Missing money for EVs: economics impacts of TSO market designs

Paul Codani

Department of Power and Energy Systems
E3S SUPELEC Systems Sciences
Gif-Sur-Yvette, 91190, France
Advanced technologies and Innovation Research Department
PSA Peugeot Citroen
Velizy-Villacoublay, 78140 France
E-mail: paul.codani@supelec.fr

Marc Petit

Department of Power and Energy Systems
E3S SUPELEC Systems Sciences
Gif-Sur-Yvette, 91190, France
E-mail: marc.petit@supelec.fr

Yannick Perez

Reseaux Innovation Territoire et Mondialisation
University of Paris-Sud
91400 Orsay, France
Department of Power and Energy Systems
E3S SUPELEC Systems Sciences
Gif-Sur-Yvette, 91190, France
E-mail: yannick.perez@u-psud.fr

Abstract: Using electric vehicles (EV) as TSO reserve providing units has been demonstrated as being both a feasible and a profitable solution. However, the surveys leading to these conclusions are always conducted either without considering the TSO market rules, or using the local TSO existing ones. We find that TSO rules potentially have a great impact on the expected revenues, and are likely to change within the next few years. Thus, this paper aims at assessing the impacts of the implemented TSO rules on the ability for EVs to provide TSO reserves and on their expected remuneration by doing so. First, we draw a list of the most important TSO rules for this use case. Then, we develop a simulation model in order to evaluate the expected revenues for the EVs. Finally, we compute these expected revenues considering various combinations of TSO rules. By doing so, we identify a missing money issue for EVs due to the use of non-optimal rules towards ancillary services remuneration. Considering the French case, according to our simulation results, this missing money per EV and per year ranges from 193€ to 593€.

Keywords: Electric Vehicles; TSO reserves; Vehicle-to-grid; Economics; Regulation

1 Introduction

In order to cope with the objectives of reduction in both air pollution and CO2 emissions, governments' environmental-friendly policies tend to incentivize more and more vehicles propelled with alternative fuels. Among the possible technical solutions, rechargeable electric vehicles (EVs) moved by electric motors and powered by electrochemical batteries represent a promising solution. As a consequence, an increasing number of car manufacturers have now plug-in hybrid and full electric vehicles in their product lines, and EV sales are expected to increase within the next few years.

However, EV sales are not following their expected trend: in 2013, the EV market share only reached 0.83% in France, and it is now commonly acknowledged that the initial objective of having 2 million EVs on the roads by 2020 will not be attained. EV sales are stagnating for three main reasons: (a) the EV limited driving ranges in comparison with their equivalent conventional vehicles; (b) the lack of charging infrastructure; and (c) their rather high prices.

One suggested way to deal with the latter issue is to use EVs as distributed storage units when they are plugged-in – that is, in France, more than 95% of the time – turning them into so-called Grid Integrated Vehicles (GIVs). Such a GIV has communication means, a controllable charging rate, and may be able to supply Vehicle-to-Grid power, i.e. to inject power back to the grid. Among the various possible technical solutions, the most profitable one seems to be the integration of EVs into transmission system operator (TSO) reserves (Kempton and Tomić, 2005a) – mainly for providing frequency regulation.

This solution has been intensively studied in the scientific literature, both from a technical (Sortomme and El-Sharkawi, 2012; Vandael et al., 2013) and an economics point of view (Dallinger et al., 2011; Han et al., 2012; Kempton and Tomić, 2005a). We find little consideration in these papers about the market rules of the targeted market: they are either ignored in the case of technical surveys, or considered as they currently are in economics studies. However, as electrical market designs are evolving due to the liberalization of electricity markets, TSO reserve market rules are intended to change within the next few years. In this paper, the authors aim at assessing the economics impacts of the implemented market rules on the expected revenues of a fleet of GIVs providing frequency regulation.

In order to do so, the authors build on from two previous studies they conducted: a survey of the aforementioned rules in (Codani et al., 2014a), and the implementation of a simulation model to assess the expected revenues of a GIV fleet providing TSO reserves in (Codani et al., 2014b).

The proposed approach is the following. First (section 2), through a survey of 6 representative TSO rules, we identify the rules that potentially have a major impact on EV expected revenues. Then (section 3), we provide a description of the model used to assess these revenues. Finally (section 4), we select two combinations of rules – a best case and a current case – and we evaluate the expected revenues in both cases by using the simulation model developed. Finally, section 5 is the conclusion.

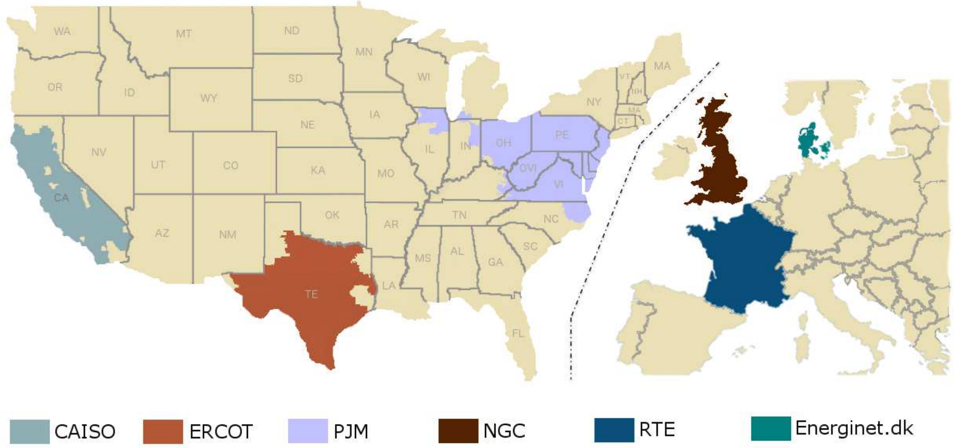

Figure 1 Maps of the six TSOs understudy

2 TSO rules survey

In this section, we aim at identifying the most important TSO rules for GIVs providing TSO reserves.

We make a comparison among 6 TSOs by screening their manuals on a list of rules and characteristics that are important for GIV deployment. The six TSOs in question, represented in figure 1, and the regulation manuals associated are: Energinet.dk (Denmark) (Energinet.dk, 2012), RTE (France) Reseaux de Transport d'Electricite (2004, 2011b,a), ERCOT (Texas, USA) (Electric Reliability Council of Texas, 2012, 2013d,c,b,a), CAISO (California, USA) (California Independent System Operator, 2013b,c, 2011, 2013a), PJM (North-East, USA) (PJM Interconnection, 2013a,b,c, 2012), and NGC (UK) (National Grid, 2012a,b, 2013).

Based on this literature, we identify two key sets of rules that gather the essential rules for GIVs development: the rules towards aggregation of EVs, and the rules defining the payment scheme of the services provided by GIVs. The two modules are described in more details in the two following subsections.

2.1 Module 1: the rules towards aggregation of Electric Vehicles

An aggregator has a fundamental role in GIV architectures for TSO services: it is responsible for presenting a fleet of EVs as a single entity to the TSOs. Aggregators are required because: (a) TSOs deal with large entities (MW rather than kW size), (b) TSO data processing capabilities do not have the bandwidth for controlling millions of kW size units; they were designed for 100s of multi-MW sized units, and (c) TSOs expect their resources to be reliable, which is a problem for a single EV. An EV necessarily gives first priority to transportation, but from the power system perspective, one EV may leave the power system at any moment. Aggregators can address these issues by controlling a large number of EVs (Kamboj et al., 2011; Kempton and Tomić, 2005b) and offering a single, statistically-reliable entity to the TSO. Finally, aggregators should also be able to deal with a large diversity of degrees of information and degrees of uncertainty induced by many different vehicle types, driver plans, and regularities in driver behaviors (Kempton and Letendre, 1997; Bessa and Matos, 2010), details well outside the business expertise or interest of TSOs.

Correspondingly, TSOs must allow such aggregation for GIV use, but what are the main rules to do so? Here we would like to insist on three rules: the size of the minimum bid, the interoperability among DSOs, and the technical form of aggregation.

2.1.1 Minimum size to be included in the market

In all reserve markets, bids cannot be less than a minimum power level; we have seen a range of minima from 100 kW (PJM, frequency regulation) to 10 MW (NGC). In terms of EV coalitions, this minimum-bidding amount can be converted into a minimum number of EVs. A high level of minimum bidding amount would represent a challenge for the development of pilot and early commercial projects, because they may not have enough vehicles to meet with the minimum.

For instance, considering charging stations of 3kW (domestic plugs), and that one EV out of three is available for reserve markets (because of transportation, charging needs...), the minimum fleet size would be 100 vehicles for a minimum bid value of 100kW. On the other side, given a minimum bidding size of 10MW, the number of EVs in a coalition should be at least 10,000. These figures should be put in perspective with those of today EV sales; in 2013, only around 10,000 EVs were sold in France for example. Thus, given a high minimum bidding size, it would be impossible to make a coalition of privately owned vehicles in France, not to mention a company fleet.

Even if we consider a high penetration of EVs, say, in 10 years, a high minimum bidding value would narrow the diversity of potential aggregators: among others, company fleets of utility vehicles, or Vehicle-to-Building scenarios (fleets gathering vehicles parked in the same parking lot), would not be allowed to become aggregators.

2.1.2 Interoperability among DSOs

Single or multiple DSO zones of technical regulation are a second key concern for aggregation business. As EVs are small moving storage entities, TSOs rules should also allow resources that may shift locations, and may be spread across different electrical distribution companies (EDCs)[a]. Regarding movement across EDCs, some TSOs work with very few EDCs (for instance RTE, whose main EDC partner is ERDF) but others are connected to many of them (for instance Energinet.dk, with 65 EDCs), and in the latter, more typical case, not being allowed to aggregate across EDCs makes aggregation more challenging or even impossible.

Thus, the best option is to allow and organize interoperability among various DSOs as done in RTE or Energinet.dk. From an aggregator point of view, a restrictive implementation of this rule could be very constraining. Indeed, the minimum fleet size is induced by the rationale described in section 2.1.1, and if this minimum has to be reached in a single DSO area, it may be impossible for aggregators to meet with the minimum fleet size requirements.

2.1.3 Telemetry versus financial aggregation

Our last criterion is a distinction between telemetry and financial aggregations. The telemetry is the best form of aggregation; it enables combining bids and then controlling distributed power flows from one or more central locations. In contrast, financial aggregation

[a]One way to manage that may be to register charging stations rather than registering EVs.

only allows combining financial bids but not power flows, which, among other things, would prevent an aggregator from implementing dispatching algorithms.

It is noticeable that TSOs may be unwilling to allow large telemetry aggregations, because it would make verification of reserve activation more difficult.

The table 1 sums up the identified rules regarding aggregation and the different possible organizations for each rule.

Table 1 The Different Organizations for Module 1

Aggregation rule	Organization	
	Best Option	Restrictive Option
R1: Minimum size	100kW	10MW
R2: Interoperability among DSOs	Possible	Impossible
R3: Aggregation level	Telemetry	Financial

2.2 Module 2: The rules defining the payment scheme of grid services

We consider the provision of grid services by GIVs as a mean to lower the total cost of ownership (TCO) of EVs. As a consequence, the payment scheme of these grid services is of a paramount importance. EVs should be remunerated in a fair a just manner, and from a financial perspective, this remuneration should at least cover the induced costs[b].

2.2.1 Nature of the payment scheme (Regulated or Market Based)

For a given reserve market, TSOs may differ in their way to dispatch the required power among all the units that are part of the reserve in question (whether primary or secondary). Raineri et al. (2006) identified several transaction mechanisms: some TSOs implement open markets in which units are allowed to bid as they want in these markets, a bid being an amount of offered capacity and its associated price; bids are either accepted or rejected by the TSO; other TSOs dispatch the total required power among all the units that are part of the reserve in proportion to their historical load share. In this situation, depending on the TSOs, providing reserve is either a choice or compulsory for a unit.

The use of market prices as a way to determine the dispatch of reserves is much more profitable for new storage resources such as GIVs. First, in a regulated approach, we would have to wait for a formal change of the rules, so that they would be suitable for new resources such as GIVs. This adaptation is likely to be lengthy, sub-optimal, and lagging EV sales, trying to catch up with the market evolution instead of taking the lead. Then, changing a contract binding an aggregator and the TSO would also be a lengthy process, not really compatible with a dynamic EV fleet. Indeed, in addition to many dynamic changes within a fleet because of transportation needs, the EV fleet itself is also likely to evolve, with new EVs joining or leaving the program.

[b]These costs include battery degradation, and hardware and software investments. They are out of the scope of this paper.

2.2.2 Incompleteness of the payment scheme

Besides the nature of the payment scheme, the second element of our frame is its consistency regarding the services offered –or possibly offered– by EVs. It is puzzling to identify ancillary services that are required but not remunerated specifically by some TSOs and DSOs. Some services are just mandatory with no explicit remuneration nor explicit reserve allocation method. Examples are for instance PJM or CAISO not paying for primary frequency regulation.

Regarding our analysis, the more the payment scheme is incomplete and does not compensate the services provided by all the actors, the more EVs are penalized in their contribution as GIV resources. A clear and complete payment scheme is needed as a condition in the Ideal TSO we seek to build.

From the TSO perspective, it could be beneficial to complete the payment scheme of ancillary services. Indeed, as ancillary services (AS) providing units do not have any incentive to provide these unpaid services, they sometimes achieve poor performance in the provision of these services. For instance, Ingleson et al. (2009) points out the fact that the total frequency droop (also referred to as frequency characteristic) of Eastern Interconnection in the US has been dangerously decreasing for the past 10 years, jeopardizing grid security.

2.2.3 Extra bonus for intense flexibility

In the United States, the Federal Energy Regulatory Commission (FERC) has investigated the different frequency regulation compensation practices of TSOs (FERC, 2011). Its conclusion is that current compensation methods are unjust and discriminatory, specifically because fast ramping resources (resources that are able to change their output very quickly) are not remunerated enough with respect to the greater amount of frequency regulation provided.

To deal with this issue, the FERC makes two recommendations. First, remuneration should not only be based on availability (i.e. in \$/MW), but also on utilization (\$/MWh), and every MWh exchanged with the grid for the purpose of frequency control should be counted as a source of positive revenue for the resource in question, whether the MWh flowed from the grid to the resource or from the resource to the grid. That way, as fast-ramping resources respond faster, they exchange more MWh with the grid than slow-ramping units, so payment will be fairer; second, regulation resources should receive a two-part payment: the first one is the capacity and utilization payment discussed above, including an opportunity cost, and the second one is based on performance, taking into account the response accuracy. Further details about the performance calculation are provided in the more recent FERC order 784 (FERC, 2013): speed and accuracy should be taken into account in the payment of ancillary services.

EVs are very fast-ramping resources. Therefore, TSOs that abide by FERC compensation recommendations, or similar compensation schemes reflecting the value of fast responses, are more attractive for GIV aggregators. The best solution is then to be able to benefit from this kind of bonus. However, the implementation of this bonus should be managed carefully. Indeed, the addition of an extra bonus to an existing payment scheme should be set at the efficient level. The risk induced by introducing a bonus is that it might create a distortion that could either overcompensate the initial problem, or not compensate enough and leave the issue unsolved.

An alternative way of proceeding would be to regard fast and slow ramping tenders as two different products. Thus, establishing a separate market earmarked for fast-ramping resources, with its own rules and regulations, might be another solution to remunerate these services in a just and fair manner.

At last, some electrical grids might not presently have the need for fast-ramping resources. The droop control method of conventional units has been operating for a long time and seems to be working quite well (provided that financial incentives are adequate, see 2.2.2). Thus, introducing more fast responses in this context has to be investigated thoroughly by the TSOs. In a first time, such services may be mostly suited for extreme frequency containment plans after severe disturbances rather than for normal operations. Then, with the increasing penetration of intermittent renewable sources, which induce more production fluctuation and less system inertia, fast-ramping units may be more and more required. We are already observing this phenomenon in some island networks, which are isolated - so very sensitive to frequency drops - but benefit from substantial wind and solar resources.

The table 2 sums up the rules dealing with the payment scheme, and the different possible organizations.

Table 2 The Different Organizations for Module 2

Payment scheme	Organization	
	Best Option	Restrictive Option
R4: Nature of the payment	Market Based	Regulated
R5: Incompleteness of the payment	All AS should be paid	Incomplete payment scheme
R6: Extra bonus for flexibility	Set at the efficient level, or separate market created	Not Existing

2.3 Conclusions

We have identified two sets of rules, leading to different organization forms. We are now able to define a best case, a worst one and some intermediate cases. To go a step further, we want to evaluate and number the missing money for EVs when a "bad" combination of rules is implemented, in comparison with an ideal combination. In order to do so, we first need to develop a simulation model which will enable us to assess the expected EV revenues.

3 Simulation model

In this section, we describe the simulation model used to assess the economic revenues of the EV fleet. In section 2, we have identified the most important rules for GIVs providing TSO reserves; in order to perform our economics evaluation, we have to focus on a particular TSO reserve market. We decide to conduct our analysis for the *primary frequency control* (see 3.1.1) market. Moreover we apply our simulations to the French case.

The outline of this section is the following. First, we recall the basics of frequency control. Then, our fleet model is presented. Finally, algorithms and simulation parameters are detailed.

3.1 Frequency Control

3.1.1 The basics of frequency control

Frequency is a common characteristic within an interconnected network; at any node of the grid, the frequency value is the same (conversely to voltage, which is different from one node to another). The frequency value fluctuates around its nominal value at each moment (50Hz in Europe). However, maintaining the frequency close to its rated value is important, because most of materials have been optimized to operate at this frequency value, and devices with magnetic materials may come out of their linear range. The agents responsible for controlling the frequency value are the local Transmission System Operators (TSOs), which operate high-voltage transmission lines.

The frequency reflects the real time balance between supply and demand. If electricity generation exceeds electricity consumption, the frequency will rise above its rated value and vice versa. Consequently, TSOs manage the frequency by implementing several control levels that balance production and demand in real time.

Even if TSOs have their own rules and regulations, they basically implement three similar control levels to monitor the frequency.

The *primary control*, sometimes referred to as *frequency reserves*, is an automatic control activated instantaneously. All the TSOs that are part of the interconnected grid participate to this control when a frequency deviation occurs. The aim of this control is to stop the frequency deviation, but it will not restore the frequency to its pre-disturbance value. Resources that are part of the primary reserve are to measure the frequency locally, and to respond accordingly. Power plants or other traditional units have been providing this service for years, mainly by implementing speed control loops on their motor shaft.

The *secondary control*, or so-called *frequency regulation*, is an automatic control performed only by the local TSO where the frequency disturbance occurred. The latter implements a PI loop with a characteristic time of 30 seconds, and sends a correction signal to all the units that are part of the secondary reserve. This control restores the frequency to its rated value.

The *tertiary control* is a manual control whose objective is to support primary and secondary controls. It has a response time of 15-30 minutes.

For more details on frequency control, the authors refer to (Rebours et al., 2007b,a). In the followings, we will only focus on the French primary control.

3.1.2 Primary frequency control technical requirements

French primary reserve amounts to approximately 700MW. Production units that are willing to be part of primary reserves have to abide by the following rules. For any frequency deviation between -200mHz and +200mHz, the frequency droop K_i of the i$^{\text{th}}$ unit specifies the required power deviation according to the formula 1:

$$P_i - P_{i_0} = \min(P_{primary\ reserve}; K_i(f - f_0)) \tag{1}$$

with P_i, P_{i_0} and $P_{primary\ reserve}$ respectively the total power output, the operational power setpoint and the power reserve of the i$^{\text{th}}$ unit. If the frequency deviation exceeds

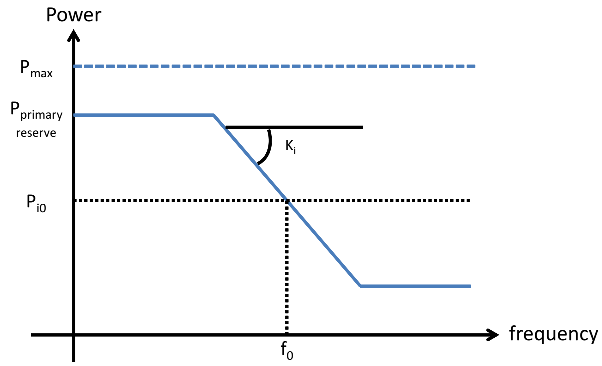

Figure 2 Power-frequency curve for a traditional unit

$\pm 200mHz$, the entire reserve should be released. Figure 2 presents the power-frequency curve of a traditional unit.

In addition to these rules, units also have to abide by the following requirements (Union for the Co-ordination of Transmission of Electricity, 2004):

- Units should be able to release half of their reserve in 15 seconds, and all of it in 30 seconds
- frequency measurement accuracy should be better than 10mHz
- a dead-band of 20mHz is allowed
- frequency measurement period must be between 0.1 and 1 second

3.1.3 Frequency data set

Because we were not able to find publicly available frequency recordings, we used a frequency meter in order to build our own data set. We came up with 5 continuous days of frequency recordings, fully compliant with ENTSOE requirements. Figure 3 displays one hour of frequency variations (one can notice the impacts of the time change from 21h to 22h and the change in Time-of-use tariff).

3.2 Electric Vehicle fleet modeling

Electric Vehicles' characteristics

The battery size of the EVs bears little impact on the final results, and 64% of EVs had a 22kWh battery in France in 2013. Therefore, we consider that the EV fleet is consisted of EVs with a 22kWh battery. We add the following constraint on the State-Of-Charge (SOC) range: $0.2 < SOC/SOC_{max} < 0.9$ in order not to reach extreme SOC values, what could damage severely the battery.

Characterization of charging stations

The power level of the charging stations, or so-called Electric Vehicle Supply Equipment (EVSE), will have a significant impact on the expected fleet earnings since market

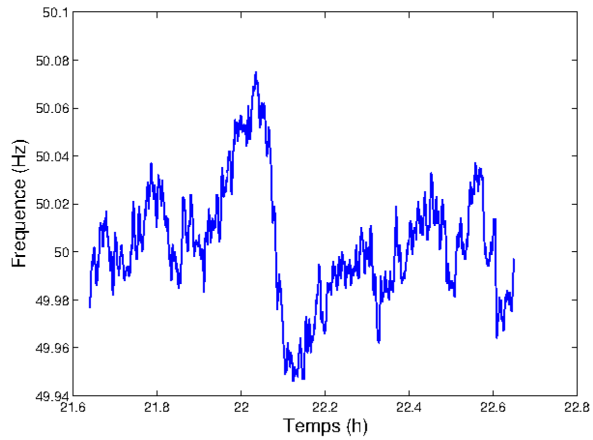

Figure 3 Frequency fluctuations over one hour, recorded at Supelec between 21h37 and 22h37 on March 28, 2014

remuneration is based on €/MW. As explained in section 3.2.1, we assume that EV uses for transportation are limited to commuting trips. Therefore, EVs can charge either at home, with their *primary EVSE*, or at work with their *secondary EVSE*. The penetration level of EVSEs at working places in 2020 remains uncertain, so we will consider four possible scenarios for this parameter. They are described in table 3.

Table 3 The four scenarios for secondary EVSE penetration levels

Scenarios	Ratio of EVs having an EVSE at work
Scenario 1	0%
Scenario 2	25%
Scenario 3	50%
Scenario 4	75%

There are four different charging levels, which are related to conventional voltage and current values: *slow charging A* (3kW, 230V, 1-phase, 16A), *slow charging B* (7kW, 230V, 1-phase, 32A), *intermediate charging* (22kW, 400V, 3-phases, 32A), *fast charging* (43kW, 400V, 3-phase, 64A – or DC charging). Table 4 presents the charging level distribution for both primary and secondary EVSEs.

This repartition was deduced from a survey achieved by Commissariat General au Developpement Durable (2013). Due to the high cost of charging stations, all EVSEs at home are slow chargers. Charging levels of *secondary EVSEs* are more distributed, apart from fast chargers whose penetration level stays marginal.

3.2.1 Electric vehicle use for transportation

EVs are first used for transportation, so we need to take into account EV trips in our model: they will have an impact on EV availabilities for frequency control (because EVs will not

Table 4 Breakdown of Primary and Secondary EVSEs by Charging Technology Type. Data from Commissariat General au Developpement Durable (2013)

Charging level	**Primary EVSE**	**Secondary EVSE**
Slow charging A (3kW)	95%	35%
Slow charging B (7kW)	5%	34%
Intermediate charging (22kW)	0%	29%
Fast charging (43kW)	0%	2%

be plugged-in, or because they will need to charge for their next trip) and on the amount of energy remaining in EV batteries. Then, the four parameters that we need are: (a) the number of trips in a day; (b) each trip duration; (c) departure times; and (d) trip energy consumptions.

We assume that EVs are only used for the daily commuting trips, what results in two trips a day for each EV. Thus, our 5-day frequency recordings (see section 3.1.3) enables us to perform simulations over an entire working week.

The average daily driving distance d is taken from internal surveys from PSA Peugeot Citroen, to which we add a normal uncertainty with a standard deviation σ. We deduce the daily trip durations from these distances by using an average speed v_{ave}. This speed is also taken from PSA internal data. It is derived from average speeds on highways, on roads, in provincial urban environments and in Paris, each average speed being balanced by the percentage of trips carried out on the roads in question.

Departure times are also distributed according to normal distributions, whose means and standard deviations are arbitrarily set to fit commuting trips in the most possible realistic way.

Eventually, energy consumption is taken from the Cross-border mobility for EVs (CROME) project results. This European project, whose first goal was to demonstrate interoperability of EVSEs across France and Germany, made its data publicly available (Cross-border Mobility for EVs, 2013). We will make a distinction between a *summer type* and a *winter type* consumption, because auxiliary loads, in particular heating and air conditioning, have substantial impacts on energy consumption.

The model and parameter values for these trip data are summarized in table 5.

Table 5 Trip-related models and parameters

Trip data	**Model**	**Parameter values**
Daily trip numbers	Steady value	2
Trip distances	$d \sim \mathcal{N}(d_{data};\sigma_d)$	d_{data} : internal use σ_d : $5km$
Departure times	$t \sim \mathcal{N}(t_{mean};\sigma_t)$	t_{mean} : Best adapted to usual commuting trips σ_t : 2 hours
Consumption	Steady values	$c_{summer} = 129Wh/km$ $c_{winter} = 184Wh/km$

3.2.2 The aggregator

An EV aggregator plays the fundamental role of presenting the EV fleet as a single entity to the TSO. One single EV is very unpredictable from the grid perspective as it may leave for transportation at any moment. Furthermore, it has a very small power level on its own. An aggregator is able to deal with these issues by controlling large, statistically reliable EV fleets.

In order to do so, aggregators basically implement two algorithms: the first ones are *scheduling algorithms* that are responsible for anticipating the future EV fleet conditions and bidding market offers accordingly, and the second ones are *dispatch algorithms*, responsible for dispatching power flows among the different vehicles in real time. In our simulation, we assume that the scheduling algorithm is fully efficient. In other words, all the aggregator capacity bids are accurate with respect to the number of EVs plugged-in, and all price bids made by the aggregator are accepted by the TSO. The dispatch algorithm implemented is described hereafter.

3.3 Algorithms and simulation parameters

3.3.1 Dispatch algorithm

The implemented dispatch algorithm mimics the one implemented in the University of Delaware demonstration project detailed by Kamboj et al. (2011). In this project, a small EV coalition participates to PJM (the local TSO) frequency regulation market, and competes in this market just as the other traditional units.

The operating principle of the algorithm is the following:

1. EVs compute their Preferred Operating Points (POP). The POP of an EV is equivalent to the operating point of a traditional unit; it represents the charging rate around which the EV will provide frequency control. Derived from the POP value, EVs calculate their power available for regulation P_{reg_i}, and communicate this value to the aggregator. The POP calculation method is described below.

2. The aggregator measures the frequency. Depending on the recorded value f, and on the power bid in the market P_b (resulting from the scheduling algorithm, here assumed to be equal to the power made available by all the EVs), the aggregator computes the power to be provided for frequency control P_r:

$$P_r = \begin{cases} -\dfrac{f - f_0}{f_{max} - f_0} P_b, & |f - f_0| < 0.2Hz \\ P_b, & |f - f_0| \geq 0.2Hz \end{cases} \tag{2}$$

with $f_0 = 50Hz$ and $f_{max} = 50.2Hz$

3. The aggregator deduces from P_r a scaling factor μ which is equal to the ratio between the power required for frequency control and the power available from EVs:

$$\mu = \frac{P_r}{\sum_{i=1}^{N_{VE}} P_{reg_i}} \tag{3}$$

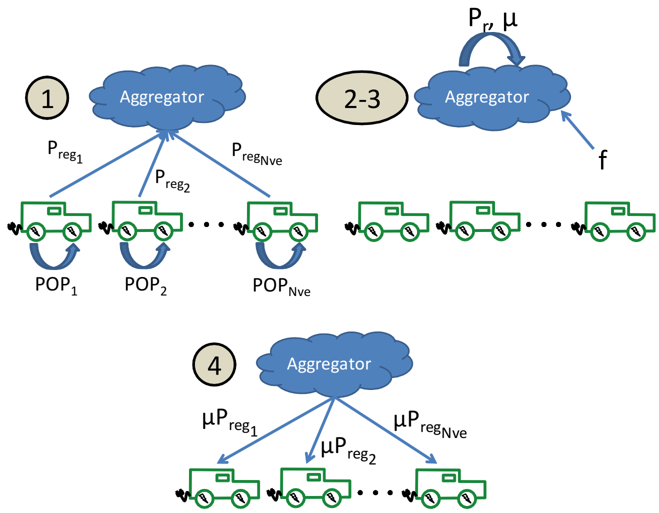

Figure 4 Dispatch algorithm operating scheme

4. The aggregator communicates to all the EVs their power set point for frequency control $\mu * P_{reg_i}$
5. Back to step 1 if EVs are allowed to change their POP, i.e. if $t \equiv 0 \pmod{\delta t}$, otherwise back to step 2.

Figure 4 summarizes the algorithm operating principle. This scheme is repeated for each new frequency measurent, that is to say for each second. It is noticeable that there are two distinct time stamps: the first one is the frequency measurement period, bound to 1 second for safety reasons, and the second one is the POP modification period δt, defined by the market rules. As we consider an hourly market, we take $\delta t = 1$ hour.

The way of computing the POP is also inspired from the University of Delaware solution (Kamboj et al., 2011). It takes into account the current EV conditions, and future trip needs:

$$\begin{cases} POP(t) = \frac{P_h + P_b}{2} \\ \quad P_h = -min(P_{max}, \frac{SOC_{max} - SOC}{\delta t}) \\ \quad P_b = min(P_{max}, \frac{SOC - E_{min}(t+\delta t)}{\delta t}) \\ P_{reg}(t) = P_{max} - \left|POP(t)\right| \end{cases} \tag{4}$$

with SOC the State Of Charge of the battery, $E_{min}(t)$ the energy required at time t to be able to achieve the next trip, SOC_{max} the upper SOC limit and P_{max} the power level of the EVSE.

In order to compute $E_{min}(t)$, we assume that the drivers provide the aggregator with information regarding their next trip. They communicate their next departure time precisely, and their driving range which they always approximate by their longest trip of the week (EV users are slightly subject to range anxiety).

Figure 5 presents the simulation results over 5 working days, for a bidirectional capable car (negative power values stand for charging). The primary EVSE level is 3kW, and there is

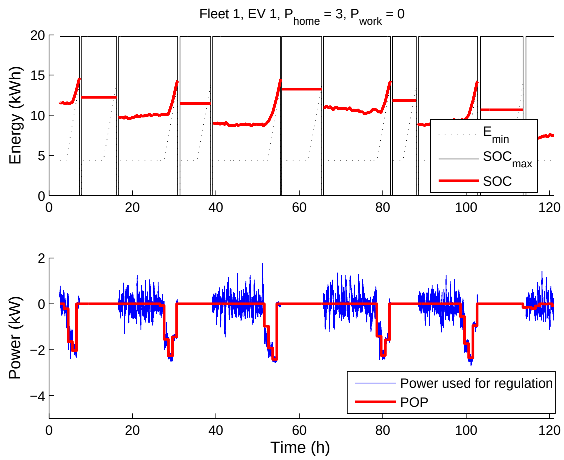

Figure 5 Simulation results for a single bidirectional capable EV over 5 working days, with $P_{home} = 3kW$ and $P_{work} = 0kW$

no secondary EVSE. This accounts for the fact that the SOC remains steady during working periods. When parked at home, the EV participates to frequency control. When the next trip approaches, the POP increases (in absolute value) and there is less power available for regulation, then less power used for regulation. Meanwhile, the battery is charging thanks to the new POP values.

4 Results and Discussion

In this section, we run simulations based on the model described in section 3, under two combinations of the rules that were detailed in section 2. First, we explain and account for the two selected combinations of rules. Then, we provide the results successively for the two use cases.

4.1 Simulation use cases

The two combinations of rules that we select are the followings:

Combination A: this set of rules corresponds to the current French rules. Based on these rules, storage units are not allowed to participate in the frequency control market. RTE dispatches the required power among the production units, "based on their historical load share". In return, the latters are remunerated based on a fixed tariff amounting to 8.48€/MW (Reseaux de Transport d'Electricite, 2011a) (thus, there is no bonus for extra-flexibility). The minimum bidding size is 1MW.

Combination B: this set of rules corresponds to our ideal case. Under this regulation, primary frequency control is organized via an hourly auction market. There is no barrier to new entrants so EV coalitions can compete as any other unit. Moreover, they receive a bonus for their extra-flexibility. The minimum bidding size is low ($\sim 100kW$), enabling small fleets to participate in the market.

A simplistic view of theses two rule combinations is presented in table 6.

Table 6 Combinations of rules understudy

Rule	**Combination A:** Current RTE rules	**Combination B:** Ideal settings
R1: Minimum Size	N/A	100kW
R2: Interoperability among DSOs	Possible	Possible
R3: Aggregation Level	Not Possible	Telemetry
R4: Nature of the payment	Regulated	Market-based
R5: Consistency of the payment	All AS are remunerated	All AS are remunerated
R6: Bonus for extra flexibility	Not existing	Set at the efficient level

4.2 Comparison of combinations A and B: results

In order to compute the revenues, we use prices from the Energinet.dk primary control market, which we raise by 30% to reflect the extra bonus for flexibility (this percentage has been observed at the UD project where a bonus is implemented by PJM). This Danish TSO is part of the same interconnected area as RTE, but primary frequency control is organized in an hourly auction market. As for trip-related consumptions, we distinguish a *winter* and a *summer* season for prices: we use data from 2013 quarters 2 & 3 for summer prices, and data from 2012 quarter 4 and 2013 quarter 1 for winter prices. These clearing prices are available online (Energinet.dk, 2013). For each simulation, we randomly select five continuous hourly market prices from our data set.

Average earnings per vehicle and per year are presented in table 7, for the various EVSE power levels and the two control strategies. As we performed simulations for five continuous working days, results in table 7 do not take into account week-end remunerations, so the overall yearly EV earnings may actually be higher. However, week-end driver behaviors are uncertain, and we did not have enough data to correctly model this behavior. Results from *summer* and *winter* simulations are averaged. We observe that results are very sensitive to the available power level. The expected remuneration reaches significant values for high power levels, up to 1 448€ per vehicle and per year.

These results, given the EVSE penetration at work and the EVSE distributions provided respectively in tables 3 and 4, lead to the findings summarized in table 8. We assume that the aggregator equally remunerates all the EVs, that is, the overall fleet earnings are fairly divided among the vehicles no matter their charging station power.

These expected revenues shed some light on the missing money value for EVs due to the implementation of restrictive TSO rules. Under the combination of rules A, EVs are merely not allowed to participate in the frequency control regulated market (then, their revenues amount to 0). Under the combination of rules B, they can expect to earn between 193€ and 593€ a year.

Table 7 Average earnings per vehicle and per year depending on the EVSE power level for the 2 use cases

EVSE power level		**Annual remuneration per EV**	
Primary	Secondary	Combination B	Combination A
3	0	180€	0€
3	3	310€	0€
3	7	505€	0€
3	22	1346€	0€
7	0	474€	0€
7	3	543€	0€
7	7	780€	0€
7	22	1 448€	0€

Table 8 Average earnings per EV and per year for each scenario and each combination of rules

Scenario	**Fleet revenues (/EV/year)**	
	Combination B	Combination A
Scenario 1	193€	0€
Scenario 2	326€	0€
Scenario 3	459€	0€
Scenario 4	593€	0€

5 Conclusion

In this survey, we have first isolated the most important rules for GIVs providing TSO reserves, and then compared the expected revenues for the EVs under two different combinations of these rules – corresponding respectively to the current and the ideal situation. Under the current regulation, EVs would not be able to participate in the market and their remuneration would be null. Under the ideal situation their revenues, depending on the charging station penetration level at work, would be between 193€and 593€per year.

Our survey has two main limits. First, the battery degradation induced by the participation to frequency control has not been evaluated. Several previous studies tried to take this parameter into account (Han et al., 2012; Peterson et al., 2010; Qian et al., 2011). Han et al. (2014) even present a battery degradation model for Vehicle-to-grid applications. However, none of these models has ever been experimentally verified, and the aforementioned surveys do not use similar methods nor find similar results. By lack of agreement on a given model or results, we decide not to model battery degradation, which is still a major issue for these technologies.

Then, we did not assess the extra cost for upgrading the power electronics to make them bidirectional capable. It is difficult to say which operator would bear these costs, between car manufacturers, car users, aggregators, charging station operators... However, they should not be too significant, as most the required power electronic devices are already present in the existing facilities.

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