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Electric Vehicles as Flexibility Management Strategy for the Electricity System—A Comparison between Different Regions of Europe

Maria Taljegard *, Lisa Göransson, Mikael Odenberger and Filip Johnsson

Department of Space, Earth and Environment, Chalmers University of Technology, 412 96 Gothenburg, Sweden
* Correspondence: maria.taljegard@chalmers.se; Tel.: +46-31-772-1453

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Abstract: This study considers whether electric vehicles (EVs) can be exploited as a flexibility management strategy to stimulate investments in and operation of renewable electricity under stringent CO_2 constraints in four regions with different conditions for renewable electricity (Sweden, Germany, the UK, and Spain). The study applies a cost-minimisation investment model and an electricity dispatch model of the European electricity system, assuming three types of charging strategies for EVs. The results show that vehicle-to-grid (V2G), i.e., the possibility to discharging the EV batteries back to grid, facilitates an increase in investments and generation from solar photovoltaics (PVs) compare to the scenario without EVs, in all regions except Sweden. Without the possibility to store electricity in EV batteries across different days, which is a technical limitation of this type of model, EVs increase the share of wind power by only a few percentage points in Sweden, even if Sweden is a region with good conditions for wind power. Full electrification of the road transport sector, including also dynamic power transfer for trucks and buses, would decrease the need for investments in peak power in all four regions by at least 50%, as compared to a scenario without EVs or with uncontrolled charging of EVs, provided that an optimal charging strategy and V2G are implemented for the passenger vehicles.

Keywords: energy system modelling; variability management; storage; vehicle-to-grid; smart charging; batteries

1. Introduction

Electric vehicles (EVs) have been proposed as an option to reduce CO_2 emissions from the European road transportation sector [1]. Concomitant with this, it is expected that the electricity system will undergo change towards a higher penetration level of renewable electricity sources, such as solar and wind power [2]. Electrification of the road transport sector, in combination with more variable renewable electricity (VRE) production, may increase or decrease the need for more flexibility strategies from the electricity system compared to the present day.

Flexibility strategies helps the system to balance electricity generation with consumption. Such a strategy could for example be in the form of different types of storage, demand-side-management, and trade with neighboring regions. Solar power and wind power require different types of flexibility from the electricity system, since the fluctuations in their electricity generation differ in characteristics. Solar power needs mainly storage for 6–12 h (to store electricity between day-time and night-time) while wind power exhibits fluctuations in electricity generation over a time period up to several days, and for some regions there is also a need to store large volumes of electricity between seasons [3].

Previous studies have shown that batteries are the preferred option for intra-day storage spanning a couple of hours [3]. However, as wind power entails fluctuations in electricity production that span several days or seasons, these fluctuations might best be handled with long-term hydrogen storage or hydro power rather than investments in batteries [3]. However, the total available battery capacity in the EV fleet in, for example, the central part of Sweden with 60% EVs, will be in the range of 17–60 GW, depending on the specific hour of the year. This can be compared with the current maximum electricity demand in central Sweden of 18 GW [4]. Studies of the driving patterns of passenger cars show that even with relatively low-capacity EV batteries, large parts of the EV fleet do not need to recharge their batteries every day in order to manage the daily driving demand [5]. Therefore, it is of interest to investigate the use of EVs as a flexibility management strategy for both solar and wind power.

Previous studies on the use of EVs as a flexibility management strategy show that uncontrolled charging of EVs (i.e., the EVs are fully charged directly while parked after a trip) might increase the need for more flexibility in the system in terms of larger investments in peak electricity generation [6–8]. This might increase the electricity system cost and might also increase the CO_2 emissions from the system [6]. However, if the integration of EVs includes a controlled charging strategy, the new EV demand could confer benefits on the electricity system in terms of system flexibility, e.g., demand response services in the form of strategic charging and, possibly, discharge back to the grid (i.e., vehicle-to-grid; V2G) according to what is optimal for the electricity system.

Several studies have used linear optimisation investment models or dispatch models to investigate the impacts of passenger EVs on, for example, the investments made in and dispatch of electricity generation technologies and the peak power demand. In some of these electricity system modelling studies, passenger EVs have been proposed as a way to facilitate the accommodation of more intermittent electricity generation in the electricity system. For example, Hedegaard et al. [9] showed that controlled charging (i.e., delaying the charging time to avoid increasing the evening peaks) and discharging a fraction of the EV batteries, facilitate a significant increase in wind power investments in Northern European countries, assuming that the flexibility of EVs is complemented by economic support for renewable energy technologies. However, the outcomes varied significantly from country to country, and the model contained no possibilities for power transmission between countries. The lack of transmission might enhance the need for flexibility management in the system described in the study of Hedegaard et al. [9].

Studies that have employed multi-regional energy models, for example those of Hadley and Tsvetkova [10] and Verzijlbergh et al. [11], are limited to dispatch models and do not include the impact of EV utilisation on the long-term investment decisions regarding power generation capacity. Taljegard et al. [12] used an optimisation model that included investments in both capacity and transmission between regions. They concluded that EVs with V2G could facilitate few percent increase in share of electricity from wind power, and that in the modelled region (Scandinavia and Germany) there was a decrease in investments in solar power [12]. In a system with V2G from EVs, i.e., a system including storage possibilities, solar power was outcompeted by V2G, since V2G could cover these peaks at a lower cost.

This study investigates if EVs can act as a flexibility management strategy to stimulate investments in and the operation of renewable electricity under stringent CO_2 constraints in four regions with different physical conditions for VRE, i.e., Sweden, Germany, UK, and Spain. The following parameters of the electricity system are analysed, to compare the need for flexibility of EVs across the four regions: (i) investments in new electricity generation capacity up to Year 2050; (ii) dispatch of the electricity generation for a specific year (Year 2030); (iii) curtailment of electricity; (iv) total system cost; and (v) CO_2 emissions from the electricity system. The present work applies a scenario analysis that includes static charging of passenger EVs, as well as some scenarios that also comprise dynamic charging with an electric road system (ERS) for trucks, buses and for passenger EVs undertaking trips that cannot be completed using only the battery.

The study uses a cost-optimisation investment model (ELIN) and a cost-minimising electricity dispatch model (EPOD) of the European electricity systems, including transmission between regions. The present study adds to the previous work by: (i) investigating the impacts of EVs both on investment decisions related to new power capacity and the dispatch of the power plants, considering an electricity system with the geographical scope of several inter-connected countries in Europe with different conditions for renewable energy; (ii) applying individual driving patterns from GPS information from 426 passenger vehicles for characterizing the vehicle fleet; and (iii) incorporating the electrification of several vehicle types (passenger cars, trucks and buses) through static charging and ERS.

This work addresses the following research questions:

- What is the system benefit associated with distributing EV charging in time (i.e., load shifting) so as to minimise costs in the electricity system?
- What are the system benefits if EVs are allowed to discharge their batteries to the grid (V2G) and EV batteries are used to provide storage for the electricity system?

2. Methods

2.1. Model Description

We apply a cost-optimisation investment model (ELIN) and a cost-minimising electricity dispatch model (EPOD) of the European electricity systems, including the electricity demand from EVs. Figure 1 shows a schematic of the modelling package applied in this work and Table 1 shows the technologies and fuels that the model can invest in. The two models have previously been used to study the transformation of the European electricity system to meet European policy targets for CO_2 emissions (for a description of the original models, see Odenberger et al. [13] and Unger et al. [14], and for refinements of the model package, see Göransson et al. [15], Nyholm et al. [16] and Taljegard et al. [12]).

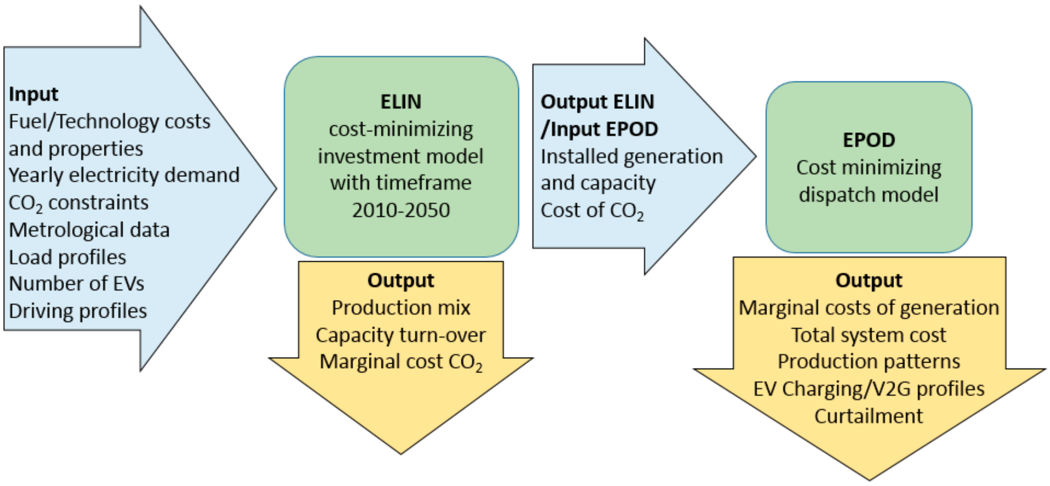

Figure 1. Schematic of the modelling package applied in this work.

Table 1. Technologies and fuels included in the modelling package.

Thermal Technologies	Condensing power plants with and without carbon capture, combined heat and power (CHP) and gas turbines
Renewable Technologies (excluding biomass)	On-shore and off-shore wind power, solar PV, and hydro power
Fuels	Biomass, biogas, coal, gas, lignite, uranium, waste

The investment model is a cost-minimisation model that is designed to analyse transformation of the European electricity system by making investment decisions in new electricity generation capacity until Year 2050 with an intra-annual time resolution of 20 representative days (i.e., 480 time-steps) per year. The dispatch model applies descriptions of the power system, fuel, CO_2 prices, and transmission lines, as obtained from the investment model for a specific year (in the present work, Year 2030), and performs optimisation to find the least-cost hourly dispatch of the system, i.e., full year with 8784 time-steps in a year.

The investment model minimises both the total investment and running cost, while the dispatch model minimises the total running cost of the electricity generation system. Equations (1) and (2) descripe the objective functions of the investment model (ELIN) and the dispatch model (EPOD), respectively. The demand in ELIN and EPOD (i.e., Year 2030 for the EPOD model) must then be satisfied for each year, time-step and region, which implies the constraint seen in Equation (3). A full mathematical description of the EPOD dispatch model is described in Goop et al. [17].

$$MIN\ C_{tot} = \Sigma_{i\in I}\Sigma_{p\in P}\Sigma_{y\in Y}\Sigma_{t\in T}(c^{run}_{i,p,y,t}\cdot g_{i,p,y,t}) + \Sigma_{i\in I}\Sigma_{p\in P}\Sigma_{y\in Y}(C^{inv}_{i,p,y}i_{i,p,y} + C^{fix}_{i,p,y}x_{i,p,y}) \quad (1)$$

$$MIN\ C_{tot} = \Sigma_{i\in I}\Sigma_{p\in P}\Sigma_{t\in T}(c^{run}_{i,p,t}\cdot g_{i,p,t} + c^{cycl}_{i,p,t}) + \Sigma_{i\in I}\Sigma_{p\in P}C^{fix}_{i,p}x_{i,p} \quad (2)$$

$$\Sigma_{p\in P}g_{i,p,y,t} + \Sigma_{j\in I,j\neq i}q_{y,t,i,j} \geq D_{i,y,t} + \Sigma_{dp\in DP}(E^{CPEV}_{i,dp,y,t} - E^{Dgrid}_{i,dp,y,t}\cdot n\ ) + E^{ERS}_{i,y,t}\ \forall\ i \in I, y \in Y, t \in T \quad (3)$$

where

Ct_{ot}	is the total system cost
I	is the set of all regions
P	is the set of all technology aggregates
Y	is the set of all years in the investment period
T	is the set of all time-steps (differ between the models)
$c^{run}_{i,p,y,t}$	is the running cost of region i, with technology aggregate p in year y at time-step t
$g_{i,p,y,t}$	is the generation in region i, technology aggregate p, for year y at time-step *t*
$c^{cycl}_{i,p,t}$	is the cycling costs (summed start-up costs and part-load costs) in region i with technology aggregate *p* in year y at time-step t
$C^{inv}_{i,p,y}$	is the annualised investment costs of technology aggregate p in region i and year y
$C^{fix}_{i,p,y}$	is the fixed operational and maintenance costs of technology aggregate p in region i and year y
$i_{i,p,y}$	is the investment in region i and technology aggregate p in year y
$x_{i,p,y}$	is the existing capacity in region i and technology aggregate p in year y
$D_{i,y,t}$	is the demand for electricity in region *i* and year y at time-step t
$q_{y,t,i,j}$	is the flow of power, positive or negative, from region j to region i in year y at time-step t
$E^{CPEV}_{i,dp,y,t}$	is the passenger EV charging for driving profile dp in region i, for year y at time-step t
$E^{Dgrid}_{i,dp,y,t}$	is the passenger EV discharging to the grid for driving profile dp in region i, for year y at time-step t
$E^{ERS}_{i,y,t}$	is the electricity demand for the electric road system in region i, for year y at time-step t
n	is the discharging efficiency of the EV battery

This work presents results for Sweden, Germany, the UK, and Spain, but the electricity system in all neighbouring countries are also modelled, except for Germany. For Germany, the modelling in the present work was limited to include Denmark and one region in France with interconnections to Germany, and thus, other surrounding regions (Austria, Czech Republic, Poland and Switzerland) were left out. All the countries are sub-divided into smaller regions based on the current bottlenecks in transmission capacity, although there is the possibility to invest in transmission capacity between the regions in all investment periods.

A cap on CO_2 emissions corresponding to a 99% reduction by Year 2050 relative to the Year 1990 emissions is assumed. Information on the current European electricity supply system in the model is derived from the Chalmers Energy Infrastructure databases (see [18] but applying 2018 version). Investments costs, life-time, and operation and maintenance costs for all technologies and fuels can be found in Table A1 in Appendix A.

In the present study, the two models are extended with an add-on module to include also an electrified road transport sector in the form of static and dynamic charging of passenger vehicles, trucks, and buses. Thus, a new demand for electric transportation has been added to both the investment model and the dispatch model (see Appendix B for a complete mathematical description of the model assumptions and equations related to the implementation of EVs and ERS). The two models optimise the time of charging and discharging of the passenger EVs by storing electricity in the EV batteries. At the same time, a given hourly passenger EV demand is fulfilled, with the number of EVs, the battery size, and the hourly EV demand being exogenously given (i.e., not optimised in the model). Several equations are applied in the model with the aim of optimising the time of charging and discharging of the passenger EVs through hourly balancing of the storage level of the battery.

The main equations relate to the implementation of EVs are: (i) the possibility to charge and discharge back to the grid each time-step, depending on whether or not the EVs are connected to the grid; (ii) a capacity charging limitation for each time-step, restricting the charging within the charging power limits of the EVs; and (iii) the battery storage capacity (energy terms) of the vehicle, which can never be less than zero or larger than the battery capacity (see Appendix B for a detailed mathematical description).

In the modelling, 426 different yearly driving profiles are included; for each of the 426 profiles, each time-step includes information as to whether the EV is parked and connected to the grid or out driving, as well as the distances driven (see also Section 2.2). In this study, there is the possibility to store electricity between days using the EV batteries in the dispatch model (modelling all hours for 1 year in this model), although there is no consideration of between-days storage in the investment model (only representative days that are not in cronological order). The intra-day storage in the investment model will of course also affect the electricity generation possible of the different technologies in the dispatch model.

2.2. Driving Patterns

Many of the previous studies that have modelled the electricity system including smart charging of EVs have been based on mainly data from travelling surveys, aggregated to one entire EV fleet in the models. It might be important to include individual driving patterns in electricity system models, to avoid the risk of over-estimating the flexibility of EVs, since using a description of the entire vehicle fleet does not take into account how the power balance in the individual vehicles meets individual transport demand profiles.

Data from these self-reported traveling surveys often under-represent the numbers of trips and focus on the travel behaviors of persons during one to a few days rather than on the movement patterns of the vehicles over a longer time period. This study applies GPS measurements of randomly chosen gasoline- and diesel-driven vehicles in the region of Västra Götaland (western part of Sweden) that in total completed 107,910 trips in the period 2010–2012. This region was found to be representative for Sweden in terms of fleet composition, car ownership, household size, and distribution of larger and smaller towns and rural areas [5]. The database includes 426 vehicles that were measured for 50–100 days each, i.e., no vehicle had a full year of logging. Thus, the measured driving period per vehicle has been extrapolated from the original period to 12 months with respect to the travelleed distance and plug-in status in each time-step. This means that the driving data for each vehicle were used repeatedly with respect to the days of the week.

The average yearly driving distance per vehicle for these 426 vehicles is approximately 15,000 km per year. The number of EVs is distributed uniformly over the 426 yearly driving profiles. Each vehicle within the yearly driving profile is either connected to the grid (i.e., all parking on any stop longer than 1 h) or not connected to the grid. The yearly driving profile includes also the distance driven each hour of the year. The model can optimise the charging of the passenger vehicles within each profile, with the limitation that all trips must be completed using the battery. The GPS data applied in this work to determine individual driving patterns for several days in a row, is so far unique and only available for one region in Sweden. Since no such data was available for the other regions investigated, we have assumed the same driving profiles for all regions investigated in Europe.

For those scenarios involving trucks, buses and long trips by passenger EVs, applied to those trips that cannot be completed using only the battery, dynamic charging is used with an ERS. The dynamic transfer of electricity can be done through overhead transmissions lines or from the road [19–21]. Electricity transfer systems that use overhead transmission lines are conductive, with the vehicle connecting to the transmission lines through a type of pantograph, whereas the road-based technologies can be either conductive or inductive. In the case of a conductive system, the supply of electricity is through a physical pick-up that connects to an electrified rail in the road, whereas in an inductive system, the electricity is supplied via a wireless power transfer from a coil in the road to a pick-up point in the vehicle [20,21]. A load profile that represents an average day for buses and trucks is taken from the analysis of traffic flow data presented by Taljegard et al. [22]. Thus, the demand from dynamic charging with ERS is the yearly load profile, i.e., the hourly share of the yearly demand, multiplied by the total amount of annual driving for the fleet. There is no possibility to optimise the electricity demand for vehicles using ERS, given that the electricity consumption by ERS is fixed in time at the instant of transportation.

2.3. Vehicle Data

The EVs are assumed to have a share of the total fleet of 20% by 2030 and 60% by Year 2050 in all European countries. The total fleet is assumed to increase by 35% until 2050 compare to 2016. The rates of fuel consumption at the wheels are assumed to be 0.16, 0.33, 1.19, and 2.06 kWh/km for passenger cars, light trucks, buses, and heavy trucks, respectively [22]. The yearly driving distances for light trucks, buses, and heavy trucks are set at 14,000, 41,000, and 57,000 km per year, respectively, and are assumed to be the same for all countries.

The EV battery capacity is assumed to be 30 kWh (i.e., a driving distance of approximately 190 km) for all passenger vehicles in the scenario of no ERS. In the scenarios with ERS, the battery capacity for the passenger cars is set at 15 kWh, since one of the economic benefits of ERS is that smaller batteries can be used in the passenger vehicles and dynamic power transfer can instead be used for the longer trips.

2.4. Scenarios

Table 2 describes the six scenarios modelled in this study. The scenarios include three different charging strategies for passenger EVs: (i) direct charging of the passenger EVs according to their driving patterns (*Direct*); (ii) optimisation of the charging time to minimise the cost of meeting the electricity demand (*Opt*); and (iii) optimised charging and a passenger vehicle-to-grid strategy that includes the possibility to discharge the passenger EVs to the grid (*V2G*).

Table 2. The six scenarios modelled in this study.

Parameter/Scenario	S1-direct	S1-direct-ERS	S2-Opt	S2-Opt-ERS	S3-V2G	S3-V2G-ERS
Geographical areas *	UK, SWE, ES, DE	UK, SWE, ES, DE	UK, SWE, ES, DE	UK, SWE, ES, DE	UK, SWE, ES, DE	UK, SWE, ES, DE
Charging strategies	Direct	Direct	Optimisation	Optimisation	Vehicle-to-grid	Vehicle-to-grid
Battery capacity (kWh)	30	15	30	15	30	15
Electric road system (ERS)	No	Yes	No	Yes	No	Yes

* All the model runs are analysed for the United Kingdom (UK), Sweden (SWE), Spain (ES), and Germany (DE).

Scenarios are also run with and without ERS, to compare the difference if also including electrification of the trucks and buses. In the scenarios that include ERS, the ERS is used as a range-extender for passenger EVs for those trips that cannot be completed using exclusively electricity from the battery, due to the battery capacity and driving pattern (in the scenarios without ERS, these trips are assumed to be covered by, for example, renting an internal combustion vehicle or taking the train).

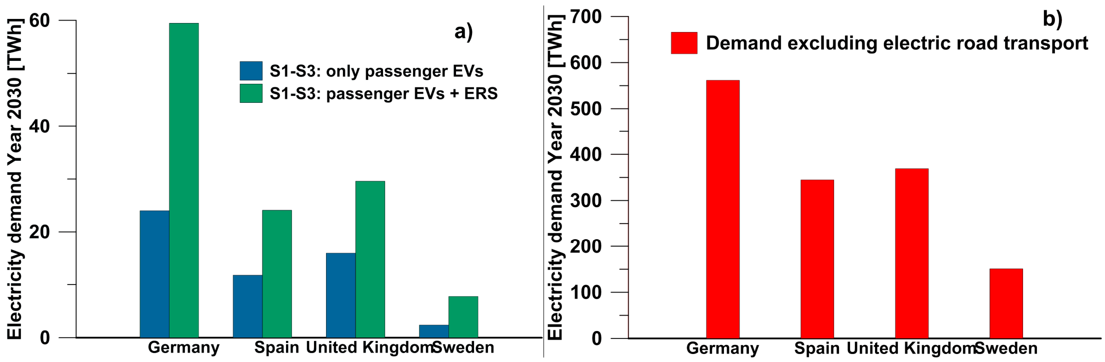

Figure 2. (**a**) The electricity demands in Year 2030 for the scenarios with static charging of passenger electric vehicles (EVs) (blue bars), and with static charging of passenger EVs and electric road systems (ERS) for all other vehicles and for those trips with passenger EVs that cannot be completed using exclusively electricity from the battery (green bars). (**b**) The electricity demand Year 2030 for all loads excluding road transport (red bars).

For trucks and buses, ERS is seen as the main mode for using electricity. Figure 2 shows the electricity demand for road transport per country investigated for Year 2030 for the scenarios with only electrification of passenger cars (blue), as well as, electrification of trucks and buses and long-distance trips for passenger EVs with ERS (green). The load excluding EVs and ERS (Figure 2b) are based on data from the European Network of Transmission System Operators for Electricity ENTSO-E [23]. The electricity demand for EVs and ERS (Figure 2a) is calculated based on the fuel consumption and yearly driving distance given from the driving profiles explained in Section 2.2 and the data presented in Section 2.3.

3. Results

3.1. Investments in Power Capacities

Figure 3a,b show the power plant capacity in Year 2050 in Spain, the UK, Sweden, and Germany without EVs (3a) and for the scenario S3-V2G (3b). Figure 3c,d show the electricity generation in Year 2050 without EVs (3c) and for the scenario S3-V2G (3d). Figure 4 indicates the difference in total installed power plant capacity Year 2050 for a scenario without EVs and the six EV scenarios presented in Table 2. Table 3 lists the shares of VRE (solar and wind power) in Year 2050 in the investigated regions.

The additional investments associated with electrification of the transport sector are somewhat different depending both on the scenario and on the country, as shown in Table 3, as well as in Figures 3 and 4. The results show that with direct charging (S1-direct and S1-direct-ERS), the share of VRE Year 2050 (Table 3) and the composition of the electricity system (Figure 4) are similar to the scenario without EVs. For example, in Germany, Spain, the UK, and Sweden the share of VRE is 63%, 79%, 83%, and 62% without EVs and 58%, 82%, 81%, and 63% with direct charging (S1-direct), respectively (Table 3). In Germany, the share of wind power is decreasing with a few percent points when introducing direct charging of EVs compared to without EVs. This is due to that the sites with the most favourable wind conditions in Germany have already been deployed and there is instead an investment in more thermal power to cover the additional EV demand (mainly gas with CCS and CCS coal co-fired with biomass).

The share of solar power increases with possibility to optimise the EV charging and to do V2G in all regions investigated (except for Sweden). The results from the model optimisation of the electricity system in Spain show that a large proportion of the additional electricity demand is met by investments in solar power (Figure 4), while at the same time there is a decrease in the investments in wind power.

The decrease in wind power is especially significant in Spain in the scenarios with V2G when the EV batteries can be discharged back to the grid and thereby help storing electricity over several hours. Storing of electricity from daytime to cover evening and morning peaks facilitates investments in solar power rather than wind power.

Solar PV together with vehicle storage is also more cost-competitive than different types of traditional base load plants in Spain, Germany, and the UK (such as condensing plants with CCS or nuclear). The total generation from VRE in Year 2050 is increasing with a few percent in Spain when optimising the EV charging compared to direct charging; however, the share of the demand covered by solar power is 25% without EVs, 32–34% in the scenarios with optimised charging of EVs, and 56–62% if also including V2G (Table 3). As seen in Table 3 and Figures 3 and 4, the same trend with increasing solar power can be seen also for the UK and Germany. However, in Germany and the UK, solar power has a maximum share of the electricity generation of 41% and 28%, respectively.

The additional EV demand in Sweden is mainly met by an increase in wind power generation (7–30%) compared to a scenario without EVs. The share of generation of wind power in Year 2050 in Sweden, as compared to the total level of generation in Year 2050, is 58% in the scenario without EVs and 59–64% in the scenarios with EVs (Table 3). This gives an increase of a few percentage points in the share of the demand supplied by wind power in the EV scenarios with V2G, as compared to the scenario without EVs.

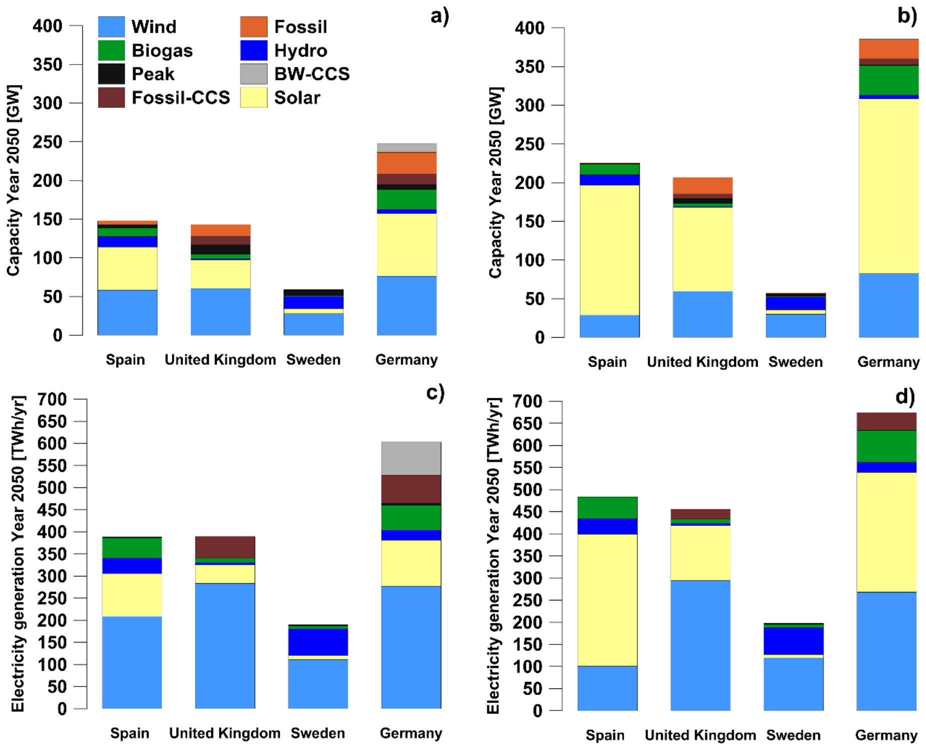

Figure 3. Installed capacity Year 2050 for the four countries investigated in the scenarios (**a**) without electric vehicles and (**b**) S3-V2G; and electricity generation Year 2050 for the four countries investigated in the scenarios (**c**) without electric vehicles and (**b**) S3-V2G. CCS, carbon capture and storage; BW, coal co-fired with biomass.

In Germany and the UK, direct charging leads to investments in additional thermal power (mainly in the form of natural gas with carbon capture and storage (CCS) and CCS coal co-fired with biomass) as compared to the other scenarios (Figures 3 and 4). This is mainly due to the increased load during daytime hours when there is already a high demand for power. However, as seen in Figures 3 and 4, a V2G charging strategy can instead substantially reduce investments in, and electricity generation from, thermal power plants in Germany and United Kingdom compared to a scenario without EVs or with direct charging of EVs. Instead, the value of investing in solar power, as compared to investing in wind power and thermal power, is increased in Germany with the introduction of EVs with V2G, as compared to a situation without EVs (Figures 3 and 4). For example, in scenario S3-V2G, the share of solar and wind power is 41% and 38%, respectively. This means investing in additional 145 GW of solar power in Germany (Figure 3b). The electricity system in the UK is still dominated by wind power, even if V2G is increasing the share of solar power (see Table 3 and Figures 3 and 4).

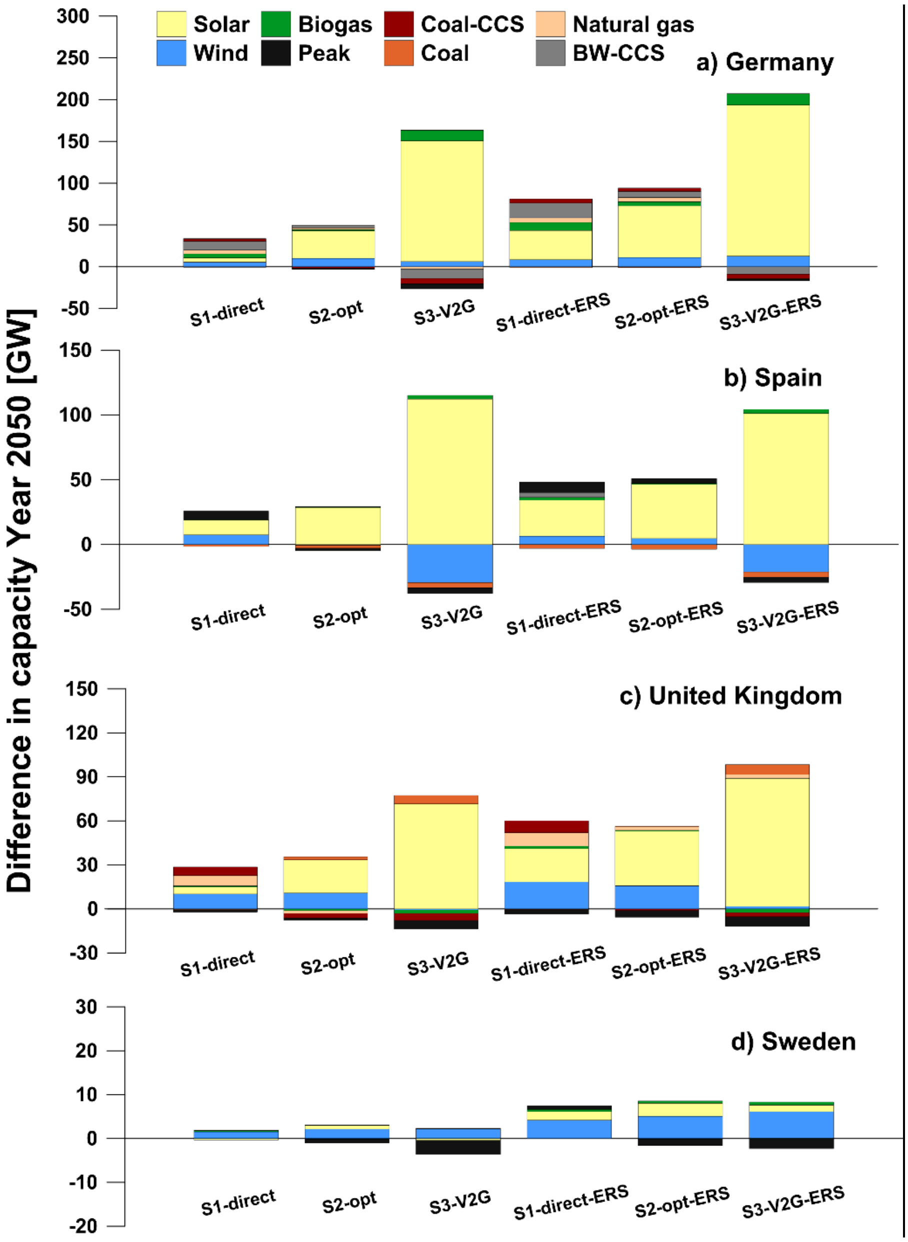

Figure 4. The differences in installed capacity Year 2050 between a scenario without EVs and the various EV and ERS scenarios investigated for: (**a**) Germany; (**b**) Spain; (**c**) the UK; and (**d**) Sweden. Opt, Optimisation of EV charging; CCS, carbon capture and storage; V2G, vehicle-to-grid; ERS, electric road system; BW, lignite co-fired with biomass.

Optimised charging with V2G reduces the need for peak power capacity in all the regions (Figures 3 and 4). If the charging is not optimised (i.e., S1-direct and S1-direct-ERS), the demand for peak power instead increases slightly and ERS will further amplify this increase in peak power in Germany, Sweden, and Spain (S1-direct-ERS in Figure 4).

A scenario with full electrification of road transport, including also ERS for trucks and buses, still decreases the need for investments in peak power, as compared to the scenario without EVs, provided that V2G is applied for the passenger vehicles. However, if all the trucks and buses use ERS and V2G is applied for the passenger vehicles, both the total investment and the investments in peak power will decrease to a greater extent than if one just optimises the charging of passenger EVs (Figure 4).

Table 3. Shares of generation from variable renewable electricity (VRE), wind and solar power in Year 2050 in the four countries investigated for the different scenarios.

	UK			Sweden			Germany			Spain		
	Solar	*Wind*	*VRE*	*Solar*	*Wind*	*VRE*	*Solar*	*Wind*	*VRE*	*Solar*	*Wind*	*VRE*
Without EV	11%	72%	83%	4%	58%	62%	17%	46%	63%	25%	54%	79%
S1-direct	11%	70%	81%	4%	59%	63%	16%	42%	58%	26%	56%	82%
S2-Opt	14%	74%	88%	4%	60%	64%	21%	44%	65%	32%	49%	81%
S3-V2G	27%	63%	90%	4%	61%	65%	40%	39%	79%	62%	21%	83%
S1-direct-ERS	13%	69%	82%	5%	61%	66%	19%	39%	58%	30%	50%	80%
S2-Opt-ERS	17%	71%	88%	5%	61%	66%	23%	40%	63%	34%	48%	82%
S3-V2G-ERS	28%	60%	88%	4%	64%	68%	41%	38%	79%	56%	27%	83%

3.2. Impact on the Net Load

Figure 5 shows the net-load curves sorted for the 168 h Year 2030 with the highest net loads for Germany (Figure 5a) and Spain (Figure 5b). The net load is the load that needs to be covered by electricity sources other than wind and solar power (i.e., the load minus useful solar and wind electricity generation). For the electricity system, there is a benefit to having a stable and low net load, since, for example, the investments in peak capacities (such as gas turbines) are dimensioned by the hour with the highest demand in terms of net load. It is clear from Figure 5 that the hours with the highest demand will decrease if V2G is applied for passenger EVs, as compared to the scenario without EV.

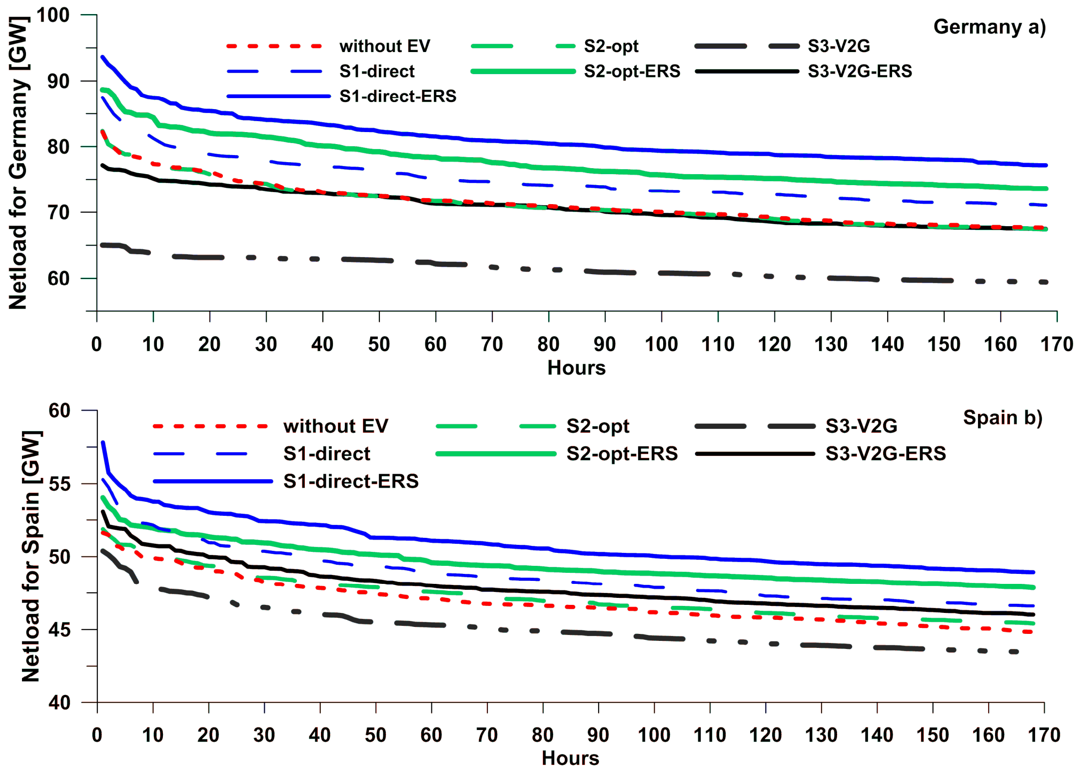

Figure 5. The net-load curves in Year 2030 sorted with respect to the 168 h with the highest net loads in: (**a**) Germany; and (**b**) Spain.

The opposite phenomenon, i.e., an increase in net load compare to the scenario without EV, can be seen in Figure 5 for the scenarios with direct charging (S1-direct and S1-direct-ERS), as well as for the scenario with optimised charging of passenger EVs and ERS (S2-opt-ERS in Figure 5). V2G is needed for the scenarios with ERS to reduce the net load compared to the scenario without EVs (Figure 5). The net load for the UK and Sweden show the same trends as seen for the two regions in Figure 5. The benefit of V2G to reduce the net load seen in Figure 5 will of course increase by 2050, when there is a large proportion of EVs and a higher share of VRE in the electricity system.

3.3. Dispatch of the Electricity System

Figure 6 shows: the net loads excluding the load from EVs and ERS; the net loads including also the loads from direct charging of EVs or V2G and ERS; and the levels of charging and discharging back to the electricity grid for 1 week in February in Germany (Figure 6a) and in Spain (Figure 6b). In Figure 6, it is clear that for both Germany and Spain, the passenger EVs are discharged to the grid when the net load is high, which reduces the need for investment in peak power capacity and curtailment of electricity.

The amount of discharging in Year 2030 is in the range of 24–25 TWh for Germany and in the range of 10–11 TWh for Spain. These amounts are small compared to the total demand Year 2030 (including static EV charging and ERS) of approximately 620 TWh and 370 TWh per year in Germany and Spain, respectively. However, they contribute with flexibility to the system, which is important for reducing the peak power demand and stimulating larger investments in VRE. For example, passenger EVs will smoothen the net load curve in the investigated regions shown in Figure 6, so that the hour with maximum net load is reduced if V2G is applied. ERS will, in contrast, as shown in Figures 5 and 6, enhance the current net load, assuming current travelling patterns.

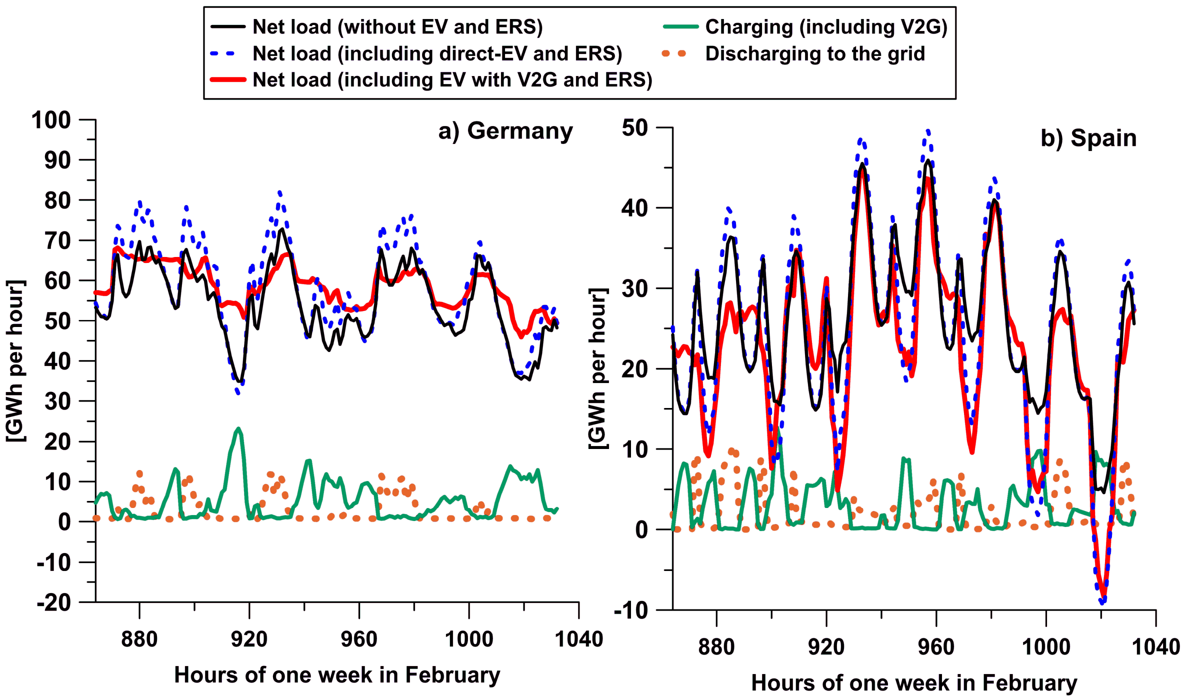

Figure 6. The net load without EVs and ERS (i.e., the load minus useful solar and wind electricity generation), the net load including direct charging of EVs and ERS for trucks and buses, the net load including EVs with V2G and ERS, and the load from charging and discharging to the grid are shown for 1 week in February for (**a**) Germany and (**b**) Spain.

There is a difference between Figure 6a and b in terms of the charging and discharging of the EV batteries to the grid. In Spain, the EV batteries are mainly handling solar power level fluctuations in the system Year 2030 and there is a diurnal pattern of charging and discharging to the grid, to store electricity each day. Germany, which has lower share of electricity from solar power and a higher share of wind power in the system Year 2030 than Spain, does not show this clear diurnal pattern of charging and discharging to the grid.

3.4. Charging and Discharging to the Grid Patterns of Electric Vehicles

Figure 7 shows the levels of charging and discharging to the grid for passenger EVs for an average day in the dispatch model. The modelling results show that for optimised charging and V2G scenarios, the major share of the charging of the passenger EVs in Year 2030 for all the countries occurs during night-time when the load from other sectors is low (Figure 7a). In Spain, charging also occurs in the middle of the day when solar power are generating electricity. In contrast, discharging back to the grid from passenger EVs for all the countries occurs mainly during the peak hours in the morning and afternoon (Figure 7b). Solar generation in the middle of the day, in combination with charging and discharging to the grid from batteries during the morning and afternoon, can then be competitive over traditional base load running many hours of the year (e.g., nuclear and thermal power plants). Sweden, which has a lot of hydro power that provides flexibility to the electricity system, has much flatter charging and discharging curves than the other countries (Figure 7).

The total level of discharging is in the range of 2–27 TWh per year in Year 2030 depending on the country, corresponding to approximately 2–7% of the total electricity generation in Year 2030, with the largest absolute numbers for the UK (7%). Flexibility derived from EVs is more valuable for the UK, mainly due to the scarcity of trading opportunities with neighbouring regions. The level of discharging to the grid for the aggregated vehicle fleet (Figure 7b) is still relatively low compared to the level of charging (Figure 7a).

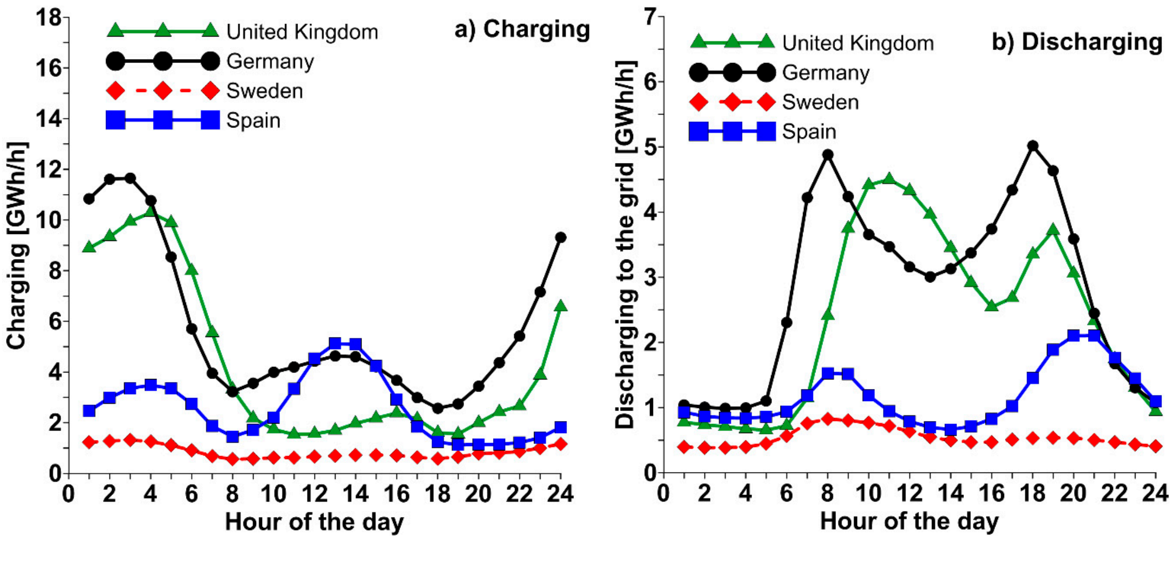

Figure 7. Levels of charging (**a**) and discharging back to the electricity grid (**b**) for the EV fleet for an average day in the four investigated countries.

In Figure 7, average values are shown for the aggregated EV fleet, although for some hours the level of discharging to the grid is at least four times the average value shown in Figure 7b. The results from the modelling reveal that the different individual EVs are charged and discharged in very different manners. The EVs with the longest yearly driving distance (~58,000 km per year) have more limited possibilities to store electricity for several days and to discharge back to the grid due to limited battery capacity and fewer hours connected to the grid. EVs with a relatively short and medium yearly driving distance (~1500 km per year) are to a large extent used for discharging back to the grid following the fluctuations in generation patterns of wind power, since a shorter driving distance means more time connected to the grid and fewer hours charging the battery that is to be used for driving.

3.5. Curtailment of Electricity

A high share of VRE in the electricity system can lead to curtailment of electricity generation (i.e., a reduction in the output from generation compared to how much electricity could otherwise be produced given the available resources). Figure 8 shows the shares of the solar and wind power production that are curtailed in Year 2030 for the scenario without EVs and for the different scenarios with EVs. As seen in Figure 8, the curtailment of VRE is low (<4%) in all countries and scenarios. The curtailment is more pronounced in the UK than in the other three countries, mainly due to fewer flexibility management options being available for handling the over-production of electricity during certain hours in the UK, as compared to for example Sweden and Germany. Examples of these flexibility management options are hydro power and trade with neighbouring regions.

In Figure 8, there is a general trend for all the countries in that the curtailment of electricity generation decreases when EV charging is optimised (i.e., in S2 and S3). The magnitude of the reduction in curtailment associated with the implementation of V2G is 90% in the UK. Direct charging and an electrified transport sector with ERS (S1-direct-ERS) has similar levels of curtailment as the scenario without EV, since both direct charging of passenger EVs and ERS increase the demand for electricity during hours when there is already a high demand.

The large-scale investment in solar PV in Spain and Germany seen in Figures 3 and 4 occurs mainly after Year 2030. Thus, if instead one models Year 2050 in the dispatch model, EV batteries become more important for handling the intra-day variations (i.e., storage of electricity between day and night hours), so as to avoid the curtailment of solar power in Spain and Germany. However, this is not shown in Figure 8, as it shows the data for Year 2030. For Year 2050, the share of solar and wind power curtailed in Spain and Germany is 9% and 14% without EVs, and 1% and 7% if EV charging is optimised with V2G included, respectively. The share of VRE will increase also for the other countries by Year 2050, as compared to 2030, making the reduction of curtailment with EVs more important in Year 2050 to facilitate a higher share of VRE.

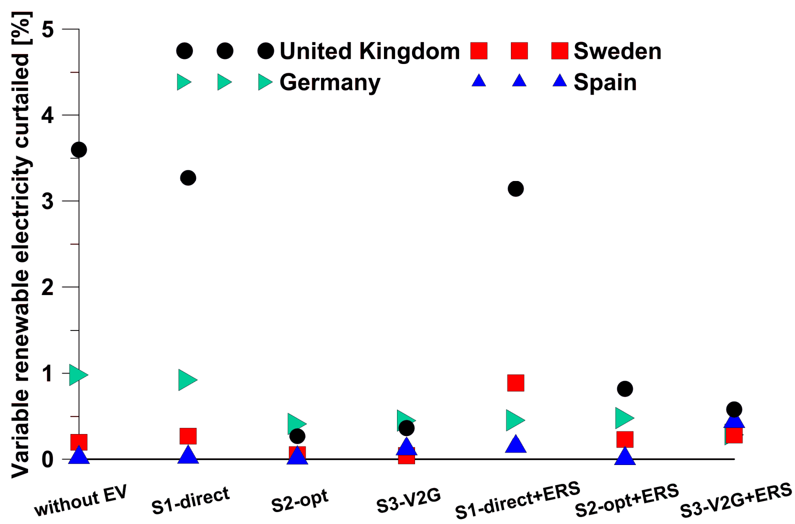

Figure 8. Shares of the electricity generated from wind and solar that are curtailed in Year 2030 for the scenarios without EV and the six scenarios with EVs in the four investigated countries.

3.6. Total System Cost and CO_2 Emissions

Figure 9 shows the total system cost from the investment model, i.e., the sum of the investment and running costs for the period 2020–2050. The total system cost increases in the scenarios with

EVs, compared to those without EVs, due to the occurrence of an increase in demand when EVs are included. The cost is slightly lower for the scenarios when the charging of EVs is optimised and is further reduced if, in addition, V2G is applied, as compared to direct charging (Figure 9). However, for Sweden, the total system cost is almost the same for all the scenarios. This is mainly due to hydro power providing low-cost electricity also in the scenarios (S1-direct and S1-direct-ERS) where the new electricity demand from road transport is increasing the electricity demand at hours with already high demand from other sectors.

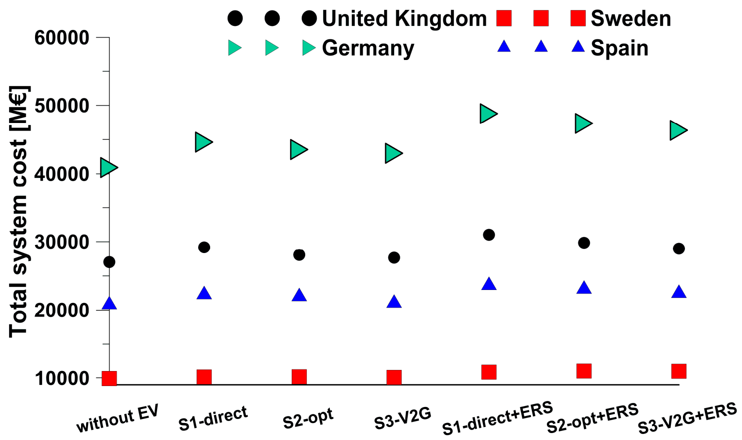

Figure 9. The total system costs for the different countries and scenarios, as derived from the cost-optimisation investment model (ELIN).

The level of CO_2 emissions from the electricity system will, in Year 2030, be in the range of 2–174 gCO_2/kWh, corresponding to 1–30 gCO_2/km for passenger vehicles, depending on the country. This can be compared with the European 2020 goal for passenger vehicles of CO_2 emissions at 95 gCO_2/km. Sweden has the lowest levels of CO_2 emissions in Year 2030 from using electricity for transport, while Germany and Spain have the highest levels among the countries investigated.

A slightly higher emission factor is noted for direct charging and ERS, as compared to optimising the charging of passenger EVs according to electricity system cost. However, since this modelling includes a cap on CO_2 emissions (expressed in absolute terms) and this is unlikely to be changed, as well as the fact that the electricity system as such has a European target of achieving 99% reduction in emissions by Year 2050 (relative to the Year 1990 emissions levels), this means that it is highly feasible to reach drastic emissions reductions from the transportation sector by changing from fossil fuels to electrification of vehicles.

4. Discussion and Conclusions

We explored the potential of EVs to function as a flexibility management strategy to stimulate investments in and the operation of renewable electricity under a stringent CO_2 constraint in four regions with different conditions for variable renewable electricity (Sweden, Germany, the UK, and Spain). The results shows that the flexibility conferred by EVs through V2G promotes an increase in solar PVs and a decrease in thermal generation and wind power, in Spain, UK, and Germany. The EV batteries provide flexibility in terms of handling the day–night time variations in solar PV output. The benefits are less prominent if only an optimum charging strategy is used, as compared to employing an optimum charging and V2G strategy. However, a benefit can still be accrued to the system by simply optimising the charging of the EVs without V2G. There is, for example, a general trend for all the countries in that the investments in peak power and curtailment of electricity generation decreases when EV charging is optimised.

In Germany, there is a large increase in investment in solar power, assuming a scenario including V2G, in Southern Germany (which is a region with a high electricity demand). This is mainly due to lack of good wind power resources in the region. One factor that could reduce this large increase in solar power investments is the potential to generate less electricity in the region and instead trade more with the neighbouring regions. However, the modelling in the present work was limited to include one region in France with interconnections to Germany, and thus, other surrounding regions (Austria, Czech Republic, Poland, and Switzerland) were left out. Investments in stationary batteries were not included as an investment option in the model, which might have an impact on the investments in solar power in the scenarios without the possibility to do V2G. However, the investment cost for stationary batteries will then be part of the cost optimisation of the electricity system, while the investment cost in EV batteries are assumed to be taken by the transport system.

Without the possibility to store electricity in EV batteries between days, which is a technical limitation associated with this type of model, EVs increase the share of wind power by only a few percentage points, even in regions with good conditions for wind power, e.g., Sweden. To increase further the penetration level of wind power, diurnal storage using EV batteries is not sufficient, since there are variations in wind power on longer time scales that necessitate weekly harmonisation measures.

This study shows that an electrified transport sector can, in all the countries considered, reduce investments in peak power capacity and reduce the net load. The demand during the hours with the highest demand of the year can be decreased if optimised charging and V2G is applied to the passenger EVs, even though the total demand for power increases with the electrification of transportation. The converse, i.e., an increase in the need for more peak power, can be seen with direct charging and ERS, which, however, to a large extent can be counter-acted if optimised charging and V2G are implemented for the passenger vehicles. Most of the EV charging occurs during night-time Year 2030 to avoid correlation with the net load. However, in Spain, a region with a high share of the electricity generation from solar power, also charging during middle of the day is important. Furthermore, the discharging to the grid occurs mainly during the peak demand hours in the morning and afternoon.

Batteries have, in other studies, proven to be too expensive for handling weekly storage of wind power [24]. Nevertheless, towards the middle of this century there may be the possibility to use spent EV batteries, which are too capacity-degraded to be used in vehicles, as stationary batteries.

In this study, we are considering typical driving patterns and the driving demands are fulfilled for all individual vehicle driving profiles in all model runs and calculations. Since data on individual driving patterns were only available for one region in Sweden and therefore applied also to the other regions investigated, this will obviously not take into account national differences in the driving profiles. Thus, there may be regional differences in working hours, leisure time activities, as well as geographical factors like Sweden being a low population density country. As a speculation, more densely populated areas may allow for vehicles spending more time connected to the grid. Thus, using Swedish driving patterns as a proxy for all countries could underestimate their participation in the electricity system. In addition, autonomous driving may substantially change the future use of vehicles. For example, a shift in the transportation of goods to night-time, would smoothen the load curve from trucks and buses using ERS. Other factors that may impact the ways in which we transport goods and persons are to what extent we will own our vehicles in the future, urbanisation, globalisation, and number of working hours. Each of these may exert an impact on the charging profile, and thereby on the possibility to use V2G as a flexibility management strategy in the electricity system.

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

Appendix A

Table A1. Technology investment cost for Year 2050, operational and maintenances costs (O&M) and life-times of some of the key technologies available in the ELIN model [25]. CCS, carbon capture and storage; CHP, combined heat and power; GT, gas turbine; CCGT, combined cycle gas turbine.

	Life-Time [Years]	Investment Cost [a] [€/kW_{el}]	Fixed O&M Cost [a] [€/kW_{el}/yr]	Variable O&M [a] Cost [€/kWh_{el}/yr]
Hard coal				
Condense	40	1980	50	2.1
CHP/BP	40	1980	50	2.1
CCS	40	2995	106	2.1
CCS + bio-cofiring	40	3363	127	2.1
Lignite				
Condense	40	1980	50	2.1
CHP/BP	40	1980	50	2.1
CCS	40	2995	106	1.36
CCS + bio-cofiring	40	3363	127	2.1
Natural gas				
GT	30	450	15	0.8
CCGT	30	1170	18	0.7
CHP/BP	30	1170	30	0.7
CCS	30	1575	50	2.1
Bio & waste				
Condense	40	1935	56	2.1
GT	30	450	8	0.7
CCGT	30	900	13	0.8
Waste	40	6210	230	2.1
CHP/BP	40	3105	105	2.1
Nuclear				
	60	5148	155	0
Intermittent				
Wind (onshore) [b,c]	25	1225	34	1.1
Wind (offshore) [c]	25	1838	90	1.1
Solar PV [c]	25	540	20	1.1
Small hydro	75	3745	73	1

[a] The values shown for investment costs and the fixed/variable O&M costs are based on the World Energy Outlook assumptions of the IEA from 2016 editions [25] and have been extrapolated for Year 2035 to Year 2050. Investment costs for CCS technologies are obtained from the Zero Emission Platform [26]. [b] Onshore wind power is divided into 12 wind classes per region, with different generation profiles (i.e., full-load hours) and different maximum capacity installation depending on region. The wind farm density is set to 3.2 MW/km^2 and is assumed to be limited to 10% of the available land area, accounting for protected areas, lakes, water streams, roads, and cities [27]. [c] Hourly weather data in the models are based on data from MERRA and ECMWF metrological data (solar [28,29] and wind [30,31]) for Year 2012.

Appendix B

The inclusion of 426 individual daily passenger EV driving profiles and ERS in the ELIN and EPOD models requires modification of the models used in previous studies. The EVs are implemented using the same equations in the investment model (ELIN) and the dispatch model (EPOD), although in the investment model every tenth year (y) until Year 2050 are modelled with 480 h per year (20 representative days with 1-hour time resolution). In contrast, the EPOD calculations are limited to Year 2030 (i.e., y = 2030) with 8760 h (1-hour time resolution). Equations (A1)–(A5) are added to the models and are implemented with the aim of optimising the time of charging and discharging of the passenger EV, while at the same time fulfilling a given hourly passenger EV demand assuming 426 individual daily passenger EV driving profiles. There are constraints on:

(i) the maximum amount of charging at each time-step (Equation (A1)); (ii) the maximum amount of discharging to the grid at each time-step (Equation (A2)); (iii) the amount of EVs connected to the grid available for charging and discharging to the grid (Equation (A3)); (iv) the balancing of the charging and discharging of the EV battery (Equations (A4) and (A5)); and (v) the maximum EV battery storage capacity (Equation (A6)).

$$E^{CPEV}_{i,dp,y,t} \leq NC_{i,dp,y,t} \cdot CP \forall\ i \in I, dp \in DP, y \in Y, t \in T \tag{A1}$$

$$E^{Dgrid}_{i,dp,y,t} \leq NC_{i,dp,y,t} \cdot BS_{i,dp,y} \forall\ i \in I, dp \in DP, y \in Y, t \in T \tag{A2}$$

$$NC_{i,dp,y,t} \leq FA_{dp,t} \cdot N_{i,dp,y} \forall\ i \in I, dp \in DP, y \in Y, t \in T \tag{A3}$$

$$SL^{PEV}_{i,dp,y,t+1} \leq SL^{PEV}_{i,dp,y,t} + E^{CPEV}_{i,dp,y,t} \cdot n - E^{DGrid}_{i,dp,y,t} - E^{DPEV}_{i,dp,y,t} \forall\ i \in I, dp \in DP, y \in Y, t \in T \tag{A4}$$

$$SL^{PEV}_{i,dp,y,tt-23} \leq SL^{PEV}_{i,dp,y,tt} + E^{CPEV}_{i,dp,y,tt} \cdot n - E^{DGrid}_{i,dp,y,tt} - E^{DPEV}_{i,dp,y,tt} \forall\ i \in I, dp \in DP, y \in Y, tt \in TT \tag{A5}$$

$$SL^{PEV}_{i,dp,y,t} \leq BS_{i,dp,y} \forall\ i \in I, dp \in DP, y \in Y, t \in T \tag{A6}$$

where

TT	is the set consisting of only the last hour of each day
DP	is the set of individual daily passenger EV driving profiles
$E^{CPEV}_{i,dp,y,t}$	is the passenger EV charging for driving profile dp in region *i*, for year y at time-step *t*
$E^{Dgrid}_{i,dp,y,t}$	is the passenger EV discharging to the grid for driving profile dp in region i, for year y at time-step t
n	is the charging and discharging efficiency of the EV battery
$NC_{i,dp,y,t}$	is the number of passenger EV that are connected to the grid for driving profile dp in region i, for year y at time-step t
CP	is the charging power
$FA_{dp,t}$	is either 1 or 0 depending if the vehicles belonging to driving profile dp are connected or not connected to the grid at time-step t
$N_{i,dp,y}$	is the number of passenger EVs belonging to driving profile dp in region i, for year *y*
$SL^{PEV}_{i,dp,y,t}$	is the storage level of the passenger EV battery for driving profile dp in region i, for year y at time-step
$E^{DPEV}_{i,dp,y,t}$	is the passenger EV discharging to the wheels for driving profile dp in region i, for year y at time-step t
$BS_{i,dp,y}$	is the maximum storage capacity of the EV batteries for driving profile dp in region i and for year y

Equations (A1) and (A2) limits the amount of electricity that can be charged and discharged each hour depending on the number of passenger EVs that are being parked for more than one hour. The maximum storage capacity of the batteries depends on both the number of passenger EVs and the capacity of each passenger EV battery. In both the dispatch model and the investment model, the balancing equations of the battery (i.e., Equations (A4) and (A5)) is executed only on a daily basis and not between days. This means that the storage level of the battery at hour *t+1* depends on the storage level and the charging and discharging of the battery at hour *t*, except for the last hour of the day (see Equation (A5)).

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