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# Policy and pricing tools to incentivize distributed electric vehicle-to-grid charging control

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ABSTRACT

Flexible electric vehicle (EV) charging could benefit the electricity system and help integrate renewables, if given the right incentives. Bidirectional vehicle-to-grid (V2G) technology increases EV flexibility and could increase those benefits. However, the business case for small-scale V2G is unclear, limiting widespread deployment. Here, we assess the impacts of different time-of-use electricity tariffs and compare three policymaker tools to improve profitability for V2G aggregators: regulating the reimbursement of network charges and taxes on discharged energy, subsidizing new stations, and increasing the spread between low and high time-of-use prices. We use an agent-based EV model in a case-study of workplace charging in Switzerland. We model the aggregator's maximization of V2G revenues over electricity, hardware, installation, and operating costs as a mixed-integer linear program. We find that different tariffs better support renewable integration or reduce peak demand. Profitability is highly sensitive to the cost of V2G stations and the difference between the lowest charging and highest discharging prices. Some subsidies will be needed until V2G station costs fall at least below 8706 ± 942 CHF. Policymakers could regulate reimbursement of network charges or taxes for discharged energy or stretch tariff price spreads to support deployment of distributed V2G.

## 1. Introduction

The rapid electrification of transportation is necessary to reduce emissions (IPCC, 2023; IEA, 2023). Electric vehicles (EVs) for personal transport will increase electricity consumption, but the timing of charging demand will determine their impact on the electricity system (Muratori et al., 2021). Charging at peak times could force early equipment upgrades or increase generation costs, while charging at off-peak times could improve the utilization of existing grid infrastructure and support renewable integration (Jenn and Highleyman, 2022; Kühnbach et al., 2020; Needell et al., 2023; Powell et al., 2022).

Flexibility can be leveraged to improve the grid impacts of EVs by shifting and reshaping charging demand. With uncontrolled charging, energy is delivered at the maximum charging rate from the beginning of the session until the battery is full. The vehicle then often sits idle, still connected until the driver's departure (Xu et al., 2018; Sadeghianpourhamami et al., 2018). With conventional controlled charging, also called V1G, the charging rate is modulated throughout the session to deliver the same amount of energy with a better charging profile (Anwar et al., 2022). With bi-directional charging, also called vehicle-to-grid (V2G), energy can even be sent back from the vehicle to the grid during the charging session (Pearre and Ribberink, 2019).

V1G and V2G have high technical potential to support the electricity system, reducing emissions (Xu et al., 2020; Di Natale et al., 2021), system costs (Van Liedekerke et al., 2023), the need for new investments in generation (Gunkel et al., 2020; Kern and Kigle, 2022), and the need for other types of flexibility or storage (Panos et al., 2019; Blumberg et al., 2022; Tarroja and Hittinger, 2021; van Triel and Lipman, 2020; Signer et al., 2023), or increasing local self-consumption (Abuelrub et al., 2020, 2019). However, existing research has used centralized control to estimate the maximum benefits from V2G. In decentralized deployments implemented like we see today, these benefits are not guaranteed but depend on the good design of markets and incentives.

Markets for ancillary services like frequency response are mostly limited to large-scale actors (Knezović et al., 2017; Gschwendtner et al., 2021). Changes toward smaller minimum bids and higher temporal granularity may help support EV participation (Borne et al., 2018a; Roschewitz et al., 2022-03-31), but these markets may also quickly be saturated with a relatively small number of EVs (Gschwendtner et al., 2021). Most small-scale actors use their flexibility to respond instead to electricity tariffs (Anwar et al., 2022; Thompson and Perez, 2020).

Electricity tariff design is key to ensure small-scale, distributed V1G and V2G deliver the positive system impacts promised by centralized

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control models. Different tariffs can lead to very different demand profiles (Gschwendtner et al., 2023). With the wrong incentives, EV flexibility can increase emissions (Fleschutz et al., 2021) or peak demand (Powell et al., 2022). Tariff design is becoming more important as more EV-specific tariffs are being introduced (Cappers et al., 2023) and new tariffs are needed for systems with high renewable penetration (Levin, 2019).

Grid-friendly tariff designs alone are not enough; sites and EV aggregators must respond to those tariffs for them to impact demand.

Widespread deployment of distributed V2G has been limited so far by issues of profitability (Noel et al., 2019; Sovacool et al., 2020). Consider the business case for an aggregator controlling charging for multiple EVs at a workplace parking lot, the most common use-case in current V2G trials (Gschwendtner et al., 2023). The aggregator can earn revenues by charging and storing energy from lower price periods to sell back to the grid in higher price periods. Yet, high V2G station costs combine with unfavorable regulations or tariff designs to make this business case unclear (Noel et al., 2019). Much V2G research has focused on profitability with direct market participation, peak shaving, the provision of grid services, or a combination of multiple value streams (Englberger et al., 2021; Gough et al., 2017; Rahman et al., 2023; Blatiak et al., 2022; Brandt et al., 2017; Zhou et al., 2023; Noori et al., 2016; Borne et al., 2018b; Abuelrub et al., 2023) with mixed results and no clear answer on profitability across cases (Heilmann and Friedl, 2021; Sovacool et al., 2020). High capital costs for charging stations are often not considered and there has been little research on the tariff-based business case of small-scale actors.

To realize the benefits of new tariff designs, policymakers can choose from several tools to improve profitability and increase distributed V2G deployment (Kester et al., 2018). Here we investigate the interaction of three under-researched tools: (1) changing regulations on discharging prices, (2) subsidizing charging stations, and (3) stretching time-of-use rates to increase benefits from arbitrage.

Regulations can limit the value of discharging back to the grid. In many regions, the price paid to charge includes energy costs, network charges or fees, and taxes, but the price paid for discharging back to the grid may only include the energy component (Kester et al., 2018). This results in double taxation of the same electricity, as tax is paid both when charging for V2G and later when that electricity is consumed by another end user. This poses a significant hurdle for the diffusion of V2G (Gschwendtner et al., 2021; Noel et al., 2019; Heilmann and Friedl, 2021). In some cases the network charges could be imposed twice as well (SFOE, 2023b). Reimbursing some portion of network charges and taxes could increase the incentive for V2G. Signer et al. explored V2G double taxation in Germany for EVs participating in the day-ahead wholesale electricity market and found that current regulations must change to meet EV users revenue expectations for participating in V2G (Signer et al., 2024). There has yet been no comprehensive analysis on the sensitivity of tariff-based V2G deployment to changes in discharge price regulations or to the double application of network charges.

Policymakers can also turn to subsidies to limit the effect of high V2G station costs (Kester et al., 2018). Prices for V2G-capable charging stations can be more than 10× higher than for V1G-capable stations in 2024 (sun2wheel, 2023), but this mark-up is almost always omitted in existing literature on V2G profitability. Further, the trade-offs between station subsidies and tariff design have not been explored.

Finally, energy arbitrage would be more valuable with a larger spread between high and low energy prices (Kester et al., 2018). Most new EV tariffs are static time-of-use (TOU) rates, with two to four different price periods throughout the day (Cappers et al., 2023). Huang et al. found the optimal peak TOU price was 4 to 9 times the valley TOU price to encourage workplace V2G in Shanghai (Huang et al., 2022). Price spreads in wholesale electricity markets have increased in recent years due to high volatility in natural gas prices (Zakeri et al., 2023), but this has not been reflected in EV tariffs. Further, the interaction between larger price spreads and changes in regulation or station cost has not yet been explored.

In this paper, we address these gaps to better understand how policymakers can unlock benefits from distributed V2G control. Our main contributions are:

1. Identifying TOU tariff designs to achieve system benefits from distributed V2G;
2. Investigating the trade-offs between three policy options to make V2G profitable under those tariff designs:
   (a) Regulating the reimbursement of charges and taxes on discharged energy,
   (b) Subsidizing new V2G charging stations, and
   (c) Increasing the price spread in EV tariffs.

The main novelties of this approach are: addressing the tariff-based business case of small-scale V2G providers, including the capital costs of V2G-capable charging stations; assessing the sensitivity to changes in discharge price regulations, double taxation, and network charge reimbursement policies; and quantifying the trade-offs between these regulatory changes, station subsidies, and increasing price spreads or other changes to tariff design.

We focus on the case study of Switzerland, where this has been an active area of innovation and discussion for policymakers (Swiss Parliament, 2022, 2023). The Swiss electricity system faces an increasing need for demand flexibility, with a forecast phase-out of nuclear generation by 2034 and a widespread increase in solar generation (SFOE, 2018; Gupta et al., 2021; Degefa et al., 2021). Recent legislation has introduced a network charge reimbursement for energy discharged from V2G (SFOE, 2023b), but the exact implementation is still undecided. In this paper, we simulate uncontrolled, V1G, and V2G charging from the perspective of a workplace aggregator. We apply an agent-based model of EV charging behavior to detailed data on individual travel patterns to simulate uncontrolled demand (BFS and ARE, 2023; Gschwendtner et al., 2023) and use data from a large-scale simulation of the Swiss energy system to evaluate the impacts on curtailments and typical peak demand (Schwarz et al., 2023). We compare an existing EV-specific tariff with a forward-looking tariff for increased PV integration and consider six options for the network charge and/or tax reimbursement.

Our results reveal that future tariffs must change to support renewable integration and realize positive impacts from distributed V2G. Aggregator profitability is highly sensitive to each of the three policy tools: too low discharging prices fail to incentivize V2G at all; high station costs can be supported in some cases, but will require large subsidies in others; and increasing the spread between low and high prices will lower station subsidies only with the right regulations on discharge prices.

The body of this paper is organized as follows: in Section 2 we detail our methodology; in Section 4 we present the results for our case study; and in Sections 5 and 6 we discuss limitations of our analysis, summarize the conclusions, and give recommendations for policymakers.

## 2. Methodology

Fig. 1 provides an overview of the modeling approach. Inputs colored dark green show the policy interventions we test in this paper.

In the first step of the framework, we simulate the operations and optimization problem of a workplace aggregator. The aggregator aims to maximize its profits under a given electricity tariff, subject to constraints of arrival time, departure time, battery capacity, and energy requirements for the individual EVs. We use an agent-based model to simulate the travel and charging constraints of each EV. We do not assume any changes in behavior or travel patterns. The electricity tariff,

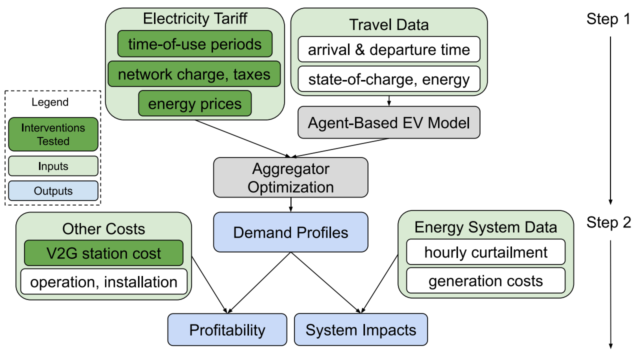


**Fig. 1.** Overview of the modeling approach. We tested policy interventions affecting the four inputs shaded dark green: all three aspects of the electricity tariff and the charging station cost. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

**Table 1**
Variable definitions. Prices are given in Swiss Francs (CHF). At the time of writing, 1 CHF = 1.09 USD = 1.01 EUR.

| Variable | Unit | Description |
|---|---|---|
| $\cdot^t$ | – | at time $t$ |
| $\cdot^v$ | – | for vehicle $v$ |
| $\cdot^y$ | – | in year $y$ |
| $D^t_{ch}$ | kW | Site-level charging |
| $D^t_{dis}$ | kW | Site-level discharging |
| $T_{dem}$ | CHF/kW | Demand charge price |
| $T^t_{ch}$ | CHF/kWh | Volumetric charging price |
| $T^t_{dis}$ | CHF/kWh | Volumetric discharging price |
| $\eta$ | – | Charging/discharging efficiency |
| $T^t_{energy}$ | CHF/kWh | Energy price |
| $T^t_{network}$ | CHF/kWh | Network charge |
| $T^t_{national}$ | CHF/kWh | National taxes |
| $T^t_{municipal}$ | CHF/kWh | Local taxes |
| $T^t_{network,\ REIMB}$ | CHF/kWh | Network charge reimbursement |
| $E^t$ | kWh | Energy charged |
| $P^{t,v}_{max,ch}$ | kW | Maximum charging power |
| $P^{t,v}_{max,dis}$ | kW | Maximum discharging power |
| $SOC^{t,v}$ | % | State-of-charge |
| $B_{deg}$ | CHF/kWh | Battery degradation cost |
| $B_{cap}$ | kWh | Battery capacity |
| $C^y$ | CHF/st | Aggregator costs per station |
| $R^y$ | CHF/st | Aggregator revenues |
| $G^t_{curt}$ | MWh | System-wide hourly curtailment |

agent-based model, and aggregator optimization are described in detail in Sections 2.1, 2.2.1, and 2.2.2, respectively.

In the second step of the framework, we evaluate the site's profitability and its impacts on the electricity system. We assess the site-level contribution to peak net demand and to increasing or decreasing curtailment as the electricity system changes from 2020 to 2050. To assess profitability we weigh any electricity cost savings or revenues against the aggregator's other costs for the charging station, operation and maintenance, and battery degradation. We compare against V1G and uncontrolled charging costs to assess the aggregator's incentive to choose V2G. These impact calculations are described in detail in Sections 2.3.1 and 2.3.2.

Table 1 presents the variables used in this section.

### 2.1. Electricity tariff

We study time-of-use tariffs with two components: one evaluated per kWh of energy comprising the energy costs, network charge, and taxes; and one demand charge evaluated with the maximum daily kW demand. Let $D^t_{ch}$ and $D^t_{dis}$ be the charging and discharging demand at time $t$, measured on the vehicle-side. Then the total charging cost at the site is the sum of the demand charge, $T_{dem}$, and energy cost, $T_{ch}$, or revenue, $T_{dis}$, components:

$$\text{Total Cost} = T_{dem} \max_t \left| \frac{1}{\eta} D^t_{ch} - \eta D^t_{dis} \right| + \sum_t \frac{1}{\Delta t} \left( \frac{1}{\eta} T^t_{ch} D^t_{ch} - \eta T^t_{dis} D^t_{dis} \right) \tag{1}$$

Charging efficiency factors of $\eta$ or $1/\eta$ convert between the grid-side and vehicle-side measurement of demand. The tariff per kWh can be broken into its components as

$$T^t_{ch} = T^t_{energy} + T^t_{network} + T_{national} + T_{municipal}. \tag{2}$$

$T^t_{energy}$ denotes the energy price in the tariff at time $t$, $T^t_{network}$ the network charge at time $t$, $T_{national}$ the national tax rate, and $T_{municipal}$ the municipal tax rate.

The concept of a network charge reimbursement is introduced so that EVs only pay the network charge for energy they consume. To implement this reimbursement, the network charge should be paid back on energy discharged back to the grid. Exact reimbursement would require a full time history of the charging and network charge paid for each unit of energy in the battery; information which may not be available to the workplace aggregator. As the best practical implementation for this reimbursement is unclear, we implement several scenarios.

Let $T^t_{network\ REIMB}$ be the network charge reimbursement at time $t$. We compare the following three scenarios for $T^t_{network\ REIMB}$:

1. "Minimum" scenario: The lowest network charge in the tariff.
$$T^t_{network\ REIMB} = \min_{\tau \in \text{day}} T^\tau_{network} = T_{net,min} \tag{3}$$
2. "Tracked" scenario: Based on the charging history. The vehicle battery is virtually divided into parts. Part one charges during the high network charge periods with $D^t_{ch,1}$ and discharges at any time with $D^t_{dis,1}$; part two charges during the low network charge period with $D^t_{ch,2}$ and discharges at any time with $D^t_{dis,2}$. When discharging the optimization can choose which virtual part of the battery to use.
$$T^t_{network\ REIMB} = \frac{T_{net,max}\ D^t_{dis,1} + T_{net,min}\ D^t_{dis,2}}{D^t_{dis,1} + D^t_{dis,2}} \tag{4}$$
3. "Current" scenario: The network charge at the moment of discharging. In this case, the reimbursement rate could be higher than the rate that was paid when charging the energy.
$$T^t_{network\ REIMB} = T^t_{network}. \tag{5}$$

To calculate the reimbursement value in the Tracked scenario, we initialize the simulation assuming all previous charging occurred using the low network charge; after two initialization days, the demand patterns and start-of-day share of network charges converge. When the vehicle drives we assume it discharges proportionally from both parts.

We further test scenarios where the taxes are or are not reimbursed on discharged electricity. With the taxes reimbursed, the discharging tariff becomes

$$T^t_{dis} = T^t_{energy} + T^t_{network\ REIMB} + T_{municipal} + T_{national}. \tag{6}$$

Without the taxes reimbursed, the discharging tariff becomes

$$T^t_{dis} = (T^t_{energy} + T_{network\ REIMB}) \times (1 - \text{VAT}). \tag{7}$$

The factor $(1 - \text{VAT})$ is added to the no-tax-reimbursed case because values of $T$ include the value-added tax (VAT).

Finally, we consider an additional scenario for each base tariff where the spread from low to high energy prices is increased by up to 100%, keeping the daily average constant.

### 2.2. EV charging demand

We generate the vehicles' uncontrolled charging demand using a detailed agent-based model of EV charging patterns adapted from Gschwendtner et al. (Gschwendtner et al., 2023). With uncontrolled charging, the vehicle charges at the maximum rate until full or until its departure. The parameters of the uncontrolled workplace charging sessions are then used in the aggregator's optimization for controlled charging.

#### 2.2.1. Agent-based EV model

The model includes two classes of agents: vehicles and charging stations. Each vehicle is described by its driving efficiency, battery capacity, status (driving or parked, charging or not charging) and travel pattern. Each charging station is described by its location type (home, workplace, or other), maximum charging rate, charging efficiency, and status (available or occupied).

The travel pattern is a list of trips taken by the vehicle on a single day, including the arrival and departure time for each trip, the trip distance, and the trip purpose. We use the vehicle efficiency and trip distance to calculate the energy use for each trip. When the vehicle agent arrives at a new location, the agent will first decide whether to try to plug-in, based on assigned behavior. If there is an available station at the location, the station is claimed and the vehicle starts charging, otherwise it parks without charging.

For this case study, we assign all vehicles the behavior "Both Home and Work": every time a vehicle arrives at home or at work, it tries to plug in. 80% of vehicles are assigned home chargers for their exclusive use. All are given shared access to workplace chargers and public fast chargers. We assume the vehicles start the sample day with 100% state-of-charge to find an upper bound on V2G potential. To focus on normal commuting patterns, we remove all sample days with over 365 kilometers traveled (80% of the driving range). Sensitivity to different behavior preferences or infrastructure scenarios is the subject of future work.

#### 2.2.2. Aggregator optimization

The aggregator optimizes each vehicle's charging to minimize costs. It must respect bounds on each vehicle's SOC and deliver the same amount of energy to each car as with uncontrolled charging.

The optimization minimizes the demand charge (DC), charging energy (CE), and battery degradation (BD) costs, minus the revenues from discharging (DR).

$$\min_{d} \quad \mathrm{DC} + \mathrm{CE} + \mathrm{BD} - \mathrm{DR} \tag{8}$$

$$\text{s.t.} \quad \mathrm{DC} = T_{dem} \max_{t} \Big| \sum_{v} \left( \frac{1}{\eta} D^{t,v}_{ch} - \eta D^{t,v}_{dis} \right) \Big| \tag{9}$$

$$\mathrm{CE} - \mathrm{DR} = \Delta t \sum_{t,v} \left( \frac{1}{\eta} T^{t}_{ch} D^{t,v}_{ch} - \eta T^{t,v}_{dis} D^{t,v}_{dis} \right) \tag{10}$$

$$\mathrm{BD} = B_{deg} \Delta t \sum_{t,v} \left( D^{t,v}_{ch} + D^{t,v}_{dis} \right) \tag{11}$$

$$D^{t,v}_{ch} \le P^{t,v}_{max,ch} \lambda^{t,v} \tag{12}$$

$$D^{t,v}_{dis} \le P^{t,v}_{max,dis} \left( 1 - \lambda^{t,v} \right) \tag{13}$$

$$\lambda^{t,v} \in 0, 1 \tag{14}$$

$$D_{ch}, D_{dis} \ge 0 \tag{15}$$

To represent different prices for charging and discharging we create separate variables for charging and discharging. We use the integer constraint in Eqs. (12)–(14) to ensure $D^{t,v}_{ch}$ and $D^{t,v}_{dis}$ are never non-zero at the same time, i.e. that each vehicle can only charge or discharge in a given time step. $P^{t,v}_{max,ch}$ and $P^{t,v}_{max,dis}$ are only non-zero when the vehicle is plugged in.

We assume a charging and discharging efficiency of $\eta = 90\%$ as displayed in Table A.1. If the station draws 11 kW from the grid, 9.9 kW arrives at the vehicle; if the vehicle discharges at 11 kW, 9.9 kW arrives at the grid. As the charging and discharging demand, $D^{t,v}$, are measured on the vehicle-side, while the electricity tariff costs are calculated on the grid-side of the charging station, factors of $\eta$ or $1/\eta$ are applied in Eqs. (9) and (10).

In Eq. (9), the demand charge is calculated based on the maximum site-level charging or discharging power. We scale down $T_{dem}$ by a factor of 30 to create a daily demand charge, rather than monthly, for the daily optimization. In Eq. (10), the charges per kWh are applied to charging and discharging energy. In Eq. (11), a penalty is applied to estimate the cost of battery degradation proportional to the amount of charging and discharging. We calculate $B = 0.0017$ CHF/kWh based on Rahman et al. (2023).

In the Current and Minimum scenarios we have the further constraints:

$$SOC^{t+1,v} = SOC^{t,v} + \frac{100}{B_{cap}} \Delta t \left( D^{t,v}_{ch} - D^{t,v}_{dis} \right) \tag{16}$$

$$SOC^{\tau,v} = SOC^{\tau,v}_{uncontrolled} \quad \tau \in \{t^{v}_{arr},\ t^{v}_{dep}\} \tag{17}$$

$$0 \le SOC \le 100 \tag{18}$$

We track the state-of-charge (SOC) of each vehicle in Eq. (16), with constraints in Eq. (17) to ensure the same total energy is delivered to each vehicle as with uncontrolled charging.

We make several changes to implement the Tracked scenario with convex constraints, including modeling the energy in the battery rather than its SOC. Each vehicle's battery is divided into two virtual components with stored energy $E^{t,v}_1$ and $E^{t,v}_2$.

$$D^{t,v}_{ch,1}, D^{t,v}_{ch,2}, D^{t,v}_{dis,1}, D^{t,v}_{dis,2}, E^{t,v}_1, E^{t,v}_2 \ge 0 \tag{19}$$

$$E^{t+1,v}_1 = E^{t,v}_1 + \frac{1}{\Delta t} \left( D^{t,v}_{ch,1} - D^{t,v}_{dis,1} \right) \tag{20}$$

$$E^{t+1,v}_2 = E^{t,v}_2 + \frac{1}{\Delta t} \left( D^{t,v}_{ch,2} - D^{t,v}_{dis,2} \right) \tag{21}$$

$$E^{t,v}_1 + E^{t,v}_2 \le B_{cap} \tag{22}$$

$$D^{t,v}_{ch,1} + D^{t,v}_{ch,2} = D^{t,v}_{ch} \tag{23}$$

$$D^{t,v}_{dis,1} + D^{t,v}_{dis,2} = D^{t,v}_{dis} \tag{24}$$

$$D^{\tau,v}_{ch,1} = 0 \quad \text{for t in low network charge period} \tag{25}$$

$$D^{\tau,v}_{ch,2} = 0 \quad \text{for t in high network charge period} \tag{26}$$

$$E^{\tau,v}_1 + E^{\tau,v}_2 = \frac{B_{cap}}{100} SOC^{\tau,v}_{uncontrolled} \quad \tau \in \{t^{v}_{arr},\ t^{v}_{dep}\} \tag{27}$$

Eqs. (20) and (21) track the energy charged and discharged to each part of the battery and Eq. (22) replaces the limit on maximum SOC. Eqs. (23) and (24) calculate the total charging and discharging for each vehicle, to be used in the objective function and earlier constraints. Eqs. (25) and (26) ensure part one of the battery is used for the high network charge energy and part two is used for the low network charge energy. On discharging, the network charge reimbursement component in term $T^{t,v}_{dis} D^{t,v}_{dis}$ in Eq. (10) is broken down for these two parts as described earlier in Eq. (4). Finally, Eq. (27) replaces Eq. (17) to ensure the same total amount of energy is delivered as with uncontrolled charging.

We use CVXPY and MOSEK to solve the optimization problem (Diamond and Boyd, 2016; Andersen and Andersen, 2000). We implement the optimization with a time step, $\Delta t$, of 5 min.

### 2.3. Result calculations

We compare the different tariff and reimbursement scenarios using three metrics: aggregator profitability, impact on renewable integration, and impact on peak net demand.

#### 2.3.1. Profitability

To calculate the aggregator's profitability, we discount and sum the station-level costs in year $y$, $C^y$, minus revenues in year $y$, $R^y$ over the station lifetime in years, $Y$, with discount rate, $d$:

$$\sum_{y=0}^{Y-1} \frac{C^y - R^y}{(1+d)^y}. \tag{28}$$

We do not make assumptions about how the aggregator charges drivers for the service, so $R^y$ reflects only revenues from discharging. If this value is lower for V2G than for uncontrolled charging, then V2G is profitable and may be deployed. The discount rate $d$ is defined as $d = \frac{1+n}{1+f} - 1$, where $n$ is the nominal discount rate $d$ and $f$ the inflation rate (Rahman et al., 2023). The assumptions and cost inputs for the profitability calculation are summarized in Table A.3.

#### 2.3.2. System impacts

To calculate the impact of a given demand profile on curtailment, we subtract the demand from system-wide curtailments, clip the value at zero so that hours with no curtailment are removed, and sum across all hours in the year:

$$\sum_h \max\left(G^h_{curt} - D^h_{V2G,net},\ 0\right). \tag{29}$$

We compare this value for V1G and V2G demand with the value for uncontrolled charging to assess the impact of control. We assume added EV demand can only impact curtailment in hours when there was already curtailment. We do not consider possible interactions between charging control across multiple sites.

To calculate the impact on peak demand, we use the mean daily profile of net load across Switzerland, $D^h_{noEVs,net}$. We add the uncontrolled or controlled EV hourly demand and assess the impact on the daily peak:

$$\max_h(D^h_{base,net} + D^h_{V2G,net}) - \max_h(D^h_{base,net} + D^h_{Uncont}). \tag{30}$$

## 3. Case study

The vehicle driving patterns are obtained from the Micro Census Mobility and Traffic survey from 2021 (BFS and ARE, 2023) which contains individual travel data for passenger cars in Switzerland. The survey data includes over 19,000 vehicles from 55,000 households. We remove car sharing vehicles and filter for only individuals who commute by car, i.e. those with at least one trip to work and one trip to home within the sample day. This reduces the number of vehicles to 5917.

We simulate a workplace parking lot with 25 charging stations and 50 vehicles arriving each day. The vehicles are assigned to available charging stations first-come-first-served on arrival. The travel behaviors are sampled according to their weights representing the Swiss population; the sampling and simulations are repeated 50 times for each result to generate uncertainty bands. Other input data for the EV model can be found in Table A.1.

We use two main time-of-use tariff designs in our analysis. First, we use a present-day tariff used for EV charging from Elektrizitätswerk der Stadt Zürich (EWZ). EWZ is the electricity provider for the city of Zürich, the largest city in Switzerland, and this tariff is one of the only tariffs in Switzerland solely for EV charging. The high price periods of this tariff are from 11 a.m. to 1 p.m. and 6 p.m. to 8 p.m. from Mondays to Saturdays. All other times are low price periods. Both the energy and network charge components have high and low values (EWZ, 2023). All cost components are listed in Table A.2.

Second, we develop a new future "PV Tariff" designed to reduce curtailments, in line with proposed tariffs from other high solar regions (Levin, 2019). The new tariff is based on the cost components of the existing EWZ Tariff but with different timing for the low and high price periods. The new PV Tariff has a low price period symmetric around 12 p.m. to encourage midday charging, aligning with peak solar hours. All other times are then high price periods, including overnight.

**Table 2**
Map of scenarios. This table lists the evaluation criteria and results section for each policy intervention tested.

| Parameter changed | Criteria | Results section | Scenarios |
|---|---|---|---|
| TOU Periods | System Impact | 4.1 | Existing EWZ Tariff<br>New PV Tariff |
| Network Charge Reimbursement | Profit | 4.2.1 | Minimum<br>Tracked<br>Current |
| Tax Reimbursement | Profit | 4.2.1 | True<br>False |
| V2G Station Cost | Profit | 4.2.2 | All Scenarios |
| TOU Energy Price Spread | Profit | 4.2.3 | 100% of Original<br>125% of Original<br>150% of Original<br>175% of Original<br>200% of Original |

We design the new PV Tariff with the same spread in energy prices as the EWZ tariff, and we keep the daily average energy prices the same to reduce the impact on charging costs for uncontrolled charging. We match the low network charge in the PV Tariff to the low network charge in the EWZ Tariff. The high rate is adjusted to keep the daily average the same. We find that the best design has four hours of low prices from 10 a.m. to 2 p.m. Tariffs with shorter low-price periods do not take full advantage of the site's flexibility, while those with longer low-price periods encourage charging outside of peak solar hours.

The hourly curtailments, $G^h_{curt}$, in Switzerland up to 2050 were calculated using the Nexus-e model of the Swiss energy system. We use the base case from the most recent Nexus-e report (Schwarz et al., 2023). This case assumes growing electricity imports in winter, no changes to the planned lifetimes of nuclear power plants, and a significant increase in rooftop solar PV production. We assume there is little congestion and sum curtailment across all regions in Switzerland. There is a small, ongoing amount of curtailment even in early years, which we assume is due to plant-level factors. We apply a threshold of 1 MWh per hour to identify hours with substantial curtailment which could be affected by controlled charging. We use the hourly net demand profile, $D_{base,net}$, from the same scenario.

## 4. Results

We organize the results to answer the research questions outlined in the Introduction. First, in Section 4.1 and Fig. 2 we assess the potential impacts of the site's charging on electricity system curtailment and peak net demand under the two main tariff designs. Second, in Section 4.2 we present the effect of three policymaker tools on aggregator profitability under those tariffs: increasing the reimbursement of taxes and network charges for discharged energy; subsidizing V2G station costs; and increasing the spread between low and high energy prices. In Section 4.2.1 and Fig. 3 we define the basic conditions under which discharging is incentivized; in Section 4.2.2 and Figs. 4 and 5 we discuss the breakdown of costs and revenues in each reimbursement case; and in Section 4.2.3 and Fig. 6 we assess impacts of increasing the price spread. The scenarios and result sections are mapped in Table 2.

### 4.1. Impacts of two time-of-use tariffs

In Fig. 2 we compare the existing EWZ Tariff with the new PV Tariff. The values in Fig. 2(a) include all price components except the demand charge, which we keep constant between the two tariffs. In Fig. 2(b) we use the scenario with tax reimbursement and the Current

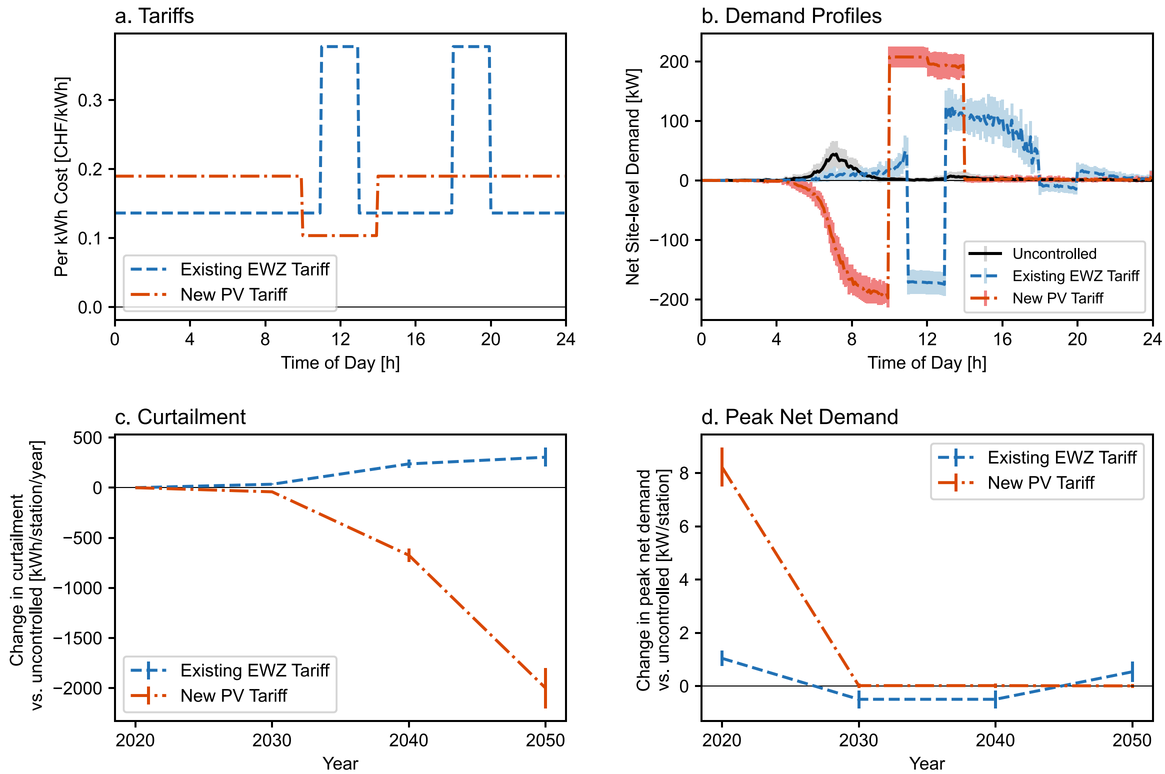


**Fig. 2. Tariffs and Impacts.** This figure illustrates the prices (a) and charging profiles (b) under the two tariffs, as well as their impact on curtailment (c) and contribution to peak demand (d) relative to uncontrolled charging. We show the mean over 50 runs with error bars for the standard deviation.

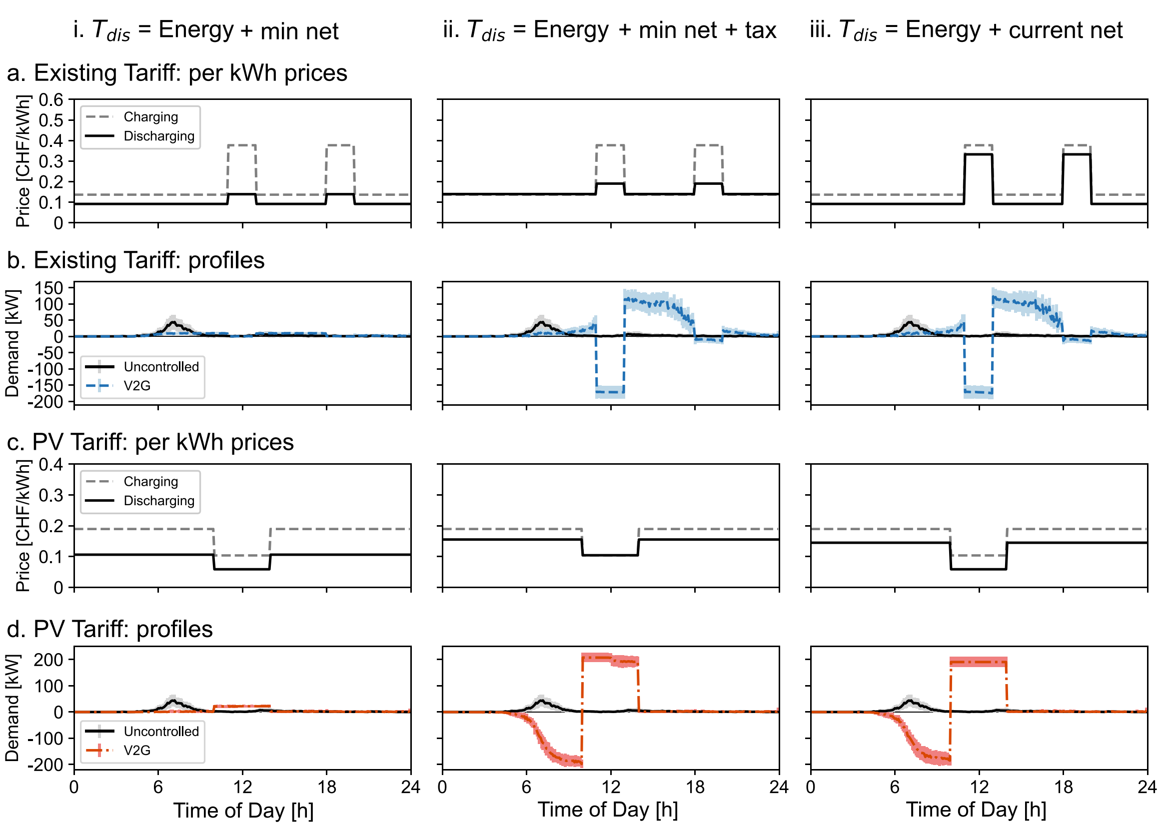


**Fig. 3. Prices and demand profiles with both tariffs.**This Figure illustrates the threshold effect in the spread between charging and discharging prices. (a and c) show the charging and discharging prices per kWh, (b and d) the resulting site-level demand profiles. We see the discharging price is too small in case (i) with only the energy price and Minimum network charge reimbursed on discharging. It is only high enough to incentivize V2G in (ii and iii), or for larger price spreads.

network charge reimbursement. Other scenario results are described in the following sections.

The existing EWZ Tariff has high price periods around noon and in the early evening to shift demand away from peak hours. With V2G, we find this encourages discharging between 11 a.m. and 1 p.m., limiting any increase in peak net demand, but increasing renewable curtailment relative to uncontrolled charging.

The new PV Tariff has low prices around noon which give the opposite effect, encouraging charging between 10 a.m. and 2 p.m. In 2020, when the system still has a mid-day peak, this increases peak net demand. However, this tariff has a much more positive impact on curtailment as more PV is added to the system, especially after 2030.

In the near-term, before there is large-scale solar deployment, policymakers may prefer the existing EWZ tariff to avoid increasing peak demand. In the long-term, as the electricity system changes, the new PV Tariff leads to better impacts from V2G.

## 4.2. Profitability

With the right choice of time-of-use periods, V2G can have positive impacts on the electricity system. To realize these impacts and see widespread deployment of V2G, however, requires that implementation at the site-level is profitable for the aggregator. In this section we compare three tools policymakers can use to improve profitability under the two tariffs.

### 4.2.1. Reimbursements for discharged energy

We find that the discharging price is critically important to incentivizing V2G deployment. Our first conclusion identifies an important threshold: if the highest discharging price is never higher than the lowest charging price, there is no basic incentive to conduct V2G and the optimization will never discharge to the grid. The spread must overcome round-trip losses to incentivize V2G.

Assume the aggregator pays $\frac{1}{\eta}T_{ch}^{t_1}\Delta E$ to put $\Delta E$ of energy in the battery at time $t_1$. If it sells that $\Delta E$ back to the grid later at time $t_2$, it is paid $\eta T_{dis}^{t_2}\Delta E$. For the sale to be worthwhile, it must hold that

$$\eta T_{dis}^{t_2}\Delta E > \frac{1}{\eta}T_{ch}^{t_1}\Delta E. \tag{31}$$

To incentivize discharging at all, there must exist times $t_2$ and $t_1$ where this holds.

The policymaker must therefore ensure at least the following condition:

$$T_{dis,max} > \frac{1}{\eta^2}T_{ch,min}. \tag{32}$$

This threshold is confirmed in our experimental results. Consider the existing EWZ Tariff shown in Fig. 3(a). The lowest charging price is 0.136 CHF/kWh. Considering the efficiency losses, Eq. (32) gives a minimum discharging price threshold of 0.168 CHF/kWh. If only the energy cost and the minimum network charge are paid for discharging (i), the highest discharging price achieved during this period is 0.139 CHF/kWh. As that is slightly below the threshold, we see the demand profile in (b) (i) shows no discharging at all. We see the same effect with the new PV Tariff shown in Fig. 3(c) and (d) in scenario (i): the lowest charging price is 0.104 CHF/kWh and the highest discharging price is 0.106 CHF/kWh, well below the minimum discharging price threshold of 0.128 CHF/kWh.

Eq. (32) holds for cases (ii) and (iii) with both tariffs. The demand charge could create a second threshold, but we find the demand charge's pressure on the peak is outweighed by the spread in energy prices in these scenarios. When the discharging price for V2G is much greater than the lowest charging price and the incentive outweighs the penalty from the demand charge, the optimization maximizes the amount of discharging in the high price period. This can be seen in Fig. 3 (b and d) (ii and iii).

There is one important constraint on the result in Eq. (32): the discharging price must always be lower than or equal to the charging price at a given time. Otherwise, the optimization is incentivized to jitter between charging and discharging, charging at a low price one minute to discharge at a high price the next. This provides no service to the grid and only wastes energy.

### 4.2.2. Charging station subsidies

To be profitable, the revenues gained through discharging must balance the additional costs of implementing V2G, including for operations, installation, and the station itself.

We assume the aggregator must meet the charging demand somehow and compare their decision between Uncontrolled, V1G, and V2G under each case. We do not make any assumptions about how much the drivers would pay the aggregator. We discount future variable costs and revenues over a lifetime of 15 years.

Fig. 4 compares all reimbursement cases for the two tariffs. The green bar shows the maximum allowable V2G station cost for the aggregator to break-even compared to Uncontrolled charging. If the station cost is larger than the green bar, V2G will not be profitable. With the EWZ Tariff, the break-even station mean value ranges from −450 ± 102 CHF to 8706 ± 942 CHF across scenarios (reporting the mean and standard deviation over the 50 model runs); with the new PV Tariff, from 331 ± 195 CHF to 4208 ± 433 CHF across scenarios. At the time of writing, 1 CHF = 1.09 USD = 1.01 EUR. A negative break-even price means the aggregator cannot break-even no matter the cost of the station.

Current V2G stations available in Switzerland cost 13000 CHF (sun2wheel, 2023). Upcoming chargers may fall in the range of 4000 USD (Moloughney, 2022), but the details in Switzerland are unknown. Depending how station costs develop, and depending largely on the tariff design, large subsidies may be needed to cover V2G station costs. If station costs stay at 13000, subsidies would be required in all reimbursement cases with both tariff designs; if station costs fall to 4000 CHF, however, the Current network charge reimbursement scheme could make V2G profitable without subsidies, even without taxes reimbursed under the EWZ Tariff case.

We find that the implementation of network charge and tax reimbursements has an important impact on the break-even station cost, too.

In the Current network charge reimbursement scenario, the aggregator would benefit from charging in low network charge periods to discharge in high network charge periods. This is the best case for the aggregator and results in the highest profitable station costs: up to 8706 ± 942 or 6145 ± 678 CHF with the EWZ Tariff, if taxes are or are not reimbursed for discharged energy. With the new PV Tariff, the reimbursement of taxes has a bigger impact on the Current network charge case as the maximum station cost ranges from 386 ± 189 to 4208 ± 433 CHF. In the Minimum and Tracked network charge reimbursement scenarios the V2G discharging revenues are smaller, so the allowable station cost mark-ups are smaller too.

In cases with no incentive for discharging, no station subsidy would be enough to incentivize V2G. For both the PV and EWZ Tariff, those are the Minimum and Tracked network charge reimbursement scenarios without tax reimbursement. In those cases it would be best from the aggregator's perspective to do V1G uncontrolled charging with a V1G station, no matter the cost of V2G infrastructure. In two scenarios where discharging does occur, we still find negative break-even prices under the EWZ Tariff: the Minimum and Tracked network charge reimbursement scenarios if taxes are reimbursed. Subsidies would need to cover even more than the cost of the station to make those two cases profitable.

Fig. 5 shows a detailed breakdown of the components for the cases with discharging revenues. Here the impact of reimbursing taxes is clear: comparing the two Current reimbursement scenarios, the tax reimbursement goes directly to increasing the allowable V2G station

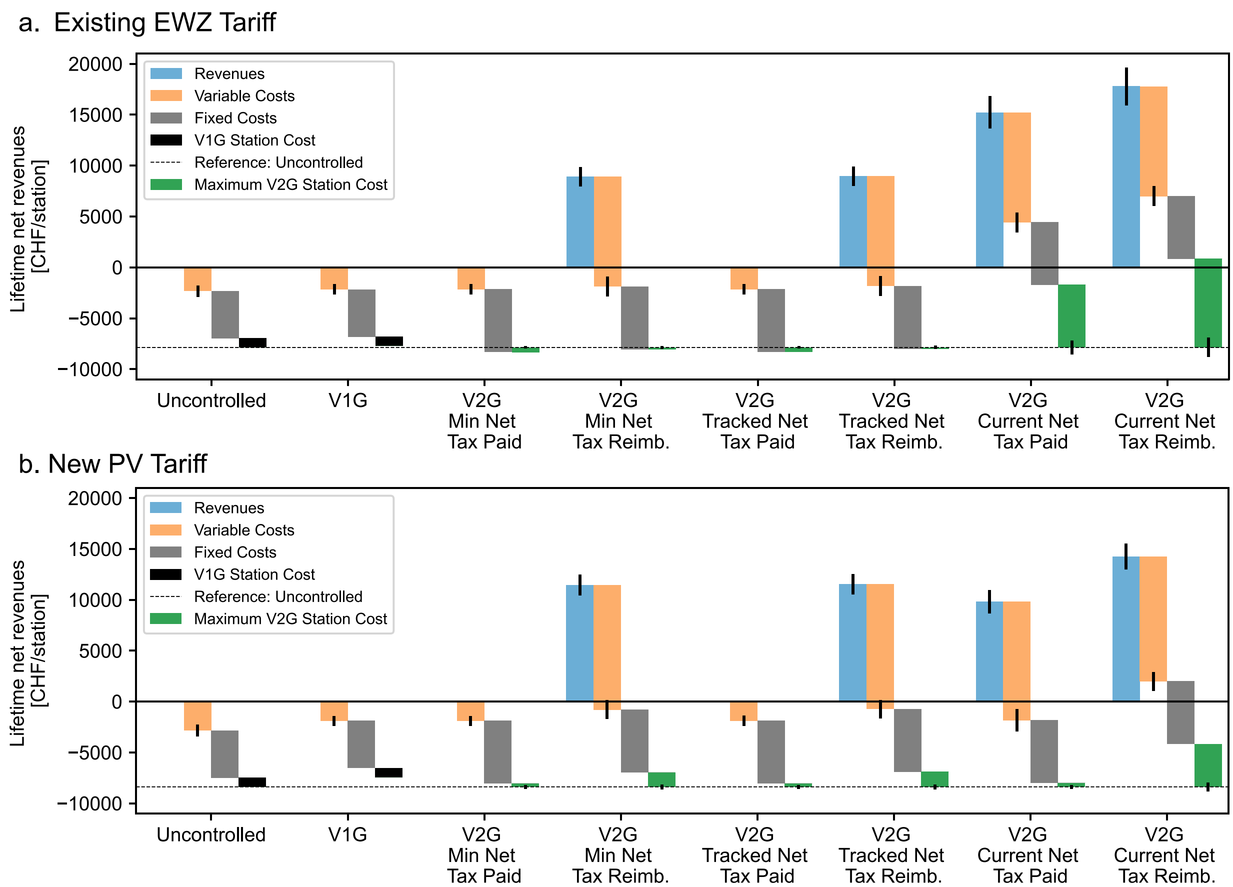


**Fig. 4. Profitability.** This figure shows the costs and revenues for different control, tax, and network charge reimbursement cases. Each case was run 50 times sampling different EVs: the bars show the mean over the 50 runs with error bars for the standard deviation. Results should be compared with the reference line from uncontrolled charging, not with zero, since we do not model payments from drivers to the aggregator for charging services. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

cost. We also see that the network charge reimbursement accounts for a majority share of the revenues, reflecting the aggregator's successful price arbitrage across low and high network charge periods.

In the Minimum network charge scenario, we can see that the network charge costs are higher than the network charge reimbursement amounts, reflecting the loss incurred when charging occurs in high network charge periods can only be reimbursed on discharging at the low network charge rate.

Finally, we also see a substantial difference in the magnitude of the revenues and break-even station costs between the EWZ and PV Tariffs. Though the average price is the same across the two tariffs, the spread between the low and high prices is smaller in the PV Tariff, reducing the benefits of doing price arbitrage.

### 4.2.3. Increasing energy price spreads

If station costs are above the break-even value, policy makers may step in to subsidize V2G stations. Another option would be to increase the spread between low and high prices in the tariff. We test this option for the energy prices in both the existing EWZ and new PV Tariff, assuming the network charge, taxes, and average energy price are held constant. The results are shown in Fig. 6.

For scenarios where V2G is incentivized, increasing the energy price spread improves the profitability of V2G, or, equivalently, decreases the break-even station cost. For example, under the EWZ Tariff with reimbursement of taxes and the Current network charge scenario, a V2G station cost of 9000 CHF would be too expensive in the base case but profitable in the cases with a 25% or larger stretch. The maximum break-even station cost increases to up to 11182 ± 1194 CHF for the EWZ Tariff and up to 9168 ± 850 CHF for the PV Tariff.

Increasing the PV Tariff price spread by more than 50% makes the low energy price negative because we hold the average price level constant. Negative prices in a tariff may face regulatory barriers. If the stretching is stopped at 50%, a more feasible scenario when the prices are all still positive, the break-even station cost is 6688 ± 641 CHF in the best reimbursement case.

We again observe that there is a threshold in the price spread only after which V2G is incentivized. Some series in Fig. 6 are not affected by smaller changes. For example, the Minimum network charge reimbursement cases under the PV Tariff only change once the price spread is increased by more than 50%. Until that point, the price spread is not enough to incentivize discharging, so, with no V2G and no price arbitrage, none of the benefits of the stretching are reflected in the break-even station cost.

## 5. Discussion

Our analysis shows that both the existing EWZ Tariff and the new PV Tariff can have positive impacts on the electricity system in Switzerland. In today's system, the existing EWZ Tariff avoids increases to peak net demand. In the future system, the new PV Tariff helps

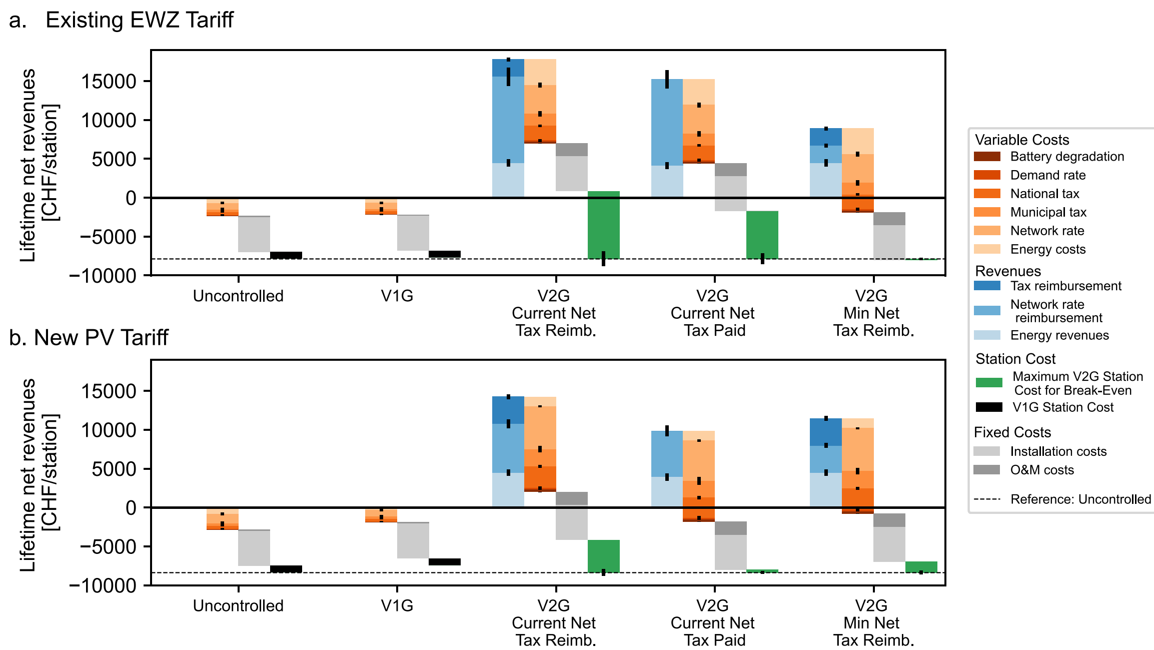


**Fig. 5. Cost and Revenue Breakdown.** This figure shows the detailed cost and revenue components in cases where V2G was incentivized. We show the mean value over 50 runs with error bars for the standard deviation. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

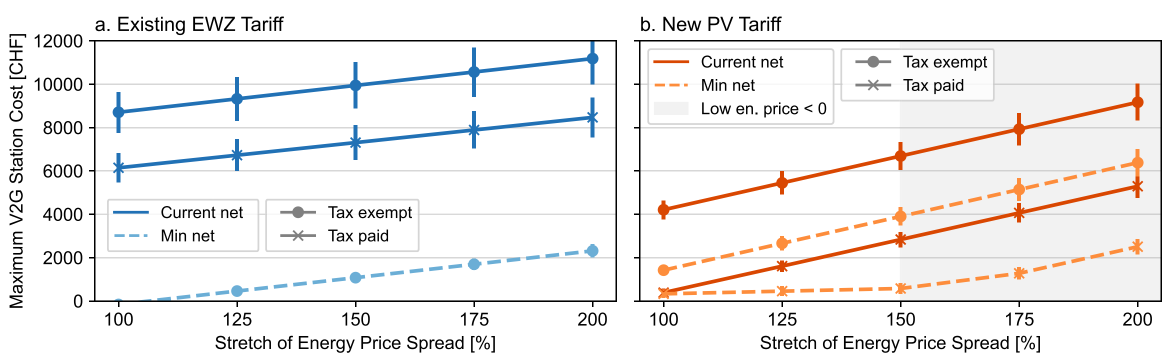


**Fig. 6. Stretching.** This figure shows the maximum V2G station cost for which an aggregator could break-even with uncontrolled charging costs, as the spread in energy prices is increased from 100% to 200% of the original spread.

reduce renewables curtailment.

To realize these impacts, we tested the trade-off between three different policy options to improve profitability for small-scale V2G aggregators. Our results show that profitability is very sensitive to certain thresholds in the price reimbursed for discharging. Policymakers can increase the discharge price by changing the implementation of the network charge reimbursement, introducing tax reimbursements, by stretching the spread between high and low energy prices, or by some combination of all three; each of these choices then affects the need for and level of subsidies for charging station hardware.

In pursuing any of these interventions, policymakers must decide on the value of V2G for their system. Our analysis assumes policymakers' goal is to make V2G profitable. In interviews with charging and electricity system experts, however, Noel et al. found many experts are skeptical whether the benefits of V2G outweigh the added costs and complexity (Noel et al., 2019). V2G also increases total energy consumption due to round-trip losses. In this paper we only tested the impacts of V2G on peak net demand and curtailment; a full assessment of the value of these tariffs would use a dispatch model to evaluate impacts on system cost.

None of these policy tools are free: direct station subsidies may come at the cost of other decarbonization budget items and changes to electricity tariffs would decrease utility revenues. Reimbursing taxes for discharged energy would also decrease tax revenues, though it should be noted that there would be no additional tax revenue to start with if V2G were not incentivized. A cost benefit analysis of these policies could help guide policymakers deciding whether to support distributed V2G deployments. However, if emissions from electricity generation are nearly zero in 2050, the benefits from aligning with solar and reducing curtailment cannot be expressed in kg of $CO_2$ avoided. Instead they correspond to reduced system costs, either from reduced overbuilding of renewables or investments in storage and other flexibility options. Those benefits cannot be quantified without a more detailed model of future electricity system dispatch. Before 2040 or 2050, there is little curtailment in the system so we see less impact on curtailment from V2G. The costs to utilities of changing tariff designs are also difficult to estimate without modeling their costs for purchasing electricity in future electricity markets.

To give a simple indication of the value of these policies, we can use a simple measure comparing the cost of direct station subsidies to the amount of curtailment avoided. If we assume the future market price for a V2G charging station is 4000 CHF, the PV Tariff is in place, and the cost of the policy is spread over benefits from the station's 15 year lifetime, then the policy cost in CHF per kWh of reduced curtailment ranges from 0 CHF/kWh (no subsidy needed) to 0.25 CHF/kWh and from 0 CHF/kWh to 0.083 CHF/kWh with 2040- or 2050-level curtailment in scenarios with taxes reimbursed, or from 0.38 CHF/kWh to 2.81 CHF/kWh and from 0.13 CHF/kWh to 0.96 CHF/kWh with 2040- and 2050-level curtailment in scenarios without taxes reimbursed. For comparison, forecasts for the levelized cost of electricity for solar plus storage systems are in the range of 0.05 to 0.10 CHF/kWh (Kost et al., 2024; IEA, 2024). The feasibility of the subsidy policy depends on the specific regulation or tariff scenario and the potential each year to reduce curtailment. With solar plus storage as the alternative, these indicators suggest the station subsidy is a viable policy option in some cases but not a clear winner. More research and modeling is needed to develop a more detailed cost–benefit analysis. Future work should more explicitly assess the trade-offs between spending on these policy interventions and the benefits more V2G would bring to the system. The benefits will also vary across countries and regions as different electricity systems have different needs for flexibility.

Further, while we consider only EV flexibility in this study, the electricity system has other options if V2G is too expensive. Many large-scale studies have found that V2G substitutes for other flexibility options like battery storage and new transmission. Future work could evaluate the costs and benefits of subsidizing V2G stations instead of installing stationary battery storage. If the funding for V2G station subsidies were redirected to V1G stations, the overall impact on EV adoption and emissions could outweigh the benefits from V2G flexibility. Future work could compare the total costs and system-level benefits of these two policy options.

The design of the network charge reimbursement also involves trade-offs for different stakeholders. The Current reimbursement case incentivizes arbitrage based on the network charge, which utilities may not have intended when designing the tariff. The Minimum reimbursement case penalizes any charging that occurs in the high network charge period, even if the energy is later discharged back to the grid. If the network charge were flat with only one price level each day, arbitrage would be based only on the energy price spread and the implementation of the network charge reimbursement would be much simpler.

Another barrier to V2G deployment not discussed in this paper is the availability of V2G-capable vehicles. Extra investment in V2G stations would add no value if vehicles charging there could only support V1G control. Regulators could encourage or require automakers to make more V2G-capable models to match investments in V2G-capable stations.

Our analysis also did not include barriers related to consumer acceptance and our "break-even" point did not include any costs for compensation to the EV drivers. Future research on drivers' willingness to allow V2G charging could inform the magnitude of payments needed, and should be included in assessments of aggregator profits.

Finally, as our results showed the sensitivity of aggregator's profit to small changes in tariff design, substantial uncertainty in future tariffs could deter businesses from investing in V2G charging. Future research should explore the impact of this uncertainty on aggregator decisions and outline possible solutions.

## 6. Conclusion and policy implications

Policymakers should first determine whether they want to support V2G and assess the value of tariff-based V2G for their electricity system. Our analysis suggests the costs of V2G-supporting policies are in the range of other cost options for increasing renewable integration, but this depends heavily on the market price of V2G stations, the specific policy and tariff settings, and the benefits to the particular electricity system. For policymakers who want to support distributed V2G deployment, we offer three main conclusions based on the results of this study.

First, as the electricity system changes, so too should time-of-use rate periods. The best times for low and high prices will be different for each country. They may also vary by objective: minimizing emissions, cost, distribution grid impacts, and curtailment could all require different tariff designs. Traditional TOU rates aimed to shift demand out of critical hours with peak and off-peak periods. Increasing renewable generation is creating new periods with extremely low net demand, and some new TOU rates have started to target these with super-off-peak prices (SDGE, 2024). Policymakers should ensure tariffs are updated to reflect the changing system to see that the system benefits from distributed V2G and other tariff-based demand response. New tariffs for V2G may also focus on TOU energy prices with flat network charges, to avoid the implementation challenges with TOU network charges outlined in this paper.

In the Swiss case, the existing tariff is designed to reduce peaks but could increase renewable curtailments in the future. A low-price period during high solar hours will be needed after 2030 when solar becomes a large energy provider in the Swiss grid.

Second, the spread between low and high prices in an EV tariff is a key determinant of the incentive for V2G. Policymakers should ensure the maximum discharging price is sufficiently higher than the minimum charging price to overcome round-trip losses. If the tariff includes a demand charge, discharging may be limited to ensure the peak discharging demand stays below the peak charging demand. Increasing the price spread or decreasing the demand charge can shift the balance between the two and incentivize more discharging from V2G.

In the Swiss case, V2G can be incentivized by reimbursing taxes on discharged energy, allowing higher network charge reimbursements, or stretching the spread in energy prices. With the minimum network charge reimbursed, without any tax reimbursements, and with the current tariff, there is no incentive to do V2G.

Third, station subsidies may be needed in the near term. Wider deployment of V2G could help reduce station costs through learning effects (Malhotra and Schmidt, 2020), but until lower cost stations are available, new tariff designs or direct subsidies may be needed to support private V2G deployment. The subsidy needed depends on the system. Policymakers could also require charging station companies to make a certain fraction of their stations V2G-capable to accelerate learning effects, but this would come with other challenges. Better alignment of charging standards across regions or networks could also increase deployment and reduce costs faster.

In conclusion, this work contributes to our understanding of the trade-offs and balance between different policy options for distributed V2G. Policymakers enjoy a wide range of tools and options to improve the business case for V2G aggregators. The value of V2G depends on the system and on the tariff design. With policymaker intervention for wider deployment and with grid-friendly tariffs, decentralized control of EV charging can have a positive impact on the electricity system transition.

## CRediT authorship contribution statement

**Daniel Andersen:** Writing – original draft, Software, Methodology, Conceptualization. **Siobhan Powell:** Writing – review & editing, Writing – original draft, Visualization, Supervision, Software, Methodology, Investigation, Conceptualization.

## Declaration of competing interest

The authors declare the following financial interests/personal relationships which may be considered as potential competing interests: Daniel Andersen is currently employed at EBP Switzerland. His involvement with the paper, however, occurred exclusively during his time at ETH Zürich. The other authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

**Table A.1**
Input data for the agent-based EV model.

| Input Data | Value | Unit | Source |
|---|---|---|---|
| Charging efficiency | 90 | % | (Gschwendtner et al., 2023), "Dominant EV" scenario |
| EV battery capacity | 80 | kWh | (Gschwendtner et al., 2023), "Dominant EV" scenario |
| EV energy consumption | 17.5 | kWh/100 km | (Gschwendtner et al., 2023) |
| Access to work charging station | 100 | % | Case-study for this paper, shared 2-to-1 |
| Access to home charging station | 80 | % | (SFOE, 2023a), "Ladewelt Bequem" in 2035 |
| Public charging capacity per EV | 0.6 | kW/EV | (SFOE, 2023a), "Ladewelt Bequem" in 2035 |
| Power work charging station | 11 | kW | (Gschwendtner et al., 2023), "Dominant EV" scenario |
| Power home charging station | 11 | kW | (Gschwendtner et al., 2023), "Dominant EV" scenario |
| Power public charging station | 22 | kW | (Gschwendtner et al., 2023), "Dominant EV" scenario |

**Table A.2**
Cost components included in the EWZ tariff "Elektromobilität: Niederspannung ≥ 22 kVA oder > 50'000 kWh pro Jahr" for "ewz.econatur" (EWZ, 2022). These values include the value-added tax (VAT).

| Component | Cost (incl. VAT) | Unit | Description: Purpose and recipient |
|---|---|---|---|
| Energy Costs | High: 9.05, Low: 4.31 | Rp/kWh | Covers the utility's costs for the generation or purchase of electricity. |
| Network Charge | High: 24.23, Low: 4.85 | Rp/kWh | Covers the costs of ancillary services, transmission, and the distribution grid. The DSO receives the part for the distribution grid, the other part is allocated to the Swiss transmission system operator Swissgrid. |
| National Tax | 2.48 | Rp/kWh | National tax rate for using transmission grid, used to subsidize renewable electricity generation (SFOE, 2016) |
| Municipal Tax | 1.99 | Rp/kWh | Tax to the City of Zurich for public lighting, energy consulting, and other subsidies for energy efficiencies and renewable electricity |
| Demand Charge | 2.15 | CHF/kW | Charged by the utility for the maximum demand in each month, used to reduce peak demand. |

**Table A.3**
Input data for the V2G profitability calculation.

| Input data | Value | Unit | Source |
|---|---|---|---|
| Inflation rate | 2 | % | (Rahman et al., 2023) |
| Nominal discount rate | 10 | % | (Rahman et al., 2023) |
| Value-added Tax VAT on charging price | 7.7 | % | (FTA, 2023) |
| Lifetime of charging station (bi- and unidirectional) | 15 | years | (Lanz et al., 2022) |
| Battery degradation costs per cycle (ie.e charging and discharging) | 0.17 | Rp/kWh | (Rahman et al., 2023) |
| Ratio of annual O&M costs to equipment costs (bi- and unidirectional) | 2 | % | (Lanz et al., 2022) |
| Additional annual O&M costs per station for V2G | 200 | CHF | (Borne et al., 2018b) |
| Unidirectional charging station costs | 900 | CHF | (sun2wheel, 2023) |
| Installation costs for charging station (bi- and unidirectional) | 4,481 | EUR | (Lanz et al., 2022) |

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## Appendix

See Tables A.1–A.3.

## Data availability

The authors do not have permission to share data.

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