Commercial EV fleet smart charging for cost reduction and renewables integration

A case study in Germany

André Corsetti
andrecorsetti@tecnico.ulisboa.pt
Instituto Superior Técnico, Universidade de Lisboa, Portugal
December 2023

***Abstract*— The transition towards electric mobility reduces transportation carbon emissions but imposes challenges to integrate a growing electricity demand with renewable electricity generation and power systems. Smart charging arises as a key technology to minimize operational costs and support higher usage of green electricity for EVs. Market analysis indicates a trend towards dynamic electricity tariffs, incentivizing EV charging at times favorable to the electricity grid. This work studies, for a commercial EV fleet in Germany, different smart charging strategies considering a Real-Time-Pricing (RTP) tariff indexed to day-ahead market prices, and renewable electricity integrations. HOMER Grid is used to model such smart charging strategies and generate new EV load profiles. A dynamic model is used to calculate project economics and carbon impact using the generated smart charging EV load profiles and varying solar PV and batteries capacities. Direct and indirect CO2 emissions and renewable electricity usage ratios are calculated based on granular electricity grid and self-consumption data. The resulting Levelized Cost of Energy (LCOE) is minimized using Microsoft Excel's Solver with GRG Non-linear solving method, varying solar PV and batteries capacities. The adoption of an RTP tariff decreases LCOE from € 0.530 to € 0.314 per kWh. A smart charging strategy designed to reduce peak demand and schedule charging at times of lower prices reduces LCOE further to € 0.283 per kWh. The lowest LCOE of € 0.281 per kWh is obtained with 34.4 kWp of solar PV capacity and no batteries. Carbon impact is minimized with larger solar PV and batteries capacities.**

Keywords- Carbon Impact, Commercial EV-Fleets, Dynamic Electricity Tariffs, Electric Vehicles, Smart Charging, Renewables Integration.

I. INTRODUCTION

The fight against climate change requires decarbonizing key sectors like industries, electricity and heat production, and transportation. The transportation sector, responsible for 25% of European CO2 emissions [1], is embracing electric vehicles (EVs) to reduce emissions. In Europe, EV sales surged by 15% from 2021 to 2022, reaching a 2.7 million EV fleet. Globally, more than 25 million EVs were operational in 2022. EV adoption rates signal progress toward decarbonization goals, and by 2030, electricity demand is expected to rise by 4% due to EVs [2]. However, the source of electricity used to charge EVs impacts their environmental footprint. If charging is not properly managed, it increases electricity demand at peak hours [3].

The electricity sector is rapidly decarbonizing, with solar and wind energy projected to constitute 25% of global electricity generation capacity by 2030 [1]. Yet, the volatility of renewable energy poses challenges for power system operators. The growth of decentralized photovoltaic installations complicates matters. To accelerate decarbonization, the European Union will include the transportation sector in the EU Emission Trading System (EU-ETS) from 2025 [4]. Since the European Carbon Market is open across industries and sectors, this inclusion tends to influence carbon markets dynamics and the electricity sector, where decarbonization is cheaper. As a result, the new EU-ETS is expected to accelerate the decarbonization of the electricity sector [5] [6].

The transition to electric mobility presents challenges in power systems and electricity distribution. If EVs charge using high-emission electricity, it can shift fossil-fuels emissions from vehicles to power plants [3]. Smart charging technologies are a key technological enabler to manage EV charging efficiently and sustainably [7]. Unidirectional (V1G) and bi-directional flow (V2X) of energy play a role, but V2X technology and regulations still require further development to become commercially widely available [1].

V1G smart charging adapts EV charging to renewable energy production, grid signals, and demand-response programs. EV aggregators facilitate communication between power systems and EVs, dynamically aggregating data and sending signals to charge EVs according to energy systems needs and value streams opportunities [7]. Financial incentives can encourage EV owners to match charging with grid needs. Dynamic Time-of-Use (ToU) tariffs are becoming a common offer in Northern Europe, especially in Sweden, encouraging EV charging at lower prices in sync with power market dynamics [8].

Commercial fleet EV adoption has been growing due to lower EV prices and improved battery range, and the majority of companies sets its own charging infrastructure [2]. To ensure low operational costs and stable operations, smart charging and local renewable electricity can be integrated. However, solar PV and batteries purchasing is capital-intensive, and the cost reduction benefits is not always compensated [9]. Proper understanding of EV charging loads, local renewable electricity generation, storage and consumption, and systems integrations is essential to deliver EV smart charging solutions beneficial for electricity systems and commercial fleets.

This work explores EV smart charging and renewable electricity integration for a commercial fleet case study in Germany. The work is performed in collaboration with RiDERgy GmbH, an energy management and EV fleet aggregator company in Berlin, Germany. Three research questions guide this work:

1) What are the economic and environmental benefits from adopting smart charging strategies, aiming to shave charging peaks and shift demand according to charging schedules?
2) What are the economic and environmental benefits from integrating solar PV and batteries with EV smart charging?
3) What is the ideal system architecture to minimize project costs over its lifetime?

This work objective is to propose a methodology to investigate smart charging strategies and renewable electricity integration based on a Real-Time-Pricing (RTP) electricity tariffs. A tool to estimate cost and carbon impact emissions reduction is created to evaluate different scenarios for a commercial EV fleet case study in Germany, supporting the investment decision making process.

II. Literature review

Utility tariffs must be cost reflective, but it is crucial to provide price stability and predictability for consumers. While fixed ToU EV tariffs encourage off-peak EV charging, they can lead to a new peak demand time. Fixed energy prices increase the system overall peak in early evening hours. Combining grid power charges and time-variant prices is an interesting alternative for utilities and EV owners [3]. [8] An overview of EV smart charging tariffs and services in Europe indicates the growing adoption of dynamic ToU tariffs, especially in Nordic Countries. These expose EV owners to day-ahead (DA) spot market electricity prices, and incentive charging at cheaper hours of lower demand or surplus generation. In Germany, the development of such tariffs is lagging, as presented in **Fig. 1**.

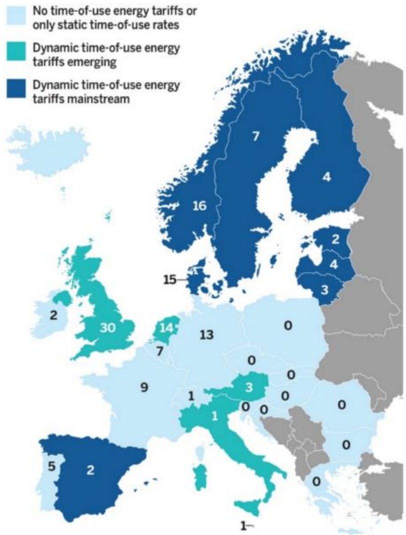

Fig. 1. Smart charging tariffs in Europe [8]

Smart EV charging with RE case studies are widely present in the scientific community. [3] analyse residential EV charging and solar integration, but do not explore different tariff structures. The authors validate smaller charging power is beneficial to decrease the household peak demand. [10] go a step further and assess integrating not only PV panels but also batteries for residential EV charging. Homer Grid software is used to identify the optimum design for this use case and demonstrate the economic feasibility of local renewable electricity integration with EV charging. The authors only consider scenarios with no grid purchases, thus no analysis on different tariff structures is performed. [11] study the integration of EV charging with an existing micro-grid system with solar PV and batteries. Fixed electricity prices from solar, battery and grid purchases are considered in the smart charging algorithm, and a large self-consumption rate is achieved. Nonetheless, since the micro-grid is already in place their work does not evaluate if the installed capacity is optimal for the existing EV demand. [12] also use Homer Grid to study wind, solar PV and storage integration for a public EV fast charging system. Two different tariff structures based on grid power charges are also studied, and the authors highlight the benefit of Homer Grid for this purpose. However, no dynamic ToU tariffs are analysed. [9] model synthetic EV fleet demand curves based on different smart charging strategies. Their simulation on smart charging strategies is limited, effectively, to a comparison between charging at maximum power versus at lowest charging power. Furthermore, no dynamic charging strategy is considered, and the authors do not study the impact on costs and CO_2 of their approach from a customer or utility perspective. [13] propose a dynamic tariff and charging strategy based on grid operation constraints for a parking lot with EV chargers. The authors successfully model a tariff that benefit both DSOs, CPOs and customers, but highlight the existing implementation challenges and innovative aspect of their solution.

The potential and effective CO_2 emissions reduction in road transportation from smart charging strategies and carbon emission certificate systems is also covered. Transition to EVs effectively helps reduce overall CO_2 emissions via a carbon emission trading system [5], [6], which validates the implementation of the recently announced EU ETS II system [14]. Smart charging enhances the integration with renewables, especially solar PV, decreasing direct and indirect emissions in the electricity system [15]. A blockchain-based technology to generate green energy certificates was proposed by [16], helping companies track their emissions accurately by considering the electricity mix at the time of consumption. Their work merges a smart charging algorithm to maximize PV self-consumption in a PV and battery micro-grid with the green energy certificate methodology.

The performed literature review indicates several references within the realm of EV smart charging and road transportation decarbonization. Research shows integration with local renewable electricity resources is beneficial to reduce costs and CO_2 emissions, and smart charging enhances the integration with grids by providing flexibility on the demand side. To achieve that, innovative utility tariffs targeted to EV charging are being developed, and EV aggregators have an important role to intermediate and optimize EV charging according to grid signals.

Specific case studies require detailed modelling to account for mobility needs, local constraints, and electricity systems. EV charging demand can be modelled by accounting for driving behaviour, EV data and parking times. When available, EV charging infrastructure data directly showcases the demand for electricity in specific locations and use cases. While some researchers develop their own algorithms, Homer Grid stands out as a powerful modelling software to simulate various micro-grid designs and complex electricity tariff structures integrated with EV charging. The software identifies the systems with lowest Net Present Cost, which translates into a cost-effectiveness analysis from a decision-making perspective. Smart charging strategies are limited, however, and no dynamic electricity tariffs smart charging strategies are identified in the literature. Furthermore, Homer Grid easily quantifies the CO_2 reduction emission in comparison to a standard electricity mix carbon footprint. To achieve more granularity in CO_2 emissions certification, [16] propose a blockchain-based approach that certifies green electricity usage on an hourly basis. No studies were found to use a similar approach and consider the electricity mix in such granular basis.

The performed literature review identified many studies proposing renewable electricity integration with smart charging, as well as different tariff structures. EV charging demand profiles are generated via different methodologies, and no work goes in-depth to assess how flexible the demand is to account for that in smart charging strategies. Moreover, no smart charging strategies to leverage on day-ahead-market indexed tariffs volatility are studied.

This work covers an existing literature gap, proposing a methodology to model and analyse smart charging strategies based on granular, dynamic electricity prices from the day-ahead-market, and local renewable electricity integrations. For a specific commercial EV fleet case study in Berlin, Germany, HOMER Grid is used to generate smart EV charging loads and energy balances considering solar PV panels and batteries integration. Such models are used to analyse the impact of adopting a Real-Time-Pricing (RTP) tariff indexed to the day-ahead market, identifying the optimum system configuration that leads to lowest costs. Furthermore, the carbon impact of such systems is assessed, quantifying direct and indirect emissions from electricity purchases from the grid, as well as self-generated solar PV electricity. The proposed methodology quantifies costs and CO_2 emissions for different systems, providing a framework for decision makers to opt on decentralized renewable energy assets (solar PV and batteries) investment and RTP smart charging strategies adoption. The work provides background to support the ongoing development of RTP tariffs in Europe for a commercial EV fleet use case, comparing different smart charging strategies and renewables integration.

III. Case study description

A company based in Berlin, Germany, owns a 65 EVs fleet and offers mobility services for their customers via a mobile application, both on-demand and via a scheduling feature. The vehicles are charged primarily at the company's charging infrastructure, located in a parking lot. Vehicles are driven all days of the week by different drivers, in two shifts (08:00 to 20:00 and 20:00 to 08:00), with slight variations based on client's demand.

The company owns a parking lot where vehicles are charged. There are 46 slow charging ports, with 11 kW capacity, and 12 fast charging ports, with up to 50 kW capacity. The fast-charging infrastructure is used when vehicles must quickly recharge their batteries before resuming their work schedule. On the other hand, slow chargers are used for charging the vehicles between work shifts, when the vehicles stay longer in the parking lot.

Vehicles are connected to fast DC chargers for shorter periods in comparison to the lower power AC chargers. On average, vehicles only stay plugged onto DC chargers for 30 minutes, while for AC chargers they remain connected for 14 hours to fulfil an average charging demand of 13.2 kWh and 14.9 kWh, respectively. In addition, the DC infrastructure is used more frequently and delivers more energy throughout the whole week. On weekdays, DC chargers deliver 427 kWh/day to the fleet, while AC chargers are used to charge 370 kWh/day. On weekends, a more pronounced behaviour is seen. Fast charging is responsible on average for 711 kWh/day of the demand, which is more than two times bigger than the 435 kWh/day from slow chargers. The total annual demand is 414 MWh per year.

Electricity provision for the charging infrastructure is dedicated, i.e. independent from other loads. It has a maximum connection capacity of 400 kW. The company pays for electricity based on a flat electricity tariff, with no specific EV charging tariff. A grid power charge of € 8.5 per kW peak per month is paid to the local utility, based on maximum monthly demand peaks. In 2022, the electricity prices for commercial sites were € 0.33 per kWh, in the first semester, and € 0.53 per kWh, in the second semester [17]. Grid sales generate € 0.082 per kWh [18]. The company has available rooftop area to install up to 200 kWp solar PV, as well as 200 kWh of storage using lithium-ion batteries. In addition, it is investigating the opportunity to adopt a Real-Time-Pricing tariff with prices indexed to the day-ahead market in Germany.

IV. METHODOLOGY

A. Smart charging strategies and HOMER Grid.

Smart charging strategies to maximize renewable electricity integration, resulting in lower costs and carbon impact are investigated to manage the slow charging demand described in the section above. Five strategies are proposed and modelled using HOMER Grid. The software simulates various systems with different solar PV and battery capacities, and indicates project economics, and operational performance information through an energy balance over the year [19]. These energy balances provide load profile data considering the proposed smart charging strategies, over the whole year, and solar PV and batteries operational performances, generating EV load profiles and energy balances.

HOMER Grid has an EV charging feature, for which charging session demand, maximum power and sessions frequency over the year are inputs. The software schedules charging to minimize charging peaks over the charging window. The generated managed charging demand is added up to a baseload (in this case, the non-flexible fast charging demand), and generates new load profiles. It also simulates solar PV and batteries integrations, and provides energy balances for every timestep simulated indicating the systems operational performance. Solar PV and battery costs are obtained from [20], [21].

46 chargers with maximum charging power of 11 kW and an EV fleet population of 35 Nissan Leaf and 30 Hyundai Ioniq vehicles are considered. The frequency in which vehicles are connected to chargers on an hourly basis (visits per hour) over the year are input to indicate the charger occupation.

Average EV energy demand per session ($E_{EV\ per\ session}$) of 15 kWh is set, based on the charging infrastructure data. The mean time vehicles are connected to chargers ($t_{EV\ connected}$) and maximum charging power per EV ($P_{EV\ max}$) are also inputs. HOMER defines charging times and power by adjusting charging power ($P_{charging}$) up to ($P_{EV\ \max}$), or delay a charging session to reduce the system overall peak demand per month. Charging sessions last for an amount of time ($t_{EV\ session}$) so that

$$E_{EV\ per\ session} = t_{EV\ session} \times P_{charging}. \qquad (1)$$

Where $E_{EV\ per\ session}$ is given in kWh, $t_{EV\ session}$ in hours, and $P_{charging}$ in kW.

To model smart charging strategies based on scheduled charging sessions, the time vehicles are connected and charging powers must be set according to the scheduled conditions (time and charging power). The time vehicles remained connected to chargers ($t_{EV\ session}$) is set according to the charging schedule time-windows ($t_{EV\ scheduled}$). The maximum charging power ($P_{EV\ max}$) is set to match the scheduled charging power ($P_{scheduled}$). From equation 1:

$$P_{EV\ max} = P_{scheduled} = \frac{E_{EV\ per\ session}}{t_{EV\ scheduled}} \qquad (2)$$

By doing so, flexibility is non-existent over the scheduled time-window since the expected demand can only be achieved if maximum charging power is used over the whole time-window.

Five smart charging strategies are proposed, aiming to maximize cost savings from DA market prices in Germany in 2022. Over the year, on weekdays lower prices are usual near the middle of the day, when solar power production is higher and demand is not at its peak, and over the night, between 23h and 06h. On weekends, the low prices remain throughout all morning and mid-afternoon, until they start increasing at peak electricity demand times after 18h.

Strategy 1 assumes EVs need to fulfil their charging demand 2 hours before the end of the total 14 hours in which they are parked and connected to chargers. Thus, scheduled charging time ($t_{EV\ connected\ S1}$) is equal to 12 hours, and the maximum charging power ($P_{EVma\ x\ S1}$) is equal to:

$$P_{EV\ \max S1} = \frac{15\ kWh}{12\ h} = 1.25\ kW \qquad (3)$$

Strategy 2 considers EV charging is scheduled and controlled to occur at moments of lower prices, leveraging o Day-Ahead market prices volatility. This strategy considers an average charging power ($P_{charging\ S2}$) equal to 5 kW. To achieve the required 15 kWh of demand per session, the time of charging session ($t_{EV\ session\ S2}$) must be equal to:

$$t_{EV\ session\ S2} = \frac{15\ kWh}{5\ kW} = 3\ hours. \qquad (4)$$

The 3 hours with lowest prices are identified over the year and are the basis to define the charging schedule in HOMER Grid. Over the year, charging occurs between 04:00 and 08:00 and between 13:00 and 15:00, with monthly variations. The distribution of charging demand within the two operational shifts on weekdays and weekends, presented in **Table I**, is considered to define the charging demand.

TABLE I

FLEXIBLE CHARGING DEMAND DISTRIBUTION OVER WEEKDAYS AND WEEKENDS.

Period	Flexible demand (kWh)
08:00 - 20:00 weekdays	158.4
20:00 - 08:00 weekdays	252.1
08:00 - 20:00 weekends	153.4
20:00 - 08:00 weekends	440.4

Over the year, charging occurs mostly between 04:00-08:00 and between 13:00-16:00, with monthly variations.

Strategy 3 also creates a 6-hours charging schedule, but considers a lower charging power ($P_{charging\ S3}$) equal to 2.5

kW. To achieve the required 15 kWh of energy per session the time of charging session ($t_{EV\ scheduled\ S3}$) must be equal to:

$$t_{EV\ session\ S3} = \frac{15\ kWh}{2.5\ kW} = 6\ hours \quad (4)$$

The same charging demand distribution shown in **Table I** is considered. Over the year, charging occurs mostly between 09:00-19:00 and between 00:00-06:00, with monthly variations.

Strategy 4 strategy aims to exploit the varying electricity prices with higher flexibility, combining the higher charging power from strategy 2 and the longer charging window of strategy 3. The same charging demand distribution shown in **Table I** is considered. An average charging power ($P_{charging\ S4}$) equal to 5 kW is considered, leading to a charging time ($t_{EV\ session\ S4}$) of 3 hours. However, the demand within the shift is dividing into two time-windows of 3 hours to generate two charging opportunities.

Strategy 5 exploits the opportunity for higher solar PV integration by scheduling charging closer to times of higher solar PV generation rates. An average charging power ($P_{charging\ S5}$) equal to 5 kW is considered, leading to a charging time ($t_{EV\ session\ S5}$) of 3 hours. The same charging demand distribution shown in **Table I** is considered. Charging sessions are scheduled to occur between 04:00-08:00, and between 11:00-14:00.

B. Dynamic modelling with Real-Time-Pricing (RTP) tariff and renewables integrations

HOMER Grid's results are used to generate a flexible model, capable of comparing all smart charging strategies and system architectures based on actual electricity grid data.

For every time interval (j = 15 min), power exchanges within the system are calculated based on smart charging load profiles from HOMER Grid. Solar PV (P_{PV_j}) production data is generated using irradiance and conversion parameters from HOMER Grid. Batteries charge ($P_{bat\ C_j}$) and discharge ($P_{bat\ D_j}$) rates and battery charge (E_{bat}) are calculated based on surplus or insufficient solar PV generation, or restricted to the maximum charging and discharging power rates. No energy arbitrage is considered using the battery, i.e. the storage system will not charge with electricity from the grid. Finally, grid purchases (GP_j) and grid exports (GE_j) are calculated, respectively, to cover the demand or to deal with surplus solar electricity, according to system's energy balance. Grid exports are limited to 400 kW, constrained by the system's grid connection capacity.

$$E_{EV_j} + GS_j + P_{bat\ C_j} = P_{PV_j} + P_{bat\ D_j} + GE_j \quad (5)$$

$$GE_j = P_{PV_j} - (E_{EV_j} + P_{bat\ C_j}) \quad (6)$$

$$GP_j = \mathrm{P_{PV_j}} - (\mathrm{E_{EV_j}} + \mathrm{P_{bat\ D_j}}) \quad (7)$$

Real-Time-Pricing (RTP) tariff prices (P_{RTP_j}) use day-ahead (DA) market prices from Germany, in 2022 [22]. These prices are matched to electricity purchased for every time interval, calculating real electricity purchase costs (C_{RTP}). Revenues from grid sales (R_{sales}) are also calculated over the year.

$$C_{RTP} = \sum_{j=1}^{35040} \mathrm{GP_j} \times P_{RTP_j} \quad (8)$$

$$R_{sales} = \sum_{j=1}^{35040} \mathrm{GE_j} \times P_{sales} \quad (9)$$

Hourly data on Germany's electricity mix's renewable electricity ratio ($RR_{MIX\ j}$), direct Emission Factor ($EF_{MIX\ D\ j}$, in gCO_2 per kWh, related to fossil-fuels combustion), and indirect Emission Factor ($EF_{MIX\ I\ j}$, in $gCO_2\ eq.$ per kWh, related indirect emissions over the whole system over its lifetime), in 2022, was obtained from [23]. It considers different power generation technologies' Emission Factors and granular electricity generation data (sources, power plants, quantities) from the German grid to calculate the carbon impact indicators mentioned above, for every time interval j [24].

Hourly data on the electricity mix carbon intensity is combined with energy balances from HOMER Grid's simulations. For every time interval j, the electricity mix direct ($DE_{MIX\ j}$) and indirect ($IE_{MIX\ j}$) carbon impact and renewable electricity ($RE_{MIX\ j}$), as well as the indirect CO_2 emissions from solar PV production (IE_{PV}) and batteries usage (IE_{bat}) are calculated:

$$DE_{MIX_j} = GP_j \times DEF_{\mathrm{MIX\ j}} \quad (10)$$

$$IE_{MIX_j} = GP_j \times IEF_{\mathrm{MIX\ j}} \quad (11)$$

$$RE_{MIX\ j} = GP_j \times RR_{MIX\ j} \quad (12)$$

$$IE_{PV\ j} = P_{PV\ j} \times EF_{PV} \quad (13)$$

$$IE_{bat\ j} = P_{bat\ D\ j} \times EF_{bat} \quad (14)$$

Where EF_{PV} and EF_{bat} are the lifecycle emission factor of solar PV (35.1 $g_{CO2\ eq.}\ per\ kWh$) and battery (297.2 $g_{CO2\ eq.}\ per\ kWh$) technologies in Germany, and $EF_{MIX\ D\ j}$ and $EF_{MIX\ I\ j}$ are the electricity grids' emission factor at time interval *j*.

For each system simulated, carbon impact indicators are calculated by adding up hourly emissions and dividing the sum by the electricity consumption (total electricity for EVs). Total renewable electricity usage for EVs (RR_{EV}) is calculated based on the following equations:

$$RE_{EV\ j} = RE_{MIX_j} + P_{PV_j} - GS_j \quad (10)$$

$$RR_{EV} = \sum_{j=1}^{35040} \frac{RE_{EV_j}}{(GP_j + E_{PV_j} - GS_{PV_j})} = \frac{RE_{EV}}{E_{EVs}} \quad (11)$$

These energy balances are generated for every smart charging strategy EV load profile, and solar PV and storage capacities are kept as input variables. An optimization algorithm using Excel's Solver (GRG Non-linear solving method) allows an effective analysis of different optimization factors, such as Levelized Cost of Energy (LCOE), Net Present Cost (NPC), Capital Expenditures (CAPEX) and Operational Expenditures (OPEX), and carbon impact and renewable electricity ratio. Sensitivity analysis on project financial metrics (interest rate and project lifetime) and equipment costs can also be easily performed.

V. RESULTS

A. Real-Time-Pricing (RTP) tariff adoption

The baseline simulation, as described, considers no smart charging strategy nor renewable electricity integration with the EV charging infrastructure. Grid power charges add up to €26,482 per year based on monthly peaks. When considering a Fixed Prices tariff (FP tariff), electricity costs add up to €174,469 per year, leading to a €200,951 annual electricity bill.

When the RTP tariff is adopted, costs are reduced significantly. While the demand charge remains the same, costs related to purchasing electricity are reduced to €92,588 per year. In total, €119,071 are spent annually if a RTP tariff is adopted. **Table II** present project economics calculated for the baseline EV load, considering both tariffs.

TABLE II

PROJECT ECONOMICS CONSIDERING BASELINE EV LOAD, FIXED PRICE (FP) TARIFF AND REAL-TIME-PRICING (RTP) TARIFF.

	Net Present Cost (€)	LCOE (€ / kWh)	OPEX (€ / yr)
FP tariff	2,346,062 €	0.530 €	200,951 €
RTP tariff	1,390,123 €	0.314 €	119,070 €

Based on electricity market prices, in Germany, in 2022, adopting a RTP tariff is economically advantageous. Operational costs are reduced by more than € 80,000 per year, and LCOE is decreased from € 0.530 per kWh to € 0.314 per kWh driven by lower prices in the day-ahead market when compared to the commercial rate.

The baseline carbon intensity and percentages of renewable electricity use are established. On average, electricity consumed from the grid has a direct emission rate of 416.2 gCO2 per kWh, and an indirect impact of 484.4 gCO2 eq. per kWh. The renewable ratio (RR) of electricity consumed by the system is 47.4%. Since all electricity demand is coming from the electricity grid, these represent the emissions and RR of electricity used to charge EVs.

From this point on, the above presented figures considering a RTP tariff are defined as the baseline to compare different smart charging strategies and renewable electricity integration.

B. EV smart charging strategies

Fig. 2. shows the daily average EV load profiles for the different smart charging strategies generated using HOMER Grid, along with average day-ahead (DA) market electricity prices over the hours of the day.

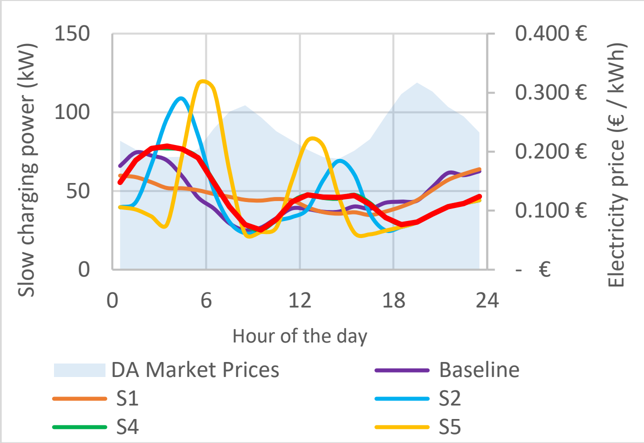

Fig. 2. Daily average smart charging strategies load profiles and day-ahead market prices.

Strategy 1 (S1) considers charging at the lowest power over the whole charging window, for every session. It effectively reduces the slow charging demand peak, and results in lower total demand peaks, reducing grid power costs. LCOE is reduced to €0.296 per kWh. Both direct and indirect emissions are lower than the baseline (-1.3% and -1.1%, respectively), and a higher ratio of renewable electricity is used (+1.4%).

Strategy 2 (S2) schedules EV charging at times of lower electricity prices in the morning and early afternoon, within 3-hours-intervals. This leads to higher charging peaks, especially in the morning when demand is higher. These lead to higher grid power costs, which are compensated by electricity purchasing at lower prices. LCEO is reduced to €0.285 per kWh. Both direct and indirect emissions are lower than the baseline (-1.2% and -1.1%, respectively), and a higher ratio of renewable electricity is used (+1%).

Strategies 3 (S3) and 4 (S4) results are presented together. Bot schedule EV charging at times of lower electricity prices in the morning and early afternoon, within 6-hours-intervals. Although S3 and S4 consider charging sessions are held at different powers levels, schedules are similar so overall EV load profiles are almost identical. In both cases, the charging strategy leads to smoother charging peaks, and electricity purchases at lower prices. LCOE is reduced to €0.283 per kWh in both cases, outperforming all other smart charging strategies. Both direct and indirect emissions are lower than the baseline (-1.4%, -1.3%, respectively), and a higher ratio of renewable electricity is used (+1.3%).

Smart charging Strategy 5 schedules EV charging within 3-hours-intervals, aiming to maximize solar PV usage. Thus, for the shift occurring between 08:00 – 20:00, charging occurs between 11:00 – 14:00, at times of higher solar PV electricity penetration (in grids and locally). The morning demand is kept at times of lower prices, according to Strategy 2's schedule. LCOE is reduced to €0.293 per kWh. Both direct and indirect emissions are lower than the baseline (-3.0%, -2.7%, respectively), and a higher ratio of renewable electricity is used (+1.3%). S5 outperforms the other strategies in reducing EV charging carbon impact.

Table III summarizes main operational and environmental indicators for all simulated smart charging strategies, as well as the baseline scenario (B) considering the RTP tariff. Strategies 3 and 4 are the most efficient to reduce operational costs, and Strategy 5 is the most efficient to reduce carbon impact of EV charging.

TABLE III

PROJECT ECONOMIC AND ENVIRONMENTAL INDICATORS FOR DIFFERENT SMART CHARGING STRATEGY.

	LCOE (€/kWh)	**OPEX** (€/yr)	CO_2DE (gCO2/kWh)	RR_{EV} (%)
B	0.314 €	119,071 €	416	47.4
S1	0.296 €	112,120 €	411	48.1
S2	0.285 €	107,942 €	411	47.9
S3	0.283 €	107,304 €	410	48.1
S4	0.283 €	107,512 €	410	48.1
S5	0.293 €	111,211 €	404	49.0

C. Solar PV and batteries integrations

The integration of solar PV panels reduces the need for purchasing electricity from the grid. As a result, operational costs are reduced and higher renewables shares are achieved for EV charging, leading to reduced direct CO2 emissions. Nonetheless, the cost of purchasing and installing a large PV system is not always compensated by its benefits. **Fig. 3** shows the relationship between solar PV capacity and LCOE for all smart charging strategies.

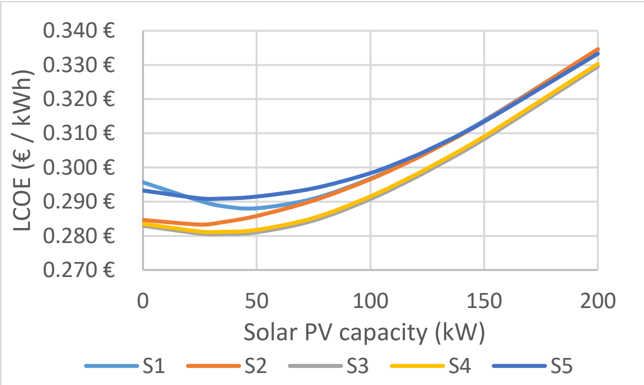

Fig. 3. Impact of solar PV capacity on LCOE, for all smart charging Strategies (S).

All curves indicate a similar trend towards reaching minimum LCOE around 25 kW and 50 kW. For systems which larger capacities, LCOE increases rapidly. Smart charging Strategies 3 and 4 again outperform the other strategies, leading to the lowest LCOE for every PV size. This the 6-hour charging window after mid-day, every day, matching a good part of solar PV production profile. Smart charging Strategy 5 also schedules EV charging session around mid-day. However, a 3-hour window is defined, and as a result a larger PV system needs to be in place to supply the larger demand peaks. Furthermore, the shorter charging window leads to higher demand charges, as described before, increasing the system operational costs.

As expected, larger solar PV systems increase the percentage of renewable electricity used for EV charging. With 200 kWp of PV capacity, 82% of electricity used to charge EVs comes from renewable sources. Most of it comes directly from the PV system, though, and the renewable ratio of electricity coming from the electricity grid decreases with larger PV systems. This is explained by the decreased demand for grid purchases at times of higher solar PV electricity generation in the mix (around noon). Nevertheless, both direct and indirect CO2 emissions per kWh of electricity consumption decrease with larger PV systems.

The winning architecture leading to minimum LCOE is identified with 34.4 kWp solar PV capacity and smart charging Strategy 3. Annually, 32.6 MWh of electricity are produced from the solar system, reducing the demand for grid purchases to 386.3 MWh per year. Grid sales from solar PV surplus reach 4.2 MWh per year. Only 7% of the EV charging demand is supplied by the solar PV system, but 87% of the locally generated electricity is consumed.

Most electricity produced is used to charge EVs, however before noon surplus PV is sold back to the grid since there is not enough EV demand. Grid purchases are reduced in times of higher prices from shifted demand. In June, electricity is more expensive in late morning hours and between 19:00-23:00, with prices of € 0.25 - € 0.30 per kWh. Electricity over the night and in the early afternoon cost around € 0.20 and € 0.15 per kWh, respectively. During December, however, electricity prices remain high even in the early afternoon, consistently above € 0.300 per kWh between 10:00 and 20:00. Solar PV production during the winter has mild impact in reducing grid purchases. Fig. 4 present the daily average solar PV, EV charging, and grid exchanges power profiles in June-2022, along with DA market prices.

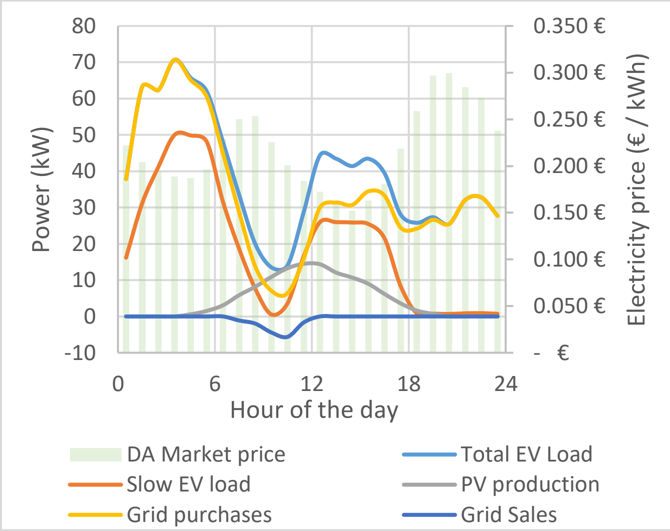

Fig. 4. Daily average power exchanges and DA market prices in Jun-22.

The system's annual operational costs reach €101,950, and CAPEX reaches €51,772. LCOE is € 0.281 per kWh. Direct and indirect CO2 emissions are reduced to 387 gCO2/kWh (-7,1%), and 453 gCO2 eq./kWh, respectively. The renewable electricity ratio increases to 52.1% (+9.9%).

The integration of batteries along with solar PV pannels supports electricity self-consumption, minimizing grid purchases and grid sales. While this leads to lower operational costs, capital requirements to install such storage systems are significant, reducing the overall cost reduction potential.

The same 34.4 kWp of solar PV capacity is coupled with different storage capacities, ranging from 0 to 200 kWh. Once again, Strategies 3 and 4 outperform the other smart charging strategies. By shifting the evening demand to times of lower prices, grid purchases avoid peak electricity prices and solar PV and storage maximize locally generated electricity usage. Lower LCOE is found in smaller systems, up to 10 kWh. As storage capacity is increased, higher solar PV self-consumption rates are obtained, but higher capital expenses offset the savings from electricity purchase over the project lifetime.

Integrating storage maximizes solar PV electricity self-consumption and reduces direct and indirect CO2 emissions only very slightly. When comparing the 34.4 kWp system with no storage to one with 50 kWh capacity, direct and indirect emissions are decreased from 385.4 to 382.7 gCO_2 per kWh, and from 451.7 to 451.0 $gCO_{2\,eq}$ per kWh, respectively. Similarly, the renewable electricity ratio of electricity used for EV charging increases from 51.2% to 51.6% from better use of solar PV generated electricity, and the electricity grid renewable ratio decreases slightly from 47.6% to 47.5%.

Comparatively, the impact of increasing storage sizes on electricity self-consumption is larger for larger PV systems. While for a 34.4 kWp the system approaches 100% of self-consumption with 50 kWh of storage, for PV systems larger than 100 kWp the trend shows self-consumption rates increasing almost linearly with storage capacity.

For a 150 kWp PV system, minimum LCOE is obtained with 61.2 kWh of storage, increasing the solar PV self-consumption rate from 56% (with no storage) to 64%. This difference results in storing and using 11.4 MWh of solar PV electricity for EV charging, instead of selling it back to the grid at lower prices. While the larger system is not economically beneficial, it leads to lower carbon emissions and higher renewable electricity usage for EV charging. In comparison to the baseline scenario, direct CO2 emissions are reduced by 21%, from 416 to 329 gCO_2 per kWh consumed. Indirect emissions are reduced by 16%, from 484 to 404 $gCO_{2\,eq.}$ per kWh, given the life-cycle carbon impact of batteries is considered in the calculation and decreases the benefit of maximizing solar PV usage. The smaller PV and battery system environmental results are similar to the winning architecture.

Table IV presents LCOE, OPEX, direct CO2 emissions and renewable electricity ratio for the presented solar PV and battery systems, as well as the baseline, allowing a thorough comparison between economic and environmental indicators. All systems consider smart charging Strategy 3.

TABLE IV

PROJECT ECONOMIC AND ENVIRONMENTAL INDICATORS FOR SMART CHARGING S3 WITH SOLAR PV AND BATTERIES.

PV (kW)	**Bat** (kWh)	**LCOE** (€/kWh)	**OPEX** (€/yr)	CO_2DE (gCO2/ kWh)	RR_{EV} (%)
0	0	0.314 €	119,071 €	416	47.4
34.4	0	0.281 €	101,951 €	387	51.1
34.4	10	0.281 €	101,412 €	385	51.2
150	61	0.306 €	93,093 €	329	58.3
200	0	0.330 €	99,228 €	333	57.8

D. Sensitivity analysis

Varying electricity prices, solar PV and batteries costs, and also project interest rate can lead to different system architectures with lowest LCOE. System architectures generating lowest LCOE are presented, based on varying these parameters by -20%, -10%, +10% and +20% in comparison to original figures.

Electricity prices from the day-ahead market are proportionally multiplied by -20%, -10%, +10% and +20% for every time interval in the dataset, keeping the original data set variability. Lower electricity prices decrease the benefits of integrating solar PV and batteries, and significantly reduce systems' LCOE. For electricity prices 20% cheaper than the day-ahead market prices in 2022, lowest LCOE €0.235 per kWh is obtained with a 9.2 kWp solar system, reducing the project Net Present Cost by 16% from €1,242,000 to €1,041,360. On the other hand, if day-ahead market prices are 20% higher than in 2022, 51.0 kWp of solar PV capacity and no batteries leads to the lowest LCOE of €0.323 per kWh.

Solar PV purchase and installation costs are replaced from the original € 1,505 to € 1,204 (-20%), € 1,354 (-10%), 1,655 (+10%) and 1,806 (+20%) per kW. Lower solar PV costs make it more interesting to install larger PV systems integrated with storage. With 20% cheaper PV systems, an LCOE of €0.277 per kWh is achieved with 52.1 kWp solar PV and 5.9 kWh storage capacities. On the other hand, higher PV costs decrease the incentive to install such systems. With 20% more expensive PV systems, an LCOE of €0.282 is obtained with 14.2 kWp solar PV capacity and no batteries.

Battery costs are replaced from the original €717 to €574 (-20%), € 645 (-10%), € 789 (+10%) and € 860 (+20%) per kWh. Lower battery costs directly impact on the optimum storage capacity. Slightly larger solar PV systems are coupled with storage to generate the lowest LCOE. The system architecture with 20% lower battery costs indicates an LCOE of € 0.280, with 38.5 kWp solar and 6.4 kWh storage capacities. On the other hand, higher battery costs do not impact the winning architecture, since lowest LCOE is already obtained with a system with no storage. Thus, indicating that installing batteries only becomes profitable at lower capital costs per kWh, or at higher electricity prices.

Project interest rate are replaced from the original 8.0% to 6.4% (-20%), 7.2% (-10%), 8.8% (+10%) and 9.6% (+20%).

Similarly to the impact of reducing capital costs, lower interest rate de-risk the investment and investing in large solar PV and battery systems become more economically interesting. The operational savings obtained in the long run become more significant than the impact of CAPEX in the cash flow. With 6.4% interest rate, the winning architecture is identified with 47.7 kWp solar and 6.5 kWh storage capacities, achieving an LCOE of € 0.275 per kWh. On the other hand, higher project interest rates decrease the incentive to invest in solar PV and batteries. This is explained because the operational costs savings in the long run have lower benefit because of higher discount rates, but CAPEX is spent in the first year of the project and is not discounted in the cash flow. With 9.6% interest rate, the winning architecture is identified with 21.0 kWp solar PV capacity and no batteries, achieving an LCOE of € 0.285 per kWh.

E. Discussion

The presented sensitivity analysis indicates that the largest influence on project economics is driven by electricity prices. That is aligned to the results presented in section 4.1, where the adoption of a RTP tariff based on 2022 day-ahead market prices in Germany reduces LCOE from € 0.530 to € 0.314 per kWh. In addition, both solar generation and storage systems power flows are significantly smaller than grid exchanges (purchases). As a result, varying electricity prices over the year lead to significant impact in electricity costs if charging is not properly managed, as indicated by the achieved savings with different smart charging strategies. The impact of price volatility is not investigated here, yet it is expected that the existing challenges to integrate growing renewables in a market ongoing electrification of transportation and other industries maintain market dynamics volatile.

Considering average day-ahead market prices were used to generate the smart charging schedules presented in this work, a dynamic charging scheduling algorithms could combine peak shaving and lower prices-signals to schedule charging optimally. This, however, requires mobility patterns prediction, i.e. understanding the times vehicles are going to be connected to chargers and their energy demand for the next period of operation. Although this falls out of the scope of this work, the identified results indicate that such strategy could enhance savings even further.

The impact of solar PV and batteries hardware and installation costs is also relevant. Since figures used in this work are obtained from the National Renewable Energy Laboratory (NREL) [18], [19] and not from real market suppliers, the benefits of local renewables integrations can be influenced by real market prices. In the same platform, NREL's work indicates market trends towards decreasing CAPEX for solar PV and batteries in the coming years, as it has been happening over the last decades. Based on current prices, however, investing in solar PV technology is a beneficial decision from an economical and environmental perspective. In addition, solar PV usage maximization can be achieved based on weather and solar generation forecasts integrated with the above-mentioned dynamic charging strategy. The use of stationary storage system is beneficial to maximize solar PV self-consumption, and it can also support energy arbitrage algorithms to maximize electricity purchases at lower costs. Furthermore, the development of bi-directional charging technology can replace the need for stationary storage systems, by leveraging on the idle EV's batteries to also perform energy arbitrage.

Different companies adopt different investment strategies using their defined project economic parameters. The optimal system architecture depends on such figures, and decision makers must assess project cash flows to make an informed decision.

Finally, current inflation rates are rising worldwide, which poses uncertainty on the cost of certain materials and commodities – like electricity, raw material for solar PV panels and lithium-ion batteries manufacturing - over the next years. The topic of inflation has not been evaluated in this work, but higher overall prices could lead to different results. The sensitivity analysis presented in section 4.4 analysed individually the impact of varying electricity, solar PV panels and batteries costs. It indicates that the developed tool is powerful to analyse different scenarios, which could combine different prices for all of these variables.

VI. Conclusions

This work provided a comprehensive analysis to evaluate EV smart charging strategies and local renewable electricity integrations, measuring economic and environmental aspects. The adoption of an RTP tariff decreases LCOE from € 0.530 to € 0.314 per kWh. A smart charging strategy designed to reduce peak demand and schedule charging at times of lower prices reduces LCOE further to € 0.283 per kWh. The lowest LCOE of € 0.281 per kWh is obtained with 34.4 kWp of solar PV capacity and no batteries. Carbon impact is minimized with larger solar PV and batteries capacities.

Results obtained successfully addressed the research questions.

First research question investigated the economic and environmental benefits from adopting smart charging strategies, aiming to shave charging peaks and shift demand according to charging schedules. Adopting smart charging strategies can save costs and decrease the environmental impact of EV charging, at no capital requirements. Charging strategies proposed in this work go hand-in-hand with the dynamic electricity tariff adoption trend presented in the literature. These tariffs encourage EV smart charging in sync with energy market dynamics, offering price incentives to charge EV with greener energy. These savings are enhanced with smart charging, which can decrease grid power fees and electricity purchasing costs.

Second research question investigated the economic and environmental benefits from integrating solar PV and batteries with EV smart charging. The benefits of integrating solar PV and batteries to reduce emissions and operational costs is clear. However, higher capital expenses for larger systems are not always compensated by lower operational costs in the long run. Sizing the ideal solar PV and batteries system depends upon properly modelling EV smart charging demand profiles, so that solar PV self-consumption, grid purchases and grid sales can be accurately quantified.

Third research question aimed to identify the ideal system architecture to minimize project costs over its lifetime. For this case study, the lowest LCOE was obtained for a system with solar PV only, since adding batteries increased project costs. 34.4 kWp of solar PV capacity was integrated to a smart charging strategy based on 6-hour charging windows of lower electricity prices from the day ahead-market in Germany. This system reduced electricity demand at times of solar PV production, minimized EV charging peaks, purchased electricity at lower prices, and increased the use of renewable electricity to charge the EV fleet.

References

P. Barman *et al.*, "Renewable energy integration with electric vehicle technology: A review of the existing smart charging approaches", *Renewable and Sustainable Energy Reviews*, vol. 183, p. 113518, set. 2023, doi: 10.1016/j.rser.2023.113518.

[2] International Energy Agency, *Global EV Outlook 2023: Catching up with Climate Ambitions*. em Global EV Outlook. OECD, 2023. doi: 10.1787/cbe724e8-en.

[3] T. Beaufils e P.-O. Pineau, "Assessing the impact of residential load profile changes on electricity distribution utility revenues under alternative rate structures", *Utilities Policy*, vol. 61, p. 100959, dez. 2019, doi: 10.1016/j.jup.2019.100959.

[4] European Parliament, "A European Green Deal | Revision of the EU emission trading system (ETS)", dez. 2022, [Online]. Available at: https://www.europarl.europa.eu/legislative-train/carriage/revision-of-the-eu-emission-trading-system-(ets)/report?sid=6501

[5] H. Heinrichs, P. Jochem, e W. Fichtner, "Including road transport in the EU ETS (European Emissions Trading System): A model-based analysis of the German electricity and transport sector", *Energy*, vol. 69, p. 708–720, maio 2014, doi: 10.1016/j.energy.2014.03.061.

[6] L. Haywood e M. Jakob, "The role of the emissions trading scheme 2 in the policy mix to decarbonize road transport in the European Union", *Transport Policy*, vol. 139, p. 99–108, ago. 2023, doi: 10.1016/j.tranpol.2023.06.003.

[7] O. Sadeghian, A. Oshnoei, B. Mohammadi-ivatloo, V. Vahidinasab, e A. Anvari-Moghaddam, "A comprehensive review on electric vehicles smart charging: Solutions, strategies, technologies, and challenges", *Journal of Energy Storage*, vol. 54, p. 105241, out. 2022, doi: 10.1016/j.est.2022.105241.

[8] J. Hildermeier, J. Burger, A. Jahn, e J. Rosenow, "A Review of Tariffs and Services for Smart Charging of Electric Vehicles in Europe", *Energies*, vol. 16, nº 1, p. 88, dez. 2022, doi: 10.3390/en16010088.

[9] T. Simolin, K. Rauma, R. Viri, J. Mäkinen, A. Rautiainen, e P. Järventausta, "Charging powers of the electric vehicle fleet: Evolution and implications at commercial charging sites", *Applied Energy*, vol. 303, p. 117651, dez. 2021, doi: 10.1016/j.apenergy.2021.117651.

[10] N. Boonrach, N. Janjamraj, e K. Bhumkittipich, "Optimal Energy Storage System in Residential Micro-Grid for EV Charging Station Penetration", em *2021 International Conference on Power, Energy and Innovations (ICPEI)*, Nakhon Ratchasima, Thailand: IEEE, out. 2021, p. 37–40. doi: 10.1109/ICPEI52436.2021.9690687.

[11] A. M. Pavan, V. Lughi, e M. Scorrano, "Total Cost of Ownership of electric vehicles using energy from a renewable-based microgrid", em *2019 IEEE Milan PowerTech*, Milan, Italy: IEEE, jun. 2019, p. 1–6. doi: 10.1109/PTC.2019.8810736.

[12] A. Ghatak, R. B. Alfred, e R. R. Singh, "Optimization for Electric Vehicle Charging Station using Homer Grid", em *2021 Innovations in Power and Advanced Computing Technologies (i-PACT)*, Kuala Lumpur, Malaysia: IEEE, nov. 2021, p. 1–7. doi: 10.1109/i-PACT52855.2021.9696626.

[13] F. Verbist, N. K. Panda, P. P. Vergara, e P. Palensky, "Impact of Dynamic Tariffs for Smart EV Charging on LV Distribution Network Operation". arXiv, 19 de junho de 2023. Acesso em: 24 de junho de 2023. [Online]. Available at: http://arxiv.org/abs/2306.10775

[14] European Commission, "EU Emission Trading System (EU ETS) Union Registry - Verified Emissions for 2021". 1º de abril de 2022. [Online]. Available at: https://climate.ec.europa.eu/eu-action/eu-emissions-trading-system-eu-ets/union-registry_en

[15] L. Xu, H. Ü. Yilmaz, Z. Wang, W.-R. Poganietz, e P. Jochem, "Greenhouse gas emissions of electric vehicles in Europe considering different charging strategies", *Transportation Research Part D: Transport and Environment*, vol. 87, p. 102534, out. 2020, doi: 10.1016/j.trd.2020.102534.

[16] O. Ayo, H. Zhang, R. Moreira, D. Bertin, e N. Zribi, "Electric Vehicle Charging with Fractional Renewable Energy Certificates Using Blockchain Technology", em *2023 IEEE Belgrade PowerTech*, Belgrade, Serbia: IEEE, jun. 2023, p. 01–07. doi: 10.1109/PowerTech55446.2023.10202972.

[17] Statista, "Annual electricity prices (including electricity tax) for industrial businesses in Germany from 1998 to 2022". 2023. Acesso em: 3 de outubro de 2023. [Online]. Available at: https://www.statista.com/statistics/1050448/industrial-electricity-prices-including-tax-germany/

[18] H. Wirth e Fraunhofer ISE, "Recent Facts about Photovoltaics in Germany", maio 2023.

[19] HOMER Software, "HOMER Grid - Distributed Energy + EV Charging". 2023. Acesso em: 19 de outubro de 2023. [Online]. Available at: https://www.homerenergy.com/products/grid/index.html

[20] U.S. Department of Energy, "NREL Annual Technology Baseline - Commercial PV 2022". 2023. Acesso em: 10 de junho de 2023. [Online]. Available at: https://atb.nrel.gov/electricity/2022/commercial_pv

[21] U.S. Department of Energy, "NREL Annual Technology Baseline - Commercial Battery Storage 2022". 2023. Acesso em: 10 de junho de 2023. [Online]. Available at: https://atb.nrel.gov/electricity/2022/commercial_battery_storage

[22] entso-e, "Day-ahead Prices Germany - BZN | DE-LU". 2023. Acesso em: 3 de outubro de 2023. [Online]. Available at: https://transparency.entsoe.eu/transmission-domain/r2/dayAheadPrices/show?name=&defaultValue=true&viewType=GRAPH&areaType=BZN&atch=false&dateTime.dateTime=01.01.2022+00:00|CET|DAY&biddingZone.values=CTY|10Y1001A1001A83F!BZN|10Y1001A1001A82H&resolution.values=PT15M&resolution.values=PT30M&resolution.values=PT60M&dateTime.timezone=CET_CEST&dateTime.timezone_input=CET+(UTC+1)+/+CEST+(UTC+2)

[23] Electricity Maps, "Data Portal - Germany". 2023. Acesso em: 3 de outubro de 2023. [Online]. Available at: https://www.electricitymaps.com/data-portal/germany

[24] Electricity Maps, "Electricity Maps Methodology". 2023. Acesso em: 10 de agosto de 2023. [Online]. Available at: https://www.electricitymaps.com/methodology