The Future of the European Electricity Grid Is Bright: Cost Minimizing Optimization Shows Solar with Storage as Dominant Technologies to Meet European Emissions Targets to 2050

Energies (ISSN: 1996-1073)

Citation for the published paper:
Norwood, Z. ; Goop, J. ; Odenberger, M. (2017) "The Future of the European Electricity Grid Is Bright: Cost Minimizing Optimization Shows Solar with Storage as Dominant Technologies to Meet European Emissions Targets to 2050". Energies, vol. 10(12),

http://dx.doi.org/10.3390/en10122080

(article starts on next page)

energies

MDPI

Article

The Future of the European Electricity Grid Is Bright: Cost Minimizing Optimization Shows Solar with Storage as Dominant Technologies to Meet European Emissions Targets to 2050

Zack Norwood [1,*], Joel Goop [2] and Mikael Odenberger [2]

1 Fysisk Resurteori, Chalmers Tekniska Högskola, Göteborg 41296, Sweden
2 Energiteknik, Chalmers Tekniska Högskola, Göteborg 41296, Sweden; joel.goop@chalmers.se (J.G.); mikael.odenberger@chalmers.se (M.O.)
* Correspondence: donkey@berkeley.edu; Tel.: +46-31-772-14-84

Received: 27 October 2017; Accepted: 4 December 2017; Published: 7 December 2017

Abstract: The European roadmap for the power sector dictates an 80–95% cut of existing levels of carbon dioxide emissions is needed by the year 2050 to meet climate goals. This article describes results from a linear cost optimization investment model, ELIN, coupled with a solar technology model, Distributed Concentrating Solar Combined Heat and Power (DCS-CHP), using published investment costs for a comprehensive suite of renewable and conventional electricity generation technologies, to compare possible scenarios for the future electricity grid. The results of these model runs and sensitivity analyses indicate that: (1) solar photovoltaics (PV) with battery storage will likely play a very large role in meeting European targets; (2) concentrating solar power (CSP) with thermal energy storage is at a slight economic disadvantage with respect to PV to compete economically; (3) the economic potential of wind power is only comparable with solar PV if high wind penetration levels are allowed in the best wind sites in Europe; and (4) carbon capture and nuclear technologies are unlikely to compete economically with renewable technologies in creating a low-carbon future grid.

Keywords: solar power; energy storage; energy systems

1. Introduction

The novelty of the research presented in this article lies in the integration of a detailed solar technology model, Distributed Concentrating Solar Combined Heat and Power (DCS-CHP), with a comprehensive linear investment optimization model, ELectricity INvestment (ELIN), based on the existing European electricity grid while allowing for grid expansion with a variety of new and existing generation technologies and both solar thermal and electrical storage. Some recent forerunners in the analysis of global energy models are, for example, Pietzcker et al. [1] whose techno-economic model, REMIND, showed that renewables including wind and solar would play a dominant role in the future energy system in the second half of this century. Fürsch et al. [2] focused on Europe showing that in order to enable large penetrations of wind and solar technologies, there would need to be a significant build out (>70% increase) of the electricity grid. Another linear optimization model, REMix, including storage, transmission and generation investments over all of Europe, shows that the environmental impacts (using LCA) of a high renewable penetration scenario are significantly lower in almost all indicators (compared to fossil fuels with carbon capture and storage (CCS), for example) except notably in mineral depletion [3]. In the U.S., the SWITCH model, also a linear economic optimization model, with scenarios focused on reduction in costs in solar technologies [4], demonstrates that very high penetrations of solar PV (accounting for more than a third of electricity by 2050) would likely occur to achieve carbon reductions of more than 80% at installed costs not unlike what we are seeing today in Europe. Furthermore, without these low solar PV costs, nuclear and CCS technologies would likely play a significant role in the western U.S. grid.

In terms of solar technology models, there have been several concentrating solar power (CSP) technology comparisons that show the large potential of CSP technologies (including as peaking plants and with thermal storage) [5] and expected learning curves [6] that would enable meeting long-term climate targets. Furthermore, the techno-economic analysis of Peters et al. [7] shows that CSP could begin to be more cost effective than PV by 2020 in favorable regions of the U.S. and Europe, whereas Denholm and Margolis [8] showed that the potential of PV with storage for much less than one day of load would allow more than 50% of total energy on the grid to come from PV in the ERCOT system in the U.S.

This article builds on these results and demonstrates the competitiveness between different solar power technologies, solar and wind, thermal and electrical storage technologies and conventional power plants including CCS and nuclear in the European grid based on techno-economic optimization modeling through the year 2050. It should be noted that this study does not aim to forecast the most probable scenario for the future European electricity system. The modeling is explorative in nature and compares suitable combinations of technologies under different scenario assumptions.

2. Method

The basis of the method applied in this work lies firstly in a comprehensive database, the Chalmers Power Plant Database (Chalmers PP Db) describing all existing power plants across the European Union, Norway, Iceland and Switzerland; secondly, in a solar model, DCS-CHP (Distributed Concentrating Solar Combined Heat and Power), which creates simulated output for many types of solar systems based on typical weather data over a grid of Europe; thirdly, in an electricity-supply system model, ELIN (ELectricity INvestment), which links the existing capacity found in the Chalmers PP Db to investments in new generation capacity to the year 2050. The ELIN model calculations include EU-27, Norway and Switzerland.

2.1. The Power Plant Database

The Chalmers PP Db (see Kjärstad and Johnsson [9]) includes information on all thermal, hydro, offshore wind and geothermal plants with power output capacities greater than 1 MW. Plants with capacities less than 1 MW (or less than 10 MW for solar PV and on-shore wind farms) are represented by regional aggregates. All thermal and hydro plants are registered at the unit level including information about, for example, age, capacity (input and output), fuel, technology and present operational status.

2.2. The Solar Technology Model

The DCS-CHP model is a solar performance model that can simulate hourly output for a large variety of solar electric and solar thermal power technologies at a specific site. The simulation uses typical meteorological year weather data (including temperature, irradiance and wind speed) to create a yearly time series of heat and electricity production for each system over 12,846 locations in Europe and 1020 locations in the United States. Through this simulation, systems composed of various permutations of collector-types and technologies can be compared geospatially and temporally in terms of their typical production in each location.

This methodology was developed and described originally in Norwood and Kammen [10] and further developed for Europe in the first article in this series [11].

2.3. The Electricity Investment Model

The ELIN model is a long-term dynamic optimization model (originally formulated by Odenberger et al. [12] and further developed by Goransson et al. [13], where these references include full model formulation) that includes the present generation system, as derived from the

Chalmers PP Db, together with an extensive array of new and existing technologies that are to be used to meet the changes in future demand as existing capacity comes of age or becomes unprofitable. Both conventional fossil fuel and CCS technologies are available for investment, as well as a portfolio of renewable technologies.

The integration with the DCS-CHP model allows ELIN to have a variety of solar technology investments to choose from. The available solar technology models in DCS-CHP are based on bottom up thermodynamic and electrical modeling of five different technology classes (CSP, tracking High Concentration Photovoltaics (HCPV), non-tracking distributed PV, tracking utility PV and non-tracking utility PV) all with different costs and inherently different production profiles.

Wind technologies, on the other hand, are divided into two technology classes (onshore and offshore) with different costs and further divided into capacity factors based on the wind resources of the locations (the highest being a 35% capacity factor). However, all solar technologies in the same technology class and all wind technologies in the same technology class, respectively, are considered to have the same investment and O&M costs (see Figure A1a,b). Therefore, the differences in the investments chosen depend entirely on the favorability of each class of technology in each location.

For solar and wind, the investment decisions are based on the available resource at specific locations in addition to the other variables affecting all generation investments such as the transmission capacity and electrical load in the respective countries. Solar production is also to a lesser extent affected by temperature, as the DCS-CHP model accounts for ambient temperature when calculating production profiles.

The ELIN model calculates the sizes and locations of investments, as well as the dispatch of new and existing capacity that minimize the total system cost over the entire modeled period. The time horizon of the ELIN model is from 2010–2050 with each discrete year separately described. The intra-annual time resolution of the ELIN model is 16 time steps, including two daily load segments (night load and day load), weekdays and weekends, which are allocated over four different seasons: winter, summer, spring and autumn. Typical model outputs from the ELIN model include capacity and production levels of electricity by fuel and country until 2050, aggregated investment costs, electricity trade between regions (or countries) and marginal costs of electricity. Generally in the model runs, a CO_2-emission cap, which is gradually reduced up to the year 2050, is imposed on emissions from the electricity production. Thus, the marginal cost of CO_2-emission reductions is also part of the model output.

A capacity constraint forces investment in peaking natural gas plants when variable renewables reach a high level in the model. The reason for this is that large capacities of wind and solar can have large short-term variations and hence are balanced with additional plants, which can ramp up and down quickly when needed (peaking natural gas is the most cost-effective of such plants). Although the magnitude of resulting investments in peaking gas are only indicative, this capacity constraint effectively puts a penalty on investments of wind and solar in the optimization process to compensate for the insufficient time resolution of the model.

In addition, distributed solar PV installations can be modeled to compete with retail prices or wholesale market prices (i.e., the relation of small-scale prosumers benefits from having a higher value of locally consumed power can be evaluated). The small-scale producer added value is implemented for PV electricity based on current national differences between retail and wholesale prices from Eurostat consumer price reports [14,15], yet excludes the value added tax since this is not part of the investment cost of the installation. When running with this option, the model applies a net metering scheme for small-scale solar PV producers, meaning that all electricity generated by the PVs gains this added value.

Another model output in ELIN is the investments in electrical transmission capacities between countries. We assume that significant transmission investments across Europe are optional, i.e., the model decides endogenously whether they are profitable or not (based on exogenous assumptions of investments costs), from 2020 and onwards. The profitability of a new interconnector depends on whether the wholesale electricity-price difference between two countries is large enough to motivate such an investment.

The first transmission investments are allowed in the model year 2020, which gives the needed time for the construction of new interconnections. Note that these transmission investments are purely between countries (international) and exclude all interconnections within the same country (intranational). The model assumes furthermore the ability to transmit free of cost within a single country.

Highly detailed wind-power availability data across Europe are also included in the ELIN model. The data have primarily been taken from the ERA Interim dataset [16] made available through the European Centre for Medium-Range Weather Forecasts [17]. Although the data were originally defined for single spatial cells of 200–700 km^2 and covering the entire EU-27, it has been aggregated to fit the ELIN regional model structure (53 intra-national regions defined by key electricity-transmission bottlenecks). Both the annual availability (full-load hours) and the production profiles for wind power have been implemented on a regional level. The estimated potential land availability for wind power, which is also an important model input parameter, is based on a detailed assessment of areas across Europe not suitable for wind power, i.e., densely-populated areas, or transportation infrastructure, waterways, seas or areas under environmental protection [18]. Based on the remaining available land surface suitable for wind-power installations and on wind availability and investment costs that develop over time, cost-supply curves are generated for new onshore wind power that are used as input to the ELIN model.

Likewise, the land potential for solar is calculated similarly to wind (excluding nature protection areas, water, etc.), but does not exclude densely-populated areas (these areas are assumed suitable for distributed PV only), nor transportation infrastructure.

2.4. The Scenario

The climate market scenario, inspired by the European Commissions Roadmap scenario "Diversified supply technologies" [19] and "Power choices reloaded" by Eurelectric [20], investigates a future with focus on stringent CO_2 emission reduction after the year 2020. Thus, the modeling presented in this work includes current EU targets to 2020 and thereafter only annual CO_2 emission constraints up to 2050 reaching 50% reduction by 2030 and 93% by 2050 compared to 1990 levels. Up to the year 2020, the constraint development follows national projections reported in the National Renewable Energy Action Plans [21]. The demand growth for electricity is implemented on a national basis resulting in a 0.91% increase per year on an average European level. This strong growth could indicate, for example, an increasing electrification of other sectors such as transport.

The technology costs (Appendix A.1, Tables A1–A4) in the base case climate market scenario are taken from the IEA's World Energy Investment Outlook (WEIO) "New Policy Scenario" [22]. Both battery and thermal storage technologies are included in the ELIN model with cost curves shown in Figure A1a produced from extrapolations of [23,24]. Other storage technologies such as pumped hydro have not been included due to various constraints including the model's time steps and are therefore outside the scope of this analysis. Cost curves over time for wind and solar technologies are curve fitted based on the same WEIO data assumptions (Figure A1a,b). The assumptions about the cost curves (exogenous) used have been compared with expected learning curves for solar PV, and we see fairly good agreement with the magnitude of investments seen here and the expected investments that would be needed to stay on the predicted cost/learning curves. Some of the important initial conditions given for the base case model run in ELIN are outlined in Figure A1 in Appendix A.1.

The combustion technologies (including biomass) and nuclear, in contrast to wind and solar, are assumed to have constant investment costs throughout the model runs (i.e., the 2012 costs in WEIO), but increasing efficiency over time, as shown in Figure A1c–e. The cost of fuel for these technologies is based on a cost-supply fuel curve that remains constant throughout the model where prices at every time step are based on the amount of consumed resources (as shown in Appendix A.2). The difference in costs for the same technologies shown in Figure A1c–e reflects the type of power plant (condensing, Combined Heat and Power (CHP) or a back-pressure plant coupled to industrial waste heat). The potential for investments in the comparatively efficient back-pressure plants is limited to current industrial levels in the ELIN model as they are available to be installed only in very specific industrial locations. A sensitivity run eliminating the possibility to invest in these back pressure plants shows little change in overall results (see S1 for all sensitivity results).

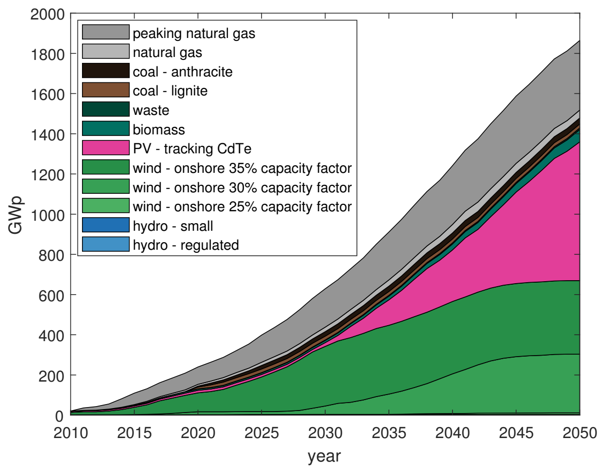
3. Results and Discussion

In order to highlight the most important trends, we have chosen to present results from nine different runs of ELIN (all using the climate market scenario) including the base case and eight sensitivity analyses focused mostly on changing the initial model assumptions for wind, solar and storage. Results from each of these model runs highlight the role wind and solar technologies will likely have in achieving a low carbon emission electricity grid and how the balance between transmission and storage needs for the grid as a whole is very dependent on the balance between these two technologies. Many more graphs not shown here and results from other sensitivity runs, as well as the models themselves can be found in the Supplementary Material (S1).

3.1. Base Case

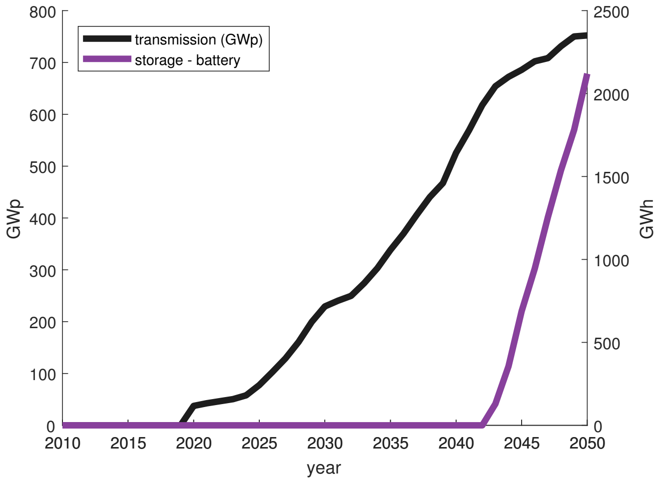
Just as in all ELIN model runs presented here, the base case allows investment in all technologies, and the model simply finds the cost optimal combination of generation technologies to install so the electricity grid as a whole meets demand and keeps carbon emissions below the targets for each year up to and including 2050.

Figure 1 shows the main results from the base case scenario ELIN model run. Figure 1a depicts the capacity of investments in electricity generation technologies that result from the optimization. Note that nearly all new investments are in solar and wind technologies, with only a very small fraction in combustion technologies excepting peaking natural gas. No CCS technologies nor nuclear technologies are invested in at all. This result is robust in all model sensitivity runs we present here; the main change seen between runs is the relative balance of investments in the different wind and solar technologies. The inflexibility to adapt to load is a trait of variable renewables, CCS and nuclear technologies. Variable renewables have production patterns dependent on weather, whereas CCS and nuclear need constant full load. With large investments in any of these technologies, there is additional cost to keeping the balance, but these results show that the investment costs of CCS and nuclear are simply too high to compete.

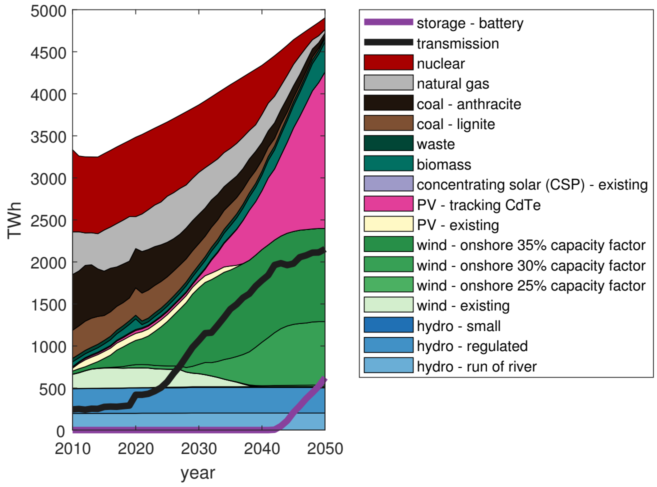


(**a**)

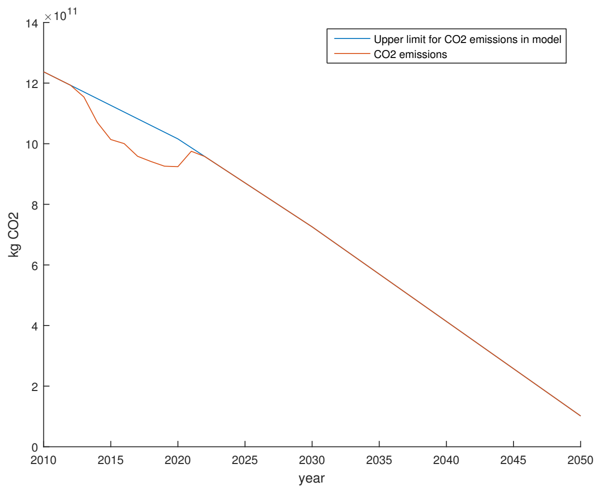
Figure 1. *Cont.*



(b)

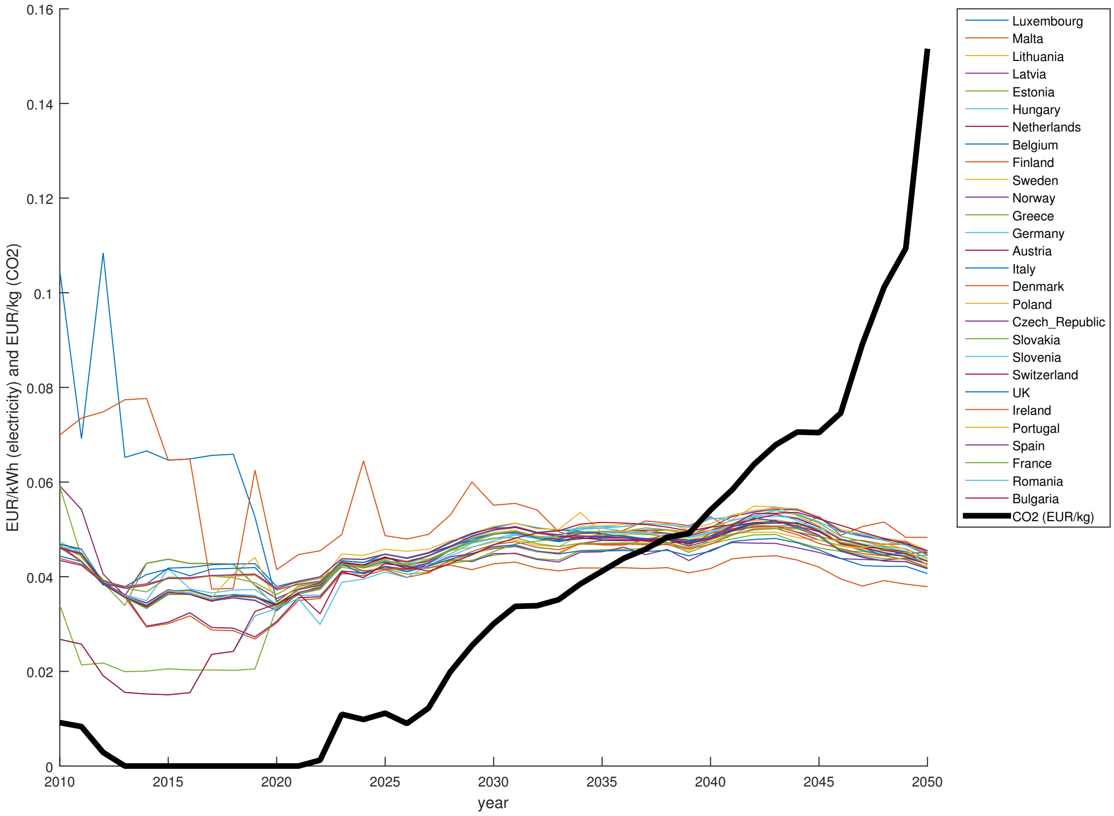


(c)

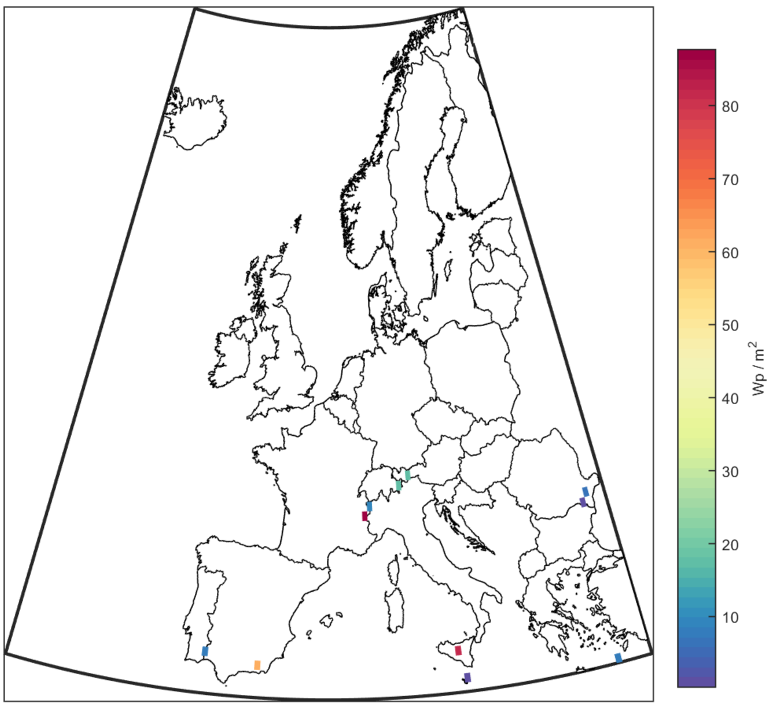


(d)

Figure 1. *Cont.*

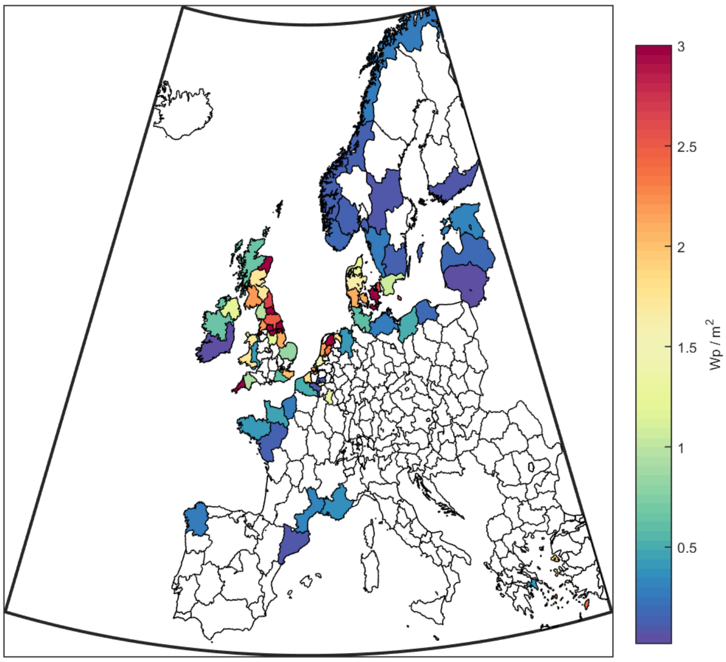


(**e**)



(**f**)

Figure 1. *Cont.*



(**g**)

Figure 1. Model results for the base scenario including (**a**) the capacity of electricity generation investments, (**b**) the capacity of new transmission (GW_p) and storage (GWh) investments, (**c**) the electricity generated by generation type and year plus yearly electricity transmitted internationally and yearly energy transferred to storage, (**d**) the upper limit allowed by the model and the actual CO_2 emissions over time, (**e**) the price of electricity in each of the countries and the marginal cost of CO_2 abatement over time, (**f**) the installed capacity of solar PV power plants, and (**g**) the installed capacity density of wind power. Note that the order of the legends for line and area plots corresponds to the order of the respective values in 2010 from top to bottom. Note also that the color of the regions/quadrants on map plots indicates the installed capacity density in the given region/quadrant where white signifies zero installations

The reader may note that a capacity constraint forces investment in the peaking natural gas seen in the base model run (Figure 1a) to account for the inflexibility of wind and solar power. Another sensitivity run (see S1) shows that removing this capacity constraint does increase, to a small extent, the amount of wind and solar invested in, but does not affect the overall trends seen in this analysis.

Of course, increased transmission and storage investments, as shown in Figure 1b for the base case, ameliorate the increased variability of wind and solar and, thus, will provide, to some degree, the same energy service as peaking natural gas plants. This synergistic effect is ignored, however, in the model for the sake of simplicity, even though storage investments after year 2045 become significant and transmission increases steadily throughout the entire time period.

Figure 1c shows the total amount of energy that is produced from each of the electrical generation technologies and the amount of energy transmitted between countries and to storage, respectively. It is noteworthy that in the base case, by the year 2050, almost 50% of energy production is sent through transmission across country borders. Furthermore, we can see that the natural gas plants produce a minimal amount of electricity despite having a quite large installed capacity (mostly peaking natural gas), meaning that most are running very seldom (i.e., low capacity factor). Due to the capacity constraint mentioned above and the low time-resolution of the model, it is significant to mention that the magnitude of energy production from these peaking plants is not a robust result.

Figure 1d shows the modeled carbon emissions from the base case in addition to the carbon cap that is enforced by the climate market scenario. The resulting modeled price of electricity in each country and the cost of carbon emissions is shown in Figure 1e. Interestingly, due to the model's adherence to existing EU renewable energy targets, there is a brief period up to the early 2020s when emissions are actually below the cap (note that renewable energy targets after 2020 are not considered). After the early 2020s, the optimum solution found by the model is to emit at exactly the capped emission level. This results in carbon emission costs that increase quickly towards the end of the simulation to more than 15 euro cents per kg of CO_2. Electricity prices on average, however, remain relatively constant through the entire model time period (even decreasing as nearing 2050). The electricity prices in different countries converge over time due to the large amount of transmission that is installed and the harmonization of the technology mixes across countries.

In the base case, solar investments are exclusively in tracking thin film CdTe solar PV technology (locations shown in Figure 1f), instead of other possible solar PV technologies (such as non-tracking or silicon chemistries) due to the facts that (1) the solar PV model used in this analysis (DCS-CHP) shows that thin film CdTe produces slightly more energy over the year (per installed peak rated power) than monocrystalline silicon or copper indium gallium selenide (CIGS) at those locations and (2) the tracking cost assumptions [25] are low enough that tracking systems are advantageous over non-tracking systems in this analysis. This result should not, however, be misconstrued to indicate that there is a statistically-significant cost savings for CdTe vs. other solar PV technologies, as this is outside the scope of this analysis. In reality, costs per peak power for each technology type are not exactly the same; fluctuations in cost due to demand and supply can be large for different technology types; and the time resolution of our model is too coarse to be affected by subtle profile differences. For more detailed analysis of the modeled differences in energy production per location and solar technology, see the first article in this series [11].

In the case of wind, the model invests in wind in the highest wind resource locations (see Figure 1g) while always optimizing based on factors such as transmission capacity and demand in the respective country, etc. It can be seen in the results that the available resource of onshore wind is sufficient in all regions and for the entire period investigated. Thus, offshore wind power is only profitable in the sensitivity analysis where the wind power density is decreased to such an extent that the model has made use of all available space for onshore wind with capacity factors of 20% and greater. In reality, investments are also taking place in offshore wind, and it should be noted that there are advantages in offshore wind power, including in some cases better public opinion. Onshore wind, however, is less costly than offshore even though the costs for offshore wind are expected to drop faster than for onshore wind. According to the IEA WEIO assumptions used in this analysis and the U.S. Energy Information Administration [26], the levelized cost of electricity is approximately 2.5-times higher for offshore than for onshore wind power entering into service in 2022.

3.2. Sensitivity with Solar Net Metering

In the solar net metering sensitivity run, the only change from the base case scenario is that net metering is allowed for distributed solar technologies. This is meant to simulate the effect that net metering policies would have on the uptake of solar PV in the European electricity grid. The results show a drastic change compared to the base scenario. Figure 2a shows that almost all PV that is installed in the net metering regime is distributed, and uptake is much more rapid than in the base case. The modeled installed capacity between 2010 and 2017 with net metering actually agrees better with historic trends during the solar PV boom in that time period in Europe than does the base case. This observation is largely due to current and historic subvention schemes for solar PV in many countries being excluded from this model, not because net metering has been implemented widely in Europe.

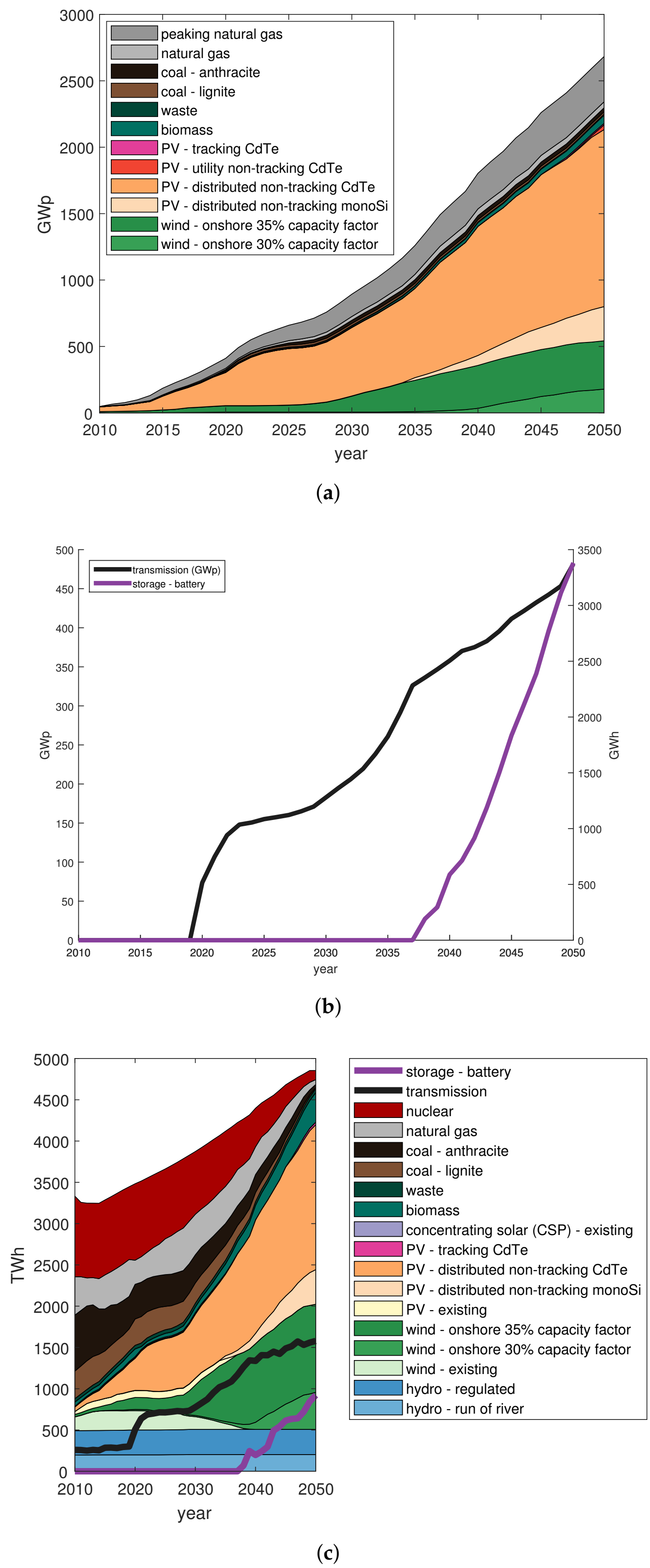
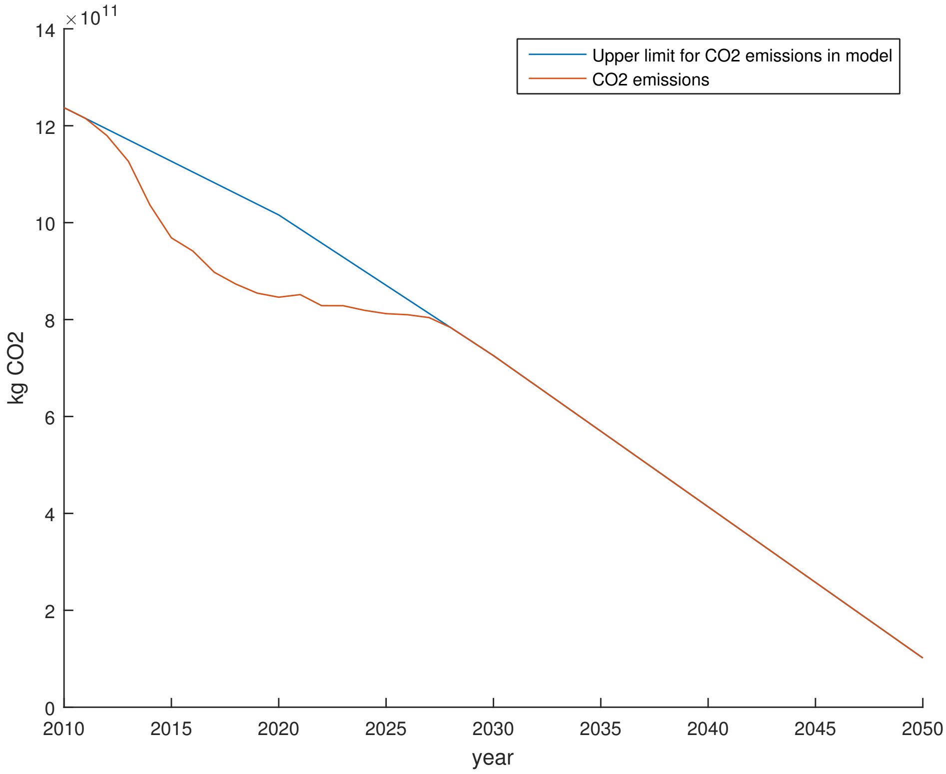
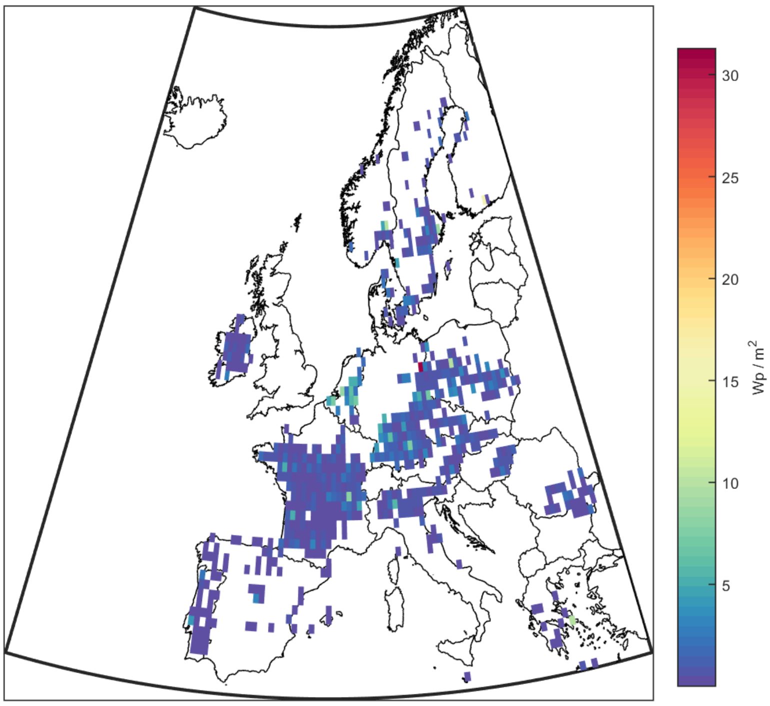


Figure 2. *Cont.*

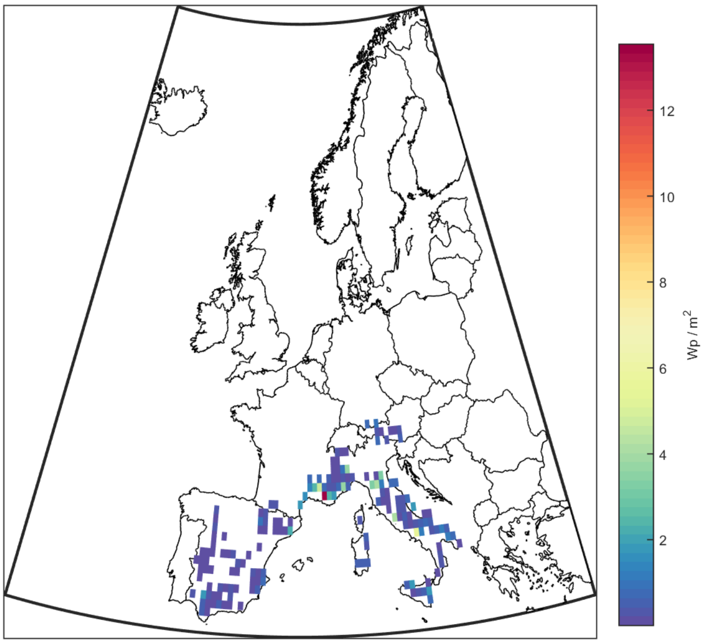


(**d**)

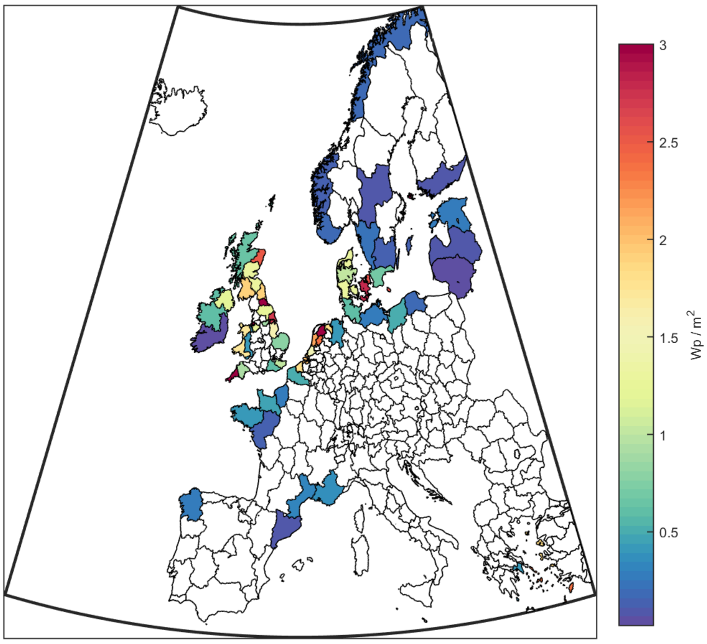


(**e**)

Figure 2. *Cont.*



(**f**)



(**g**)

Figure 2. Model results for the solar net metering scenario including (**a**) the capacity of electricity generation investments, (**b**) the capacity of new transmission (GW_p) and storage (GWh) investments, (**c**) the electricity generated by generation type and year plus yearly electricity transmitted internationally and yearly energy transferred to storage, (**d**) the upper limit allowed by the model and the actual CO_2 emissions over time, (**e**) the installed capacity of distributed solar PV (CdTe), (**f**) the installed capacity of distributed solar PV (mono-Si), and (**g**) the installed capacity density of wind power. Note that the order of the legends for line and area plots corresponds to the order of the respective values in 2010 from top to bottom. Note also that the color of the regions/quadrants on map plots indicates the installed capacity density in the given region/quadrant where white signifies zero installations

A few additional trends are worth noting in the solar net metering results. Because of the dominance of distributed solar PV, we see decreased wind installations compared to the base case. This changes the relative amount of storage vs. transmission that is installed by 2050: we see an approximately 55% increase in battery storage and an approximately 35% decrease in transmission (Figure 2b) in 2050 compared to the base case (Figure 1b). This is due to the fact that the diurnal nature of solar energy is more complementary to local storage, whereas the more long-term and spatial variations of wind are more complementary to transmission. Battery storage investments, furthermore, begin about five years earlier in the net metering model (2037) than in the base scenario (2042). The total energy contribution from PV to the grid in 2037 reaches approximately 30% (Figure 2c), and total variable renewables reach 50% in this scenario, which explains the earlier uptake of battery storage. It should be noted that this analysis is limited to including storage invested in by the model for balancing purposes and, thus, does not consider any investments in battery storage that is driven by other purposes. In reality though, there could be investments in for example electric vehicles offering battery capacity to the system either by flexible charging strategies or by vehicle to grid. Such additional available battery capacity would favor solar generation technologies according to this analysis.

Another interesting result seen in the net metering scenario is shown in Figure 2d. This is the only scenario where we do not see a significant rise in carbon emissions when the existing EU climate targets end in 2020. This is because, after 2020, renewables are almost always the most cost-effective production technologies when net metering is allowed.

Figure 2e,f shows the locations and amounts of installed distributed CdTe solar PV and distributed mono-Si solar PV, respectively. Compared to the base case, we see that the distributed technologies are much more spread out with a lower spatial density overall. This is due to the fact that the model limits distributed solar technologies to only the built environment (based on GIS analysis), and thus, we see the highest concentrations in dense urban areas and very low concentrations elsewhere. This spatial capacity constraint leads to the investment in mono-Si, a more space-efficient technology (due to its higher solar conversion efficiency) in countries where distributed PV is nearly maximized in the sunnier regions.

Differences in the capacity of solar investments in countries with similar solar resource in Figure 2e are often explained by net metering comparably benefiting prosumers in countries with higher net taxes and fees (e.g., Ireland taxes and fees being nearly double those in the U.K.).

Finally, Figure 2g shows that the distribution of wind power, a centralized technology, is not significantly changed compared to the base scenario, but that the capacity density is lower than the base case in many regions.

3.3. Sensitivity with Lower Solar Costs

The third through fifth sensitivity runs (results shown in Figures 3–5) reduce the cost curves for solar technologies to what might be considered more realistic levels than those used in the base scenario (from IEA).

The cost curves for all solar technologies are reduced by a factor to agree with costs from the Fraunhofer Institute for Solar Energy Systems [27] for centralized PV (as shown in Appendix A.1, Figure A2a). As would be expected, Figure 3 shows that the lower solar cost scenario results in a marked increase in the total solar energy investments compared to the base scenario (Figure 1a). This increase is on par with the net metering scenario indicating that sinking PV costs alone could drive the sort of PV expansion that would be needed to produce more than 50% of electricity in Europe from solar by 2050.

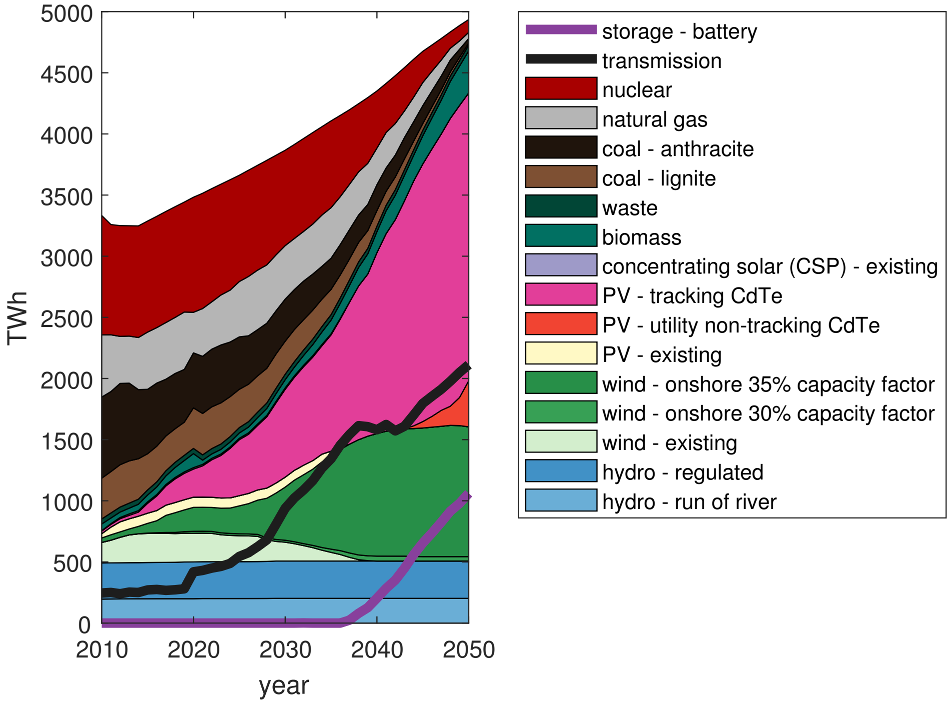


Figure 3. Electricity generated by generation type and year plus yearly electricity transmitted internationally and yearly energy transferred to storage in the lower solar cost scenario.

An additional result that can be seen in Figure 3 is the switch over from investment in exclusively tracking PV to more and more non-tracking PV after 2043. The main difference between the tracking and non-tracking technologies (other than price) is that the tracking technologies have more favorable production profiles (i.e., more production during evenings and early mornings). Tracking solar requires somewhat less storage on average because the demand is better matched by the profile of that technology. This benefit compared with non-tracking PV is, however, offset in the later years of the model by the availability of inexpensive battery storage. The results show just how cost competitive tracking and non-tracking systems are in the model. Just small changes in the cost curves in this sensitivity run bring the absolute prices closer together and lead to a crossover in the optimum technology in the later years of the model. When this type of crossover will occur (or if it already has) in the actual PV market is not meant to be predicted by this model, but the result is interesting nonetheless. In reality, this behavior could be expected to happen because the balance of system costs (including tracking) will not likely decrease as quickly as solar cell costs will.

3.4. Sensitivity with Lower HCPV Cost

The lower HCPV cost sensitivity analysis reduces the cost curve of just one solar technology, High Concentration Photovoltaics (HCPV), by a constant factor (see Figure A2b in Appendix A.1) to agree with the Fraunhofer report's [27] costs while leaving the other technology costs at the levels from the base scenario. The results (Figure 4), showing large investments in HCPV, indicate that although HCPV is priced out of the market at current costs, the situation could swing in favor of HCPV given large, but still possible cost reductions compared to PV.

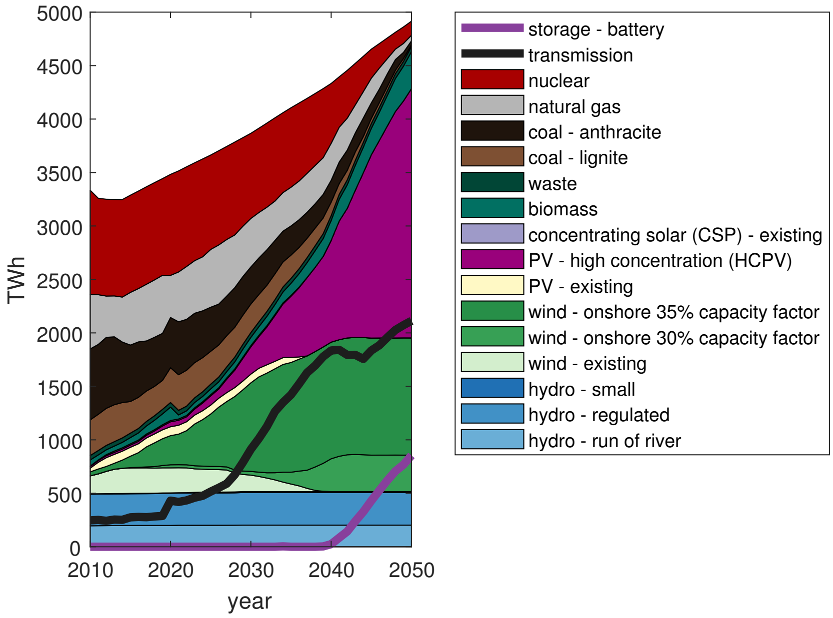
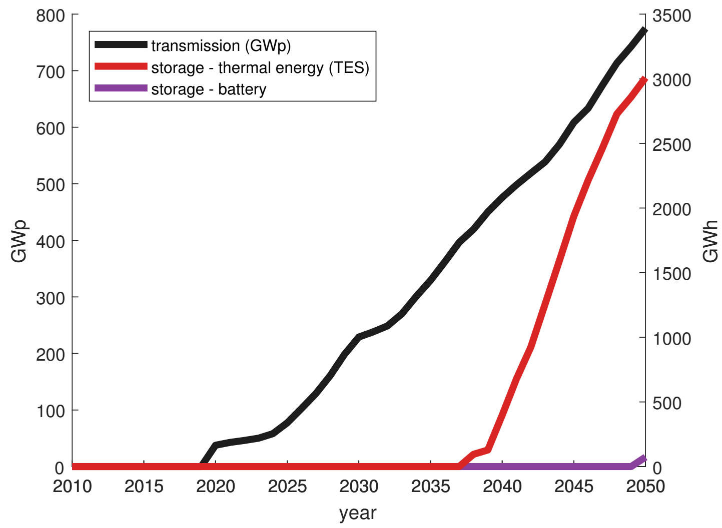


Figure 4. Electricity generated by generation type and year plus yearly electricity transmitted internationally and yearly energy transferred to storage in the lower HCPV cost scenario.

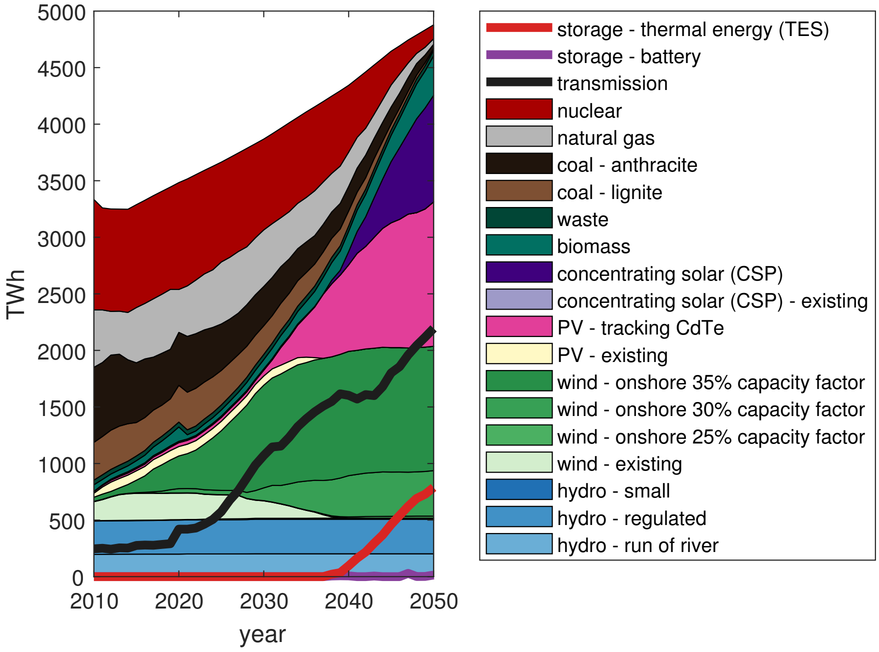
3.5. Sensitivity with Lower CSP Cost

The lower CSP cost sensitivity analysis reduces both the investment costs and operating and maintenance costs of CSP according to Kost et al. [27] (Figure A2c,d in Appendix A.1), while leaving the other technology costs at the levels from the base scenario. The most interesting result from the lower CSP cost scenario is that we see that storage investments shift almost completely from battery to thermal storage (Figure 5a,b). This is due to the fact that CSP technologies are allowed to be coupled with the less expensive thermal storage (instead of batteries), a combination that is less expensive than PV and batteries if the capital cost of CSP is low enough. In conclusion, CSP with thermal storage can be cost competitive in areas of high direct insolation (like those with installed capacity shown in Figure 5c) given significant, but not implausible cost reductions compared to PV with battery storage.

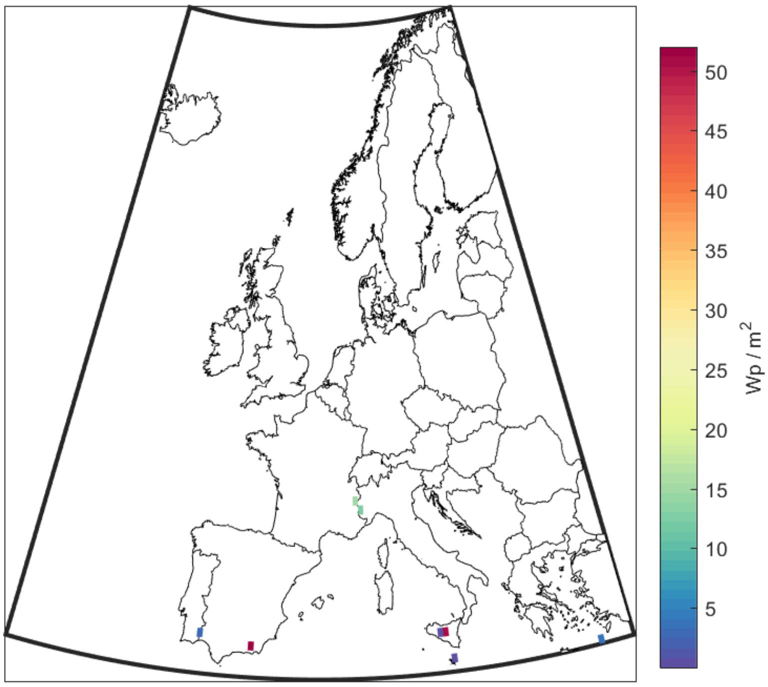


(a)

Figure 5. *Cont.*



(**b**)

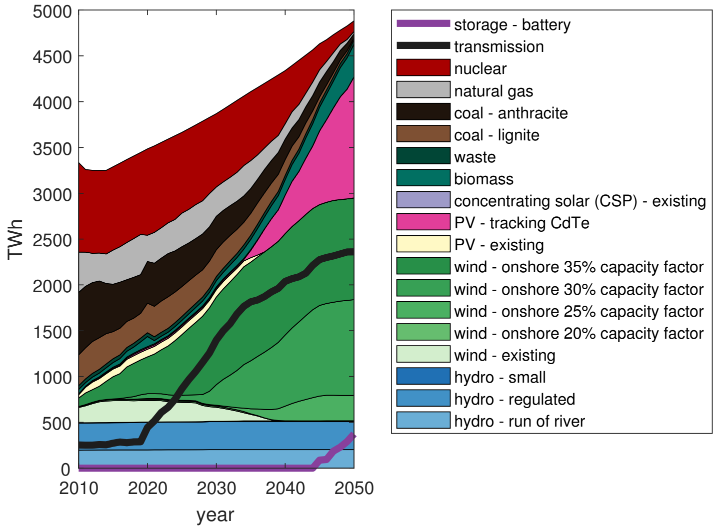


(**c**)

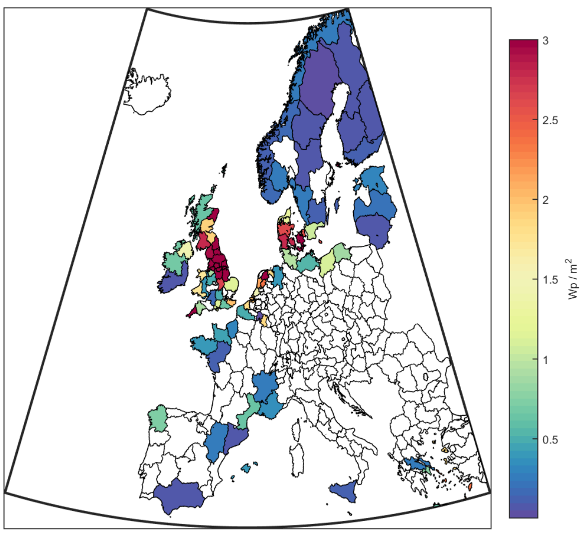
Figure 5. Model results for the lower CSP cost scenario including (**a**) the capacity of new transmission (GW_p) and storage (GWh) investments, (**b**) the electricity generated by generation type and year plus yearly electricity transmitted internationally and yearly energy transferred to storage, (**c**) the installed capacity of CSP. Note that the order of the legends for line and area plots corresponds to the order of the respective values in 2010 from top to bottom. Note also that the color of the regions/quadrants on map plots indicates the installed capacity density in the given region/quadrant where white signifies zero installations.

3.6. Sensitivity with Lower Wind Cost

Figure 6 shows the results for the lower wind cost sensitivity analysis. The cost curves for wind power (onshore and offshore) were decreased by a constant factor according to Kost et al. [27] (Figure A2e in Appendix A.1) while leaving the other technology costs at the levels from the base scenario. As with other runs that yield a larger fraction of wind power, Figure 6a shows that the amount of transmission investments increases significantly, while solar and battery investments as a result sink somewhat, as compared to the base case. The increased wind power investments can also be seen spread over a larger geographic region, especially in the Nordic countries, as shown on the map in Figure 6b.



(**a**)

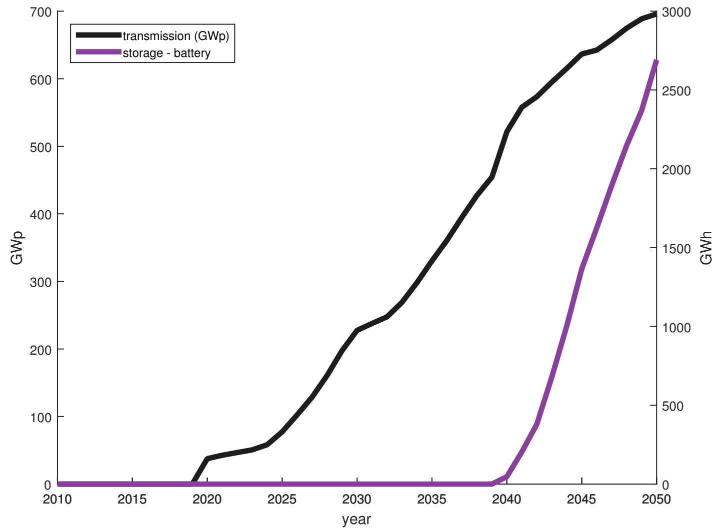


(**b**)

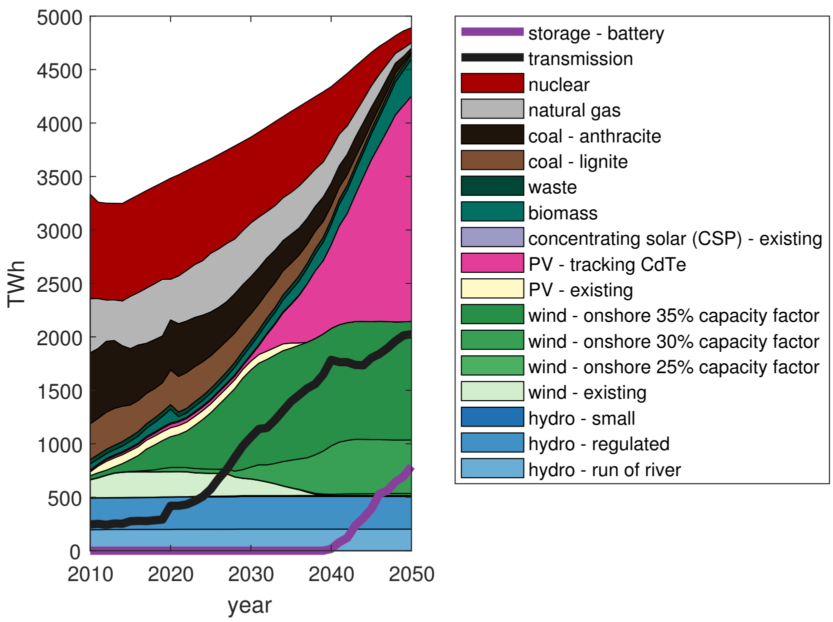
Figure 6. Model results for the lower wind cost scenario including (**a**) the electricity generated by generation type and year plus yearly electricity transmitted internationally and yearly energy transferred to storage, and (**b**) the installed capacity density of wind power. Note that the order of the legends for line and area plots corresponds to the order of the respective values in 2010 from top to bottom. Note also that the color of the regions/quadrants on map plots indicates the installed capacity density in the given region/quadrant where white signifies zero installations.

3.7. Sensitivity with Lower Storage Cost

The lower storage cost sensitivity scenario demonstrates the clear contrast between the coupling of solar and batteries vs. wind and transmission. In this sensitivity analysis, all costs of storage are decreased by a constant factor as shown in Figure A2f in Appendix A.1. The results (Figure 7a,b) show approximately 30% more battery investments (and a few years of earlier uptake) at the same time as 7% less transmission investments by the year 2050 as compared to the base scenario. This also is accompanied by an increased share of solar power investments relative to wind investments compared to the base scenario.



(**a**)

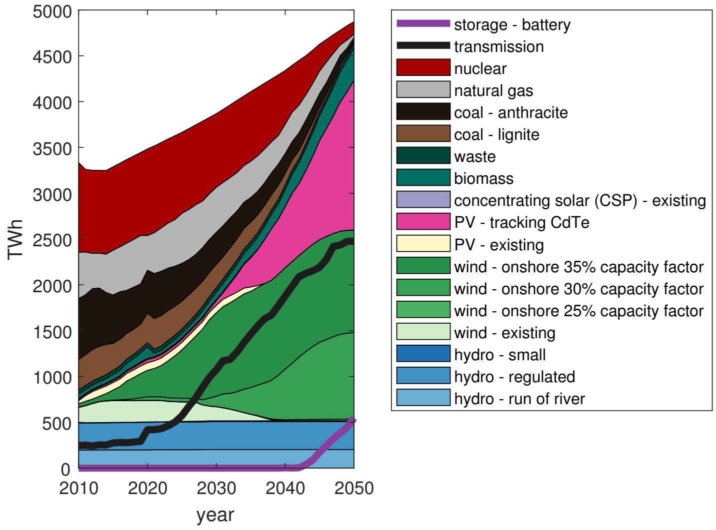


(**b**)

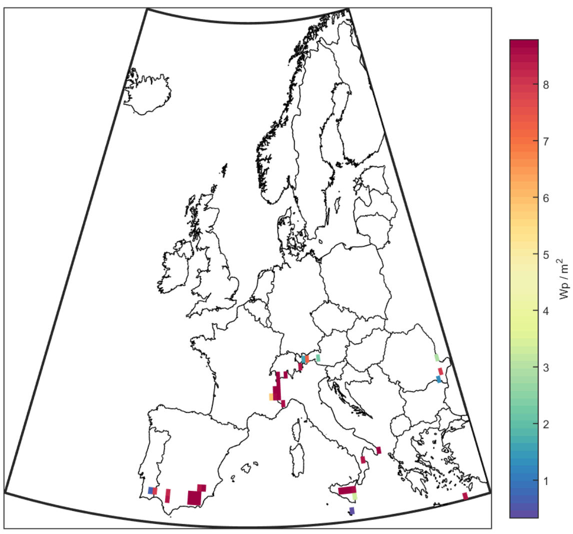
Figure 7. Model results for the lower storage cost scenario including (**a**) the capacity of new transmission (GW_p) and storage (GWh) investments, and (**b**) the electricity generated by generation type and year plus yearly electricity transmitted internationally and yearly energy transferred to storage. Note that the order of the legends for line and area plots corresponds to the order of the respective values in 2010 from top to bottom.

3.8. Sensitivity with Lower Allowed Installed Solar Density and Wind

The final two sensitivity analyses play with the idea of allowed spatial density for solar and wind technologies. In the lower allowed solar density scenario, a reduction by a factor of 10 (to slightly less than 9 W_p/m^2) in the allowed solar power density results in only slightly less (approximately 5%) solar power investments (Figure 8a) by 2050 compared to the base scenario, but at the same time, the solar power is, not surprisingly, more geographically spread out (Figure 8b). The fact that solar power installations are still relatively sparse on the map shows that the availability of suitable locations is not a very limiting factor for solar power.



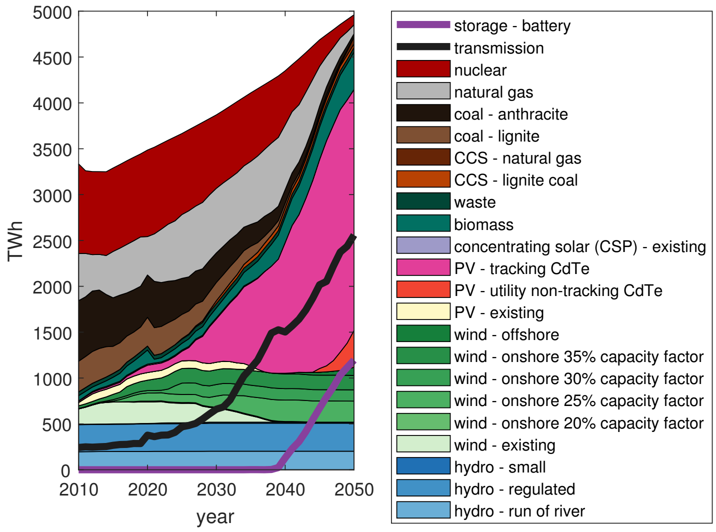
(**a**)



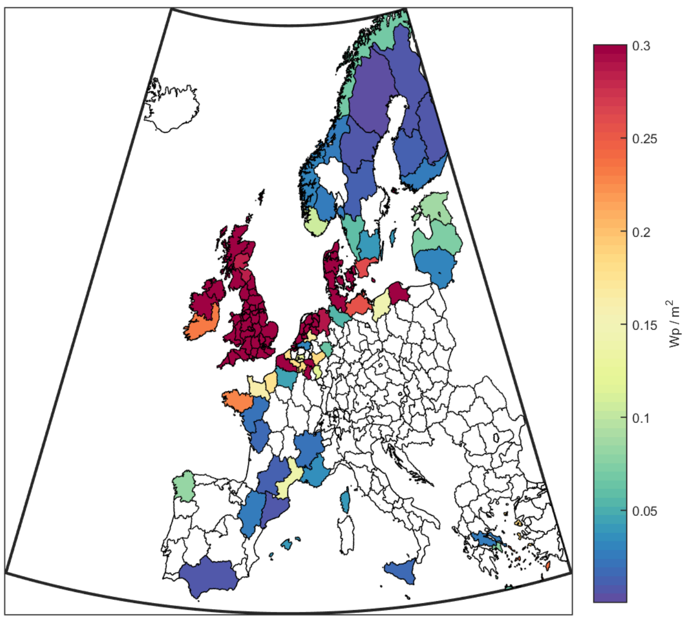
(**b**)

Figure 8. Model results for the lower allowed solar density scenario including (**a**) the electricity generated by generation type and year plus yearly electricity transmitted internationally and yearly energy transferred to storage, and (**b**) the installed capacity of solar PV. Note that the order of the legends for line and area plots corresponds to the order of the respective values in 2010 from top to bottom. Note also that the color of the regions/quadrants on map plots indicates the installed capacity density in the given region/quadrant where white signifies zero installations.

The lower allowed wind density scenario, however, shows a completely different result (Figure 9). Here, we can see that reducing the allowed wind density also by a factor of 10 (to 0.3 W_p/m^2) results in a severely reduced (approximately 70%) wind power investment (Figure 9a) by 2050 compared to the base case. Locations of sufficiently good wind resource are so saturated in fact (Figure 9b) that the model chooses offshore wind investments for the first time (Figure 9c). Although there is more than a doubling of the total electricity sent to storage compared to the base case, we also see in the lowered wind density scenarios an increased investment in transmission (25% more). This seems contrary to the other sensitivities, which generally correlate decreasing installed wind power capacity with decreasing transmission needs. The normal trend is broken because of the fact that wind power is being forced to spread out more (including offshore) than in all the other scenarios, and hence, the wind power placement is not as optimal with respect to load. Therefore, higher transmission capacity is needed even if the total capacity of wind power is significantly lower.

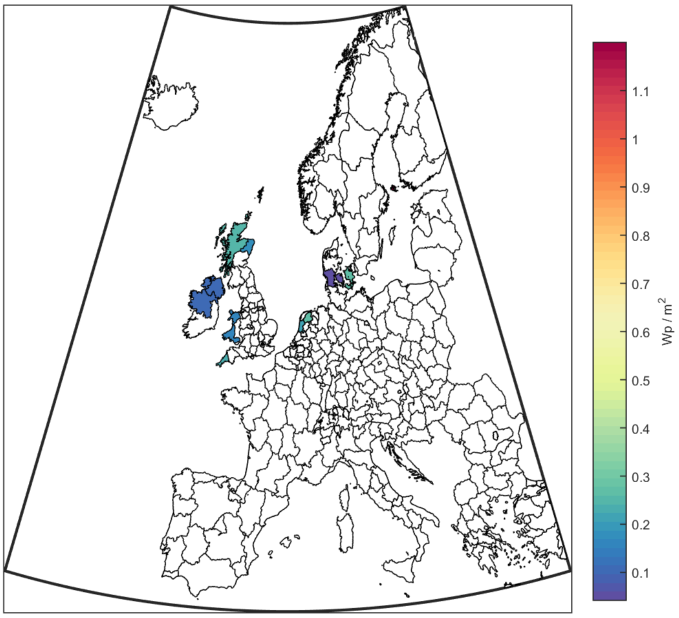


(**a**)



(**b**)

Figure 9. *Cont.*



(**c**)

Figure 9. Model results for the lower allowed wind density scenario including (**a**) the electricity generated by generation type and year plus yearly electricity transmitted internationally and yearly energy transferred to storage, (**b**) the installed capacity density of onshore wind power, and (**c**) the installed capacity density of offshore wind power represented in terms of capacity per land area of the region it is connected to. Note that the order of the legends for line and area plots corresponds to the order of the respective values in 2010 from top to bottom. Note also that the color of the regions/quadrants on map plots indicates the installed capacity density in the given region/quadrant where white signifies zero installations.

These last two sensitivity analyses show that economic wind power potential on the grid is much smaller if a high density of wind power is not allowed in the best sites in Europe, whereas solar power is not limited in this way.

4. Conclusions

In conclusion, running a carbon-constrained linear cost optimization (ELIN) model based on a European power plant database (Chalmers PP Db) combined with detailed modeling of solar technologies (DCS-CHP) in one base case and eight sensitivity analyses has shown several trends that likely will shape the future European electricity grid.

All runs show that solar will likely play a large role in terms of both energy produced and new installed capacity to the year 2050. This result holds true even with conservative price assumptions for solar and wind in the model that overestimate even today's market prices. Furthermore, as storage becomes less expensive and the total variable renewable penetration becomes higher than 50% on the grid, storage will play an increasing role on the grid, likely in the form of batteries coupled to PV. If, however, the prices for CSP decrease faster than PV, then perhaps PV and batteries will be joined with significant amounts of CSP with thermal storage.

Wind power also plays a significant role in all scenarios, and large investments in wind power lead to larger transmission investments (as high as 10-times current transmission levels) as compared to large investments in solar, which lead to larger storage investments (as much as 3.5 TWh electrical capacity). This result is significant and shows that the relationship between transmission, storage, wind power and solar power is complex and geographically dependent, both in terms of where load occurs in Europe and where the best wind and solar resources exist. What can be concluded from this analysis is that total wind power investments by 2050 depends on the maximum capacities of wind that are allowed to be installed in the windiest onshore regions. Wind power density limitations (due to conflicts over wind farm siting, etc.) on the windiest sites would severely constrain the economic potential of wind power as a whole and could lead to offshore wind becoming relevant approaching 2050.

Solar power, however, has a much greater resource potential than wind, and limiting the allowed density at the best sites does not severely limit the installed capacity. In fact, if net metering policies were implemented giving solar PV in the built environment an economic advantage reflecting the fact that it can directly offset consumer load on-site (as prosumers), these results show that the potential for solar PV could reach 50% of total electricity production by 2050. The results show that such a large solar PV penetration could occur even without net metering based on current cost trajectories of PV, but in such a scenario, large PV power plants would be more common than distributed PV. It should be noted, however, that the feasibility of such high penetration levels of solar power cannot be fully assessed considering the limited time resolution of the model used here.

A summary of the total solar and wind electricity production in 2050 as a share of total production for the base case and the eight sensitivity analysis results is shown in Figure 10. It is interesting to note that solar plays a large role in all scenarios by the year 2050, with the total share varying between 31 and 61 percent of all production. Wind share varies between 12 and 50 percent for all runs, whereas the sum of wind and solar is relatively constant at approximately 73–76 percent of total production in all scenarios.

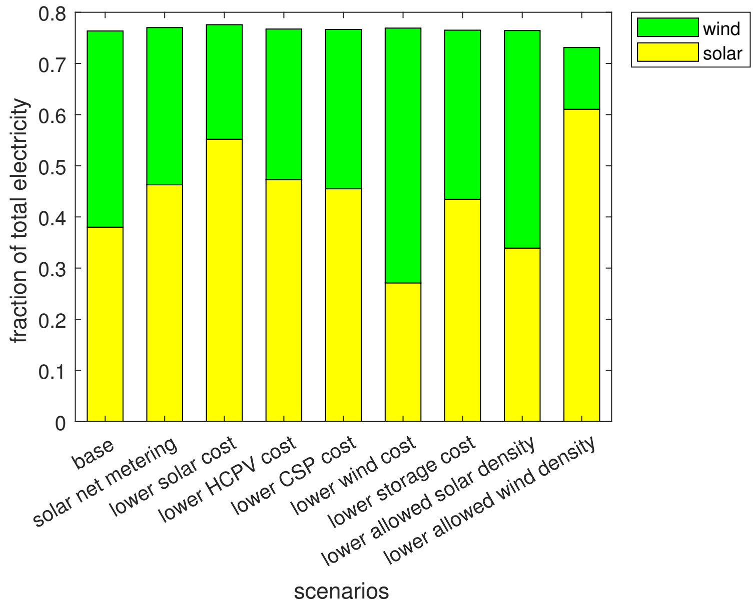


Figure 10. Solar and wind technologies' share of total electricity production (energy) in 2050 for the base case and sensitivity runs.

The fact that neither the base case nor any sensitivity resulted in investments in CCS or nuclear technologies (despite optimistic cost assumptions) lends support to the idea that coal and nuclear technologies can and should be phased out of the electricity supply [28,29] for both environmental and economic reasons.

Additionally, since this analysis was completed, a new version of the IEA World Energy Outlook report has been released. The strong trends in decreasing costs for solar PV and offshore wind shown in this and other reports recently strengthen the conclusions of this article in regards to the role of variable renewables in the future electricity grid.

Further analysis and model development is needed, however, to be able to better analyze the time-dependent nature of variable renewables and storage and more exactly specify the magnitude of transmission, storage and/or peaking plants that would be required on the regional level to keep the grid balanced at all times. For example, in future work, the modeling methodology could consider an hourly time resolution for many more individual hours to better reflect a power balance comparable with the resolution of market clearance. This could be done by using representative days to limit the number of time steps in the calculations. Such a time resolution would additionally enable short-term dynamics to influence the long-term investment decisions. Representative days have, however, implications for evaluating the value of storage, which need a chronological timeline to show the full value of storage. Such compromises are made with all energy system models at this scale to make them solvable.

Supplementary Materials: The following are available online at www.mdpi.com/1996-1073/10/12/2080/s1.

Acknowledgments: The authors would like to thank the Pathways to Sustainable European Energy Systems for providing funding for this project.

Author Contributions: Research design, analysis, and reporting in this study was completed by Zack Norwood, Joel Goop, and Mikael Odenberger. Simulations were run by Zack Norwood and Joel Goop.

Conflicts of Interest: The authors declare no conflict of interest.

Appendix A

Appendix A.1. Technology Input Data

Table A1. Base input data and assumptions for new thermal electricity generation technologies available for investment in the ELIN model. Investment costs come from [22]. Assumptions regarding lifetimes are based on [30].

Generation Technology	Technical Lifetime (years)	Costs		Efficiency (%)	Annual Availability (%)
		Investment (€/kW$_e$)	Fixed O&M (€/kW$_e$, year)		
Nuclear	60	5148	154.4	39–42	85
Anthracite					
Condensing	40	1560	33.5	47–55	85
CHP [a]	40	1560	33.5	35–45	85
BP [b]	40	1560	33.5	81–84	85
Lignite					
Condensing	40	1560	33.5	46–56	85
CHP [a]	40	1560	33.5	35–45	85
BP [b]	40	1560	33.5	81–84	85
Natural gas					
CCGT [c]	30	780	19.5	60–70	85
CHP [a]	30	1014	30.4	48–57	85
GT [d]	30	390	15.6	35–45	85
BP [b]	30	1014	30.4	81–84	85
Biomass					
Condensing	40	1856	64.7	40–49	85
CHP [a]	40	3151	118.6	29–39	85
BP [a]	40	3151	118.6	81–84	85
Waste					
CHP [a]	40	6630	251.9	16–21	85

[a] Combined heat and power; [b] industrial back-pressure (replacement of existing capacity only); [c] combined cycle gas turbine; [d] gas turbine.

Table A2. Base input data and assumptions for thermal electricity generation technologies with carbon capture and storage (CCS) available for investment in the ELIN model. Investment costs come from [22]. Technical lifetimes are assumed to be 40 years for all CCS technologies (based on the assumptions in [30]).

Generation Technology	Costs		Efficiency (%)	Annual Availability (%)	Capture Efficiency (%)
	Investment (€/kW$_e$)	Fixed O&M (€/kW$_e$, year)			
Anthracite	3003	90.5	35–43	85	87.7
Lignite	3003	90.5	35–43	85	88.9
Natural gas	1800	35.1	46–53	85	88.5
Biomass co-fire [a]					
Anthracite	3463	107.6	34–41	85	87.7
Lignite	3463	107.6	34–41	85	88.9

[a] Biomass fraction is assumed to be 10%.

Table A3. Base input data and assumptions for variable renewable electricity generation technologies available for investment in the ELIN model. Investment costs come from [22], and the cost curves used in the model are fitted from these data. Technical lifetimes are assumed to be 25 years for all variable renewable technologies (based on the assumptions in [30]).

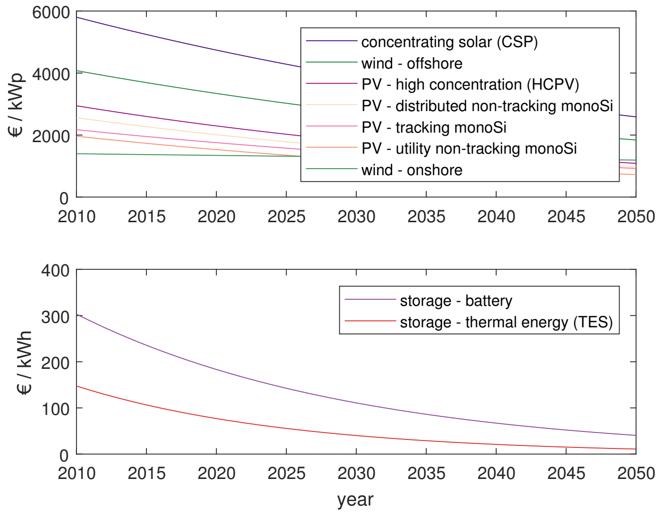
Generation Technology	Costs 2012		Costs 2020		Costs 2050	
	Investment (€/kW$_e$)	Fixed O&M (€/kW$_e$, year)	Investment (€/kW$_e$)	Fixed O&M (€/kW$_e$, year)	Investment (€/kW$_e$)	Fixed O&M (€/kW$_e$, year)
Wind power						
Onshore	1386	35.5	1343	34.1	1192	29.5
Offshore	3918	136.9	3341	116.9	1838	64.6
Solar power [a]						
Non-concentrating PV [b]						
Building	2439	25.2	2011	24.2	976	20.6
Utility	1867	19.2	1529	18.4	724	15.7
Tracking	2081	21.5	1754	21.1	923	19.7
HCPV [c], tracking	2800	28.8	2294	27.6	1085	23.5
CSP [d], tracking	5570	222.8	4739	189.5	2586	103.2

[a] Investment costs are given per kW$_p$; [b] including mono-crystalline Silicon (mono-Si), cadmium telluride (CdTe) and copper indium gallium selenide (CIGS); [c] high concentration photovoltaics; [d] concentrating solar power, storage costs not included.

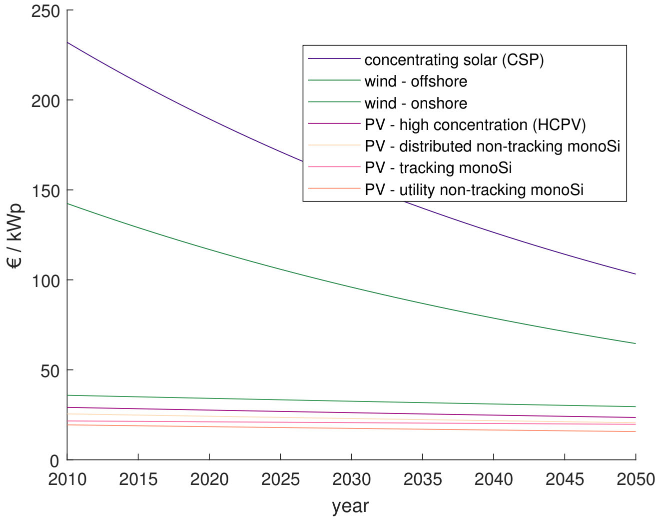
Table A4. Base input data and assumptions for storage technologies available for investment in the ELIN model. The cost curves used in the model are fitted from these data.

Storage Technology	Technical Lifetime (years)	Investment Cost (€/kWh)			Round-Trip Efficiency (%)
		2012	2020	2050	
TES [a]	25	129	77	11	0.95
Battery	10	274	183	41	0.9

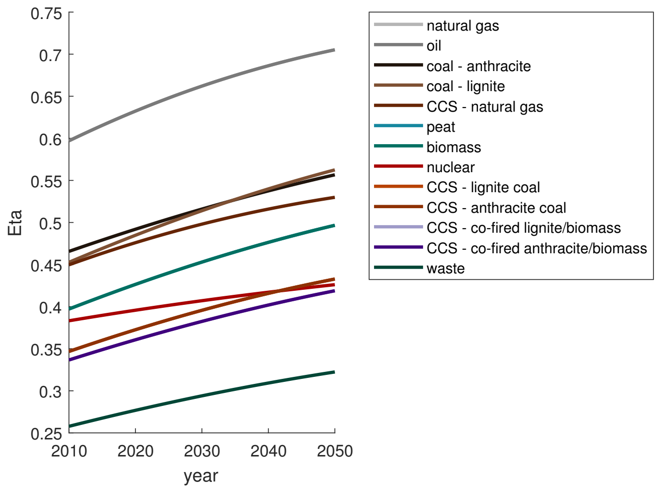
[a] Thermal energy storage (TES), installed with concentrating solar power (CSP).



(**a**)

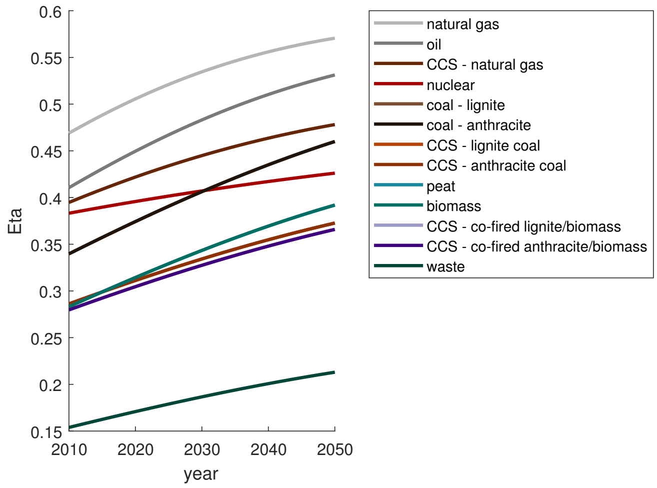


(**b**)

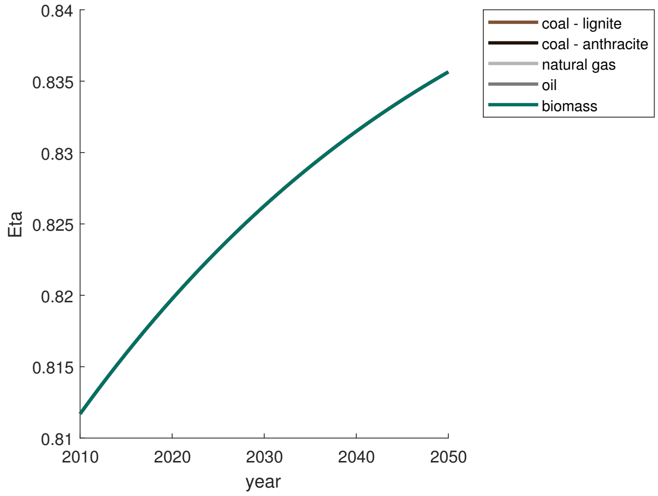


(**c**)

Figure A1. *Cont.*

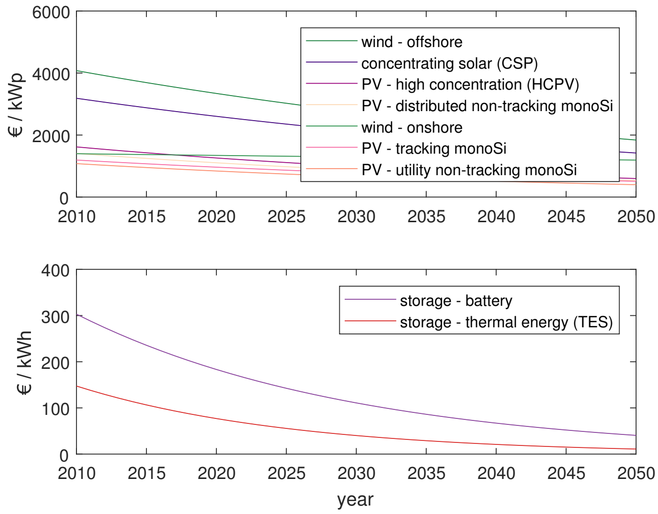


(**d**)

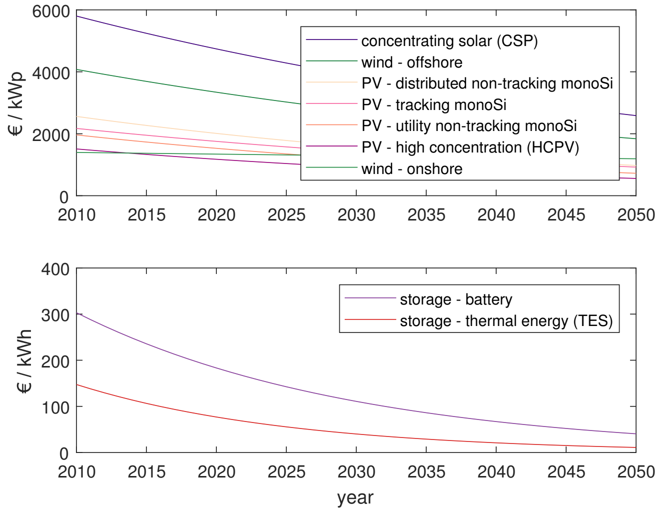


(**e**)

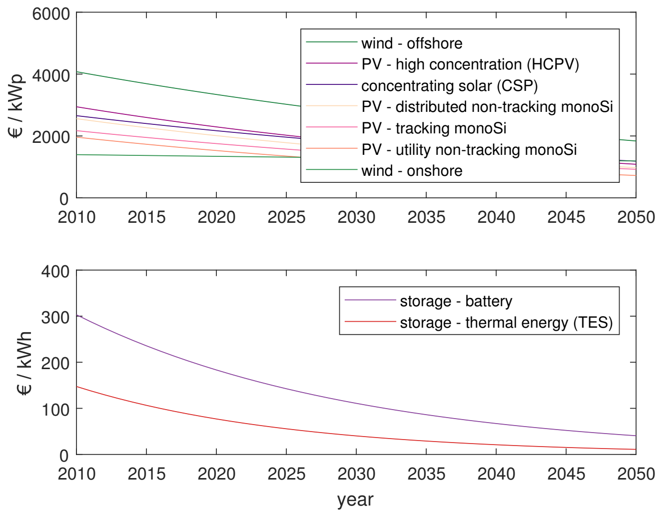
Figure A1. Technology assumptions include: (**a**) The investment costs for all solar and wind electricity generation technologies (upper) and storage technologies (lower) in the base scenario. (**b**) The operation and maintenance costs for all solar and wind electricity generation technologies in the base scenario. (**c**) The expected improvements in cycle efficiency (eta) over time for the condensing power plant technologies in all scenarios. Note that in this subfigure the curves for natural gas and oil technologies are indistinguishable, as are the curves for peat and biomass technologies and CCS technologies with lignite and anthracite, respectively. (**d**) The expected improvements in cycle efficiency (eta) over time for the CHP power plant technologies in all scenarios. Note that in this subfigure that the curves for anthracite and lignite coal technologies are indistinguishable, as are the curves for peat and biomass technologies, respectively. (**e**) The expected improvements in cycle efficiency (eta) over time for the back-pressure power plant technologies in all scenarios. Note in this subfigure that the curves for conventional coal, natural gas, oil and biomass technologies are indistinguishable. Note furthermore that back pressure plants are disallowed for all other technologies.



(**a**)

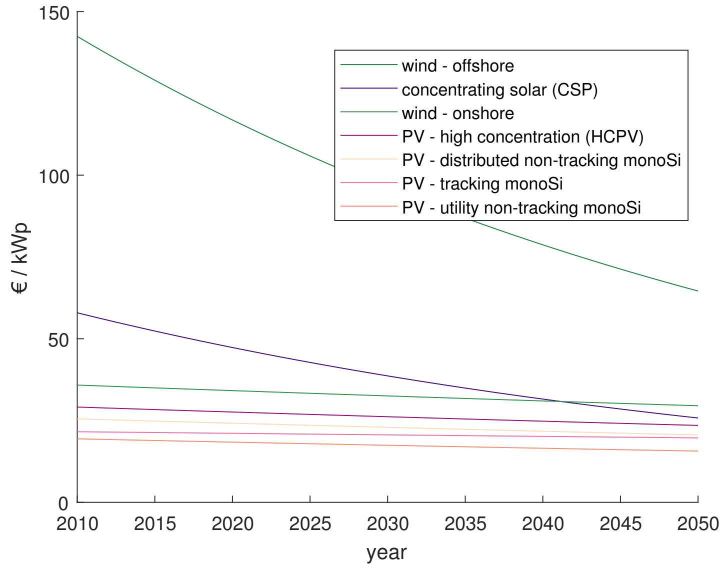


(**b**)

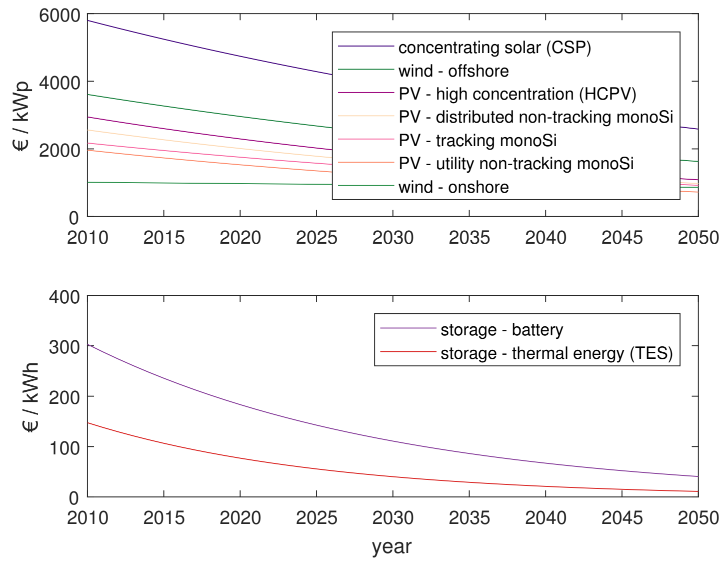


(**c**)

Figure A2. *Cont.*

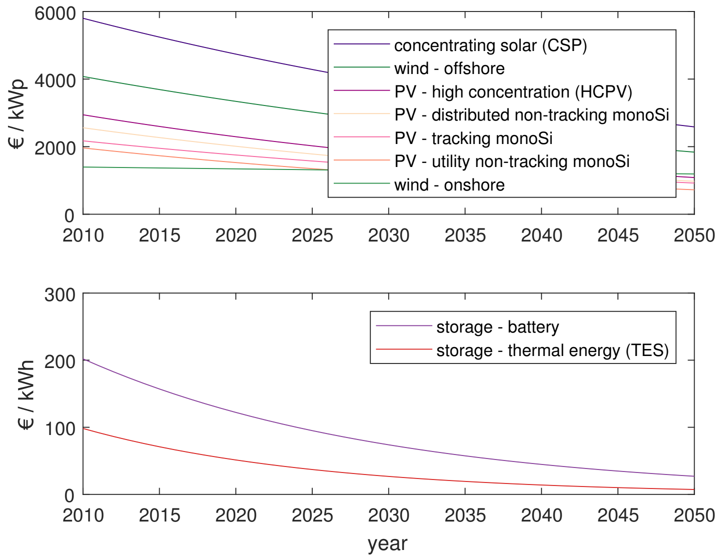


(**d**)



(**e**)

Figure A2. *Cont.*



(**f**)

Figure A2. Cost assumptions in the sensitivity cases include: (**a**) The investment costs for all solar and wind electricity generation technologies (upper) and storage technologies (lower) in the lower solar cost scenario. Solar costs are curve fitted from [27] in this scenario. (**b**) The investment costs for all solar and wind electricity generation technologies (upper) and storage technologies (lower) in the lower HCPV cost scenario. HCPV costs are curve fitted from [27] in this scenario. (**c**) The investment costs for all solar and wind electricity generation technologies (upper) and storage technologies (lower) in the lower CSP cost scenario. CSP costs are curve fitted from [27] in this scenario. (**d**) The operations and maintenance costs for all renewable electricity generation technologies in the lower CSP cost scenario. CSP costs are curve fitted from [27] in this scenario. (**e**) The investment costs for all solar and wind electricity generation technologies (upper) and storage technologies (lower) in the lower wind cost scenario. Wind costs are curve fitted from [27] in this scenario. (**f**) The investment costs for all solar and wind electricity generation technologies (upper) and storage technologies (lower) in the lower storage cost scenario.

Appendix A.2. Fuel Supply Curves

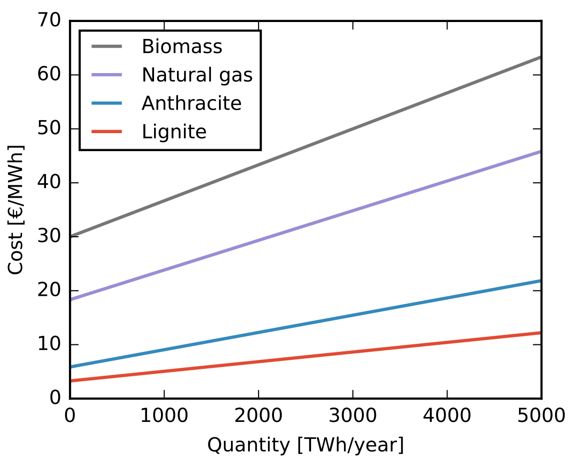


Figure A3. Supply curves, i.e., fuel cost as a function of total quantity consumed annually in the model, for lignite, coal, gas and biomass. Note that for biomass, this only refers to internationally-traded fuel. Each country also has a supply of local biomass resources.

References

1. Pietzcker, R.C.; Stetter, D.; Manger, S.; Luderer, G. Using the sun to decarbonize the power sector: The economic potential of photovoltaics and concentrating solar power. *Appl. Energy* **2014**, *135*, 704–720.
2. Fürsch, M.; Hagspiel, S.; Jägemann, C.; Nagl, S.; Lindenberger, D.; Tröster, E. The role of grid extensions in a cost-efficient transformation of the European electricity system until 2050. *Appl. Energy* **2013**, *104*, 642–652.
3. Berrill, P.; Arvesen, A.; Scholz, Y.; Gils, H.C.; Hertwich, E.G. Environmental impacts of high penetration renewable energy scenarios for Europe. *Environ. Res. Lett.* **2016**, *11*, 014012, doi:10.1088/1748-9326/11/1/014012.
4. Mileva, A.; Nelson, J.H.; Johnston, J.; Kammen, D.M. Sunshot solar power reduces costs and uncertainty in future low-carbon electricity systems. *Environ. Sci. Technol.* **2013**, *47*, 9053–9060.
5. Zhang, Y.; Smith, S.J.; Kyle, G.P.; Stackhouse, P.W. Modeling the potential for thermal concentrating solar power technologies. *Energy Policy* **2010**, *38*, 7884–7897.
6. Viebahn, P.; Lechon, Y.; Trieb, F. The potential role of concentrated solar power (CSP) in Africa and Europe—A dynamic assessment of technology development, cost development and life cycle inventories until 2050. *Energy Policy* **2011**, *39*, 4420–4430.
7. Peters, M.; Schmidt, T.S.; Wiederkehr, D.; Schneider, M. Shedding light on solar technologies—A techno-economic assessment and its policy implications. *Energy Policy* **2011**, *39*, 6422–6439.
8. Denholm, P.; Margolis, R.M. Evaluating the limits of solar photovoltaics (PV) in electric power systems utilizing energy storage and other enabling technologies. *Energy Policy* **2007**, *35*, 4424–4433.
9. Kjärstad, J.; Johnsson, F. The European power plant infrastructure—Presentation of the Chalmers energy infrastructure database with applications. *Energy Policy* **2007**, *35*, 3643–3664.
10. Norwood, Z.; Kammen, D. Life cycle analysis of distributed concentrating solar combined heat and power: Economics, global warming potential and water. *Environ. Res. Lett.* **2012**, *7*, 044016, doi:10.1088/1748-9326/7/4/044016.
11. Norwood, Z.; Nyholm, E.; Otanicar, T.; Johnsson, F. A Geospatial Comparison of Distributed Solar Heat and Power in Europe and the U.S. *PLoS ONE* **2014**, *9*, e112442.
12. Odenberger, M.; Unger, T.; Johnsson, F. Pathways for the North European electricity supply. *Energy Policy* **2009**, *37*, 1660–1677.
13. Göransson, L.; Goop, J.; Unger, T.; Odenberger, M.; Johnsson, F. Linkages between demand-side management and congestion in the European electricity transmission system. *Energy* **2014**, *69*, 860–872.
14. Eurostat. Electricity Prices Components for Domestic Consumers, from 2007 Onwards—Annual Data [nrg_pc_204_c]. 2015. Available online: http://appsso.eurostat.ec.europa.eu/nui/show.do?dataset=nrg_pc_204_c&lang=en (accessed on 10 September 2015).
15. Eurostat. Electricity Prices for Domestic Consumers, from 2007 Onwards—Bi-Annual Data [nrg_pc_204]. 2015. Available online: http://appsso.eurostat.ec.europa.eu/nui/show.do?dataset=nrg_pc_204&lang=en (accessed on 10 September 2015).
16. Dee, D.P.; Uppala, S.M.; Simmons, A.J.; Berrisford, P.; Poli, P.; Kobayashi, S.; Andrae, U.; Balmaseda, M.A.; Balsamo, G.; Bauer, P.; et al. The ERA-Interim reanalysis: Configuration and performance of the data assimilation system. *Q. J. R. Meteorol. Soc.* **2011**, *137*, 553–597.
17. European Centre for Medium-Range Weather Forecasts (ECMWF). ERA-Interim. 2016. Available online: http://www.ecmwf.int/en/research/climate-reanalysis/era-interim. (accessed on 2 September 2016).
18. Nilsson, K.; Unger, T. *Bedömning av en Europeisk Vindkraftpotential med GIS-Analys*; Project Report; Profu AB: Mölndal, Sweden, 2014. (In Swedish)
19. European Commission. *Energy Roadmap 2050*; Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions, COM(2011) 885 Final; European Commission: Brussels, Belgium, 2011.
20. Eurelectric. Power Choices Reloaded: Europe's Lost Decade? 2013. Available online: http://www.eurelectric.org/media/79057/power_choices_2013_final-2013-030-0353-01-e.pdf (accessed on 31 August 2016).
21. European Commission. National Action Plans. 2015. Available online: https://ec.europa.eu/energy/en/topics/renewable-energy/national-action-plans (accessed on 10 September 2015).

22. International Energy Agency. WEIO 2014—Power Generation Investment Assumptions. 2014. Available online: http://www.worldenergyoutlook.org/media/weowebsite/2014/weio/WEIO2014PGAssumptions.xlsx (accessed on 10 September 2015).
23. Nykvist, B.; Nilsson, M. Rapidly falling costs of battery packs for electric vehicles. *Nat. Clim. Chang.* **2015**, *5*, 329–332.
24. European Solar Thermal Electricity Association. SET-Plan—Solar Thermal Electricity European Industrial Initiative (STE-EII). 2013. Available online: https://setis.ec.europa.eu/system/files/Solar%20CSP%20EII%202013-2015%20IP_0.pdf (accessed on 10 September 2015).
25. GTM Research. Solar Balance-of-System: To Track or Not to Track, Part I. 2012. Available online: http://www.greentechmedia.com/articles/read/Solar-Balance-of-System-To-Track-or-Not-to-Track-Part-I (accessed on 10 September 2015).
26. U.S. Energy Information Administration. Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2017. Technical Report. 2017. Available online: https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf (accessed on 6 September 2017).
27. Kost, C.; Mayer, J.N.; Thomsen, J.; Hartmann, N.; Senkpiel, C.; Philipps, S.; Nold, S.; Lude, S.; Saad, N.; Schlegl, T. Levelized Cost of Electricity Renewable Energy Technologies. 2013. Available online: https://www.ise.fraunhofer.de/en/publications/veroeffentlichungen-pdf-dateien-en/studien-und-konzeptpapiere/study-levelized-cost-of-electricity-renewable-energies.pdf (accessed on 10 September 2015).
28. Hansen, J.; Sato, M.; Kharecha, P.; Beerling, D.; Berner, R.; Masson-Delmotte, V.; Pagani, M.; Raymo, M.; Royer, D.L.; Zachos, J.C. Target atmospheric CO_2: Where should humanity aim? *arXiv* **2008**, arXiv:0804.1126.
29. Magné, B.; Chateau, J.; Dellink, R. Global implications of joint fossil fuel subsidy reform and nuclear phase-out: An economic analysis. *Clim. Chang.* **2014**, *123*, 677–690.
30. International Energy Agency; Nuclear Energy Agency. Projected Costs of Generating Electricity—2015 Edition. Technical Report NEA No. 7057. 2015. Available online: https://www.iea.org/publications/freepublications/publication/projected-costs-of-generating-electricity-2015-edition.html (accessed on 6 September 2017).