



HAL
open science

Large-scale deployment of electric vehicles in Germany by 2030: An analysis of grid-to-vehicle and vehicle-to-grid concepts

Rodica Loisel, Guzay Pasaoglu, Christian Thiel

► **To cite this version:**

Rodica Loisel, Guzay Pasaoglu, Christian Thiel. Large-scale deployment of electric vehicles in Germany by 2030: An analysis of grid-to-vehicle and vehicle-to-grid concepts. *Energy Policy*, 2014, 65, pp.432-443. 10.1016/j.enpol.2013.10.029 . hal-04571196

HAL Id: hal-04571196

<https://hal.science/hal-04571196>

Submitted on 7 May 2024

HAL is a multi-disciplinary open access archive for the deposit and dissemination of scientific research documents, whether they are published or not. The documents may come from teaching and research institutions in France or abroad, or from public or private research centers.

L'archive ouverte pluridisciplinaire **HAL**, est destinée au dépôt et à la diffusion de documents scientifiques de niveau recherche, publiés ou non, émanant des établissements d'enseignement et de recherche français ou étrangers, des laboratoires publics ou privés.

Large-Scale Deployment of Electric Vehicles in Germany by 2030 An Analysis of Grid-to-Vehicle and Vehicle-to-Grid Concepts

Rodica Loisel,^{1,2,3} Guzay Pasaoglu,^{1,4} Christian Thiel¹

Abstract

This study analyses battery electric vehicles (BEVs) in the future German power system and makes projections of the BEVs hourly load profile by car size ('mini', 'small', 'compact' and 'large'). By means of a power plant dispatching optimisation model, the study assesses the optimal BEV charging/discharging strategies in grid-to-vehicle (G2V) and vehicle-to-grid (V2G) schemes. The results show that the 2% rise in power demand required to power these BEVs does not hamper system stability provided an optimal G2V scheme is applied. Moreover, such BEV deployment can contribute to further integrating wind and solar power generation. Applying a V2G scheme would increase the capacity factors of base and mid-load power plants, leading to a higher integration of intermittent renewables and resulting in a decrease in system costs. However, the evaluation of the profitability of BEVs shows that applying a V2G scheme is not a viable economic option due to the high cost of investing in batteries. Some BEV owners would make modest profits (€6 a year), but a higher number would sustain losses, for reasons of scale. For BEVs to become part of the power system, further incentives are necessary to make the business model attractive to car owners.

¹European Commission, DG Joint Research Centre, Institute for Energy, P.O. Box 2, 1755 ZG Petten, The Netherlands. The views expressed are purely those of the authors and may not in any circumstances be regarded as stating an official position of the European Commission.

²Corresponding author. E-mail address: rodica_jl@yahoo.com.

³University of Nantes, IEMN-IAE LEMNA, France

⁴Istanbul Technical University, Institute of Energy, Istanbul, Turkey

1. Introduction

The European Union (EU) has agreed ambitious targets for renewable energy and reducing carbon emissions (EC, 2010). This would require a significant transformation of the electricity system, including electrifying the transportation sector (EC, 2011; EC, 2013a). The deployment of renewable energy has led to substantial wind and solar power generation, but has also increased concerns about their intermittent nature. Germany has the largest installed capacity of wind and photovoltaic power in the EU, and it is planning to increase this from 27.2 GW for wind power and 17.3 GW for photovoltaic power in 2010, to 46 GW and 52 GW respectively by 2020 (National Renewable Energy Action Plan, 2009). Germany's current power system is undergoing major changes, driven by strong social and political pressure to phase out nuclear power and to reduce demand through energy efficiency.

Recent announcements and launches of battery electric vehicles (BEVs) and plug-in hybrid vehicles suggest that a larger number of electric vehicles could be deployed in the coming years. It remains uncertain whether the current momentum regarding electromobility can be sustained in the future. Many challenges remain to a larger uptake of BEVs, notably their relatively higher investment costs over conventional internal combustion engine vehicles, and the need to deploy charging infrastructure on a large scale (Thiel et al., 2010; Pasaoglu et al., 2012). Several countries have established roadmaps for deploying a larger number of electric vehicles, indicating future market penetration targets. Germany has set itself a penetration target of 1 million electric vehicles by 2020 (German Ministry of Economics and Technology, 2009).

Currently, BEVs have rather low penetration, and there is no well-developed practice or strategy for planning the time of charging, e.g. during the night, or during periods of high wind inflows. Rather, this is performed on an individual basis which depends on personal behaviour, preferences and economics, such as the propensity for electricity consumption and the price elasticity of income. This paper projects a future with significant diffusion of BEVs in which an aggregator of all electric cars implements smart strategies for recharging batteries. These smart actions need perfect information, as well as coordination between drivers and system operators through smart metering.

This paper builds BEV loads by 2030 using a rich database of car driving patterns in Germany for four different sizes of car, corresponding to 'mini', 'small', 'compact' and 'large' car types. By means of a power plant dispatching model, the research endogenously assesses the battery charging profile for each car category. The programme of minimising system costs is set within a highly detailed time formulation over one year, i.e. 8760 hours. The power price is the output of the dispatching model, which links the decision to recharge a battery with the planning and operation of the power system.

The main contributions to the field are: 1) an estimate of the loads induced by BEVs in the German car fleet by 2030 based on current patterns of driving behaviour; 2) an analysis of the impact of electric road transport on the power system; 3) the use of a methodology which describes the hourly profile of the power demand and of hydro, wind

and solar power generation. Based on these analyses and calculations, the study points out cases in which V2G could be an optimal solution justifying further incentives, while other cases reveal — for reasons of scale — costs which outweigh the benefits to the system. Other studies have made a partial representation of the German power system with representative weeks, such as Schill (2011), thus ignoring important fluctuations over the year in resources which cannot be dispatched. Göransson et al. (2010) present recharging opportunities as a function of off-peak periods only. By contrast, our methodology also considers the possibility of recharging batteries during conventional peak times when suitable meteorological conditions (with large inflows of wind and solar energy) allow efficient use of resources.

This paper is organised as follows. Section 2 describes the methodology for the BEV load projections for 2030 and the recharging optimisation applied to the German power system. Section 3 discusses the relevant results and impacts of large-scale BEV deployment. Section 4 summarises the main findings of the work.

2. Methodology

2.1. Electricity demand of battery electric vehicles: a projection for Germany by 2030

The load profiles induced by BEVs depend on the charging patterns of the cars, which are directly influenced by driving and parking patterns. It is assumed that these patterns will not change with the introduction of BEVs. This work applies current parking and driving patterns of passenger cars in Germany, which are analysed by car size (section 2.1.1) and extrapolated to obtain the load profiles of BEVs by 2030 (section 2.1.2).

2.1.1. Building potential BEV driving patterns for the base year (2008/2009)

The driving pattern for passenger cars has been extracted from MiD 2008, which is the most recent German mobility survey, consisting of 25 992 households and 60 713 individuals. MiD 2008 contains detailed information on the key characteristics of each participating household and each vehicle to which they have access. Each individual within the household is interviewed and asked to complete a one-day trip diary. The MiD 2008 database is structured in three main files. The ‘Cars’ file documents the size and model of car, along with the fuel type, engine size, power of the car and other car-specific data. The ‘Trips’ file consists of data related to trips made by individuals, such as the mode of transport used, departure and arrival times, the duration of the trip, usage of a household vehicle and the class of the vehicle, as well as the points of departure and arrival. The ‘Households’ file describes vehicle ownership, household size, socio-economic situation and residential area.

In this study, it is assumed that BEVs have a range limit of 160 km, as presented in Perujo and Ciuffo (2010). Therefore, only the driving and parking patterns of passenger cars with short daily travel distances (less than 160 km) are analysed — a total of around 19 000 passenger cars.

The driving and parking patterns of each passenger car are aggregated from one-minute time intervals to hourly time periods in order to match the time formulation of the power plant dispatching model, described in section 2.2.

The preliminary analysis reveals that the driving patterns, fuel consumption per kilometre and total daily travel distances of the passenger cars differ between car segments. Therefore, in this study, passenger cars are categorised into four segments based on the detailed car information provided by MiD: mini, small, compact and large (see Table 1).

Table 1. Main features of BEVs

Passenger car segment	Capacity (kWh)	Range (km)	Electricity Consumption (kWh/100 km)	Share in the fleet (%)
Mini	15	160	11	11.35
Small	20		15	23.38
Compact	24		18	35.81
Large	30		23	29.46

Sources: Perujo and Ciuffo (2010), German Federation for Motor Trades and Repairs (2011).

2.1.2. Projections of electricity demand of BEV fleet in Germany by 2030

The projected demand for electricity of BEVs by 2030 is the input to the power plant dispatching model: the demand for power from BEVs is fixed for the power generation system and is fulfilled every hour by optimally dispatching the power plants. Re-charging batteries is, instead, endogenous to the model of the power system.

The BEV fleet size projections for Germany in 2030 are based on two of the BEV deployment scenarios described by Pasaoglu et al. (2012). The first scenario is a ‘highly decarbonised’ scenario, with high oil and natural gas prices and large development of alternative vehicles and refuelling infrastructure. The second scenario is a ‘slightly decarbonised’ scenario, with low oil and gas prices and low consumer acceptance of changes.

In the ‘highly decarbonised’ scenario, the projected size of the passenger car fleet of BEVs by 2030 is estimated to be 4.8 million passenger cars and 1.1 million cars in the ‘slightly decarbonised’ scenario.

The projected BEV fleet size for each passenger car segment, illustrated below in Table 2, is based on the figures presented in Table 1 and market penetration rates from Pasaoglu et al. (2012). The driving patterns of passenger cars vary by car segment; the charging patterns are thus treated individually in the dispatching model. The car segment share is determined based on the current distribution of car segments, while admitting that the proportion of large passenger cars may decrease by 2030 due to high travel costs (i.e. the high cost of a large battery, etc.).

Table 2. Projected BEV fleet size per passenger car segment for Germany in 2030

Passenger car segment	# of vehicles in 'highly decarbonised' scenario	# of vehicles in 'slightly decarbonised' scenario
Mini	547 196	125 725
Small	1 126 964	258 933
Compact	1 726 274	396 632
Large	1 420 105	326 286
Total	4 820 539	1 107 575

The next table introduces additional techno-economic features of BEVs for lithium-ion batteries that will be further used to perform the cost-benefit analysis of V2G strategies.

Table 3. Techno-economic parameters for BEVs in 2030

Techno-economic parameters	Assumed values
Round-trip efficiency, %	90 ^a
Depth of discharge (DoD), %	80 ^b
Life cycle of Li-ion batteries (number of deep-discharge cycles) ⁵	4 500 ^c
Battery Cost (€/kWh)	237 ^d , 204 ^e

Sources: a, b, c: Hartmann and Ozdemir (2011); d, e: Pasaoglu et al. (2012) for the 'slightly decarbonised' scenario and 'highly decarbonised' scenario, respectively.

The demand for electricity of BEVs in 2030 is further calculated by replicating existing driving patterns using the BEV deployment forecast for each passenger car segment, illustrated in Table 2. The aggregated demand for electricity of potential BEVs reveals that driving patterns differ across seasons, days and passenger car segments. For example, Figures 1 and 2 illustrate the aggregated potential electricity demand curve per passenger car segment for a weekday (Tuesday) and a weekend day (Saturday), respectively, in 2030. Here, spring is randomly selected solely for illustrative purposes; as a reminder, the model deals with all seasons, days and passenger car types.

The total consumption of passenger cars in Figure 1 illustrates that the majority of BEVs are mainly driven between 7:00 a.m. and 5:00 p.m. The use of BEVs during the morning peak hour (2400 MWh) and during the evening peak hour (2700 MWh) represents mainly commuting trips.

Figure 1. Electricity consumption of BEVs on a spring Tuesday in 2030 in the 'highly decarbonised' scenario

⁵ The lifetime of a battery depends on the depth of discharge. In this study, to avoid battery degradation due to deep cycling, DoD is set to 80%, which implies a lifetime of 4500 charging cycles (Hartmann and Ozdemir, 2011).

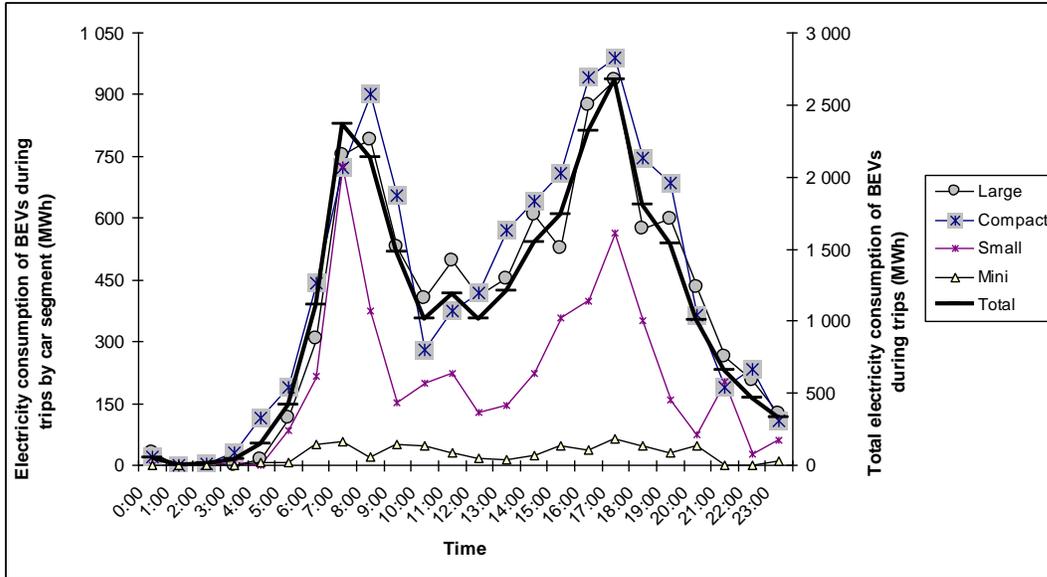


Figure 2 illustrates three aspects that are different at the weekend (i.e. on a Saturday): 1) the majority of trips start later than during a week-day; 2) the trips are more homogeneously distributed throughout the day than on a weekday, when the peak hours were 7:00 a.m. and 5:00 p.m.-7:00 p.m.; 3) cars consume more electricity on a Saturday than on a Tuesday, indicating increased travel activity on Saturdays (a total consumption of 28 355 MWh versus 26 195 MWh).

Figure 2. Electricity consumption of BEVs on a spring Saturday in 2030 in the ‘highly decarbonised scenario’

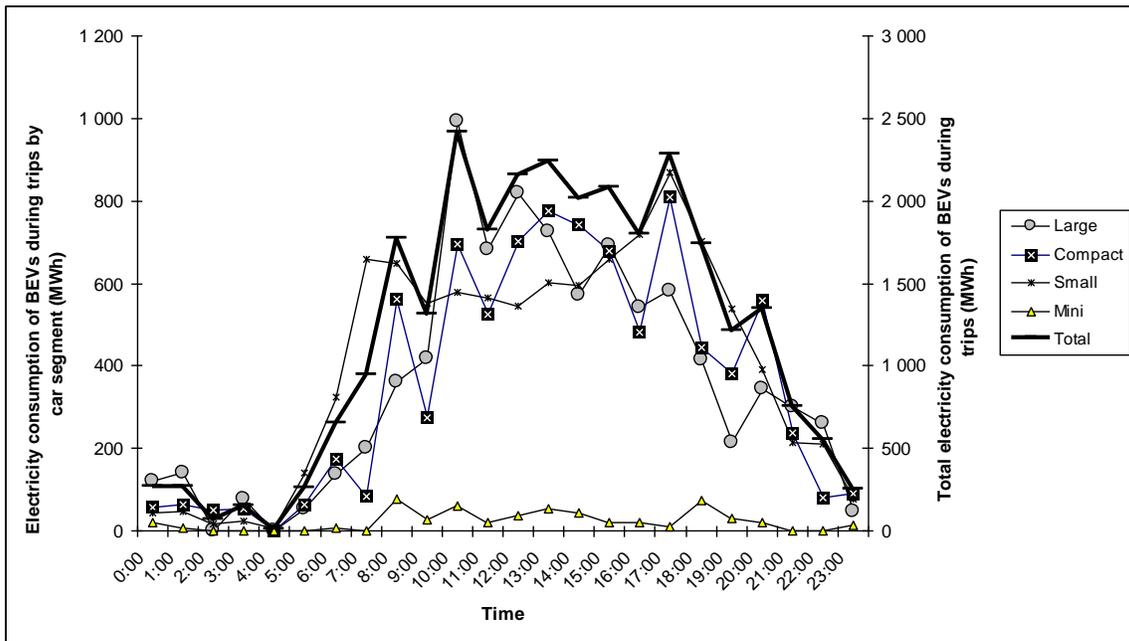


Table 4 illustrates the 24-hour distribution of average vehicle use (the fraction of the fleet of cars in operation) on a weekday and a weekend day during spring. It reveals that more than 70% and 90%, respectively, of passenger cars are not in use 7:00 a.m. – 7:00 p.m. and 8:00 p.m. – 6:00 a.m., respectively, and thus they are available for charging/discharging operations. It is worth stating that the patterns of behaviour are similar on other weekdays.

Table 4. Usage ratios of BEVs on Tuesdays and Saturdays in spring (assumed for 2030 based on the data derived from MiD 2008).

Time	BEV usage ratio Tuesday (%)	BEV usage ratio Saturday (%)
00:00	0.3	2.6
01:00	0.0	1.9
02:00	0.3	0.7
03:00	0.3	1.1
04:00	0.8	0.2
05:00	2.7	1.6
06:00	8.2	3.8
07:00	18.9	4.7
08:00	21.7	11.7
09:00	16.5	16.7
10:00	16.3	30.0
11:00	17.2	25.3
12:00	16.1	23.0
13:00	17.5	23.6
14:00	17.1	22.2
15:00	19.1	19.2
16:00	25.6	15.0
17:00	25.7	16.9
18:00	20.7	15.2
19:00	18.9	11.2
20:00	9.9	10.8
21:00	7.9	5.2
22:00	5.3	4.9
23:00	3.4	2.6

The transport analysis supplies more information to the dispatching model about the number of cars parked and those in use by 2030. This provides an estimate of the capacity of the batteries available to the grid in each of the G2V and V2G schemes. It is assumed that the parked cars are connected to the electricity network and, therefore, are available to participate in the charge and discharge strategies. The total annual power demand of BEVs is 2 TWh in the ‘slightly decarbonised’ scenario, and 8.9 TWh in the ‘highly decarbonised’ scenario. Each scenario will be considered in the projection of the German power system by 2030.

2.2. Power plant dispatching model

2.2.1. Description of the model

The power plant dispatching model, based on linear programming, is designed to describe the power generators in the German system. The model, Dispa-SET, was developed at the Joint Research Centre during activities undertaken as part of the Strategic Energy Technology Plan to analyse power storage technologies.

The model is implemented in GAMS, using the CPLEX solver.⁶ The model has also been applied to large-scale storage technology within the French power system (Loisel, 2012). The problem consists of minimising annual variable system costs by operating power generators and interconnection capacities (see Table 5). No investment occurs over the simulation year, as the installed generation capacities are fixed. Fixed demands are addressed for the national supply and export flows of power, while imports are endogenously set.

Dynamics principles describe the system over one year, with 8760 time slices. The model minimises the total operational cost of the power system under technical and economic constraints. The system costs include fuel costs, the carbon price, the variable O&M costs, the import cost, and feed-in tariffs for biomass and combined heat and power (CHP). Technical constraints are the minimum operational loads, ramping restrictions and maximum load factors. Minimum operational levels are introduced on an hourly basis to reflect the operational limitations of nuclear power plants in the base year. On a yearly basis, the minimum operational level takes into account purchase obligations (biomass) or a lack of heat demand for CHP.

Ramping rates define the variation in output between two periods from one hour to the next. In line with Traber and Kemfert (2011), they are defined for nuclear power plants (base year only), coal-fired plants, combined-cycle gas-fired units (CCGTs), and for lignite-fired, hard coal, and gas with CHP processes. High or full flexibility is assumed for the other technologies due to their aggregation, since a system composed of several power plants is more flexible than a single power plant.

Maximum load factors can define the maximum use of a technology due to load-following operation, limited inflow of natural resources, and power plant unavailability due to maintenance or political planning decisions.

The maximum load factor is specified for every hour for solar, wind and hydro power, based on data from German TSOs;⁷ it has an average annual value for dispatchable resources, such as biomass. The maximum load factors reported in Table 5 are calibrated against the data on installed capacity and power generation by technology from Eurostat (2010) and Schlesinger et al. (2011). The values for annual load factors shown in Table 7 (see section 3.1) are, instead, the outputs of the model, simulated under the constraint of the maximum load factors above.

⁶www.gams.com/dd/docs/solvers/cplex.pdf.

⁷www.enbw-transportnetze.com; www.amprion.de; www.tennetso.de; www.50hertz.com/.

The system selects solar and wind power according to their position in the merit order curve,⁸ taking into account the ability of other technologies to ramp down their generation. Under Germany's Renewable Energy Act (EEG), transmission system operators are allowed to curtail the infeed of wind only as a last resort.

Modelling BEV integration assumes that recharging is managed by a central fleet operator acting as an aggregator of individual vehicles. Battery charging occurs at the lowest price, which is the marginal power generation cost. The V2G framework described does not correspond to a business model from the perspective of maximising profit for drivers; it responds to system needs to increase its flexibility. No speculation is allowed on the market through price arbitrage with batteries. The programme is framed in the context of the system as a whole, where a double constraint exists: on the demand side to fulfil the hourly load demand, BEV included, and on the supply side to respect the ramping limitations for nuclear, CCGT and coal-fired power plants. Under operational limitations, charging batteries could be useful to the system in cases of excess power from non-dispatchable sources, in order to avoid power curtailment.

For given installed generation capacities, the model dispatches the generators to meet the fixed demand. The calibration year is 2010, which is different from the calibration year of the transport model; their common point is the projection to the year 2030. The hourly demand is obtained from Entsoe,⁹ and shows a total of 548 TWh and a peak of 92 GW. Detailed hourly information is implemented for exports and for wind, solar and hydropower.¹⁰ Technology descriptions for installed capacities are provided by Eurostat, and operational parameters by SETIS calculator.¹¹

⁸The merit order curve ranks power plants based on their variable costs from low merit-order base-load units to high merit-order peak-load units.

⁹[https://www.entsoe.eu/index.php?id=92&no_cache=1&sword_list\[\]=values](https://www.entsoe.eu/index.php?id=92&no_cache=1&sword_list[]=values) (last accessed at 04/11/2011).

¹⁰www.enbw-transportnetze.com; www.amprion.de; www.tennetso.de; www.50hertz.com/.

¹¹<http://setis.ec.europa.eu/> (website accessed on 15/02/2012).

Table 5. Main inputs in the model for the years 2010 and 2030

Technology	2010							2030						
	Installed capacity	Efficiency	Fuel Cost	CO2 emissions	Max Load	O&M costs	Ramp	Installed capacity	Efficiency	Fuel Cost	CO2 emission	Max Load	O&M costs	Ramp
	MW	%	€/MWh	kg/kWh	%/yr	€/MWh	%/h	MW	%	€/MWh	kg/kWh	%/yr	€/MWh	%/h
Nuclear	20 480	33	2.1	0	78	1.75	0,9	0	33	3				
Hard Coal	16 715	36	7.2	0.34	66	2	14	4 373	38	9	0.34	35	1.9	13
Coal Lignite	12 699	39	4.5	0.36	90	2.6	8	6 803	42	4.5	0.36	55	2.5	8
Hydro	4 246	100	0	0	51	2.6	100	5 400	100	0	0	51	2.6	100
Oil	3 652	33	17.2	0.28	23	1.5	100	400	33	17.6	0.28	10	1.4	100
CCGT	2 663	50	21.7	0.2	40	1.3	50	6 471	58	25	0.2	40	1.3	50
NGGT	7 799	35	21.7	0.2	46	1.5	100	18 953	35	25	0.2	46	1.5	100
Biomass, waste	6 453	27	37.7	0	50	1.6	100	4 000	27	50	0	35	1.59	100
CHP	21 790	30	25	0.2	50	2.16	50	35 900	30	25	0.21	35	2.16	50
Wind On-shore	26 680	100	0	0	15	0	100	35 800	100	0	0	25	0	100
Wind Off-shore	520	100	0	0	29	0	100	16 700	100	0	0	43	0	100
Solar	9 800	100	0	0	15	0	100	43 100	100	0	0	15	0	100
Other	5 729	30	10	0	43	1	100	4 100	30	20	0.15	58	1	100
Total Installed Capacity	139 226							182 000						
Imports, MW	15 000							25 000						
Export, GWh	54 132							20 730						
Storage	6 976	81			15	0.12	100	6 976	81			25	0.12	100
Demand, GWh	520 808							456 651						
Losses, GWh	11 733							9 742						
CO₂, €₂₀₁₀/tCO₂	10							41.3						

Note: CCGT stands for ‘Combined Cycle Gas Turbine’, NGGT for ‘Natural Gas Gas-Turbine’, CAES is ‘Compressed Air Energy Storage’ and PHS is ‘Pumped Hydroelectric Storage’.

2.2.2. Description of scenarios

Several scenarios have been developed for 2030 for deploying electric vehicles, based on the projections of Schlesinger et al. (2011; the ‘Ausstieg’ scenario, p. 3739). The phasing out of nuclear power generation by 2030 is assumed, as is the use of more coal-fired and gas-fired units. The demand for electricity will drop by 13 % compared to 2010, and the proportion of renewables will increase (60 % from installed capacities in 2030).

Two scenarios for 2030 are analysed for electric vehicles as a function of the number of cars determined in section 2.1. The first scenario, called ‘Slow’, assumes a slow rate of development of the current fleet to 1.1 million by 2030. The second scenario assumes the number of BEV cars will increase to 4.8 million (the ‘Accelerated’ scenario, or ‘Acc’).

Each projection assumes that battery charging and discharging take place at a connection capacity of 3.7 kW for half the cars, and that the other half has access to fast charging stations of 60 kW. At this high capacity, the performance of charging is improved in terms of speed, safety and communication (Nationale Plattform Elektromobilität, 2010).

The model is run using perfect foresight of the demand for both residential consumption and electric vehicles, which implies that security and safety criteria are always met with minimum safety margins. In practice, larger safety margins should be provided by the vehicle system operator as a guarantee that the demand for BEVs will always be fulfilled. To deal with uncertainties, sensitivity tests are performed to investigate how robust the

model is for different configurations of power demand for electric vehicles. It is assumed that the central operator of the car fleet provides a safety margin of 10 % of the total battery stock (the ‘REZ’ scenario). Two structures are tested: 100 % of cars would be charged from home, and none using fast charging (‘HOME’), or conversely, zero from home and 100 % with fast charging (‘FAST’). Table 6 summarises the scenarios.

Table 6. Summary of scenarios and tests

Scenarios	Scenario SLOW cars = 1.1×10^6	Scenario Accelerated cars = 4.8×10^6
G2V scheme	G2V_Slow	G2V_Acc
V2G scheme	V2G_Slow	V2G_Acc
Tests	Scenario SLOW cars = 1.1×10^6	Scenario Accelerated cars = 4.8×10^6
Tests: car reserve = 10 %		
V2G scheme	V2G_S_Rez	V2G_A_Rez
Tests: charge = 100 % Home		
G2V scheme	G2V_S_HOME	G2V_A_HOME
V2G scheme	V2G_S_HOME	V2G_A_HOME
Tests: charge = 100 % Fast		
G2V scheme	G2V_S_FAST	G2V_A_FAST
V2G scheme	V2G_S_FAST	V2G_A_FAST

3. Analysis of results

3.1. Grid-to-vehicle scenarios

Base year 2010. This simulation evaluates the ability of the model to reproduce the system behaviour in 2010. Table 7 presents the main outputs, aggregated over the year. The generation mix calculated with the Dispa-SET model reproduces the shares of generation in 2010 in the German power system: coal (35 %), nuclear (26 %), CHP (15 %), gas (4 %), oil (1.3 %), hydro (4 %), wind (6.6 %), biomass (2.6 %), solar (2.3 %) and others. Storage accounted for 1.8 % of total demand. The system produces 15.4 % of net energy generation from renewable sources (16.2 % of net internal demand), of which 43 % is generated using wind power, followed by hydro (25 %), biomass (17 %, without CHP processes) and photovoltaic (15 %).

The year 2030, no electric vehicles. In line with the projections set for installed capacity, the power generation structure changes by 2030 as follows: the phasing out of nuclear power generation is compensated for by commissioning coal- and gas-fired power plants with CHP technology, and by increased renewables and decreased export flows. Network capacity extensions allow for greater imports of power, 50 % more than in the base year. The proportion of renewables in total generation amounts to 49 % (or 50 % of total demand). Despite the increase in technologies with low variable costs, such as wind and

solar power, the average shadow cost¹² rises by 38%, from €₂₀₁₀67/MWh in 2010 to €₂₀₁₀93/MWh in 2030; this is due to the increased power generation based on high operating and fuel costs, such as gas-fired (+11 TWh from the base year) and CHP-based power (+27 TWh).

Wind power generation amounts to 140 TWh for installed capacities of 52.5 GW. Curtailing wind power is an option to integrate wind power fluctuations; it amounts to 2.9 GWh, which represents a minor share of the total wind power flow. This reflects the occasional limits of the system in absorbing the entire wind inflow, due in particular to ramping constraints set on coal, CCGT and CHP technologies. The wind inflow in Table 7 is net of wind curtailment and accounts for the power on the grid in the base year. In practice, wind curtailment attains higher values (Fink et al., 2009). Solar power, with a potential of 56 TWh, has a curtailment rate of 2% in this model.

The year 2030, grid-to-vehicle scenarios. The G2V scenarios introduce an additional power demand by 2030: 0.45% in the Slow scenario and 2% in the Accelerated scenario. The periods when BEV power demand enters into the system are essential for the stability of the grid and for the overall equilibrium of supply and demand. The model frames the optimisation for charging millions of batteries; in this context, charging batteries could add not only power demand to the system, but also the opportunity to absorb excess wind and solar power. The aggregated results of the simulations are presented in Table 7.

Table 7. Aggregated results of scenarios for 2010 and 2030 for baseline, G2V and V2G, with tests on higher load factors allowed for coal and gas use

¹²The shadow cost is the maximum price that the system is willing to pay for an extra unit of power generated. It corresponds to the infinitesimal change in the objective function by infinitesimally straightening the constraint. In practice, it might not correspond to the wholesale price set on the Epexspot market, which is the platform where German power exchanges occur. The average power price in 2010 was around €₂₀₁₀44/MWh (<http://www.epexspot.com/en/market-data/auction/auction-table/2009-12-31/DE>). Our theoretical price level is different from the market price due to the additional costs implicit to the system, implied for instance by ramping rates and political constraints, such as limits on the use of coal and gas. The shadow cost might differ from the market price by a theoretical proportionality factor as, in practice, operators might have a higher degree of freedom to act on the market price.

Technology	Scenarios						Tests on LF	
	2010	2030, no BEV	G2V_SLOW	G2V_ACC	V2G_SLOW	V2G_ACC	V2G_SLOW_high LF	V2G_ACC_high LF
	Generation GWh	Generation GWh						
Nuclear	139 936	-	-	-	-	-	-	-
Hard Coal	93 517	11 492	11 492	11 492	11 492	11 492	6 054	10 015
Coal Lignite	100 119	29 797	29 797	29 797	29 797	29 797	56 209	58 581
Hydro	21 204	23 280	23 456	23 910	23 701	23 925	23 474	23 870
Oil	7 358	350	350	350	350	350	343	343
CCGT	9 331	14 171	14 171	14 171	14 171	14 171	48 750	48 750
NGGT	6 832	13 725	15 322	21 635	14 977	21 621	7 097	7 090
Biomass, waste	14 132	7 008	7 008	7 008	7 008	7 008	7 008	7 008
CHP	83 504	110 069	110 069	110 069	110 069	110 069	62 897	62 897
Wind On-shore	35 098	77 685	77 685	77 685	77 685	77 685	77 685	77 685
Wind Off-shore	1 326	62 508	62 508	62 508	62 508	62 508	62 508	62 508
Solar	12 463	53 963	54 347	54 810	54 481	54 811	54 306	54 790
Other	21 580	20 831	20 831	20 831	20 831	20 831	20 831	20 831
Total, GWh	546 400	424 882	427 039	434 269	427 073	434 271	427 163	434 369
Storage discharge, GWh (PHS, CAES)	7 808	7 517	7 517	7 517	7 517	7 517	7 517	7 517
Imports	42 048	63 948	63 948	63 948	63 948	63 948	63 948	63 948
Export, GWh (input)	54 132	20 730	20 730	20 730	20 730	20 730	20 730	20 730
Net exports, GWh	12 084	-43 218	-43 218	-43 218	-43 218	-43 218	-43 218	-43 218
Demand, GWh	520 808	456 651	456 651					
Demand BEV, GWh (G2V)	-	-	2 049	8 918	2 049	8 918	2 049	8 918
Supply BEV, GWh (V2G)	-	-	-	-	323	21	1 150	923
Losses, GWh	10 867	9 742	9 742	9 742	9 742	9 742	9 742	9 742
Storage charge, GWh (PHS, CAES)	9 583	9 223	9 223	9 223	9 223	9 223	9 223	9 223
Battery charge, GWh			2157	9 387	2 515	9 410	3 431	10 410
CO ₂ emissions, Mt	252	123	124	128	124	128	118	122
CO ₂ emission rate, g/kWh	460	289	290	294	290	294	276	281
RES Curtailment, GWh	467	851	467	4	333	3	508	24
Average marginal cost, € ₂₀₁₀ /MWh	67.16	92.47	93.29	95.64	94.75	95.85	60.03	61.95
System cost, million € ₂₀₁₀	17 949	18 451	18 832	19 442	18 799	19 441	16 829	17 195

Note: CCGT stands for ‘Combined Cycle Gas Turbine’, NGGT for ‘Natural Gas Gas-Turbine’, CAES is ‘Compressed Air Energy Storage’ and PHS is ‘Pumped Hydroelectric Storage’.

In the ‘G2V_Slow’ scenario, solar power curtailment is reduced by a significant amount — 384 GWh — which represents 18% of the additional generation due to BEV power demand. Hydropower also increases in this scenario, representing 8% of additional power generation; some of the hydropower is modelled as a non-dispatchable resource with a fixed natural hydro profile. Therefore, the power could be curtailed in the baseline and used below the maximum natural potential. Unlike wind and solar, O&M costs for hydropower are not insignificant; therefore, the technology ranks higher than wind and solar in the merit order curve. The remaining part of the increased power generation comes from NGGTs (74%).

This extends the increase in CO₂ emissions by 0.9 Mt of CO₂, or 0.8% from the baseline, which should be considered in the context of the savings in CO₂ emissions as a result of

the presence of BEVs in the transport sector.¹³ In the overall generation mix, the rate of CO₂ emissions is on the order of 290 g/kWh, which is only slightly higher than the baseline, due to greater integration of solar and hydropower. If the BEVs in the G2V_Slow and G2V_Acc scenarios were replaced with gasoline and diesel internal combustion engine cars, there would be an additional 1.3 Mt and 6.5 Mt of CO₂ emissions, respectively.¹⁴

Generating more power by means of natural gas turbines increases the system costs by €381 million from the baseline. Additional costs related to the use of the infrastructure, information costs and other transaction costs are not included here, with the understanding that they could, in fact, be significant. However, the overall cost of power generation should be put into perspective against the total cost of fighting climate change, reducing dependency on imported oil and securing market share in the automotive industry, if gains are to be obtained for national car production and exports. The average shadow cost of power generation increases by 0.9% from the baseline, which again should be analysed in the context of forecasts of increased oil prices by 2030.

The scenario with an accelerated rate of BEV penetration, 'G2V_Acc', has a higher impact on the power generation mix, due to higher demand for power (2%) and higher battery capacity. This further accentuates the effects seen in the Slow scenario: higher avoidance of solar power curtailment (+847 GWh from the baseline), higher hydro power generation (+630 GWh), higher dispatch of natural-gas gas turbines (+7.9 TWh), higher CO₂ emissions (+4.5 Mt), higher system costs (+€991 million) and higher power generation costs (+3.4%).

The analysis next depicts the potential gains that both car owners and power companies may experience by exploiting the power storage potential of batteries by using cars which are not being driven as vehicle-to-grid devices.

3.2 Storage provision through vehicle-to-grid scheme

The results of the scenarios for V2G, both Slow and Accelerated, are reported in Table 7 of the previous section. The analysis first depicts the 'V2G_Slow' scenario, in which the energy provision is higher than in the Accelerated scenario due to the higher need for flexibility. In this scenario, in optimal conditions 323 GWh could be provided by means of BEVs. The total power generation is close to the total amount of electricity produced in the G2V_Slow scenario, since no additional demand for power is created. This amount has to be modified for losses due to additional charging and discharging of batteries, i.e. 35 GWh of losses with an efficiency rate of 95% for each charging and discharging operation. The main difference between G2V and V2G scenarios in generating the same power flow lies in the mix of technologies and the way their dispatching is differentiated by time. During the simulation year, V2G integrates more variable flows from hydro and solar power than G2V, replacing the most expensive technology in the merit order curve

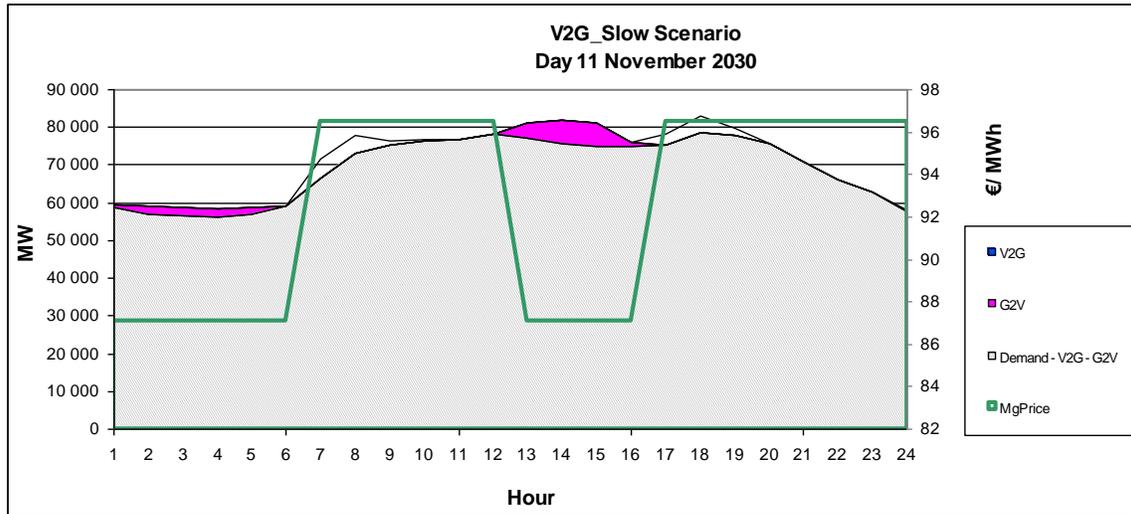
¹³For a more detailed analysis of the CO₂ aspects of electric vehicles, see Thiel et al. (2010).

¹⁴ Calculations are based on values for technological improvement factor and wheel-to-wheel efficiencies from Pasaoglu et al. (2012).

(NGGTs). During one day, this is reflected in the graphs in Annex 1, which are representative of the dispatch described when batteries are called on to meet the demand.

The diagram below gives a daily representation of charging and discharging batteries as a function of the marginal power cost. It should be noted that charging occurs not only at night, but also during the day if the wind and solar power excess favours this operation. On the discharge side, the use of batteries as back-up to the power system occurs during the morning and evening load peak times, with additional provision at the end of solar power provision, specific to a November day lighting profile.

Figure 3. Battery charging/ discharging operations during one day



The capacity of the total car fleet is 26.4 GW in the Slow scenario, and 114.8 GW in the Accelerated scenario. Many cars are parked even during peak driving times (70–90%). The potential available if this capacity is used could exceed the depth of markets of ancillary services (Peterson et al., 2010). Andersson et al. (2010) document the size of the German regulating power market at 11 GW in 2008. This is one of the reasons we model the wholesale market only, while admitting that additional benefits for BEVs could be obtained on the secondary and tertiary reserve markets (Kempton and Tomic, 2005; Andersson et al., 2010). However, these markets would be saturated for high car penetration rates, which would decrease potential revenues in these market segments (Peterson et al., 2010). Additional benefits for storage could arise from avoiding grid congestion in the case of massive inflows of wind and solar power, which would reduce power curtailment and would defer the investment for grid reinforcement (Loisel et al., 2010, 2011).

The outputs of the model show that batteries are used more for energy provision than for power supply, as indicated by the low number of calls (131 times or 1.5% of the time) and the high average capacity called during the year: 2.5 GW, peaking at 8 GW.

By contrast, in the Accelerated scenario (V2G_Acc), the reserve provided by batteries is minor, 21 GWh. This is primarily because the high number of BEVs in this scenario

already provides a negative control reserve, which reduces the need for any additional reserve. The low figure for wind and solar power curtailment in the G2V_Acc scenario indicates that charging batteries optimally already introduces a higher flexibility into the system, and thus it relies less on batteries than V2G does.

Second, more power demand for charging cars reduces the freedom power generators have to perform inter-temporal arbitrage between storing electricity in batteries and supplying the total power demand. For instance, increasing the maximum load factors in the model for fossil-fuel power plants could increase the freedom of generators to dispatch their operation differently and would result in a different use of batteries. The modelling framework has fixed maximum levels for load factors (LFs) of coal- and gas-fired power plants, according to the scenario forecast by the German authorities (Schlesinger et al., 2011). The choice of these assumptions (fixed LFs lower than the technical potential) translates into a political will to reduce the use of polluting fuels, since only 1.4 GW of hard-coal and lignite power plants, out of 20 GW (CHP included), are provided with CCS systems. Removing these political parameters, another scenario has been designed, ‘V2G_highLF’, in which batteries contribute not only to the integration of variable renewables, but also support the ramping operations of less flexible technologies, lignite-fired units and gas-fired units with combined cycle systems.

The test on higher load factors with a slow rate of BEV penetration, ‘V2G_Slow_highLF’, results in more lignite-fired units and combined cycle gas turbines being dispatched than in the G2V_Slow scenario, which is detrimental to CHP and NGGT power plants. The use of batteries to support inflexible units is higher than for the limited-load-factor baseline case, by 923 GWh. The new optimisation enhances the decrease in system costs and power generation costs, along with CO₂ emissions. Other system benefits would arise from avoiding ramping up and down the base-load and semi-base-load units; these benefits are not quantified here, but could represent an additional driver for the power system to use batteries to induce more flexibility in base-load units in their interaction with variable renewables (Peterson et al., 2010).

The Accelerated scenario, ‘V2G_Acc_highLF’, qualitatively follows the same trends as the Slow scenario, with fewer possibilities with regard to the availability of generators to charge batteries due to an increased power demand from BEVs.

3.3. A cost-benefit analysis of the V2G scheme

The benefits of the system are viewed from the perspective of the costs of battery degradation due to V2G provision (Annex 2). It is assumed that complete charging-discharging cycles occur to an 80% discharge depth and that the depreciation cost directly correlates with the number of cycles. In practice, depreciation increases towards the end of the life of the battery. Wood et al. (2011) show that, at an 80% discharge depth rate battery degradation occurs linearly until 2400 cycles, and increases non-linearly after this point. At different discharge depth rates, the depreciation trend varies. Indeed, both indicators, battery capacity and battery power, should be considered when assessing battery degradation. According to the same authors, modern EVs are designed to allow

for battery degradation without affecting the electric power capability of the drivetrain. Therefore, we assume improved performance in terms of energy and power capability by 2030.

The battery depreciation cost is obtained by dividing the battery investment cost by the total number of cycles, which multiplies the number of cycles due to V2G provision. By car type, the depreciation costs ranges from €0.68/cycle for a 15 kWh capacity car (mini) in the Accelerated scenario to €1.58/cycle for a 30 kWh car (large) in the Slow scenario. Investment costs differ according to the assumptions made about mass car deployment. These costs do not include the salvage value of the battery, which may include additional services which could be provided after the ‘driving lifetime’ of the battery, during a potential ‘second lifetime’(Neubauer and Pesaran, 2011). The additional cost for car owners for providing energy to the grid is different in different scenarios:

- In the Slow scenario, the total power provided to the grid is 323 GWh and there are 22.5 cycles per car per year, on average. The degradation cost is, on average, €25.80 per car per year (€20.20 for a mini car, €23.80 for a small car, €26.00 for a compact car, and €33.30 for a large car).
- In the Accelerated scenario, the provision of power is low — 21 GWh — while the number of electric vehicles is high. The degradation cost is between €0.00 and €1.30 per car per year.

The benefits of the power system range from €22 to €37 per car in the Slow scenario, and from €0 to €1 in the Accelerated scenario. If car owners were rewarded based on this added value, the net benefit, not including the cost of battery degradation, would be at a modest level of around €2 per year per car, and even negative in the Accelerated scenario. This would certainly not be an incentive for car owners to participate in a V2G scheme, unless capacity payments were added to this market revenue. Additional benefits could be effective if they were based on criteria other than the market (e.g. social, political or environmental); for instance, in the V2G_Slow scenario, batteries contribute to avoiding the curtailment of 176 GWh of solar power. In the model, renewable energy is valued at the marginal operational cost, which is close to zero; therefore the benefit of BEVs to the system as support for renewables could receive further consideration. Fixed price margins could add to the real-time pricing that the model applies.

The results in terms of benefits by car are calculated as averages. In practice, not all cars would participate in the V2G scheme, due to different infrastructure configurations and different individual decisions. If the full capacity of a car is used for V2G, moderated by the depth of discharge rate, then the proportion of BEVs by car type which would be involved in the V2G scheme would be 50%, 44%, 45% and 42% for mini, small, compact and large cars, respectively. If the benefits were to be shared between this reduced number of cars, the revenue by car would rise to €47–88, but the degradation cost would increase too, since the number of cycles per car would increase from 40 to 79 per car per year. The net benefit per car would be €1–2 higher than if all cars participated in V2G.

Using batteries as reserves is not a viable business case: if the system benefit were to be shared between all owners of BEVs, each individual would make a modest profit of €5–6 per year in the Slow scenario, and even a loss in the Accelerated scenario. The results could be different under a programme designed to maximise profits for BEV car owners, where individuals would act as independent power operators and would bid on the market at higher prices or freely chose the delivery time. This model instead minimises system costs and constrains the energy delivery time.

Other studies have assessed the economics of V2G from the perspective of BEV investors. Peterson et al. (2010) estimate that the profit from BEVs would be US\$10–120 per car per year in three US power markets. Srivastava et al. (2010) also indicate that BEVs as base-load power providers would face uncompetitive prices, while Kempton and Tomic (2005) state that BEVs would not be competitive for size reasons. Our results join this literature and add the findings that, for a high number of cars (e.g. the 4.8 million in the Accelerated scenario), the optimal charging of batteries through G2V would be enough to increase the reliability of the system for high RES penetration rates; adding V2G becomes a costly measure. For a lower number of cars (e.g. the 1.1 million tested in the Slow scenario), the profit for car owners remains insufficient as an incentive to participate in a V2G scheme (a maximum of €6 per car per year), while system benefits as high as €33 million a year could represent an argument for it being in the interests of power plants and grid operators to build V2G business models.

3.4 Sensitivity tests

A set of tests was run to identify the role of assumptions set on the number of cars participating in the V2G scheme.

The first test assumes that a reserve is provided in terms of recharged batteries to satisfy the demand for power at any moment. This reserve is fixed at 10 % of the total number of cars. The results in the V2G scenario are robust, where the number of cars called by the model for V2G is below 50 % at any moment of the year (see Table 8).

Before conducting tests on the charging station, the results of the V2G scenarios are analysed in terms of the number of cars charging from home and from fast charging stations. The Slow scenario is the most relevant in terms of power delivered to the grid and of the number of cars participating in V2G. In average, the proportion of V2G cars charging from home is broadly similar to the proportion of cars delivering power to the grid from home, ranging between 13 % and 25 % from the total number of cars.

Table 8. Statistics of cars involved in V2G scheme at full capacity

V2G_Slow scenario, 50 % HOME, 50 % FAST	Mini	Small	Compact	Large
Total number of cars	125 725	258 933	396 632	326 286
Maximum Power V2G delivered during one hour, MWh	754	1 840	3 427	3 287
Maximum Power delivered by one car V2G, kWh	12	16	19	24
Maximum number of cars V2G at full capacity	62 863	114 982	178 484	136 970
Power delivered to the grid, V2G, GWh	28	67	112	117
Power delivered from home, GWh	7	13	21	11
Power delivered from fast points, GWh	20	54	90	106

Sensitivity tests assuming 100% charging from fast charging stations do not make a significant difference to the V2G_Slow reference scenario and have even less effect on V2G_Acc, where the power supplied through V2G was very low. The explanation is that the proportion of V2G cars chosen by the model to be connected to fast charging stations was already very high in the reference (between 73% and 91%, depending on car type). The difference is significant in terms of the infrastructure cost necessary to connect fast charging stations to the grid in as many centres as possible. This cost is estimated by the Boston Consulting Group (2009) to be US\$21 billion in Europe for 0.6 million BEVs by 2020.

The test where 100% of V2G operations take place from home limits the ability of batteries to participate in V2G. In the Slow scenario, the test ‘V2G_S_HOME’ indicates lower levels of power delivered (152 GWh instead of 323 GWh) with different consequences in terms of curtailment-avoiding capacity (140 GWh less) and more gas-based power generation (216 GWh). The ‘G2V_S_HOME’ scenario shows similar impacts, such as reduced RES curtailment avoidance (54 GWh), higher gas-fired power generation, and increased system costs (€3 million).

The Accelerated scenario ‘G2V_A_HOME’ also has negative impacts in terms of avoiding power curtailment (-55 GWh), compensated for by increased dispatch of gas-fired units with a higher system cost (+€6 million).

4. Conclusions

This study analysed the impact of BEV penetration on the German power system by 2030 and proposed the case for optimal battery charging using a power plant dispatching model. The results of G2V schemes show the positive impact of charging batteries in a controlled way. Notable effects include increased penetration of renewables — solar in particular — since solar generation has stronger daily fluctuations compared to wind variations, which can be of longer duration. The study indicates the support that BEVs could bring to a V2G scheme for base-load and mid-load power plants by increasing their capacity factors and reducing the number of ramping operations (lignite-fired units and CCGT). V2G therefore contributes to a higher integration of variable renewables than G2V does, as well as reducing system costs due to lower gas consumption. Despite these benefits, profits for car owners remain modest — or even negative — due to accelerated battery degradation, which argues against the economic rationale for car owners to accept such V2G schemes.

The current power pricing scheme based on variable costs would not reward a BEV scheme for the benefits it would bring to the system in terms of support to renewables, grid reliability and increased energy independency. Neither does the wholesale power market reward the degree of innovation of BEVs which bid into the market along with conventional mature generators. Other market segments would be more profitable, such as ancillary services (Bloomberg New Energy Finance, 2011). However, the market would be saturated at high BEV penetration rates, and marginal revenues would decrease accordingly (Peterson et al., 2010; Anderson et al., 2010).

In the V2G scenario, in which BEVs are basically used as a storage asset within the power market, mobile electric batteries compete with other flexibility options that could potentially provide similar flexibility services at lower cost. In the future, these alternative means could include ‘second-life’ battery applications, even further reducing the financial viability of V2G (Taylor, 2012). Under current market regimes, electricity can be rewarded more highly when used for transport than when used within the power sector, as it competes in the transport sector with highly taxed and rather expensive conventional transport fuels (Thiel et al., 2010). This explains the insufficient value proposition that V2G can offer to consumers, as pointed out in our analysis. An important aspect of making V2G more competitive is reducing battery degradation, and consequently increasing battery cycle life. This could improve the cost equation for V2G.

An option that could potentially be more attractive for end users is ‘vehicle-to-building’ concepts (V2B), especially if combined with decentralised variable renewable generation in the same building. This could potentially lead to deferrals of investments in the grid. The latest amended German Renewable Energy Act (EEG) incentivises auto-consumption at the consumer level, and thus could support V2B. However, in order to become effective as a grid deferral option, Ruester et al. (2012) point out that it is important to base the incentive in the EEG also on power, and not only on energy.

This study supports integrating BEVs into the energy portfolio based on new regulatory incentives, such as smart grids and metering initiatives, on both supply and demand sides. For BEVs to become an effective option in the power system, synchronisation between all parties is necessary, and none of the stakeholders is likely to create a viable BEV business case alone.

In the automotive industry, further technological improvements are expected in terms of rated capacity, battery cycle life, battery energy, power performance and cost reductions. In the power system, integrating BEVs requires that grid operators adopt new standards and protocols allowing BEVs to bid in different market segments, most probably through aggregators. From the perspective of policymakers, signals should be framed so that all stakeholders can duly adapt the infrastructure in time, at least for G2V, to optimally control the charging flows. On the consumer side, rising oil prices will further incentivise individual behaviour and social perceptions in favour of electro-mobility. At supranational level, European initiatives are being undertaken to harmonise national standards and regulations, which currently differ between Member States and are at different stages of maturity (European Commission, 2013b).

Our study clearly points out the difficulties that are associated with reconciling electromobility in the transport system with the needs and economics of the power system. Further research is needed to fully understand the potential role of ‘prosumers’ (both producers and consumers of energy), owning or using BEVs within G2V, V2G, or V2B contexts. The complexity of the research topic requires an interdisciplinary approach and further communication and exchanges of information between stakeholders.

Acknowledgements

We are very grateful to Lisa Göransson and Filip Johnsson from Chalmers University of Technology and to our colleagues Alicia Perez (JRC) (for her help with data processing) and Andreas Zucker (JRC) (for his valuable comments). We would also like to express our gratitude to the anonymous referees and the editor, who provided constructive comments and critical feedback on a draft version of this paper. These led to a significant improvement in the paper. The ideas expressed within and any remaining omissions are our sole responsibility.

References

- Andersson, S.L., Elofsson, A.K., Galus, M.D., Göransson, L., Karlsson, S., Johnsson, F., Andersson, G., 2010, ‘Plug-in hybrid electric vehicles as regulating power providers: Case studies of Sweden and Germany’, *Energy Policy* 38(6): 2751–2762.
- Boston Consulting Group, 2009, *The Comeback of the Electric Car?*, www.bcg.com/documents/file15404.pdf
- Bloomberg New Energy Finance, ‘Will electric vehicle cause a pile-up in power reserve markets?’, 23 January 2011.
- ECN, 2011. National Renewable Energy Action Plans of the European Member States, <http://www.ecn.nl/units/ps/themes/renewable-energy/projects/nreap/>
- European Commission, 2010, *Energy infrastructure priorities for 2020 and beyond — A Blueprint for an integrated European energy network*, COM(2010) 677 final.
- European Commission, 2011, ‘A Roadmap for moving to a competitive low-carbon economy in 2050’, COM(2011) 112 final.
- European Commission, 2013a, Paving the way to electrified road transport, DG JRC/IET, Report EUR 25832.
- European Commission, 2013b. *Communication — Clean Power for Transport: A European alternative fuels strategy*. COM(2013) 17.

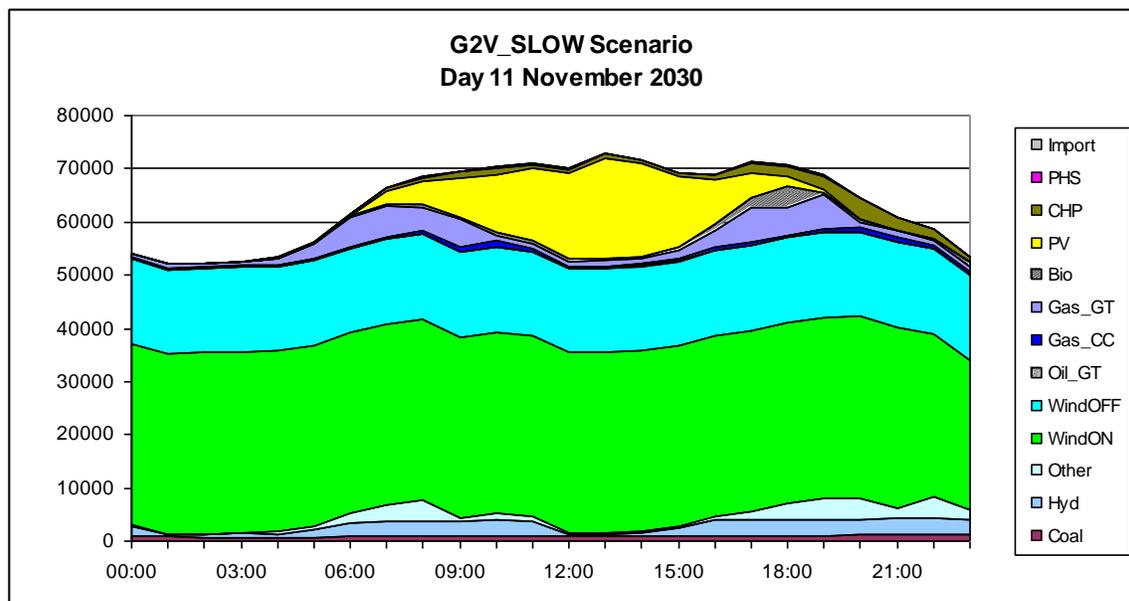
- German Federation for Motor Trades and Repairs, 2011, *Zahlen & Fakten / Deutsches Kraftfahrzeuggewerbe 2010*, Wirtschaftsgesellschaft des Kraftfahrzeuggewerbes mbH im Auftrag des Deutschen Kraftfahrzeuggewerbes Zentralverband, Franz-Lohe-Straße 21, 53129 Bonn.
- German Federal Ministry of Economics and Technology, 2009. *German Federal Government's National Electromobility Development Plan*. www.bmwi.de.
- Göransson, L., Johnsson, F., 2009, 'Dispatch modeling of a regional power generation system — Integrating wind power', *Renewable Energy*; 34(4): 1 040–1 049.
- Göransson, L., Karlsson, S., Johnsson, F., 2010, 'Integration of plug-in hybrid electric vehicles in a regional wind-thermal power system', *Energy Policy*; 38(10): 5 482–5 492.
- Hartmann, N., Özdemir, E.D., 2011, 'Impact of different utilisation scenarios of electric vehicles on the German grid in 2030', *Journal of Power Sources*; 196(4): 2 311–2 318.
- Kempton, W., Tomic, J., 2005, 'Vehicle-to-grid power fundamentals: calculating capacity and net revenue', *Journal of Power Sources*; 144(1): 268–279.
- Loisel, R., 2012. 'Power system flexibility with electricity storage technologies: A technical–economic assessment of a large-scale storage facility'. *International Journal of Electrical Power and Energy Systems*; 42(1): 542–552
- Loisel, R., Mercier, A., Gatzen, C., Elms, N., 2011, 'Market evaluation of hybrid wind-storage power systems in case of balancing responsibilities'. *Renewable and Sustainable Energy Reviews*; 15(9): 5 003–5 012.
- Loisel, R., Mercier, A., Gatzen, C., Elms, N., Petric, H., 2010, 'Valuation framework for large scale electricity storage in a case with wind curtailment'. *Energy Policy*; 38(11): 7 323–7 337.
- MiD 2008*, (Mobilität in Deutschland 2008), Basisstichprobe Deutschland, Datensätze, Tabellen, Methodenbericht, Nutzerhandbuch und Ergebnisbericht. Version: März 2010.
- Neubauer, J., Pesaran, A., 2011, 'The ability of battery second use strategies to impact plug-in electric vehicle prices and serve utility energy storage applications', *Journal of Power Sources*; 196(23): 10 351–10 358.

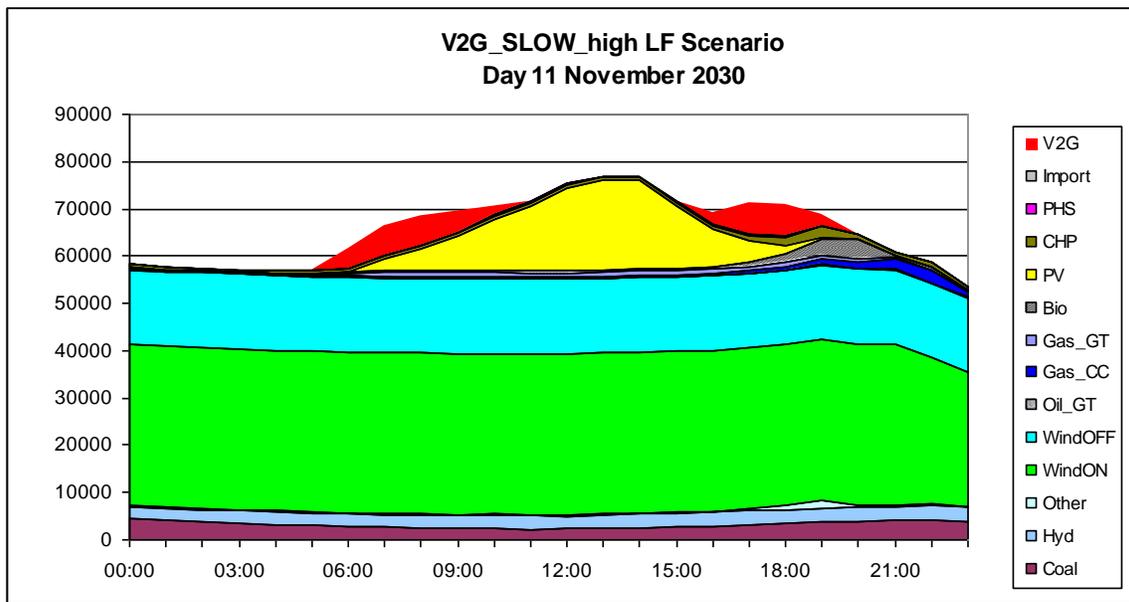
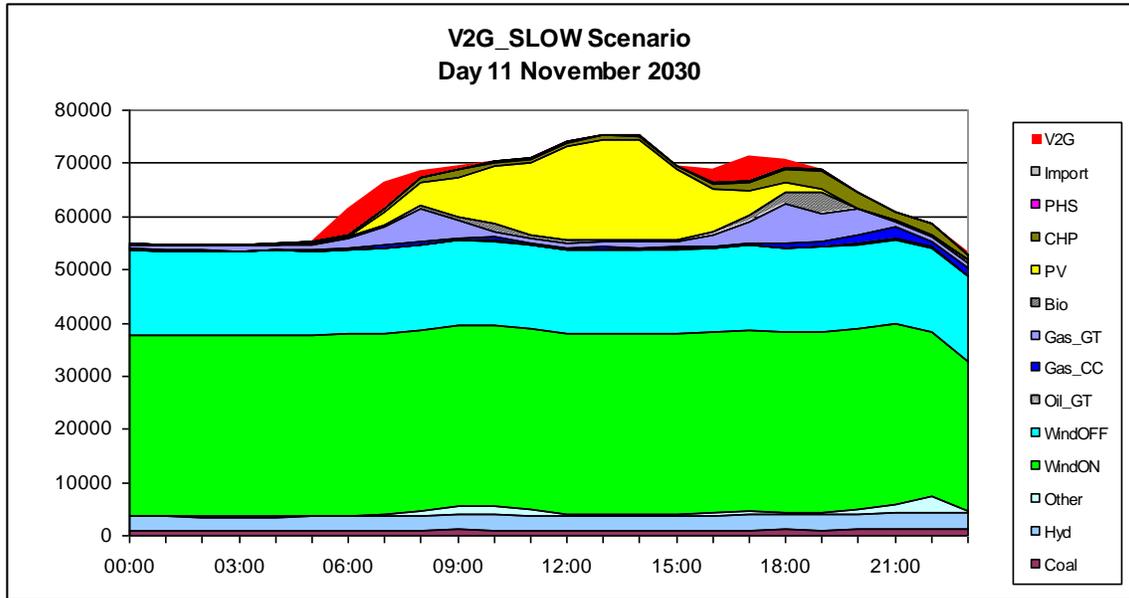
- Nationale Plattform Elektromobilität, *Interim Report of the National Platform for Electromobility*, Nov. 30, 2010. <http://www.bmwi.de/English/Redaktion/Pdf/electromobility-report,property=pdf,bereich=bmwi,sprache=en,rwb=true.pdf>.
- Pasaoglu, G., Honselaar, M., Thiel, C., 2012, 'Potential vehicle fleet CO₂ reductions and cost implications for various vehicle technology deployment scenarios in Europe', *Energy Policy*; 40: 404–421.
- Peterson, S.B., Whiteacre, J.F., Apt, J., 2010, 'The economics of using plug-in hybrid electric vehicle battery packs for grid storage', *Journal of Power Sources*; 195: 2377–2384.
- Perujo, A., Ciuffo, B., 2010, 'The introduction of electric vehicles in the private fleet: Potential impact on the electric supply system and on the environment. A case study for the Province of Milan, Italy', *Energy Policy*; 38(8): 4549–4561.
- Ruester, S., Vasconcelos, J., He, X., Chong, E., Glachant, J-M., 2012, *Electricity Storage: How to Facilitate Its Deployment and Operation in the EU*. THINK project topic 8.
- Schill, W.P., 2011, 'Electric vehicles in imperfect electricity markets: The case of Germany', *Energy Policy*; 39(10): 6178–6189.
- Schlesinger, M., Lindenberger, D., Lutz, C., *Energieszenarien 2011*, Projekt Nr. 12/10 des Bundesministeriums für Wirtschaft und Technologie, http://www.prognos.com/fileadmin/pdf/publikationsdatenbank/11_08_12_Energieszenarien_2011.pdf
- Srivastava, A.K., Annabathina, B., Kamalasan, S., 2010, 'The Challenges and Policy Options for Integrating Plug-in Hybrid Electric Vehicle into the Electric Grid', *The Electricity Journal*; 23(3): 83–91.
- Taylor, P., Bolton, R., Stone, D., Zhang, X.P., Martin, C., Upham, P., 2012. *Pathways for energy storage in the UK*. Report 007/2012, published by the Centre for Low Carbon Futures.
- Thiel, C., Perujo, A., Mercier, A., 2010, 'Cost and CO₂ aspects of future vehicle options in Europe under new energy policy scenarios', *Energy Policy*; 38(11): 7142–7151.
- Traber, T., Kemfert, C., 2011, 'Gone with the wind? — Electricity market prices and incentives to invest in thermal power plants under increasing wind energy supply', *Energy Economics*; 33(2): 249–256.

Vennemann, P., Gruber, K-H., Haaheim, J.U., Kunsch, A., Sistenich, H-P., Thöni, T., 2011, 'Pumped storage plants — Status and perspectives', *VGB PowerTech* 4/2011, <http://www.vennemann-online.de/papers/Vennemann2011.pdf>

Wood, E., Alexander, M., Bradley, T.H., 2011, 'Investigation of battery end-of-life conditions for plug-in hybrid electric vehicles', *Journal of Power Sources*; 196(11): 5 147–5 154.

Annex 1. Dispatching of power generators during one day in V2G and G2V scenarios, with slow penetration rate of BEVs





Annex 2. Table with inputs, outputs and calculation of battery cost-benefit

		Car Type			
		min	small	compact	large
Assumptions	Inputs: Discharge for driving (GWh)				
	SLOW scenarios	141	366	758	784
	ACC scenarios	612	1 595	3 297	3 412
COST ASSESSMENT					
Assumptions	Average discharge by cycle car during life time (kWh)				
	All cases	8.6	11.4	13.7	17.1
	FOM by cycle by car (€₂₀₁₀/cycle)				
	SLOW scenarios	0.8	1.1	1.3	1.6
	ACC scenarios	0.7	0.9	1.1	1.4
Model outputs	Discharge for V2G only (GWh)				
	V2G_ SLOW	28	67	112	117
	V2G_ ACC	9	3	0	8
Calculation	Discharge by car for V2G only (kWh)				
	V2G_ SLOW	219	257	282	360
	V2G_ ACC	17	3	0	6
	Number of cycles due to V2G (#)				
	V2G_ SLOW	26	23	21	21
	V2G_ ACC	2	0.2	0.0	0.3
	FOM by car by year for V2G (€₂₀₁₀)				
	V2G_ SLOW	20.2	23.8	26	33
V2G_ ACC	1.3	0.2	0.0	0.5	
REVENUES ASSESSMENT					
Model outputs	Cost of charging for V2G only (million €₂₀₁₀)				
	V2G_ SLOW	2.4	5.8	9.9	10.4
	V2G_ ACC	1.00	0.3	0.0	0.9
	Revenues from V2G (million €₂₀₁₀)				
	V2G_ SLOW	2.8	6.5	11.0	11.3
	V2G_ ACC	1.0	0.3	0.0	0.8
Calculation	Revenues by car from V2G (€₂₀₁₀)				
	V2G_ SLOW	22.1	25.3	27.7	34.5
	V2G_ ACC	1.8	0.3	0.0	0.6
BENEFIT ASSESSMENT					
Calculation	Benefit by car from V2G (€₂₀₁₀)				
	V2G_ SLOW	2.7	2.8	2.7	2.7
	V2G_ ACC	-0.04	-0.02	0.0	-0.06
	Net Benefit, €₂₀₁₀/ car (Net Benefit = V2G Benefit - FOM)				
	V2G_ SLOW	-17.5	-21	-23.3	-30.5
	V2G_ ACC	-1.4	-0.2	0.0	-0.5
Model outputs	System benefit (V2G compared to G2V, million €₂₀₁₀)				
	V2G_ SLOW	33			
	V2G_ ACC	1			
Calculation	Benefit by car by year, €₂₀₁₀				
	V2G_ SLOW	22.3	26.3	28.8	36.7
	V2G_ ACC	0.97	0.16	0.0	0.33
	Total Net Benefit, €₂₀₁₀ (= V2G Net Benefit + System Benefit)				
	V2G_ SLOW	4.8	5.3	5.4	6.1
	V2G_ ACC	-0.4	-0.1	0.0	-0.2