need to be balanced for each time slice, given the available generation, transmission and storage capacities. Storage can be used to transfer power between time slices. The model takes on a social planner perspective, implying a centralized cost minimization of the overall system, and assumes perfect foresight and perfect information. By determining investment decisions and dispatch of capacities endogenously, it is ensured that all investments are refinanced by the rents that are generated over time. The model simultaneously solves a long term investment decision problem and a short term unit commitment problem.

Figure 1.5 sketches an overview of the integration challenges as discussed above, aligned along the three problem dimensions spatial distribution, short-term dynamics and long-term development. The shaded area marks the challenges that are taken into account by the LIMES model. Due to its long time horizon and the inter-temporal optimization approach, LIMES incorporates long-term changes of fuel prices, demand, investment costs of emerging technologies, and climate policy constraints. It also takes capacity additions and their depreciation into account explicitly. This holds for generation, transmission and storage capacities. The model does represent the uneven spatial distribution of renewable resources at the level of model regions. Fluctuations of supply and demand are taken into account on a seasonal, diurnal and intra-day scale. The temporal resolution can be adjusted within the limits drawn by numerical costs – in the model versions used in Chapters 3 to 5, it varies between 24 hours and one hour. The cost-efficient dispatch of capacities at the chosen temporal resolution is determined endogenously. System stability issues – as they manifest at sub-hourly time scales – are not considered.

The model does not distinguish single power plants or single transmission lines – all power plants of one type inside a region are treated as an aggregate capacity, and connections between regions are represented as aggregated transmission corridors. Therefore, the flexibility of single plants (ramping abilities, startup and shutdown processes) cannot be considered explicitly.[7] Distribution grid infrastructure is not taken into account.

The LIMES modeling framework itself is flexible and can be adapted to different system configurations. In this thesis, three LIMES model versions are used to answer different research questions: A conceptual three region model, a model of Eastern Germany that has only a single region, but high temporal resolution, and the LIMES-EU$^+$ model, a multi regional representation of the European, Middle East and North Africa regions.

1.5 Thesis objective and outline

This thesis aims to improve our understanding of how renewable power generation can contribute to mitigate CO_2 emissions. It analyzes the system integration challenges that result from large shares of variable and spatially dispersed renewable power generation, how an expansion of long distance transmission and storage capacities can be facilitate system integration, and how system integration issues – and the availability of integration options – affect long term strategies for power system decarbonization. More specific, it investigates if (and how) Europe can reach its ambitious power sector decarbonization targets by expanding renewable generation capacities.

These issues have been addressed in four journal publications which are reproduced in Chapters 2 to 5. Each chapter covers a specific research question; these questions are introduced below. Chapter 6 presents a synthesis of the main results of this thesis and provides an outlook for further research.

1. What is the role of renewable power generation in achieving long-term emission reduction targets? (Chapter 2)

This chapter addresses the issue of determining power sector decarbonization levels that are required to reach economy wide emission reduction targets, and more specific, the importance of renewable power generation in relation to other mitigation options. It proposes a methodology to attribute mitigation shares in multi-sectoral models to end-use sectors and technology groups. This methodology is applied to analyze how emission reductions are achieved in different world regions in various long-term mitigation scenarios generated with the Integrated Assessment Model REMIND.

[7] Ramping constraints have been implemented in a simplified form in Eastern Germany model (Chapter 3).

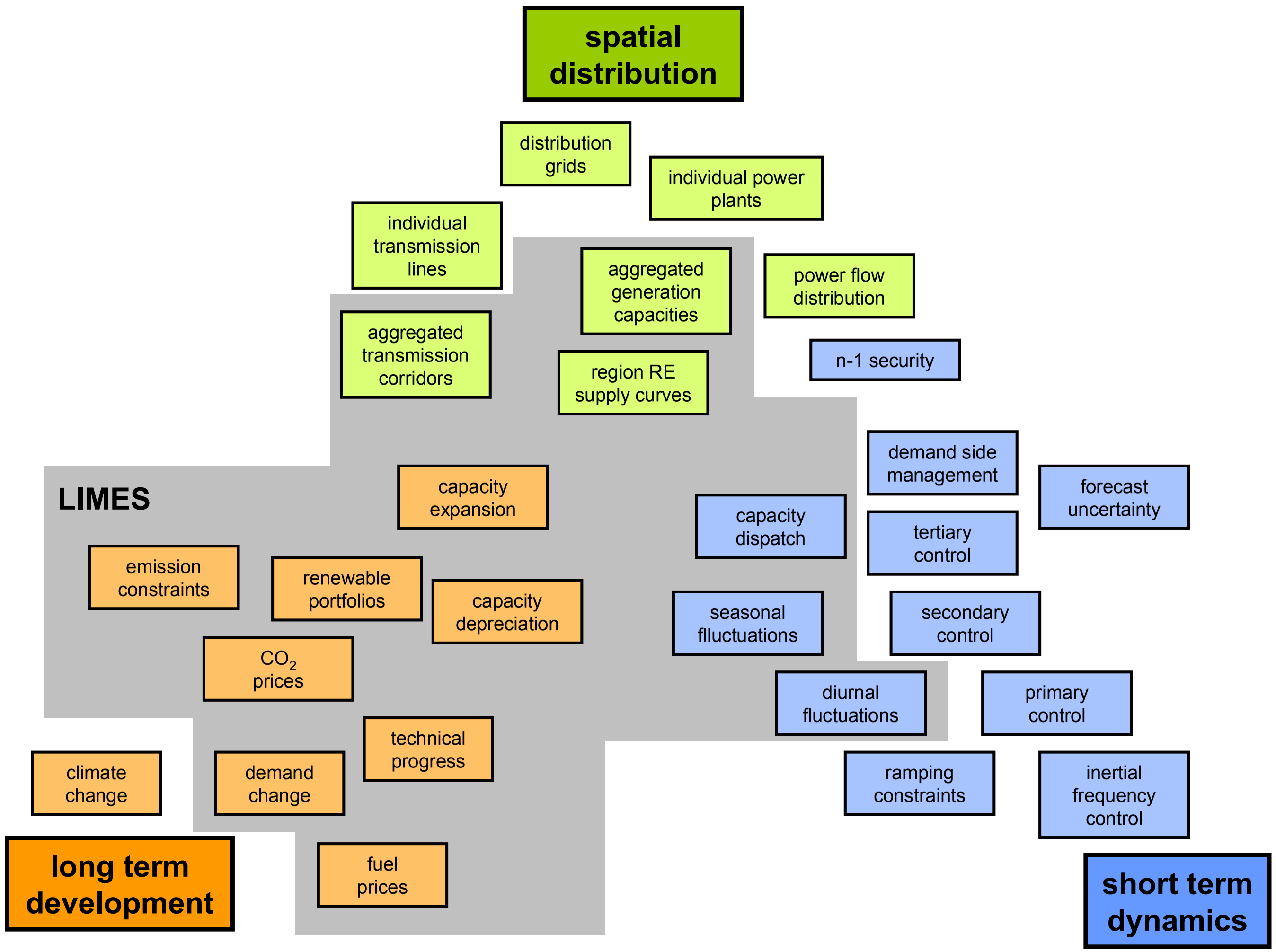

Figure 1.5: System integration of fluctuating renewable energy: overview of challenges. The shaded area marks the challenges that are taken into account by the LIMES model.

2. How does improved representation of short-term dynamics affect investment decisions in generation capacities? (Chapter 3)

This chapter analyzes long-term power system scenarios for the Eastern part of Germany (the TSO balancing area covered 50hz Transmission GmbH). This region has only weak grid interconnections to neighbouring areas, and due to large onshore and offshore wind potentials, integration of fluctuating renewable generation is likely to become a serious issue in the medium and long-term. The LIMES model is used to investigate how short-term dynamics of supply and demand affect long-term investment scenarios under climate policy constraints. Because of the small geographical size of the model area, a single region model is used. Different temporal resolutions between 24 hours and one hour are applied to analyze which level of detail is required to appropriately represent short-term fluctuations.

3. How does adequate expansion of transmission and storage capacities affect deployment and spatial allocation of generation capacities? (Chapter 4)

Transmission and storage infrastructure are important options to facilitate the system integration of renewable energy sources. Transmission infrastructure enables interregional sharing of resources, and storage capacities are required to match fluctuation patterns of demand and renewable supply. It can be assumed that deployment pathways and spatial allocation of renewable generation capacities depend on the availability – and on the timely deployment – of these options. The system wide effects of the availability of storage and of constrained expansion rates for transmission capacities are analyzed in a conceptual three region LIMES model.

4. What are cost-efficient coordinated renewable power generation scenarios for EU and MENA regions that take the expansion of integration facilities into account? (Chapter 5)

The challenges Europe is facing to reach its ambitious emission reduction and renewable expansion targets have been outlined in Section 1.3.2. This chapter investigates pathways that lead to near complete power system decarbonization until 2050, and that rely on a massive expansion of renewable energy sources. It determines feasible limits for the integration of fluctuating and spatially dispersed renewable power generation and analyzes how these limits are affected by an expansion of long-distance transmission infrastructure. The analysis is performed with the LIMES-EU$^+$ model, a multi-region model that covers the EU-27, Norway, Switzerland, and the countries surrounding the Mediterranean Sea.

Chapter 2

The role of renewable power generation in achieving long-term emission reduction targets*

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Asia's Role in Mitigating Climate Change: A Technology and Sector Specific Analysis with ReMIND-R

Gunnar Luderer+, Robert C. Pietzcker, Elmar Kriegler, Markus Haller, Nico Bauer*

Abstract.

We use the ReMIND-R model to analyze the role of Asia in the context of a global effort to mitigate climate change. We introduce a novel method of secondary energy based mitigation shares, which allows us to quantify the economic mitigation potential of technologies in different regions and end-use sectors.

The 2005 share of Asia in global CO_2 emissions amounts to 38%, and is projected to grow to 53% under business-as-usual until the end of the century. Asia also holds a large fraction of the global mitigation potential. A broad portfolio of technologies is deployed in the climate policy scenarios. We find that biomass in combination with CCS, other renewables, and end-use efficiency each make up a large fraction of the global mitigation potential, followed by nuclear and fossil CCS. We find considerable differences in decarbonization patterns across the end-use sectors electricity, heat and transport. Regional differences in technology use are a function of differences in resource endowments, and structural differences in energy end use. Under climate policy, a substantial mitigation potential of non-biomass renewables emerges for China and other developing countries of Asia (OAS). Asia also accounts for the dominant share of the global mitigation potential of nuclear energy. In view of the substantial near term investments into new energy infrastructure, early adoption of climate policy is found to be of particularly high value for China and India.

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1. Introduction

Stabilizing climate change at a level in line with the targets formulated by the international community will require a substantial reduction of greenhouse gas emissions relative to business-as-usual (IPCC, 2007, Ch. 3). The recent scenario literature shows that in absence of climate policy further expansion of fossil fuel use would result in an increase of CO_2 emissions from energy and industry by a factor 1.6-5.4 by 2100 relative to year 2000 levels IPCC, 2007, Ch. 3; Clarke et al., 2009; Edenhofer et al., 2010; Luderer et al., 2011).

In its 'Copenhagen Accord', the United Nations Framework Convention on Climate Change has adopted the target of limiting the increase in global mean temperature to 2°C (UNFCCC, 2009). This target implies a tight limit on the remaining budget of anthropogenic greenhouse gas emissions (Meinshausen et al., 2009). The majority of modeling studies that have considered climate change mitigation targets consistent with climate stabilization at 2°C arrived at 2050 emissions reductions of at least 50% with respect to 2005 levels, and long term emissions that are close to zero or negative at the end of the century (Clarke et al., 2009; Edenhofer et al., 2010). Clearly, emission reductions of this magnitude require a large-scale transformation of global energy systems and a massive expansion of low carbon energy technologies.

Thus, crucial research question relate to the role of technologies in achieving climate targets (e.g. Nordhaus and Nakicenovic, 2011). What can individual technologies contribute to emissions reductions? What are the determining factors for their effectiveness in reducing emissions and how do these factors vary regionally? And which technologies carry the largest part of the mitigation effort? The answer to these important questions is complex, because the role of technologies for mitigating climate change is not determined by their individual characteristics alone. Rather it strongly depends on the entire mitigation pathway characterized by a portfolio of technologies deployed over time.

Integrated Assessment Models (IAMs) with a detailed representation of the energy-economic system fully cover the relevant dynamics, and therefore are well suited for studying the role of technologies in achieving climate targets. This requires deducing their individual contribution to the mitigation effort from the model output. The most common method is to study deployment levels of low-carbon technologies under climate policy and make comparisons to baseline levels (e.g., van Vuuren et al., 2007; Calvin et al., 2009; Krey and Riahi, 2009; Edenhofer et al., 2010; Luderer et al., 2011; Krey and Clarke, 2011). This approach provides an assessment of the technologies supported by climate policy, but does not directly address economic efficiency and mitigation effectiveness. For an assessment of economic efficiency, some studies have considered scenarios in which the expansion of individual low carbon technologies is assumed to be restricted or unavailable (Krey and Riahi, 2009; Edenhofer et al., 2010; Luderer et al., 2011). Comparing mitigation costs in such technology constrained scenarios against scenarios with the full set of technologies available allows the modeler to derive the increase in mitigation costs that arises from the technology restriction. This cost markup provides a good indicator for the contribution of a technology to the economic efficiency in achieving climate targets.

A complementary approach would be to assess mitigation effectiveness, i.e. the contribution of a technology to emissions reductions. How can emission reductions be attributed to individual technologies? Although this question seems rather simple, there is no straight-forward way of quantification. The term “Stabilization Wedges” has been coined by Pacala and Socolow (2004), who claimed that the mitigation gap, i.e. the difference between baseline emissions and emission levels required to achieve climate stabilization, can be bridged by a combination of currently available technologies. While such technology wedges have now become a common tool for illustrating climate stabilization pathways to stakeholders and decision-makers (e.g. Edmonds et al., 2000; Placet et al.,2004; EPRI, 2007; IEA, 2010), we are only aware of a few purely scientific IAM studies that use technology wedges (Riahi et al., 2007; Shukla et al., 2008).

A problematic aspect of the Pacala and Socolow approach is the implicit suggestion that mitigation scenarios can be constructed by adding up mitigation wedges, and that individual technology wedges can be used interchangeably. As mentioned above, however, the role of individual technologies cannot be assessed in isolation. Their contribution to emissions reduction is an emergent system property Thus, any method of attributing emission reductions to technologies should be regarded as a diagnostic tool for analyzing mitigation strategies for a given climate policy scenario, rather than a tool for constructing mitigation scenarios. Technology contributions are a function of each other and the mitigation scenario, and cannot be combined arbitrarily. This discussion reflects a fundamental tension between integrated assessment models of climate policy that decidedly take a systems perspective, and bottom-up approaches that try to combine individual mitigation potentials to marginal abatement cost curves (e.g. McKinsey & Company, 2009).

In this paper, we want to take the concept of attributing emissions reductions to individual technologies a step further while retaining a strict integrated systems perspective. We introduce a new method for attributing emission reductions as foreseen in mitigation scenarios from IAMs to individual technologies. This is a purely diagnostic tool for decomposing the mitigation effort. Due to the system dependency, the resulting mitigation shares per technology cannot be taken out of context and be recombined to different mitigation scenarios. In order to avoid confusion with the popularized concept of mitigation wedges that has been used frequently in the latter way, we will call the fraction of emissions reductions attributed to a specific technology a “mitigation share” in the following.

We believe that the attribution of emissions reductions to technologies provides useful complementary information on their role for mitigating climate change. While the assessment of deployment levels and technology constrained vs. full technology scenarios targets favorability and economic efficiency, respectively, the decomposition of the emissions reductions provides a direct indicator for the mitigation effectiveness of technologies.

The regional focus of the paper is on Asia and a comparison with other key emitting regions such as the USA and the European Union. A number of studies have analyzed mitigation potentials and emission reduction strategies in Asia (Jiang et al., 2000; Kainuma et al., 2003) or individual countries of Asia, in particular China (e.g., Jiang and Hu, 2006; Chen, 2005; Chen et al., 2007; Steckel et al. 2011) and India (Shukla et al., 2008). The focus of our study is to analyze climate change mitigation in the context of the global effort. We apply the newly proposed decomposition method to the AME scenarios from the integrated assessment model ReMIND to investigate the following research questions: What are the most significant mitigation technologies, and how do their emission reduction potential compare across end-use sectors? How do realized mitigation potentials of technologies change with increasing stringency of climate policy? How do mitigation potentials and decarbonization strategies compare across regions within Asia and between

Asia and the rest of the world? What is the benefit of early adoption of climate policies in Asia?

Our paper is structured as follows: In the next section, we explain the model and scenario setup are introduced. Section 4 describes the methodological approach for the calculation of secondary energy based mitigation shares, and how it is distinguished from other approaches of determining the contribution of technologies to mitigation. Section 4 presents results from global and cross-sectoral perspective. Region specific results for Asia are reported in Section 5, along with an analysis of the role of early climate policy action in Asia. There are important caveats to the use and interpretation of this methodology. They are discussed in Section 6, followed by a concluding summary of the paper.

2. Model and scenario setup

The Refined Model of Investment and Technological Development ReMIND in its version 1.4 is used for this study. It is a global Integrated Assessment Model that represents 11 world regions and considers the time horizon from 2005-2100. A detailed description of this model is available from previous publications Leimbach et al., 2010), and the technical model documentation (Luderer et al., 2010).

ReMIND is composed of three components: (a) the macro-economic growth module that describes socio-economic developments and determines the economy's demand for final energy, (b) a detailed energy system module describing conversion pathways from various types of primary energy via secondary energy to final energy, and (c) a climate module that simulates the response of the climate system to anthropogenic emissions of greenhouse gases and other forcing agents. A key feature of the model is that all three components are solved in an integrated, intertemporal optimization framework, thus fully accounting for feedbacks between all components of the system (Bauer et al., 2008).

In particular in terms of its macro-economic formulation, REMIND-R resembles well-known energy-economy-climate models like RICE (Nordhaus and Yang, 1996) and MERGE (Manne et al., 1995). REMIND-R is characterized by a high technological resolution of the energy system, the consideration of technological learning in the energy sector, and the representation of trade relations between regions. This results in a high degree of where-flexibility (abatement can be performed where it is cheapest), when-flexibility (optimal timing of emission reductions and investments), and what-flexibility (optimal allocation of abatement among emission sources) for the mitigation effort.

The scenarios used for this study (Table 1) are based on the harmonized scenario set used for the AME intercomparison exercise comprising of one reference scenario, three scenarios with a prescribed global carbon tax, and two climate stabilization scenarios (Calvin et al., this issue). Many Asian countries have already adopted climate mitigation measures. In order to test the value of early adoption of climate policy, we prepared a variant of the TAX-30 scenario as an addition to the standard AME scenarios. In this (counter-factual) DELAY scenario, the Asian macro-regions China, India, and other Asian developing countries are assumed to follow their business-as-usual trajectory without emissions pricing until 2020 and without anticipation of future climate policy, while all other world regions implement a uniform carbon tax already in 2015. The Asian regions are assumed to adopt the globally uniform tax from 2025 onwards.

AME scenario name	**Description**	**Short descriptor**
Reference	Reference Scenario. No climate policies beyond Kyoto Reductions for EU and Japan	**REF**
CO_2 Price \$10 (5% p.a.)	CO_2 pricing scenarios with globally uniform tax starting from 2015 increasing a and increasing at a rate of 5% p.a. 2020 price levels are \$10, \$30, \$50, respectively.	**TAX-10**
CO_2 Price \$30 (5% p.a.)		**TAX-30**
CO_2 Price \$50 (5% p.a.)		**TAX-50**
3.7 W/m^2 NTE	Stabilization scenarios aiming at radiative forcing at 3.7 W m^{-2} (550ppm CO_{2e}, not-to-exceed), and 2.6 W m^{-2} by 2100 (450ppm CO_{2e}, overshooting allowed)	**3.7NTE**
2.6 W/m^2 OS		**2.6OS**
	Variant of TAX-30 scenario with Asian developing countries myopically following reference scenario until 2020. Asia adopts carbon tax in 2025, all other world regions in 2015.	**delay2020**

Table 1: Description of reference and climate policy scenarios used. REF, TAX scenarios, as well as 550NTE and 450OS are part of the harmonized scenarios set of the AME study. DELAY2020 is a complementary scenario conducted for this paper.

3. Secondary energy based mitigation shares

As discussed above, mitigation shares aim at quantifying the contribution of individual technologies or technology groups to the emission reduction effort under climate policy. Unfortunately, there is a high degree of ambiguity in existing approaches for calculating mitigation contributions. Most importantly, different accounting methods exist.

By choice of an accounting method, implicit assumptions about substitutions between baseline and climate policy case are made. For instance, if mitigation contributions are calculated based on changes in primary energy consumption (e.g. Edmonds et al., 2000; Riahi et al., 2007), it is implicitly assumed that one unit of high carbon primary energy in the baseline is replaced by one unit of low carbon primary energy or energy conservation in the policy scenario. This assumption is problematic for several reasons. First, there is no unambiguous way of primary energy accounting (Lightfoot, 2007; IPCC, 2011, Annex II). This ambiguity in primary energy accounting translates directly to ambiguity in the calculation of CO_2 emission mitigation contributions (cf. Supplementary Online Material). Secondly, climate policy will induce substitutions on the level of secondary energy production (e.g. by replacing electricity from coal with electricity from nuclear power), or on the level of final energy demand (e.g. by a switch from non-electric final energy demand in households and industry to electricity). Such substitutions will not necessarily result in a one-to-one substitution on the primary energy level. Thirdly, related to the second point, different secondary energy carriers have different conversion efficiencies and emission intensities. For accurate accounting how much each energy carrier contributes to reduce emissions it matters, for instance, if renewable energy replaces fossils in electricity production (where one unit of wind or solar primary energy replaces some two to three units of fossil primary energy), or to produce heat (where renewables and fossils have similar conversion efficiencies). This difference is not captured by primary energy accounting.

In view of the shortcomings of primary energy accounting, we propose a refined methodology that is based on secondary energy accounting, thus tracking substitutions at the level of detail represented in the model. This approach (a) fully differentiates according to emission intensities of different secondary energy types, (b) explicitly accounts for the mitigation contribution from end-use energy efficiency improvements and shifts in final energy carriers, and (c) captures the effect of joint production, e.g. in combined heat and power plants (CHP). Our goal is to establish an approach that is transparent and intuitive, and helps to reduce the ambiguity in the attribution of emission reduction to technologies.

A full documentation of the methodology is provided in supplementary material. The basic rationale is to consider climate-policy-induced changes in the technology portfolio for each region, time period, and secondary energy type, and to attribute emission reductions to individual energy conversion technologies. The method is unique in the sense that it tracks substitutions within the energy sector at the finest resolution represented in the model. It is composed of six distinct steps (the indices for region *r* and time *t* have been omitted for better readability):

1. For each technology *i* and secondary energy type *j*, calculate the difference of production between baseline and policy scenario ΔS_{ij} :

$$\Delta S_{ij} = S_{ij}^{\text{pol}} - S_{ij}^{\text{bau}}$$

2. Calculate emission intensities ε_{ij} for each technology *i* producing secondary energy carrier *j*:

$$\epsilon_{ij} = \frac{E_{ij}}{S_{ij}}$$

In the case of joint production, emissions for each technology are distributed across products according to the relative output shares.

3. Calculate the average emission intensity $\overline{\varepsilon}_j$ of replaced production of secondary energy carrier *j* :

$$\overline{\epsilon}_j = \frac{\sum_{i:\Delta S_{ij}<0}(\epsilon_{ij}\Delta S_{ij})}{\sum_{i:\Delta S_{ij}<0}\Delta S_{ij}} ,$$

where the sums run over all technologies with deployment ΔS_{ij} lower than in the baseline, and ε_{ij} denoting the emission intensity of technology *i* in producing secondary energy carrier *j.*

4. For all conversion technologies *i* that are deployed at higher levels than in the baseline, calculate mitigation contribution M_{ij} for the production of secondary energy carrier *j*: The mitigation contribution is assumed to be zero for technologies with deployment

$$M_{ij} = \begin{cases} \Delta S_{ij}(\overline{\varepsilon}_j - \varepsilon_{ij}) & \text{if } \Delta S_{ij} > 0 \\ 0 & \text{if } \Delta S_{ij} \leq 0 \end{cases}$$

lower than in the baseline. Note that M_{ij} will be positive for all technologies with emission intensities ε_{ij} smaller than the average emission intensity of the replaced technologies. This is usually the case, since climate policy will result in expansion of low emission technologies.

5. For each secondary energy carrier *j*, calculate the contribution of adjustments in energy end-use to emission reductions. These terms capture both the reductions in final energy demand and substitutions between end-energy carriers.

$$M_j^{\text{eff}} = -\sum_i (S_{ij}^{\text{pol}} - S_{ij}^{\text{bau}})\bar{\epsilon}^j$$

Note that M_i^{fin} can become negative if the secondary energy demand *j* is higher in the policy case than in the baseline. For some of the scenarios considered, we find electrification of energy end use to result in higher electricity consumption than in the baseline, thus yielding a negative end-use share for electricity. In line with intuition, however, this is found to be smaller than the end-use related emission reduction from non-electric end use.

We can proof that the sum of all technology contributions M_{ij} and the end-use contribution M_i^{fin} is equal to the difference of baseline and policy emissions (see supplementary online material). Hence, the decomposition of emission reductions into the above components is complete. An important feature of this approach is thus that the end-use contribution is calculated explicitly, rather than determined as the residual of the mitigation gap.

6. For 11 regions, 48 primary to secondary energy conversion technologies and 9 secondary energy carriers represented in ReMIND-R, steps 2 and 3 result in some 450 non-zero summands of individual reduction contributions for each time step. For the further analysis, we thus group these 'micro-shares' into different technology categories, end-use sectors, and region groups.

4. Economic mitigation potential of technologies

4.1 The global perspective

In order to achieve climate stabilization, emissions have to be reduced substantially compared to business-as-usual. The scale of this challenge is illustrated in Fig. 1. Under our baseline scenario, which describes a world without any climate policy, emissions from the energy system would more than double between 2005 and 2060, and slightly decrease thereafter. Driven by a nine-fold increase in gross world product between 2005 and 2100, the scale of the global energy system would reach almost 1200 EJ/yr in terms of primary energy use[1] (Figure 2). This increase is largely driven by an increase in coal use. Our medium tax scenario TAX-30 results in a climate forcing of 2.9 W m^{-2} by 2100, roughly consistent with the 2°C target. Global energy-related CO_2 emissions peak in 2020 and decline to negative net emissions by 2080.

Based on the methodology outlined in Section 2, the emission reductions performed relative to the baseline scenario can be attributed to the technology groups fossil fuel switch, fossil CCS, biomass without CCS, biomass with CCS, other renewables, nuclear, as well as improvements in end-use efficiency. This analysis reveals that the bulk of the mitigation effort is borne by bioenergy use with CCS (BECCS), non-biomass renewables, and end-use efficiency. It is important to note that the end-use share accounts not only for the improvements of demand side efficiency in using various final energy carriers, but also for the substitution from energy carriers that are less efficient or more carbon intensive to those that are more efficient and less carbon intensive, e.g. increased use of electricity instead of solids in households and industry. The share of end-use efficiency in total abatement is particularly high initially, and continues to contribute substantially to the mitigation effort throughout the century. The significance of biomass lies (a) in its versatility as primary energy carrier for transport fuels, electricity production, and non-electric secondary, and (b) in the possibility to generate negative net emissions using BECCS. For this study we assumed a resource constraint on the availability of bioenergy that increases from 2005 deployment levels of 55 EJ to 200 EJ in 2050. With this constraint, the main contribution of biomass to emissions abatement comes from redirecting bioenergy feedstocks to BECCS conversion pathways, rather than the expansion of bioenergy production. ReMIND considers a variety of BECCS conversion technologies, ranging from biomass based internal gasification combined cycle power plants (Bio-IGCC), to biomass-to-liquid, bio-gasification, and biomass-based hydrogen production. Non-biomass renewables deployment is dominated by wind energy, solar photovoltaic, and concentrating solar power, all of which contribute substantially to the provision of carbon-free electricity in the climate policy scenario.

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[1] Primary energy demand is expressed in direct equivalent terms, see IPCC (2011, Annex II) for a detailed discussion of primary energy accounting methods.

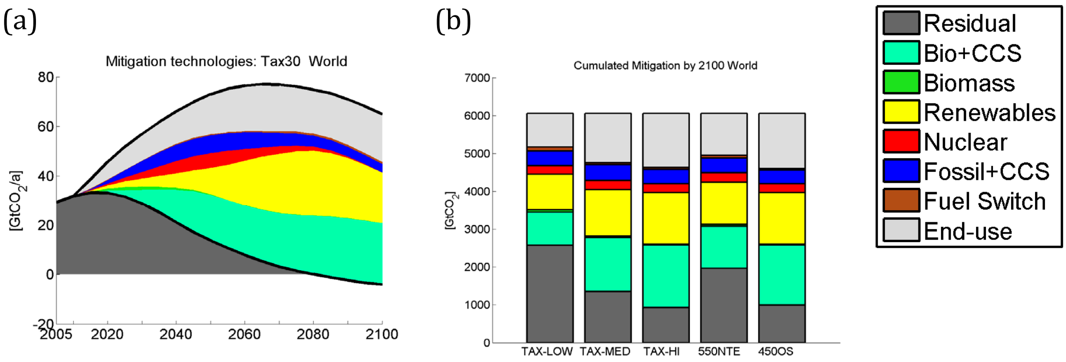

Figure 1: (a) Emission gap between the baseline scenario and the Tax30 climate policy scenario. The emission reductions induced by climate policy are decomposed into six technology groups as well as the contribution of changes in end-use. (b) Global emission reductions cumulated 2005-2100 for different climate policy scenarios.

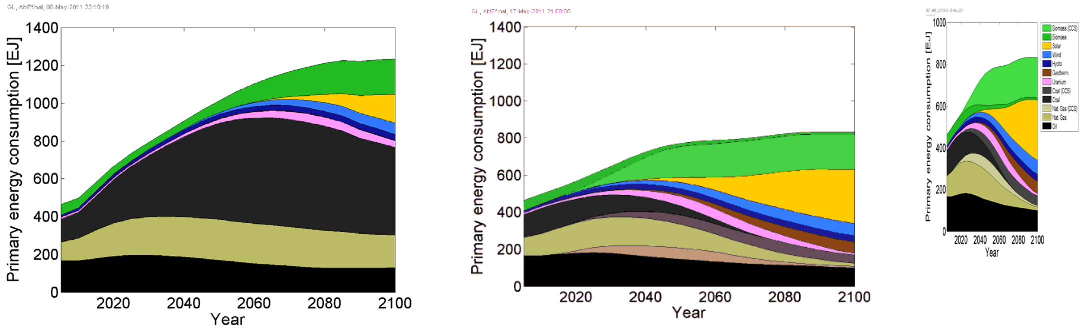

Figure 2: Primary energy consumption (direct equivalent accounting) in (a) the baseline, and (b) the TAX-30 climate policy scenario.

The expansion of nuclear energy and the introduction of fossil CCS contribute at a smaller scale, and their contribution declines in the 2nd half of the century. We assume a constraint on global uranium availability of 23 MtU_3O_8, which limits the long-term deployment level of nuclear. Fuel recycling of uranium and the use of alternative nuclear fuels are assumed to be unavailable. The competiveness of fossil vis-à-vis carbon-free alternative technologies decreases with increasing carbon prices due to the significant residual emissions, thus making fossil CCS less attractive on the long term. Fuel switch (i.e. use of less carbon-intensive fossil fuels, e.g. natural gas in lieu of coal) only have negligible contributions to the mitigation effort. At the level of ambition considered here, fuel switch is unattractive due to the small emission reductions compared to advanced low carbon technologies.

The dominance of BECCS, other renewables, and end-use efficiency in global mitigation potentials is robust over the entire set of climate policy scenarios (Figure 1b). Their emission reduction potential increases with increasing climate policy ambition and carbon prices. The contribution of nuclear remains almost constant, largely due to the limited uranium resource. Similarly, the cumulated economic mitigation potential for fossils with CCS is similar across scenarios, because in the high carbon price scenarios higher and earlier deployment of CCS in the first half of the century is offset by lower deployment of CCS in the later decades. Fuel switch from coal to gas accounts for a small portion of emission reductions in the TAX-10 and 3.7NTE scenarios, but becomes increasingly insignificant for the more ambitious scenarios.

Scenario	CO2 FF&I 2005-2100 [10^3 $GtCO_2$]	GHG 2005-2100 [10^3 $GtCO_2$]	Forcing in 2100	GMT increase in 2100	Mitigation costs
REF	6.1	7.4	6.0 W m^{-2}	3.5 °C	-
TAX-10	2.5	3.5	3.7 W m^{-2}	2.5 °C	0.4%
TAX-30	1.4	2.1	2.8 W m^{-2}	2.0 °C	1.1%
TAX-50	0.9	1.7	2.5 W m^{-2}	1.8 °C	1.7%
3.7NTE	2.3	3.2	3.7 W m^{-2}	2.4 °C	0.6%
2.6OS	1.2	2.0	2.6 W m^{-2}	1.9°C	1.4%
DELAY2020	1.6	2.4	3.0 W m^{-2}	2.1 °C	1.0%

Table 2: Overview of scenario results in terms of cumulative CO2 emissions from fossil fuels and industry; cumulative emissions of CO2, N2O and CH4; anthropogenic radiative forcing (including long-lived GHGs, aerosols, and other forcing components); increase of global mean temperature relative to pre-industrial levels; and mitigation costs in terms of cumulated consumption losses relative to baseline discounted at 5%.

Table 2 provides an overview of the scenarios considered. The reference scenario results in a cumulated emissions budget from fossil fuel use of 6.0 $TtCO_2$ for the time horizon 2005-2100. An increase of radiative forcing to 6.1 W m^{-2} would result, with a transient temperature response of 3.5°C by 2100. The carbon tax scenarios result in reductions of cumulated CO_2 emissions to 2.5 $TtCO_2$ (TAX-10), 1.4 $TtCO_2$ (TAX-30), and 0.9 $TtCO_2$ (TAX-50). Emission budgets for the climate stabilization scenarios 3.7NTE and 2.6OS are 2.3 and 1.2 $TtCO_2$, respectively. The tax scenarios lead to radiative forcing levels of 2.5-3.7 W m^{-2}. While our model project three of the climate policy scenarios to lead to a stabilization of global mean temperature increase below (TAX-50, 2.6OS) or slightly above (TAX-30) the 2°C mark, the TAX-10 and 3.7NTE scenarios would clearly fall short of this target.

The ordering of mitigation costs corresponds to that of emission budgets. The cumulated discounted consumption losses incurred by climate policy range from 0.4% (TAX-10), 0.6% (3.7NTE), to 1.1% (TAX-30), 1.5% (2.6OS), and 1.6% (TAX-50). A strongly convex cost pattern emerges: incremental mitigation costs increase substantially with increasing levels of climate policy ambition.

4.2 Decarbonization of end-use sectors

The method of secondary energy based mitigation shares makes it possible to attribute the mitigation effort to the three end-use sectors electricity, heat, and transport. In 2005, electricity generation worldwide accounted for emissions of 9.8 $GtCO_2$, while emissions from the heat sector (households and industry) and transport were 12.5 $GtCO_2$, and 7.2 $GtCO_2$, respectively[2].

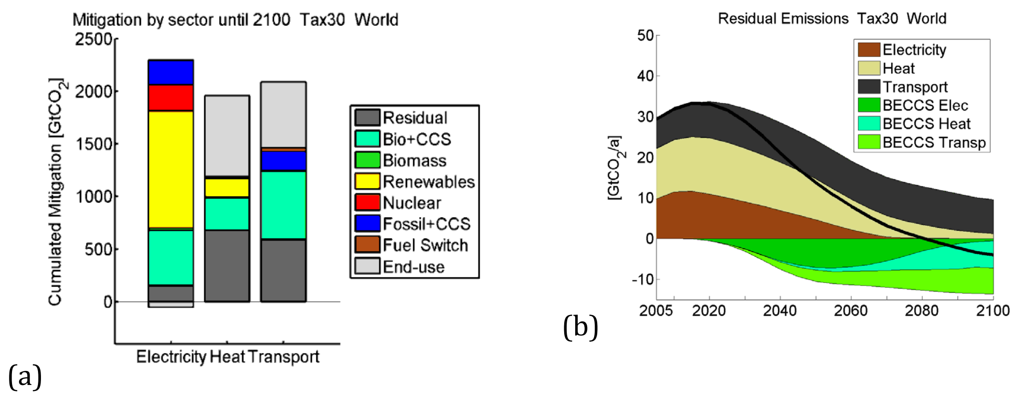

Figure 3: (a) Mitigation contribution of technologies cumulated from 2005-2100, and broken down by the end-use sectors electricity, heat, and transport for the TAX-30 climate policy scenario. (b) Residual emissions decomposed by end-use sector. The solid black line in (b) indicates net emissions.

Figure 3(a) breaks down emission reductions for the TAX-30 scenario by the end-use sectors electricity, heat and transport. The analysis reveals that mitigation potentials and decarbonization patterns differ considerably across these three sectors. An array of supply-side low-carbon alternatives is available for the power sector: renewables (mostly wind, photovoltaics and concentrating solar power), nuclear power, and CCS with fossils or

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[2] ReMIND results based on calibration to IEA Energy Balances (IEA 2007a, IEA 2007b)

biomass. As a consequence, cumulative emissions are reduced to 7% of the emissions that would occur under business-as-usual. Much fewer technology options are available for non-electric energy use, therefore the heat and transport sector account for the bulk of the residual CO_2 emissions from the energy system. In the transport sector, the production of synfuels and H_2 from biomass, and to a lesser extent also from coal, in combination with CCS are the most important mitigation technologies in our model. End-use (efficiency improvements and demand reduction) accounts for 29% of emission reductions relative to the reference scenario.

The heat sector is characterized by the highest share of residual emissions (35% of reference levels). The relevant supply-side mitigation technology options are methane and hydrogen production from BECCS, and non-biomass renewables for low-temperature heat. They combine to a reduction of 26% relative to reference levels. The dominant share of emission reductions (37%) in the heat sector originates from end-use: In addition to the reduction of energy intensity, the shift to electricity as a final energy carrier contributes strongly. Conversely, based on the emissions accounting methodology used here, the resulting increase of electricity demand yields a negative contribution of end-use for electricity.

The difficulty of decarbonizing heat and transport hints at a dominant role of these sectors in defining the lower limit of achievable reduction targets ("feasibility frontier", cf. Knopf et al., 2011). Figure 3(b) provides a complementary perspective on sectoral emission patterns by decomposing residual fossil emissions and the negative BECCS contribution by end-use sectors. The fossil fuel emissions from the power sector are dominated by residual emissions from existing vintages of present generation capacities. These emissions decline gradually as old vintages of fossil-based power generation capacities are replaced by low-carbon alternatives. Fossil emissions from the heat sector remain substantial, and decrease only gradually in the 2^{nd} half of the century, when an increasing share of the global bioenergy becomes available for this sector. Due to the lack of competitive alternatives, fossil fuel emissions from the transport sector remain above 2005 levels throughout the century, despite the considerable increase of carbon prices.

5. Climate change mitigation in Asia

5.1 Emissions abatement and technologies

Asia[3] accounted for 36% of global energy-related CO_2 emissions in 2005. In absence of climate policy, emissions are projected to increase more than three-fold over the course of the century, resulting in a 53% share of global emissions in 2100. The introduction of a price on carbon is found to result in a substantial decrease of CO_2 emissions (Table 3).

Scenario	CO_2 Fossil Fuel and Industry Emissions 2005-2100 [$GtCO_2$]				Asian share of global total
	CHN	IND	OAS	JPN	
REF	1.47×10^3	473	698	160	46%
TAX-10	630	256	267	77	48%
TAX-30	356	122	181	62	53%
TAX-50	262	86	140	57	59%
3.7NTE	542	213	248	72	50%
2.6OS	286	99	158	69	57%
DELAY2020	513	180	209	61	61%

Table 3: Overview of regional cumulative energy-related CO_2 emissions for the different scenarios.

Emissions trends in the reference scenario differ considerably across world regions, largely driven by differences in socio-economic developments, energy resource potentials, and patterns of energy end-use. Similarly, domestic abatement efforts and the role of technologies in realizing emission reductions vary according to regional specificities.

Figure 4 illustrates regional primary energy consumption in selected regions. Until mid-century, the bulk of the energy supply is provided by fossil fuels. China, India, Japan and USA are projected to rely heavily on coal, thus their energy systems are highly emission-intensive. By 2100, an increasing share of energy supply comes from wind, solar and

[3] In this study, we consider the four Asian regions China, India, Japan, and OAS (other developing countries of Southern, Eastern, and Southeastern Asia as well as Korea). We refer to the aggregate of these four regions as "Asia".

biomass, particularly in the USA, China, OAS and other developing countries. Under climate policy, fossil use is scaled back substantially in all world regions.

For the TAX-30 scenario, biomass and nuclear is expanded considerably compared to REF in 2050, and fossil-CCS is deployed at large scale. It is noteworthy that about four fifth of the global nuclear energy is projected to be deployed in Asia. By the end of the century, primary energy supply is dominated by renewables. Strong regional differences emerge in particular in terms of the role of solar energy, which has the highest resource potential in China, OAS, USA and other developing countries. Biomass use plays an important role in Russia (included in othIC), as well as Latin America and Africa (included in othDC).

As shown in Section 4.2, the sectoral structure of energy end-use affects technology options for climate change mitigation. Current patterns of final energy exhibit strong regional patterns (Figure 5): In 2005, the role of transport fuels in final energy use in the Asian regions is less significant compared to the USA and Europe. The share of electricity in end-use is comparatively small for developing countries. For the future, we project increasing electrification and an increase in the demand for transport fuels in the developing world. The effect of climate policy on final energy is two-fold: First, it results in a substantial contraction of final energy demand in all world regions, and second it tends to increase the share of electricity in final energy use.

Figure 6 illustrates regional decarbonization patterns for the time span from 2005-2100, both in relative and in absolute terms. The reductions in cumulative emissions relative to BAU levels in the climate policy scenarios provide an indication of the economic mitigation potential. Under the Tax30 climate policy scenario, global cumulative emissions contract to one fifth of the emissions that would occur under BAU. Regional abatement potentials vary strongly, with Europe and Japan reducing no more than 55% and 60% of BAU emissions, while other world regions (in particular biomass-rich Russia, Latin America and Africa) are almost carbon neutral over the course of the century. Renewable potentials, both biomass and non-biomass renewables, are found to be key drivers of regional decarbonization patterns. According to the renewable resource estimates used for ReMIND (Trieb et al., 2009) China features a high-quality solar resource potential, thus these technologies contribute strongly to emissions abatement. In India, by contrast, the resource potential of non-biomass renewables is of lesser quality, making BECCS and end-use efficiency somewhat more important.

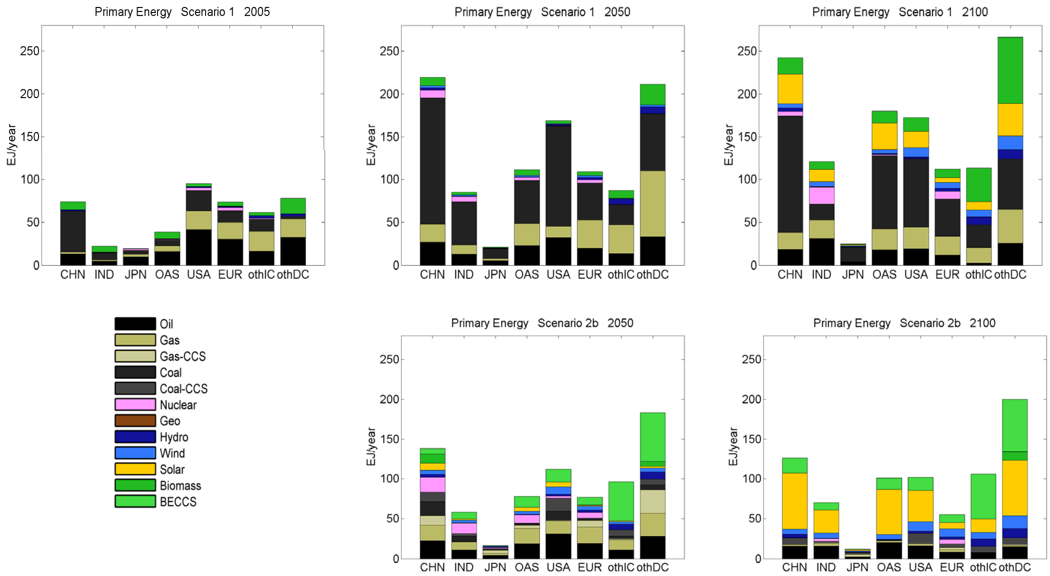

Figure 4: Regional PE mixes (direct equivalent accounting for nuclear and non-biomass renewables) for different world regions in 2005, 2050 and 2100. Upper row: REF scenario; lower row: TAX-30 scenario (othIC: other industrialized countries; othDC: other developing countries).

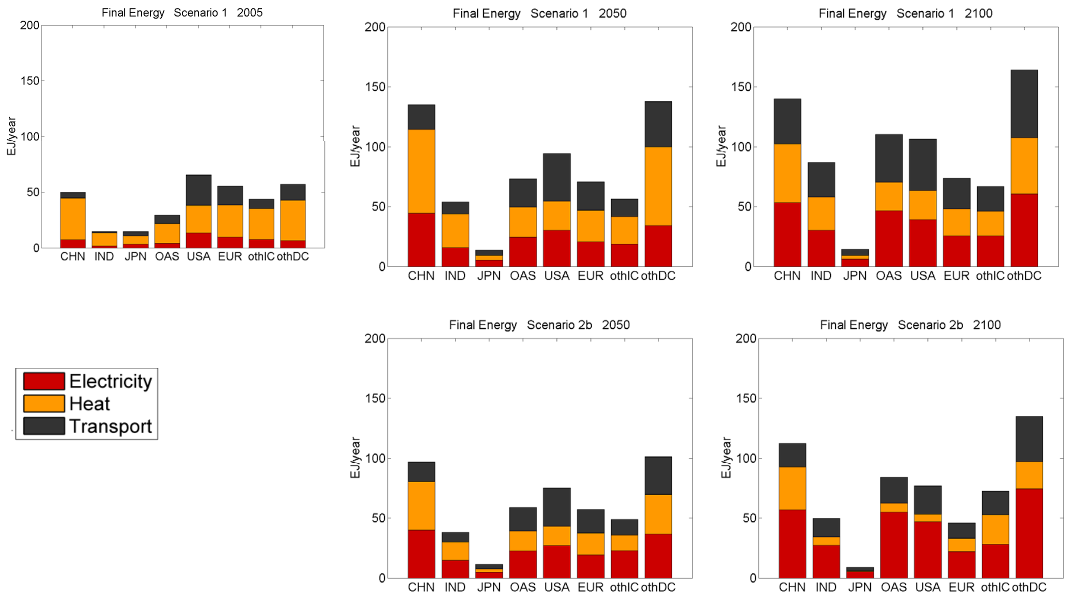

Figure 5: Regional final energy consumption by end-use sectors electricity, heat and transport for different world regions in 2005, 2050 and 2100. Upper row: REF scenario; lower row: TAX-30 scenario (othIC: other industrialized countries; othDC: other developing countries).

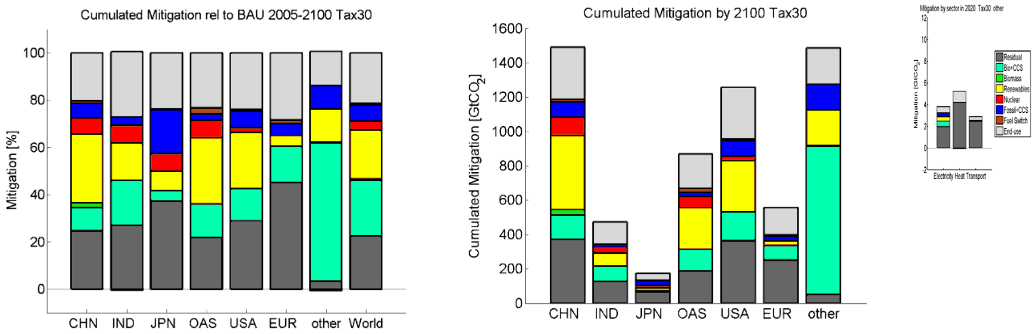

Figure 6: Cumulated mitigation from 2005-2100 in selected model regions, expressed (a) relative to baseline emissions, and (b) in absolute terms.

5.2 The significance of early action: Asian developing countries

The rapidly developing economies of Asia have recorded considerable increases of greenhouse gas emissions over the past years (e.g. Raupach et al., 2007). Our baseline projects a further rapid increase of emissions if no climate policy is implemented, due to continued economic growth, and a strong reliance on coal as a source of energy. In order to satisfy the growing energy demand, substantial investments into energy infrastructure are required. This is exemplified by the rapid expansion power sector as shown in Figure 7. In absence of climate policy, the bulk of the near term investments in China and India will go to coal-based installations. OAS is less coal-reliant. In the medium term, the share of nuclear in investments increases substantially. Even without climate policy, investments in renewables are significant, and account for a dominant share of power sector investments by the end of the century. It is important to note, however, that the share of investments into renewables and nuclear tends to overstate their share in electricity production, since capital expenditure is much higher for these technologies than for fossil-based installations.

Climate policy has several effects on power sector investments. In both China and India, investments into conventional coal-fired power plants decline rapidly and vanish after 2020. In the medium to long-term, as the capital-intensive nuclear and non-biomass renewable technologies account for an increasing share of new installations, the overall scale of investments increases substantially. After 2070, renewable investments decrease due to a stabilization of electricity demand and limitations in the renewable resource potential. Nuclear investments are brought forward in the climate policy case compared to the baseline. In the case of India, nuclear investments in the 2nd half of the century are smaller than in the reference case, due to a depletion of global uranium resources, and the increasing competiveness of wind and solar energy.

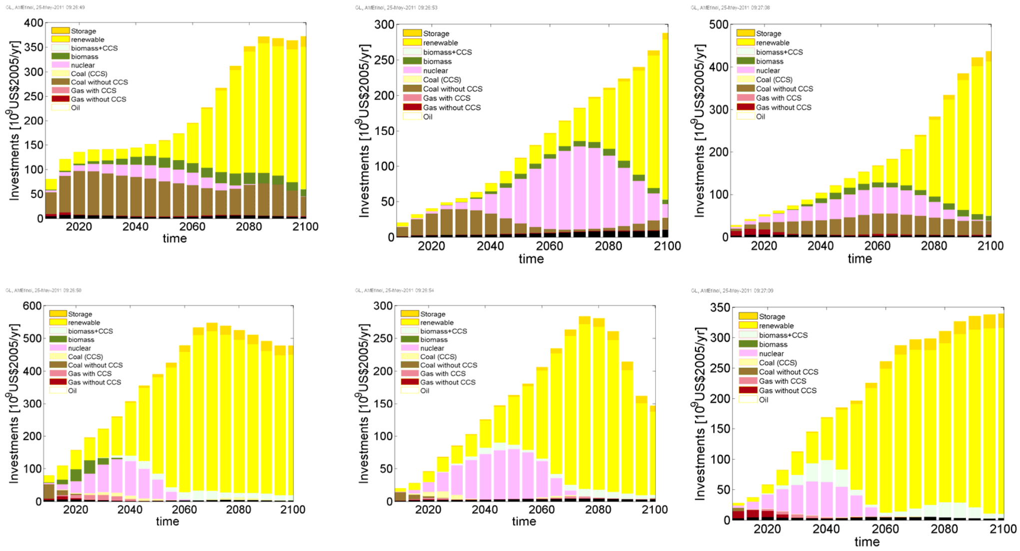

Figure 7: Investments into power generation capacities for China (left), India (middle) and OAS (right), for the reference case (left) and the TAX-30 climate policy scenario (right).

In view of the large investment needs in developing Asia, as well as the strong effect of climate policy on near-term investments the question arises to what extent near-term climate policy affects energy system emissions in the long-term. In order to contrast the short-term and long-term effects of early adoption of climate policy, we constructed a variant of the TAX-30 scenario ("delay2020") in which China, India, and other developing countries of Asia were assumed to delay climate policy and to follow the reference development myopically until 2020, while other world regions adopt the uniform carbon tax from 2015. The Asian regions are assumed to join the global climate mitigation effort in 2025 by adopting the carbon tax. Considering the substantial climate mitigation efforts that are already under way in Asia, it is important to note the assumption of no climate policy until 2020 presents an already counter-factual development. For instance, China's Copenhagen Pledges in terms of reductions of the emission intensity of GDP and the low-carbon share in primary energy provision are roughly in line with our TAX-30 scenarios. By contrasting our hypothetical delay2020 scenario with immediate adoption of climate policy in all world regions, we can not only analyze how near-term emissions decrease in response to climate policy, but also how early action influences the achievability of deep emission cuts in the medium to long-term future.

Figure 8 shows mitigation shares for both the TAX-30 and the delay2020 case for China, India, and OAS. Immediate adoption of climate policy results in a peaking of energy-related emissions in 2020 at a level of 7.2 $GtCO_2$ (China), or 2025 at a level of 1.9 $GtCO_2$ (India) and 3.0 $GtCO_2$ (OAS). For a delay in climate policy, the time of peaking remains unchanged for China and India, but emission levels in 2020 are 56% higher than in the case of China, 69% higher in the case of India, and 26% in the case of OAS.

Due to the lock-in into carbon-intensive energy generation capacities, the effect of delay on long-term emissions is substantial. For delay2020, emission levels in 2050 are still 1.9 $GtCO_2$ (China) and 1.1 $GtCO_2$ (India) higher, respectively, than in the TAX-30 scenario with immediate action. The emissions of China cumulated from 2005-2100 in the delay2020 case are 513 $GtCO_2$, roughly 44% higher than in TAX-30. In the case of India, the cumulative emissions amount to 180 $GtCO_2$, which corresponds to an almost 50% increase relative to TAX-30. For OAS, the effect of delay is less pronounced because the bulk of future emission growth in the no-policy scenarios is projected to occur after 2020.

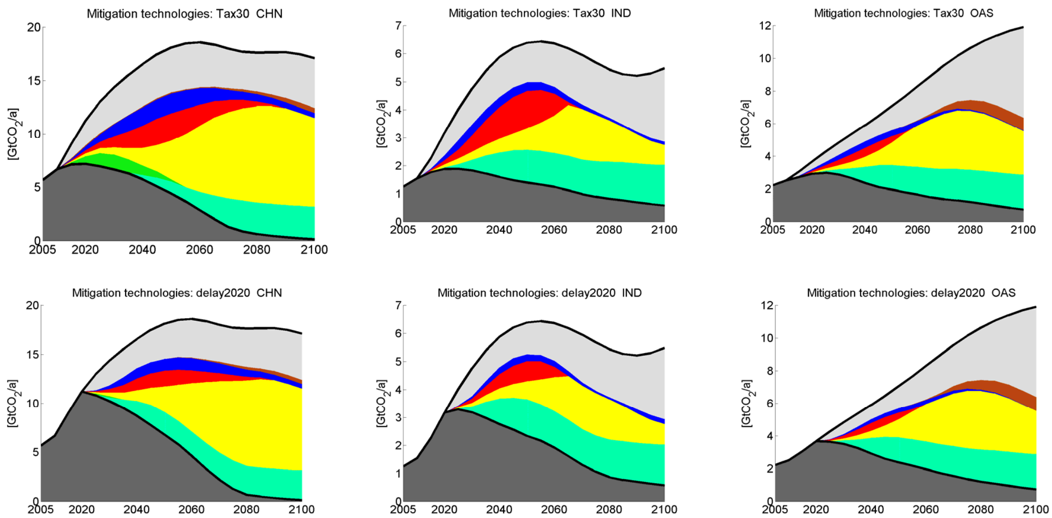

Figure 8: Emission reductions for China (left), India (middle), and other developing Asia (OAS, right) in response to the carbon taxation for the TAX-30 scenario (upper row) and the delay2020 scenario (lower row). Same color code as in Figure 1.

6. Discussion and conclusion

The analysis of the role of technologies in reducing energy system emissions ranks high on the agenda of climate mitigation research in general and integrated assessment modeling in particular. As discussed in Section 1, different ways of characterizing the role of technologies in for climate change mitigation exist. They can be grouped into (a) analyses of deployment levels, (b) analyses of the cost markups arising from foregoing certain technology options (“knock-off scenarios”), and (c) analysis of mitigation effectiveness, i.e. the quantification of the contribution of technologies to emission reductions. In this paper, we introduced the concept of secondary energy based mitigation shares, which falls into the latter category.

While these three different approaches result provide a consistent perspective, they are not equivalent. They assess the role of technologies from different angles, and thus are largely complementary. Studies of deployment levels can inform about technology roadmaps and expansion rates that are consistent with climate stabilization targets. Technology knock-off scenarios give an indication of the degree of indispensability of low carbon technologies, and allow quantifying their strategic economic value. Our mitigation shares provide a metric for the contribution of technologies in terms of emission reductions achieved, i.e. the realized mitigation potentials. Their added value as a diagnostic tool lies in weighting the expansion of each technology with the emission reductions induced by replacing secondary energy production capacities that would have been utilized in the absence of climate policy, thus synthesizing information about deployment levels in the policy case relative to the baseline, as well as substitutions within the energy system.

It is important to note, however, that every single approach is incomplete and limited. For instance, the relative shares of low carbon technologies in primary energy supply depend strongly on the accounting method. Unless compared to a corresponding baseline scenario, deployment levels of technologies in climate stabilization scenarios do not inform to what extent technologies are used for mitigation, or would have been deployed even in absence of climate policy. For technology knockoff scenarios, the quantification of the importance of technologies via cost markups depends on the extent of deployment restrictions, cost-metrics, and discounting.

A number of different approaches exist for quantifying emission reduction contributions of technologies. This ambiguity in methodology led to uncertainty about the appropriate decomposition of emission reductions. We argue that the secondary energy based shares are superior to existing approaches, chiefly because substitutions of fossil-based technologies by low-carbon alternatives are traced at the finest level resolved by the model, thus substantially reducing the ambiguity in accounting.

Several important caveats and limitations remain: (a) In view of the complex system dynamics within the energy system, it is not possible to construct alternative mitigation scenarios by recombining individual mitigation technologies. The decomposition of emission reductions into mitigation fractions is thus only a diagnostic tool for the analysis of climate change mitigation scenarios. This caveat is particularly important for the communication of results to stakeholders and policy-makers. (b) The method only accounts for expansion of mitigation technologies beyond baseline levels. Thus it tends to obscure the role of low-carbon technologies with substantial deployment levels in the reference scenario, e.g. nuclear and wind power. (c) The calculation of secondary energy based mitigation shares is rather complex and needs to be tailor-made to the representation of the energy supply structure that is specific to each individual model.

7. Summary and conclusion

We have described the results of a reference and several climate policy scenario runs conducted with ReMIND-R. The focus of our analysis was on the economic mitigation potential of technologies, with a special focus on Asia.

A number of important policy-relevant conclusions emerge from our analysis: Firstly, we find that Asia plays a pivotal role in the global efforts to achieve climate stabilization. Asia currently accounts for almost two fifth of global emissions, and its share is projected to grow further, both in the reference and the climate policy scenarios. Clearly, without involvement of Asian countries, ambitious climate targets cannot be reached. Reconciling the legitimate priorities of Asian developing countries in terms of development and economic prosperity with the requirements of global climate change mitigation requires a substantial deviation from current emission trends and large-scale deployment of low-carbon technologies.

On the global scale, we find biomass in combination with CCS, other renewables, and the reduction of energy demand to offer the largest CO_2 emission reduction potential. Nuclear and fossil CCS also contribute substantially to emission reductions, particularly in the medium term. We find substantial differences in decarbonization of different end-use sectors. While renewables, nuclear and CCS present ample opportunities exist for reducing emissions from electricity supply, only few mitigation options exist for non-electric energy demand. Consequently, much larger emission reductions are realized in the power sector, and the bulk of residual emissions originate from the transport and heat sectors. This result is in line with the findings of the RECIPE project (Luderer et al., 2011), and suggests that the development of advanced mitigation options for non-electric energy demand are of crucial importance for the cost and achievability of low stabilization targets.

Regional differences in the role of mitigation technologies can emerge from three different factors: (a) supply-side differences in fossil and renewable energy resource endowments; (b) demand-side differences in the current structure and the future development of final energy use; and (c) differences in technology factors, such as capital costs, labor costs, and the policy environment, e.g. due to subsidies, regulation, and public acceptance. In our scenarios, differences in resource endowments result in considerable regional differences in technology deployment. While the biomass resource potential and fossil fuel resources are limited in Asia, other renewables are an important long-term mitigation option for China, other developing Asia, and, to a lesser extent, India. In the medium term, nuclear contributes sizably as a bridging technology under climate policy. So far, systematic studies of the effect of structural changes in energy end use, as well as the effect of differences in technology factors are missing. Such analyses should be a priority for further research.

Finally, our results emphasize the long-term benefits of early implementation of climate policy. Many countries in Asia have already adopted climate policy measures. We performed a stylized analysis that contrasts the scenario with immediate and globally coordinated climate policy to a scenario of delayed participation of Asian developing countries. Our results demonstrate that early adoption of climate policy does not only result in near-term emission reductions, but also avoids lock-in into carbon intensive infrastructure and thus leads to a much higher long-term mitigation potential, in particular in China and India.

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Secondary Energy Based Mitigation shares.

Supplementary Material for the Paper
"Asia's Role in Mitigating Climate Change:
A Technology and Sector Specific Analysis with ReMIND-R"

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Markus Haller, Nico Bauer

June 2, 2011

This document provides supplementary information on the abovementioned article. It contains a detailed description of the approach used to calculate mitigation shares and proofs that the approach is complete in the sense that the sum of all individual shares is equal to the difference between baseline and policy emissions.

1 Basic concept

The basic rationale is to attribute emission reductions induced by climate policy to individual technologies by tracking the substitution between different technology pathways for the provision of secondary energy. By considering region, time period, and secondary energy type individually, the calculation is performed at the highest possible resolution represented in the ReMIND model.

More formally, we base our method on the following requirements, or *axioms*:

(A1) The sum of all individual technology shares shall equal the difference between baseline and policy emissions for each time step and region.

(A2) For each time step, region and secondary energy carrier, the abatement credit (i.e., the emission intensity per unit of secondary energy production capacity replaced relative to baseline) shall be equal for all technologies with deployment levels higher than in the baseline.

(A3) For each time step, region and secondary energy carrier, the abatement credit for reductions of end-use shall be equal to that of secondary energy producing technologies.

(A4) For each time step and region, the mitigation share of technologies with deployment levels lower than in the baseline shall be zero.

These axioms are rather intuitive. (A1) demands that the decomposition of emissions abatement into shares be complete. (A2) and (A3) ensure that all technologies that produce the same secondary energy carrier as well as end-use efficiency are credited equal for the replacement of CO2-emitting production capacities that would have existed in the baseline. Axiom (A4) ensures that none of the emission reductions are attributed to "dirty" technologies for being deployed at lower levels than in the baseline.

2 Algorithmic Implementation

Based on the above axioms, secondary-energy based mitigation shares can be constructed in a straight-forward way. It is essential that the method is applied for each time step and region individually. However, for the sake of better readability the indices for region r and time t are omitted in the following. The routine is composed of the following distinct steps:

1. For each technology i and secondary energy type j, calculate the difference of production between baseline and policy scenario ΔS_{ij}:
$$\Delta S_{ij} = S_{ij}^{\text{pol}} - S_{ij}^{\text{bau}} \tag{1}$$

2. Calculate emission intensities for each technology i producing secondary energy carrier j:
$$\varepsilon_{ij} = \frac{E_{ij}}{S_{ij}} \tag{2}$$
In the case of joint production, emissions for each technology are distributed across products according to the relative output shares.

3. Calculate abatement credit as the average emission intensity of replaced production capacities of secondary energy carrier j:
$$\overline{\varepsilon}_j = \frac{\sum_{i:\Delta S_{ij}<0}(\varepsilon_{ij}\Delta S_{ij})}{\sum_{i:\Delta S_{ij}<0}\Delta S_{ij}} \tag{3}$$
where the sums run over all technologies with deployment ΔS_{ij} lower than in the baseline, and ε_{ij} denoting the emission intensity of technology i in producing secondary energy carrier j. We show in Sec. 4 that this definition of $\overline{\varepsilon}_j$ ensures that axiom (A1) is satisfied – i.e. that the sum of all individual technology shares equals the difference bewteen baseline and policy emissions.

4. For all conversion technologies i that are deployed at higher levels than in the baseline, calculate mitigation contribution M_{ij} for the production of secondary energy carrier j:
$$M_{ij} = \begin{cases} \Delta S_{ij}(\overline{\varepsilon}_j - \varepsilon_{ij}) & \text{if } \Delta S_{ij} > 0 \\ 0 & \text{if } \Delta S_{ij} \leq 0 \end{cases} \tag{4}$$

The mitigation contribution is assumed to be zero for technologies with deployment lower than in the baseline. Note that M_{ij} will be positive for all technologies with emission intensities ε_{ij} smaller than the average emission intensity of the replaced technologies $\overline{\varepsilon}_j$. This is usually the case, since climate policy will result in expansion of low emission technologies.

5. For each secondary energy carrier j, calculate the contribution of adjustments in energy end-use to emission reductions. These terms capture both the reductions in final energy demand and substitutions between end-energy carriers.

$$M_j^{\text{eff}} = -\sum_i (S_{ij}^{\text{pol}} - S_{ij}^{\text{bau}})\overline{\varepsilon}_j \tag{5}$$

Note that M_j^{eff} can become negative if the secondary energy demand j is higher in the policy case than in the baseline. For some of the scenarios considered, we find electrification of energy end use to result in higher electricity consumption than in the baseline, thus yielding a negative end-use share for electricity. In line with intuition, however, this is found to be smaller than the end-use related emission reduction from non-electric end use.

3 Aggregation to sector shares

In the model setting discussed in the paper, the concept described in Sec. 2 results in about 450 mitigation contribution time series M_{ij} – one for each technology and region, plus one end-use share for each energy carrier and region. Fig. 1 gives a graphical representation of these *micro shares.*

The micro shares can be further aggregated across regions, end-use sectors, or technology groups (see Fig. 2). Table 1 shows the composition of the technology groups and their contribution to different end-use sectors. Note that the assignment to technology groups is complete; all conventional technologies are part of the *Fuel Switch* group and have a mitigation contribution unequal to zero if they are deployed at higher levels than in the baseline.

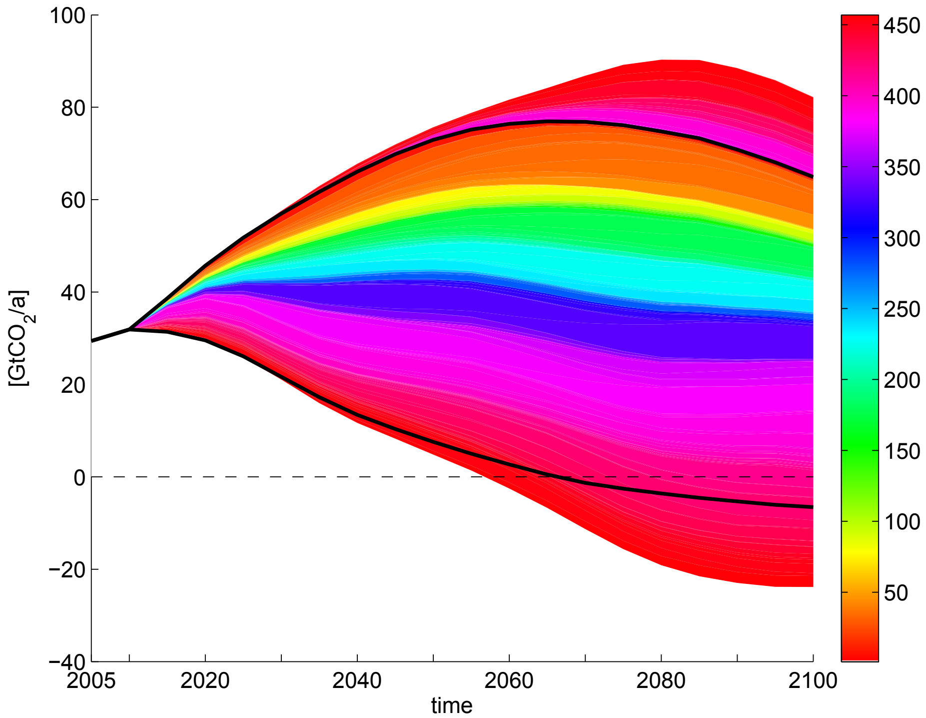


Figure 1: Micro shares: One technology share for each mitigation technology and region, plus one efficiency share for each secondary energy carrier and region, results in a total of about 450 shares.

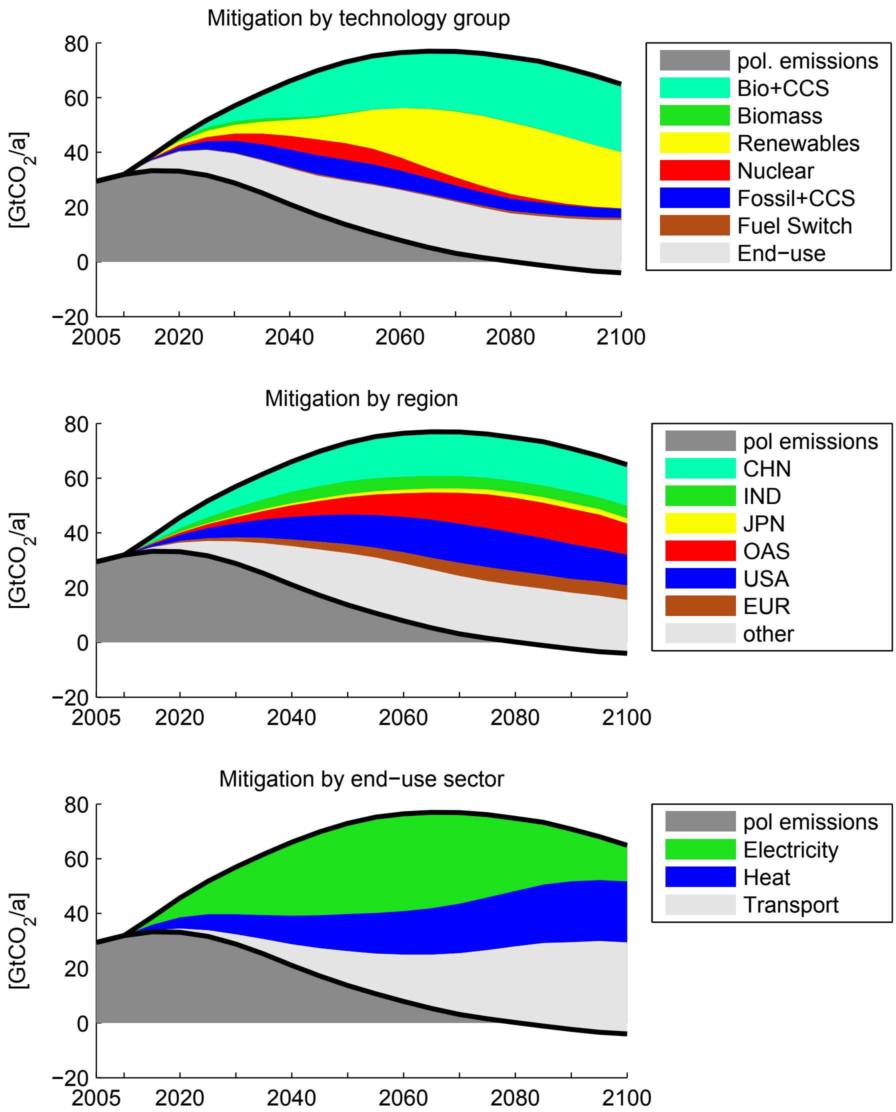


Figure 2: Aggregation of micro shares across technology groups, regions and end-use sectors.

Table 1: Technology groups and their contribution to end-use sectors. PP: power plant, CHP: combined heat and power, CC: combined cycle, IGCC: integrated gasification combined cycle.

	Electricity	Heat	Transport
Renewables	Concentrating Solar Power Solar PV Wind turbine Hydropower Geothermal	Solar thermal Heat pump	
Biomass	Biomass IGCC Biomass CHP	Biomass HP Biomass CHP Biomass gasification Biomass to H_2 Traditional biomass	Biomass to liquid Biomass to H_2
Biomass + CCS	Biomass IGCC + CCS Biomass to liquid + CCS	Biomass to H_2 + CCS	Biomass to H_2 + CCS Biomass to liquid + CCS
Fossil + CCS	Gas CC + CCS Pulverized coal PP + CCS IGCC + CCS Oxfuel PP	Gas to H_2 + CCS Coal to H_2 + CCS	Gas to H_2 + CCS Coal to H_2 + CCS Coal to liquid + CCS
Nuclear	Thermal reactor		
Fuel Switch	Pulverized Coal PP Coal IGCC Gas turbine Gas CC Diesel turbine Coal CHP Gas CHP	Gas HP Gas CHP Gas to H_2 Gas direct Coal HP Coal CHP Coal gasification Coal direct Refinery	Gas to H_2 Coal to H_2 Coal to liquid Refinery

4 Completeness of decomposition

By construction, the secondary energy shares as described in Section 2 fulfill axioms (A2-A4). In the following we proof that algorithm also fulfills axiom (A1), i.e. that the decomposition is complete in the sense that the sum of all technology contributions M_{ij} and the end-use contribution M_j^{eff} is equal to the difference of baseline and policy emissions:

$$M_j = E_j^{\text{bau}} - E_j^{\text{pol}} = \sum_{i:\Delta S_{ij}>0} M_{ij} + M_j^{\text{eff}} \tag{6}$$

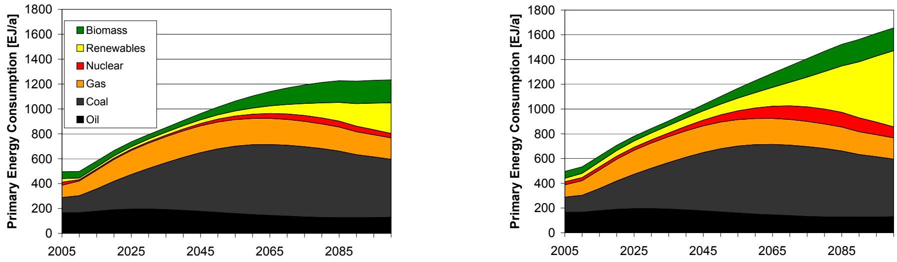
Inserting equations 4 and 5 into equation 6 and rearranging the resulting terms yields:

$$\begin{aligned}
M_j &= \sum_{i:\Delta S_{ij}>0} M_{ij} + M_j^{\text{eff}} && (7)\\
&= \sum_{i:\Delta S_{ij}>0} \Delta S_{ij}(\bar{\varepsilon}_j - \varepsilon_{ij}) - \sum_i (S_{ij}^{\text{pol}} - S_{ij}^{\text{bau}})\bar{\varepsilon}_j && (8)\\
&= \bar{\varepsilon}_j \sum_{i:\Delta S_{ij}>0} \Delta S_{ij} - \sum_{i:\Delta S_{ij}>0} \varepsilon_{ij}\Delta S_{ij} - \bar{\varepsilon}_j \sum_i \Delta S_{ij} && (9)\\
&= \bar{\varepsilon}_j (\sum_{i:\Delta S_{ij}>0} \Delta S_{ij} - \sum_i \Delta S_{ij}) - \sum_{i:\Delta S_{ij}>0} \varepsilon_{ij}\Delta S_{ij} && (10)\\
&= -\bar{\varepsilon}_j \sum_{i:\Delta S_{ij}<0} \Delta S_{ij} - \sum_{i:\Delta S_{ij}>0} \varepsilon_{ij}\Delta S_{ij} && (11)\\
&= -\sum_{i:\Delta S_{ij}<0} \varepsilon_{ij}\Delta S_{ij} - \sum_{i:\Delta S_{ij}>0} \varepsilon_{ij}\Delta S_{ij} && (12)\\
&= -\sum_i \varepsilon_{ij}\Delta S_{ij} && (13)\\
&= E_j^{\text{bau}} - E_j^{\text{pol}} && (14)
\end{aligned}$$

As shown, the decomposition of emission reductions into technology and end-use shares is complete for each secondary energy carrier j, and thus also for the total emissions.

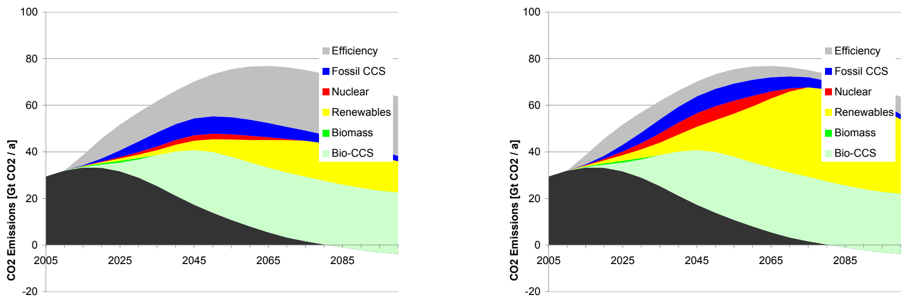
5 Primary Energy vs. Secondary Energy Accounting

To our knowledge, most existing approaches for the calculation of mitigation shares from integrated assessment scenarios are based on primary energy accounting. As elaborated in Section 3 of the main paper, this is problematic for two reasons: (a) substitutions in the model occur mostly on the secondary level (e.g. one unit of nuclear electricity for one unit of coal-based electricity), rather than on the primary level; and (b) ambiguities in primary energy accounting translate directly into ambiguities in the calculation of mitigation shares.



(a) direct equivalent accounting (b) substitution method

Figure 3: Primary energy supply for the ReMIND TAX-30 scenario, (a) based on direct equivalent accounting, and (b) based on substitution method.



(a) direct equivalent accounting (b) substitution method

Figure 4: Illustrative primary energy mitigation shares for the ReMIND TAX-30 scenario based on a simple calculation using an ad-hoc method. The use of (a) direct equivalent accounting, or (b) the substitution method has a strong effect on the resulting mitigation shares.

In order to illustrate the second point, we present PE mixes based on (a) the direct equivalent accounting method, and (b) the substitution method. In direct equivalent accounting, one unit of secondary energy production from non-combustible primary energy (in particular nuclear and non-biomass renewables) is accounted as one unit of primary energy. The substitution method, by contrast, reports primary energy from non-combustible sources as if it had been substituted for combustible energy. See IPCC (2011, Appendix II) for a detailed discussion of primary energy accounting. The different methods result in a factor of three difference in primary energy accounting of fossils and non-biomass renewables. As shown in Figure 3, the difference between PE accounting methods is substantial, in particular for mitigation scenarios with high penetration of non-biomass renewables and nuclear.

The ambiguity in primary energy accounting translates directly to ambiguity in the calculation of primary energy based mitigation shares: As illustrated in Figure 4, for the substitution method, mitigation shares of nuclear and non-biomass renewables are much larger than in the case of direct equivalent accounting, while efficiency assumes is much higher for direct equivalent accounting compared substitution method. An important advantage of the methodology of secondary energy energy based mitigation shares(Figure 2) is that the ambiguity arising from primary energy accounting is removed.

Chapter 3

Considering short term dynamics in long term power system scenarios*

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Fluctuating renewables in a long-term climate change mitigation strategy

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ABSTRACT

Integrated Assessment models, widely applied in climate change mitigation research, show that renewable energy sources (RES) play an important role in the decarbonization of the electricity sector. However, the representation of relevant technologies in those models is highly stylized, thereby omitting important information about the variability of electricity demand and renewables supply. We present a power system model combining long time scales of climate change mitigation and power system investments with short-term fluctuations of RES. Investigating the influence of increasingly high temporal resolution on the optimal technology mix yields two major findings: the amount of flexible natural gas technologies for electricity generation rises while the share of wind energy only depends on climate policy constraints. Furthermore, overall power system costs increase as temporal resolution is refined in the model, while mitigation costs remain unaffected.

1. Introduction

Research in the field of climate change mitigation (e.g. [1,2]) has shown that on the road toward a low-carbon power system, several technology options play a role: RES, carbon capture and storage (CCS), biomass and nuclear energy. Among the options considered, RES prove to be especially important for the electricity sector where they take a major role in the decarbonization process. Increasingly large shares of fluctuating renewable energy sources (RES) for electricity generation in countries like Germany (see [3]) and RES targets for larger regions like Europe raise several general questions: How can a large share of fluctuating energy sources be handled by the power system? How does the uneven distribution of renewable potentials affect regional integration possibilities and, more specific, how do these problems influence power system and climate change mitigation costs?

Generally, two very different types of quantitative models are used to assess this kind of questions: Integrated Assessment Models (IAMs), with long time frames, allow for the analysis of different scenarios considering technology investments and climate targets. Dispatch models are applied for the assessment of power system operation given a certain technology mix and considering short time horizons.

Most IAMs can not give satisfactory answers to questions of RES integration due to a reduced temporal resolution or lack of technological details necessary to allow for the computation of long-term scenarios. Dispatch models fall short in the area of scenarios for power system adaption due to the limitation to short time frames. LIMES (Long-term Investment Model for the Electricity Sector) fills a gap by integrating long-term time scales of climate change mitigation and power system investments with the issue of short-term fluctuations of RES integrated in one model.

This study answers the following specific research questions: What are the integration costs when the amount of fluctuating RES within the power system is increased to attain decarbonization targets? Which time scales are relevant when analyzing how short-term fluctuations affect long-term investment paths and mitigation costs and which consequences arise for necessary model resolution?

The remainder of this article is structured as follows: Section 2 presents a literature review on the questions raised in this introduction, Section 3 outlines the methodology, Section 4 presents results and Section 5 concludes.

2. Literature review

In the existing literature, the majority of modeling approaches that include RES as a climate change mitigation option in the power system adopt one of two extremes. Either they investigate long-term scenarios and treat fluctuations of RES in a very stylized manner or they perform short-term simulations that are not capable of considering structural capacity changes over time. Connolly et al. [4] provide a good overview on energy models that are used for the investigation of renewable energy integration, both on long-term and short-term time frames. Long-term IAMs like

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Table 1
Comparison of modeling approaches for the evaluation of RES fluctuations and the relation to climate policy.

Model	Method and Objective	Model Features		Research Issue	Policy Scenarios	
		Investment Time Horizon	Temporal Resolution		Climate Target	RES Target
BALMOREL [18]	Partial-equilibrium tool for the electricity sector	1–20 years	1h–2 weeks	Bottom up investment and operation optimization	Emission tax	No
ReEDS [21]	Minimization of power system costs over 2-year-periods	2006–2050	16 time slices	Cost assessments of RES targets (Energy policy assessment)	No	Yes
Investment planning model [22]	Least cost investment planning optimization	2005–2020	20 load segments for 52 weeks	Investment scenarios considering intermittent RES sources and transmission requirements	CO_2 price	Yes
LIMES	Intertemporal ESM cost minimization	2005–2100	Variable number of time slices	Long-term assessment of integration of fluctuating RES into power sector under climate constraints	Yes	Yes

ReMIND [5], PERSEUS-CERT [6], MESSAGE-MACRO [7], DEMETER [8] or WITCH [9] represent the reduced availability of RES using highly aggregated parameterizations. Implementations include using load factors or secured capacities – see [10] for an example of fluctuation modeling. These generally use long time steps of five to ten years that do not allow for a more thorough investigation of fluctuation issues. On the other extreme, models with a focus on short-term power plant dispatch either neglect capacity extensions or only consider investments annuities. Lund [11] analyzes wind energy integration into the Danish power system using the EnergyPLAN model to perform technical and economical assessments under different regulatory assumptions. Benitez et al. [12] use a cost minimization model where hourly demand has to be met by existing generators. Maddaloni et al. [13] use a similar approach but include network constraints. DeCarolis and Keith [14] combine an hourly simulation of wind energy output with a minimization of remaining system costs over the time period of the simulation, which is five years only. Other models, such as GTMax [15] or MICOES [16] do not consider periods longer than one year.

To bridge the gap between short-term and long-term analyses, there is the need for models combining both time frames. Furthermore, it is necessary to include a sufficient amount of technological detail to allow for the assessment of measures needed to balance RES fluctuations such as backup and storage technologies.

To date, there are very few models that aim at positioning themselves somewhere in the range spanned between the two approaches mentioned above by bringing both the long-term and short-term aspects together. Some models from the MARKAL/TIMES family [17] introduce a certain number of time slices to represent changes in yearly energy production. BALMOREL [18] allows for a flexible number of years and yearly subdivisions, depending on the study purpose. AEOLIUS is an extension to the PERSEUS model [19] using a 1-year simulation of the German power market including wind power time series derived from the ISI wind model [20]. Both models are solved iteratively. Due to the high computational costs (every single hour of a year is simulated) only a time frame until 2020 is considered. The ReEDS model [21] uses a different approach by introducing several time slices to emulate variations of demand and RE supply during a year. It is solved sequentially by optimizing 2-year intervals for the time frame 2006–2050. Neuhoff et al. [22] use an investment planning model with regional demand and wind output profiles for 20 load segments for 52 weeks but only consider a limited time horizon of 2005–2020. Table 1 shows a comparison of the relevant features of three of the aforementioned models. The modeling focus of most approaches lies on the representation of short to mid-term policy measures. However, technical power plant lifetimes of 40–50 years call for a long-term examination. This also holds for analyses of climate change mitigation options and their respective degree of utilization. LIMES fills this gap by combining long-term and short-term time scales and enables an analysis of the influence of temporal resolution on the technology mix in the electricity sector as well as on power system and climate change mitigation costs. Furthermore, the intertemporal optimization assures the refinancing of investments into generation technologies as the model optimizes capacity expansion under the constraint of short-term variability, leading to varying degrees of power plant utilization.

3. Methodology

LIMES constitutes a power system model minimizing total discounted power system costs for the time period 2005–2100 while meeting exogenously given demand paths. Investments into power generation capacities and their operation subject to the given variability of electricity demand and supply are decision variables to the model. Hence, the built-up of fluctuating RES implies that also investments into capacities balancing these fluctuations are necessary to ensure stable operation of the electricity system. Such capacities include conventional backup technologies or storage technologies. Long distance electricity transmission is not considered as an option to counterbalance RES variability in this study due to the small size of the model region. An overview of relevant model equations is given in Appendix B. The model introduces time slices to allow for the consideration of short time frames alongside long-term investment horizons. These are assessed in detail in Section 3.1. A broad range of electricity generation technologies are included as well as storage technologies (see Sections 4.2 and Appendix A). The model considers climate policy constraints in cost-effectiveness mode, operationalized by either emission trajectories, budgets or CO_2 prices[1](Section 3.3).

LIMES is calibrated to the area of Germany that is covered by the company 50 Hz Transmission GmbH (formerly Vattenfall Transmission, mainly eastern Germany and Hamburg, see Fig. 1). A comparison of model results and region data is conducted in Section 3.4.

The following sections detail the main methodology aspects of LIMES.

3.1. Modeling temporal variability

To represent variability of demand and RES supply within the model, we use a combination of two different approaches: subdivision of a year into different periods oriented at load differences

[1] Furthermore, it is possible to set goals for electricity generation from RES.

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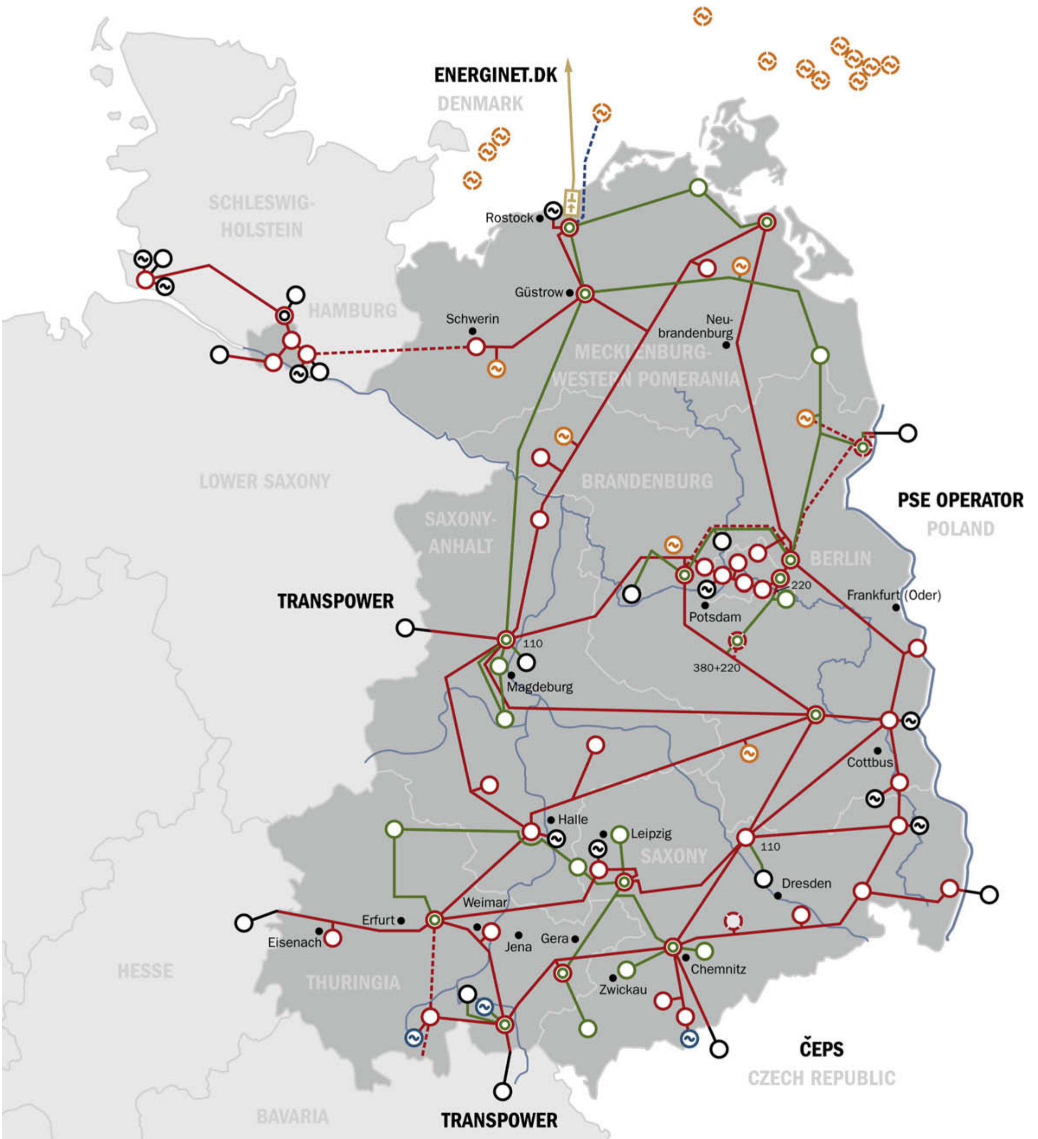

Fig. 1. Map of the Area covered by 50 Hz Transmission GmbH (Figure source: [23]).

and an assessment of fluctuations left uncovered by this parametrization.

Fluctuations are represented within LIMES by dividing a year into various characteristic periods, called time slices hereafter. The time slices differentiate variations between seasons, days of the week and phases of the day. Fig. 2 shows the electricity demand for 16 time slices of the year 2007. Neighboring bars represent 6 h intervals for the spring, summer, autumn and winter season. Other time slice configurations evaluated in this analysis distinguish more or less phases of the day, leading to the settings illustrated in Table 2. The time slices are generated using quarter-hourly data sets for demand, wind feed-in and solar energy feed-in for Eastern Germany, as well as the installed capacities for RES [24–26]. Following a subdivision into four seasons and different times of the day, the data is grouped into the respective time slices. The input values for electricity demand as well as wind and solar capacity

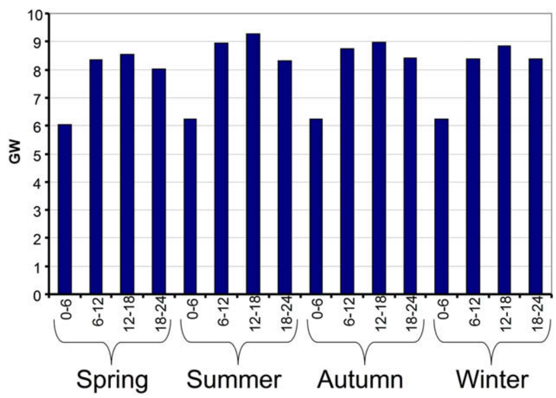

Fig. 2. Mean electricity demand in time slices for the 6 h setup.

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Table 2
Different time slice setups evaluated in this analysis.

Time Slice Setup	Number of Time Slices	Time Slice Length
24 h	4	24 h
12 h	8	Day/night (12 h each)
6 h	16	6 h
2 h	48	2 h
1 h	96	1 h

factors are determined by calculating the mean values of the data points belonging to each time slice.

As mentioned above, the underlying data for the representation temporal variation in the model originates from actual time series for RES feed-in and electricity demand. Since time slices are derived through sorting and averaging of this data, no additional stochasticity is introduced. Although uncertainty about fluctuations, especially of wind energy, is an important driver for investments into backup capacities and other balancing options, wind forecasts have shown major improvements over the last years [27]. Their increasing accuracy for short time frames of two to 4 h allow power system operators to take necessary actions for fluctuation balancing in due time. Since the time sales used in LIMES are similar to those relevant for system operation, the deterministic representation of fluctuations deems sufficient. Assessment of necessary backup and balancing capacities is conducted at the end of this section.

To assess which share of total variability contained in the initial data set is covered by the respective time slice setup, we calculate variances for the complete data set and those in the time slices (Eq. (1)).

$$\text{vari\_cover} = 1 - \frac{\sum\limits_{ts}\sum\limits_{j=1:n_{ts}}(x_j - \bar{x}_{ts})^2}{\sum\limits_{i=1:n}(x_i - \bar{x}_{\text{all}})^2} \tag{1}$$

The variability covered in the respective time slice setup vari_cover is calculated by dividing time slice variability by data set variability: the sum of the n squared differences of all data points x_i in the complete data set to the mean value $\bar{x}_{\text{all}}$ is divided by the sum of the squared differences of all n_{ts} data points x_j belonging to one time slice ts to the mean value of this time slice $\bar{x}_{ts}$, summed overall time slices. Fig. 3 shows the results of this calculation for different time slice setups: with increasing temporal resolution, more and more of the variability of demand and solar energy can be covered. Both display fairly regular daily and seasonal patterns that are caught well by time slices[2]. Wind, however, shows insufficient coverage of variability through time slices. Apart from seasonal variations, which follow regular patterns, wind fluctuations have strong stochastic properties that are difficult to represent using average values for different periods of the year. As mentioned above, high quality wind forecasts ensure stable power system operation despite fluctuations. However, since the time slice method chosen for this model does not cover every aspect of wind energy fluctuations, additional parameterizations have been introduced to represent backup and balancing capacities necessary for system operation.

To approach this shortcoming, we consider variations happening on shorter time scales by analyzing the change of wind electricity generation between different time intervals. Fig. 4 shows the changes of wind power production sorted by magnitude for different time intervals, e.g. the largest drop of wind power production within 2 h was 2645 MW and the largest increase was 2691 MW. From the analysis of these variations, we derive requirements for fast-ramping backup capacities needed within the system (the system has to provide sufficient backup capacities to encounter the largest drop) and supplementary electricity generation needed for fluctuation balancing. Backup and balancing capacity requirements are linked to the installed amount of variable RES to account for the increasing impact on power system operation when reaching higher shares of RES integration.

To account for periods with low electricity generation from wind and high demand, which typically occur during the winter time in the region considered, an additional time slice is introduced. This time slice combines the highest occurring electricity demand in the data set with the lowest observed wind output into a superpeak-slice. A length of 48 h is assumed for the superpeak period. Hence reserve capacities need to be available and system reliability is ensured according to this constraint.

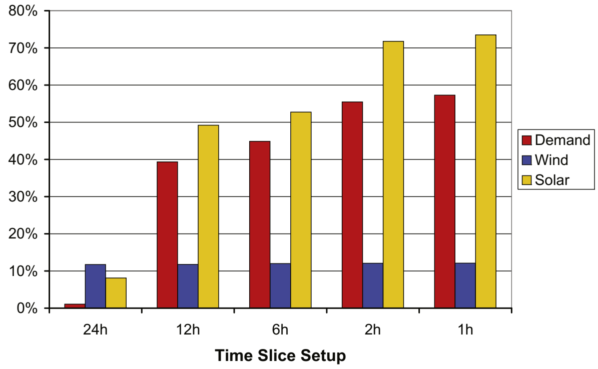

Fig. 3. Share of variability covered by time slices of different lengths.

3.2. Introducing technological detail

The model includes a total of 14 different technologies for producing electricity and one storage technology. This choice is based on the power plant fleet currently installed in the area

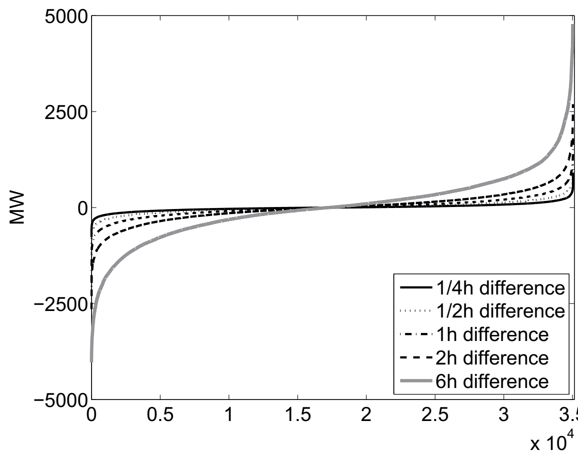

Fig. 4. Load change curve of wind power (The x-axis displays the number of observations in the data set).

[2] Small fluctuations beyond these patterns, e.g. cloud coverage for solar PV or electricity demand spikes can not be represented by time slices due to the averaging process used for their derivation. However, the above analysis shows good coverage of general daily and seasonal patterns for solar energy feed-in and electricity demand.

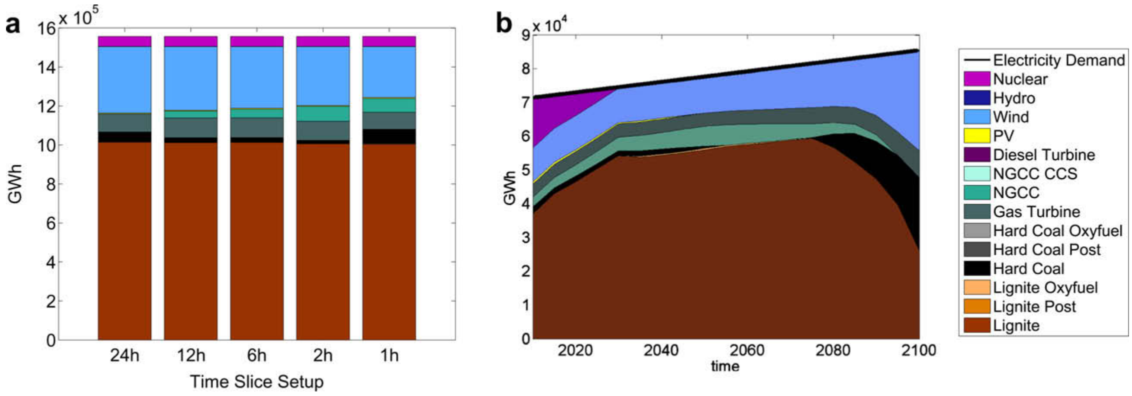

Fig. 5. Reference scenario, BAU case, electricity generation.

considered plus additional options such as carbon capture and storage (CCS). Electricity generation from nuclear power plants is phased out until 2030 and no investments into new nuclear capacities are possible for the model to represent German nuclear policy. Table A.3 in Appendix A displays the techno-economic parameters and the initially installed capacities for all electricity generation technologies considered. The maximum output of a power plant is constrained by the availability factor ν (cf. Eq. B.2 in Appendix B) to represent scheduled outages for maintenance.

Electricity storage is modeled through the introduction of a generic storage technology, which allows for the subsequent assessment of different technologies by introducing the relevant sets of parameters. It consists of two distinct parts: Storage quantity and generation capacities. Both can be extended by investments. There is a constraint on maximum storage duration, allowing for storage only within one representative day. However, to allow for a thorough analysis of different options, storage is not available in the reference cases presented in Section 4.1. Section 4.2 shows an assessment of different storage options in LIMES.

3.3. Climate policy assessment

Climate policy constraints can be introduced using emission trajectories, emission budgets or CO_2 prices, mirroring different policy setups. The long model time horizon allows for an analysis of the impact of international climate agreements on the model region by prescribing emission budgets or CO_2 prices, while emission trajectories can be used to represent local climate policy laws. Because of the small model area, exogenously set CO_2 price paths are used for the assessment of policy impacts in Section 4.

3.4. Calibration and scenario definition

To assess the quality of the model calibration, results for the year 2010 are compared to electricity generation in the region according to the main power producer Vattenfall. According to [28], in 2009, 50 TWh electricity were generated from lignite while only 2.4 TWh were generated in nuclear power plants, due to long outages of the nuclear power plants Brunsbüttel and Krümmel. They both have been offline since mid-2007 after the occurrence of different incidents and have not returned to generating electricity until the end of 2010. LIMES model results for 2010 yield 40 TWh electricity from lignite and 13 TWh from nuclear energy. This is considered a reasonable result, since it can be expected that less electricity would have been generated from lignite, had the nuclear facilities not been offline.

A series of experiments are analyzed subsequently to assess the incremental effects of different setups for temporal resolution within the model on the technology mix in the electricity sector and on power system and climate change mitigation costs. Basically, the reference case distinguishes between a business-as-usual (BAU) scenario and a scenario with policy constraints (POL) where we impose a price path for CO_2 emissions. Based on [1], a price of 15€/tCO_2 is set for 2005 and we assume an exponential increase of 5% per year in accordance with the model interest rate. The reference model version for these assessments is presented in Section 4.1. The storage availability on the electricity mix is discussed in Section 4.2. In Section 4.3, we investigate the impact of feed-in priority for electricity from RES on the power sector composition.

The insights gained from these experiments are combined in Section 4.4 to answer questions about the significance of variability for power system costs as well as climate change mitigation costs.

4. Results

4.1. Reference setup

Fig. 5a displays cumulated electricity generation[3] for the BAU scenario in all five different time slice setups. Common to all is a considerable share of generation from lignite power plants together with a fairly substantial amount of wind energy. The difference between the various time slice setups lies in the amount of variability (of load and renewable energy supply) that can be represented. One would assume that more information about variability leads to less usage of RES as these show different load factors in each time slice. Together with ramping constraints on inflexible fossil fuel technologies, this entails that less wind energy would be used in the system. For the BAU scenario, this trend can clearly be seen in Fig. 5a. The share of wind energy in electricity generation decreases from 22% to 17% as temporal resolution becomes finer. While the usage of natural gas turbines remains fairly constant at about 6%, the share of NGCC rises as mentioned above – wind energy is replaced by natural gas.

For the 1 h setup, Fig. 5b shows evolution of the electricity generation mix over time. As noted in Section 3, the total amount of extractable lignite is constrained, which explains the decrease of lignite use at the end of the century. Also, hard coal plants replace NGCC as natural gas prices increase throughout the century. The

[3] Please note that the reference setup does not contain storage technologies.

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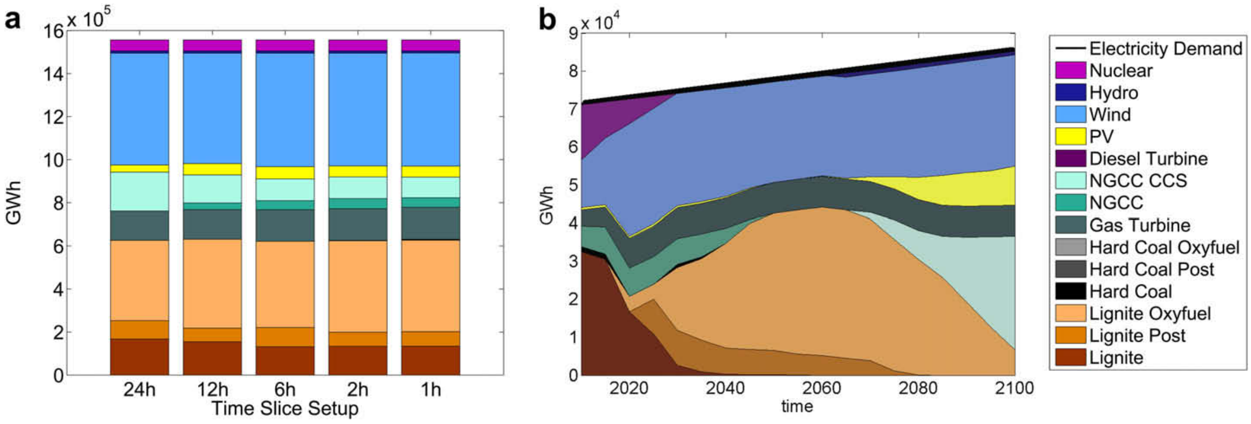

Fig. 6. Reference scenario, POL case, electricity generation.

amount of generation from gas turbines rises with the share of wind energy due to backup constraints.

As a next step, we investigate the impact of a CO_2 price path starting at 15€/tCO_2 (about the current level in the EU ETS) in 2005 on the technology mix in the electricity sector using the same time slice setups as for the BAU scenario. The constraint on emissions leads to shifts in technology usage as can be seen from Fig. 6b for the 1 h setup. While conventional lignite power plants are still used at the beginning of the century, no new capacities are installed and the existing plants are mothballed. Instead, a switch to facilities using CCS is performed. Lignite Oxyfuel and post-combustion plants are introduced and also NGCC generators in use at the beginning of the century are substituted by their counterparts with CCS.

Fig. 6a shows that the evaluation of different time slice choices draws a partly different picture than in the BAU scenario. The technology mix displays an overall share of about 33–34% wind energy in electricity generation for all time slice setups, which is more than 10 percentage points higher than for the BAU scenario. The amount of flexible natural gas turbines and NGCC increases with increasing resolution to balance fluctuations of demand and RES. Usage of NGCC with CCS, less flexible than its counterpart without capture, is reduced. The total amount of electricity production from lignite stays about constant while oxyfuel plants replace conventional capacities to make up for the lower deployment of NGCC with CCS as costs from CO_2 emissions underly the cost minimizing optimization.

4.2. Assessment of storage technologies

To assess the impact of different storage technologies on the usage of natural gas and lignite technologies, we subsequently introduced the following storage technologies into the model: Pumped Hydro Storage, Compressed Air Storage, Lead Acid batteries, Hydrogen Fuel Cells (in combination with electrolysis), Vanadium Redox Flow Batteries and Lithium Ion Batteries. Table A.4 in Appendix A shows the parameterizations chosen for the different storage technologies. The analysis showed that even under optimistic assumptions for investment costs and efficiency of the different technologies, pumped hydro storage was the only

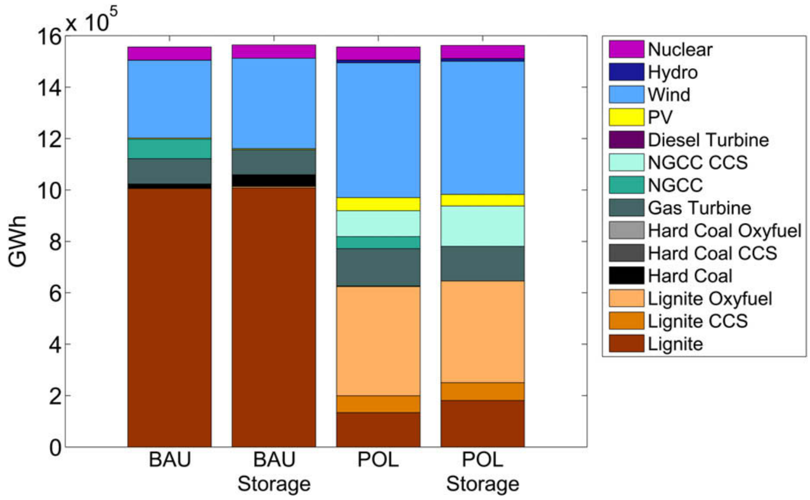

Fig. 7. Electricity generation for scenarios with and without storage (*2h* setup).

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technology used before the end of the century. We will thus focus on the results obtained with pumped hydro storage in the following.

The introduction of pumped hydro storage into the model shows interesting impacts on cumulated yearly electricity generation. For the BAU as well as POL model settings (2 h time slice setup), the presence of storage reduces the necessity for flexible NGCC plants to almost zero (Fig. 7). The BAU scenario shows an increased amount of hard coal usage as the lower flexibility of this technology can be balanced by the use of storage. Similarly, the change for the policy setting consists in a higher usage of NGCC plants with carbon capture and lignite, mainly with oxyfuel capture. There is only little change between different time slice setups for experiments with storage availability. Increasing the number of time slices leads to more information about system variability and thus knowledge about the need for flexible generation technologies; storage, however, provides additional power generation flexibility and allows for high usage of slow-ramping power plants. Technology choice is thus influenced only slightly by increasing temporal resolution when storage is available. The same is true for emissions: though the trajectories differ between the cases with and without storage, the same residual emissions threshold of about 50MtCO_2 is observed for POL scenarios with storage.

There is, however, another impact that can be seen when analyzing curtailment of wind power plants as displayed in Fig. 8: in the presence of storage, the installed capacity of wind shows a strongly increased utilization level and curtailments are reduced to less than 5% over the time horizon considered. For the scenario without storage, this picture is largely different as up to 17% of wind power plants switched off due to system constraints.

Fig. 9 displays electricity generation for all 48 time slices (2 h setup). It becomes apparent that wind production during lower demand periods at night is stored to be used for peak electricity demand during the day. This leads to a higher utilization of wind power over the year, thus reducing the need for curtailments. A constraint on maximum storage duration only allows for daily storage but storage accounting shows that even in model runs without this constraint, the technology is mostly used for daily balancing.

4.3. Feed-in priority for RES

In several countries, e.g. Germany, electricity from RES is given a priority when it comes to grid feed-in. Curtailments are only

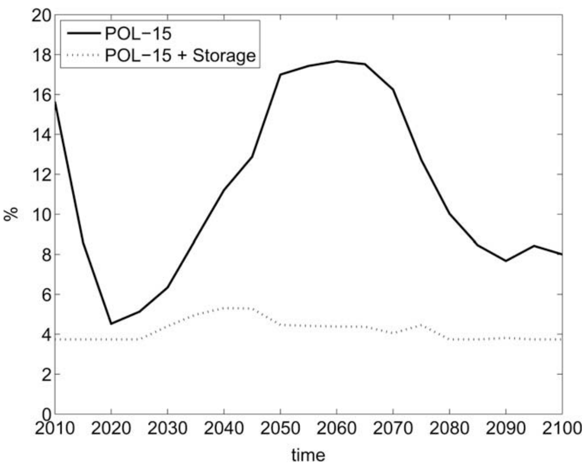

Fig. 8. Wind Curtailment with and without storage (POL, *2h* setup).

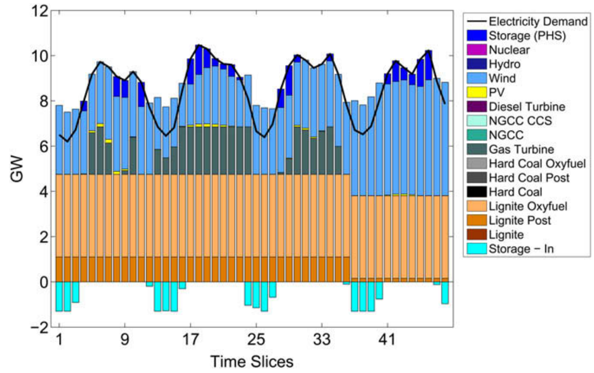

Fig. 9. Electricity generation in 2040 with 24h storage over time slices (POL, *2h* setup).

possible for strictly technical reasons in case of imminent danger for power grid operation [29]. While this preference is a reasonable measure to support RES development and force necessary grid extensions, an assessment of impacts on the operation of conventional power plants and electricity network operation seems reasonable. However, most studies (see e.g. [30,31]) concerning the (mostly financial) repercussions of RES development in Germany treat the feed-in priority as given and do not analyze scenarios where curtailment is possible. One of the few sources analyzing welfare losses induced by priority feed-in are Andor et al. [32] who suggest a revision of RES policies to allow for curtailments to increase social welfare.[4]

For the following analysis, it has to be kept in mind that the present model takes the perspective of a central social planner, optimizing the system as a whole instead of considering the decentral decisions of different players in the market. Furthermore, no technical aspects of electricity grid bottlenecks or power plant wear from frequent ramping of output are taken into account.[5]

Fig. 10 displays cumulated electricity generation for the BAU and POL scenarios, with the first and third bars showing the standard situation where output from all power plants can be reduced (with the curtailment velocity being only limited by ramping abilities of different technologies) and the second and fourth bar presenting model runs where of wind and solar energy must not be curtailed. For the BAU scenarios, the model chooses to reduce investment in wind energy capacities (the share of wind in total energy production drops from 22.5% to 17.1%) and, more substantially, in lignite capacities (64.7%–54.7% of electricity generation) to build up flexible natural gas CC plants instead.

The reduction in wind power production, however, is not observed in the POL scenarios. On the contrary, electricity generation from wind energy increases from 33.7% to 43.3% of total power generated. Inflexible lignite power plants are replaced by mainly gas fueled generation: NGCC, gas turbines and NGCC + CCS to reduce costs from CO_2 emissions. The overall electricity price is lowered through the forced feed-in of mostly wind, reducing refinancing possibilities of inflexible lignite base load plants. The

[4] Social welfare is to be understood as overall benefits to the system from minimized energy system costs. This means in the present situation that plant operators who forego their market opportunity to sell their electricity to customers could be in principle compensated by those plant operators who sell their output to customers at a positive price. In the present example the compensation might be organized via an implementation across time slices. Research about the market design of efficient curtailment is – however – yet in its infancy.

[5] While we consider constraints on ramping abilities of power plants, we do not include reductions of efficiency in part-load situations so far.

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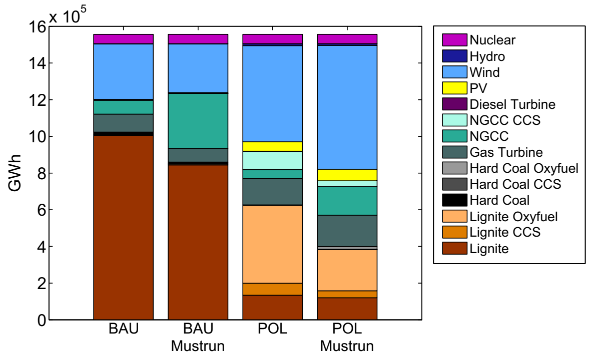

Fig. 10. Cumulated electricity generation for scenarios with and without RES priority feed-in (*2h* setup).

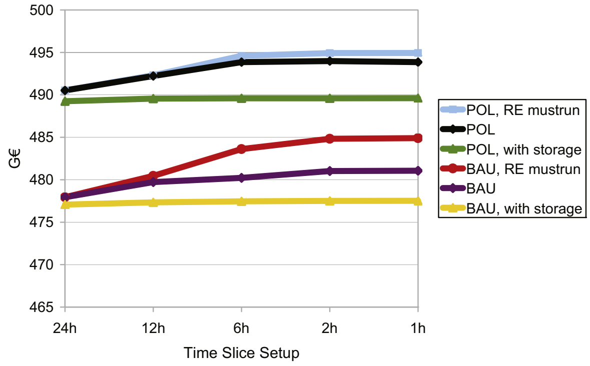

Fig. 11. Comparison of total discounted power system cost for all time slice setups and scenarios.

missing flexibility of RES thus leads to a decrease of lignite oxyfuel usage. Since curtailments are not possible in this case to balance demand fluctuations, additional investments into natural gas technologies are undertaken, thus limiting the amount of lignite oxyfuel plants in the technology mix. An assessment of power system costs for cases with and without feed-in constraints is conducted in Section 4.4.

These results show that the possibility of curtailments of renewable energy technologies is of importance for system operation as this can provide some of the flexibility necessary for balancing of demand variations. This analysis, however, keeps a strict social planner perspective and does not comprise assessments of political support systems that have grid parity of RES as their aim. As the reduction of investment costs for wind and solar energy is an exogenous assumption in this model, it is not possible to assess the impact of learning curve progression through capacity extensions.

4.4. Cost assessment

In this section, we assess power system and mitigation costs for the different scenarios presented in the previous sections to assess the effect of different temporal resolutions on cost estimations for the electricity sector.

Fig. 11: shows the total discounted power system costs[6] for BAU and POL scenarios for all time slice setups including model runs with storage availability and RE feed-in priority for different scenarios and time slice setups. Costs increase if more variability is considered in the model, mostly due to the increased use of natural gas technologies where fuel costs rise significantly throughout the century. This trend holds for power system costs of both BAU and policy scenarios, thus leading to the conclusion that models that use an aggregated representation for variability underestimate power system costs.

Fig. 11 also shows that the increase in power system costs level out with increasing temporal resolution. Experiments with a temporal resolution of 1 h for time slices shows only minor cost increases compared to the 2 h setup, pointing to an information threshold after which additional information about variability does not lead to substantial changes in results.

A comparison of different scenarios shows that the most important factor for the level of power system costs is natural gas consumption. Experiments in which storage is available display lower costs while scenarios with RES feed-in constraints, where additional balancing is required, show higher costs.

The difference between total discounted power system costs in BAU and POL scenarios, i.e. mitigation costs, changes only slightly between 2% and 3% for the different setups as can be seen from Fig. 11 by comparing the respective BAU and POL cost trajectories. As the need for flexible technologies in the presence of fluctuation causes higher power system costs already in the BAU scenarios, the difference between BAU and POL costs diminishes leading to similar results for all different time slice setups. While disregarding variability within models can lead to underestimation of power system costs, it does not have a clear effect on mitigation costs.

5. Conclusions and outlook

This analysis investigates impacts on the technology mix for electricity generation and on power system costs using different setups for temporal resolution and varying emission constraints. Increased temporal resolution, representing more of the fluctuations in RES and load, leads to a decrease of the share of inflexible technologies while more flexible power plants are employed to cover electricity demand. The dominant technologies remain wind power and lignite power plants (with or without CCS). As flexible natural gas technologies display higher fuel costs than base load lignite plants, this leads to higher power system costs regardless of whether CO_2 prices are considered or not. However, the increase shows a stabilization, leading to the conclusion that further increases in temporal resolution might not lead to more accurate results. While power system costs increase under parameterizations of time with increasing resolution, climate change mitigation costs display little change.

The availability of storage strongly reduces the need for curtailments of wind energy and displaces NGCC plants almost completely. As the potential for pumped hydro storage is limited in most regions, further research will include several types of storage with differing properties and costs. The interdiction of renewables curtailment in a system without storage leads to significant increases in natural gas usage and, for the BAU scenario, a reduction in wind energy deployment. Our analysis takes a social planner perspective and suggests that decentral explorations including multiple players and policy assessments should take a deeper look into the impacts of RES feed-in priority.

Further research will take a closer look at the temporal resolution based on time slices. The model results gained so far point to the importance of higher temporal resolution. Since time slices

[6] ower system costs consist of investment costs, O&M costs, fuel costs and costs for CO_2 emissions.

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designed around electricity demand show limitations for wind variability representation as discussed in Section 3.1, other methods should be investigated for time slice generation. Different clustering methods should help to find time slices that constitute an adequate representation of variability of RES and electricity demand while not overly increasing model complexity and thus numerical cost.

A planned European multi-region version of LIMES as presented conceptually in [33] will allow for investigation of the importance of electricity transmission for the integration of substantial amounts of RES into the electricity mix. Considering a larger geographical area also enables the analysis of pooling effects of regional resources of RES. As a further option for RES integration, demand side management measures will be investigated. This includes price elastic demand and load-shifting measures. Combined heat and power plants with electricity-controlled operation and CCS plants with flexibility for post-combustion measures will complete the technology options.

The combination of these options within one model will allow us to determine the optimal combination of measures to balance variability of RES sources in the electricity sector while providing a cost-optimal solution. Emission targets will add climate protection measures to the picture to provide the necessary long-term scenarios for the energy sector with a sufficiently high temporal resolution to account the effect of fluctuations of RES.

Appendix A. Model data

Appendix A.1. Technologies

The model includes a total of 14 different technologies for producing electricity and one storage technology. This choice is based on the power plant fleet currently installed in the area considered plus additional options such as carbon capture and storage (CCS). Table A.3 Appendix A displays the techno-economic parameters and the initially installed capacities for all electricity generation technologies considered.

Fixed O&M costs contain labor costs and yearly overhead maintenance, while variable O&M include all costs related to auxiliary material as well as wear and tear maintenance. Please note that variable O&M Costs do not include fuel costs. Fuel costs are treated below the table in Section Appendix A.2.

Table A.3
Techno-economic parameters (See sources indicated in the table for mapping to technology).

Technology[a]	Investment Costs [€/kW][b]	Fixed O&M Costs [% Inv. Cost]	Variable O&M Costs [€/GJ]	Initial Capacity [GW]	Technical Lifetime [a]
PC [34,35,36]	1100	2	2.11	0.5	50
PC + Post [34,35,36,37]	1800	2	3.52	–	50
PC + Oxy [34,35,36]	1900	2	4.23	–	50
Lignite [34,35,37]	1300	2	2.82	9.3	50
Lignite + Post [34,35]	2100	1	4.58	–	50
Lignite + Oxy [34,35]	2200	2	5.28	–	50
DOT [37,38]	322	3	0.28	–	35
NGT [37,39]	300	3	0.57	1	30
NGCC [39]	500	6	0.16	–	40
NGCC + CCS [38]	850	4	0.58	–	40
Wind (onshore) [38]	1000	3	0	9.5	40
PV [38]	4000	1	0	0.3	30
Hydro [38]	5000	2	0	0.009	80
TNR [40]	–	3	0.87	2.1	60
PHS	1200	0.38	0.76	2.9	–

[a] Abbreviations: PC – Pulverized Coal Power Plant (Hard Coal), Post – Post-combustion capture, Oxy – Oxyfuel Capture, Lignite – Lignite Power Plant, DOT – Diesel Oil Turbine, NGT – Open Cycle Gas Turbine, NGCC – Natural Gas Combined Cycle, Wind – Wind Turbine, PV – Solar Photovoltaics, Hydro – Hydroelectric Power Plant, TNR – Thermonuclear Reactor, PHS – Pumped Storage.
[b] All investment costs are overnight costs. All €-values in this paper are 2005 values.

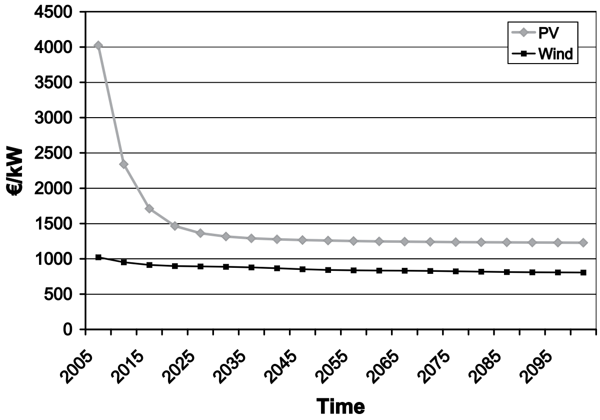

Fig. A.12. Wind and PV investment costs.

Wind and solar photovoltaics are technologies characterized by decreasing investment costs over time due to learning effects. As these are overwhelmingly determined by global capacity increases we do not include learning curves for our model, but introduce an exogenous cost degression deduced from the model ReMIND-D [38]. Fig. A.12 shows the investment cost curves implemented within LIMES.

The technical potential for onshore wind energy in Germany is estimated to be 71^{TWh}/a by Kaltschmitt and Streicher [41]. Using the European Wind Atlas [42], the assumption is made that one third of this potential is situated in the region considered. For photovoltaic energy, we combine data from [43] and [44] to obtain a technical potential of 37^{TWh}/a. Average yearly capacity factors are at about 21% for wind and 8% for PV. To emulate current RES deployment, it is not possible to reduce capacities for wind energy below once installed numbers. Biomass fueled technologies are not considered in the current model setup due to major political insecurity about their projected role and, furthermore, to allow for a better determination of main model trends by limiting the number of technologies considered.

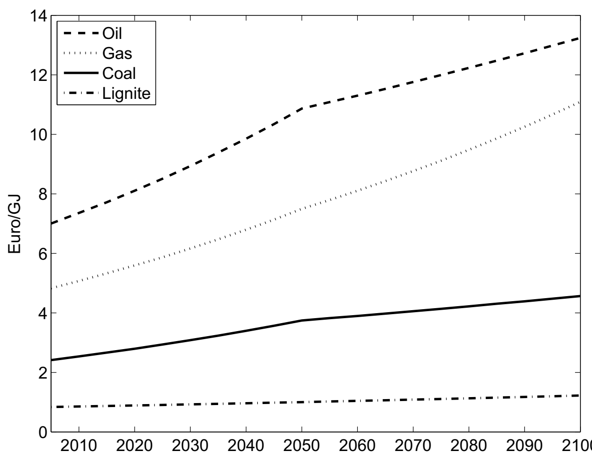

Fig. A.13. Fuel price and cost paths (source: [50,51]).

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Table A.4
Parametrization of storage technologies.

	Inv. costs generator [€/kW]	Inv. costs storage vol. [€/kWh]	Efficiency [%]	O&M fix [%inco/year]	O&M var [€/kW]	Technical lifetime [a]
PHS[a] [45,46]	1500.00	16.10	80	0.5	21.43	80
CAES[b] [45–47]	482.94	40.25	60	1.0	15.23	30
Lead Acid [48,47]	300.00	375.00	70	1.0	56.41	8
H2 FC[c] [45]	800.00	12.07	45	1.0	0.00	15
VRB[d] [45,48]	2500.00	300.00	70	1.0	0.00	10
LiIon[e] [46,48,49]	1.00	500.00	95	1.0	0.00	10

[a] Pumped Hydro Storage.
[b] Compressed Air Energy Storage.
[c] Electrolysis and Hydrogen Fuel Cell.
[d] Electrolysis and Hydrogen Fuel Cell.
[e] Lithium Ion Battery.

Table A.4 shows the parametrization used in Section 4.2.

Appendix A.2. Fossil resources and CCS potential

The 50 Hz Transmission region is assumed to act as a price taker for several fossil fuel types, fuel prices are thus unaffected by demand for fossil energy. Prices for internationally traded hard coal, oil and natural gas are derived from [50] [7] for the period of 2005–2050, and a constant increase of 2% over 5 years is assumed for the second half of the century. For the price of domestic lignite, we assume a growth rate of 5% p.a. starting from [51]. Fuel price evolution over time is presented in Figure A.13. Furthermore, to represent the lignite open cast mine situation in the 50 Hz Transmission region, we introduce a cap on cumulative lignite extraction following [52] for economically extractable resources in approved mines (2.5/Gt). Hence intertemporal optimization implies a scarcity rent that is added to the cost of fuel for lignite.

In line with [53], a total potential of about 10 Gt CO_2 for carbon sequestration is presumed for Germany. We assume that one third of this potential is available for our model region. Power plants equipped with Post-Combustion CCS (PC + CCS, Lignite + CCS, NGCC + CCS) have a capture rate of 90% while Oxyfuel plants are assumed to capture 95% of emissions.

Electricity demand is given exogenously. Starting with 2007 values obtained from [26], an increase of 0.2% p.a. is assumed as this region is expected to experience a moderate development of energy demand. The interest rate is set to 5% p.a.

Appendix B. Model equations

This Section provides an overview on the equations used in the model. A nomenclature containing all variables can be found in Table B.5. The model objective (Eq. B.1) consists of a minimization of total discounted power system costs over the model time frame from 2005 to 2100. Power system costs are the sum of investment costs C_I in technologies i in each time step t and operation and maintenance costs $C_{O\&M}$ and fuel costs C_{Fuel} for each technology in each time slice τ and time step t. Furthermore, costs from the applied CO_2 price C_{Emi} are added to power system costs.

$$\min \sum_t \left(\sum_i C_I(t,i) + \sum_{\tau,i} C_{O\&M}(t,\tau,i) + \sum_{\tau,i} C_{\mathrm{Fuel}}(t,\tau,i) + \sum_\tau C_{Emi}(t,\tau) \right) e^{-\rho t} \tag{B.1}$$

[7] We use fuel cost path B with a moderate increase.

Table B.5
Nomenclature.

i	Technology
t	Time step
τ	Time slice
ρ	Interest rate
η_i	Transformation efficiency
ℓ_τ	Length of time slice
$C_I\,(t,i)$	Investment costs
$C_{O\&M}\,(t,\tau,i)$	O&M Costs
$C_{\mathrm{Fuel}}\,(t,\tau,i)$	Fuel Costs
$C_{Emi}\,(t,\tau)$	Costs from CO_2 prices
P_i	Electricity generation by technology i
K_i	Capacity of technology i
ν_i	Availability rate
D	Electricity demand
P^j_{in}	Storage input
P^j_{out}	Storage output

Electricity generation P_i is constrained by capacities K_i for each technology i and their availability rate ν_i (Eq. B.2). For renewable energy sources, ν_i depends on grades that distinguish differences in resource potential.

$$P_i(t,\tau) \le \nu_i K_i(t) \quad \forall t,\tau \tag{B.2}$$

Demand for electricity D and production by the different technologies P_i and storage input P^j_{in} and output P^j_{out} have to be balanced within each time slice τ and each time step t (Eq. B.3).

$$\sum_i P_i(t,\tau) + \sum_j P^j_{\mathrm{out}}(t,\tau) = \sum_j P^j_{\mathrm{in}}(t,\tau) + D(t,\tau) \quad \forall t,\tau \tag{B.3}$$

From analyses of power drops in the system (as shown in Fig. 4), we derive the maximum backup capacity that needs to be present within the system (relative to the amount of wind and solar power installed). This is introduced into the model as a constraint on necessary backup capacity as shown in Eq. B.4. $\mathrm{TE_{BACK}}$ describes the group of technologies providing backup (Gas and Oil Turbines, NGCC, Hydropower and storage) and $\mathrm{TE_{REN}}$ contains wind power and photovoltaics.

$$\sum_{i\in \mathrm{TE_{BACK}}} K_i(t)n \ge \mathrm{maxdropfrac} \cdot K_k(t) \quad \forall t, k\in \mathrm{TE_{REN}} \tag{B.4}$$

The same analyses also show how much electricity generation from backup technologies was necessary because of drops in output from renewables. The variable backupprodfrac designates this production relative to the installed capacity of wind power and photovoltaics in Eq. B.5, which shows the constraint on output $P_i(t,\tau)$ of backup facilities.

$$\sum_\tau \sum_{i\in TE_{\mathrm{BACK}}} P_i(t,\tau) \ge \mathrm{backupprodfrac} \cdot K_k(t) \quad \forall t, k\in \mathrm{TE_{REN}} \tag{B.5}$$

The storage implemented into the model consists of two parts: the turbine/pump facility, determining how much power can be produced/stored within each time slices and the storage volume limiting the amount of energy storage in the reservoir. Eq. B.6 shows the connection between storage in- and output and storage volume (with η_j being the transformation efficiency of the storage technology and ℓ_τ the length of a time slice) while Eq. B.7 describe the additional capacity constraints for storage.

$$P^k_{\mathrm{stor}}(t,\tau) = P^k_{\mathrm{stor}}(t,\tau-1) + \left(\eta_j \times P^j_{\mathrm{in}}(t,\tau) - P^j_{\mathrm{out}}(t,\tau)\right) \times \ell_\tau \quad \forall t,\tau \tag{B.6}$$

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$$P^j_{\text{in}}(t,\tau) \quad \leq \nu^j(\tau)K^j(t) \quad \forall\tau \quad \text{Storage input} \tag{B.7}$$

$$P^j_{\text{out}}(t,\tau) \quad \leq \nu^j(\tau)K^j(t) \quad \forall\tau \quad \text{Storage output} \tag{B.8}$$

$$P^k\text{stor}(t,\tau) \quad \leq \nu^k(\tau)K^k(t) \quad \forall\tau \quad \text{Storage quantity} \tag{B.9}$$

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Chapter 4

The effects of transmission and storage availability on power system expansion strategies*

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Bridging the Scales: A Conceptual Model for Coordinated Expansion of Renewable Power Generation, Transmission and Storage

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Abstract

To analyze the challenge of large-scale integration of renewables during the next decades, we present a conceptual power system model that bridges the gap between long term investment allocation and short-term system operation decisions. It integrates dynamic investments in generation, transmission and storage capacities as well as short-term variability and spatial distribution of supply and demand in a single intertemporal optimization framework. Large-scale grid topology, power flow distributions and storage requirements are determined endogenously. Results obtained with a three region model application indicate that adequate and timely investments in transmission and storage capacities are of great importance. Delaying these investments, which are less costly than investments in generation capacities, leads to system-wide indirect effects, such as non-optimal siting of renewable generation capacities, decreasing generation shares of renewables, increasing residual emissions and hence higher overall costs.

1 Introduction

Due to decreasing costs of renewable energy technologies, increasing scarcity of fossil fuels, changing demand patterns and, most importantly, efforts to mitigate climate change, power systems are facing substantial structural changes during the next decades. Long-term modeling exercises with Integrated Assessment Models (IAMs) (e.g. [3, 17]) show that the power sector plays an important role in ambitious climate change scenarios, because in this sector a large number of mitigation technologies are available at comparably low costs. Renewable energy (RE) sources play a decisive role in the majority of these scenarios.

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1.1 A challenge to power system design and operation

The integration of large shares of RE sources into existing power systems, however, is a demanding task. Theoretical annual RE potentials, if aggregated over large areas, are very large, but temporal variability and uneven spatial distribution of RE supply require the provision of reserve and storage capacities, demand side management, and the expansion of transmission grid infrastructure for large area pooling. Investments are needed to provide these flexibility options, and these investments must be timed and placed adequately to complement the shift towards renewable energy sources on the generation side. Investment decisions and capital stocks on both generation and network side are obviously tightly interconnected and it can be expected that coordinated long-term planning for both sides would significantly ease the large-scale integration of RE generation.

1.2 A challenge to power system modeling

This, however, poses a challenge to power system modeling: The transformation process towards a carbon free power system is likely to span several decades, and plant lifetimes are typically in the order of 40 to 50 years. This calls for a long-term examination. Investment decisions over the next decades, however, will be affected by the technological and economical implications of fluctuating RE integration – and these effects occur on very small temporal and spatial scales.

IAMs with long time horizons and coarse spatial resolution usually represent variability and spatial distribution of RE sources into the power system by using highly aggregated parameterizations ([8, 4, 10, 1]). On the other hand, bottom-up grid models, which represent grid and generation infrastructure with high spatial resolution and calculate supply-demand balancing and dispatch of generation capacity on small time scales (e.g. [9]), usually do not take long-term investment decisions into account. Some recent publications present models with a more integrated approach: In [12] the PERSEUS model is soft-linked to a dispatch model representing short-term variability, but the time horizon is limited to 2020, and transmission infrastructure is not taken into account. ReEDS [14], a model of the United States' power system, determines generation, transmission and storage capacities endogenously. It features a high spatial resolution and a detailed representation of generation technologies, but relies on a recursive dynamic approach (as opposed to intertemporal optimization).

1.3 Bridging the scales

As a way to complement the existing modeling strategies, and to bridge the gap between them, we propose a hybrid model that integrates these issues into a single intertemporal optimization framework. In this partial, multi-regional model of the power sector, temporal variability and spatial distribution of supply and demand are modeled explicitly while maintaining a long time horizon. Investments in aggregated transmission capacities between large geographical regions and power flow distributions across the resulting network are determined endogenously. Refinancing of these investments is assured by optimizing under the constraint of short term variability which leads to varying degrees of capacity utilization. In this framework, coordinated expansion scenarios for both generation capacities and flexibility options (transmission and storage capacities) can be developed. Furthermore, the benefits of optimal (i.e. cost efficient) timing of investments, as well as the indirect system-wide effects of constrained expansion of transmission and storage capacities, can be assessed.

Our model determines intertemporally optimal investment paths for generation, transmission and storage capacities over a time horizon of 100 years by minimizing total discounted energy system costs. Long-term transition processes are driven by CO_2 prices, endogenous technological learning and increasing fuel costs. Characteristic time slices are used to represent short-term temporal fluctuations of supply and demand, and the geographical distribution of resources and demand centers is modeled explicitly. Power flow distribution constraints are taken into account following the Direct Current Load Flow (DCLF) approach [13].

1.4 Structure of this article

The modeling framework and the parameterization are presented in Section 2. In Section 3 we discuss results obtained with a conceptual application of the model, featuring three regions, low temporal resolution, and a small number of representative generation technologies. We analyze the effects of limiting transmission and storage investments under stringent climate policy constraints and perform a sensitivity analysis with respect CO_2 prices, storage potentials and power flow constraints. Section 4 concludes with a summary of the main findings, and an outlook on further developments.

1.5 Limitations

The conceptual mode configuration presented here can only provide qualitative results. It is well suited to demonstrate the capabilities of the modeling framework and to identify robust findings and sensitive parameters, which is of interest for the power system modeler's community. For quantitative assessments, which will then be of interest for stakeholders and policy makers, a fully calibrated model with a higher level of technological detail as well as an increased temporal and spatial resolution will be required.

It is important to note that our model takes on a single actor, partial equilibrium, perfect foresight perspective. It provides insights in economy wide costs and benefits of certain scenarios and constraints, but it cannot attribute investments or any kind of decision to specific actors.

2 Methodology

This section describes the modeling framework (Section 2.1) and parameterization (Section 2.2).

2.1 Modeling framework

2.1.1 Objective function

The model minimizes total discounted energy system costs C^{tot} (1), aggregated over all time steps t. Energy system costs are the sum (over all regions r, connections c, technologies i and time slices τ) of capital costs for generation, storage and transmission capacity (C^G, C^S and C^T, respectively), fuel costs C^F associated with the operation of fossil fuel power plants, and emission costs C^E due to CO_2 prices. The interest rate ρ is 5%/a.

$$C^{\text{tot}} = \sum_t e^{-\rho t} \left(\sum_{r,i} C^G_{r,t,i} + \sum_r C^S_{r,t} + \sum_c C^T_{c,t} + \sum_{r,\tau,i} \left(C^F_{r,t,\tau,i} + C^E_{r,t,\tau,i} \right) \right) \tag{1}$$

2.1.2 Technologies and transformation pathways

The model features two fossil generation technologies, coal and natural gas combined cycle power plants, and two renewable generation technologies, wind turbines and solar photovoltaics (PV). Transformation processes are linear. Consumption of fossil fuels is associated with fuel costs and CO_2 emissions. Specific fuel costs are given exogenously[1] and increase over time to reflect the scarcity of fossil fuels. Renewable energy resources are divided into grades to reflect different site categories. Each grade is characterized by an upper limit of installable nameplate capacity and a capacity factor to reflect resource quality. Generated power can either be consumed, stored or transmitted to neighboring regions via transmission lines. The only transmission technology that is represented are high voltage AC overland transmission lines. Distribution grid infrastructure substations, and all remaining capital assets other than the transmission lines themselves are not taken into account. The only storage technology that is represented is pumped hydro storage.

2.1.3 Spatial and temporal scales

The geographic area represented by the model is divided into several regions. Each region features a set of transformation technologies and is characterized

[1] It is assumed that global fuel costs are not affected by extraction patterns inside the model region (i.e. the model region acts as a price taker).

by a specific electricity demand and specific renewable energy potentials.

The model features two different time scales: Investment decisions in grid and generation capacities occur on a long-term time horizon (2005-2100, in five year time steps t). Short-term economic dispatch of available capacities is calculated for a set of time slices τ.[2] Electricity demand as well as capacity factors for renewable energy sources differ across regions and time slices. Electricity demand is exogenous and price inelastic.

2.1.4 Balancing supply and demand

Regional demand can be met either by generation in the respective region, by transmitting power between regions, or by providing previously stored power. For each region r, time step t and time slice τ, generation G, load D, net transmission flows T (aggregated over all incoming and outgoing transmission lines c_{in} and c_{out}) as well as storage charge and discharge S^{in} and S^{out} need to be balanced. Transmission flows T are diminished by dissipative transmission losses which are assumed to be linear with respect to transmission flow and line length.[3]

$$
\begin{aligned}
0 = \sum_i G_{r,t,\tau,i} - D_{r,t,\tau} + S^{\text{out}}_{r,t,\tau} - S^{\text{in}}_{r,t,\tau} \\
+ \sum_{c_{\text{in}}} ((1 - \lambda_{c_{\text{in}}} \beta_{c_{\text{in}}}) T_{c_{\text{in}},t,\tau}) - \sum_{c_{\text{out}}} T_{c_{\text{out}},t,\tau} \qquad \forall t, r, \tau
\end{aligned}
\tag{2}
$$

Non-negativity contraints apply for generation, demand and storage (3-6). Transmission flows can be positive or negative, depending on flow direction.

$$
\begin{aligned}
G_{r,t,\tau,i} &\geq 0 & \forall r, t, \tau, i \qquad (3)\\
D_{r,t,\tau} &\geq 0 & \forall r, t, \tau \qquad (4)\\
S^{\text{in}}_{r,t,\tau} &\geq 0 & \forall r, t, \tau \qquad (5)\\
S^{\text{out}}_{r,t,\tau} &\geq 0 & \forall r, t, \tau \qquad (6)
\end{aligned}
$$

2.1.5 Capacity constraints

Electricity generation by fossil (dispatchable) technologies ($i \in i_{\text{fos}}$), transmission, storage charge and discharge flows $G, T, S^{\text{in}}, S^{\text{out}}$ are constrained by installed generation, transmission and storage capacities K, K^T, K^S:

[2] See Sec. 2.2 for details on the concept of time slices.

[3] Global trade balances are not required as the consistency of bilateral transmission flows is completely taken into account by the set of regional balance equations.

$$G_{r,t,\tau,i} \leq K_{r,t,i} \qquad \forall r,t,\tau,i \in i_{\text{fos}} \tag{7}$$

$$T_{c,t,\tau} \leq K^T_{c,t} \qquad \forall c,t,\tau \tag{8}$$

$$S^{\text{in}}_{r,t,\tau} \leq K^S_{r,t} \qquad \forall r,t,\tau \tag{9}$$

$$S^{\text{out}}_{r,t,\tau} \leq K^S_{r,t} \qquad \forall r,t,\tau \tag{10}$$

The (region and time slice specific) relationship between installed capacity and max. output for renewable energy technologies ($i \in i_{\text{ren}}$) is represented by Eq. 11, where ν represents the maximum capacity factor achieved at the regions's best generation sites, and ν' accounts for decreasing average capacity factors as generation sites of lesser qualities are occupied.

$$G_{r,t,\tau,i} \leq \nu_{r,t,\tau,i} K_{r,t,i} - \nu'_{r,t,\tau,i} K^2_{r,t,i} \qquad \forall r,t,\tau,i \in i_{\text{ren}} \tag{11}$$

Investments in generation, storage, and transmission capacities and the technological depreciation of these capacities are modeled explicitly. Capacity additions for each region and connection are continuous, i.e. single cables and power plants are represented by regionally aggregated capacities.[4] Capacities have a limited lifetime and are put out of operation following technology specific depreciation curves. Initial capacity endowments (i.e. capacities that are already in place in the first time step) and their age distribution are also taken into account.

2.1.6 Power flow distribution

Our model includes a simplified power flow distribution module, following the DCLF approach [13]. DCLF has been widely used to analyze active power flow distributions in meshed grids (eg. [16, 9]). It assumes a flat voltage profile, lossless transmission ($R \ll X$), and small voltage angle differences throughout the network.[5] Under these assumptions, the model is reduced to a system of linear equations. The power T transmitted along a line depends on the line's reactance X (per unit length), line length lg, voltage level U and the voltage angles θ at the two ends of the line r_1 and r_2:

$$T = \frac{U^2}{Xl}(\theta_{r_1} - \theta_{r_2}) \tag{12}$$

In our model, not only voltage angles θ, but also line reactances X are control variables, as transmission capacities change over time. Reactance $X_{c,t}$ of line c at time step t is expressed as a function of aggregated transmission capacity $K^T_{c,t}$ by representing each connection c as an aggregate of n identical

[4] See below for a discussion of how aggregated transmission capacities are treated in the DCLF constraints.

[5] [11] analyzes the validity of these assumptions and states that, although errors on single lines can be significant, the DCLF approach gives a good approximation of active power flows in most networks.

single transmission lines that are connected in parallel. Each of them features a reactance X_c^s and a nameplate transmission capacity of $K_c^{\mathrm{T,max,s}}$, and the aggregate reactance can be calculated as:

$$\frac{1}{X_{c,t}} = n\frac{1}{X_c^s} = \frac{K_{c,t}^T}{K_c^{\mathrm{T,max,s}}}\frac{1}{X_c^s} \tag{13}$$

Inserting this into (12) yields:

$$T_{c,t,\tau} = \frac{K_{c,t}^T U^2}{K_c^{\mathrm{T,max,s}} X_c^s \beta_c}\left(\theta_{r_1,t,\tau} - \theta_{r_2,t,\tau}\right) \qquad \forall c,t,\tau \tag{14}$$

Note that, although the DCLF approach is a linear approximation of power flow distributions, (14) acts as a nonlinear constraint in our model, as both K^T and θ are decision variables.

2.1.7 Storage balance

To distinguish between seasonal and diurnal storage applications, storage can be employed to shift power between time slices if these time slices belong to the same storage group g_τ. Inside each storage group, time slices are ordered sequentially. The energy stored in the reservoir E at any given time slice τ is

$$E_{r,t,\tau_i} = E_{r,t,\tau_{i-1}} + \frac{\alpha_{\tau_i}}{n_{g_{\tau_i}}}\left(\eta S_{r,t,\tau_i}^{\mathrm{in}} - S_{r,t,\tau_i}^{\mathrm{out}}\right) \qquad \forall r,t,\tau, \tag{15}$$

where $n_{g_{\tau_i}}$ states how often a sequence of time slices (e.g. one characteristic day) is repeated per storage group. For each region r, time step t and storage group g_τ storage charge and discharge flows need to be balanced (15). A round trip efficiency η of 85% is assumed [7].

$$0 = \sum_{\tau \in g_\tau} \alpha_\tau \left(\eta S_{r,t,\tau}^{\mathrm{in}} - S_{r,t,\tau}^{\mathrm{out}}\right) \qquad \forall r,t,g_\tau \tag{16}$$

No costs are associated with expanding reservoir size, but upper limits on reservoir size can be implemented to reflect geographical limitations of storage potential.

2.1.8 Learning effects

One factor learning curves (e.g. [6]) are implemented to represent specific investment costs as a function of cumulated installed capacity. Cost reductions achieved by learning are limited by fixed floor costs. Learning effects are taken into account for wind turbines and solar PV.

Table 1: Parameters of generation technologies ([3, 7]). For fuel costs, the two numbers indicate the specific extraction costs in 2005 and 2100. For investment costs of learning technologies, they denote initial costs and floor costs.

	Inv. costs [\$/kW]	Learn. rate [%]	$K_{t0,\mathrm{cum}}$ [GW]	Fuel costs [\$/GJ]
Coal PP	1400	–	–	$2.0 \rightarrow 3.4$
Gas CC PP	650	–	–	$5.5 \rightarrow 7.1$
Wind turbine	$1200 \rightarrow 883$	12	60	–
Solar PV	$4900 \rightarrow 600$	20	5	–
Pumped Hydro Storage	1500	–	–	–

2.1.9 Emissions and CO_2 prices

CO_2 prices are applied to represent climate policy constraints. For the scenarios presented in Sec. 3 a price of 10\$/tCO_2 is applied.[6] This corresponds to the average carbon price profile used in [17].

2.1.10 Implementation

The resulting optimization problem is of the NLP type. Nonlinear equations are related to learning curves, DCLF constraints (14) and capacity factor contraints for Renewables (11). The model is implemented in GAMS [5] and solved using the CONOPT solver. It is based on the code of the REMIND model [8]. The model has been coupled to the multi-run environment SimEnv [15] and various post processing tools. This makes it possible to perform extensive sensitivity studies, which is valuable to explore the model behavior over a wide range of parameters.

2.2 Parameterization

This section describes the model parameters used in this study. Techno-economic parameters of generation and transmission technologies are given in Tables 1 and 2.

2.2.1 Regional parameterization

The model features two *resource regions* with low demand and high potentials for the two renewable energy sources, and a *demand region* with high power demand and low renewable potentials. Table 3 shows regional distribution of demand and RE resources. Demand and renewable resources, although being

[6] CO_2 prices are given in present value (2005) prices. Current value CO_2 prices increase exponentially over time with the interest rate of 5%/a.

Table 2: Parameters of transmission technologies [2, 18].

Parameter	Unit	Value
Voltage U	kV	345
Reactance X per unit length	Ω/km	0.371
Loss coefficient λ per unit length	%/km	0.012
Active power transmission capacity $K^{\mathrm{T,max,s}}$	MW	747
Investment costs	\$/kWkm	0.5

Table 3: Regional distribution of demand and RE resources. $\overline{D}$: avg. annual demand. $\overline{\nu}$: avg. annual capacity factor for the best resource location.

	$\overline{D}$ (TWh)	Wind $\overline{\nu}$ (-)	Solar $\overline{\nu}$ (-)
Wind res. region	220	0.2	0.1
Solar res. region	220	0.1	0.2
Demand region	880	0.125	0.125

unevenly distributed, are larger than zero in all three regions. This creates the two options of either generating renewable based electricity at high quality resource locations and transmitting it via the grid, or relying on domestic renewable resources with lower quality to reduce grid requirements. If not stated otherwise, there are no regional constraints on maximum storage capacities.

Transmission lines can be built between all neighboring regions. Geographical distances between all regions are equal; the length of each grid connection is 500km. Initial RE generation capacities as well as initial grid and storage capacities are zero. Initial coal and gas power plant capacities in all regions are sufficiently large to meet initial domestic demand.

2.2.2 Temporal parameterization

Long-term addition and depreciation of capacities occurs in 5 year time steps t between 2005 and 2100. Short-term variability is expressed by dividing each time step into a set of time slices τ. These time slices (which can have different lengths) capture various characteristic combinations of supply and load.

In the current parameterization, we distinguish two characteristic days (summer and winter), each with six time slices to represent low, average, and high RE supply at daytime and nighttime. Storage is possible between time slice that belong to the same season; seasonal storage is not available. Table 4 shows the fluctuation of demand and RE capacity factors around their regional averages across these twelve time slices.

Over the long time horizon, an annual demand growth of 0.3%/a is assumed. Fluctuation patterns do not change over the long time horizon. It is assumed that fluctuation patterns for each RE type are perfectly correlated across regions, and the fluctuations of wind and solar resources are positively correlated. This might lead to an overestimation of the overall fluctuations of renewable supply and an underestimation of the benefits of long-distance transmission to pool statistically uncorrelated resources across large areas. On the other hand, stochastic fluctuations are not taken into account at all.

It should be kept in mind that this parameterization is conceptual. It intends to capture characteristic features of a stylized power system in a qualitative way. A proper calibration using empirical data will be reserved for future model versions.

3 Results and discussion

We present a set of different scenarios that all share a stringent CO_2 price path (as discussed in Sec. 2.1.9). These CO_2 prices represent ambitious climate mitigation policies and induce – in the long-term – a complete (or nearly complete) decarbonization of the power sector. We examine how this transformation process is affected by the availability of storage and long-distance transmission capacities. We first present a reference scenario (Sec. 3.1), in which investments in both options are possible without timing constraints. In Sec. 3.2 the system-wide effects of disabling transmission and storage completely and of limiting transmission capacity expansion to 1GW/a per connection are discussed (see Tab. 5 for a scenario list). Sec. 3.3 presents a sensitivity analysis of model results with respect to storage potential, CO_2 prices and power flow constraints.

3.1 The reference case

Fig. 1 and 2 show generation mix and discounted investment costs time series (both calculated endogenously) for the reference scenario, without restrictions of investments in grid or storage capacities. Investments in new coal and gas power plants decline to zero in 2015 and 2030, respectively. Coal based generation is phased out during the first half of the century. It is being gradually replaced, first by natural gas power plants, then by wind and solar capacities. The power sector is decarbonized completely by 2080. The order in which wind and solar energy enter the system (wind first) is determined by the lower initial specific investment costs for wind turbines (see Table 1). Investments in grid and storage capacities are small compared to investments in generation capacities.

Fig. 3 gives a more detailed view of the power system for the year 2075. It shows how generation and storage are dispatched across time slices to meet demand. Storage is mainly used to shift RE generation from high to low supply time slices, complemented by a small share of gas based generation. Storage capacities are high – for this scenario, the ratio of storage discharge capacity to average load reaches up to 80%, and reservoir capacities could provide average load for up to five hours.[7]

[7]not shown in figures.

Table 4: Fluctuations of demand and RE capacity factors across time slices (around their average values given in Table 3).

Storage group		summer						winter					
Time of day		day			night			day			night		
RE supply		low	medium	high	low	medium	high	low	medium	high	low	medium	high
$D_\tau/\overline{D}$	[-]	1.2	1.2	1.2	0.8	0.8	0.8	1.2	1.2	1.2	0.8	0.8	0.8
$\nu_\tau/\overline{\nu}$ (solar)	[-]	1.5	3.0	4.5	0.0	0.0	0.0	0.5	1.0	1.5	0.0	0.0	0.0
$\nu_\tau/\overline{\nu}$ (wind)	[-]	0.0	0.6	1.1	0.0	0.9	1.9	0.0	0.9	1.9	0.0	1.6	3.1
Length	[h]	438	1314	438	438	1314	438	438	1314	438	438	1314	438

Table 5: Scenarios overview. For the reference scenario (bold), both flexibility options are available without timing constraints.

	with storage	without storage
with transmission	**tON-sON**	tON-sOFF
without transmission	tOFF-sON	tOFF-sOFF
limited transm. expansion rate (1GW/a)	tLIM-sON	tLIM-sOFF

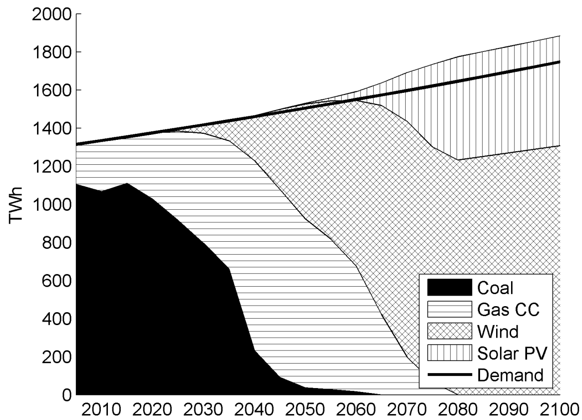


Figure 1: Generation mix and demand over time for the reference scenario. The differences between total generation and demand is due to transmission and storage losses. Curtailed power from RE sources is not shown.

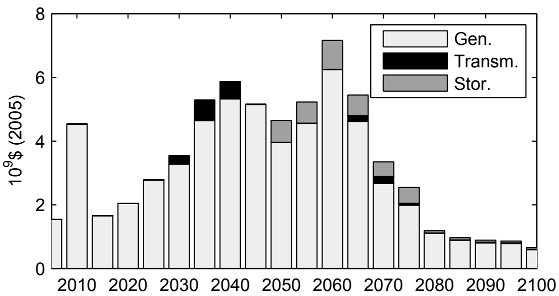


Figure 2: Investments over time for the reference scenario. Investments decrease over time as they are discounted to net present values.

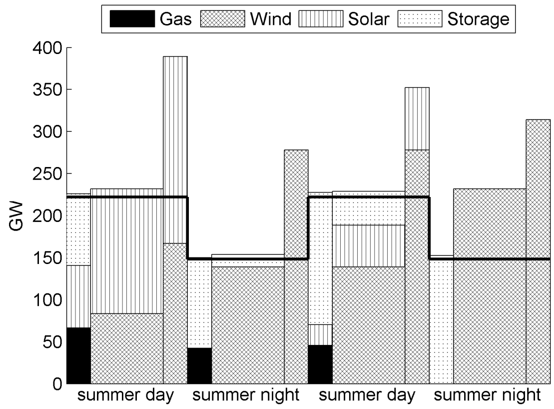


Figure 3: Global generation and storage dicharge across time slices (in 2075). The black line denotes demand; surplus generation is used to charge storage reservoirs. RE curtailments are not shown.

3.2 Limited availability of transmission and storage

Fig. 4 examines how power system characteristics are affected if the transmission capacity expansion rate is constrained. The figures show generation, demand and transmission flows in 2075, aggregated over all time slices. With grid expansion constraints (in this case, 1GW/a per connection) in place, the realized transmission flows between resource and demand regions are reduced substantially. A significant share of RE generation capacity is shifted from the resource regions to the demand region, although this region is endowed with renewable potentials of lower quality.

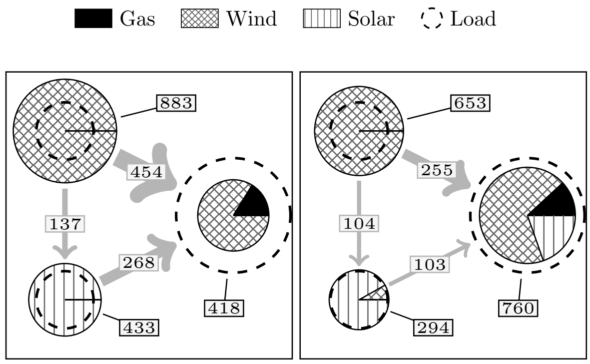
To further evaluate this effect, Fig. 5 compares the development of the average realized capacity factor[8] of solar PV,[9] for six different scenarios: with and without storage and transmission available, and with transmission expansion rates constrained to 1GW/a per connection.

For all scenarios, realized capacity factors decrease over time, as resource grades are utilized in order of decreasing quality. Applying constraints on grid expansion significantly decreases the overall capacity factor in later time periods, caused by the suboptimal siting of new generation capacities. Storage, if available, increases realized capacity factors by shifting renewable power supply between time slices and thus reducing curtailments.

The timing of investments does not only affect location choices for RE generation capacities. It also has an influence on how fast RE generation penetrates

[8]generated power divided by installed nameplate capacity, aggregated over all regions and time slices. This parameter is affected by resource quality as well as by curtailments. It is only defined if installed capacities are larger than zero.

[9]Results for wind turbines, which are not shown here, are similar.



(b) reference (no constraints) (c) constrained grid investments ($K_{\text{Grid}}^{\max} = 1\text{GW/a}$)

Figure 4: Generation and net flows in 2075, aggregated over all time slices. The area of the pie diagrams and the numbers next to them show regional generation; the dashed circles show regional demand. The numbers show net transmission and regional demand (TWh).

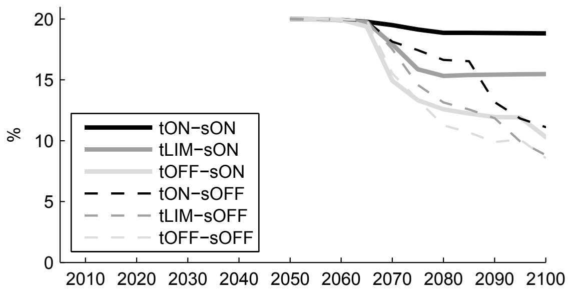


Figure 5: Average realized capacity factor for Solar PV.

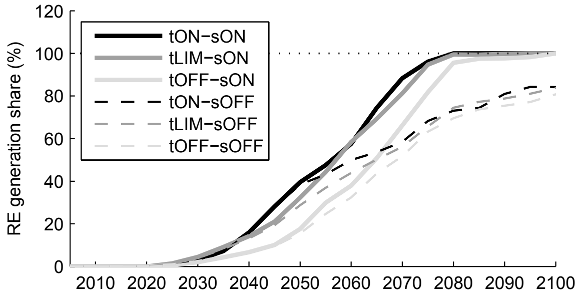


Figure 6: Generation share of RE over time. Both RE share and penetration rate depend on the availability of grid and storage options.

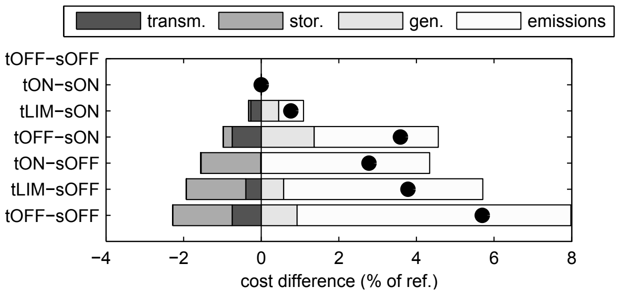


Figure 7: Decomposition of cumulated system costs, relative to the reference scenario (`tON-sON`). Total costs are denoted by the black dots.

the market. This is shown in Fig. 6, which presents RE shares of total power generation for the six scenarios discussed above. The figure also shows that availability of storage affects the maximum achievable RE share – complete decarbonization is only reached if storage is available.[10]

Fig. 7 displays discounted cost differences between the six scenarios, cumulated over the complete time horizon. If transmission and storage options are constrained, the higher residual emissions by fossil generation lead to higher emission costs and, consequently, to increasing overall costs. It is interesting to note that investments in storage actually increase if transmission is available – in these scenarios, both flexibility options do not act as substitutes, but as complements.

[10]This can be attributed to the assumption that fluctuation patterns of supply and demand are perfectly correlated across regions, which means that low supply / high demand situations cannot be mitigated by large area pooling.

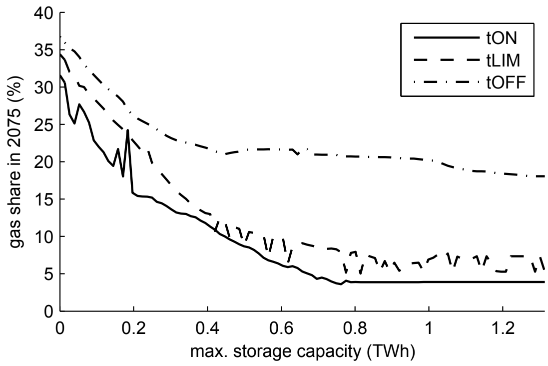


Figure 8: Sensitivity analysis for maximum storage reservoir size. Generation share of gas (shown for 2075) is reduced if the available storage potential increases.

3.3 Sensitivity analysis

Fig. 8 presents the effects of constraining storage potential (modeled as a regionally uniform constraint on storage reservoir size). The figure shows gas power plant generation shares in 2075. The importance of gas as balancing option increases significantly if storage potentials are limited. Again, the availability of transmission leads to an increased usage of storage and decreased requirements of gas capacities for balancing purposes.

Fig. 9 shows how mitigation levels (emission reduction between 2005 and 2075, relative to 2005 levels) depend on CO_2 prices.[11] CO_2 prices below 2\$/tCO_2 lead to an increase in emissions (negative mitigation levels). Prices between 2 and 3.5\$/tCO_2 trigger a fuel switch from coal to gas[12] and mitigation levels are unaffected by the availability of transmission and storage. At prices above 3.5\$/tCO_2 RE play an increasingly important role. Complete decarbonization is reached if storage is available; without storage, even prices of 15\$/tCO_2 have little effect on the residual emissions caused by gas powerplants required for balancing purposes.

Fig. 10 displays total system costs relative to the reference scenario, for different maximum grid expansion rate constraints, and it compares model runs with and without DCLF constraints. Due to their non-linearity, omitting DCLF constraints has beneficial effects on model complexity – Fig.10 shows that without DCLF constraints model results are much smoother throughout the parameter space. As expected, power flow constraints increase total costs (as any additional binding constraints should do). This effect, however, is much smaller than the effect of constraining grid expansion rates or storage availability. This result may be specific for the symmetric regional layout used in the present study, and

[11] CO_2 prices are given in present value terms.
[12] not shown in figure.

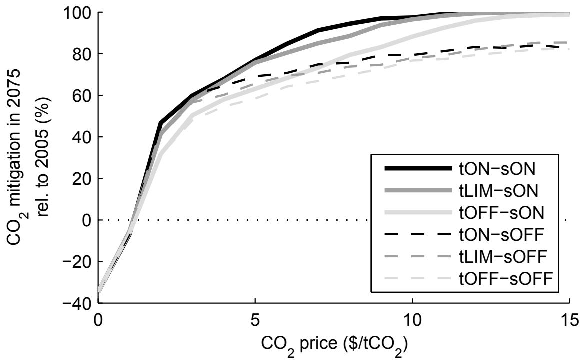


Figure 9: Sensitivity analysis for CO_2 prices. Mitigation levels (the figure shows emission reductions in 2075, relative to emissions in 2005) are highly sensitive towards price variations. Low CO_2 prices lead to negative mitigation levels, i.e. an increase in emissions relative to 2005. CO_2 prices are given in present value (2005) terms; current values prices increase over time at 5%/a.

needs to be checked for robustness with calibrated and more complex model versions. Nevertheless, it indicates that – although DCLF constraints certainly do affect actual power flow distributions at certain points in time – their effect on long-term developments of system costs may be rather small.

4 Conclusions and outlook

We present a modeling framework of intermediate complexity that integrates long term investment decisions in generation, transmission and storage capacities as well as the effects of short term fluctuation of renewable supply. It fills the gap between highly aggregated Integrated Assessment Models and bottom-up dispatch models and is well suited to assess cost efficient power system decarbonization pathways.

Results obtained with the conceptual three region model indicate that long-distance transmission and electricity storage play an important role for the large-scale integration of fluctuating RE into the power system. Although the direct investment costs that are required to put transmission and storage capacities in place are small compared to the investments required on the generation side, the *indirect* system-wide effects of delaying investments in these options can be substantial. Achievable RE generation shares, market penetration rates as well as total system costs depend on the availability of these flexibility options. Delayed investments in transmission and storage capacities lead to suboptimal siting of RE generation capacities, reduced realized capacity factors, lower overall RE generation, higher emissions by fossil based generation, and subsequently to higher overall costs.

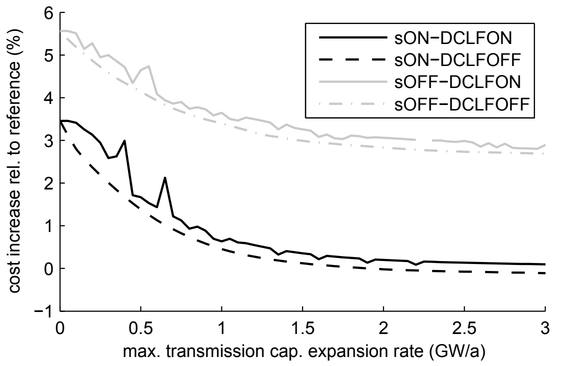


Figure 10: Sensitivity analysis for max. transmission expansion rate and DCLF constraints. Overall costs are affected by power flow distribution modeling, but the effect is smaller than that constraining transmission and storage availability.

An interesting finding is that in our model both flexibility options do not to act as substitutes, but as complements: investments in storage are actually highest if the transmission option is available (and vice versa), and achievable cost savings are highest if both technologies are available at the same time. This result, however, may depend on the fluctuation and spatial distribution patterns of supply and load, and their robustness needs to be checked with a calibrated model.

Representing power flow distributions constraints endogenously by means of the DCLF model has relatively small effects on model results. This finding, as well, may depend on the simplified and symmetrical network topology and should be checked for robustness in future model versions.

To manage and coordinate the transition processes that present power systems are facing during the next decades, it will be crucial to gain a better understanding of how single elements of these systems (e.g. generation, transmission, and storage facilities) interact with each other on different time scales. The presented model provides valuable qualitative insights in the characteristics of these interactions.

The modeling framework is flexible enough to create real world applications for different regions, given that the required data is available. It is currently being calibrated to represent the German and European power system. This also includes the implementation of all major generation technologies (CCS, nuclear energy, biomass, offshore wind, CSP), HVDC transmission, and different types of storage. Further interesting applications would be geographically large power systems with rapid growth and diverse RE resources (e.g. India, China).

Table 6: Nomenclature.

Symbol	Unit	Description
c, i, r, t, τ	-	indices for connection, technology, region, time step, and time slice
C^{tot}	\$	total aggregated energy system cost (objective function)
C^E	\$	emission costs (due to CO_2 prices)
C^F	\$	fuel costs
C^G, C^S, C^T	\$	capital costs (generation, storage, transmission)
D	W	power demand
E	Wh	stored energy
G	W	generated power
I	A	current
K, K^S, K^T	W	installed capacity (generation, storage, transmission)
$K^{\mathrm{T,max,s}}$	W	max. active power transmission capacity (single line)
L	W	transmission losses
$S^{\mathrm{in}}, S^{\mathrm{out}}$	W	storage charge / discharge
T	W	transmitted power
U	V	voltage
X	Ω/km	line reactance (per unit length)
α	h	time slice length
β	km	transmission line length
η	-	storage round trip efficiency
λ	km^{-1}	loss coefficient (per unit length)
ν, ν'	-	capacity factor coefficients for RE generation
ρ	-	interest rate
θ	rad	voltage angle

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Chapter 5

A multi-scale power system model for the EU and MENA regions*

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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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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.

Keywords: integration of renewables, power system planning, CO_2

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abatement

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 to 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 to 99% in the power sector. A number of recent studies explore the possibilities for decarbonization of the European power sector, and renewable energy (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. Due to the uneven spatial distribution and the seasonal, daily, and short term variability of RE resources, balancing demand and supply requires 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 north-western 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, cross-border interconnections are still limited. ENTSO-E (2010) identifies 42100km 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. 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 efficient 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 a European power system model that takes transmission requirements and system operation into account, but it does not include the MENA region and has only twelve 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 has a time horizon of only four years.

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 explore how the power sector of the European and MENA regions can be decarbonized by relying on RE resources.

We use to explore the following research questions:

- What reduction levels of power system emission reductions are technically and economically feasible by expanding RE generation?
- What role does an interconnected European and Mediterranean transmission grid play, and how does its availability effect feasible RE penetration levels?
- What are cost efficient investment pathways that, in the long term, lead to a decarbonized power system?

The paper is structured as follows: Sec. 2 introduces the structure of the LIMES-EU$^+$ model and gives an overview of the parameterization. In

Sec. 3.1 we analyze the transition process that leads to a low carbon power system. Sec. 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 efficient choice of RE technologies depends on the availability of grid expansion beyond current levels. In 3.3, we perform a sensitivity analysis and show how CO_2 and electricity prices depend on the emission reduction target. Sec. 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 modelling 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 modelled 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 need to be balanced for each time slice, given the available generation, transmission and storage capacities. By determining investment decisions and dispatch of capacities endogenously, it is ensured that all investments are refinanced by the rents that are generated over time.

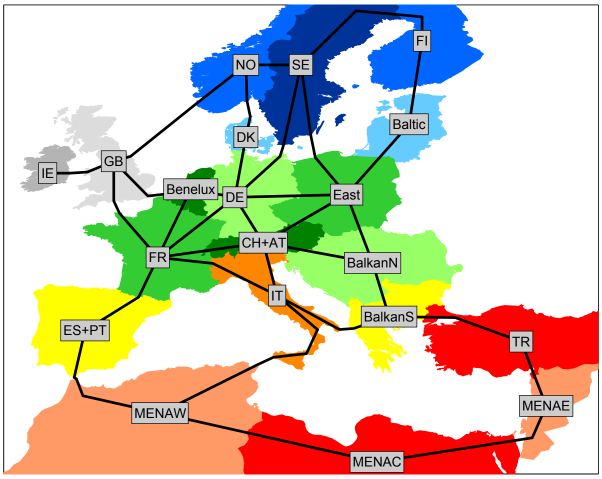


Figure 1: Regional layout of the LIMES-EU$^+$ model.

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 (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 Tab. 1).

Long term investment decisions are modelled in 5 year time steps from 2010 to 2050. Short term fluctuation patterns are represented by 49 time

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

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

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 six hours. An additional super peak time slice represents high demand and low RE supply. A selection algorithm ensures that the twelve 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). We assume decreasing specific investment costs for solar and wind generation technologies.[2] High voltage

[1]Details are provided in the supplementary material.
[2]The supplementary material provides details on cost curves.

AC lines are used as transmission technology. Investment costs for overland lines and sea cables are differentiated. Two generic storage technologies allow for day/night storage and intra-seasonal storage. CSP is modelled with integrated day/night storage. Tables 2 and 3 give an overview of the technoeconomical parameters of generation and storage technologies.

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.

	investment costs [Euro/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

Wind onshore/offshore, PV and CSP supply curves for each region and

Table 3: Parameters of storage technologies.

	investment costs [Euro/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

time slice have been derived from gridded meteorological data (Kalnay et al., 1996). The methodology for the calculation of capacity factors and installable capacities is based on EEA (2009) and Hoogwijk (2004). Fig. 2 gives an overview of the regional RE potentials. Biomass potentials are taken from EEA (2007).

Initial generation capacities are based on the Chalmers Energy Infrastructure database (Kjärstad and Johnsson, 2007) and IEA (2010a,b). Intital 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 1GW/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 Euro/GJ.

Climate policy targets are represented by applying annual emission caps.

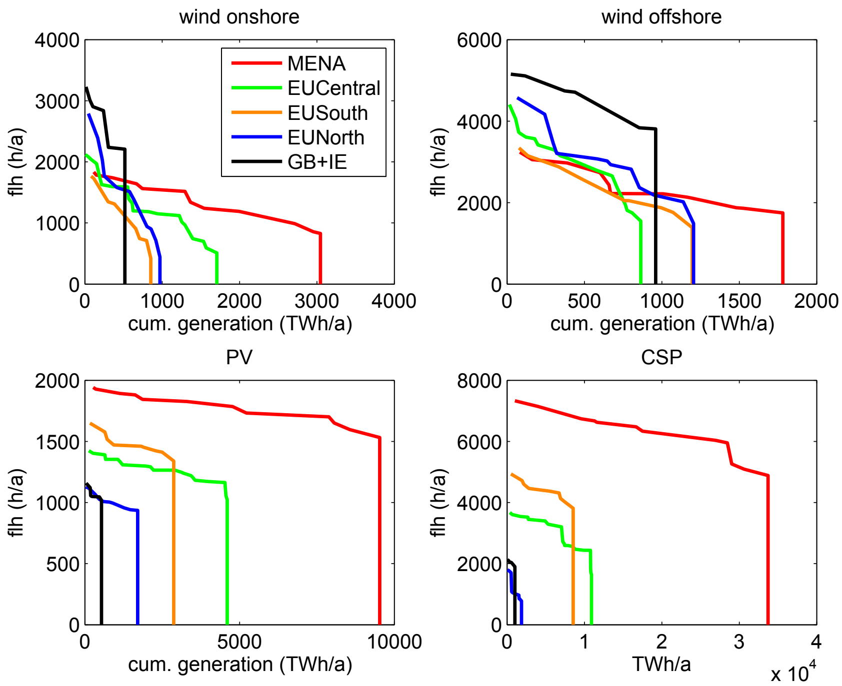


Figure 2: RE potentials (marginal annual full load hours over total generated power) for aggregated region groups.

Table 4: List of scenarios.

	emission reduction until 2050 (rel. to 2010)	transmission expansion beyond 2010 levels
PolGrid	90%	yes
PolNoGrid	90%	no
BAUGrid	none	yes
BAUNoGrid	none	no

In this paper we refer to emission reduction targets in 2050 relative to emissions in 2010. Emission caps decreases linearly from 2010 to 2050. There are no regionally differentiated emission targets; the cost efficient allocation of reductions across regions is determined endogenously.

3. Results and Discussion

Tab. 4 shows the four scenarios that are presented. To explore the role of an interconnected trans-European and Mediterranean grid, we compare scenarios with grid expansion and scenarios where power transfers between regions are allowed, but transmission capacities are limited to current levels. Both grid scenarios are shown for a 90% emission reduction target and for a Business as Usual (BAU) scenario without climate policy constraints.

Sec. 3.1 discusses – in aggregated figures – the long term transformation process that is required to reach the desired target system in 2050. Sec. 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 Sec. 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 fluctuation 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.[3] Foregoing the option of

[3]In the absence of emission caps, gas powerplants are almost completely replaced by

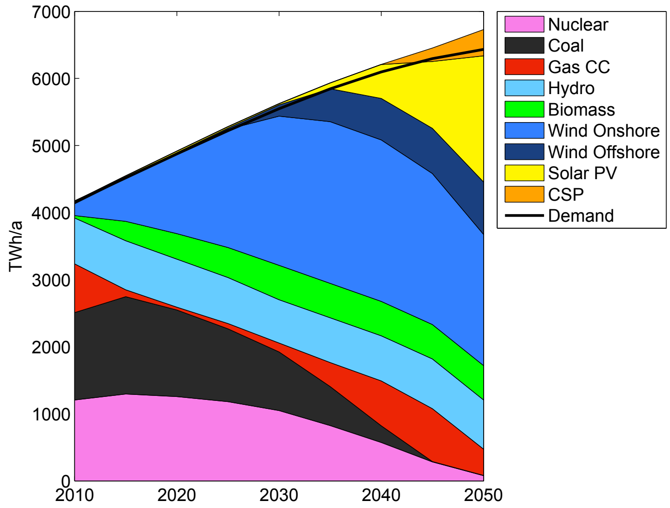


Figure 3: Generation mix over time for the `PolGrid` scenario, aggregated across all regions.

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[4] 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

coal power plants. This leads to a coal / RE mix scenario, where emissions in 2050 are 50% higher than in 2010, despite the increased RE shares.

[4] The import share of consumption is defined as demand which is not met by domestic resources, divided by total demand.

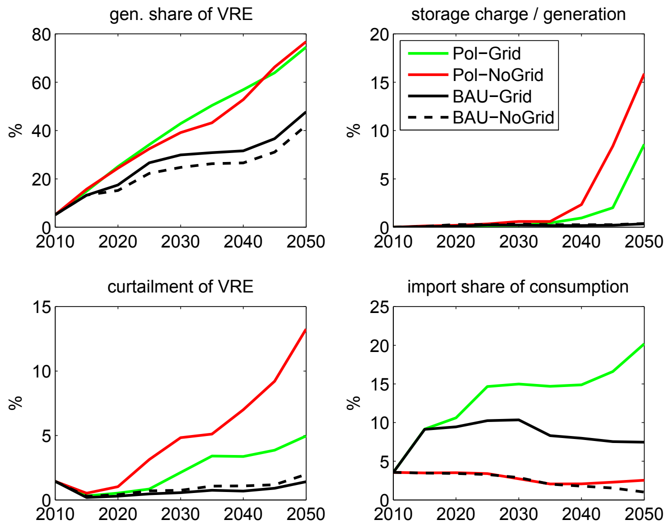


Figure 4: Long term system development for all scenarios. The panels show generation share of fluctuating RE, storage charge to total generation ratio, import to total consumption ratio, and curtailments of fluctuating RE.

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.

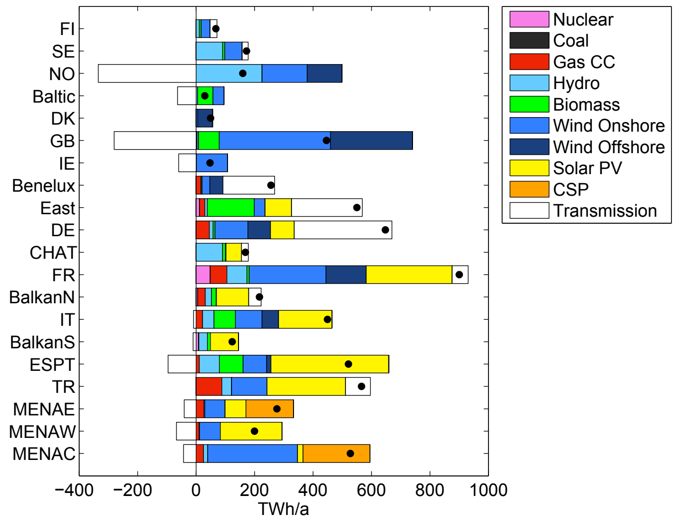
3.2. The power system in 2050

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

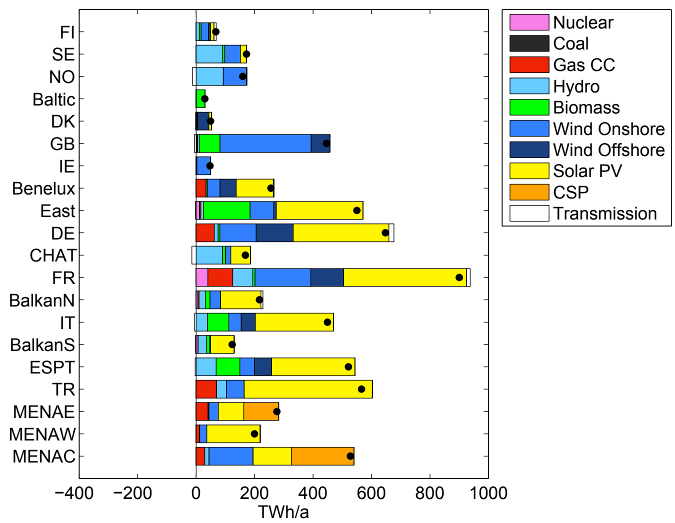
Fig. 5 shows regional generation mixes in 2050 for the `PolGrid` and `PolNoGrid` scenarios. If transmission expansion is allowed, it plays an important role – although all regions exploit their domestic RE resources to a certain extent. Central European regions are net importers (mainly Germany, Eastern 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 Tab. 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.

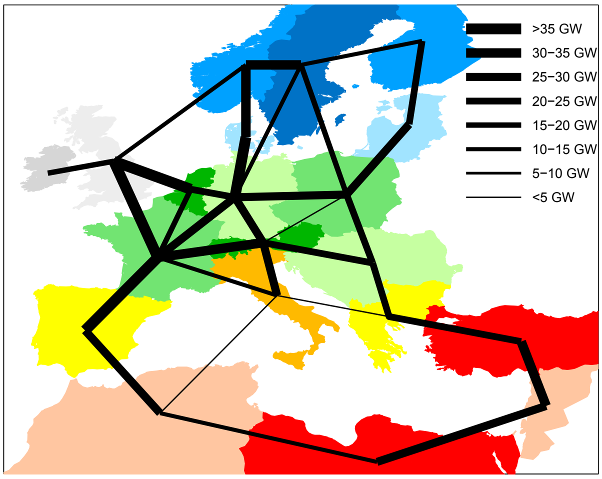


(a) `PolGrid` scenario.

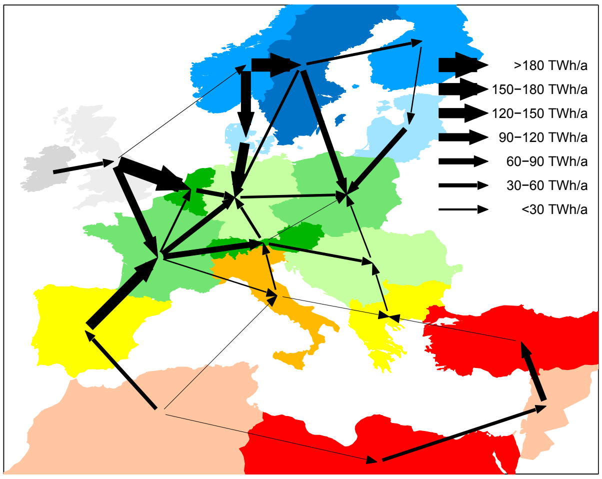


(b) `PolNoGrid` scenario.

Figure 5: Regional generation mix in 2050 for the `PolGrid` and `PolNoGrid` scenarios. The dots mark domestic demand.



(a) Transmission capacities.



(b) Net transmission flows.

Figure 6: Transmission capacities and net transmission flows in 2050 (PolGrid scenario).
[todo: *bessere Skalierung der Liniendicken*]

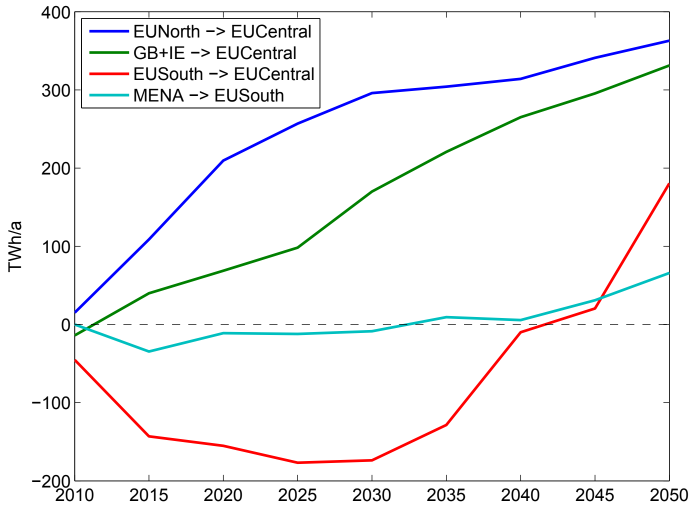
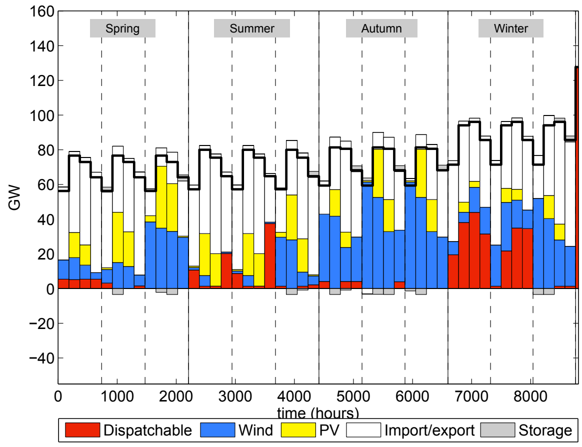


Figure 7: Net transmission flows over time across the four major transmission corridors (`PolGrid` scenario).

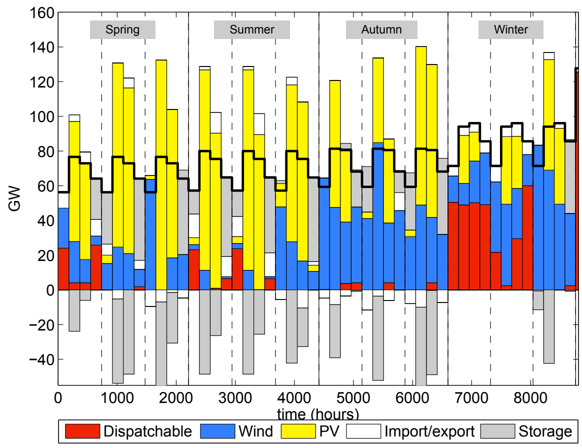
Fig. 8 shows generation across time slices in 2050 for Germany, which is the largest net importer in the `PolGrid` scenario. In this scenario, wind onshore and offshore dominate the generation mix, and supply and demand fluctuations are almost completely balanced by imports. Additional generation by gas power plants 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 at 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 (and thus, emission caps are binding) for 2050 emission levels of 120-140% rel. to 2010. This means that until 2050, in the absence of emission caps, emissions increase by 20-40%, depending on the availability to expand transmission capacities. 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.



(a) PolGrid scenario.



(b) PolNoGrid scenario.

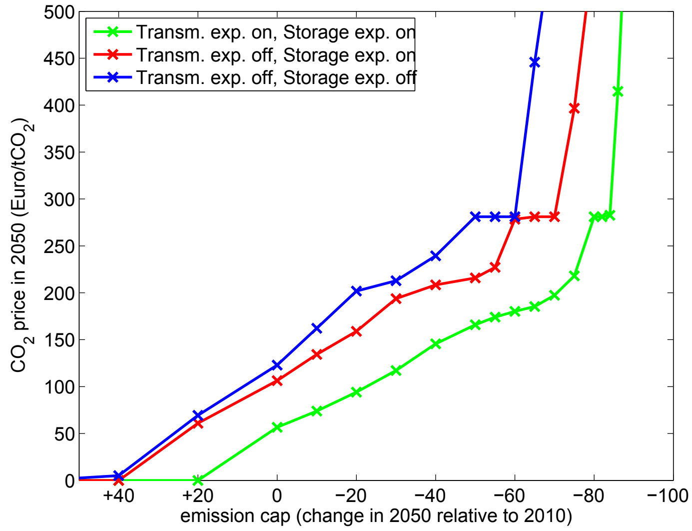
Figure 8: Generation mix across time slices in 2050, for Germany (`PolGrid` and `PolNoGrid` scenarios). The black line represents domestic demand. To improve readability, technologies have been aggregated to groups (dispatchable: coal, gas, hydropower, biomass, nuclear; wind: wind onshore / offshore;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

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.

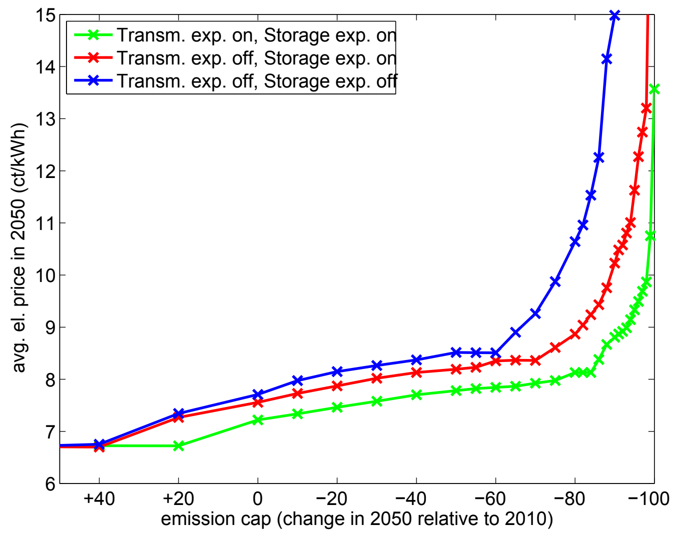
Allowing for the expansion of transmission and storage capacities has two effects: Firstly, for emission reductions of less than 60%, it reduces CO_2 prices and electricity prices, by 70-120 Euro/tCO_2 and 0.8-1.2ct/kWh, respectively. Secondly, it shifts the frontier where prices increase above tolerable 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.[5] 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. 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

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



(a) CO_2 prices in 2050.



(b) Electricity prices in 2050.

Figure 9: CO_2 prices and electricity prices in 2050 depend on the emission cap and the availability of transmission and storage expansion.

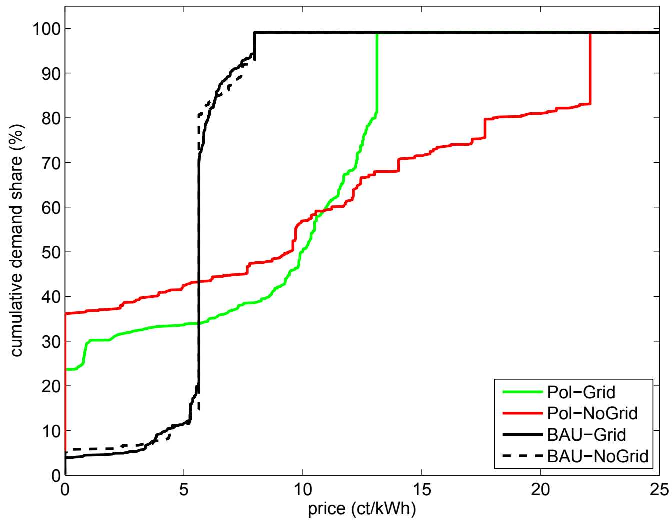


Figure 10: Cumulative distribution function of electricity prices in 2050 (prices for all regions and time slices).

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 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. Power exports from MENA to European countries increase after 2040, but they play a minor role.

If the option to expand transmission capacities beyond their current levels is not used, domestic RE resources are sufficiently large and diverse to reach emission reductions of up to 90%, but this requires higher investments in storage capacities and results in increasing RE curtailments and electricity prices.

We identify a threshold for emission reductions where CO_2 prices and electricy prices escalate. By expanding transmission and storage capacities beyond their current levels, this threshold can be shifted from 70-90% reductions up to 2050 (rel. to 2010).

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 explicitely 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 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).

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Decarbonization Scenarios for the EU and MENA Power System: Considering Spatial Distribution and Short Term Dynamics of Renewable Generation
Supplementary material

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January 30, 2012

Contents

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symbol	description
t	long term time step (long term time scale)
τ	time slice (short term time scale)
r	region
i	technology
g	renewable resource grade
f	fuel type
k	storage group

Table 1: List of indices

symbol	description
i_{gen}	generation technologies
i_{stor}	storage technologies
i_{trans}	transmission technologies
i_{ren}	renewable generation technologies
i_{conv}	conventional technologies
i_{fluc}	generation technologies with fluctuating output
i_{nfluc}	dispatchable generation technologies

Table 2: List of sets.

This text provides background information to the abovementioned article. It presents the algebraic formulation and the parameterization of the LIMES-EU$^+$ model.

1 Model formulation

1.1 General remarks

A list of all used symbols can be found in the appendix (Tab. 12). Barring some exceptions, large Latin characters represent control variables, and Greek characters represent parameters. Small Latin characters are used to represent indices.

As LIMES is a multi scale model, the indices of parameters as well as control variables can sometimes be confusing. Tab. 1 show the indices used in this documentation. The model uses two distinct temporal scales. The terms *time steps* and *time slices* are used for the discretization of long term and short term time scales, respectively.

Elements of the model (e.g. technologies, regions, and fuel types) are assigned to groups with different characters. In GAMS syntax, these groups are called *sets*. This term is used in the documentation as well; they are listed in Tab. 2.

1.2 Model equations

1.2.1 Objective function and costs

Objective function The objective function of the model is the minimization of total system costs C^{tot}, defined as the sum of costs at each time step t, discounted to present values using discount rate ρ. Total system costs at each time step t are the sum of investment costs C^I, fuel costs C^F and operation and maintenance costs C^{OM}, minus a salvage value V for each technology i to account for capital stocks that remain at the end of the time horizon.

$$C^{\text{tot}} = \Delta t \sum_t e^{-\rho t} \left(C_t^I + C_t^F + C_t^{OM} \right) - e^{-\rho(t_{\text{end}} - t_0)} \sum_i V_i \tag{1}$$

Fuel costs Fuel prices for each primary energy type f and time step t are defined exogenously. Fuel costs C_t^F are the product of fuel price σ, primary energy consumption P, and time slice length l_τ, aggregated over all fuel types, regions, and time slices. Fuel prices are a function of time t.

$$C_t^F = \sum_{r,\tau,f} \left(\sigma_{t,f} P_{r,t,\tau,f} l_\tau \right) \qquad \forall t \tag{2}$$

Investment costs For generation and storage technologies, investment costs are the product of specific investment costs α and capacity additions ΔK. For transmission technologies, investment costs are the product of specific transmission investments costs α^T, transmission capacity additions K^T and transmission corridor length l^T.[1] For learning technologies specific investment costs α are a function of time t, for other technologies they are constant over time. Total investment costs C^I are calculated by aggregating over all regions, connections and technologies.

$$C_t^I = \underbrace{\sum_{r,i} (\alpha_{t,i} \Delta K_{t,r,i})}_{\text{generation and storage}} + \underbrace{\sum_{c,i} (\alpha_{t,i}^T l_c^T \Delta K_{t,c,i}^T)}_{\text{transmission}} \qquad \forall t \tag{3}$$

Operation and maintenance costs The model considers fixed and variable operation and mainentance costs. Fixed operation and mainentance costs β are given as a percentage of investment costs per year; variable operation and mainentance costs γ are correlated with power generation G. Total operation and mainentance costs C^{OM} are the sum of both terms, aggregated over all regions, technologies and time slices.

[1] Capacities of transmission technologies need to be treated separatly as they are indexed over connections c instead of regions r.

$$C_t^{OM} = \underbrace{\sum_{r,i} (\beta_i \alpha_{t,i} \Delta K_{t,c,i}}_{\text{fixed}} + \underbrace{\sum_{\tau,r,i} \gamma_i G_{t,\tau,r,i})}_{\text{variable}} \qquad \forall t \tag{4}$$

Salvage values The salvage value V for each technology i represents the value of capacities that are still operation after the last time step t_{end}. It depends on the capacity additions ΔK made before t_{end}, takes into account the specific investment costs α at the time step the capacity additions were made, and is subtracted from the system costs in the objective function.

$$V_i = \Delta t \sum_{\tilde{t}=0}^{\psi_i} \left(1 - \frac{1 - e^{\rho \Delta t (\tilde{t}+1)}}{1 - e^{\rho \psi_i}}\right) \alpha_{t_{\text{end}}-\tilde{t},i} \Delta K_{t_{\text{end}}-\tilde{t},r,i} \tag{5}$$

1.2.2 Energy balances and capacities

Electricity balance For each time step, region and time slice, the sum of generation G, storage charge S^{in}, storage discharge S^{out}, imports and exports F^T need to be equal to demand D. In this equation c^{in} and c^{out} represent the sets of all connections entering and leaving the actual region r. Transmission losses are subtracted from all flows that enter a region. Losses are represented by transmission loss coefficient ι^T. They are a linear function of transmission line length l^T.

$$D_{t,\tau,r} = \sum_{i \in i^{\text{gen}}} G_{t,r,\tau,i} + \sum_{i \in i^{\text{stor}}} (S^{\text{out}}_{t,r,\tau,i} - S^{\text{in}}_{t,r,\tau,i}) + \sum_{c \in c^{\text{in}}} \left((1 - \iota_i^T l_c^T) F^T_{t,c,i}\right) - \sum_{c \in c^{\text{out}}} F^T_{t,c,i} \qquad \forall t, r, \tau \tag{6}$$

Storage balance Time slices are associated with storage groups k. Storage can be used to shift power between time slices that belong to the same storage group. For each region, time step and storage group, the sum of storage charge S^{in} and discharge S^{out} need to be balanced (taking into account the round trip efficiency η.)

$$0 = \sum_{\tau \in k} l_\tau \left(\eta S^{\text{in}}_{r,t,\tau} - S^{\text{out}}_{r,t,\tau}\right) \qquad \forall r, t, k \tag{7}$$

Fuel consumption The ratio between fuel consumption P and power generation G is defined by the technology specific conversion efficiency η:

$$P_{t,r,\tau,f} = \sum_{i \in (i \to f)} \frac{1}{\eta_i} G_{t,r,\tau,i} \qquad \forall t, r, f \tag{8}$$

Capacity constraints Electricity generation by non fluctuating generation technologies technologies, transmission, storage charge and storage discharge flows $G, T, S^{\text{in}}, S^{\text{out}}$ are constrained by installed generation, transmission and storage capacities K and K^T. Fluctuating renewable generation is constrained by maximum generation $G^{\max}$, a control variable that is a function of region, time slice, and resource grade. Availabile transmission capacity K^T is scaled down with a security margin κ.

$$G_{r,t,\tau,i} \leq K_{r,t,i} \qquad \forall r,t,\tau,i \in i_{\text{nfluc}} \tag{9}$$
$$G_{r,t,\tau,i} \leq G^{\max}_{t,r,\tau,i} \qquad \forall r,t,\tau,i \in i_{\text{fluc}} \tag{10}$$
$$T_{c,t,\tau,i} \leq \kappa_i K^T_{c,t,i} \qquad \forall c,t,\tau,i \in i_{\text{trans}} \tag{11}$$
$$S^{\text{in}}_{r,t,\tau,i} \leq K^S_{r,t,i} \qquad \forall r,t,\tau,i \in i_{\text{stor}} \tag{12}$$
$$S^{\text{out}}_{r,t,\tau,i} \leq K^S_{r,t,i} \qquad \forall r,t,\tau,i \in i_{\text{stor}} \tag{13}$$

Cumulated annual availability of capacities To take planned and unplanned outages into account, we define an average annual availability factor ν for each dispatchable generation technology and for each storage technology. For each time step, region and technology, generation G aggregated over all time slices must not exceed installed capacity K times the availability factor ν. For hydro power, this availability factor is different for each meteorological season, and Eq. 14 is formulated for each season separately.

$$\sum_{\tau}(l_\tau G_{t,r,\tau,i}) \leq \nu_i \sum_{\tau} l_\tau \ K_{t,r,i} \qquad \forall t,r,i \tag{14}$$

Expansion and depreciation of capacities Each technology has a maximum lifetime ψ. Installed capacities are taken out of service according to technology specific depreciation curves which decline to zero once their maximum lifetimes are reached. These depreciation curves are described by depreciation coefficients ω. Available capacities K for each technology i, region r and time step t are the sum of previous capacity additions ΔK, scaled down with the depreciation coefficients. Available transmission capacities K^T are calculated in an equivalent equation (not shown here).

$$K_{t,r,i} = \Delta t \sum_{\tilde{t}=0}^{\psi_i} \left(\omega_{i,\tilde{t}} \Delta K_{t-\tilde{t},r,i}\right) \qquad \forall t,r,i \in (i_{\text{gen}} + i_{\text{stor}}) \tag{15}$$

1.2.3 Fluctuating renewable supply

For each fluctuating RE generation technology we define a discrete number of resource grades k. These resource grades are defined by a maximum installable generation capacity per region and grade $K^{\text{G,max}}$ and a maximum capacity factor λ which differs across region, time slice and resource grade.

The total installed capacity of fluctuating RE generation technologies K is the sum of the capacities in each grade K^G:

$$K_{t,r,i} = \sum_k K^G_{t,r,i,k} \qquad \forall t, r, i \in i_{\text{fluc}} \tag{16}$$

Capacities in each grade K^G are constrained by the maximum installable capacity per grade:

$$K^G_{t,r,i,k} \leq K^{\text{G,max}}_{r,i,k} \qquad \forall t, r, i \in i_{\text{fluc}} \tag{17}$$

Maximum generation is the sum over all grades k of installed capacities K^G times the grade specific maximum capacity factor λ:

$$G^{\max}_{t,r,\tau,i} = \sum_k (\lambda_{r,\tau,i,k} K^G_{t,r,i,k}) \qquad \forall t, r, \tau, i \in i_{\text{fluc}} \tag{18}$$

1.2.4 Other equations

Emissions Total CO_2 emissions are the product of fossil fuel consumption P and the fuel specific emission coefficient δ, aggregated over all regions, time slices, and fuel types.

$$E_t = \sum_{r,\tau,f} (\delta_f \; l_\tau \; P_{t,r,\tau,f}) \qquad \forall t \tag{19}$$

Constraint on biomass consumption For each time step and region, consumption of biomass is constrained by region and time specific biomass potential $P^{\max}$:

$$\sum_\tau (l_\tau P_{t,r,f}) \leq P^{\max}_{t,r,f} \qquad \forall t, r, f \in f^{\text{bio}} \tag{20}$$

Emission constraints Emissions for each time step E_t are constrained by emission caps $E^{\max}_t$:

$$E_t \leq E^{\max}_t \qquad \forall t \tag{21}$$

2 Parameters and calibration

This section documents how the input parameters for the LIMES-EU$^+$ model were derived.

2.1 Potentials of fluctuating renewable resources

For fluctuating renewable energy sources (wind onshore and offshore, photovoltaic, and CSP), gridded meteorological data sets have been used to estimate installable capacities per region, average annual capacities per region and capacity factors per region and time slice.

2.1.1 Matching data grids and model regions

The geographic boundaries of model regions are defined based on ADM-0 administrative boundaries.[2] Islands have been excluded. The model region has been limited to the geographical extents 27°N - 67°N / 15°W - 45°E, and all shapefiles have been cropped accordingly.

For each region an offshore buffer zone of 50km around the coastline has been created. These offshore areas are used to assess offshore wind potentials.

2.1.2 From meteorological data to capacity factors

The NCEP/NCAR 40-year reanalysis project [9] has been used to parameterize wind onshore, wind offshore, PV and CSP potentials.[3] The data set contains 6h average wind speed in 10m height, on a global grid with a spatial resolution of 1.5° x1.5°. The current calibration uses data for the year 2009.

All NCEP grid cells have been mapped to the onshore surface areas an offshore buffers of the model regions. We define the coefficients $A_{c,r}^{\text{onshore}}$ and $A_{c,r}^{\text{offshore}}$, which for each grid cell c gives the intersecting surface area with land and offshore area of region r, respectively.

Wind turbine capacity factors Wind speed data is based on the NCEP data sets `uwnd` and `vwnd` (wind speeds in north-south and east-west direction), and overall wind speed is calculated as

$$v_{t,c} = \sqrt{\text{uwnd}_{t,c}^2 + \text{vwnd}_{t,c}^2}. \tag{22}$$

Offshore wind speeds are generally higher than onshore wind speeds. This is reflected in Fig. 1, which shows – for all grid cells – the relationship between the cell's offshore to onshore surface ratio and it's average annual wind speed. Based on this relationship, we derive offshore and onshore wind speeds from each cell's average wind speed:

$$v_{t,c} = \frac{A_{c,r}^{\text{onshore}} v_{t,c}^{\text{onshore}} + A_{c,r}^{\text{offshore}} v_{t,c}^{\text{offshore}}}{A_{c,r}^{\text{onshore}} + A_{c,r}^{\text{offshore}}} \tag{23}$$

$$v_{t,c}^{\text{offshore}} = 1.85 \cdot v_{t,c}^{\text{onshore}} \tag{24}$$

The methodology to convert wind speeds to capacity factors follows [4]. Wind speeds are scaled up from measurement heigth (10m) to hub height using equation 25. Wind speeds at hub height are converted to capacity factors using equation 26, which also takes into account turbine availability and turbine array efficiency. The coefficients used are summarized in table 3.

$$v_{t,c}^{\text{hub}} = \frac{\ln(h^{\text{hub}}/z_0)}{\ln(h^{\text{data}}/z_0)} \tag{25}$$

[2] Shapefiles available online `http://www.gadm.org/`. Accessed on July 5, 2010.

[3] The data is available in netCDF format at `http://www.esrl.noaa.gov/psd/data/gridded/data.ncep.reanalysis.html` (accessed october 2010).

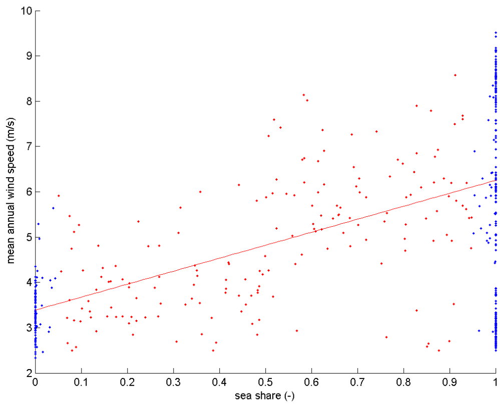

Figure 1: NCEP/NCAR wind speed data: Relationship between the cell's offshore to onshore surface ratio and average annual wind speed.

$$\epsilon_{t,c} = \epsilon^{\text{array}} \epsilon^{\text{turbine}} (\lambda_1 v_{t,c}^{\text{hub}} - \lambda_2) \tag{26}$$

Table 3: Parameters for capacity factor determination of wind onshore and offshore turbines [4].

Parameter	Unit	Onshore	Offshore
hub height h^{hub}	m	80	120
roughness length z_0	m	0.25	0.001
array efficiency ϵ^{array}	-	0.925	0.90
turbine availability $\epsilon^{\text{turbine}}$	-	0.97	0.90
fitting parameter λ_1	sh/ma	626.51	626.51
fitting parameter λ_2	h/a	1901	1901

PV and CSP capacity factors The NCEP dataset `dswrf` (downward solar radiation flux) has been used to parameterize PV and CSP potentials. We assume that this parameter equals global irradiance I.

The actual capacity factor of PV plants is the relationship between actual global irradiance $I_{t,c}$ and irradiance under reference conditions $I^{\text{ref}} = 1000W/m^2$, corrected with a system efficiency $\epsilon^{\text{system}} = 0.75$ [5].

$$\epsilon_{t,c} = \epsilon^{\text{system}} \frac{I_{t,c}}{I^{\text{ref}}} \tag{27}$$

Whereas PV plants can utilize both direct and diffuse irradiance, CSP plants can only convert direct irradiance. We use the following empirical correlation to derive direct normal irradiance DNI data from global irradiance data:

$$DNI_{t,c} = I_{t,c}\left(1 - 0.25\left(\frac{lat_c}{30}\right)^{1.6}\right) \tag{28}$$

This assumes that the DNI share of global irradiance is 0.75 at a latitude of 30°, and that it decreases for larger latitudes.

CSP plants are modeled with internal thermal storage. We assume a SM4 (Solar Multiple 4) configuration [12] where the collector area is four times the size required to reach nominal output at reference conditions, and the thermal storage capacity is large enough to run the plant at nominal output for 18 hours if the storage is completely filled. We therefore assume that the maximum capacity factor for CSP plants differs between days, but that it is equal for all four time slices within a single day. It is calculated as the mean value of each time slice's capacity factor, multiplied with four:

$$\epsilon_{t,c} = 4\frac{\sum_{i=1}^{n_i}\frac{DNI_{i,c}}{DNI^{\mathrm{ref}}}}{n_i} \tag{29}$$

2.1.3 Maximum installable capacities of fluctuating RE

The maximum generation capacity K that can be installed per grid cell c correlates with the cell's surface area A:

$$K_c = DfA_c \tag{30}$$

The power density factor D defines how many GW nameplate capacity can be installed per km^2 of land or sea area. The land suitability factor f defines the share of surface area that is available to be used for generation capacity installation. Technology specific, uniform values are used for both parameters (Tab. 4).

Table 4: Parameters for determination of installable generation capacity per area ([5], own calculations).

	Power density D (MW/km^2)	suitability factor f (-)
Wind onshore	4	0.20
Wind offshore	4	0.20
PV	70	0.025
CSP	70	0.025

2.1.4 Resource grades

The derived data on capacity factors and installable capacity per grid cell (see Sec. 2.1.2 and 2.1.3) is aggregated to parameterize resource grades for each model region. For each region, we define three resource grades for each technology, each with an average annual capacity factor and a maximum installable

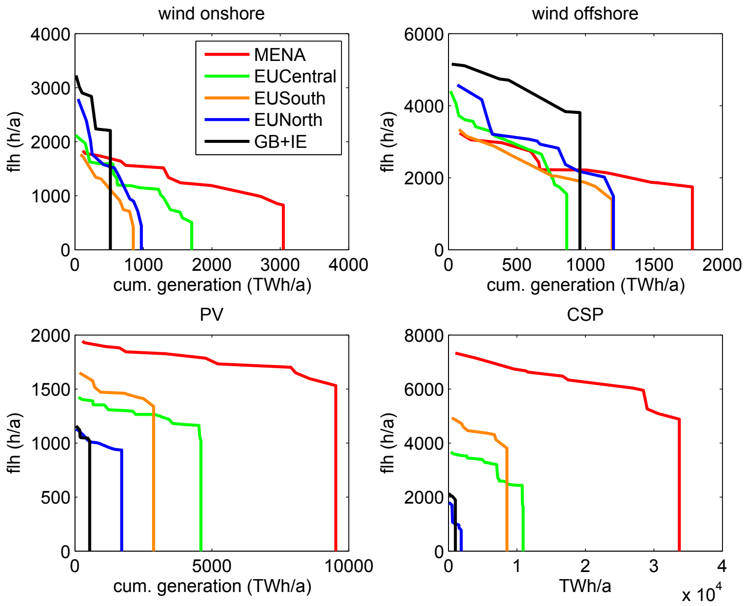

Figure 2: Regional potentials for fluctuating renewable energy resources.

capacity. Fig. 2 shows supply curves (marginal full load hours over total generated power) derived by sorting these grades, for five model region groups. The detailed data is show in Tables 6 and A.

2.1.5 Time slices and choice of characteristical days

The model features 49 time slices to represent short term fluctuations of supply and demand. In each time slice, supply and demand need to be balanced given the currently installed generation, storage and transmission capacities. The time slice scheme is shown in Tab. 5. There are four seasons and three RE supply regimes, which results in 12 characteristical days. Each day is represented by four time slices, each one with a length of six hours (starting at 0.00am). An additional super peak time slice represents high demand and low RE supply.

Fluctuations of RE supply are represented by the technology specific capacity factors which differ across region, resource grade and time slice.

1. For each region, a average wind speed duration curve is constructed (by all data points of the complete one-year time series by descending average wind speed.)

2. Out of the 365 days of the year, two candidates are determined for each of the twelve characteristical days, based on the average wind speed for this

Table 5: Time slice scheme and numbers of time slices.

	RE supply		
	low	medium	high
spring (3/01 – 5/31)	4	4	4
summer (6/01 – 8/31)	4	4	4
autumn (9/01 – 11/30)	4	4	4
winter (12/01 – 2/28)	4	4	4
super peak		1	

day, across all grid cells (e.g. the two spring days with the lowest average wind speed, the two spring days with the highest average wind speed, and the two spring days during which wind speed deviation from average wind speeds in spring is smallest.)

3. Out of these 24 candidates, a set of all possible combinations is constructed.
4. For each of these 512 combinations, a wind speed duration curve for each model region is constructed.
5. For each combination, wind speeds are scaled up so that their regional averages equal the regional averages of the complete time series.
6. The scaled regional wind speed duration curves (each one consisting of only 48 data points) are compared with the complete time series curves by calculating the coefficient of determination R^2 for each combination and region.
7. The combination with the largest sum of regional R^2 values is chosen for parameterization of the time slices.

2.2 Biomass potentials

Tab. 9 shows regional biomass potentials. The data is based on [3]. The reference gives primary energy potentials until 2030 for EU-25 member countries (for most countries, potentials increase over time due to efficiency increases and increased land utilization). Potentials are assumed to remain constant after 2030. For countries outside EU-25 a biomass potential of zero is assumed due to their endowment with other renewable resources (wind and hydro power resources for Norway, PV and CSP resources for MENA countries).

2.3 Seasonal availability of hydropower

To reflect the seasonal availability of hydro power resources, average capacity factors of hydro power capacities are constrained by season specific availability factors (see Tab. 10). Seasonal availabilities have been estimated based on average monthly power generation by hydro power plants published by entso-e[4] and installed capacities from [10]. They are assumed to be region independent.

Hydro power capacities are limited to current levels (data from [10]). Although studies claim that the potential for hydro power generation in Europe is not yet fully utilized (e.g. [8]) it is assumed that remaining potentials will rather be used for pumped hydro storage.

2.4 Power demand

2.4.1 Average annual demand until 2050

Tab. 8 shows demand projections for all model regions until 2050. For EU-27 member countries, we use the reference scenario from [2]. The reference gives empirical data from 1990-2009 and annual projections from 2010-2030. Demand from 2035-2050 has been extrapolated from this data. For countries outside EU-27 we calculate average annual demand growth rates for 1990-2008 from [6, 7]. We assume that demand growth rates for these countries linearly decrease to zero until 2050.

2.4.2 Demand fluctuations across time slices

Power demand across time slices is based on hourly load data published by ENTSO-E[5]. This data has been scaled to match average annual power demand published by IEA [6, 7]. Time slice demand is the average of hourly demands matching the respective time slice. For MENA countries hourly demand data was not available. Demand profiles have been created by scaling the demand profiles of neighbouring countries to match annual power demand published by IEA.

2.5 Initial generation and storage capacities

Ta. 11 shows generation and storage capacities in 2010. For EU-27 member countries, Norway and Switzerland, the data has been aggregated from the Chalmers Energy Infrastructure Database [10]. For other countries, generation capacities have been estimated based on the power mix for 2008 given in [6, 7].

2.6 Initial transmission capacities

Initial transmission capacities are based on Net Transfer Capacities (NTC's) published by ENTSO-E[6] In case where involved TSOs state different NTC values for a connection, the average of both values was used. Initial transmission

[4]Detailed monthly production tables for 2009, available online (`www.entsoe.eu/resources/data-portal/production`). Accessed on July 26,2011.

[5]System vertical load for 2009, available online (`www.entsoe.net`). Accessed on February 1, 2011.

[6]NTC values summer 2009, available online (`www.entsoe.eu/resources/ntc-values/ntc-matrix`). Accessed on December 1, 2010.

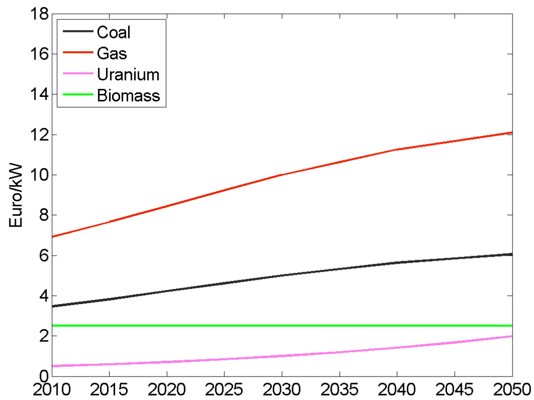

Figure 3: Price paths for fossil fuels, uranium and biomass.

capacities between MENA countries (which are not published by ENTSO-E) are assumed to be zero.

2.7 Fuel prices

Fig. 3 shows fuel prices for coal, natural gas, uranium and biomass. Coal, gas and uranium price scenarios are from [1]. For biomass a constant price of 2 5Euro/GJ is used.

2.8 Investment costs over time

Fig. 4 shows investment cost time paths for learning technologies. This data has been taken from the REMIND model [11]. The underlying scenario assumes that global emissions are reduced sufficiently to limit global mean temperature increases to 2°C until 2100, which results in ambitious RE expansion in the power sector. For other technologies, costs are assumed to be constant over time. The values are given in the paper.

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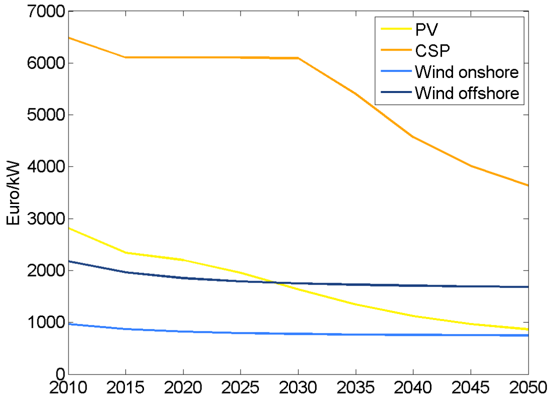

Figure 4: Investment cost time paths for learning technologies.

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A Data tables

Table 6: Average annual capacity factors for RE resource grades (%).

	Wind onshore			Wind offshore			PV			CSP		
Grade	1	2	3	1	2	3	1	2	3	1	2	3
NO	32	27	18	52	48	35	12	11	11	12	12	11
SE	23	17	11	39	32	23	12	11	11	12	12	11
DK	23	21	16	50	46	35	13	12	12	21	19	19
FI	18	10	5	33	27	17	12	12	11	10	10	9
Baltic	20	16	8	37	34	25	13	13	12	20	20	19
GB	34	32	25	58	54	44	13	13	12	24	23	22
IE	37	33	26	59	54	43	12	12	12	24	24	23
DE	24	18	14	43	41	31	15	14	13	31	30	28
East	15	13	8	30	27	22	14	14	13	30	29	28
BalkanN	11	8	6	21	20	18	16	15	15	42	40	39
BalkanS	10	9	5	23	20	16	17	17	16	52	51	49
FR	22	18	13	41	38	32	16	16	14	41	40	37
Benelux	24	21	19	42	39	36	14	14	13	30	29	28
CH+AT	14	12	7	0	0	0	15	15	15	39	39	38
IT	20	15	8	36	30	21	17	16	15	47	46	44
ES+PT	20	15	11	38	33	23	19	18	17	56	54	50
TR	18	14	10	28	24	20	19	18	17	60	58	56
MENAW	20	17	11	35	31	21	21	21	19	76	74	69
MENAC	21	19	14	37	34	25	22	22	20	84	82	77
MENAE	20	15	9	25	24	21	22	21	20	76	72	68

Table 7: Installable capacities for RE resource grades (GW).

	Wind onshore			Wind offshore			PV			CSP		
Grade	1	2	3	1	2	3	1	2	3	1	2	3
NO	16.8	50.3	100.6	14.2	42.7	85.4	34.8	104.4	208.8	34.8	104.4	208.8
SE	29.6	88.8	177.6	15.7	47.1	94.3	64.4	193.2	386.4	64.4	193.2	386.4
DK	1.6	4.9	9.9	3.3	10.0	20.0	7.2	21.6	43.2	7.2	21.6	43.2
FI	19.8	59.4	118.7	7.4	22.3	44.5	42.9	128.8	257.6	42.9	128.8	257.6
Baltic	14.4	43.1	86.1	7.1	21.4	42.7	30.0	90.0	180.0	30.0	90.0	180.0
GB	16.1	48.4	96.7	18.0	54.0	108.0	39.2	117.6	235.2	39.2	117.6	235.2
IE	4.7	14.1	28.1	4.7	14.1	28.1	11.3	33.9	67.9	11.3	33.9	67.9
DE	28.3	84.9	169.8	5.4	16.1	32.2	62.1	186.4	372.8	62.1	186.4	372.8
East	33.4	100.3	200.6	4.5	13.5	27.0	75.7	227.1	454.2	75.7	227.1	454.2
BalkanN	44.3	133.0	266.0	6.1	18.3	36.5	97.3	292.0	584.1	97.3	292.0	584.1
BalkanS	21.9	65.7	131.4	14.8	44.3	88.7	47.9	143.7	287.4	47.9	143.7	287.4
FR	42.0	125.9	251.7	10.6	31.8	63.5	91.1	273.4	546.8	91.1	273.4	546.8
Benelux	3.7	11.2	22.4	2.0	6.1	12.2	12.2	36.6	73.3	12.2	36.6	73.3
CH+AT	10.0	30.1	60.2	0.0	0.0	0.0	18.2	54.7	109.3	18.2	54.7	109.3
IT	21.0	62.9	125.8	18.4	55.2	110.4	46.6	139.8	279.7	46.6	139.8	279.7
ES+PT	45.5	136.6	273.3	22.9	68.7	137.4	101.7	305.2	610.5	101.7	305.2	610.5
TR	47.4	142.1	284.2	24.2	72.7	145.4	105.3	315.8	631.7	105.3	315.8	631.7
MENAW	121.0	363.0	726.1	25.8	77.4	154.8	261.1	783.2	1566.4	261.1	783.2	1566.4
MENAC	63.1	189.3	378.6	25.5	76.5	153.1	138.3	414.9	829.8	138.3	414.9	829.8
MENAE	18.1	54.3	108.6	4.2	12.6	25.3	42.8	128.3	256.5	42.8	128.3	256.5

Table 8: Average annual demand projections until 2050 (TWh/a).

	2010	2015	2020	2025	2030	2035	2040	2045	2050
NO	142.7	146.4	149.8	152.6	155.0	156.9	158.2	159.0	159.2
SE	149.4	152.5	155.5	158.4	161.3	164.0	166.8	169.4	172.0
DK	36.8	37.9	39.2	40.5	42.0	43.6	45.4	47.2	49.2
FI	79.0	82.2	84.1	84.7	83.9	81.8	78.3	73.6	67.5
Baltic	30.4	33.4	36.3	39.2	42.0	44.7	47.4	50.0	52.5
GB	391.1	404.2	415.5	424.9	432.5	438.3	442.2	444.3	444.5
IE	30.7	34.0	36.9	39.5	41.8	43.8	45.6	47.0	48.1
DE	641.2	662.5	679.1	690.8	697.6	699.7	697.0	689.4	677.0
East	276.8	301.9	329.7	360.2	393.4	429.4	468.2	509.6	553.8
BalkanN	189.3	204.4	220.9	238.6	257.7	278.0	299.7	322.7	347.1
BalkanS	121.6	131.7	142.3	153.2	164.5	176.3	188.4	200.9	213.8
FR	585.3	623.0	661.2	699.8	739.0	778.7	818.9	859.6	900.8
Benelux	198.6	209.4	219.5	228.6	237.0	244.5	251.2	257.0	262.0
CH+AT	134.7	142.6	150.0	156.8	163.0	168.5	173.2	177.1	180.2
IT	321.9	341.7	360.4	378.0	394.5	409.7	423.9	436.9	448.7
ES+PT	373.8	412.7	446.0	473.8	495.9	512.4	523.4	528.7	528.5
TR	219.9	278.2	341.1	405.3	466.7	520.6	562.5	588.6	596.3
MENAW	83.3	101.5	120.5	139.4	157.0	172.2	183.9	191.1	193.2
MENAC	178.3	229.7	286.4	345.5	403.0	454.3	494.6	519.9	527.4
MENAE	131.4	156.4	182.6	208.7	233.2	254.5	270.8	280.9	283.9

Table 9: Biomass consumption constraints (PJ/a).

	2010	2015	2020	2025	2030	2035	2040	2045	2050
NO	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SE	24.1	35.4	46.8	52.5	58.3	58.3	58.3	58.3	58.3
DK	15.7	9.1	2.5	2.8	3.0	3.0	3.0	3.0	3.0
FI	78.4	76.9	75.4	64.7	54.0	54.0	54.0	54.0	54.0
Baltic	116.6	219.2	321.7	387.4	453.0	453.0	453.0	453.0	453.0
GB	141.6	255.7	369.8	493.2	616.5	616.5	616.5	616.5	616.5
IE	0.0	2.4	4.8	5.4	5.9	5.9	5.9	5.9	5.9
DE	76.4	59.5	42.6	49.4	56.1	56.1	56.1	56.1	56.1
East	649.4	869.6	1089.9	1239.8	1389.6	1389.6	1389.6	1389.6	1389.6
BalkanN	52.0	73.4	94.8	117.3	139.7	139.7	139.7	139.7	139.7
BalkanS	0.0	35.7	71.4	81.2	91.0	91.0	91.0	91.0	91.0
FR	112.9	119.5	126.0	95.9	65.7	65.7	65.7	65.7	65.7
Benelux	11.3	17.7	24.1	28.1	32.1	32.1	32.1	32.1	32.1
CH+AT	25.5	42.8	60.1	73.3	86.4	86.4	86.4	86.4	86.4
IT	170.4	271.1	371.9	504.2	636.5	636.5	636.5	636.5	636.5
ES+PT	354.7	464.8	574.9	639.9	704.8	704.8	704.8	704.8	704.8
TR	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MENAW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MENAC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MENAE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 10: Seasonal hydro power availability (maximum average capacity factor per season).

spring	summer	autumn	winter
0.37	0.35	0.33	0.41

Table 11: Initial generation and storage capacities (GW).

	Nuclear	Coal	Gas	Hydro run-off	Wind onshore	Wind offshore	SPV	Hydro PS	Bio	CSP
NO	0.0	0.0	1.2	26.7	0.4	0.0	0.0	1.1	0.0	0.0
SE	9.3	0.6	1.0	15.8	1.5	0.2	0.0	0.0	1.9	0.0
DK	0.0	4.9	2.5	0.0	2.7	0.9	0.0	0.0	0.4	0.0
FI	2.7	5.4	2.3	2.8	0.1	0.1	0.0	0.0	1.8	0.0
Baltic	0.0	3.0	2.8	1.7	0.2	0.0	0.0	0.8	0.0	0.0
GB	10.1	29.1	34.9	1.5	3.6	1.3	0.0	2.8	0.5	0.0
IE	0.0	1.4	4.1	0.2	1.4	0.0	0.0	0.3	0.0	0.0
DE	20.5	47.4	25.3	2.9	25.6	0.1	10.1	6.8	1.3	0.0
East	5.4	40.9	2.4	2.6	1.0	0.0	0.1	4.0	0.1	0.0
BalkanN	3.9	9.1	8.7	6.7	0.5	0.0	0.0	0.3	0.2	0.0
BalkanS	1.9	10.5	4.2	3.8	1.2	0.0	0.0	2.1	0.0	0.0
FR	63.1	8.2	6.3	14.6	4.5	0.0	0.1	5.5	0.2	0.0
Benelux	6.4	5.8	20.4	0.1	2.0	0.3	0.1	2.4	0.5	0.0
CH+AT	3.2	1.5	2.5	20.6	1.0	0.0	0.0	6.3	0.1	0.0
IT	0.0	9.8	46.9	12.1	4.8	0.0	0.1	6.8	0.4	0.0
ES+PT	7.5	14.0	31.3	18.0	21.8	0.0	1.2	4.0	0.6	0.7
TR	0.0	9.4	17.3	7.6	0.0	0.0	0.0	0.0	0.0	0.0
MENAW	0.0	1.9	10.3	0.3	0.0	0.0	0.0	0.0	0.0	0.0
MENAC	0.0	0.0	23.5	3.4	0.0	0.0	0.0	0.0	0.0	0.0
MENAE	0.0	5.8	13.5	0.8	0.0	0.0	0.0	0.0	0.0	0.0

Table 12: List of symbols used in the model description. Symbols used for indices and sets are listed in Tab. 1 and 2.

symbol	unit	description
D	GW	demand
G	GW	generation
P	GW	primary energy consumption
S^{in}	GW	storage charge
S^{out}	GW	storage discharge
F^T	GW	transmission flow
C^{tot}	Euro	total system costs (objective function)
C^I	Euro	investment costs
C^F	Euro	fuel costs
C^{OM}	Euro	operation and maintenance costs
K	GW	available capacity (generation and storage)
ΔK	GW	capacity additions (generation and storage)
K^T	GW	available capacity (transmission)
ΔK^T	GW	capacity additions (transmission)
E	GtCO_2	emissions
l_τ	h	time slice length
α	Euro/kW	specific investment costs (generation and storage)
α^T	Euro/kWkm	specific investment costs (transmission)
β		fixed operation and maintenance costs
γ		variable operation and maintentance costs
δ		emission coefficient
η	-	conversion efficiency
ι^T	%/km	transmission losses
κ	-	security margin for utilization of transmission capacities
ω	-	depreciation coefficient
ψ	a	technical lifetime
ρ	%/a	discount rate
σ	Euro/GJ	specific fuel costs
l^T	km	transmission line length
Δt	a	time step length

Chapter 6

Synthesis and Outlook

The main objective of this thesis has been to examine the role renewable power generation can play in achieving ambitious mitigation targets, to assess the system integration challenges that result from renewable generation expansion, and to investigate how long term power system decarbonization strategies are affected by these challenges.

These topics have been addressed in a number of model based studies. Results show that investments in generation, transmission and storage capacities are in fact tightly interrelated, and that important insights can be gained by addressing the multi-scale problem of renewable generation expansion in an integrated modeling framework.

It has been demonstrated that, for the EU and MENA regions, ambitious emission reduction targets can be met by expanding renewable power generation, and without relying on CCS and new nuclear capacities. The economic costs of this effort, and the feasible level of emission reductions, strongly depends on the availability and adequate expansion of transmission and storage capacities.

This chapter starts with a methodological review in Section 6.2, which discusses the characteristics of the LIMES model and clarifies how this approach contributes to the field of power system planning planning tools. The synthesis of the findings of Chapters 2 to 5 are presented in Section 6.1. Finally, Section 6.3 provides an outlook on challenges for further research.

6.1 Synthesis of results

The major findings from Chapters 2 to 5 are presented along the research questions formulated in Chapter 1.

Chapter 2 investigates the importance of power sector decarbonization – and the role of renewable power generation – for economy-wide mitigation efforts:

1. What is the role of renewable power generation in achieving long-term emission reduction targets?

The study presents long-term mitigation scenarios created with the Integrated Assessment Model REMIND. It proposes a novel approach for calculating secondary energy based mitigation shares. This approach provides a well-defined metric to allocate emission reductions across technology groups, end-use sectors and regions, and to distinguish between mitigation achieved by technology choice and by efficiency improvements respectively demand reductions.

Mitigation strategies were found to differ widely across regions, depending on socio-economic development, demand characteristics and resource endowments. Nevertheless, it could be shown that the power sector plays an important role in achieving low emission targets, and that it is decarbonized to an overproportionally large degree: Cumulated emissions (2005 - 2100) are reduced to 7% relative to baseline emissions, compared to 35% and 32% in heat and transportation sectors, respectively.[1] This is due to the broad portfolio of low carbon technology options for power generation (nuclear, CCS and renewable energy sources). Although all three options are used, renewable technologies have the largest contribution (47%) towards power sector mitigation, and their mitigation share in the power sector is significantly higher than in heat and transport sectors.

The electricity sector is set apart from the other sector by another aspect: In the heat and transportation sectors, a significant share of mitigation (41% and 29%, respectively) is not achieved by a switch to low emission technologies, but by efficiency improvements and demand reductions. In contrast to that, electricity demand was found to increase relative to baseline demand. This indicates that due to the varying availability of mitigation options across sectors, climate constraints induce a substitution process towards sectors that are easy to decarbonize - in that case, towards electricity.

These results show that power sector decarbonization in general, and expansion of renewable power generation in specific, play a crucial role in achieving ambitious emission reduction targets. However, the REMIND modeling approach focuses on long term developments and disregards system integration issues due to large generation shares of fluctuating renewable energy sources. Chapter 3 addresses this gap by adding the problem dimension of short term dynamics:

[1] The given numbers refer to the Tax30 scenario, see Chapter 2, Figure 3(a).

2. How does improved representation of short-term dynamics affect investment decisions in generation capacities?

The chapter examines power system mitigation scenarios for Eastern Germany, a small geographic area that is managed by a single transmission system operator (TSO) and has only limited interconnections with neighbouring regions. The region has large wind onshore and offshore potentials, and the projected expansion of wind based power generation is likely to create considerable integration challenges. Long-term investment strategies under different CO_2 price scenarios were investigated while varying short-term temporal resolution (regarding supply and demand fluctuations) between one and 24 hours. The scenarios have been created with a single region version of the LIMES model.

Improving the representation of short-term dynamics leads to increased deployments of flexible gas power plants in a power system that is largely dominated by wind and coal based generation. Due to the price difference between coal and gas, this leads to an increase in power system costs of 1-2%.[2] If the option to expand storage capacities is available, flexibility is provided by storage instead, and the cost increase is dampened significantly. Cost increases stabilize for high temporal resolutions, which indicate that refining the representation of short-term dynamics beyond hourly resolution might not lead to more accurate results. The cost increases induced by higher temporal resolution are insensitive towards CO_2 price levels – baseline and policy scenarios exhibit similar flexibility requirements, and considering these requirements does increase system costs while leaving mitigation costs largely unaffected.

It has also been shown that curtailments of renewable generation can be cost-efficient from a system cost minimization point of view: Interdicting curtailments increases requirements for natural gas generation and, in the baseline scenario, reduces wind energy deployments.

Overall, it has been demonstrated that disregarding short term dynamics within models can lead to an underestimation of flexibility requirements and, subsequently, to an underestimation of system costs. Chapter 4 adds the problem dimension of spatial distribution:

3. How does adequate expansion of transmission and storage capacities affect deployment and spatial allocation of generation capacities?

This study analyzed how long term investment strategies under climate policy constraints are affected by limited availability of transmission and storage capacities. The experiments have been performed with a conceptual three region version of the LIMES model, incorporating the three problem dimensions – long term development, short term dynamics, and spatial distribution – into an integrated framework.

If the option to expand transmission capacities is available, renewable generation capacities are distributed across regions in such a way that the best resource locations are used, and transmission capacities are expanded accordingly to allow for power transfer between regions. Constraining transmission expansion rates leads to system-wide effects: As power transfers between regions are limited, renewable generation capacities are clustered closer to demand centers, at resource locations of lesser quality. Besides

[2] See Chapter 3, Figure 11.

that, limited interregional power transfers reduce the ability of the system to level out short-term fluctuations by pooling of sources with uncorrelated fluctuation patterns. Limiting the availability of storage expansion leads to increased deployment of dispatchable gas power plants. These results show that the characteristics of the target system depend on constraints that limit the inter-temporal deployment of capacities, which is a strong argument for analyzing transition processes of power systems from an inter-temporal optimization perspective.

Expanding transmission and storage capacities incurs additional investment costs. These costs, however, are small compared to investments in generation capacities (which contribute to more than 90% of total investments), and they are outweighed by their system-wide beneficial effects. Adequate and timely expansion of transmission and storage capacities leads to optimal spatial allocation of generation capacities, high realized capacity factors, reduction of curtailments, reduced gas backup requirements and lower residual emissions and reduces overall system costs by 1-6%.[3]

Finally, in Chapter 5, a fully calibrated version of the LIMES model has been used to examine decarbonization scenarios for the EU and MENA regions:

4. What are cost-efficient coordinated renewable power generation scenarios for EU and MENA regions that take the expansion of integration facilities into account?

Chapter 5 examined how Europe can reach its ambitious emission reduction targets for the power sector until 2050 by relying on the expansion of renewable power generation. The analysis was performed using a multi-region version of the LIMES model that covers the EU-27 member countries, Norway and Switzerland as well as the countries surrounding the Mediterranean Sea (LIMES-EU$^+$).

Results show that until 2050 power sector CO_2 emissions can be reduced by 90% (relative to 2010) by expanding renewable generation capacities, transmission and storage in a coordinated manner. This target can be reached without using CCS, and without new nuclear generation capacities. Renewable generation capacities are allocated across regions according to the regional distribution of renewable resources. Depending on the availability of transmission infrastructure expansion, a clear pattern of net importing and net exporting regions emerges. Power exchanges between EU and MENA regions play a minor role – CSP plays an important role in the MENA region, but Europe relies mainly on it's own large and diverse renewable potentials without requiring electricity imports on a large scale. Until 2030 wind onshore and offshore capacities are expanded; the largest share of generation capacity is located in Scandinavia and the British Islands. This is accompanied by a rapid expansion of transmission infrastructure to transport wind power to the demand centers in central and southern Europe. After 2030, PV and CSP capacities are expanded in the Southern European and MENA regions, and their share increases continuously until 2050. This regime shift[4] – the transition from a wind and fossil based system to one that is dominated by wind and solar generation – leads to different integration challenges and to a change of the pattern of importing and exporting regions. North-South transmission capacities are expanded, and southern European and MENA

[3] See Chapter 4, Figures 7 and 10.

[4] See Chapter 5, Figure 7.

regions become net exporters. The expansion of PV capacities also increases day/night storage requirements. Electricity imports in central Europe – mainly in Germany and eastern European countries – increase up to 50% of domestic demand.[5]

As the expansion of transmission capacity is uncertain, and concerns about import dependency may limit the willingness of countries to pursue the option of a highly integrated European grid, the chapter also presents scenarios where transmission capacities are limited to current levels. Results show that low emission targets can also be achieved if regions rely on their domestic renewable resources. Wind generation capacities are distributed more evenly across regions, and the shares of PV generation in central European countries increase. This leads to high storage requirements, higher curtailments, and increasing overall costs.

Lowering the emission caps leads to increasing CO_2 prices and electricity prices. Imposing a cap of 90% emission reductions in 2050 (relative to 2010) leads to an increase in average electricity prices to 8.7 ct/kWh – compared to 6.8 ct/kWh in the baseline scenario. If transmission capacities are limited to current levels, average electricity prices increase to 10.1 ct/kWh. In this case, storage plays an especially important role: if neither transmission nor storage expansion are available, prices reach 15.3 ct/kWh.[6]

Imposing emission caps – and the resulting higher shares of fluctuating renewable generation – does not only affect average electricity prices, but also lead to higher temporal and spatial price variations. In 2050, in the baseline scenario 3% of all regional spot prices are zero (indicating that supply exceeds demand). For the 90% reduction scenarios, this number increases to 22% and 38% (with and without transmission expansion beyond current levels, respectively).[7] This could lead to considerable problems with markets that are based on marginal pricing methods (as they are currently in place in Europe) and calls for the development of alternative market designs (e.g. capacity markets).

A sensitivity analysis with respect to different emission caps show a non-linear relationship between CO_2 prices / electricity prices and the stringency of emission targets. There is a critical value for emission caps where prices escalate. This threshold can be shifted towards more ambitious reduction targets if storage and transmission capacities are expanded in a coordinated manner. It varies between 70% and 95% reductions (relative to 2010 emissions), depending on the availability of transmission and storage expansion. These results indicate that the emission reductions which can be achieved by expanding renewable generation shares are not limited by overall renewable resources, but by the adequate use of technical options to facilitate system integration.

[5] See Chapter 5, Figure 5b.
[6] See Chapter 5, Figure 9.
[7] See Chapter 5, Figure 10.

Main findings

In summary, the main findings of this thesis are:

- The decarbonization of the power sector in general, and the expansion of renewable power generation in specific, play a pivotal role for CO_2 mitigation.
- The management of renewable generation expansion is a multi-scale problem: Spatial distribution and short term variability of renewable resources cause system integration challenges. The requirements for – and the availability of – technologies that ease the integration process (transmission infrastructure and storage capacities) affect cost-efficient long term investment decisions.
- In fact, the level of decarbonization that can be achieved by increasing renewable generation shares is not limited by overall renewable resources, but the efforts that are required to integrate them into power systems. In Chapter 5 CO_2 and electricity prices were shown to escalate if emission caps exceed a certain limit.
- This threshold can be shifted by adequate expansion of transmission and storage capacities. This shows that investments in system integration technologies are crucial for achieving low emission targets. In Chapter 4 it was shown that these investments are small compared to investments in generation capacities, and that they are overcompensated by their system-wide beneficial effects.
- For the EU and MENA regions, emission reductions of 90% in 2050 (relative to 2010) can be reached by expanding renewable power generation – without using CCS or building new nuclear power plants. Renewable resources in Europe are large and diverse enough that this target can be met without relying on large scale electricity imports from the MENA region.
- Cost-efficient expansion pathways for generation capacities in Europe until 2050 are far from linear: Until 2030, the system is characterized by a mixture of wind and fossil generation, followed by a switch to a wind and solar based generation mix. This transition on the generation side results in different integration challenges, and it changes the interregional patterns of power transfer and the way the existing transmission infrastructure is used.
- Ambitious reduction targets can also be reached without establishing a trans-European grid. This, however, leads to higher storage requirements, higher curtailments of renewable generation, and higher system costs.

6.2 Methodology review

The thesis centers around the development and application of the LIMES modeling framework. Its multi-scale approach, with a strong focus on intertemporal optimization, makes it a valuable addition to the field of system integration studies for renewable power generation.

The three model versions that have been applied in Chapters 3 to 5 are very different in scope and functionality. This demonstrates that the modeling framework is flexible and can be adapted to answer a large number of research questions. They also document how the model developed and improved as new insights were gained. An example are the insights that lead to the choice of Linear Programming (LP) model formulation. The conceptual model version used in 4 is formulated as a Non-linear Programming (NLP) problem. Non-linear equations are required for formulating power flow distribution constraints, endogenous learning and a non-linear formulation of renewable resource quality as a function of installed generation capacities. Taking into account power flow distribution constraints, however, was shown to have little effect on model results. By neglecting these constraints, replacing endogenous learning by exogenous cost curves and discretization of renewable resource grades, the model was reformulated as an LP problem. This reduced numerical costs by several orders of magnitude and made it possible to significantly increase technological detail and temporal resolution for the LIMES-EU$^+$ model.

In methodological terms, the added value of the LIMES approach is that it focuses not only on the feasibility of a long-term target system (although system operation is taken into account in a simplified manner), but on the optimal design of a pathway that leads to this system. The results presented in Chapter 5 show that the transition towards a low carbon power system is much more complex than a linear extrapolation of capacities until 2050 – a simplified assumption that is made, for example, in ECF (2010). Due to the long time horizon, the LIMES-EU$^+$ model add new insights compared to other studies that are limited to medium term time horizons and mostly consider only an expansion of wind generation capacities, e.g. EWEA (2009).

The advantages of the multi-scale approach come at the cost of limitations in terms of temporal, spatial and temporal resolution. The strongest simplification may be the representation of short-term dynamics by characteristic time slices. Different parametrization approaches have been used in the presented model versions to ensure that time slices adequately represent real world dynamic processes. For the LIMES-EU$^+$ model an algorithm was designed to choose characteristic days in a manner that spatial and temporal fluctuation patterns are preserved.

Figure 6.1 helps to put LIMES into relation with other modeling approaches. It compares dispatch of generation and storage capacities for the German power system in 2050, as they are calculated with the ReMIX and the LIMES-EU$^+$ model.[8] The underlying scenarios are similar.[9] It is apparent that the ReMIX model is far superior in terms of temporal resolution. The figure also shows that LIMES-EU$^+$ covers many critical system operation points: wind supply varies between close to zero and more than 100% of domestic demand. Solar generation exceeds demand by far during daytimes, and storage is required to shift surplus renewable generation to time slices with low availability of renewables supply. Both scenarios are similar in terms of generation mix and storage capacities. Model design should not aim to increase the level of detail as far as possible, but represent relevant system characteristics in a methodologically and numerically effective manner. A careful validation with higher detailed models (in terms of temporal, spatial

[8] See Section 1.3.2 for a discussion of the ReMIX model.

[9] The ReMIX scenario assumes 100% renewable generation and does not allow for cross border transmission. The LIMES-EU$^+$ scenarios assumes 90% CO_2 emission reductions relative to 2010 and limits cross border transmission capacities to current levels.

and technological resolution) will be necessary to ensure that the LIMES model approach satisfies these demands.

6.3 Further research

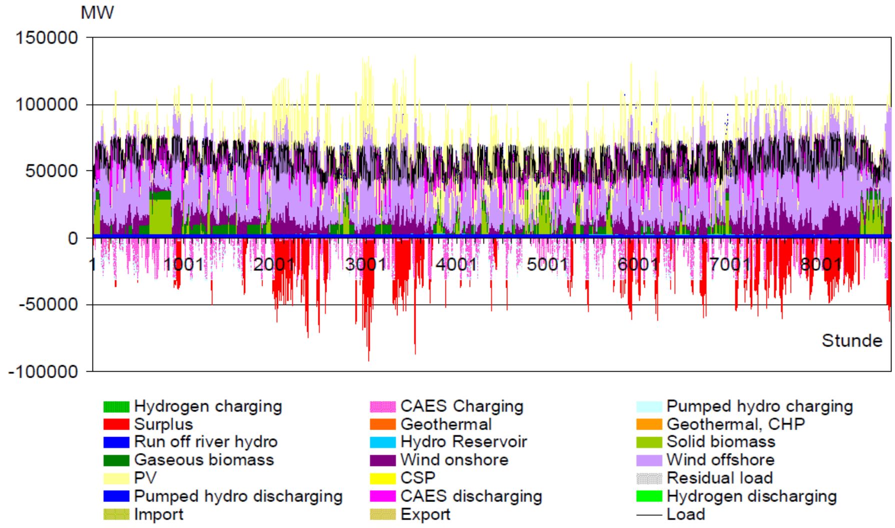
There are many challenges for future research. First of all, scenarios derived with LIMES should be analyzed with a dedicated system operation model that does not consider inter-temporal investments, but represents spatial distribution of resources, grid infrastructure and short-term dynamics with higher accuracy. This would serve several purposes: LIMES results could be validated, and additional flexibility requirements or operation constraints could be fed back into LIMES in form of simplified parametrizations. A model that determines optimal storage capacities and their operation on small time scales is currently being developed at PIK. It will be used to improve the representation of storage requirements in LIMES. LIMES, on the other hand, can provide other models with deployment levels and spatial allocation schemes of capacities that result from inter-temporally optimized investment scenarios.

The LIMES-EU$^+$ model currently has a temporal resolution (time slice length) of six hours and does not capture dynamics at smaller time scales. Considering these effects may be important – Chapter 3 shows that increasing short-term resolution up to one hour does reveal certain flexibility requirements that would be neglected otherwise. The low temporal resolution may be a reason for onshore wind being preferred over offshore wind in LIMES-EU$^+$ scenarios – less short-term variability is an advantage of offshore wind generation that is obscured by the current parametrization. Increasing temporal resolution is not only an issue of numerical costs, but also of data availability – high resolution meteorological data sets are hard to obtain. An option is to disturb data with random fluctuations to approximate real world variability patterns (this approach has been used in EWEA (2009)).

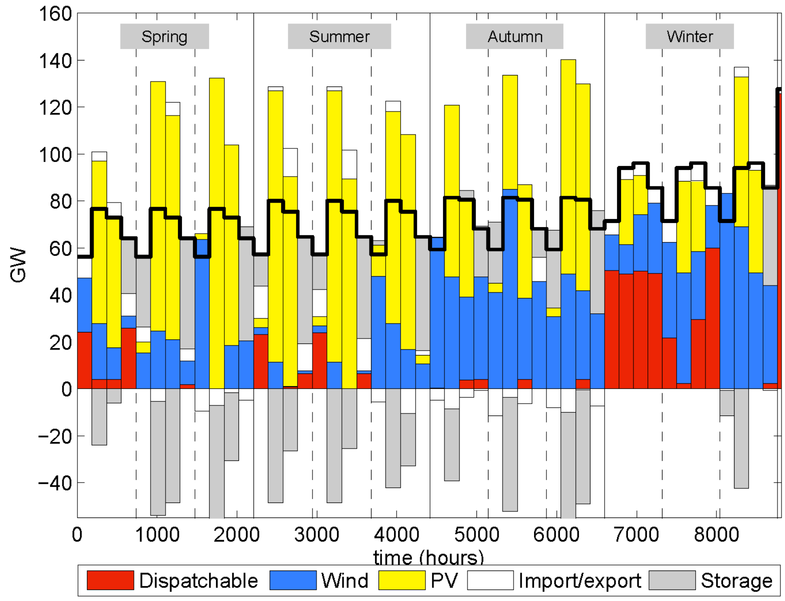
A pressing issue is to assess the advantages (and limitations) of a combined usage of renewable generation, nuclear power and CCS. Chapter 2 shows that nuclear power and CCS can contribute significantly to CO_2 mitigation. However, reduced base load requirements in power systems with renewable generation shares may limit the range in which large, inflexible power plants can operate. Regional availability of geological formations to store captured CO_2 could be taken into account in the LIMES model.

Regarding the LIMES-EU$^+$ model, a natural next step will be to take into account different national policies inside the EU and MENA region. The model allows to analyze different policy measures (e.g. CO_2 prices, feed-in tariffs, taxes, and quota systems) and their effect on mitigation efforts in general and the expansion of renewable generation in specific. An interesting question would be how effective harmonized or fragmented policy regimes are in incentivising the deployment and system integration of renewable generation capacities across the EU and MENA regions.

Chapter 2 shows that cost-efficient mitigation strategies vary significantly across regions, and IPCC (2011) states that this is especially the case for renewable integration challenges. A multi-region LIMES model for the German power sector is currently being developed. Beyond that, a question that could well be analyzed within the LIMES frame-



(a) ReMIX model, hourly resolution.



(b) LIMES-EU$^+$ model, 6h characteristic time slices.

Figure 6.1: Comparison of results from the ReMIX and LIMES-EU$^+$ models (SRU (2010) and Chapter 5, Figure 8). The figure shows generation mixes across the year for Germany in 2050 for similar scenarios. Despite the lower temporal and technical resolution, pivotal system characteristics are well captured by the LIMES approach.

work how system integration issues affect long term investment decisions in emerging economies (e.g. China, India) where the challenge of decarbonization is coupled with an expansion process for the whole system due to socio-economic growth.

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Nomenclature

AC	Alternating current
CCPP	Combined cycle power plant
CCS	Carbon Capture and Sequestration
CSP	Concentrating solar power
DC	Direct current
DCLF	Direct current load flow algorithm
EC	European Commission
ECF	European Climate Foundation
ENTSO-E	European Network of Transmission System Operators for Electricity
EU	European Union
EWEA	European Wind Association
GAMS	Generic Algebraic Modeling Language
GHG	Green house gas
IPCC	Intergovernmental Panel on Climate Change
LCOE	Levelized Cost of Electricity
LIMES	Long-Term Investment Model of the Electricity Sector
LP	Linear Programming
MENA	Middle East and North Africa
NLP	Nonlinear Programming
PIK	Potsdam-Institut für Klimaforgenforschung (Potsdam Institute for Climate Impact Research)
PP	Power plant
PV	Photovoltaic
RE	Renewable energy
REMIND	Regionalized Model for Induced Technological Change
SRU	Sachverständigenrat für Umweltfragen
TSO	Transmission system operator
UNEP	United Nations Environmental Programme
WWF	World Wildlife Fund

Statement of Contribution

The four core chapters of this thesis (Chapters 2 to 5) are the result of collaborations in this PhD project between the author of this thesis and his advisor, Prof. Dr. Ottmar Edenhofer, involving additional colleagues as indicated. The author of this thesis has made extensive contributions to the contents of all four papers, from conceptual design and technical development to writing.

This section details the contribution of the author to the four papers and acknowledges major contributions of others.

Chapter 2: Gunnar Luderer developed the method of calculating secondary energy based mitigation shares and wrote the major part of the article, with revisions and contributions by all other authors. The author contributed to the implementation and parametrization of the REMIND model, particularly regarding the energy system module, implemented the post-processing tools for calculating the mitigation shares, and contributed to writing the methodological part of the article and the major part of the supplementary material. Robert Pietzcker performed the model experiments and provided the supplementary material on energy accounting. Nico Bauer contributed to the development of the model version used in the AME project, in particular the fossil fuel extraction sector and the adjustment costs.

Chapter 3: This section uses the LIMES modeling framework which has been designed and implemented jointly by the author and Sylvie Ludig, under the supervision of Nico Bauer. Sylvie Ludig implemented the Eastern Germany version of the LIMES model, performed the model experiments and wrote the article, with revisions by the other authors. The author contributed to the implementation of storage, and to calibrating renewable generation and demand across time slices. Eva Schmid contributed to the parametrization of the model, especially with regard to techno-economical parameters of generation technologies.

Chapter 4: This section uses the LIMES modeling framework which has been designed and implemented jointly by the author and Sylvie Ludig, under the supervision of Nico Bauer. The author is solely responsible for implementing the representation of transmission infrastructure in the model. The author implemented the conceptual version of the LIMES model, performed the model experiments and wrote the article, with revisions by Nico Bauer and Sylvie Ludig.

Chapter 5: This section uses the LIMES modeling framework which has been designed and implemented jointly by the author and Sylvie Ludig, under the supervision of

Nico Bauer. The author was solely responsible for implementing the EU and MENA version of the LIMES model and for generating the model parameters. The author conducted the model experiments and wrote the article, with revisions by Nico Bauer and Sylvie Ludig.

Tools and Resources

The LIMES modeling framework was implemented in GAMS (GAMS, 2010). The CONOPT3 and CPLEX solvers were used to solve NLP and LP model formulations, respectively.

MATLAB[10] was used for all data pre- and postprocessing work. The MATLAB Mapping Toolbox[11] was used to process geospatial data.

Multi-run experiments were performed with SimEnv (SimEnv, 2010). ComVis (Matkovic et al., 2008) was used for more complex results visualization tasks.

All code projects were managed using the Subversion version control system.[12].

The text was typeset in LaTeX[13]. JabRef (JabRef Development Team, 2011) was used for literature management.

[10] www.mathworks.de
[11] www.mathworks.de/products/mapping
[12] http://subversion.apache.org
[13] www.latex-project.org

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I wish to thank Sylvie Ludig for accompanying me on that long, winding road that led to this strange beast called LIMES.[14] I also thank Falko Ueckerdt and Michael Pahle for their discussions and knowledgeable – sometimes clever – advice, Brigitte Knopf for her valuable support during the last months, Eva Schmid for diligent and ruthless proofreading, and Thomas Nocke for introducing me to the fascinating world of multi-dimensional visualization techniques.

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[14]the model formerly known as Horst.