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RESEARCH ARTICLE

Flexibility of Electric Vehicle Charging With Demand Response and Vehicle-to-Grid for Power System Benefit

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ABSTRACT As charging load from electric vehicles (EVs) increases, its temporal demand may challenge existing power systems. However, as EVs could also supply power to the grid, they could provide benefits for the power systems. Moreover, by controlling the charging, they could reduce their charging costs. Thus, in this study the flexibility of EV charging load within charging events was modeled, considering available charging power, ambient temperature, and unidirectional and bidirectional controlled charging. Then, the charging flexibility was first analyzed by minimizing the charging costs for individual EVs. The results showed that with high electricity market prices, with high fluctuation, the EVs could reduce their charging costs up to 27% and 35%, with unidirectional and bidirectional controlled charging respectively, compared to uncontrolled charging. Secondly, the EV charging flexibility was analyzed for the benefit of the power system by an aggregator, assuming a fully electrified car sector. The benefit was measured by the required additional power source capacity and generation. During the analyzed period, 2018-2023 which peak load was 14.7 GW, the required power source capacity increased significantly with uncontrolled charging, by 2-2.8 GW (40-54%), whereas with controlled unidirectional charging the increase was 0.3-0.8 GW (7-15%), and with bidirectional charging the capacity was the same as without EVs, or slightly less (−11-1%). However, the yearly differences were notable, and during 2020, with bidirectional charging, this capacity increased. Moreover, the required power source generation was greatly affected by the assumed power generation capacities, and was lower with controlled charging, compared to uncontrolled charging.

INDEX TERMS Electric vehicle, demand response, vehicle-to-grid, power system flexibility, renewable energy generation.

I. INTRODUCTION

The International Energy Agency predicts, in their Stated Policies Scenario, that the number of battery electric vehicles (BEVs), will globally increase up to 390 million by 2035 [1]. During 2023, 9.5 million new battery electric vehicles, and 4.3 million plug-in hybrid electric vehicles (PHEVs) were registered, which accounted for 12.4% and 5.6% of the total car sales [1]. Regionally, in the European Union (EU), the share of BEVs was 14.6 % of the new car registrations in 2023 [2]. In addition, the EU has agreed that all new cars and vans should not emit any CO_2 emissions by 2035 [3].

When the share of electric vehicles increases to high levels, the charging load from the vehicles is likely to increase such, that it begins to affect power systems on a national level. Moreover, depending on the temporal variation of this load, it may possess challenges to the existing power systems. However, as the electric vehicles could supply power to the grid utilizing bidirectional charging, vehicle-to-grid (V2G), they could also provide benefits for the power systems, or mitigate the challenges.

Several studies of large-scale EV fleet integration on power systems have been conducted, for a variety of objectives and

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analyses. Increasing the integration of variable renewable energy, by altering the BEVs charging behavior, including V2G, has been studied already in 2008 by Lund and Kempton [4], where they found out that controlling the BEV charging can increase the share of integrated wind power production significantly, on a national level. In addition, increasing the share of renewable generation by controlling the BEV demand has been studies in [5], where the electrification of transportation was able to reduce emissions and increase the share of renewable energy, while in [6] and [7] controlled charging was able to reduce emissions and increase the share of renewables compared to uncontrolled charging. Moreover, in [8], on a European level, the benefits of controlled BEV charging for renewable generation and load mismatch were examined. Moreover, in [9] the effect of BEV charging, with uncontrolled and two controlled charging strategies, on curtailment of renewable energy, costs, emission, and trade balance were analyzed. They found out that the uncontrolled charging often resulted drawbacks on the metrics, while the controlled charging strategies either limited these drawbacks or provided benefits for the system.

The charging behavior on market prices has been studied in [10] and [11], where controlled charging was found to reduce the wholesale energy cost, while in [12], [13], and [14] controlled charging was found to lower the BEVs charging costs. Moreover, in [15] it was found that coordinated charging can reduce the electricity grid's operating costs and wind curtailment at the same time.

A few studies have also focused on the generation capacity requirements with and without electric vehicles. In [16], the effects of different charging strategies on the residual load, i.e., load after renewable generation, in Switzerland were analyzed. They found out that compared to without BEVs, uncontrolled charging increased the residual peak load notably, while controlled unidirectional charging increased it slightly, and controlled bidirectional decreased it. Likewise, in [17] bidirectional charging was found to decrease the peak load, while uncontrolled charging increased it. In addition, in a Chinese case study it was found that utilizing controlled charging, both unidirectional and bidirectional, can reduce the need for newly installed power capacity compared to the same power system without BEVs [18]. Similar findings were presented for Northern Europe in [19] where the need for thermal generation capacity was reduced with V2G, except for the German power system, where the need was increased.

However, also studies where the generation capacity required has increased while utilizing bidirectional charging have been conducted. For a 100% renewable Australian power system, it was found that the capacity required was increased with bidirectional controlled charging, although it decreased compared to uncontrolled charging [20]. Moreover, in a city scale study [21], it was found that uncontrolled charging increased the peak load, while controlled bidirectional charging decreased it to almost to the same level as without BEVs. Moreover, in [22] and [23] the controlled charging decreased the peak load compared to uncontrolled charging.

Although there are studies which have examined the capacity requirements in a power system with BEVs, charging uncontrolled and controlled, they base their analysis in rather short time periods, as also noted in [20]. In the previously mentioned studies [16], [17], [18], [19], [20], [21], [22], [23] the time frames have varied from 24 hours to a year. Furthermore, they differ to each other such, that in some the controlled bidirectional charging was able to reduce the peak load or residual peak load, whereas in some it increased the peak load, or the generation capacity required. As the studied power system varied, as did the BEVs, this is understandable. However, it is uncertain whether these variations in the controlled charging can occur with the same power system and BEVs, if a long enough time horizon is observed. Moreover, especially with increasing amounts of variable renewable generation, the yearly differences on generation can be significant. Furthermore, as the power system load varies year to year, the combination of these variations should be considered. Thus, to the authors knowledge, there is a research gap on the required generation capacity with different BEV charging strategies, while considering the generation and load for a power system for several years, to grasp these interannual variations.

Hence, in this study, the possible flexibility provided by the BEV charging loads was analyzed by modeling three cases. In the first case, the BEV charging load was uncontrolled. In the second one, the BEVs where optimized individually to minimize their charging costs by utilizing controlled unidirectional or bidirectional charging. In the last one, an aggregator was utilized to control the BEVs' charging loads, unidirectional or bidirectional, for the benefit of the power system. These analyses were used to examine how these different options for charging affect the power system capacity requirements. In addition, they considered power system generation, load, and cost data for six years, and increased generation capacities for wind and solar photovoltaic (PV) power, to include interannual variations. Moreover, with the increased renewable generation capacities and an aggregator, the effect of BEV charging on the integration of renewable generation, simultaneously with the additional required power source generation, was examined.

The remainder of the study is formulated as follows. In Section II, the BEV data, and the methodology for charging flexibility are described. In Section III, the results for BEV costs, and generation capacity and energy for a power system with BEVs are presented. Section IV concludes the study and discusses the findings.

II. MATERIALS AND METHODS

A. ELECTRIC VEHICLE DATA

BEV charging profiles have been previously modeled in [24], based on vehicle driving patterns derived from national household travel survey (NHTS) data [25], where the respondents recorded all their trips on a given day. The charging profiles were modeled for a week and considered three charging power scenarios (CPSs), which were also utilized in this study, where the available charging power by charging location was as presented in Table 1. In addition, the energy consumption of the BEVs was based on the driving speed and ambient temperature. Moreover, each BEV, represented by a charging profile, was assigned a battery capacity based on its maximum daily driving distance on a week or on a weekend day. These were 40 kWh for BEVs driving 100 km or less, 70 kWh for BEVs driving 100 to 200 km, and 100 kWh for the ones driving more than 200 km a day. Furthermore, 80% of these total battery capacities were assumed to be operatable by the modeling of the profiles, bringing the usable battery capacities to 32, 56, and 80 kWh, respectively.

TABLE 1. Available charging power in each charging power scenario, CPS, as in [24]. Location types for vehicles based on the NHTS [25].

Location type	Available charging power (kW) Low	Medium	High
Home Workplace Relatives & friends Cottage & vacation home	3.68	7.36	11.0
Shopping & errands Hotel or motel	7.36	11.0	22.1
Other work site Educational building Restaurant & café Sports or recreational area Other destination	-	-	-
Fast charging	50	50	100

The detailed modeling methodology can be found in [24], but is explained here briefly:

1. First the minimum battery state of charge (SoC) level required to complete the trips assigned to a BEV, based on the NHTS data, available charging power, and energy consumption, was determined.
2. If the minimum SoC required was greater than the usable battery capacity of the BEV, fast charging events were added to the profile by two steps. Firstly, by considering single trips which consumption was greater than the battery capacity. And secondly, by considering the greater consumption due to multiple consecutive trips and shortage of charging time.
3. For the BEVs which required SoC was lower than the maximum battery capacity, i.e., were electrifiable, two charging profiles were calculated; one which charged immediately after a trip, and one which charged just before a trip.

The two charging profiles charged the same amount over the examined week, but during single stops the charged energy varied. This was since the immediate charging profile charged immediately after a trip the amount the previous trip consumed, whereas the other profile charged the amount the next trip required. However, as the trips occurred in a repetitive manner, during a week the profiles charged the same amount. For this study the immediate charging profile was utilized, as it was considered far more realistic. Moreover, as in this study the flexibility of charging was modeled, a shifted version of the immediate charging profile was created. This shifted charging profile simply charged the same amount during each stop as the immediate one but shifted the charging to the end of the charging event. This shift is visualized in Section II-B Fig. 2, with further elaboration.

TABLE 2. Mean monthly temperature (°C), weighted by the share of registered light vehicles [26] for each climate zone in Finland [27] and rounded to the closest 5 degree Celsius as in [24], based on monthly temperature from 1991-2020 [28].

	Ambient temperature (°C)						
	Climate zone						
Month	I	II	III	IV	Mean	Weighted mean	Rounded weighted mean
1	-4.3	-4.8	-7.3	-12.5	-7.2	-5.8	**-5**
2	-4.9	-5.4	-7.6	-12.1	-7.5	-6.3	**-5**
3	-1.4	-1.9	-3.5	-7.1	-3.5	-2.5	**-5**
4	4.5	3.9	2.5	-0.8	2.5	3.4	**5**
5	10.9	10.0	9.1	5.6	8.9	9.7	**10**
6	15.3	14.3	14.0	11.9	13.9	14.3	**15**
7	18.3	17.0	16.7	15.0	16.8	17.1	**15**
8	16.6	15.5	14.6	12.4	14.8	15.3	**15**
9	11.6	10.6	9.4	7.0	9.7	10.3	**10**
10	5.8	4.9	3.6	0.0	3.6	4.4	**5**
11	1.4	0.7	-0.9	-5.8	-1.2	0.0	**0**
12	-1.9	-2.6	-4.5	-9.6	-4.7	-3.4	**-5**

In [24], with the modeling methodology described earlier, 93.9% of the vehicle profiles were electrifiable. The mean daily driving distance of all modeled vehicle profiles were 60.0 km, whereas it was 50.6 km for the electrifiable vehicles. Hence, from the total driving distance of vehicles the electrifiable ones covered 79.1 %. Thus, in this study the addition of fast charging events for the previously non-electrifiable BEVs (6.1% from all) were recalculated, with relaxing the conditions for the second addition for fast charging. These relaxations were based on the authors informed judgment on the common reasons why the profiles were previously non-electrifiable, and they were:

- Increasing the usable battery capacities for these BEVs to 80 kWh
- Allowing the addition of charging events not only for the longest trip of a day, but for multiple trips (at most five), and dividing the charging demand between them
- Allowing the addition of charging events also for days where the BEV did not consume more than it charged
- Allowing the charging event to be longer than the previous duration of the trip

However importantly, the modeling of the charging profiles remained the same as in [24], only the addition of charging

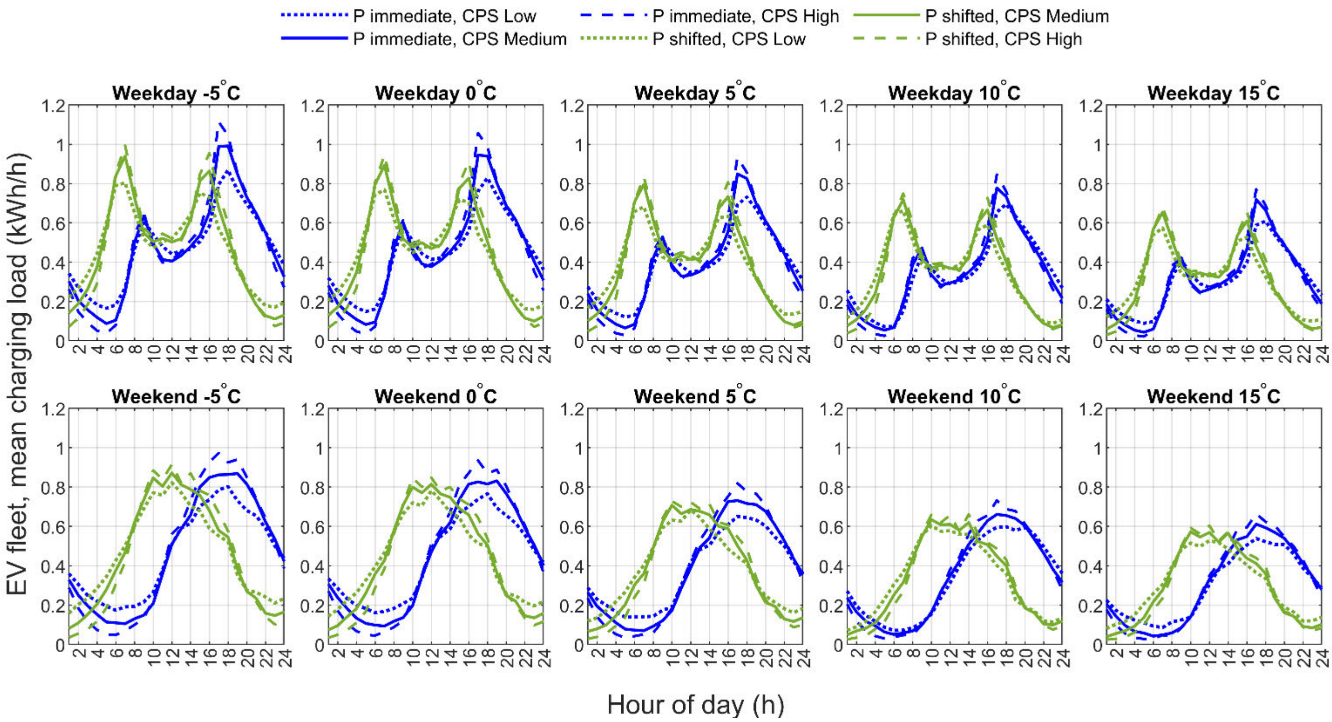

FIGURE 1. Mean charging load per BEV in a BEV fleet, for the $p^{immediate}$ and $p^{shifted}$ charging profiles, on a week and weekend day, by charging power scenario and ambient temperature [24].

TABLE 3. Mean charging load during a week, weekdays, and weekend days for a BEV in a BEV fleet, considering inactive BEVs, by temperature and charging power scenario, CPS. For active vehicles only, the values were 28.1 % greater.

		Ambient temperature				
	CPS	15°C	10°C	5°C	0°C	-5°C
Weekday (kWh)	Low	7.38	8.21	9.29	10.70	11.34
	Med	7.34	8.19	9.24	10.65	11.28
	High	7.31	8.16	9.21	10.61	11.24
Weekend day (kWh)	Low	7.17	8.05	9.05	10.45	11.08
	Med	7.28	8.11	9.17	10.58	11.23
	High	7.35	8.19	9.26	10.67	11.32
Week (kWh)	All	51.25	57.17	64.56	74.42	78.85

events was relaxed for these BEVs. That is, all trips assigned to each BEV were still completed as previously. With these relaxations for the previously non-electrified BEVs, the total share of electrifiable vehicles increased to 98.6% and their mean daily driving distance to 56.6 km, thus covering 92.9% of the total driving distance of all modeled vehicles. In addition, the total charging load increased by 12.5 %, and the mean battery capacity increased from 49.4 kWh to 51.8 kWh.

Previously in [24], the charging profiles were calculated for ambient temperatures of 15, −5, and −20°C, which represent an average summer and winter temperatures, and a very cold winter temperature. As in this study the BEV charging was analyzed over a year, the BEV profiles were modeled with the same methodology for ambient temperatures of 0, 5, and 10°C. Thus, obtaining load profiles which correspond to the mean monthly temperatures in Finland [28], when weighted by the share of registered light vehicles [26] for each climate zone in Finland [27], as presented in Table 2. The vehicle shares are presented in Table 12 in Appendix. In addition, in Table 13 in Appendix, the relative energy consumption rate of BEVs is presented for a wider range of temperatures, from which it can be noted that e.g. the consumption rates at −10°C and 25°C are close to those at −5°C and 15°C respectively. These charging profiles were utilized to formulate charging bounds as presented in the next Section II-B.

The charging profiles, which were modeled based on the activity-travel schedules derived from travel survey data, represent active vehicles, in other words the ones driven on the survey day. Hence, when considering a real life vehicle fleet, also the inactive vehicles should be considered, i.e., the ones which are not driven on a given day [29]. In [24] this share of inactive vehicles was determined as 28.1%, by utilizing the methodology from [29].

As mentioned, the mean daily driving distance of all the vehicle profiles modeled in [24], representing active vehicles, was 60.0 km. Thus, considering inactive vehicles too, this distance dropped to 43.2 km per day, which then represents a total vehicle fleet. For comparison, in Finland the mean daily driving distance of passenger cars and vans is 42.9 km [30], [31].

For the modeled electrifiable vehicles, the mean daily driving distance was 56.6 km, which, when considering inactive vehicles too, became 40.7 km for a total vehicle fleet. For a total vehicle fleet, the electrifiable vehicles covered 92.9 % of the total driving distance, as with the modeled vehicles only.

The mean charging load for a BEV is presented in Fig. 1 for the immediate and shifted charging profiles for mean week and weekend days, considering the different charging power scenarios and ambient temperatures. Fig. 1 presents the mean load for a total vehicle fleet which takes into account the share of inactive vehicles. These and all the subsequent figures and tables present the values considering a charging efficiency of 90% as in [24], based on [32] and [33].

In Table 3, the mean daily charging demand (kWh) by temperature and charging power scenario for the immediate charging profile are presented. There was a minor difference on the allocation of the demand for week and weekend days depending on the available charging power, as with higher available charging power the demand was concentrated closer to consumption. For a week, the total demand was the same regardless of the available charging power.

In addition, the arrival and departure moments for the BEVs for home and work, the two locations with the highest demand for charging, are presented in Fig. 13, in Appendix.

B. CUMULATIVE CHARGING LIMITS FOR ELECTRIC VEHICLES

Three charging strategies were analyzed for the BEVs in this study. First was uncontrolled charging, which assumed that the BEVs charged immediately after arriving to a charging location, as the $p^{immediate}$ charging profile. In addition, two controlled charging strategies were modeled, one which allowed only unidirectional (UD) charging from grid to vehicle, and one which also allowed bidirectional (BD) charging, i.e., vehicle-to-grid.

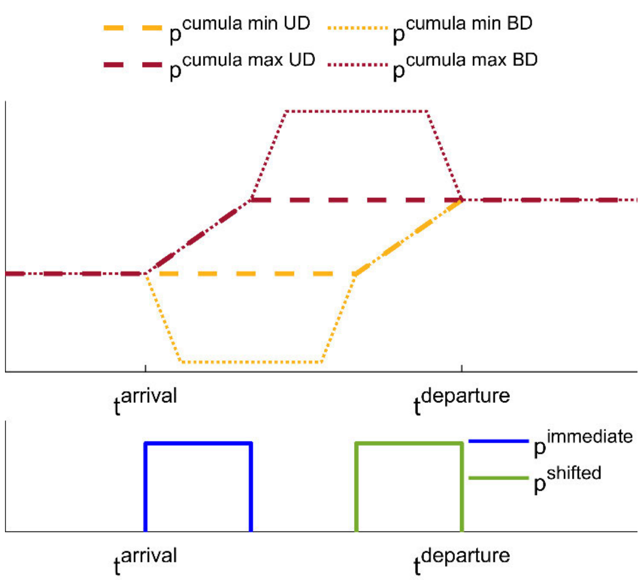

FIGURE 2. Visualization of the modeling of cumulative, unidirectional (UD) and bidirectional (BD), charging bounds for BEVs.

To be able to model the flexibility of charging, related to the two controlled charging strategies, constraints for the BEV charging were required. These constraints were modeled based on the immediate, $p^{immediate}$, and shifted, $p^{shifted}$, charging profiles for each BEV. As the $p^{immediate}$ charging profile charged immediately when a BEV arrived at a location where charging was available, it represented a limit by which the BEV fulfilled its charging demand during each charging event as early as possible. Whereas the $p^{shifted}$ charging profile shifted the same charging demand during the charging event to as late as possible, and thus represented the later limit. Similar type of methodology has been used for example in [34], where energy and power boundaries were formulated during charging events for BEVs. In this study, these charging limits were formed as the cumulative charging loads of the $p^{immediate}$ and $p^{shifted}$ charging profiles for each BEV, which then formulated an upper and lower cumulative charging bound for each BEV. This is visualized in Fig. 2, where a single charging event is presented. The $p^{cumula\ max\ UD}$ and $p^{cumula\ min\ UD}$ are the cumulative loads of $p^{immediate}$ and $p^{shifted}$ charging profiles, and they formulated a region in which the BEVs cumulative charging could be operated freely, when considering unidirectional (UD) charging from grid to vehicle. That is, the BEV charging could be shifted to another moment of time during the charging event. Moreover, these cumulative bounds had the same values at the beginning (at $t^{arrival}$) and end (at $t^{departure}$) of the charging event, and thus constrained the BEV to charge the same amount during the charging event as it would have charged with the uncontrolled charging profile, hence with the $p^{immediate}$ charging profile.

TABLE 4. Modeled time periods for each temperature over one year.

Months	Modeled period	Temperature (°C)
Jan. – Mar.	1.1. – 1.4.	-5
Apr.	2.4. – 29.4.	5
May	30.4. – 3.6.	10
Jun. – Aug.	4.6. – 2.9.	15
Sep.	3.9. – 30.9.	10
Oct.	1.10. – 4.11.	5
Nov.	5.11. – 2.12.	0
Dec.	3.12. – 31.12.	-5

When bidirectional charging i.e., V2G, was allowed, a relaxation of these charging limits was required. These are presented in Fig. 2 as $p^{cumula\ max\ BD}$ and $p^{cumula\ min\ BD}$. These limits allowed the BEV to charge or discharge such, that its cumulative charging exceeded momentarily the previous 'UD' limits during the charging event. However, at the end of the charging event, the cumulative charging must have reached the same level as with the unidirectional and uncontrolled charging, hence, the battery SoC must have increased the same amount as it would have with the uncontrolled charging. Furthermore, these limits were constructed over one year, considering the five different ambient temperatures as presented in Table 2. As the charging profiles were modeled for a week, also these limits considered the temperatures for full weeks. These modeled time periods over one year are presented in Table 4.

TABLE 5. Cost parameters for charging and discharging of BEVs [38], [35], [36], [37], [39].

Description	Value	Unit
Energy price (DA)	Day-ahead market price	c/kWh
Marginal for the electricity company ($DA^{marginal}$)	0.5	c/kWh
Transmission and distribution cost ($T\&D$)	3.91	c/kWh
Electricity tax (E^{tax})	2.794	c/kWh
Battery wear cost (C^{bw})	7.0	c/kWh

C. CHARGING BASED ON DAY-AHEAD MARKET PRICE

For a BEV owner, the cost of charging is one the major costs for determining the economics of the vehicle. Thus, here it was examined how the BEV owners could lower their costs for charging, by controlling their vehicle's charging and discharging, by utilizing the bounds for charging as presented in Section II-B. The BEVs charging and discharging prices were assumed to be based on an hourly day-ahead market price, and the objective was to minimize the total cost of charging for each BEV individually. Furthermore, three charging strategies were analyzed: uncontrolled charging, unidirectional controlled charging, and bidirectional controlled charging.

The costs parameters are presented in Table 5, where all values include the value added tax (VAT) of 24%. The cost of energy was day-ahead market price, for which data from the Finnish SPOT market (NordPool SPOT) from 2018 to 2023 was utilized [35]. The electricity transmission and distribution (T&D) cost, was the mean cost from the distribution system operators in Finland [36], weighted by the number of customers per system operator [37]. And the day-ahead marginal a typical fee for the energy company. The cost of charging included cost of energy with VAT, except for negative hours, T&D cost, and the electricity tax. Whereas the price for discharging only included the cost of energy, without VAT, which the electricity company would pay to the BEV owner. Thus, for the V2G operation to be profitable for the BEV owner, the day-ahead price while discharging, DA^{dch}, must satisfy the following condition:

$$\Delta t P^{dch}\left(\mathrm{DA}^{dch}-\frac{C^{bw}}{\eta^{dch}}\right) \geq \Delta t P^{ch}\left(\mathrm{VAT}\cdot\mathrm{DA}^{ch}+\mathrm{T\&D}+E^{tax}+\mathrm{DA}^{marginal}+\eta^{ch}C^{bw}\right) \quad (1)$$

which simplifies, when $\Delta t P^{dch} = \Delta t P^{ch}\eta^{dch}\eta^{ch}$ and $\eta^{dch} = \eta^{ch}$, to

$$\mathrm{DA}^{dch} \geq \frac{\mathrm{VAT}\cdot\mathrm{DA}^{ch}}{\left(\eta^{ch}\right)^2}+\frac{\mathrm{DA}^{ch}+\mathrm{T\&D}+E^{tax}+\mathrm{DA}^{marginal}+2\eta^{ch}C^{bw}}{\left(\eta^{ch}\right)^2} \quad (2)$$

which further becomes

$$DA^{dch} \geq 1.531\cdot DA^{ch}+24.449(\mathrm{c/kWh}) \quad (3)$$

when inputting the corresponding values for each variable from Table 5, the charging and discharging efficiency of 90% and VAT of 24%. In (1)-(3) both the day-ahead charging and discharging costs are without VAT. Thus, while charging and discharging, the difference on the price of electricity must be significant, to allow profitable V2G operation for the BEV owner. The hourly day-ahead market prices for electricity, without VAT, in Finland from 2018-2023 are presented in Fig. 3. There it can be seen that during years 2018 to 2020 and 2023, the hours when the price exceeded the fixed term of 24.5 c/kWh in (3) were very limited. Thus, during these years the opportunities for profitable V2G operation, with costs as in Table 5, were limited for the BEV owners.

As stated before, when as the cost of charging was assumed to be based on the day-ahead market price, the objective was to minimize the charging costs for each BEV individually by controlling the charging and discharging of the BEV, as presented in (4) below,

$$Min \sum_{t=1}^{T} P_t^{ch}C_t^{ch} - \sum_{t=1}^{T} P_t^{dch}C_t^{dch} + \sum_{t=1}^{T}\left(P_t^{ch}\eta^{ch} + \frac{P_t^{dch}}{\eta^{dch}}\right)C^{bw} \quad (4)$$

where P_t^{ch} and P_t^{dch} are the charging and discharging powers for each time interval t, C_t^{ch} and C_t^{dch} are the price of charging and discharging for time t as defined earlier. Moreover, η^{ch} and η^{dch} are the charging and discharging efficiencies, and C^{bw} is the battery wear cost. The time interval is one hour; thus the energy charged or discharged each hour equals the corresponding power.

The constrains for the optimization, allowing bidirectional charging, i.e., V2G, were:

$$P_t^{cumula} = P_{t-1}^{cumula} + P_t^{ch} - \frac{P_t^{dch}}{\eta^{ch}\eta^{dch}},\ t > 1 \quad (5)$$

$$P_t^{cumula} = P_t^{cumula\max UD},\ t = 1 \quad (6)$$

$$P_t^{cumula} \leq P_t^{cumula\ max\ BD} \quad (7)$$

$$P_t^{cumula} \geq P_t^{cumula\ min\ BD} \quad (8)$$

$$P_t^{ch} \leq P_t^{ch\ available} \quad (9)$$

$$P_t^{dch} \leq P_t^{dch\ available} \quad (10)$$

$$\mathrm{SoC}_t = \mathrm{SoC}_{t-1} + P_t^{ch}\eta^{ch} - \frac{P_t^{dch}}{\eta^{dch}} - BEV_t^{consumption}\quad t > 1 \quad (11)$$

$$\mathrm{SoC}_t = \mathrm{SoC}^{initial}\quad t = 1 \quad (12)$$

$$\mathrm{SoC}_t \leq \mathrm{BEV}^{battery\ capcity} \quad (13)$$

$$P_t^{cumula\ max UD} - P_t^{cumula} = 0,\ t = 8760 \quad (14)$$

$$\mathrm{SoC}_t,\ P_t^{ch}, P_t^{dch} \geq 0 \quad (15)$$

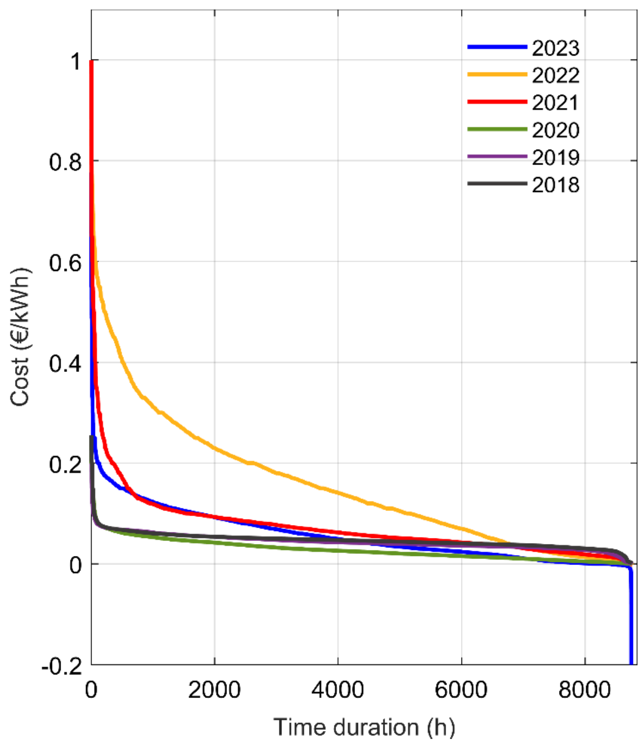

FIGURE 3. Day-ahead market prices in Finland from 2018 to 2023, without VAT. The y-axis is cut from −0.2 €/kWh, while during 2023 there were 10 hours with a price of −0.5 €/kWh.

where (5) and (6) define the cumulative charging, p^{cumula}, of a BEV, which is then constrained to between its minimum and maximum by (7) and (8). Note that, in (5) the term $\left(P^{dch}(t)\right) / \left(\eta^{ch}\eta^{dch}\right)$ includes both the charging and discharging efficiencies. This is since cumulative limits for charging were from the grids point of view, and the charging and discharging efficiencies must be considered when discharging. For example, if a BEV charges 10 kWh more than it must charge during a charging event, it must also discharge this excess charging before its departure. With the 10 kWh from the grid, the BEV SoC increases by 9 kWh ($\eta^{ch} = 90\%$). Then this 9 kWh is discharged, bringing the battery SoC to the same level as without the excess charging. From this 9 kWh, 8.1 kWh is discharged to the grid ($\eta^{dch} = 90\%$). Thus, to bring the cumulative charging of the BEV, P_t^{cumula}, to the correct level, and the same level it would be without the excess charging and discharging, the charging and discharging efficiencies must be accounted for. However importantly, when the profit from discharging is calculated, only the amount the vehicle supplies power to the grid is considered in (4). In (9) and (10) the charging and discharging are limited by the available charging power in the charging location. Equations (11) to (13) limit the battery SoC between its minimum and maximum and (14) ensures that the vehicle charges annually the same amount with the optimized charging as it would with the uncontrolled charging. The initial SoC was 50%, or half way of the minimum and maximum plausible SoC for each BEV at t = 1.

TABLE 6. BEV sample properties for each charging power scenario, CPS.

Parameter	Sample CPS Low	Sample CPS Med.	Sample CPS High
MAPE (%)	2.8	3.0	3.9
Mean battery capacity (kWh)	51.9	51.9	51.9
Annual demand compared to all BEVs (%)	+0.2	-0.3	+0.0

When the BEVs charged unidirectionally, i.e., V2G was not allowed, (7), (8), and (10) were replaced with (16), (17), and (18) respectively.

$$P_t^{cumula} \leq P_t^{cumula\ max\ UD} \tag{16}$$

$$P_t^{cumula} \geq P_t^{cumula\ min\ UD} \tag{17}$$

$$P_t^{dch} = 0 \tag{18}$$

where (16) and (17) are the cumulative charging limits which do not allow momentarily exceeding the charging need during a charging event, as visualized in Fig. 2. Moreover, the discharging power was set to zero for each hour in (18), which prevents discharging and effectively brought the terms related to discharging in (4), (5), and (11) to zero.

D. AGGREGATOR CONTROLLED CHARGING FOR POWER SYSTEM FLEXIBILITY

To be able to analyze the benefit of BEV charging flexibility for the power system, the combined effect of all BEVs in a BEV fleet must be considered. Moreover, as later presented in Section III-A, when all BEVs optimized their charging separately, it concentrated the charging to specific hours, which would likely increase the market price during those hours, and in turn affect the charging of BEVs. Furthermore, as the share of variable renewable electricity generation will almost certainly increase in the future, a greater utilization of it could be enabled by controlling the charging load of BEVs. Thus, to consider this interplay between BEVs and the rest of the power system, their charging was optimized here for the benefit of the total power system by an aggregator, by utilizing the charging bounds presented in Section II-B.

First, a realistic power system was formulated, where the generation sources included were nuclear, hydro, combined heat and power (CHP) for industry and district heat (DH), wind and solar photovoltaics. Hence, condensing power generation and electricity import were not included. If the included generation sources were not able to satisfy the load, with BEVs, an additional power source was required. And correspondingly, if the generation was greater than the load, with BEVs, an additional power sink would have been required, to prevent the curtailment of generation.

The objective for the aggregator, to control the charging of BEVs, was two-fold; first to minimize the capacity of the required additional power source by the power system, and secondly to minimize the required energy from the power

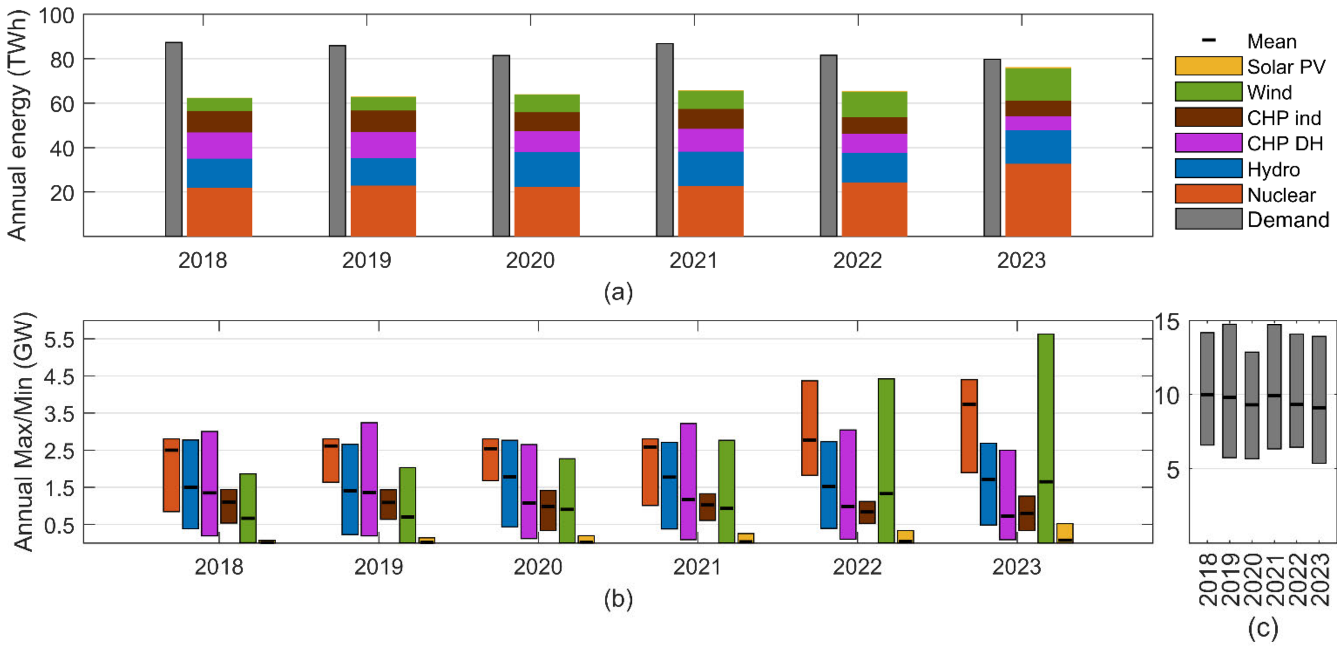

FIGURE 4. The annual power generation and demand in Finland in (a). In (b), the minimum, maximum and mean generation by each generation source, and demand in (c). Data for years 2018 to 2023 [40], [41], [42].

source, while setting the capacity obtained for it as a constraint. This allowed the analysis of how the BEV fleet can on a national level provide flexibility for the power system, by changing its charging behavior.

Again, three charging strategies for the BEVs were analyzed: uncontrolled charging, where the BEVs charged immediately after arriving to a charging location, controlled unidirectional charging from grid to vehicle, and controlled bidirectional charging which also allowed discharging of the BEVs.

The power system was formulated by utilizing time-series data of the aforementioned generation sources and load from the Finnish power system from 2018 to 2023 [40], [41], [42]. The parameters for the system are presented in Fig. 4. During these years the annual load greatly exceeded the annual generation, except in 2023 when they nearly matched, due to increased wind and nuclear generation. Moreover, the addition of BEVs, corresponding to a fully electrified passenger car and van sector increased the annual load by 10.0 TWh, which further increased this difference. The number of corresponding vehicles in 2016 in Finland was 2 968 860 [31], of which 2 927 890 were considered electrifiable (98.6%). As in the last section, the time periods began from the first Monday of the year and considered 8760 hours beginning from there.

The total number of modeled BEV profiles were 9610. As the optimization of these profiles over one year simultaneously is computationally extremely heavy, even impossible for a regular desktop, adjustments were required.

First a sample of 500 BEVs was created, which represented well the total BEV fleet. The accuracy between the sample and all the BEVs was measured with mean absolute percentage error (MAPE), which measures the average absolute error between two time series [43]. Here it compared the mean charging loads of the sample and all BEVs, considering both the $p^{immediate}$ and $p^{shifted}$ charging profiles and the five temperatures. The sample was created such that from an initial random sample, one BEV at a time was replaced with another one, which reduced the MAPE the most. The properties of the resulting three samples, corresponding to each CPS, are presented in Table 6. These sample BEVs were then scaled up such that they represented a completely electrified passenger car and van transportation sector in Finland, with 2.928 million BEVs.

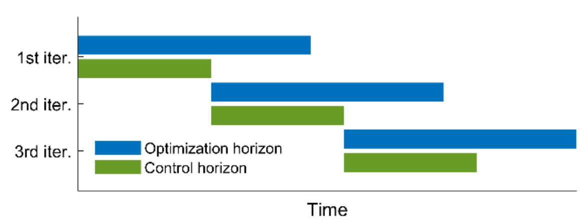

FIGURE 5. Visualization of the rolling horizon optimization.

Furthermore, optimizing 500 BEVs over one year is still computationally very heavy, and thus a rolling horizon optimization method was utilized. A similar type of rolling horizon optimization has been previously utilized for example in [9]. The optimization horizon (OH) was the period over which the optimization was conducted at once, and the control horizon (CH), a shorter period of time, for which the results were saved. This is visualized in Fig. 5, similar to [9]. Furthermore, information for battery SoC and cumulative charging was exchanged from the previous optimization to the next one. That is, for example, the initial SoC in the beginning of an optimization horizon, was the SoC at the end of the control horizon of the previous iteration.

The optimization was performed with a Matlab – GAMS platform and a CPLEX solver, with the following objective function and constraints. First by minimizing the required power source capacity in (19). Here (20)-(36) allow the V2G operation.

$$Min\ P^{p\ source\ capacity} \tag{19}$$

$$\text{S.t. } P_{i,t}^{load\ historical} + P_{i.t}^{EV\ ch} - P_{i,t}^{EV\ dch} = P_{i,t}^{gen\ fixed} + P_{i,t}^{p\ source} - P_{i,t}^{p\ sink} \tag{20}$$

$$P_{i,t}^{p\ source} \leq P^{p\ source\ capacity} \tag{21}$$

$$P_{i,t}^{EV\ ch} = \sum_{n=1}^{N} P_{i,t,n}^{ch} \tag{22}$$

$$P_{i,t}^{EV\ dch} = \sum_{n=1}^{N} P_{i,t,n}^{dch} \tag{23}$$

$$P_{i,t,n}^{cumula} = P_{i,t-1,n}^{cumula} + P_{i,t,n}^{ch} - \frac{P_{i,t,n}^{dch}}{\eta^{ch}\eta^{dch}},\ t \neq t^{OH\ start} \tag{24}$$

$$P_{i,t,n}^{cumula} = P_{i-1,t=t^{CH\ end},n}^{cumula} + P_{i,t,n}^{ch} - \frac{P_{i,t,n}^{dch}}{\eta^{ch}\eta^{dch}},\quad t = t^{OH\ start}\quad t > 1 \tag{25}$$

$$P_{i,t,n}^{cumula} = P_{t,n}^{cumula\ max\ UD},\ t = 1 \tag{26}$$

$$P_{i,t,n}^{cumula} \leq P_{t,n}^{cumula\ max\ BD} \tag{27}$$

$$P_{i,t,n}^{cumula} \geq P_{t,n}^{cumula\ min\ BD}. \tag{28}$$

$$P_{i,t,n}^{ch} \leq P_{t,n}^{ch\ available} \tag{29}$$

$$P_{i,t,n}^{dch} \leq P_{t,n}^{dch\ available} \tag{30}$$

$$\text{SoC}_{i,t,n} = \text{SoC}_{i,t-1,n} + P_{i,t,n}^{ch}\eta^{ch} - \frac{P_{i,t,n}^{dch}}{\eta^{dch}} - BEV_{i,t,n}^{consumption}\ t \neq t^{OH\ start} \tag{31}$$

$$\text{SoC}_{i,t,n} = \text{SoC}_{i-1,t=t^{CH\ end},n} + P_{i,t,n}^{ch}\eta^{ch} - \frac{P_{i,t,n}^{dch}}{\eta^{dch}} - BEV_{i,t,n}^{consumption}\quad t = t^{OH\ start},\ t > 1 \tag{32}$$

$$\text{SoC}_{i,t,n} = \text{SoC}_{n}^{initial},\ t = 1 \tag{33}$$

$$\text{SoC}_{i,t,n} \leq \text{BEV}^{battery\ capcity} \tag{34}$$

$$P_{t,n}^{cumula\ maxUD} - P_{i,t,n}^{cumula} = 0,\ t = 8760 \tag{35}$$

$$\text{SoC}_{i,t,n},\ P_{i,t,n}^{ch},\ P_{i,t,n}^{dch},\ P_{i,t}^{EV\ ch},\ P_{i,t}^{EV\ dch},\ P_{i,t}^{p\ source},\ P_{i,t}^{p\ sink} \geq 0 \tag{36}$$

where i depicts iteration, t time, and n BEVs. Moreover, (20) ensured that the historical load, $P_{i,t}^{load\ historical}$, and the load from all the BEVs, positive for charging $P_{i.t}^{EV\ ch}$ and negative with discharging $P_{i,t}^{EV\ dch}$, were satisfied with the generation, including the historical generation, wind, and solar PV in $P_{i,t}^{gen\ fixed}$, the required power source generation, and also considering the possible power sink requirement to avoid generation curtailment. Equations (22) and (23) sum the charging and discharging of all BEVs for each hour, whereas (24) to (35) are similar to (5) to (14) for day-ahead market price optimization, and constraint the individual BEV charging, discharging, and SoC between its allowed limits.

After the minimum required additional power source capacity was solved, the optimization was repeated to minimize the energy generation required from the power source, with the objective function as in (37),

$$Min\ \sum_{t=t^{OH\ start}}^{t=t^{OH\ end}} P_{i,t}^{p\ source} + \left(\sum_{t=t^{OH\ start}}^{t=t^{OH\ end}} P_{i,t}^{EV\ ch}\right)\varepsilon \tag{37}$$

while setting the highest minimum power source capacity over the solved year, rounded up to the next MW, as a constraint, as in (38) and keeping (20)-(36) as previously.

$$P^{p\ source\ capacity} \leq \textit{Solution from } (19) \tag{38}$$

In the second objective function, the first term minimizes the energy required from the power source, while the second one formulates a penalty with penalizes from charging the BEVs. This penalty is important to prevent the BEVs to unnecessarily charge and discharge when the generation, without power source, is greater than the total load, and additionally prevents the BEVs to charge and discharge during the same hour. However, as the second term is multiplied by a very small coefficient, it does not affect the minimization of the required back-up energy. Moreover, the results with the second optimization function in (37) were saved for each iteration i for the control horizon, that is between $t^{OH\ start} \leq t \leq t^{CH\ end}$. These are also the final results of this aggregator-controlled optimization.

When V2G was not allowed, the (39), (40), and (41) were utilized to limit the charging for unidirectional charging only, and they replaced (27), (28), and (30) respectively.

$$P_{i,t,n}^{cumula} \leq P_{t,n}^{cumula\ max\ UD} \tag{39}$$

$$P_{i,t,n}^{cumula} \geq P_{t,n}^{cumula\ min\ UD} \tag{40}$$

$$P_{i,t,n}^{dch} = 0 \tag{41}$$

where in (39) and (40) the cumulative charging limits in are the ones which did not allow even momentarily exceeding the charging need during a charging event, as visualized in Fig. 2. Moreover, the discharging power was set to zero for each hour in (41) which further prevented discharging and effectively brought the terms related to discharging in (20), (23), (24), (25), (31), and (32) to zero. Otherwise, the optimization was the same as when V2G was allowed.

Furthermore, as presented in Fig. 4 in the historical power system in Finland, without import and condensing power, the annual demand exceeded greatly the annual generation. The addition of BEVs, corresponding to the fully electrified passenger car and van sector with 2.928 million BEVs, further increased this difference by 10.0 TWh. Hence, additional future power system scenarios were analyzed, where the

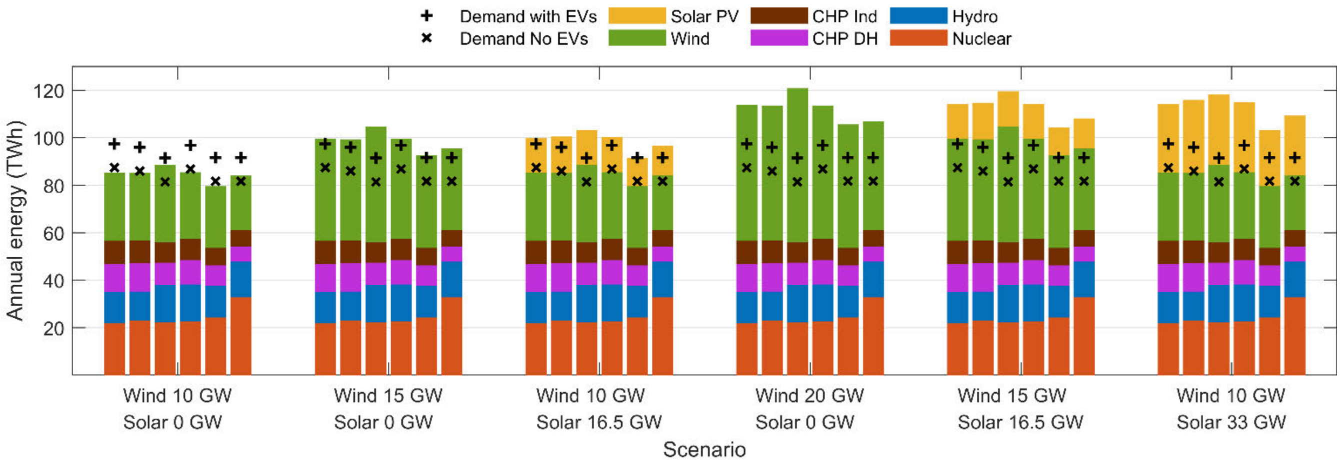

FIGURE 6. The annual generation and load of the Finnish power system with increased wind and solar PV generation for selected future scenarios. For each scenario, bars from left to right represent years from 2018 to 2023.

annual generation and load, including BEVs, was brought to the same magnitude, and then the generation was further increased. For the future scenarios the historical wind and solar PV generation were scaled up to represent generation from a certain capacity. In Finland, between 2018 and 2023, one GW of installed wind power capacity generated on average 2.77 TWh of power, whereas one GW solar PV would have generated 0.85 TWh [40], [41], [42], [44], [45], [46], [47]. In the beginning of 2024, there was nearly 7 GW of installed wind capacity in Finland, and it is estimated to pass 10 GW in 2026 [48]. Thus, 10 GW of wind capacity was always included in the future scenarios and increased by steps of 5 GW. In addition, instead of increasing wind by 5 GW a corresponding increase, in terms of energy, of solar PV capacity (16.5 GW) was assumed. The annual generations in the selected scenarios are presented in Fig. 6 where the yearly variation in the annual generation can be observed. Moreover, as the historical generation without wind and solar never exceeded the load during 2018 to 2022, and in 2023 it exceeded it by 0.006 TWh, when the optimization minimized the additional power source generation required, it simultaneously maximized the utilization of the added wind and solar generation, as other sources were unavailable.

III. RESULTS

In this section the results are first presented when the BEVs individually minimized their charging costs and then when they were optimized to minimize the required additional power source capacity and generation in a power system.

A. CHARGING BASED ON DAY-AHEAD MARKET PRICE

Here the results are presented when each BEV optimized its charging and discharging individually, to minimize its charging costs, when the pricing was based on the day-ahead market price of electricity as described in Section II-C. Thus, with these results it is possible to examine how the BEV owners may affect their charging costs and how the electricity price can control the BEV charging.

Three charging strategies for the BEVs were compared. First was the uncontrolled, UNC, charging strategy where the BEVs charged immediately when they arrived at a charging location. The second one was a controlled charging scenario, where only unidirectional charging from grid to vehicle was utilized, and the BEVs could shift their charging load during each charging event. This strategy was named here as price-controlled one (PC1). The last charging strategy was one which allowed also bidirectional charging, i.e. V2G, and the BEVs could shift their charging demand during each charging event. This was named price-controlled charging two (PC2).

In Table 7 the mean cost of charging for all the BEVs, in €/kWh, is presented for uncontrolled, UNC, controlled unidirectional, PC1, and controlled bidirectional, PC2 charging, with three different available charging power scenarios, CPS, as presented in Table 1, for years 2018-2023, while the cost of charging was based on the day-ahead market price of electricity. In Table 7, the battery wear cost is only included for the additional operation for V2G, and not to changes in the battery SoC due to BEV consumption or charging for non-V2G operation. Compared to the uncontrolled charging scenario, in all analyzed scenarios the controlled charging decreased the mean cost for charging. With price-controlled unidirectional charging, PC1, the costs decreased by 5 to 27%, and with V2G allowed in PC2, they decreased by 5 to 35%, compared to uncontrolled charging. In addition, only during the year 2022, with exceptionally high day-ahead prices, there was a significant difference between the mean costs with PC1 and PC2. During years 2018-2020 the price fluctuation was not enough to allow a profitable V2G operation, whereas during 2021 and 2023 it was profitable, but the difference to only utilizing unidirectional charging was at most a few percent. Moreover, with higher available charging power the costs were lower compared to lower charging

TABLE 7. Mean charging cost for BEVs with uncontrolled (UNC), unidirectional (PC1), and bidirectional (PC2) charging during 2018-2023, with three different charging power scenarios (CPS).

		UNC	PC1		PC2	
Year	CPS	€/kWh	€/kWh	(%)	€/kWh	(%)
2018	Low	0.095	0.090	-5 %	0.090	-5 %
2018	Med.	0.095	0.089	-6 %	0.089	-6 %
2018	High	0.095	0.089	-7 %	0.089	-7 %
2019	Low	0.093	0.087	-7 %	0.087	-7 %
2019	Med.	0.093	0.086	-8 %	0.086	-8 %
2019	High	0.094	0.086	-8 %	0.086	-8 %
2020	Low	0.080	0.072	-10 %	0.072	-10 %
2020	Med.	0.081	0.071	-12 %	0.071	-12 %
2020	High	0.081	0.071	-13 %	0.071	-13 %
2021	Low	0.125	0.107	-15 %	0.106	-15 %
2021	Med.	0.127	0.105	-17 %	0.103	-19 %
2021	High	0.128	0.104	-18 %	0.102	-20 %
2022	Low	0.201	0.157	-22 %	0.149	-26 %
2022	Med.	0.204	0.152	-26 %	0.138	-32 %
2022	High	0.206	0.151	-27 %	0.134	-35 %
2023	Low	0.109	0.095	-13 %	0.094	-14 %
2023	Med.	0.110	0.093	-16 %	0.091	-18 %
2023	High	0.111	0.092	-17 %	0.090	-19 %

power scenarios, as the BEVs could utilize the low cost and high profit hours by a greater extent.

When the BEVs minimized individually their costs, their effect on the power system and energy market was neglected. That is, if the number of BEVs would be such large that their charging load would be significant compared to the total load of a given power system, the BEV fleet's charging and discharging operation would affect the power and energy balance of the system, and the hourly price of electricity. This is highlighted in Table 8, where the effect of the charging demand from a fully electrified passenger car sector to the total load of the Finnish power system was analyzed, when assuming that each BEV was optimized individually, and their charging and discharging did not affect the other BEVs, the power system, and the day-ahead market price.

With uncontrolled charging the peak load of the power system increased by 15 to 22%, whereas with PC1 and PC2 the peak load increased at most by 71% and 144%, compared to the same power system without BEVs. Moreover, if all BEVs discharged simultaneously the system load was negative. This highlights that a large BEV fleet, which annual demand is roughly 10 to 13% of the power system's annual load, can in theory provide a short-term power balance, exceeding the peak load of the power system without the BEVs, if the BEVs are connected to chargers, the compensation is sufficient, and if the power balance can be provided during the BEV charging events, as the flexibility of charging was limited within them.

As the battery wear cost affects the BEVs cost of charging and thus whether it is beneficial for the BEV to participate in

TABLE 8. Peak power in the Finnish power system without BEVs, and uncontrolled and controlled charging of BEVs, based on time of use of pricing. Assuming a fully electrified passenger vehicle transportation, and that each BEV optimizes its charging independently from the others. Also, for PC2 the minimum system load is presented.

		No BEVs	UNC		PC1		PC2		
Year	CPS	GW	GW	%	GW	%	GW	%	MIN GW
2018	Low	14.2	16.2	+14%	19.0	+34%	19.0	+34%	7.0
2018	Med.	14.2	16.5	+16%	21.9	+54%	21.9	+54%	6.8
2018	High	14.2	16.8	+18%	23.5	+65%	23.5	+65%	6.7
2019	Low	14.7	16.9	+15%	18.7	+27%	18.7	+27%	7.0
2019	Med.	14.7	17.2	+17%	21.9	+49%	21.9	+49%	6.9
2019	High	14.7	17.4	+18%	23.7	+61%	23.7	+61%	6.8
2020	Low	12.8	15.0	+17%	17.5	+37%	17.5	+37%	7.0
2020	Med.	12.8	15.3	+20%	20.3	+59%	20.3	+59%	6.8
2020	High	12.8	15.7	+23%	21.9	+71%	21.9	+71%	6.6
2021	Low	14.7	17.1	+16%	19.3	+31%	21.1	+44%	4.4
2021	Med.	14.7	17.5	+19%	22.2	+51%	28.4	+93%	-0.6
2021	High	14.7	17.8	+21%	23.8	+62%	35.9	+144%	-3.9
2022	Low	14.1	16.2	+15%	18.3	+30%	18.3	+30%	2.2
2022	Med.	14.1	16.6	+18%	21.1	+50%	25.3	+79%	-4.7
2022	High	14.1	16.8	+19%	22.7	+61%	32.3	+129%	-11.2
2023	Low	13.9	16.4	+18%	18.9	+36%	18.9	+36%	2.4
2023	Med.	13.9	16.7	+20%	21.3	+53%	22.9	+65%	-3.4
2023	High	13.9	17.0	+22%	22.7	+63%	28.4	+104%	-9.4

bidirectional charging, the optimization was repeated with a battery wear cost of 3.5 c/kWh, half from the one previously used. These results are presented for PC2 in Table 14 in Appendix, as the bidirectional charging was the one effected by the battery wear cost. With lower battery wear cost the charging costs with bidirectional charging decreased and the system peak power increased, due to a higher participation share of BEVs to bidirectional charging.

B. AGGREGATOR CONTROLLED CHARGING FOR POWER SYSTEM FLEXIBILITY

With high shares of electric vehicles, their combined charging load can become such large, that it affects the operation of the power system. Thus, examining them as part of the power system is crucial. If the BEVs charging can be adjusted, based on the needs of the power system, they could provide flexibility for it by either shifting their charging load or even providing power to the grid by V2G operation. This flexibility could be especially beneficial for limiting the peak generation requirement, and increasing the share of variable renewable energy generation, which is inflexible by nature. Hence, it is important to analyze the BEVs as part of the power system.

In this study, when the BEV were analyzed as part of the power system, the modeled BEV demand was scaled up to correspond to a fully electrified passenger car and van sector in Finland with 2 927 890 electrifiable BEVs, of which 28.1% inactive, as presented in Section II-A. This resulted in annual demand of 10.0 TWh from the BEVs. In addition, three charging strategies for the BEVs were examined. One where the BEV charging was uncontrolled, UNC, and the BEVs were assumed to charge immediately when arriving at a charging location, as the $p^{immediate}$ charging profile. In the other two strategies the BEV charging was controlled by the aggregator, and the charging was either unidirectional only, from grid to vehicle, or bidirectional where also V2G was allowed. The aggregator controlled unidirectional charging is referred to as AGC1 and the strategy which allows bidirectional charging as AGC2.

When the BEV charging was controlled by the aggregator, its objective was to minimize the required additional power source capacity and generation, as presented in Section II-B.

The analysis was first conducted for the historical power system from 2018 to 2023 in Finland, and secondly considering future scenarios with increased renewable generation.

1) HISTORICAL POWER SYSTEM

In Fig. 7 the required generation capacity from an additional power source and the corresponding annual generation are presented for years 2018-2023, while considering the power system without BEVs, with uncontrolled, UNC, controlled unidirectional, AGC1, and controlled bidirectional, AGC2, charging. Moreover, the three different charging power scenarios, Low, Medium, and High are also presented as in Table 1. The properties of the generation and load, without BEVs, during these years were as presented in Fig. 4.

From Fig. 7 it can be observed that without BEVs the Finnish power system required between 3.4 to 5.4 GWs of generation capacity to satisfy the load after the yearly nuclear, hydro, CHP, wind, and solar PV generation, during 2018 to 2023. When BEVs were included and assumed to charge uncontrolled, that is as the $p^{immediate}$ charging profile, the power source capacity required was increased between 6.4 to 8.3 GWs with the High charging power scenario. Moreover, with uncontrolled charging, a lower available charging power resulted in lower required power source capacity. The benefit of which varied yearly from 1 GW or 12% (in 2021) to 0.3 GW or 4% (in 2019), when comparing the Low and High CPSs. Furthermore, with aggregator controlled charging the power source capacity increased significantly less, compared to uncontrolled charging. With unidirectional charging, in AGC1, it was between 4.8 to 6.2 GWs, which compared to No BEVs was an increase of at most 1.5 GW (in 2023) and the least of 0.5 GW (in 2018). Furthermore, when V2G operation was allowed, in AGC2, the required power source capacity approached the requirement without BEVs. That is, with AGC2 the required power source capacity was at most 0.7 GW greater than without BEVs (CSP Low 2023), while during 2021, with CPS High, it was only 5 MW greater.

Focusing on the required energy from the additional power source, its demand was significant during years 2018 to 2023, as was foreseeable from Fig. 4 earlier. Without BEVs this demand was the lowest in 2023 with 6 TWh, and the highest in 2018 with 25 TWh. With uncontrolled and controlled

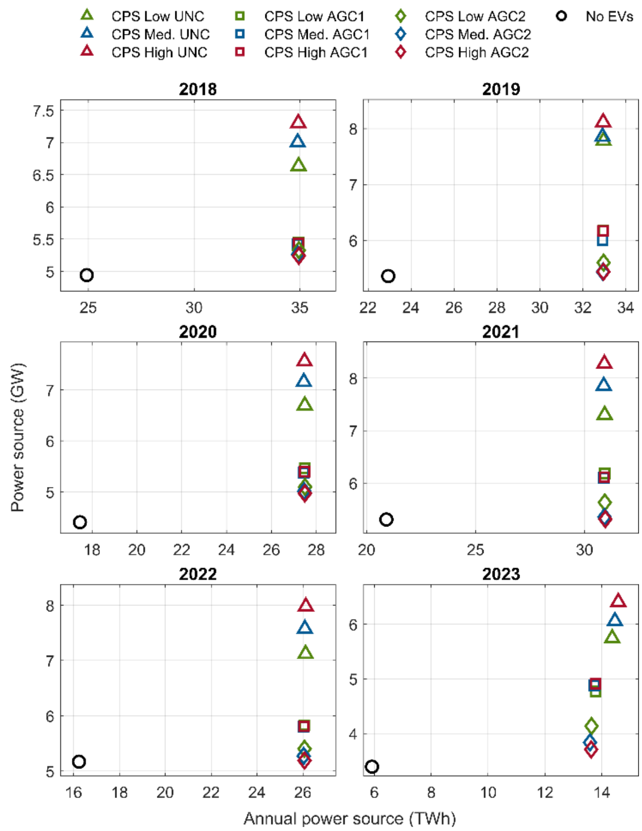

FIGURE 7. **Peak additional power source capacity required and the corresponding annual generation for power system without BEVs, and BEVs with uncontrolled (UNC), unidirectional controlled (AGC1), or bidirectional controlled (AGC2) charging capability. For years 2018-2023 and for three charging power scenarios (CPSs).**

charging during years 2018 to 2022, this generation demand from the power source in practice increased by the demand of the BEVs, 10 TWh, to 35 TWh at most. This was since, during these years the total generation from the selected sources was such low compared to the load, that the BEV load was required to be satisfied by the generation from the additional power source. However, during 2023 the annual generation nearly matched the annual load, and more importantly the hourly generation also exceeded the hourly load, in total by 2.4 TWh, during the year, without BEVs. Hence, there was opportunities such that the BEV charging load could utilize this excess generation by shifting its load. Thus, the required additional power source generation decreased from 14.4-14.6 TWh with uncontrolled charging to 13.8 TWh with AGC1, and further to 13.6 TWh with AGC2.

2) FUTURE POWER SYSTEM

Here the same analysis was conducted as in the previous section for a future power system with increased amounts of wind and solar PV generation, while keeping the historical load, nuclear, hydro and CHP generations, as presented in Section II-D Fig. 6. The objective was to minimize the required capacity and energy from an additional power source. In addition, as the historical generation never exceeded the load, except in 2023 by 0.006 TWh, this minimization simultaneously maximized the utilization of the added wind and solar power, as other sources were unavailable.

a: YEARLY RESULTS FOR FUTURE POWER SYSTEM

In Fig. 8 the required power source capacity is presented on the top row as GWs, and on the bottom row as the ratio between the power source capacity and the peak system load without BEVs. Both considering the selected years, increased renewable generation scenarios, available charging powers, and charging strategies for the BEVs. In Fig. 8, the scenarios are named as the installed capacities of wind 'W' and solar PV 'S' in them. The results are presented separately for each year, for allowing the observation of yearly differences. The annual generations from wind and solar PV were as presented in Fig. 6, where the first one with 10 GW of wind and none solar PV capacity, generated annually approximately 10 TWh less than the load with BEVs. The second and third renewable scenarios with either 15 GW of wind and none solar, or 10 GW of wind and 16.5 GW of solar generated approximately 5 TWh more annually than the load with BEVs. And finally, the last three with 20 GW, 15 GW, and 10 GW of wind and 0 GW, 16.5 GW, and 33 GW of solar PV respectively, generated close to 20 TWh more annually than the load with BEVs.

In Fig. 8 similar behavior as in Fig. 7 can be observed. That is, with uncontrolled charging the peak back-up generation requirement increased significantly, up to 7.6-7.8 GW in 2022. With unidirectional controlled charging, AGC1, this increase was at most of 1.1 GW in 2019 and 2020, with CPS High, compared to No BEVs. However, with bidirectional charging allowed, AGC2, the power source capacity requirement decreased during several years, compared to without BEVs. With AGC2, the greatest decrease was 0.9 GW in 2018 with high amounts of renewable generation and CPS High. However, during 2020 the required power source capacity increased even with the bidirectional charging allowed, compared to without BEVs. On the bottom panel row in Fig. 8, which presents the share of the additional power source capacity to the peak load without BEVs, it is highlighted that the power source capacity required was great compared to the peak load without BEVs, already without BEVs. As presented on the top panel, uncontrolled charging increased this share, while the two controlled charging strategies mitigated, or even in some cases lowered this capacity requirement.

Overall, in terms of requirement for additional power source capacity, there was relatively small differences between the future scenarios, as the same generation was scaled by a different factor, whereas the difference between different years was greater, although the scenarios with higher share of wind power had slightly lower values, compared to the ones with solar PV. However, weather the BEVs charging was uncontrolled, or controlled as in AGC1 or AGC2, had a great impact on the capacity requirement. Furthermore, with uncontrolled charging the available charging power had a notable impact on the peak power source requirement, whereas with AGC1 the difference was minor. With V2G in AGC2 the charging power affected slightly the results, as the Low CPS had a lesser benefit to the system compared to the CPS Medium and High.

In Fig. 9 the annual requirement for energy from the additional power source are presented on the top row panels, and the annual additional energy requirement for power sink, which would prevent curtailment of energy, on the bottom ones. Both considering the years from 2018 to 2023, increased renewable generation scenarios, available charging powers, and the three charging strategies for the BEVs. As in Fig. 8, in Fig. 9 the increased renewable generation is expressed on the x-axis, where 'W' depicts wind capacity and 'S' solar PV capacity. With uncontrolled charging the required energy from a power source increased significantly compared to without BEVs. When utilizing controlled charging, with AGC1 the energy need was lower, and with AGC2 it was further decreased, compared to uncontrolled charging. Moreover, the available charging power had a minor effect on the required energy from an additional power source, regardless if uncontrolled or controlled charging was utilized. There was some yearly variation on the power source generation requirement, due to different system load and solar and wind generation during the years.

The demand for power sink decreased similarly as the power source requirement, when uncontrolled and controlled charging were utilized. This was since the minimization of the power source generation meant that the aggregator tried to utilize the generation from the added wind and solar by the greatest extent.

In Fig. 10 the duration curves for the years 2022 and 2020, for the additional power source and power sink requirements are presented, to further display their shapes. For these the medium charging power scenario was selected. Year 2022 was selected as during it the required power source capacity was the highest, and the year 2020 was selected as during it the bidirectionally controlled charging was not able to lower the power source requirement, compared to the same system without BEVs. Moreover, in Fig. 10, the generation included 15 GW of wind and 0 GW of solar PV, as then the generation was relatively close to load, and it was considered one that could likely occur in the near future, whereas the one with 10 GW of wind and 16.5 GW of solar would require a huge increase of solar PV generation in Finland from the capacity of 850 MW in 2023. In the scenarios presented in Fig. 10, the total generation, without power source, was 93 TWh and 104 TWh, and the total load, with BEVs UNC, was 92 and 91 TWh during 2022 and 2020 respectively.

In Fig. 11, it is further investigated why the V2G operation in AGC2 was unable to lower the required power source capacity during 2020. There it can be seen that there was a close to four days long period with a great deficit of

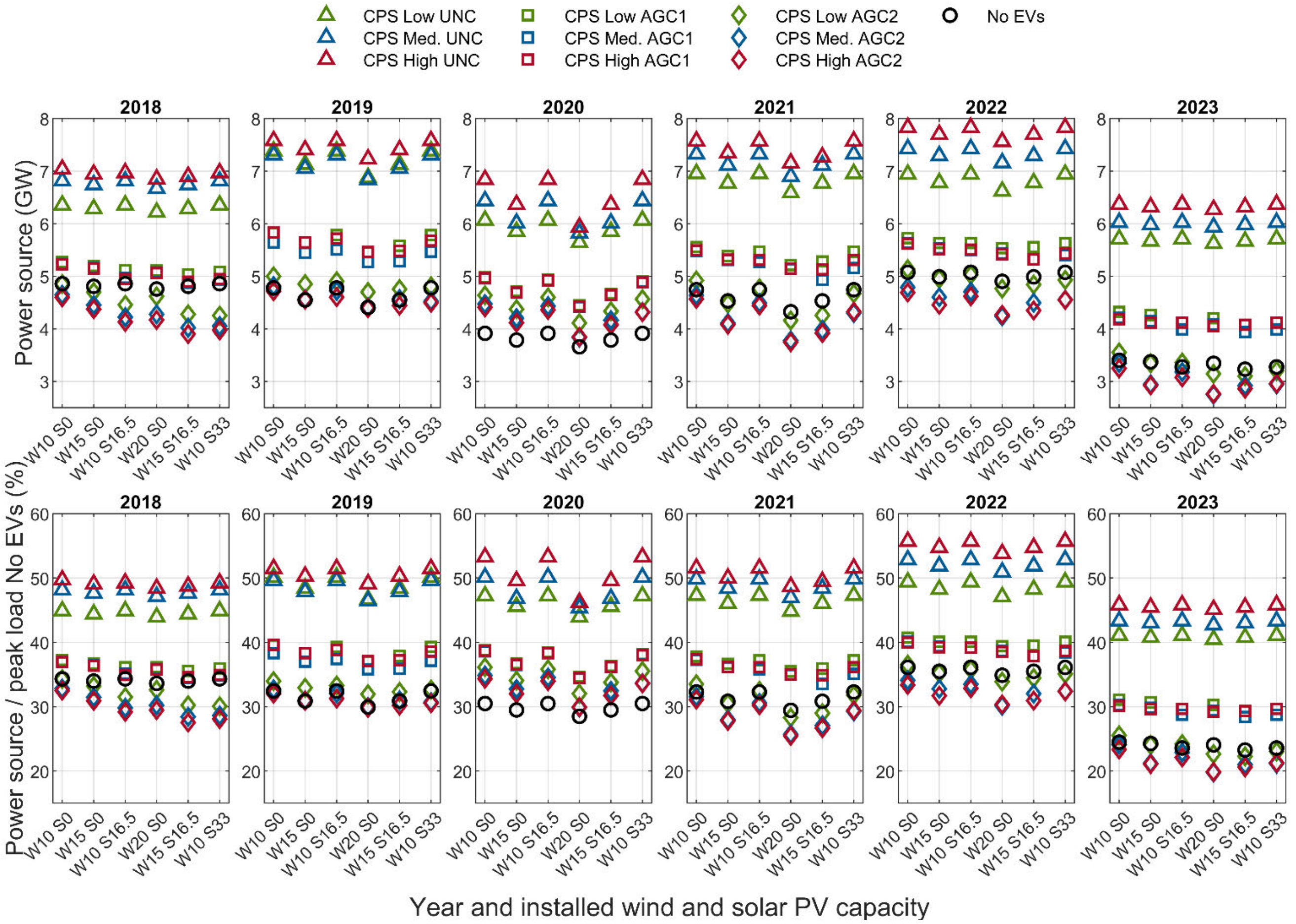

FIGURE 8. **Required power source capacity for years 2018 to 2023, in GW and as a share to peak load without BEVs. Considering the charging power scenario, CPS, uncontrolled, UNC, controlled unidirectional, AGC1, and controlled bidirectional, AGC2, charging. In addition, includes values for different increasement of wind and solar PV generation.**

generation capacity. Thus, the BEVs capability of limiting the increasement of power source capacity was limited to valley filling and peak shaving operation, where in essence all the generation supplying the BEV load was from the additional power source. Whereas, if there had been some generation peaks of renewable energy the BEVs could have additionally shifted their generation to those. However, now the BEVs had to provide flexibility without the help of renewables, within their charging events. In Fig. 11 this can be seen as increased load during nighttime with AGC2, compared to uncontrolled charging and the load without BEVs. And the opposite during the day, compared to UNC, where the load decreased. However, the BEV flexibility was not capable to shift enough load from day to night to limit the power source capacity to the same level as without BEVs, as the capacity requirement was 0.4 GW greater than without BEVs, with 15 GW of wind and 0 GW of solar PV. With 10 GW of wind and 16.5 GW of solar PV it was 0.5 GW greater.

b: RESULTS FOR FUTURE POWER SYSTEM CONSIDERING ALL YEARS

The two-phase optimization presented in Section II-D, for minimizing the additional power source capacity and energy, was also conducted by only minimizing the power source energy, without the constraint of the power source capacity, i.e., only utilizing the objective function in (37). These results showed that the annual capacity constraint had almost negligible effect on the required energy, as the annual power source energy requirement was at most 1% greater with the constraint than without it. Thus, the yearly results for the power source and power sink energy can be summed for the total of six years, with high accuracy.

In Table 9 the peak capacities required from an additional power source to satisfy the load during years 2018 to 2023 are presented, considering the different increasements in wind and solar PV generation, three charging powers, and three charging strategies for the BEVs. In addition, similarly presented are the maximum power sink capacities required to prevent the curtailment of energy. Depending on the scenario, the peak power source capacities were required either during 2019 and 2022 as these years had the greatest difference between the load and generation. As evident from the yearly observations in Fig. 8, the installed capacities of wind and solar PV generation had a minor effect on the required power source capacity, whereas the effect of charging strategy was major. That is, with uncontrolled

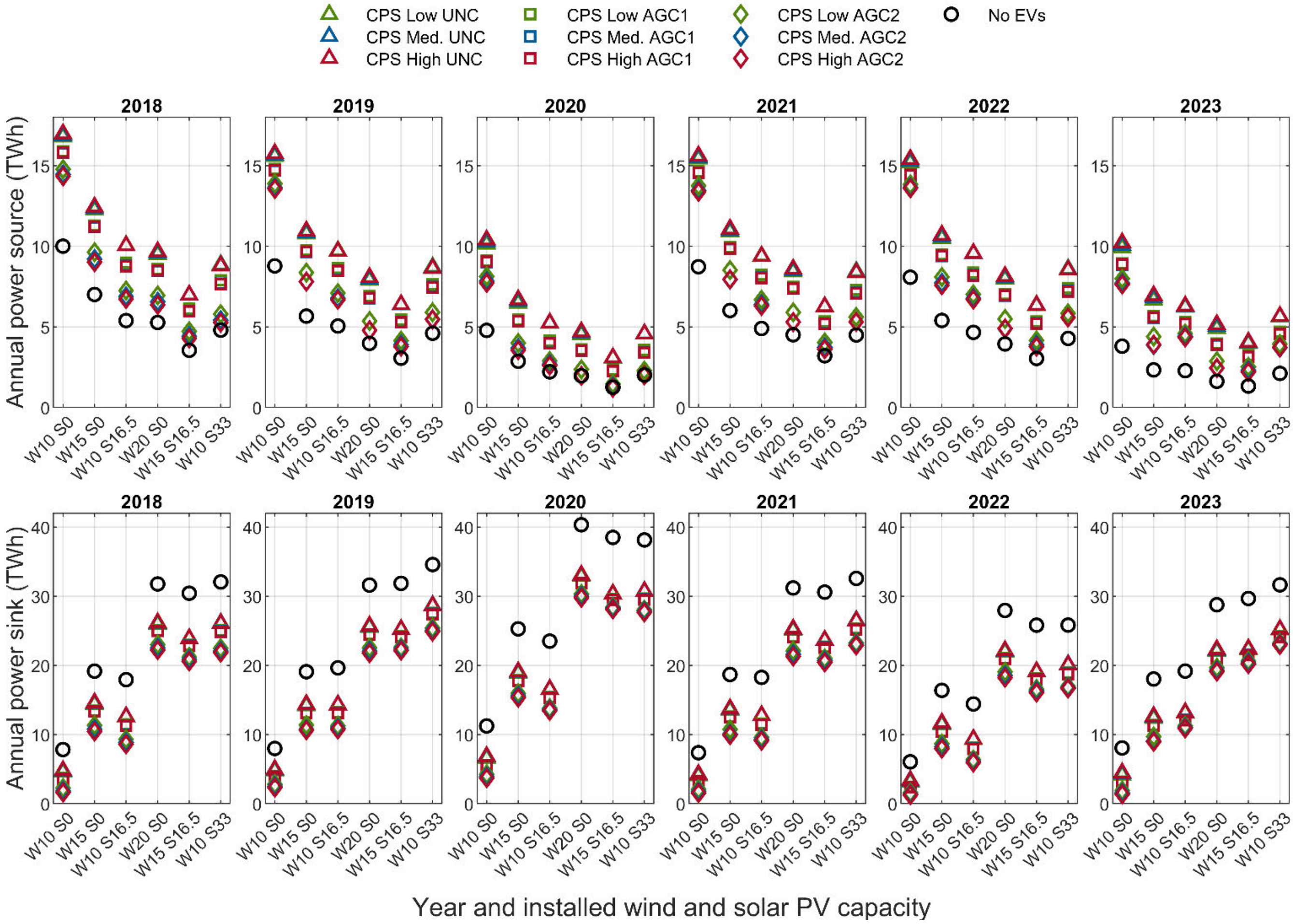

FIGURE 9. Required power source generation and power sink energy for years 2018 to 2023. Considering the charging power scenario, CPS, uncontrolled, UNC, controlled unidirectional, AGC1, and controlled bidirectional, AGC2, charging. In addition, for different increasement of wind and solar PV generation.

charging the peak power source capacity was 2.0 to 2.8 GW (40 to 54%) greater compared to the same system without BEVs. However, with unidirectional aggregator-controlled charging, AGC1, this increase was reduced to 0.3 to 0.8 GW (7 to 15%). Moreover, when V2G was utilized with bidirectional aggregator-controlled charging, AGC2, the capacity was either the same or lower, at most 0.5 GW less (−11%), than without BEVs. The variation was due to available charging power, which when higher, increased the capacity demand with uncontrolled charging, and with controlled charging decreased it. Furthermore, keeping in mind that these behaviors varied also annually, and as presented in Fig. 8, during 2020 with AGC2 the power source capacity increased, compared to the system without BEVs. But since here the greatest power source capacity during 2018 to 2023 is presented, this is not shown in Table 9, as the requirement during 2020 was somewhat lower in general.

The requirement for power sink capacity, that would be required to prevent any curtailment of energy, increased as the installed capacity of wind power and solar PV increased. Moreover, the required power sink capacity was high already with relatively small amounts of installed wind and solar power, but with high amounts it increased greatly, when considering that the peak load without BEVs was 14.7 GW between 2018 to 2023. The highest power sink capacities required were due to windy and sunny summer days with low load. However, it is good to note that there was no incentive for the aggregator in the optimization to limit the capacity of the power sink.

In Table 10, the total load, generation, additional required power source and power sink energies over the years 2018 to 2023 are presented for the different increasements of wind and solar PV generation, charging power scenarios, and three charging strategies. In addition, the corresponding values are presented for a system without BEVs. The load had a minor difference depending on the charging power scenario, CPS, as the sample representing the total BEV fleet was different for each, as presented in Table 6 in Section II-D. Moreover, with AGC2 the losses related to V2G increased the charging load slightly compared to UNC and AGC1. The generation from an additional power source was affected substantially by the amount of increased wind

TABLE 9. Peak capacity required from an additional power source, and the peak of the power sink required to prevent curtailment of energy during 2018 to 2023.

Installed Wind and Solar PV capacity	CPS	Power source (GW)				Power sink (GW)			
		No BEVs	UNC	AGC1	AGC2	No BEVs	UNC	AGC1	AGC2
Wind 10 GW Solar PV 0 GW	Low	5.1	7.4	5.8	5.1	6.8	5.9	5.8	6.2
	Med.	5.1	7.4	5.6	4.8	6.8	6.2	6.1	6.4
	High	5.1	7.8	5.8	4.7	6.8	6.4	6.0	6.4
Wind 15 GW Solar PV 0 GW	Low	5.0	7.1	5.6	4.9	11.7	10.5	10.7	11.0
	Med.	5.0	7.3	5.5	4.6	11.7	10.6	11.0	11.1
	High	5.0	7.7	5.6	4.6	11.7	10.8	11.0	11.2
Wind 10 GW Solar PV 16.5 GW	Low	5.1	7.4	5.8	5.0	16.4	15.6	15.3	14.9
	Med.	5.1	7.4	5.5	4.7	16.4	15.6	15.6	15.3
	High	5.1	7.8	5.7	4.6	16.4	15.5	15.6	15.3
Wind 20 GW Solar PV 0 GW	Low	4.9	6.9	5.5	4.8	16.6	15.2	15.3	15.9
	Med.	4.9	7.2	5.4	4.5	16.6	15.4	15.5	15.9
	High	4.9	7.6	5.5	4.4	16.6	15.6	15.4	16.1
Wind 15 GW Solar PV 16.5 GW	Low	5.0	7.1	5.6	4.8	20.4	19.6	19.3	19.2
	Med.	5.0	7.3	5.3	4.6	20.4	19.7	19.5	19.4
	High	5.0	7.7	5.5	4.4	20.4	19.5	19.7	19.2
Wind 10 GW Solar PV 33 GW	Low	5.1	7.4	5.8	4.9	29.2	28.5	28.3	27.9
	Med.	5.1	7.4	5.5	4.6	29.2	28.5	28.6	27.8
	High	5.1	7.8	5.7	4.6	29.2	28.4	28.5	27.8

and solar PV generation, as with more generation from these, the required power source generation decreased significantly. In addition, the charging strategy utilized by the BEVs had a major effect. Compared to uncontrolled charging, UNC, the unidirectional aggregator-controlled charging, AGC1, decreased the power source requirement between 5.2 to 7.7 TWh during 2018 to 2023. Moreover, utilizing the bidirectional aggregator-controlled charging, AGC2, this decrease was between 10.7 and 19.0 TWh, depending on the amount of increased wind and solar and the CPS. Notably, utilizing V2G, in AGC2, with the scenarios with approximately 250 TWh of wind and solar, resulted in the same magnitude of power source requirement as uncontrolled charging with the scenarios of roughly 333 TWh of wind and solar generation. A higher available charging power for the BEVs increased the required power source generation for uncontrolled charging, but for AGC1 and AGC2 it decreased it, as the BEVs were able to utilize more of the added renewable generation. This effect of the available charging power was greater for bidirectional charging in AGC2, but in general, the effect of CPS was much smaller than the effect of charging strategy. In addition, from the increased renewable energy scenarios which had the same magnitude of generation, (2^{nd} and 3^{rd}, and 4^{th}-6^{th}), the ones which had some solar PV in addition to wind, had slightly lower demand for generation from the additional power source. This indicates that the wind and solar PV generation had a negative correlation, which was beneficial for the power system. Furthermore, with bidirectional charging in AGC2, in the increased renewable scenarios with approximately 333 TWh of wind and solar, the power source demand was close to the value without BEVs, but as next discussed, then the power sink demand was increased significantly.

As the requirement for additional power source generation decreased by increasing the installed capacities of wind and solar PV, consequently the power sink required to prevent curtailment of energy increased. Without BEVs, wind, and solar, the generation only exceed the load during 2023, by 0.006 TWh, thus, in practice, all the BEV load was required to be satisfied by the added generation of wind and solar PV, and lastly by the additional power source. Moreover, all energy prone to be curtailed without an additional power sink was due to the added wind or solar PV generation. When the wind and solar PV generation were increased more than just 10 GW of wind, the power sink requirement increased

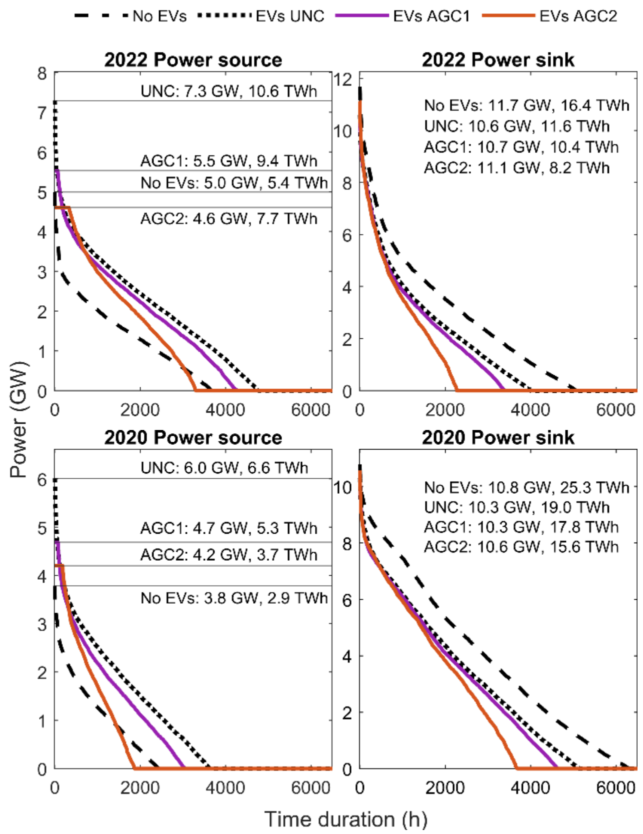

FIGURE 10. Duration curves for the additional power source and sink requirements during 2022 and 2020, without BEVs, with uncontrolled (UNC), and aggregator controlled unidirectional (AGC1) and bidirectional (AGC2) charging. The medium charging power scenario was selected from Table 1, and the power system included 15 GW of installed wind capacity and 0 GW of solar PV. A total year with 8760 h was analyzed, but the x-axis is cut from 6500 h for better visibility.

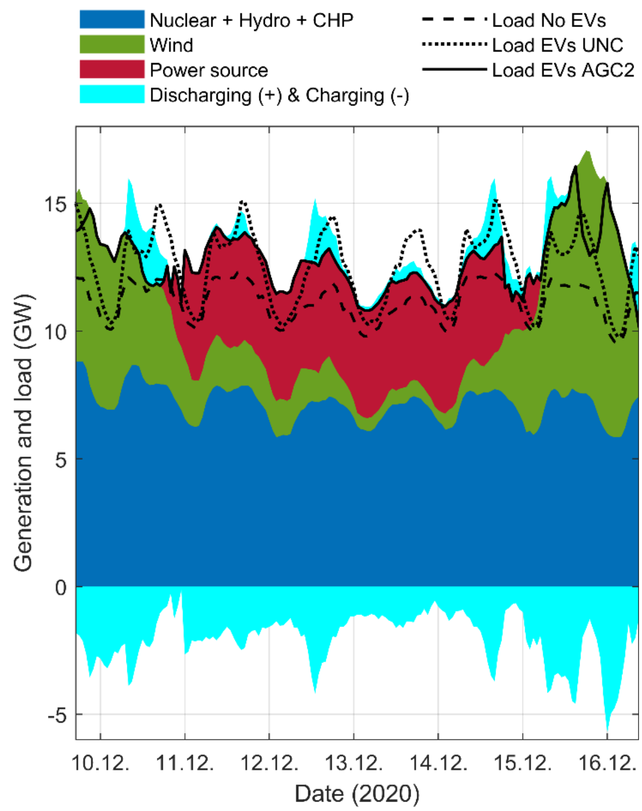

FIGURE 11. Example of low wind and high load period during 2020, with 15GW of wind power and 0 GW of solar PV. Charging power as with CPS Medium. The charging, discharging, and power source generation are presented, when the BEVs used bidirectional charging in AGC2.

more than the power source requirement decreased, while taking into account that some of the added generation anyway exceeded the load, as the load merely changed. For example, with UNC and CPS Low, when increasing the generation of wind from 10 GW to 15 GW, without solar, the generation was increased by 83 TWh. Neglecting the hourly matching of generation and load, of this generation 27.2 TWh exceeded the load anyway, as it remained the same. From the 55.8 TWh which could supply the load, if it could have been freely allocated, 25.5 TWh was possible to be supplied to the load, and 30.3 TWh required some additional power sink, when the hourly matching was considered. This highlights that, by the realistic assumption of limiting the BEV charging flexibility within charging events, the BEVs can provide rather short-term flexibility for the power system.

3) NUCLEAR POWER

In the previous section the wind and solar PV generation were increased to obtain several scenarios with high amounts of renewable generation. Here the corresponding amount of nuclear power, in terms of energy, was added instead, to analyze an alternative power system. As previously mentioned, the Finnish power system already has 7 GW of wind power, which is expected to reach 10 GW in 2026, and thus also 10 GW of wind was included. In the last section wind was increased by 5 GW and solar PV by 16.5 GW steps, which on average generated annually 13.8 and 14.0 TWh. Here the corresponding added capacity for nuclear power was 1.6 GW, which generated, assuming a constant generation, 14.0 TWh annually. The results considering the required power source and power sink capacity and energy during years 2018 to 2023, are presented in Table 11. The scenario with increased nuclear capacity of 1.6 GW is comparable with the scenarios in Tables 9 and 10 where the wind and solar generation were approximately 250 TWh, and the one with 3.2 GW with the ones with approximately 333 TWh of wind and solar.

Compared to increasing wind and solar, increasing nuclear capacity resulted in a lower required additional power source capacity. The capacity required was, in essence, lowered by the additionally installed capacity of nuclear, as the decrease varied by 1.3 to 1.6 GW, with 1.6 GW of additional nuclear capacity. The effect of charging strategy was as before; uncontrolled charging increased the power source capacity, as did the AGC1 charging, although less, whereas with AGC2 charging the capacity was the same or slightly lower

TABLE 10. Generation required from an additional power source, and the energy of the power sink required to prevent curtailment of energy during 2018 to 2023. Also included are the load with and without BEVs, combined generation from nuclear, hydro and CHP power plants, and the combined generation from wind and solar PV power during 2018 to 2023, for each installed capacity of wind and solar PV.

		Load (TWh)			Generation (TWh)		Power source (TWh)				Power sink (TWh)			
Installed Wind and Solar PV capacity	CPS	No BEVs	UNC and AGC1	AGC2	Nuclear, hydro, and CHP	Wind and Solar PV	No BEVs	UNC	AGC1	AGC2	No BEVs	UNC	AGC1	AGC2
Wind 10 GW Solar PV 0 GW	Low		563.1	564.8			44.1	83.0	77.8	72.3	48.5	27.2	22.0	14.8
	Med.	503.0	562.9	565.2	341.3	166.0	44.1	83.6	77.3	70.7	48.5	28.1	21.7	12.8
	High		563.0	565.8			44.1	84.3	77.4	70.2	48.5	28.6	21.7	11.7
Wind 15 GW Solar PV 0 GW	Low		563.1	565.6			29.3	57.5	51.5	43.0	116.6	84.7	78.7	67.7
	Med.	503.0	562.9	566.1	341.3	249.0	29.3	58.1	50.9	40.2	116.6	85.6	78.4	64.4
	High		563.0	566.9			29.3	58.8	51.1	39.8	116.6	86.0	78.4	63.2
Wind 10 GW Solar PV 16.5 GW	Low		563.1	565.4			24.5	50.2	43.6	35.5	112.8	78.4	71.9	61.5
	Med.	503.0	562.9	565.6	341.3	250.0	24.5	50.2	42.7	33.9	112.8	78.7	71.2	59.7
	High		563.0	566.1			24.5	50.3	42.6	33.3	112.8	78.6	70.9	58.6
Wind 20 GW Solar PV 0 GW	Low		563.1	565.6			21.3	43.2	37.5	28.9	191.5	153.4	147.7	136.6
	Med.	503.0	562.9	566.1	341.3	332.0	21.3	43.7	36.9	26.7	191.5	154.2	147.4	133.9
	High		563.0	566.7			21.3	44.3	37.0	25.7	191.5	154.6	147.3	132.3
Wind 15 GW Solar PV 16.5 GW	Low		563.1	565.0			15.4	33.0	27.8	21.0	186.7	144.2	139.0	130.3
	Med.	503.0	562.9	565.2	341.3	333.0	15.4	33.1	27.1	19.5	186.7	144.5	138.5	128.6
	High		563.0	565.7			15.4	33.2	27.0	18.8	186.7	144.4	138.3	127.4
Wind 10 GW Solar PV 33 GW	Low		563.1	565.5			22.3	44.9	38.5	29.4	194.7	157.1	150.7	139.2
	Med.	503.0	562.9	565.6	341.3	334.1	22.3	44.7	37.5	27.9	194.7	157.2	149.9	137.6
	High		563.0	566.0			22.3	44.6	37.3	27.4	194.7	156.9	149.6	136.7

TABLE 11. Peak capacity and generation required from an additional power source, and the capacity and energy of the power sink required to prevent curtailment of energy during 2018 to 2023, for two additionally installed capacities of nuclear power generation.

		Capacity (GW)								Energy (TWh)							
		Power source				Power sink				Power source				Power sink			
Installed Wind and Nuclear capacity	CPS	No BEVs	UNC	AGC1	AGC2	No BEVs	UNC	AGC1	AGC2	No BEVs	UNC	AGC1	AGC2	No BEVs	UNC	AGC1	AGC2
Wind 10 GW	Low	3.5	5.8	4.2	3.5	8.4	7.5	7.4	7.8	10.6	34.3	28.4	22.7	99.0	62.7	56.8	49.1
Additional	Med.	3.5	5.8	4.0	3.2	8.4	7.8	7.5	7.9	10.6	35.3	28.0	21.1	99.0	63.8	56.6	47.2
Nuclear 1.6 GW	High	3.5	6.2	4.2	3.1	8.4	8.0	7.4	8.0	10.6	36.1	28.1	20.5	99.0	64.5	56.5	45.9
Wind 10 GW	Low	1.9	4.2	2.6	1.9	10.0	9.1	9.1	9.4	0.5	7.7	4.4	2.7	173.1	120.1	116.8	114.5
Additional	Med.	1.9	4.2	2.4	1.6	10.0	9.4	9.2	9.5	0.5	8.5	4.2	2.3	173.1	121.2	116.9	114.2
Nuclear 3.2 GW	High	1.9	4.6	2.6	1.5	10.0	9.6	9.4	9.5	0.5	9.2	4.3	2.1	173.1	121.7	116.7	113.7

than without BEVs. The generation required from the power source when nuclear power was increased, decreased significantly compared to increasing wind and solar generation. That is, with 10 GW of wind and 1.6 GW of additional nuclear capacity, with a combined generation of 250 TWh the power source generation requirement was reduced to the same level as with 15 GW of wind and 16.5 GW of solar capacity, with generation of 333 TWh. Hence, this highlights the benefits of a constant generation source, when comparing the requirements for additional power source capacity and generation.

Furthermore, the duration curves for the power source and sink during years 2022 and 2020 with 10 GW of wind and the additional nuclear capacity of 1.6 GW, are presented in Fig. 12, in comparison to Fig. 10, where the same were presented with 15 GW of added wind generation.

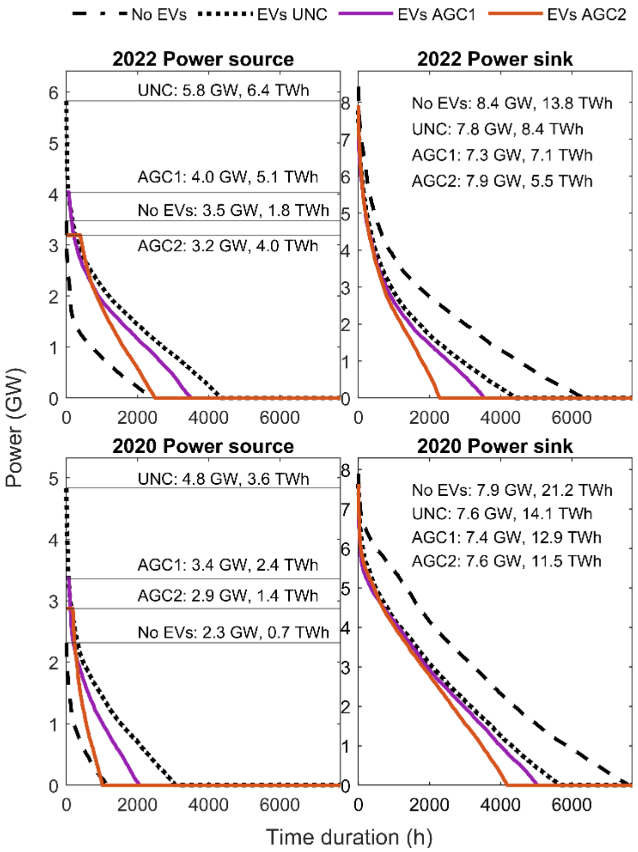

FIGURE 12. Duration curves for the additional power source and sink requirements during 2022 and 2020, without BEVs, with uncontrolled (UNC), and aggregator controlled unidirectional (AGC1) and bidirectional (AGC2) charging. The medium charging power scenario was selected from Table 1, and the power system included 10 GW of installed wind capacity, 0 GW of solar PV, and 1.6 GW of additional nuclear capacity. A total year with 8760 h was analyzed, but the x-axis is cut from 7700 h for better visibility.

IV. DISCUSSION AND CONCLUSION

In this study the flexibility of electric vehicle charging within charging events was modeled, considering ambient temperature, available charging power, and unidirectional and bidirectional controlled charging. Moreover, with this methodology, the flexibility of BEV charging was analyzed over the selected years, for ether minimizing the charging costs for individual BEV owners, or by utilizing the flexibility of charging for the benefit of the total power system by an aggregator.

When the charging costs for BEV owners were minimized individually, their effect on the power system was neglected. However, this examination presented how the BEV owners may affect their charging costs by controlling their charging load. The results showed that, for years with great fluctuation in the market prices, controlling the BEV charging load, can on average reduce the cost of charging by 27% with unidirectional charging, and by 35% with bidirectional charging, compared to uncontrolled charging where the BEVs charged immediately after arriving to a charging location. Moreover, with higher available charging power the savings were greater compared to lower charging power, as the BEVs could further utilize the low-cost hours for charging, and high profit hours for discharging. However, during years where the market price was low, there was a lower benefit for controlling the BEV charging, and for years with minor fluctuation of the market price, there was no difference between unidirectional and bidirectional charging, as the price fluctuation was not great enough to allow profitable V2G operation. Moreover, it was further showed, that if a fully electrified passenger car and van sector would charge as the individually controlled vehicles, the peak load in the analyzed power system could increase up to 144% with bidirectional charging. However, this would only occur if the market price would not react to the increased load of the BEVs.

In addition, the BEV flexibility was optimized in combination with the rest of the power system, to examine the possible benefit of the BEV charging load flexibility for the total system. This was conducted such that the BEV load was optimized by an aggregator to first minimize the additional power source capacity required to supply the total load of the system. And secondly by setting the capacity obtained as a constraint and minimizing the additional power source generation required to satisfy the load. The analysis was performed for the historical power system in Finland during 2018 to 2023, including the power generation from nuclear, hydro, combined heat and power for industry and district heat, wind, and solar PV. That is, power import and condensing power were excluded. Moreover, the same analysis was performed with increased capacities of wind and solar PV generation, while keeping the rest of the generation sources the same. The generation required from the power source could then be supplied by, for example, power imports or condensing power generation.

For the historical power system, the uncontrolled charging increased the capacity requirement from an additional power source significantly, up to 8.3 GW, while the aggregator controlled unidirectional charging increased it at most to 6.2 GWs. With bidirectional charging to 5.6 GW, only 0.2 GW greater than without BEVs. With the historical wind and solar generation, the load was much greater than the generation, there was only minor differences on the additional power source generation requirement, depending on, if the BEVs charged uncontrolled, or controlled.

When the generation capacity of wind and solar PV power were increased, to analyze possible future developments of the power system, there was relatively small difference between the increased generation scenarios, on the requirement of additional power source capacity. However, the variation between different years was notable. In terms of required power source generation, there was again some difference between the years, which was mainly due to the varying annual system load without BEVs, but now the difference between the increased generation scenarios was notable. When these results were examined over the selected years, it was evident that the uncontrolled charging increased the capacity requirement from an additional power source significantly, up to 6.9-7.8 GW compared to 4.9-5.1 GW without the BEVs. However, when the BEV charging was controlled by an aggregator, with unidirectional charging this capacity was between 5.4 and 5.8 GW, and with bidirectional charging between 4.6 to 5.1 GWs. Thus, the controlled bidirectional charging could prevent the BEV load to require any additional generation capacity in the system. The variations in the values were due to the available charging power, and the increased amount of wind and solar PV generation. However, as presented in Fig. 8, there were notable yearly variations, and during the year 2020 the required power source capacity increased even with bidirectional charging. Thus, for long period planning this limitation must be considered. When the generation from the power source was analyzed, the increased wind and solar generation had a major impact, as with more generation from these, the required power source generation decreased. However, as the flexible operation of the BEVs was limited to within the charging events, when increasing the wind and solar generation hugely, only a rather small part of the added generation was utilized by the load.

Furthermore, the same analysis of required capacity and generation from an additional power source was conducted while increasing the generation of nuclear power, by the same amount as the wind and solar power previously, in terms of energy. With this added constant generation of nuclear, both the capacity and energy requirements from the power source decreased notably compared to when increasing wind and solar PV generation. The requirement for power sink also decreased while adding more nuclear power, as the BEVs were able to utilize more of the added generation.

When the generation capacities for wind, solar PV, and nuclear power were increased, to obtain possible future power system generation mixes, only the power source and power sink requirements were analyzed. Thus, the costs related to these new generation mixes were not considered. Hence, examining the costs for these different future developments, and the related costs of the additional power source, would provide beneficial information for the power system development. These could be modeled and analyzed in future studies.

In this study the flexibility of charging was limited within each charging event. That is, during each charging event, the BEVs were constrained to charge the same amount they would have charged with uncontrolled charging. This limited the flexibility of charging in such cases that the BEV would not necessarily have to charge during a charging event. For example, a BEV which has a relatively short trip from home to work and back, could be able to charge the demand for these trips completely overnight at home and avoid charging during the day at work, when in general the load in the power system is high. In this example, in this study the BEV was required to charge also at work the demand due to the previous trips. However, constraining the charging to each charging event was considered a rather realistic consideration, as it was assumed that many BEV owners would like to charge their BEVs while stationary in a location with charging possibility. Moreover, analyzing the BEV owner's willingness to charge or postpone the charging was outside the scope for this study. Thus, further analysis could be conducted on this willingness to charge or postpone the charging to a later time.

Furthermore, in this study, the BEV charging was either controlled individually by the market price of electricity, or by an aggregator for the utilization of the power system. These considerations could be further modeled such that the electricity price would be affected by the charging of the BEVs, and a new market price would be formed. In addition, the aggregator-controlled charging could be further modeled to include the reaction of several generation sources, such as hydro power and electricity storage, to the altering load, including BEVs. A limitation of this study is that it does not consider these aspects. Moreover, a greater consideration could be modeled, where, in addition to the now included power generation and load with electric transportation sector, the electricity demand, and the power sink capability, from other sectors, such as heating, households, and industry could be included. This modeling could provide knowledge, of how these sectors can together adjust their load such that for example a greater share of the emission-free power generation can be utilized. Moreover, as the combined heat and power generation, CHP, is combustion based, even if biofuels are used, a future power generation mix without it could be modeled. This would affect the results as, especially CHP for district heating, generates significantly more during the high load periods.

APPENDIX

In Figure 13, the arrival and departure moments of the BEVs for home and work, the two most charged locations, are presented. Each subplot presents the share of moments for the particular day and location. Moreover, the moments are presented with ambient temperature of 15°C and with CPS Medium, although the difference between scenarios was minor.

In Table 12 the share of passenger cars and vans are presented for each climate zone in Finland.

In Table 13 the energy consumption rate of BEVs by ambient temperature is presented in relation to 20 °C.

TABLE 12. Share of passenger cars and vans per each climate zone in Finland [26] and [27].

Climate zone	Share of cars and vans (%)
I	19.2
II	46.1
III	29.8
IV	5.0

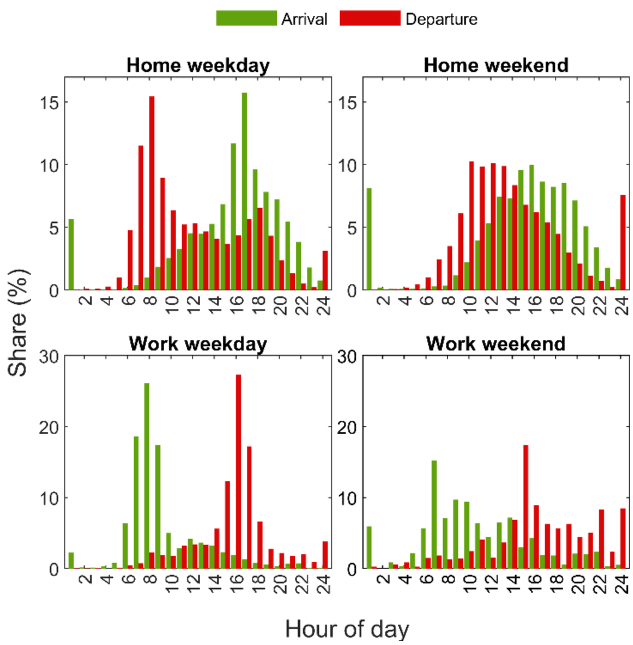

FIGURE 13. Arrival and departure moments for the BEVs for home and work locations, the two most charged locations.

TABLE 13. Electric vehicle energy consumption rate in relation to consumption at 20°C, by ambient temperature.

	Reference						
T (°C)	[49]	[50]	[51]	[52]	[53]	[32]	Mean
-20	-	1.32	-	1.79	2.94	2.00	2.01
-15	-	1.27	-	-	2.94	1.78	2.00
-10	-	1.22	-	1.57	2.24	1.60	1.66
-5	-	1.17	1.92	-	1.87	1.46	1.60
0	2.00	1.12	1.69	1.36	1.55	1.33	1.51
5	1.57	1.07	1.31	-	1.37	1.23	1.31
10	1.21	1.02	1.15	1.21	1.19	1.14	1.16
15	1.00	1.00	1.08	-	1.08	1.07	1.04
20	1.00	1.00	1.00	1.00	1.00	1.00	1.00
25	1.07	1.13	1.08	-	0.91	1.07	1.05
30	1.21	1.23	1.23	1.07	-	1.14	1.18

In Table 14 the mean charging cost for BEVs with bidirectional charging (PC2) and the effect of the charging demand from a fully electrified passenger car sector to the total load of the Finnish power system, while assuming that the battery wear cost was 0.035 €/kWh. These assumed that each BEV was optimized individually, and their charging and discharging did not affect the other BEVs, the power system, and the day-ahead market price. The values are presented for years 2018 to 2023 and to three charging power scenarios. Moreover, the percentage difference compared to uncontrolled charging in Table 7 is presented for the mean cost, and the percentage difference of the peak power to the system peak without EVs in Table 8.

TABLE 14. Mean charging cost for BEVs and the peak power in the Finnish power system with PC2 charging, based on time of use of pricing. Assuming a fully electrified passenger vehicle transportation, and that each BEV optimizes its charging independently from the others. Additionally, the minimum system load is presented.

		PC2 Costs		PC2 Power system		
Year	CPS	€/kWh	% Comp. UNC	MAX GW	% Comp. No EVs	MIN GW
2018	Low	0.090	-5 %	19.9	+40 %	6.7
2018	Med.	0.089	-6 %	24.7	+74 %	4.0
2018	High	0.089	-7 %	28.7	+102 %	1.3
2019	Low	0.087	-7 %	18.7	+27 %	6.3
2019	Med.	0.086	-8 %	21.9	+49 %	6.2
2019	High	0.086	-8 %	23.7	+61 %	6.1
2020	Low	0.071	-10 %	17.5	+37 %	6.4
2020	Med.	0.071	-12 %	22.6	+77 %	2.2
2020	High	0.070	-13 %	27.8	+117 %	-2.1
2021	Low	0.105	-15 %	21.2	+44 %	5.5
2021	Med.	0.101	-17 %	28.4	+93 %	-0.4
2021	High	0.101	-18 %	35.9	+144 %	-5.7
2022	Low	0.140	-22 %	18.7	+33 %	1.5
2022	Med.	0.124	-25 %	25.8	+83 %	-5.6
2022	High	0.117	-27 %	33.0	+134 %	-12.5
2023	Low	0.093	-13 %	18.9	+36 %	1.2
2023	Med.	0.089	-15 %	23.7	+71 %	-3.9
2023	High	0.088	-17 %	31.4	+126 %	-10.0

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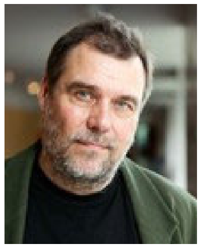

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