Using the sun to decarbonize the power sector: the economic potential of photovoltaics and concentrating solar power

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Abstract

Photovoltaics (PV) has recently undergone impressive growth and substantial cost decreases, while deployment for concentrating solar power (CSP) has been much slower. As the share of PV rises, the challenge of system integration will increase. This favors CSP, which can be combined with thermal storage and co-firing to reduce variability. It is thus an open question how important solar power will be for achieving climate mitigation targets, and which solar technology will be dominant in the long-term.

We address these questions with the state-of-the-art integrated energy-economy-climate model REMIND 1.5, which embodies an advanced representation of the most important drivers of solar deployment. We derive up-to-date values for current and future costs of solar technologies. We calculate a consistent global resource potential dataset for both CSP and PV, aggregated to country-level. We also present a simplified representation of system integration costs of variable renewable energies, suitable for large-scale energy-economy-models. Finally, we calculate a large number of scenarios and perform a sensitivity study to analyze how robust our results are towards future cost reductions of PV and CSP.

The results show that solar power becomes the dominant electricity source in a scenario limiting global warming to 2°C, with PV and CSP together supplying 48% of total 2010-2100 electricity. Solar technologies have a stabilizing effect on electricity price: if both solar technologies are excluded in a climate policy scenario, electricity prices rise much higher than in the case with full technology availability. We also analyze the competition between PV and CSP: PV is cheaper on a direct technology basis and is thus deployed earlier, but at high supply shares the PV integration costs become so high that CSP gains a competitive advantage and is rapidly developed, eventually overtaking PV. Even in the most pessimistic scenario of our sensitivity study with no further cost reductions, CSP and PV still supply 19% of 2010-2100 electricity. We conclude that if a stringent climate target of 2°C is to be met cost-efficiently, solar power will play a paramount role in the long-term transformation of the electricity system.

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Keywords

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Introduction

In the last decade, photovoltaic (PV) has seen an unprecedented boom. Driven by feed-in tariffs in many countries, deployment both at residential and utility scale has risen at a remarkable pace, leading to a hundred-fold increase of the global PV market from 2000 to 2011 [1] and a cumulative capacity[1] of ~140GW in 2013. Although silicon shortages lead to temporary price increases between 2005 and 2010 [2], [3], PV has seen continual price decreases over the last 40 years, resulting in a price drop by more than 85% in the last 25 years [4]. In contrast, concentrating solar thermal power (CSP) has seen a much slower growth. After the construction of the 354MW SEGS plants from 1981-1991, commercial deployment only restarted in 2007, leading to a 2012 global capacity estimated at 2.5GW [5].

During the same period, climate mitigation has become an increasingly prominent item on the international agenda, with the goal of limiting global warming below 2 °C above pre-industrial temperatures. Achieving this goal requires a fundamental restructuring of the global energy system, with most studies pointing to the electricity sector as the first mover [6]–[10]. A large number of technologies potentially allow to produce low-carbon electricity, but most of them face technical, economical or societal risks that may slow or hinder a substantial scale-up – be it public opposition to CCS and nuclear power, limited resource potential to expand hydropower, sustainability issues and competition from the transport sector for biomass, or noise and nature conservation concerns about wind power.

Given these developments and the restrictions on other low-carbon power sources, two questions come to mind: What is the role of solar power for decarbonizing the electricity sector? And second: Have the impressive reductions of PV capital costs decided the competition between PV and CSP in favor of PV, or might CSP see a resurgence and become more important in the future?

This study sets out to answer these questions with the help of the global, long-term energy-economy-climate model REMIND. Since this requires up-to-date knowledge about technology costs and resource potentials, as well as a representation of the relevant integration challenges, we augmented the model in several aspects. First, we develop a novel approach for including integration costs associated with both temporal variability and spatial heterogeneity of variable renewable energies (VRE) into large-scale energy-economy models. Second, derive updated technology costs and learning parameters based on a comprehensive literature survey of the techno-economic literature on both technologies. Finally, we also develop a new and consistent global data set of resource potential data for PV and CSP.

Using the augmented model, we perform a large number of scenario runs to investigate the deployment of solar power under various cost assumptions and to determine the relevance of solar technologies for the power sector. For a deeper understanding of the role of solar technologies, we analyze several metrics, namely amount of electricity production, influence on

[1] „Cumulative capacity“ is the sum over all capacity that was ever installed – thus cumulative capacity increases monotonously, while capacity can increase or decrease over time, as capacities are newly built or retired.

electricity price, levelized costs of electricity (LCOE) and share in total cumulated electricity production.

There have been numerous studies analyzing the importance of solar technologies that have either focused exclusively on CSP [11]–[14] or PV [15], [16]. Other studies have performed a comparison purely based on LCOE analysis [17]–[20], or have limited their analysis to only one region [21]–[25], and most of the studies have not explicitly looked at scenarios without climate policy.

Our study improves the understanding of the economic potential of solar power along several dimensions. Firstly, REMIND calculates inter-temporal optimal technology investment paths, taking into account all costs for investment, fuel, and emissions of the complete technology portfolio. The model fully accounts for endogenous technological learning, thus the competition for capital between the two technologies is captured within the model. While some energy-economy models include both solar technologies, they usually do not model the competition for installation sites with high solar irradiation. Finally, an important characteristic differentiating PV and CSP is the possibility of CSP to use thermal storage and co-firing of gas or hydrogen, thus capable of providing both dispatchability and firm capacity and thereby reducing the need for additional electricity storage. For a sensible analysis, a model needs to internalize this crucial difference between the integration challenges for PV and CSP, as was implemented in REMIND.

The paper proceeds as follows: We start by discussing the basic design setup in Section 2, including a description of the REMIND model and the scenario design. In Section 3, an approach for representing integration costs of variable renewable energies in large-scale energy-economic models is presented. In Section 4, current and future costs for PV and CSP are derived, while a consistent resource potential dataset for PV and CSP is calculated in Section 5. Section 6 presents and analyzes the REMIND scenario results, while Section 7 concludes.

2. Study design

In this section, we present the building blocks that we need to analyze the role of solar technologies for the decarbonization of the power sector. We start with a brief technology description to acquaint the reader with the relevant characteristics of PV and CSP, and then sketch the main features of the REMIND model that was used to explore future energy systems. We describe the scenario groups that we employ to understand the effects of solar power on the energy system and to analyze the robustness of the results. Finally, we discuss the calculation of a metric relevant for the analysis, namely levelized cost of electricity.

2.1 Solar power technology description

Solar energy can be converted directly into electricity using PV, or indirectly using thermal CSP plants. In the following we briefly describe the main characteristics of these two classes of solar power technologies, for more detailed technology information on CSP we refer the reader to [26]–[29], for PV to [30], [31]. The paper focuses on a generalized PV and a generalized CSP technology, without differentiating between the large variety of sub-technologies (e.g., crystallized silicon vs. thin film for PV, or trough vs. tower technologies for CSP). The sub-technologies share the same defining technological characteristics as far as the modeling framework is concerned, and the generalized long-term learning curves utilized in integrated assessment models (IAMs) incorporate the switch to cheaper sub-technologies within the same technology class.

PV cells generally employ semiconductor materials to harness the photoelectric effect. Better understanding of materials and device properties has resulted in continually increasing cell efficiencies. PV power generation is easily scalable to adapt to local requirements: for instance, decentral powering of water pumps is possible using single modules with 200W capacity, while the modules can also be combined into vast arrays (power plants with capacities up to 250MW have been constructed) for grid-connected operation. Also, PV modules can be placed on roofs or integrated into the building structure, thus allowing power production close to demand and tapping into a resource potential that cannot be used by other energy technologies.

CSP technologies use focusing optics like mirrors to concentrate sunlight on an absorber to heat the contained heat transfer medium to temperatures of 400-1000°C. The thermal energy can either be directly used to generate electricity via steam turbines – as done in any conventional steam cycle process – or be stored to allow transformation into electricity at a later time. Most current CSP designs incorporate a natural gas burner for times of insufficient solar thermal energy supply as well as for heat fluid freeze protection[2]. The combination of thermal storage and gas co-firing makes CSP plants fully dispatchable while strongly reducing emissions compared to a natural gas power plant.

The two main types of large-scale CSP systems are trough systems and power tower systems. A trough system uses either long, parabolic mirrors or Fresnel mirrors constructed from many flat mirrors positioned at different angles to focus solar radiation on a line absorber that is heated to 400-600°C. A power tower system consists of a large field of mirrors (heliostats), concentrating sunlight onto a point-like receiver at the top of a tower, thus producing higher intensities and heating the working fluid up to or above 1000°C.

When a CSP plant is combined with thermal storage, the size of the solar field is usually increased relative to the generator size to generate enough solar thermal energy [32]–[34]. This is measured in “solar multiples” (SM): A CSP plant with SM1 generates enough heat at reference irradiance to run the turbine at nominal power, while a CSP plant with SM3 has a three times larger solar field and thus supplies three times the heat. If such a plant is combined with thermal storage units, the additional heat can be stored to allow full turbine operation for hours after irradiance levels drop below normal operation values. This substantially increases the capacity factor, so that a CSP plant with SM4 and 18 hours of storage can reach a capacity factor similar to a base load plant. In future energy systems with high shares of CSP plants, CSP plants will also need to be designed as intermediate plants, thus using less storage and a lower solar multiple. In general, the LCOE of CSP plants with optimum storage/SM ratios does not change substantially between 6 and 12h of storage [33], [35]. As intermediate plants usually have

[2] Until December 2012, the Spanish feed-in tariff allowed for a 15% co-firing of natural gas with full remuneration.

substantially higher marginal costs than base load plants, this niche market might help the market penetration of CSP [36].

Although CSP plants always require some fresh water for cleaning of mirrors, it is possible to reduce the water consumption by about 90% by using a dry-cooling design if the CSP plant is built in a location with scarce water resources [37]. However, dry cooling reduces electricity production by around 7%, equivalent to a decrease of thermal conversion efficiencies by 2-3 percentage points relative to a design with water cooling [38].

2.2 Model description: REMIND 1.5

The energy-economy-climate model REMIND is a Ramsey-type general equilibrium growth model of the macro-economy in which inter-temporal global welfare is maximized, with a technology-rich representation of the energy system [39]–[41]. It represents capacity stocks of more than 50 conventional and low-carbon energy conversion technologies, including technologies for generating negative emissions by combining bioenergy use with carbon capture and storage (BECCS). REMIND accounts for relevant path-dependencies, such as the build-up of long-lived capital stocks, as well as learning-by-doing effects and inertias in the up-scaling in innovative technologies. REMIND represents 11 world regions, and operates in time-steps of five years for the period from 2005 to 2060, and ten years for the rest of the century. A detailed description can be found in the published model documentation [42].

2.2.1 Technological learning

To model technology development of comparatively novel technologies with substantial scope for further technology and cost improvement, like wind, PV and CSP, we use a one-factor learning curve to represent learning-by-doing [43]–[47]: costs decrease according to a power law as cumulative globally installed capacity increases.

To reflect that learning slows down as a technology matures as well as the existence of thermodynamic limits and minimum material requirements, we modified this commonly used relationship by splitting investment costs into learning costs and floor costs as shown in Eq. 1. One part of the initial investment costs can be reduced through the normal learning curve, while the floor cost specify the minimum costs that are reached asymptotically at very high cumulative capacities. Thus, total learning slows down as the floor costs are approached.

$$\boldsymbol{IC(cumulative\ capacity) = FC + IICL * \left(\frac{cumulative\ capacity}{initial\ capacity}\right)^{\ln(1-pLR)/\ln 2}} \quad \textbf{(1)}$$

with IC the investment costs at a given cumulative capacity, FC the floor costs, IICL the part of the initial investment costs that is reducible through learning, and pLR the partial learn rate.[3]

[3] It should be noted that when calculating the partial learn rate with Eq. 1 from total system costs at different capacities, the resulting value is higher than the system learn rate that would be calculated from an equation without floor costs, as the learn rate in Eq. 1 applies only to a fraction of total costs. This ensures that initial cost improvements are in line with historic trends (see Section 4 and Figure 2).

2.3 Description of scenario ensembles

To explore the two main research questions, namely the role of solar technologies for future power sectors and if either PV or CSP clearly dominates the other technology, we run a number of different scenarios: The two basic policy settings are "reference" (REF), a scenario in which no climate policy is enacted, and "policy" (POL), in which full global climate policy is enacted by 2015. This climate policy is represented in the model through a global GHG budget of 2500 Gt CO_2eq for the period 2005-2100, which is roughly equivalent to a two-thirds chance of staying below 2° global warming [41].

To analyze the influence of one technology on a crucial metric such as electricity prices, we furthermore run scenarios in which we excluded the solar power technologies. In these scenarios, investments into PV and/or CSP are excluded after 2015. Removing solar power technologies from the portfolio of mitigation options leads to a different energy system and higher costs, as the reliance on other technologies increases. These scenarios reveal the economic value of these technologies for the energy system. Finally, to test the robustness of our results, we run a large number of scenarios in which we vary the future reductions of PV and CSP investment costs.

2.4 Levelized costs of electricity – direct and integration costs

Average and marginal LCOEs are important diagnostic indicators that help to understand the economic competition between the solar technologies. While LCOE are a commonly used metric to evaluate power technologies, it is important to specify the different input assumptions that influence the calculated LCOE [48]. For marginal costs, we use build-time investment, fuel and carbon costs, build-time capacity factors of the worst resource grade that is used for this renewable technology, as well as technology-specific lifetimes. For average LCOEs, we use the investment costs that were seen when building the capacity standing at one point of time – thus, marginal costs can be lower than average costs for learning technologies whose investment costs decrease. For the LCOE calculation, we assume a real discount rate of 5.5%, which is close to the model-internal discount rate that varies between 5 and 6%.

To be able to analyze the impact of integration constraints due to the variability of solar irradiance, we also calculate the three LCOE markups resulting from the implemented integration and transmission requirements (see Section 3.1 and 3.2) ex-post after a model run: (a) the markup from curtailment and storage losses, (b) the markup from investment costs for storage, and (c) the markup from investment costs for transmission grid extension. Through analysis of these markups, it is possible to understand the trade-off between integration challenges and direct technology costs.

2.5 Limitations

As any modeling exercise, our analysis comes with limitations. Due to the long-term nature of climate change, mitigation scenarios need to extend far into the future. Technology projections are inherently risky and limited by current knowledge and imagination. The aggregation into 11 world regions omits details interesting to national policymakers. However, technology development and diffusion happen on a global scale, thus large-scale global models are required for answering questions about long-term transformation scenarios.

On the competition between PV and CSP, additional caveats apply. Due to its scalability and the absence of moving parts requiring constant maintenance, PV could easily be used in many less-developed and remote regions to power villages not connected to a central electricity grid (island grids) [49]. Also, the scalability enables local ownership, which can be more a more decisive factor for technology choice than pure cost advantage [50], especially if residential PV electricity is valued at retail instead of wholesale electricity costs ("grid parity" or "socket parity", [51], [52]). At the same time, CSP can be easily combined with a thermally driven desalination plant, adding an additional incentive for water-scarce regions. Also, the combination with co-firing makes a CSP plant capable of providing services to the grid very similar to a normal gas plant, thus lowering the initial acceptance barrier PV might encounter from power system operators. Such aspects cannot be fully represented in a model the size of REMIND, but their effects can only be approximated by assuming higher or lower technology costs, as done in Section 6.4.

3 System integration costs

To analyze the role of PV and CSP in future electricity systems, it is necessary to include into the model the main technology characteristics that influence deployment. Fundamentally, electricity output from PV and CSP is heterogeneous in space and variable in time. As heterogeneity and variability happen on scales smaller than those explicitly modeled within REMIND, we develop a simplified mechanism to represent the effects of both characteristics within the model. This mechanism is very generic, and thus easily transferrable to other aggregated energy-economy models. It depends on the exact parameterization, which can be updated as new research about costs and limitations of flexibility options becomes available, and better data availability allows better regionalization of storage and grid requirements.

3.1 Storage

PV and wind turbines depend on renewable energy sources whose incidence is variable, while electricity demand in the current system is quite inflexible. Once variable renewable energies (VRE) make up a large share of the electricity system, measures like more flexible power plants, storage, curtailment and demand side management (DSM) are required to match electricity supply and electricity demand. The variability happens on many different temporal and spatial scales: clouds can lead local to fluctuations on a scale of minutes to hours, day and night lead to very strong diurnal cycles for PV, synoptic-scale weather systems can lead to periods of several days to several weeks with low incidence of wind or sun, and there are substantial seasonal variations for the incidence of both wind and sun.

It should be noted that PV and CSP can actually have positive integration benefits at low deployment: in many countries with high solar irradiation, peak electricity demand occurs on summer afternoons due to electricity consumption from air conditioning. In these regions, highest electricity demand strongly coincides with maximum output from PV/CSP plants. Installation of solar power leads to substantial "peak shaving effects", thereby reducing the need for expensive peak load plants and decreasing the peak electricity prices – an effect easily observable in the change of German hourly electricity prices for summer days as 29GW of PV were installed from 2007 to 2013 [53]–[56]. However, due to this price-decreasing effect, solar technologies cannot fully capitalize on the additional benefit they offer to the system – rather, consumers or utilities profit from reduced costs to provide peak electricity [57], [58].

Endogenously calculating the optimal measures to integrate VRE would require very detailed temporal and spatial resolution, which would make a numerical long-term non-linear optimization model too complex for solving. We thus develop a simplified VRE integration representation in the model that combines estimates of the different integration measures (such as storage and curtailment of summer peaks) into a) a cost penalty due to investments into storage technologies, and b) an energy penalty resulting from storage losses and curtailment. This energy penalty results in the need to install higher production capacities of this VRE to supply a certain share of total power demand, thus increasing net costs.

The requirement for these integration measures rises with the share of a VRE in the total power mix, as described in Eq. 2, 3 and 4. This is based on the both intuitive and observed notion that integration challenges increase with the amount of variable energy in the system [56], [59]–[64]. As demand itself is somewhat variable, all existing electricity systems require a certain amount of flexibility. Adding a minor new fluctuating source does not have a large impact on the system, as the individual uncorrelated fluctuations only marginally increase total variability. Existing electricity systems in Germany, Denmark or the US had no major difficulty in including PV or wind shares of 5-10%. As one technology dominates the energy mix, however, its fluctuations have much more impact on the energy system and thus require more integration measures. We therefore require the model to build (and pay for) a certain amount of storage capacity, and to curtail a certain amount of the produced VRE energy. In each time step, the integration requirements for each VRE technology with a share higher than 7% are calculated in REMIND according to

$$\boldsymbol{TSC\_Bat_{VRE}[kW] = SMSC\_Bat_{VRE}\left[\frac{kW}{kWyr}\right] * \left(\frac{Net\ Share_{VRE} - 7\%}{93\ \%}\right)^{a} * Net\ Power_{VRE}[kWyr]} \quad \textbf{(2)}$$

$$\boldsymbol{TSC\_H2_{VRE}[kW] = SMSC\_H2_{VRE}\left[\frac{kW}{kWyr}\right] * \left(\frac{Net\ Share_{VRE} - 7\%}{93\ \%}\right)^{a} * Net\ Power_{VRE}[kWyr]} \quad \textbf{(3)}$$

$$\boldsymbol{TCE_{VRE}[kWyr] = SMC_{VRE}\left[\frac{kWyr}{kWyr}\right] * \left(\frac{Net\ Share_{VRE} - 7\%}{93\ \%}\right)^{a} * Net\ Power_{VRE}[kWyr]} \quad \textbf{(4)}$$

where TSC_Bat/H2 are the total storage capacities of batteries and hydrogen storage built for this VRE, SMSC and SMC the specific maximum storage capacity /curtailment for each VRE, a = 1 the share exponent that determines how specific storage requirements increase with VRE share, TCE the total curtailed/lost energy for this VRE, the net share of this VRE in total electricity generation, and the net electricity produced from this VRE. Due to computational issues with negative integration capacities, the gains at market shares below 5-10% are not represented in REMIND but rather set to zero, thus initial deployment of solar technologies in the model might be slightly slower than if all benefits were included.

The VRE-specific parameters SMSC and SMCE are based on assumptions about a mix of storage technologies that is able to deal with short-term and seasonal variability while balancing the trade-off between storage costs, the implied energy conversion losses, and curtailment. The exact values assumed in REMIND are described in Section 3.3 and in the supplementary information SI2.

The differences in integration requirements are one of the main differences between PV and CSP and are reflected in different values for the SMSC and SMCE parameters: while PV sees a very strong day-night cycle and thus requires substantial short-term storage systems (like flow battery systems), CSP includes 12h thermal storage and a solar multiple of three in the basic plant setup modeled in REMIND and can thus be run 18-24 hours per day. For full dispatch capability, CSP plants can furthermore easily co-fire natural gas or hydrogen. To represent that CSP and PV are linked by the same solar resource, thus being exposed to the same seasonal variations and therefore negatively influencing the integration requirements of the other solar technology, we add 1/3rd of the net share of the linked VRE to the bracket in Eq. 2, 3 and 4.

3.2 Transmission grid

PV, CSP and wind parks often cannot be sited close to electricity demand, but require specific site conditions with high incidence of solar or wind energy to be economical. The feasibility of future power systems with high shares of renewable supply are therefore contingent on an increase in long-distance electricity transmission from sites with favorable renewable resources to demand centers [61], [65]–[68]. A full representation of this aspect would require explicit modeling of individual supply and load centers in each region, which would again make a long-term non-linear optimization model like REMIND too complex for solving. The current state of knowledge about dependence of grid expansion on VRE shares is limited, with a recent literature review finding grid costs of 2-10€/MWh at wind shares around 40% [69]. As there is a lack of comprehensive bottom-up scenarios covering different ranges of VRE shares, we here use geometric principles to develop a conservative estimation of long-distance grid costs arising from a given share of a VRE source in the electricity mix. We only calculate the *additional* cost directly related to the localized nature of VRE, and otherwise assume a fully developed AC grid which is able to distribute electricity on smaller spatial scales and whose costs only depend on total electricity demand and not on VRE deployment, and can thus be modeled as linear markups on all electricity, disregarding the generation type.

A cost-efficient approach to transporting electricity from regions with high quality VRE resources to other regions on a national to continental scale (500-4000km) would be an overlay grid [66], ideally using high voltage direct current (HVDC) technology to minimize losses [70]. Such a grid would allow both a net energy transfer from regions with high quality VRE resources as well as balancing between regions with different temporal VRE incidence.

When the first VRE plants are built in a region that is rich in VRE incidence, the power can initially be used by the energy demand centers close by, thus no new long-distance grid is required. As more and more of the VRE resource is developed, local demand cannot take up the produced power so long-distance transmission is needed to reach more distant demand centers.

Assuming that VRE sources are located along one edge of a region, like the solar resources in the South of the US, or wind resources in the north of China, the length of the needed transmission lines increases approximately linear with this VRE's share in total energy production. The requirement for new transmission grid capacity at VRE shares >7% are thus calculated according to

$$\boldsymbol{TGL_{VRE}[kWkm] = 0.5 * SMGL_{VRE}\left[\frac{kwkm}{kWyr}\right] * \left(\frac{Net\,Share_{VRE}-7\%}{93\,\%}\right)^{b} * Net\,Power_{VRE}[kWyr]} \qquad \textbf{(5),}$$

with TGL the total grid length, SMGL the specific maximum grid length, b = 1 the share exponent that determines how specific grid requirements increase with VRE share, the net production share of this VRE technology and the net power produced by this VRE. The factor 0.5 results from the fact that if line length of new lines increases linearly with the production share, the average line length will be half of the maximum line length.

Differentiating SMGL by VRE technology and region allows modelers to represent the general pattern that PV resources are more evenly distributed than CSP resources, as well as differences in regions' size and homogeneity. Areas suitable for CSP partially coincide with sites suitable for PV, thus we also add 1/3rd of the net share of the linked VRE to the bracket in Eq. 5. The exact parameters used in REMIND are described below and in the supplementary information SI3.

3.3 REMIND Implementation

In REMIND the integration challenge of variable renewable energies is completely attributed to each variable renewable technology. We require the model to invest into storage and reduce (curtail) VRE electricity output to represent the additional costs arising from the variability. The current parameterization is based on two storage technologies: redox flow batteries as short-term storage for day-night cycles and short-term fluctuations, and hydrogen electrolysis as long-term storage. While other flexibility options exist, their potential is more limited by regional characteristics (pumped hydro power, compressed adiabatic air storage) or not yet fully researched (demand side management). As the two parameterized technologies do not

Table 1: REMIND parameters for storage, grid and curtailment at different market shares of the respective VRE technology. *: The assumed CSP plant setup already includes an H2 turbine for co-firing, so no additional investment is needed.

For each 1kWyear of electricity replaced by VRE electricity production, the model would need to build on average the following amounts of capacity:		**@20% share of this VRE**			**@40% share of this VRE**		
		PV	**CSP**	**Wind**	**PV**	**CSP**	**Wind**
of this VRE (PV/CSP/Wind)	[kW]	6.70	1.89	3.58	7.97	1.99	3.97
Battery	[kW]	0.24	0.00	0.17	0.60	0.00	0.44
H2 electrolyzer	[kW]	0.10	0.10	0.10	0.27	0.27	0.27
H2 turbine	[kW]	0.21	-*	0.21	0.53	-*	0.53
Curtailment/ Storage Losses	[kWyear]	0.14	0.03	0.08	0.35	0.09	0.19
HVDC grid	[kWkm]	210	280	280	532	710	710
Assumed average resource quality:	*[FLh]*	*1490*	*4800*	*2630*	*1490*	*4800*	*2630*

fundamentally depend on specific local conditions, they could be deployed at large scale in each world region. Although the current values are based on technology costs for batteries and hydrogen, the general approach could be recalibrated to include effects of other flexibility options such as power-to-heat. The resulting storage and curtailment numbers used in REMIND are shown in Table 1, while the full parameters and background assumptions are described in the supplementary information SI2.

It should be noted that the storage technologies are modeled as technologies whose costs reduce via learning-by-doing, thus exact integration costs at a point in time depend on the capacities installed until that date. The size of this effect can be seen in Figure 1, where the marginal integration costs for PV are displayed both for the investment costs in 2020, as well as for the investments costs in 2050 seen in the REMIND Policy scenario described below. To keep the figure readable, the resulting integration costs arising at different shares of wind and CSP are only displayed for the 2050 investment costs.

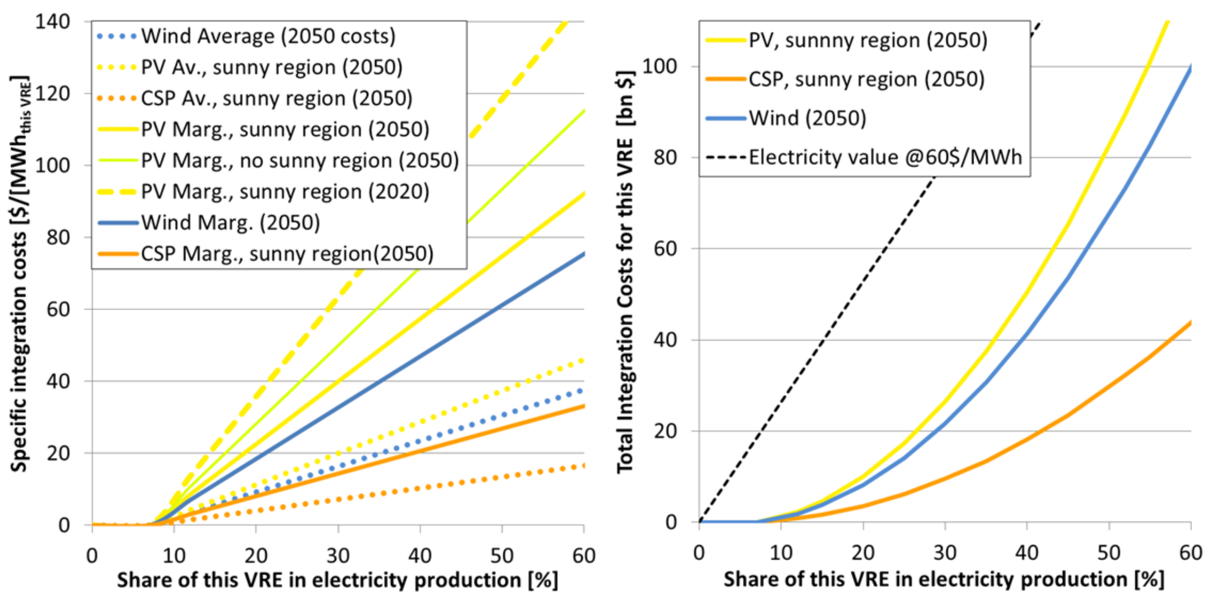

Figure 1: REMIND integration costs for each VRE technologies as a function of this VRE's share in electricity production. Left: Average and marginal specific integration costs, assuming 2050 investment costs for storage technologies. As the share of one VRE in the power mix increases, the per-kWh integration costs rise linearly. To demonstrate the size of technological learning, we also show 2020 costs for PV. As described in SI 2, the integration costs for solar are reduced for "sunny regions" where solar incidence and peak demand overlap well (Africa, Middle East/Asia, India and the US). Right: Total integration costs, assuming a total power system size of 4400 TWh, comparable to the US. As the linearly increasing per-kWh integration costs are multiplied with the produced VRE electricity, the total integration costs increase quadratic in VRE share. For comparison, the total value of the produced VRE power when valued at 60$/MWh is also displayed.

When comparing the marginal integration costs and curtailment levels resulting from our parameterization with the values reported in literature [56], [63], [69], [71], we find that they are in a similar range. A recent overview of integration cost studies by Hirth et al [69] estimates near-to-medium term marginal wind integration costs (including profile, balancing and grid costs) of 25-35€/MWh at 30-40% share. Our parameterization yields marginal integration costs at 30-40% wind share of 41-59$/MWh in the short term, decreasing to 35-47$/MWh in 2050, and thus seems a conservative estimate which likely overstates the integration costs slightly. As for the subcategory grid costs, the REMIND implementation results in marginal grid expansion costs of 10$/MWh at 40% wind share, which is in line with the 2-10€/MWh reported by Hirth et al [69]. These integration costs substantially influence technology deployment, as will be discussed in Section 6.3.

3.4 Limitations

Both the storage and grid mechanisms are simplified and parameterized approaches. Their aim is to include an estimation of the monetary impact of variability of wind and solar into IAMs, not to develop new bottom-up insights about integration costs.

Our approach is a rough approximation of what would actually happen in a real electricity system; especially, it cannot explicitly capture the effect that remaining conventional capacities reduce their full load hours, which shifts the market in favor of low-capital technologies. It does, however, require substantial investments into storage, so that the resulting VRE output could be termed "dispatchable production" – therefore, while the model cannot determine endogenously the optimal cost-efficient mix of flexibility options, it includes a realistic-to-high estimate of integration costs. Both the storage and transmission grids installed for VRE in REMIND could also have a value for the rest of power system in the real world and thus lead to lower net cost increases, which is not explicitly included here.

In Eq. 2-5, we assume that the average per-kWh integration constraint increases linearly with VRE share, once a threshold of 7% has been passed. It might also be that the integration constraints are more convex (concave), thus implying that the exponents a and b are larger (or smaller) than one. While the principal behavior is very intuitive – integration challenges increase with increasing VRE share – the exact behavior depends on a number of parameters that will be different for different energy systems in different regions, such as the coincidence of load, wind, and solar; geographical aspects like availability of reservoirs for pumped hydro storage; the residual energy system; resource prices; and elasticity of demand. It is thus clear that our approach cannot produce the optimal results for a given region. Rather, our aim is to include a *plausible* conservative estimation of integration challenges into IAMs to improve realism of the aggregated IAM results. In the supplementary material, we test how different values for the exponents a and b influence VRE deployment. Further research based on a large number of detailed bottom-up scenarios with high shares of VRE is needed to better inform the shape and parameterization of the integration requirements in the future, and to better differentiate between the challenges observed in different regions.

From the limited number of currently available studies, the exact dependence of integration challenges on VRE share seems an open question. The review by Hirth et al [69] of profile costs for wind in different publications does not give a clear picture, but Figure 12 in their paper is consistent with marginal integration costs rising linearly or even less than linearly in the reported range (up to 40% wind share). Denholm et al [60] find wind and solar curtailment rising faster than linearly, but do not assume that storage size is adapted to increasing VRE shares. Here we assume that storage increases with VRE share, which would reduce the resulting curtailment and might lead to the linear behavior implemented in REMIND. In SI7, we discuss how REMIND results change when we vary the functional form of the grid and storage equations.

A limitation of the current approach is the reduced representation of the interaction between solar and wind. In the current approach, increasing the wind share does not change the integration constraints for solar, and vice versa – thus the two technologies are assumed to be not correlated. In reality, the correlation between the two technologies might be positive in one region and negative in another. Future work with detailed time series is needed to regionally parameterize the positive or negative correlations between wind and solar.

Another possible limitation of this approach is that integration constraints cannot explicitly take into account the current resource quality of the VRE, so the integration requirements per kWh are the same for PV electricity, not regarding if it was produced at a site with very high capacity factors and at a site with low capacity factors. Only regional differences, e.g., that PV time series in the US are better correlated with load than PV time series in Europe, can be represented.

While the current parameterization is geared towards the representation of storage, it is possible to adjust the parameters to represent other flexibility options. Future work will explore how integration costs are influenced by different assumptions about flexibility options and compare our implementation of integration challenges to other approaches, such as time slices [72] or additional capacity and flexibility equations [73].

All in all, we think that while the limitations are definitely relevant and require further in-depth analyses, they are basically second-order effects on the first-order effect of having integration costs at all. Based on the comparison with literature, the presented approach seems a reasonable approximation that is somewhat on the conservative side, possibly underestimating integration challenges in a few instances, but generally slightly overestimating them.

4 Solar power technology investment costs

The choice between technologies in energy-economy-models depends crucially on technology costs. To develop a sound basis for capital cost values, we undertook an extensive literature survey, using scientific publications, technical reports and market research. For consistency reasons, all prices need to be in the same unit and valued at the same time. Thus, all prices from literature were first converted to US dollars using the average annual exchange rate [74], and then inflated to 2012 values using the average of the US and EU CERA power plant price index without nuclear [75]. The exact assumptions for this can be found in the supplementary information SI1.

The PV boom starting at the end of the 90s spurred a large number of cost studies, and the IEA Photovoltaic Power Systems Programme [76] has annually monitored national PV system prices and markets over the last decade. As no commercial CSP plant was built between 1990 and 2007, the amount of real market data for CSP is more limited, and prices from individual installation figure more strongly in the cost analysis.

Comparing cost numbers for CSP is more complicated than for PV, as the capital costs per kW strongly depend on the amount of storage and the size of the solar field and thus need to be harmonized to be comparable. Izquierdo et al analyzed the influence of different ratios between solar multiple and storage size and found least cost of electricity at solar multiples over 2.5 in combination with storage of 8 hours and greater [33]. The basic CSP plant setup in REMIND was thus chosen to have a solar multiple of 3 and 12 hours of storage. We therefore rescaled all numbers found in literature to this setup to make them comparable.

4.1 Resulting technology costs

The collected rescaled data for overnight investment costs of PV and CSP systems is displayed in Figure 2. For PV, the last twenty years have shown a continuously increasing amount of installations, so reliable cost figures are available that monitor the substantial price decrease. Although economic cycles (due to, e.g., scarcity of feedstock silicon that led to high PV module prices in 2005-2009) caused price fluctuations lasting for several years, over longer time scales PV consistently showed a very high learning rate of 20±5% [2], [3], [46], [77], [78] .

The numbers show a substantial cost differential between different countries: At the end of 2012, at a global cumulative capacity of ~100GW, the total system cost for PV systems larger than 10kW were in some countries as low as 1.6 (China), 1.3-3.3 (Italy) or 1.7-2.1\$/Wp (Germany), while other countries showed values around 3-5\$/Wp (USA) or even 5.5\$/Wp (Japan)[4] [79].

Recently, a study by the Lawrence Berkeley National Laboratory analyzed the substantial price gap between Germany and the US and found several drivers, including market fragmentation, standardization of installation procedures, amount of skilled labor required, permitting procedures, and financing impacts of remuneration policies [80].

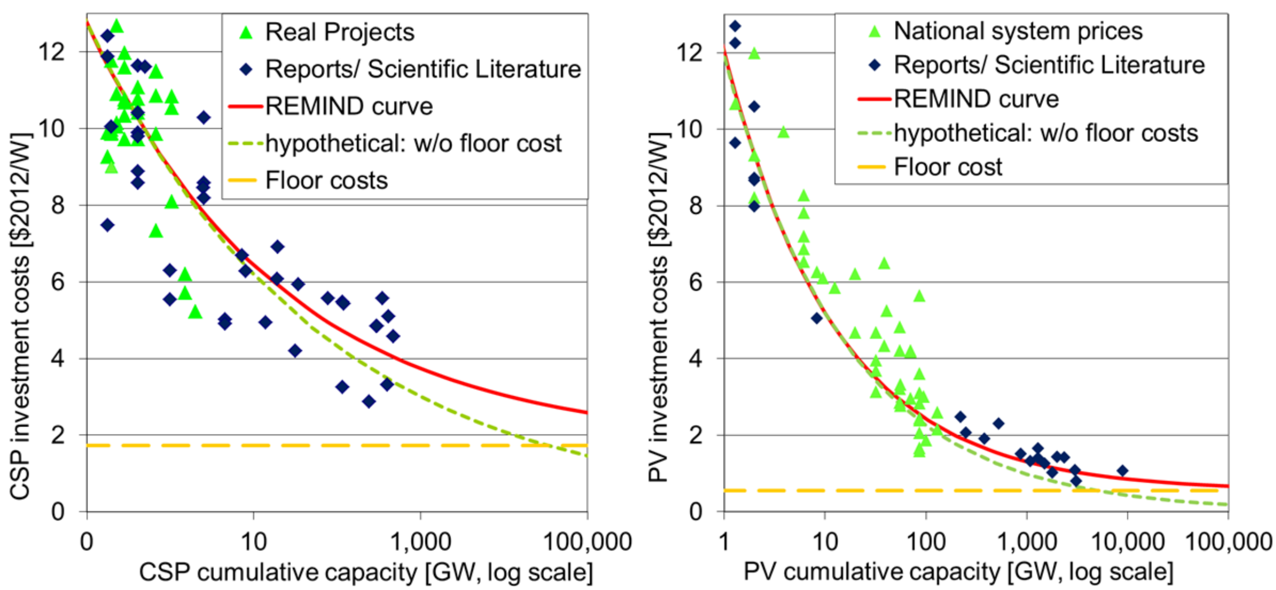

Figure 2: Overnight investment costs for CSP (left) and PV systems, collected from national market averages, individual projects, reports and scientific publications. To reflect the model-internal CSP systems design, CSP costs are scaled to SM3 and 12h storage, and cumulative capacity values for CSP are divided by 2. Data was collected from [2], [21], [24], [31], [76], [77], [81]–[92], with mapping of sources to individual data points presented in the supplementary information SI1

[4] If not specified otherwise, all prices in this text are expressed in terms of US$2012.

In the current REMIND version, investment costs are not regionalized, so we derived one global investment cost value. The very low prices seen in some countries in 2012 are at least partially due to the build-up of production overcapacities at the same time as support policies were strongly reduced. This led to market shakeouts, which are often accompanied by prices below cost. On the other hand, market size and market maturity have a large decreasing influence on PV prices [77], [80]. As PV markets around the world continue to develop and grow, the higher costs seen in the currently younger and smaller markets will generally converge towards the lower values seen in the currently larger and more mature markets. We thus derived a global value that is in line with the cluster of low current cost values seen in Figure 2, with the final parameterization displayed in Table 2.

Table 2: Technology parameters for solar technologies in REMIND

	Overnight investment costs end 2013	Cumulative capacity end 2013	O&M costs	Learn rate 2002-2013	Floor cost	Life time	Resulting partial learn rate in Eq. 1
	\$2012/Wp (\$2005/Wp)[5]	GW	% of Capital cost		\$2012/Wp (\$2005/Wp)	years	
PV	2.3 (1.7)	140	1.5%	20%	0.7 (0.5)	30	24%
CSP (SM3, 12h storage)	8.5 (6.2)	1.7 [(6)]	2.5%	10%	1.7 (1.3)	30	12%

5 Solar resource potential

An assessment of future deployment of solar technologies requires data on the total resource potential for this technology in each of the modeled regions. This has been assessed by previous studies, but none of these were sufficient for our analysis: Several of these studies focus on only one of the two solar technologies [32], [93], some report only aggregated global values [94], and others have aggregated the data in such a way that the substantial variations in resource *quality* (Irradiance/capacity factor (CF)/ Full Load hours (FLh)) in each region are strongly suppressed [16], [95] or even totally removed so that only resource *quantity* is reported [96], [97]. Using data from different detailed studies for the two solar technologies is problematic, as the studies can have very different assumptions on land use and excluded areas, thereby introducing a strong artificial bias towards one of the technologies. It was thus necessary to develop new data in which both solar technologies are treated equally.

[5] As the currency in REMIND is \$2005, we also state the investment cost numbers in \$2005

[6] As most CSP installations until today are equipped with little or no storage, this value (and all CSP capacity values in this paper) are scaled down by a factor of two in relation to industry figures to accommodate for the SM3, 12h storage CSP design used in REMIND

The two solar technologies use different aspects of the light: CSP can only use direct sunlight normal to the plane of incidence, termed "direct normal irradiation" (DNI), while PV cells can also use indirect – diffuse – light reflected from clouds, thus the relevant measure is "global tilt irradiation" (GTI). In general, sites with high DNI also have high GTI values and vice versa, thus the two technologies compete for similar sites.

To produce new consistent resource potential data for PV and CSP, we developed a routine to derive both direct normal irradiance (DNI) and global tilt irradiance (GTI) hourly data from NASA's SRB 3.0 data [98], and calculate capacity factors for both CSP and PV (For more detail on the algorithms, see Stetter 2013 [99]). Using GIS map filters, we exclude unsuitable land and develop a potential map binned by capacity factor, countries and distance to grid. CSP plants need flat ground, while PV modules can also be installed in mountainous regions – thus a much larger land area is usable by PV than by CSP, see results presented below. The FLh for CSP were scaled to SM3 using the formula by Trieb et al [24].

The resource potential data for PV and CSP goes beyond previous work as it (a) derives coherent resource potentials for both CSP and PV using the same solar radiation data and applying the same exclusion factors for both technologies (except for the slope as PV can be installed on much steeper terrain), (b) reports results on a national level, allowing data aggregation to various region definitions for use in other IAMs, (c) bins the resource potential by capacity factor, thus leaving all technology cost assumptions to the modeler, and (d) differentiates potential sites by distance to grid, thus allowing modelers to include markups for additional grid connection costs.

5.1 Competition for installation sites

CSP and PV compete for the sites with highest irradiation, and all sites usable for CSP can also be used for PV. It was thus necessary to implement an additional mechanism to guarantee that at no time, the model would use more than the total available land area, while still allowing the model full flexibility of allocating the land area to PV or CSP. We therefore developed a competition mapping for the land that can be used by both CSP and PV, by splitting the available area into nine resource grades, ordered by resource quality. Additional information about the resource potential calculation, aggregation and land use constraints can be found in the supplementary information SI4.

To represent the competition for installation sites with good irradiation in the model, we added an additional land constraint equation. Therefore, electricity production from solar resources is limited by three equations: two equations limiting the maximum energy production for each solar technology (Eq. 6 & 7), and a combined equation that requires the sum of the area used by the solar technologies to be smaller than the total available land area (Eq. 8). These equations are applied individually to each resource grade category g, in each time step.

$$\forall \boldsymbol{g}: \quad \boldsymbol{Available\ Area_{PV,g}} \geq \boldsymbol{Cap_{PV,g}} * \boldsymbol{LandUse_{PV,g}} \quad \textbf{(6)}$$

$$\forall \boldsymbol{g}: \quad \boldsymbol{Available\ Area_{CSP,g}} \geq \boldsymbol{Cap_{CSP,g}} * \boldsymbol{Landuse_{CSP,g}} \quad \textbf{(7)}$$

$$\forall \boldsymbol{g}: \quad \boldsymbol{Available\ Area_{PV,g}} \geq \boldsymbol{Cap_{CSP,g}} * \boldsymbol{Landuse_{CSP,g}} + \boldsymbol{Cap_{PV,g}} * \boldsymbol{Landuse_{PV,g}} \quad \textbf{(8)}$$

with Available Area in km^2 , Cap in MW, and Landuse in km^2/MW[7]. As all areas available for CSP can also be used by PV, $Available\ Area_{CSP,g} \subset Available\ Area_{PV,g}$. The landuse values applied in REMIND are 0.009-0.017 km^2/MW for PV (regionally differentiated due to different shadowing effects of tilted installation at different latitudes, see Table 10 in the SI), and 0.045 km^2/MW for CSP (latitude effects are included in the capacity factor calculation).

5.2 Resulting resource potential data

In line with previous assessments [97], we find the total technical potential for solar electricity to be immense (see Figure 3 for regional and SI 2 for regional and country data), surpassing today's electricity demand by a factor of more than 20 in each region except Japan[8]. Besides this obvious fact, several interesting facets can be seen in the potential data:

- For PV, each of the eleven macro-regions considered in REMIND except JPN and RUS could supply today's electricity demand by PV installations with CF>0.17 (FLh >1500), which are considered as good conditions that would result in comparatively low electricity costs. For comparison, average FLh values for PV plants in the south of Germany are around 950-1050.
- For CSP, the difference between regions with more and less irradiation is more pronounced: In the regions AFR, LAM, MEA, ROW and USA, today's electricity demand could be supplied by CSP installations with CF>0.53 (FLh>4700).
- After applying all the exclusion factors, 0.5 – 20% of the total land area of a region are theoretically usable for the installation of PV.

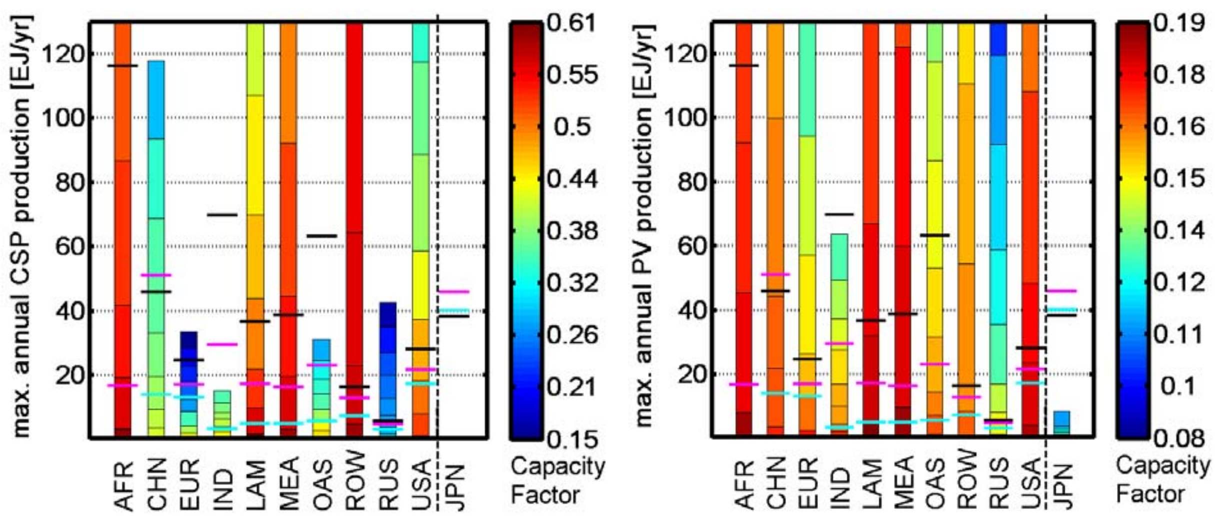

Figure 3: Resource potential for CSP (left) and PV (right) aggregated to REMIND regions. The resource potential is binned according to capacity factor, as shown by the color coding. The three horizontal lines represent the secondary electricity production in the REF scenario: cyan in 2010, magenta in 2050, black in 2100. The energy values for Japan are upscaled by a factor of 10 to be able to display them in the same plot.

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[7] As Cap and Landuse are always positive, Eq. 6 holds automatically when Eq. 8 holds.

[8] For Japan, the high population density and rough terrain lead to a very low total solar potential according to the GIS exclusion areas. To account for the potential of roof-top PV, we added conservative estimates from other sources (more information in SI4).

- As PV can be installed in regions with a higher slope, in all regions except for AFR and ROW more than 50% of the total usable area can only be used for PV and not for CSP.

Compared to previous CSP potential data studies that directly use the aggregated annual NASA DNI data [32], we find lower capacity values for regions with high solar irradiance, such as the US or North Africa. This might be the result of the processing of the radiation data, including temporal downscaling and application of a clearness index model, which leads to a mean deviation of -8% against long-run NASA annual averages, but only a -1.8% RMBE against direct measurements from 18 ground sites, as described in [99]. At the next release of NASA satellite radiation data, the calculated values should therefore be checked against the new satellite data and against data from a larger number of ground sites.

By assuming technology costs, it is possible to translate these resource potentials into supply cost curves for PV and CSP. In Figure 4, we show the supply cost curves that result from the presented resource potentials in combination with investment costs resulting from the default REMIND learning parameters and an assumed cumulative capacity of 10TW for PV and 3 TW for CSP9.

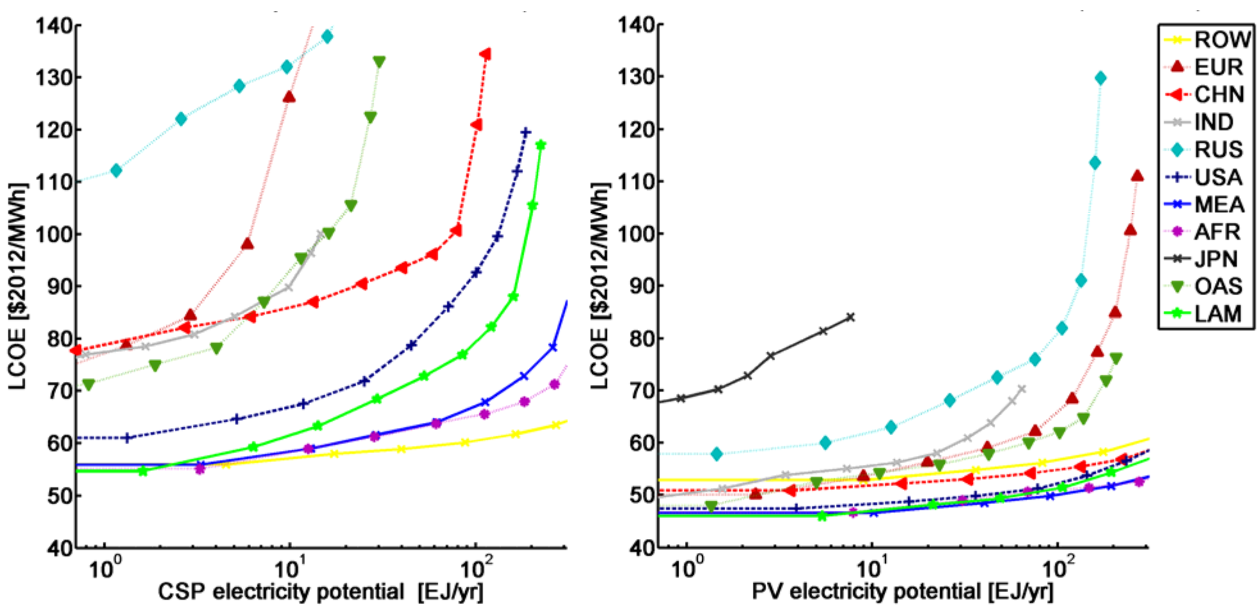

Figure 4: Cost supply curves for CSP (left) and PV (right), assuming investment costs at 10TW cumulative capacity for PV and 3 TW cumulative capacity for CSP. The potential for Japan is again upscaled by a factor of 10 to be visible at the given scale.

6. Scenario Results

In the following, we determine the role of solar power for decarbonizing the power system by analyzing the model results from the various scenario groups along several metrics. We start with a discussion of the default scenario with and without climate policy, using the most direct metric, namely electricity generation. We then elaborate on the interplay of solar deployment and

[9] These cumulative capacity values are realized in the default REMIND climate mitigation scenario between 2050 and 2060. The factor three difference between the cumulative capacities for CSP and PV reflects the different CFs.

electricity price, using a scenario in which we exclude the solar. We discuss the importance of integration costs for the choice between PV and CSP. Finally, we use a large scenario ensemble with a wide range of assumptions about future cost reductions for solar technologies to test the robustness of our findings on solar deployment..

6.1 Future electricity generation

To analyse the deployment of solar electricity technologies in REMIND, we show the globally aggregated electricity production in the two default scenarios in Figure 5 and Table 3. Immediately apparent is the dominance of solar technologies in the climate policy scenario (POL), where they together account for 48% of the total electricity produced from 2010-2100. Even without climate policy (REF), PV and CSP supply a sizeable share of total electricity in the second part of the century.

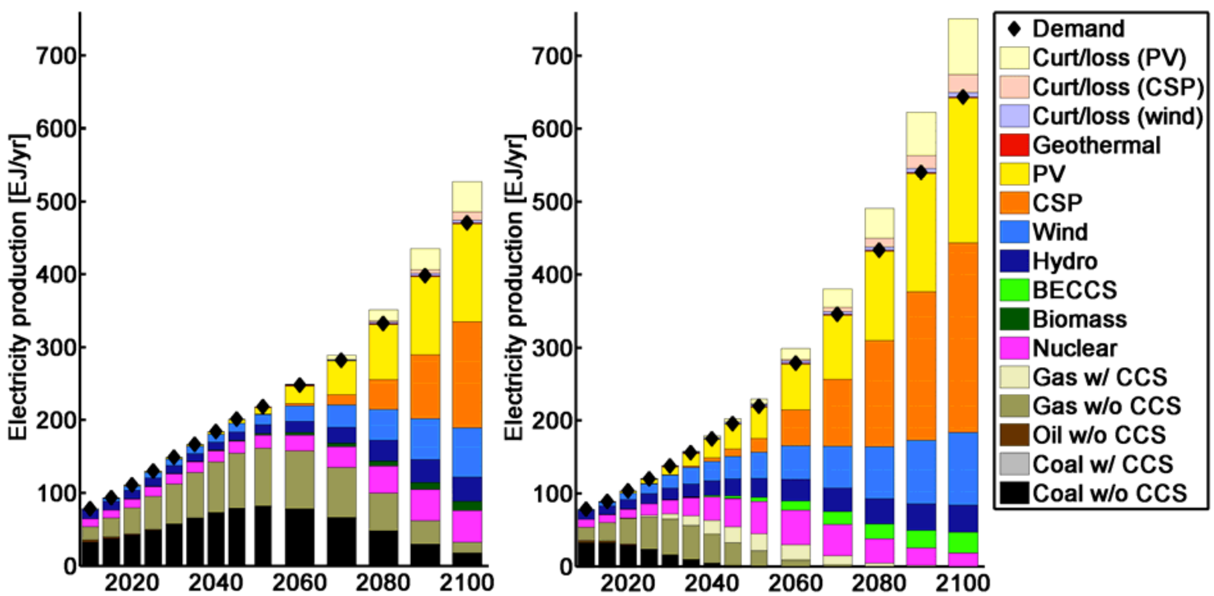

Figure 5: Electricity Production (globally aggregated) in REF scenario (left) and POL scenario (right). The black diamond represents the net electricity that satisfies electricity demand, while the shaded "Curt/loss" represents the production from PV, CSP and wind that is either curtailed or lost due to conversion losses in electricity storage.

In both cases, the electricity production increases steadily during the century. The energy demand is determined largely by three factors: the assumed population growth scenario (exogenous assumption), the economic growth (quasi-exogenously determined via assumptions on labour productivity growth), and the resulting electricity price calculated endogenously by REMIND. The continuous decrease of fossil fuel resources and the increase in energy efficiency counteract the general trend toward higher electrification, thus dampening the upward development of electricity consumption. The POL scenario shows higher electricity demand than REF due to stronger electrification – the power sector is easier to decarbonize than heat or liquid fuel production, so the whole energy system shifts towards electricity.

The electricity production in the REF case is dominated by fossil power plants for the next fifty years, while variable renewable energies take over in the last decades of the century. Electricity from coal and gas increases strongly in the next decades because of low resource costs and flexible trade, together supplying more than 70% of total electricity. As for renewable energies, wind supplies around 6% of yearly electricity demand until 2050, then increases due to increasing extraction costs of coal and gas. The use of solar energy only starts in the second half of the century, with the share of solar in the generation mix staying below 3% until 2050. After this late start, the deployment of solar power and wind increases strongly, so that the share of variable renewable energies surpasses 60% by 2090. As biomass is scarce and at the same time valuable for the provision of non-electric fuels for the transport and heating sectors, its share in electricity production never surpasses 3%.

Table 3: Capacity values, cumulative capacity values (the sum over all capacities that were ever installed) and investment costs for PV and CSP in REF and POL scenarios

			2010	2020	2030	2040	2050	2060	2070	2080	2090	2100
REF, global values	**CSP capacity**	[GW]	1.0	1.8	1.9	3.5	26	184	810	2,447	5,405	9,217
	Cumulative CSP capacity	[GW]	1.0	2.1	2.3	4.6	29	188	824	2,525	5,749	10,337
	CSP investment costs	[$/kW]	8,940	8,020	7,900	7,180	5,620	4,480	3,820	3,430	3,190	3,040
	PV capacity	[GW]	83	296	337	524	1,422	4,021	8,483	15,194	23,327	30,982
	Cumulative PV capacity	[GW]	83	306	363	630	1,726	4,467	9,403	17,558	28,861	41,565
	PV investment costs	[$/kW]	3,280	1,950	1,870	1,640	1,340	1,120	1,030	960	910	880
POL, global values	**CSP capacity**	[GW]	1.0	4.1	39	259	1,101	3,031	5,904	9,565	13,463	17,374
	Cumulative CSP capacity	[GW]	1.0	4.4	40	262	1,119	3,139	6,387	11,141	17,287	24,416
	CSP investment costs	[$/kW]	8,940	7,210	5,390	4,310	3,710	3,360	3,160	3,020	2,920	2,850
	PV capacity	[GW]	83	480	1,876	4,734	8,797	13,662	19,962	29,274	39,988	49,926
	Cumulative PV capacity	[GW]	83	489	1,906	4,915	9,628	16,194	25,779	40,188	58,179	77,694
	PV investment costs	[$/kW]	2,590	1,620	1,220	1,050	960	900	860	830	810	790

In the policy scenario, drastic changes in the energy system are induced by the imposed carbon budget. While the use of fossil fuels is significantly reduced and coal is phased out completely, renewable technologies and nuclear energy are developed earlier. In contrast to the REF scenario, both PV and CSP are built immediately, so that PV reaches 8% generation share in 2030, and CSP reaches 8% in 2050. From 2055 onwards, solar technologies dominate the power mix. In 2100, the share of all non-biomass renewable technologies in the electricity mix surpasses 90%. The large-scale deployment of solar technologies in the POL scenario drives down the investment costs much earlier than in the REF scenario, as can be seen in Figure 6 and Table 3.

The substantial deployment of PV and CSP seen in the POL scenario might raise questions about potential bottlenecks to this scale-up. While a detailed analysis of this question goes beyond the scope of this paper, the following rough estimation of the most likely limiting factors shows that the presented scenarios are plausible.

Area-wise, the globally installed capacity of 50 TW of PV and 17 TW of CSP in 2100 cover an area of ~1.3 million km2, equal to 1% of the global land area. In the US, the covered area in 2100 is ~79,000 km2, comparable to the 73,000 km2 used in 2009 for ethanol production from corn [100], thus land usage does not appear to be a binding limit to deployment.

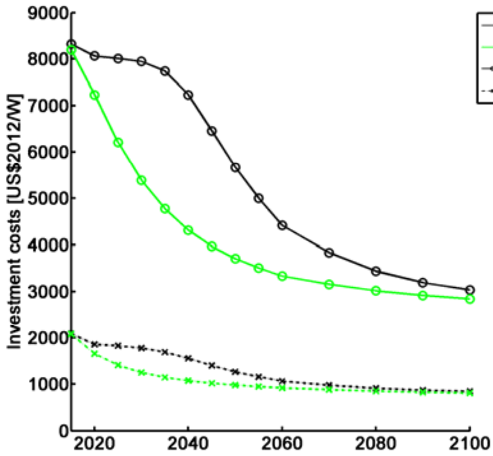

Figure 6: Endogenous decrease of overnight investment costs for PV and CSP over time in the REF and POL scenarios due to learning-by-doing.

From a raw material point of view, there are no clear bottlenecks currently expected for CSP. The production of certain molten salts for thermal storage might be a limiting factor, but a large number of alternative storage mediums are currently under research, with some as cheap and widely available as concrete [101]. For PV the situation is a bit different: while silicon supply is close to unlimited in the long run, the silver used for the electric contacts might be a critical input, as the silver use for PV accounted for about 7% of total silver production in 2010 [102]. On the other hand, research into replacements for silver has been ongoing for decades, and a number of research groups and companies have managed to produce PV cells with Ni/Cu-contacts using industry-applicable procedures, thus presenting a possible route to widely available materials as replacement for silver [103].

Finally, the speed of the technology scale-up also seems within plausible ranges. For PV, the market growth in the scenarios slows from the historically observed annual growth rates of around 40% between 1995 and 2010 [52] to less than 15% per year after 2015. For CSP, the initial scale-up shows high annual growth rates around 25-30% per year for the first 20GW, then slows to values below 10% per year after 2050.

6.2 The impact of technologies on electricity prices

These substantial deployments show the relevance of solar technologies, but for a deeper understanding of the interactions it is instructive to compare the timing of renewable deployment with the endogenous development of electricity prices in both scenarios (see Figure 5 and Figure 7). In the following, all discussed energy prices are wholesale market prices, before distribution costs and taxes. In the REF scenario, the price stays close to the initial price of ~55 $/MWh until 2050, and increases due to rising resource prices to a level of ~80 $/MWh in 2080, where it remains until 2100. In the POL scenario, the carbon budget leads to a carbon price that starts in 2015 with 24$/t CO_2 and increase with the model-internal discount rate of about 5% per year. The rising carbon price immediately makes electricity from coal – and to a lesser extent gas – power plants more expensive, thereby increasing the electricity price to levels around 80 $/MWh in 2040. At this level, the electricity price is high enough to incentivize the large-scale deployment of solar technologies, which decarbonizes the electricity system and thereby slows the electricity price increase, so that the global electricity price stays in the range of 85-95 $/MWh from 2070-2100. Only regions with limited solar resources (Japan, India, and to a lesser extent OAS) see electricity prices above 110 $/MWh.

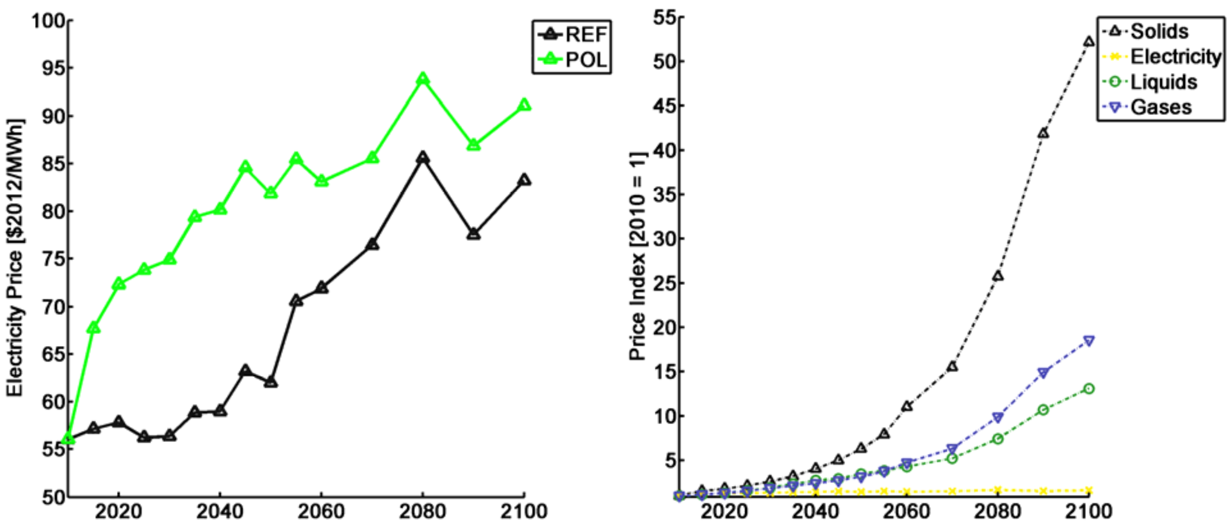

Figure 7: Model-endogenous prices for energy carriers at power plant/refinery level (generation-weighted global average). ***Left*****: Electricity prices in the REF and POL scenarios. Due to interactions between the long-lived capital stocks in both electricity generation and distribution, the prices do not develop smoothly but shows some jumps up and down.** ***Right*****: Prices of several energy carriers in the POL scenario, indexed to 2010 values. The transport sector relies mostly on liquids, while heating services are mostly provided from solids, liquids and gases.**

The interaction between electricity price and solar technology deployment is bi-directional: In both REF and POL scenarios, the large-scale deployment of PV and CSP is triggered as electricity prices rise above ~70 $/MWh. In return, this deployment decouples the electricity price from both resource and carbon prices: While the global coal price in REF increases 6-fold from 2010 to 2100, and the carbon price in POL increases 70-fold from 2015 to 2100, the increase of the electricity price is strongly dampened and never surpasses a level of 95$/MWh, less than a two-fold increase over 2010 values. In contrast, the other conventional energy carriers do not see such a decoupling, and all experience a more than 12-fold increase in the POL scenario, as displayed in Figure 7.

Impact of technology exclusions on electricity prices

The scenarios in which the deployment of a solar technology is limited allow exploring the interaction with the electricity price in more depth[10]. Changes in electricity prices induced by exclusion of certain technologies demonstrate the relevance of that technology for the power system (Figure 8). As discussed above, electricity prices increase even in REF until 2100 by 50% compared to 2010 due to rising resource costs. In POL, the prices increase earlier due to the carbon constraint, but do not go much higher due to the stabilizing effect of wind and solar deployment.

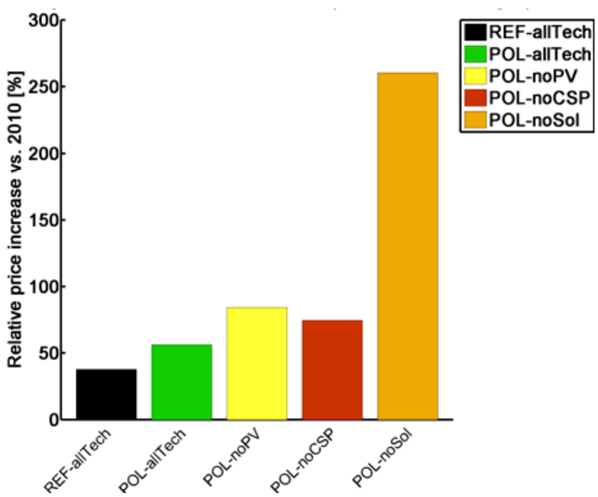

Figure 8: Effect of excluding solar technologies on the relative increase of average 2050-2100 electricity price at the wholesale market level (generation-weighted global average) over the 2010 value.

In Figure 8 we see that the decarbonization of the power sector hinges on the availability of at least one solar technology: Excluding both CSP and PV increases average 2050-2100 electricity prices by 260% over 2010. On the other hand, PV and CSP seem well capable of replacing each other should one of the two face substantial deployment barriers: excluding only *either* PV *or* CSP decreases the price increase to below 90%.

Thus, having at least one solar power technology available allows the power sector to factually decouple from scarcities in the rest of the energy system and carbon prices. While the energy carriers used for the transport sector (liquids) and provision of heat (solids, liquids, gases) face substantial difficulties when decarbonizing, leading to strongly rising energy prices in these sectors (see Figure 7), the electricity sector can deploy large shares of solar power at only gradually rising costs, thereby slowing the electricity price increase and decoupling it from the price increase for liquids, solids or gases. If neither PV nor CSP are available, carbon prices drive electricity prices to much higher levels.

6.3 The impact of VRE integration costs on LCOE

As shown in Figure 5, the deployment of PV precedes the deployment of CSP, but later in the century CSP becomes more important although PV investment costs are substantially below

[10] The resulting electricity production in 2100 in the technology exclusion scenarios are displayed in SI Figure 1 in the supplementary material.

those of CSP. This behavior can be explained by the larger need for storage when deploying PV, which becomes decisive at high VRE shares. To better understand the competition between the two solar technologies, we employ the concept of System LCOE from Ueckerdt et al [64] and analyze how VRE integration costs influence the average and marginal levelized costs of electricity production over time[11] (see Figure 9). Put very briefly, "System LCOE" of a technology are based on the conventional LCOE measure, but try to include the monetary value of all additional effects that adding a unit of electricity from this technology has on the total system costs – including changes of required peaking plants or storage, changes of load factors of other power plants, or changes of grid requirements.

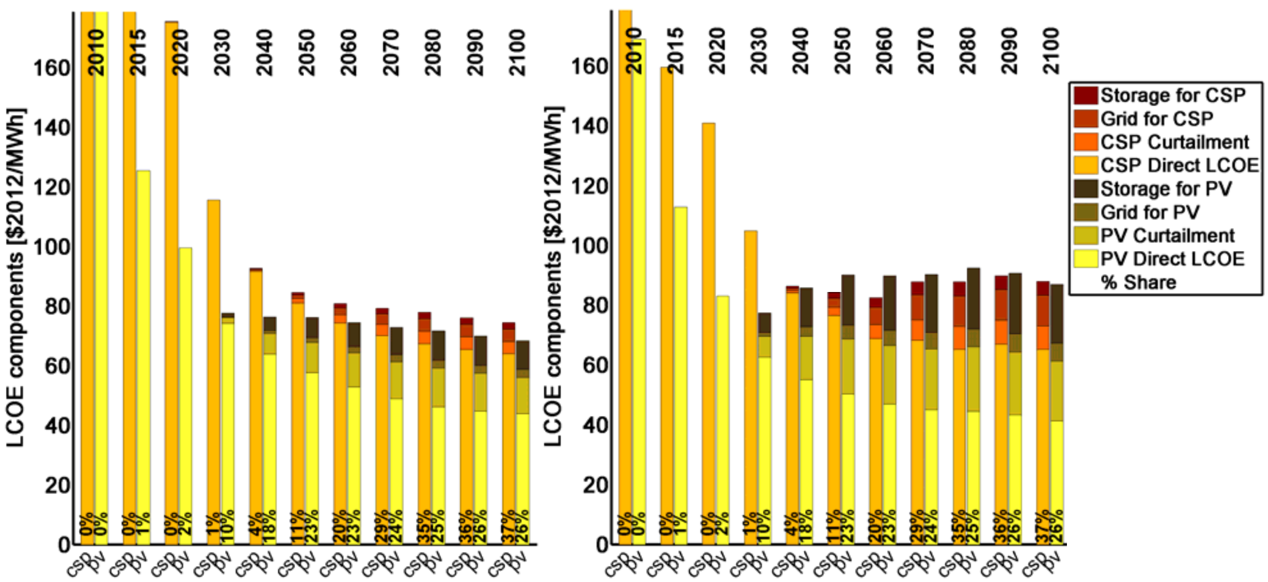

Figure 9: Development over time of average (left) and marginal (right) System LCOE of electricity supplied by solar technologies in the USA in the POL scenario (calculated ex-post as diagnostic variable). The vertical percentage numbers display the share of this technology in total electricity generation.

For the direct LCOE, which only depend on investment cost, operation and maintenance costs, capacity factors, life times and discount rate, the learning effect is the strongest driver. Learning-by-doing decreases the capital costs of a technology as this technology is deployed more (see Figure 6), thus decreasing LCOE of newly built plants. There is also a smaller counteracting effect: as more sites are used for a certain technology, the resource quality of the new sites decreases, leading to lower capacity factors, thus slowing LCOE decrease.

Besides the direct LCOE, three markups on LCOE can be calculated for VRE: the cost increase due to curtailed electricity and electricity loss in storage, due to investments into grid expansion, and due to investments into storage. The relative importance of the three integration requirements is different for the two solar technologies. Due to our assumption that PV sites are

[11] Although it may at first seem counterintuitive, for learning technologies the marginal LCOE can be below average LCOE at a certain point in time, as the average LCOE take into account the investments that were needed to create the power system at a certain point in time. When investment costs for learning technologies decrease, the marginal LCOE decrease immediately, but average LCOE are only affected with a delay as most of the currently standing plants were built at earlier times with higher investment costs.

more evenly distributed across a region than CSP sites, the grid expansion costs are more relevant for CSP than for PV. On the other hand, the storage requirements and electricity losses due to curtailment are much higher for PV than for CSP.

Although the direct marginal LCOE of CSP are more than 30% higher than those of PV in every time step, the total marginal LCOE of CSP are lower than those for PV after 2040. This can be explained by the fact that the marginal integration costs of PV rise strongly as the share of PV in electricity production increases, leading to integration costs that can be higher than the direct LCOE. The impact of the integration requirements on the competition between PV and CSP can easily be observed in Figure 9. As total marginal LCOE for CSP are lower than for PV after 2040, CSP is deployed much faster so that the CSP share eventually overtakes the share of PV. This analysis emphasizes how important it is to include the effects of VRE integration into energy economy models and not to draw conclusion solely based on direct LCOE values.

As shown in Figure 9, the calculated cost markups on marginal LCOE become substantial once total VRE shares surpass 20-30%, especially so for PV, where additional costs from storage, grid and curtailment can become larger than direct LCOE. The ranges we calculate in REMIND are in a similar range as those calculated by Mills and Wiser [63] who analyzed how the market value of VRE in California would change as their deployment level is increased. At 30% market share, they find that the marginal economic value of PV is decreased to one third of the initial value, while for CSP with 6h of thermal storage the value is only reduced to two-thirds. Denholm and Margolis [71] analyze the value of PV in the ERCOT market at different storage levels, finding a doubling of PV energy costs somewhere between 17 and 35% PV share, depending on assumptions of residual system flexibility and storage capacity. Apart from these studies, there is only limited literature to compare these values to: Hirth [56] performed an extensive literature research about VRE integration costs, but only very few of the studies analyzing integration costs of solar technologies look at PV shares beyond 10%.

While the exact values of integration costs are surely up to discussion and will change as knowledge improves, these comparisons make us confident that our approach is a good step for approximating VRE integration challenges in large-scale models that do not allow modelers to explicitly represent full time series of load and VRE incidence due to numeric complexity. At the same time, we acknowledge that substantial further research is needed to a) improve the parameterization, b) determine the impact of regionally different time series and geographies, and c) analyze in depth the trade-off between different flexibility options like demand side management, storage, transmission grid improvement, and flexibility of the residual system. To achieve all this, more results from dedicated electricity sector model studies covering a wide range of VRE shares as well as different world regions are needed.

6.4 Sensitivity of results to cost assumptions

Both PV and CSP are implemented in REMIND as technologies that have decreasing investment costs as deployed capacity increases (see Section 2.2.1). For both PV and CSP, there are detailed engineering proposals behind the projected decreases of capital cost in the future [31], [38], [104], [105]. Furthermore, the last 25 years have shown that substantial learning was achieved for PV technologies, leading to cost reductions of more than 85% for PV. Still, there is uncertainty about what part of the future projected cost reductions will be achieved over what time frame. To analyse the impact of these future cost uncertainties on solar technology deployment, we performed a sensitivity study: We varied the future investment costs at a certain cumulative installed capacity[12] by changing learning rates and floor costs as displayed in Table 4. The values for the "expensive" limit were chosen such that long-term costs were slightly below today's costs, while the values for the "cheap" limit represent very optimistic assumptions.

Table 4: Maximum parameter range of learning rates and floor costs for the sensitivity study

	PV		CSP	
	2002-2013 LR	**Floor cost [$/W]**	**2002-2013 LR**	**Floor cost [$/W]**
Expensive	16%	2.2	7%	7.7
Cheap	26%	0	16%	0.5

Our scenarios show that the importance of solar power for the electricity sector under a strict mitigation target is robust. This can be seen in Figure 10, where we display the resulting net shares of CSP and PV in the cumulated electricity production from 2010 to 2100 for the POL scenarios under the different future cost assumptions. Even for the most pessimistic cost projections, namely the unlikely case of no further learning for PV and CSP beyond the currently reached price, the share of solar in cumulated electricity production over the next century is 19%. As the costs projections are reduced and get more closer to current estimates, the solar share increases to 48% at default assumptions, and rises further to up to 78% for the most optimistic assumptions of 280$/kW for PV and 1300$/kW for CSP.

The sensitivity runs also confirm that PV and CSP can partially substitute for each other. At a given cost for a PV plant, an increase of future investment costs for CSP leads to less electric power production from CSP and more production from PV, and vice versa. They are imperfect substitutes, as the total share of solar electricity is reduced in this process. Both technologies coexist and contribute significantly to total electricity production over a wide range of costs.

[12] To reflect the factor three differences in capacity factor between CSP plants with thermal storage and PV plants, the investment costs are given for a cumulative installed capacity of 10TW for PV and 3TW for CSP – both of which are reached between 2050 and 2070 in the default POL scenario

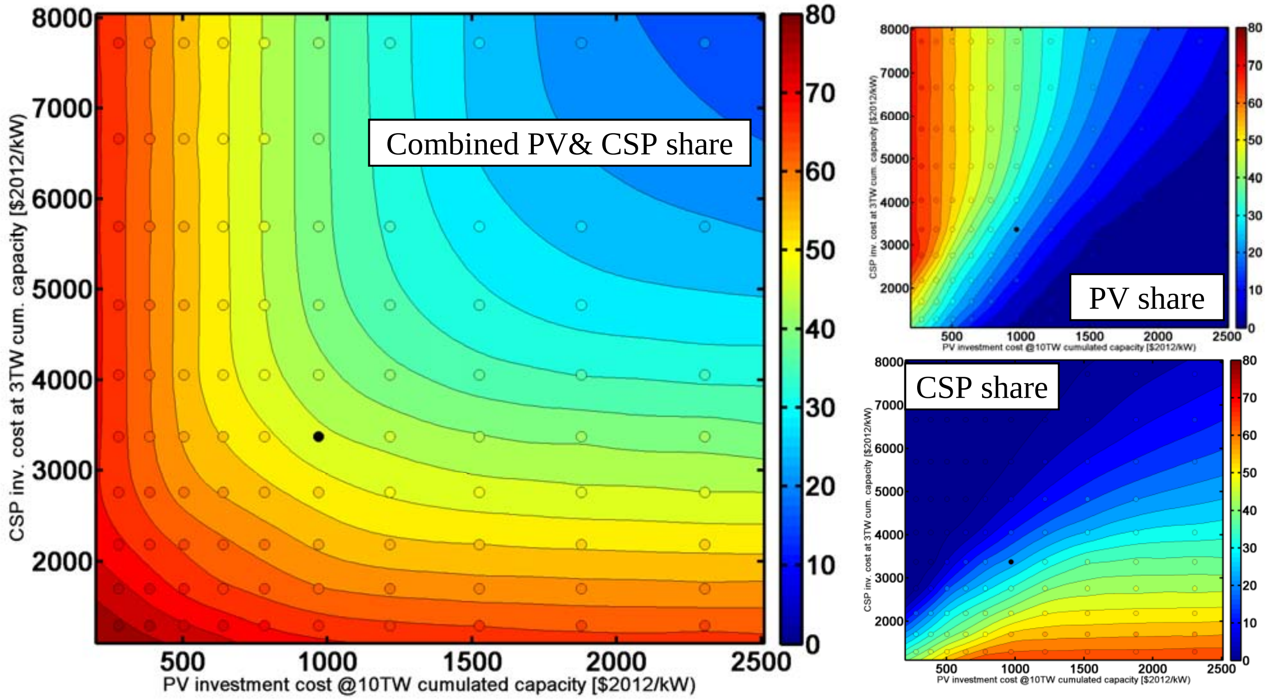

Figure 10: Share of solar/PV/CSP electricity in total cumulated electricity production 2010-2100 at different future investment costs. The investment costs for CSP (always on the y-axis) are given at an installed capacity of 3TW, for PV (always on the x-axis) at 10TW to account for the factor three differences in capacity factors. The open circles mark the individual REMIND runs, the black circle denotes the default assumptions.

7. Summary and conclusions

In this paper we analyzed the role of solar technologies for decarbonizing the power sector as well as the competition between PV and CSP using the hybrid energy-economy model REMIND. To this end, we developed the following datasets and algorithms to augment the representation of solar power technologies in large-scale energy-economy-models:

- A simplified representation of integration challenges arising from high market shares of VRE, useful for large-scale IAMs that cannot handle more detailed power system representations due to computational limitations. Through these integration requirements, models are able to value the benefit that CSP gets from thermal storage. At high VRE penetration levels, the marginal integration costs of PV can be higher than the direct technology costs, so it is crucial to include these costs.
- Estimates of current investment cost as well as future cost reductions.
- A consistent resource potential data set for the two solar technologies, suitable for use in IAMs. The data set goes beyond previous work as it (a) derives coherent resource potentials for both CSP and PV using the same algorithm and exclusion factors, (b) reports results on a national level, allowing flexible regional aggregation, (c) bins the resource potential by capacity factor, thus leaving technology cost assumptions to the modeler, and (d) differentiates potential sites by distance to grid. The resulting potential is very large: today's electricity demand could be supplied by PV at good insolation levels (>1500 FLh) in all REMIND macro-regions except Japan and Russia.

We then performed several groups of scenario ensembles and analyzed the results, using the metrics electricity generation, electricity price, levelized cost of electricity as well as share in cumulated electricity generation. The main findings are:

- Solar electricity is projected to be the main source of electricity in the second half of the century, supplying 48% of the cumulated global electricity produced from 2010-2100 in a scenario with cost-efficient mitigation policies to achieve the 2°C target. Even without climate policy, solar becomes the main source of electricity after 2070.
- In a climate policy world, the electricity system is highly dependent on having at least one solar technology available: excluding both PV and CSP leads to substantial electricity price increases, with average 2050-2100 prices 260% higher than in 2010.
- Integration costs are highly relevant for the competition between PV and CSP: Although PV consistently has lower direct LCOE than CSP and is initially deployed faster, CSP catches up and overtakes PV at the end of the century due to lower integration costs of CSP.
- The dominance of solar technologies for the power is quite robust to changing cost assumptions: Even under the most pessimistic view that the projected cost decreases are not realized and investment costs remain at current levels, solar technologies produce 19% of cumulated 2010-2100 electricity in a climate mitigation scenario.
- Both technologies can partially substitute each other: In cost-optimal scenarios, PV and CSP complement each other, but if one of the two technologies faces deployment barriers, the other can strongly increase its' share in total electricity production and partially make up for the loss of the other technology.

Solar technologies could thus be characterized as a backstop technology for the power sector in most regions: they require a certain electricity price before being deployed, but then manage to decouple the electricity price from resource and carbon price increases, as they can supply large quantities of electricity in most world regions without escalating costs.

As any modeling exercise, our results come with limitations. Due to the long-term nature of climate change, mitigation scenarios need to extend far into the future. Technology projections are inherently risky and limited by current knowledge and imagination. The aggregation into 11 world regions omits details interesting to national policymakers. However, technology development and diffusion happen on a global scale, thus large-scale global models are required for answering questions about long-term transformation scenarios.

Furthermore, technology choice is influenced by many additional parameters beyond the modeled investment costs and integration challenges, such as political preferences, differing maintenance requirements, or the possibility to produce technologies locally. Such aspects cannot be fully represented in a model the size of REMIND. Nevertheless, the wide range of future investment costs at which both technologies are used in the mitigation scenario (see Section 6.4) can act as a benchmark for how large these additional effects would have to be to knock out one of the two technologies.

Despite these caveats, the current study can be seen as a conservative scenario of a future in which no unforeseen technology[13] revolutionizes our energy system: if such a world is dedicated to limiting global warming to below 2° at lowest cost, both photovoltaics and concentrating solar power will play a substantial, maybe even paramount, role in the power system.

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[13] e.g., advanced nuclear with unlimited resources and without waste disposal issues.

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