Mitigation of the Impacts of EV Inclusion into Electricity Markets through Demand Aggregators

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***Abstract*—The uncoordinated charge of a large fleet of electric vehicles (EV) will create difficulties in the management and technical operation of power systems, because it'll increase the peak of the daily load profile. In order to avoid that effect, this paper presents a coordinate charging model creating a new agent that aggregate the energy demand of EVs and also exploit business opportunities of the batteries in electricity markets. In this context, aggregators will achieve two main goals: first, allow network operators to improve system performance by given control over demand side variables; second, aggregators will remove barriers to having more EVs on the roads. Nevertheless, is important to say that aggregators won't come up as a market solution to the problems of uncoordinated charge, because providing services to the grid will cause the degradation of expensive batteries.**

***Index Terms*—Battery, Demand aggregator, Demand response, Electric vehicle, Energy market, Policy, Prosumer, Vehicle to grid.**

I. Introduction

Projections of electric vehicles (EVs) development indicate the technology has reach the maturity needed to maintain a constant growth in the market [1]. In consequence, the size of the EV fleet in the world will surpass one hundred millions units before 2035 [2], becoming the 6% of the total of vehicles. Although, considering the climate change mitigation goals, the interest of the users in emerging mobility technologies and the decreasing tendency of batteries' cost, the number of EVs worldwide could be more than two hundred millions before 2030 [3].

Furhtermore, according to Bloomberg Tech, EV sales will surpass the ones of internal combustion engine cars (ICE) by 2038 [4], thanks to the efforts of several gobernments for promoting new mobility options and cleaner technologies [5]. This gives credibility to the most optimistic scenarios of EVs' growth in market share, because the total fleet of vehicles will be the double in 2035 respect to 2015, and the triple in developing countries [2].

This inevitable electrification of the transport sector is a great opportunity to achieve the environmental goals of the COP23 meeting [6]. Nervertheless, it isn't enough with having a large number of EVs, it's also needed that the energy fueling the vehicles comes from renewable resorces [7] to ensure the reduction in greenhouse gases (GHG) emissions.

Previous studies have shown that allowing uncoordinated charge of the EVs [8] will produce higher peaks in the daily load profile [9], which is a problem because in most cases the short-term peaks must be supplied with thermal power stations of fast response and low intermittency in their operation. This means that EVs couldn't reduce GHG emissions, just shift them from the cities to the generators locations.

That problem, and the need for improve market efficiency to sucessfully integrate EVs, motivated this thesis project. In that sense, the first proposed objective is to predict possible negative effects in electricity markets as of the daily load profile shape of a large fleet of EVs when nobody is persuading its owners to recharge at certain time. After explore the consequences of uncoordinated charge, the next objective is to propose a coordinate charging method trough new market agents that aggregate and control the energy demand of the EVs [10].

For evaluating the coordinated charging method is assumed that smart grids expansion will be faster than the growth of EVs in the market. So, when the size of the fleet start to cause problems, the telecommunications tools will be ready to enable demand response programs [11] and it will be possible to manage the energy of the EVs in the distribution grid [12]. This assumption is coherent with the projections of the Energy International Agency [13] and with the visions of the governments [14], because they consider smart grids and demand response programs as key milestones in the evolution of power systems in the near future [15].

This paper is structured as follows: in section II is sumarized the methodology to forecast the EVs power demand and the way the aggregators will operate in power systems. Afterwards, in section III are presented two case studies where is possible to analyse the effects of demand aggregators in different price schemes. Next, in section IV are presented the results when the aggregators harness the batteries to flatten the daily load profile. Finally, in section V are detailed the main challenges for implementing demand aggregators in a real case.

II. Methodology

As said, the first task is to forecast the daily load profile of a large fleet of EVs to identify the possible negative effects that will appear in electricity markets. Subsequently, it's necessary to define the aggregators model to integrate them into power systems, and along with this, the methodology for measuring the flattening effect in load profiles caused by aggregators action.

A. Demand forecasting

The methodology is based in the analysis of the data from the National Household travel Survey 2009 [16], in U.S., and from the mobility survey of 2015 in Bogota, Colombia [17]. With this information is feasible to obtain parking times, traveled distances and distributions of types for the current ICE vehicles. Once characterized the data, then is possible to find the consumption of a EV fleet that follows the same mobility patterns.

In figure 1 is summarized the implemented methodology. In the left are the required data from the surveys. As shown, the main results are the daily load profile and the evolution of the available e-storage capacity per hour.

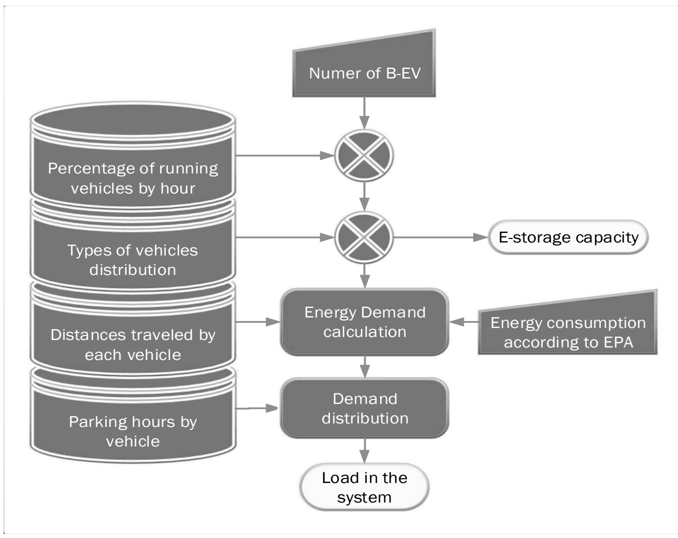


Fig. 1. Methodology for forecast the energy demand of the EVs

The energy consumption is calculated with the data published by the Environmental Protection Agency (EPA) of U.S. [18]. These data is a good reference for the analysis because is obtained in controlled conditions [19] and is at hand for commercial purposes.

For avoiding using all the available EV models, in this paper the fleet was divided into three categories: compacts, SUVs and VANs or PickUps. And for each category was chosen a representative vehicle as shown in the next table

TABLE I
EVs FEATURES

Category	Brand	Model	Year	Consumption per 100 miles	E-storage Capacity
Compacts	Nissan	Leaf	2017	30kWh [18]	30kWh [20]
SUV	Tesla	Model X AWD 90D	2017	37kWh [18]	90kWh [21]
VAN / PickUp	Ford	Transit Connect	2012	54kWh [18]	28kWh [22]

Due to the constant search for efficiency and reliability in the EVs by the manufacturers, is important to use information of the most recent models available to get a better approximation of the energy demand and capacity. Nowadays, there are VAN models with better performance than the chosen model of Azure Dynamics and Ford, however, this is the only VAN with tested consumption so it's the only model comparable in this analysis.

Once the consumption is calculated, is important to consider the losses in the distribution grid. In this case, the efficiency of the chargers is assumed as 94% (equivalent to the Siemens chargers VC30 [23]), and the network losses as 2% which is an acceptable value in the colombian technical standards [24].

The interest in this paper is to find the best scenario of uncoordinated charge. So, to calculate the load is assumed that all the consumed energy is refueled during the same day and is distributed according to the probability of the vehicle being connected to the grid. The probability depends on the time the vehicle is parked, for example if the vehicle is parked eight hours or more the probability of being recharging is 1 and if the parking time is half hour or less the probability is zero. Distributing the demand along the day gives the best scenario of uncoordinated charge, because in any other case the load profile peaks will be higher, even considering permutations between charging days.

The focus in that favorable circumstances is because the negative effects detected will appear in any other possible case. In contrast, the worst scenario will occur when all the EVs are connected at the same time with the maximum power of a DC charger 60 kW [25], but it has no sense to analyze that case because is highly unlikely.

It's important to mention that the method here exposed is appropriate for forecasting the demand when the number of vehicles is high enough to apply the law of large numbers [26]. For small fleets the correct procedure will be modeling the users behaviors by using game theory.

B. Aggregators model

There are a lot of possibilities to mitigate the negative impacts of uncoordinated charging of EVs. For example, the International Energy Agency (IEA) suggest that the expansion of the distribution grid should be adapted to the penetration of EVs into the market, and it also should enable the system operator to manage the demand at more detailed levels each time through price signals [3]. According to this proposal, the infrastructure development for integrate EVs must take place in the following three stages:

1) In the first stage, each vehicle have a dedicated charger and the owners must pay for the grid expansion according to their needs
2) In the second stage, there will be necessary that distribution grid operators (DSO) balance the load to avoid cost overruns in the grid expansion.
3) In the third stage, each parking lot must balance their load with the available vehicles to perform a constant load during the day.

However, the problem is to think that there could be an efficient load balancing by sending price signals to the EV owners. In several studies in countries like Portugal [27], Germany [28], Australia [29], Mozambique [30] and UK [31], have been demonstrated that power demand is inelastic to the energy price, even when the users have hourly price feedback [32]. In other words, it would be needed a high increase in the price to produce a small change in the energy consumption, so it cannot be guaranteed that the demand will effectively maximize its benefit when the charging time decision rests on the EV owners.

On the other hand, EV's batteries as distributed resource in the power system have special characteristics that make them more interesting than conventional generators to supply the demand fluctuations. Characteristics like their fast response, automatic operation, low stand-by cost, and a lower investment per installed power capacity [33]. Indeed, this features can be exploited in such way that leave insubstantial their disadvantages, like their low life time and the opportunity cost of the energy when is used for providing services to the grid instead of mobility affairs.

With these reasons exposed, in this paper is considered that the best way to reduce negative impacts of uncoordinated charging is to involve new retailer agents into the market who aggregate the demand and exploit business opportunities of the batteries. Moreover, these agents will maximize their benefit when achieve the flattest feasible load profile.

The implementation of these new agents will depend on the market conditions. In consequence, is hard to propose a specific business model that works under all the situations. But, here below are exposed some general concerns that must regulate the aggregators' operation.

- Chargers infrastructure is a common pool resource and must be owned by the DSO because it's already a natural monopolist. So, the aggregators should pay to the DSO grid and chargers usage tariffs
- Each aggregator should possess its own telecommunications infrastructure that allows it to collect data through the smart grid and design its offers to the energy market. The State of charge (SoC) of the vehicles must be monitoring at least four times per hour to guarantee the fulfillment of the energy bids [34], that implies the aggregators will need Big Data processors.
- Aggregators must collaborate with the DSO and TSO or ISO to avoid problems of voltage stability and to minimize the losses in the grid. These services could be an important income to the aggregators depending on how they contract their functions.
- The payment of the EV owners to the aggregators shouldn't depend on the energy used in mobility services, but it should depend on the hours the vehicles were unplugged from the grid during the billing period. This to motivate the owners to left their batteries available to provide services to the power system when possible.
- When the aggregators use the batteries, they're reducing the life time of the vehicle assets, so aggregators must settle some compensation scheme to the owners.

In this way, aggregators will remove the barriers users have identified as main impediments for switch to an electric car [5]. To sum up, aggregators could be the solution not only to adapt power systems to large fleets of EVs, but also the solution to the low coverage of chargers and to chaotic reinforcements of distribution grids.

In an ideal scenario, the smart grid and the chargers infrastructure will be ready before the size of the EV fleet start to produce negative effects in power systems, so the aggregators will be able to begin their operation with no delay. However, it isn't convenient that aggregators start to work with small fleets because it'll be difficult to estimate the energy demand and to support the energy bids in the market.

Now, in order to integrate aggregators on the case studies, they will be modeled as prosumers. As shown in figure 2, in each PQ node the aggregators could be a generator or a load depending on the conditions of price and stored energy. Due to the speed of the power inverters, aggregators can change their operation mode between the hourly intervals in which the prices are calculated.

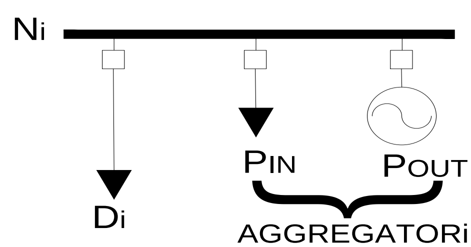


Fig. 2. Representation of aggregators as prosumers in power systems

It's possible that according to the size of the power systems, it exist more than one aggregator in a single node. However, their actions are additive so the previous representation is appropriated for analyzing their effects.

In this paper, the aditional services that aggregators can provide aren't taking into account. So, each aggregator will maximize its revenue only by buying or selling active power, this situation is depicted in the following equations:

$$\max \sum_{t=1}^{24} \lambda_t(\Delta t)(P_{OUTt} - P_{INt}) \tag{1}$$

$$\textit{Subject to: } E_{t+1} = E_t + (\Delta t)P_{INt} - (\Delta t)P_{OUTt} \tag{2}$$

$$\rho * C_t \leq E_t \leq C_t \tag{3}$$

$$E_{24} = E_1 \tag{4}$$

Where λ_t is the price for Megawatt-hour at time t; P_{OUTt} is the power from the EVs to the grid at t; P_{INt} is the power from the grid to the EVs at t; E_t is the stored energy in the vehicles at t, and C_t is the available batteries' capacity at t. So it's clear that $P_{OUTt} > P_{INt}$ means the aggregator works as a generator at t. Besides, it's always into the dispatch because its marginal price is zero.

That said, the stored energy must be upper than a ρ percentage of the available capacity at any time to ensure there will always be energy at hand to use in mobility services. This percentage was established through sensibility analysis in range from 50% to 90% in both study cases, to find the minimum percentage required by the aggregators to flatten considerably the load profile.

This model constraint the energy at the end of the day to be equal to the energy at the beginning. So, the aggregators' operation is repeatable for the average day, and it's possible to estimate the expected cost for longer periods, like months or years, without increase the optimization span.

In both test systems, the problem was solved for one hour periods. But, as seen, each solution depends on the result for the previous hour, so the solving method chosen to find the operation schedule of the aggregators was a simple evolutionary algorithm programmed in Python using Pypower libraries [35].

C. Flattening effect measurement

Here, the Valley-to-Peak ratio will be used to measure the falttening effect on the load profile, the same way as mentioned in the benefit measurements of smart grids proposed by the colombian Mining and Energy planing unit (UPME) [14]. The difference between V/P ratios (VPR) will be expressed as percentage in the flattening factor (FF) as follows:

$$VPR = \frac{\text{Demand in the valley}}{\text{Demand in the peak}} \tag{5}$$

$$FF = \left| \frac{VPR_{\text{with aggregators}} - VPR_{\text{without aggregators}}}{VPR_{\text{without aggreagtors}}} \right| * 100\% \tag{6}$$

III. Case studies

From early studies, like the one made by the Joint Research Centre of the European Commision in 2013 [26] based on mobility data of seven countries [36], and the study of the National Renewable Energy Laboratory (NREL) of U.S. [9], is known that uncoordinated charge implies an increase in the load peak. Mainly, because the hours with more EVs connected to the grid coincide with the period of maximum residential energy demand in most cases. This outcome is strengthened with the results presented here using the methodology exposed in section II, first integrating 410.000 EVs in the IEEE 24-bus Reliability Test System, and later integrating 400.000 EVs in the colombian power system.

The size of the EV fleet was chosen by considering the projections of the energy and mining planning unit (UPME) for the colombian case in 2030 [37], where they forecast that is feasible to have 400.000 in Colombia according to the evolution of the electric sector. Currently, there are countries with larger EV fleets like China and U.S. but due to its power system size, the uncoordinated charge isn't a problem for them yet.

A. IEEE 24-bus Reliability Test System

This test system published in 1979 [38] is suitable for study economic dispatch because it provides complete information about the demand and generators' cost functions. In this paper is used the demand in the system for an average weekday, where the first peak at 11:00 a.m. is close to 2037 MW and the second one at 7:00 p.m. is close to 2020 MW.

The energy demand of the 410.000 EVs, that follow the mobility patterns identified in the NHTS survey [16], produce a peak of 529,3 MW at 7:00 p.m.. Conversely, the minimum power demand is at 6:00 a.m. when 10% of the EVs are on the

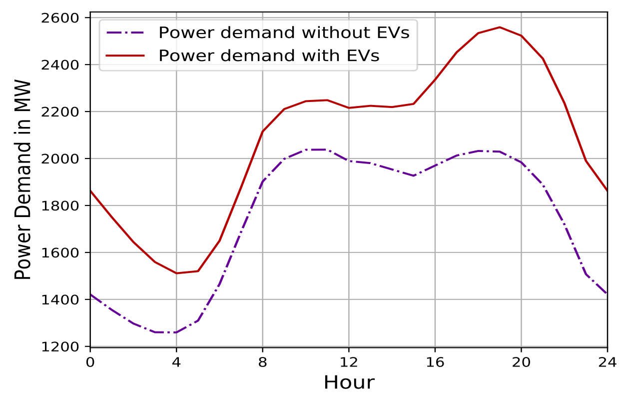


Fig. 3. Power demand on the IEEE RTS system

Other important information from the mobility survey is the vehicle type distribution. The data indicates that compact cars are the most common vehicles, and they duplicate the quantity of the other categories. Here below is presented the obtained distribution:

- Compacts: 52,4%
- SUV: 21,9%
- VAN y Pickup: 25,0%

For incorporate the EV fleet into the power system, it was divided using the same percentages of the original demand in the system, because it's logical that the buses with higher demand will have more vehicles. In so doing, the 410.00 units were placed as shown in table II. Although, it's possible that during the day some vehicles get connected to different buses in the transmission system, but for this estimation that effect was despised due to the size of the fleet.

TABLE II
Vehicle distribution in the IEEE RTS

bus	vehicles	bus	vehicles	bus	vehicles
1	15.580	7	18.040	15	45.510
2	13.940	8	24.600	16	14.350
3	25.830	9	25.010	18	47.970
4	10.660	10	27.880	19	26.240
5	10.250	13	38.130	20	18.450
6	19.680	14	27.880		

Adding the EVs' energy demand to the test system, the impact on costs is higher when using uniform spot price.

This is because the peak grows and all the demand pays the marginal price of the most expensive generator in the dispatch. In contrast, using nodal marginal prices, the total cost of power generation grows less because not all the loads were penalized with the congestion prices. Here below is summarized this situation:

Without EVs

- Cost using uniform spot price: 796.141,28 USD/day
- Cost using nodal marginal prices: 448.288,78 USD/day

With + EVs

- Cost using uniform spot price: \$1'168.254,47 + \$249.191,25 = 1'417.445,72 USD/day (+78%)
- Cost using nodal marginal prices: \$551.446,27 + \$107.063,02 = 658.509,3 USD/day (+46,9%)

As seen, the demand grows only 19,3%, but the total cost of energy rises 78% when using uniform spot price and close to 47% when using nodal marginal prices. Additionally, is important to note that the cost for EV owners when using nodal marginal price is 107.063 USD/day, less than half the cost when using uniform spot price. This indicates that the majority of the demand is near to low cost generators and the congestion in transmission lines don't affect them greatly. However, the distribution of the fleet can change that situation if the vehicles' demand is placed mostly in low interconnected buses, so it's relevant to analyze the locations of the EVs for using nodal prices.

To finish the characterization of the EV fleet, is necessary to analyze the available energy capacity. In this field, the result is pretty positive because when roads are full, at 5:00 p.m., there are still 88,5% of the vehicles parked, indicating that, in the power system will exist a lot of available batteries at every time. Between 12:00 p.m. and 3:00 a.m. the 410.000 EVs represent a distributed battery of more than 17 GWh in the system.

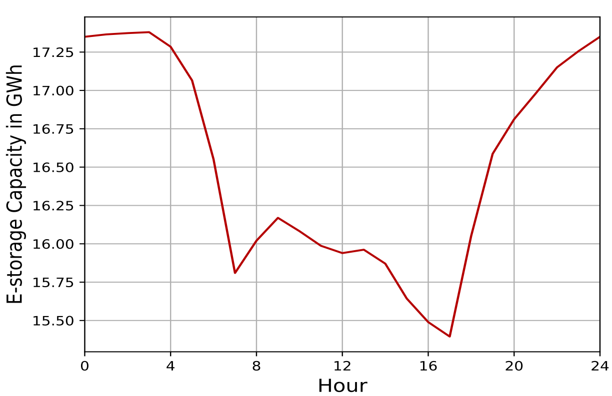


Fig. 4. Evolution of the available e-storage capacity

B. Colombian power system

The independant system operator of the colombian market, XM [39], publish all the information related to the economic dispatch organized by days. Using this data, it was possible to obtain the load profile for an average weekday of 2017, in this profile the peak of demand is 9.555,8 MW at 7:00 p.m.

In the real operation of the system the only price scheme is uniform spot price, so it'll be the only one taking into account in the analysis. Besides, in this case the cost functions of the 53 generators are unknown, so the dispatch order was established using the average value of the offers made by the generators during 2017.

To include the energy demand of a fleet of EVs, in this case, the consumption of 400.000 EVs was projected using mobility data of Bogota. Now, the EVs demand peak is 105,28 MW at 8:00 p.m. and the minimum point is 38,58 MW at 6:00 a.m. The energy consumption of the vehicles in this case is less than the one obtained with mobility data of U.S. for a similar size fleet, because the vehicles in Bogota travel shorter distances, even though they're on the streets more time.

As mentioned before, this is the best scenario of uncoordinated charge. In the worst case, when all the vehicles are recharging at the same time with fast DC chargers, the demand peak will be of 24 GW during 4 minutes and 10 seconds. In fact, none of the two scenarios here indicated are expected, but they establish the limits for the real demand peak.

The mobility data from Bogota is also different from the data of U.S. in the distribution of vehicle types. For example, in this survey the compact cars are more than 70% of the fleet. This means that not only the consumption but also the e-storage capacity is lower. The distribution of vehicles categories obtained in Colombia is the following:

- Compacts: 70,1%
- SUV: 16,6%
- VAN y PickUP: 13,3%

Going back to the colombian power system under original conditions, the total cost of generation for the average weekday is 20.648'261.083 COP/day. But, when adding the energy demand of the EVs, in the best uncoordinated charge case, the total cost grows to 21.191'252.842 COP/day, which means a cost overrun of 2,45% when the demand grows only 0,9%. Of this total cost the EV owners should pay 186'577.269 COP/day for the energy used in mobility services. Nevertheless, in the real operation of this system, the costs could be close to three times the ones here presented because the charges of transmission, distribution and reliability are added to the price per kilowatt-hour.

The costs overruns are caused by the distortion in the load profile when the EV fleet grows. This effect can be seen figure 5 where are two grades of penetration of EVs in the colombian market (400.000 and 13'000.000). Clearly, the difference between the peak and the valley of the profile is magnified by the EVs, which also results in a more pollutant power sector.

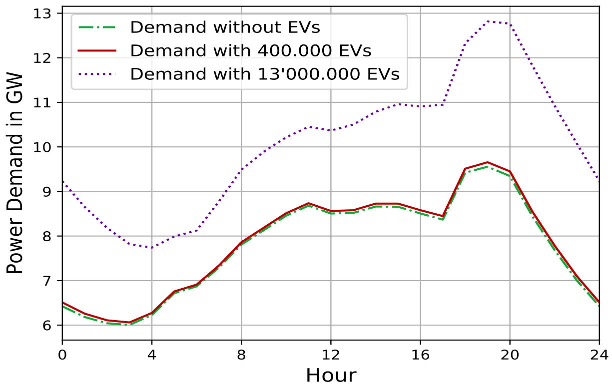


Fig. 5. Comparison between two grades of inclusion of EVs in the colombian case

Apart from the cost overruns, there are another undesirable effects caused by the rise of the demand peak. For example, the installation of generators with low capacity factor is one of the most notorious effects in the long term. Additionally, the expensive expansion of the transmission and distribution grids that will be used only during the short duration of the peak, implies more harms for the consumers.

Finishing the characterization of the EV fleet, here below is presented the evolution of the available e-storage capacity during the day. In this case, the parked batteries gather more than 15 GWh in capacity between 9:00 p.m. and 4:00 a.m. This is a huge amount, considering that the total generation capacity of the colombian power system is close to 16 GW. On the other hand, during the hours when the streets are saturated, at 7:00 a.m. and 7:00 p.m., there are still 83% of the vehicles parked, which means there are a lot of unused batteries at any gi

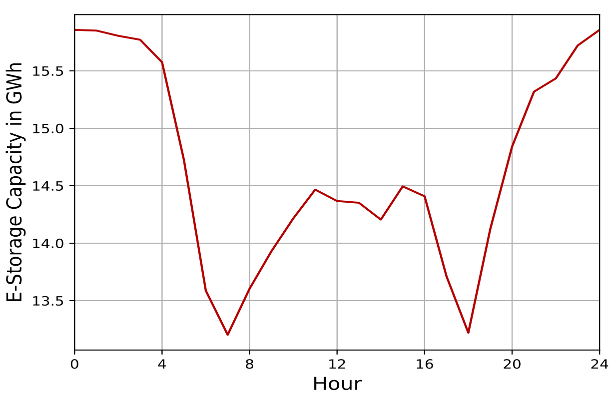


Fig. 6. Evolution of the available e-storage capacity in the colombian case

IV. Results and Analysis

Now, the demand aggregators will be incroporated into the power systems presented in section III, with the aim to analyze its effectiveness.

A. Results in IEEE RTS using uniform spot price

In this system, aggregators can achieve a notorious flattening factor, just by using 20% of the available capacity in the batteries. As shown in figure 7, the peak of the load profile disappears. In consequence, the V/P ratio rise from 0,59 to 0,75 when aggregators take action, which means, they produce a flattening factor of 26.7%

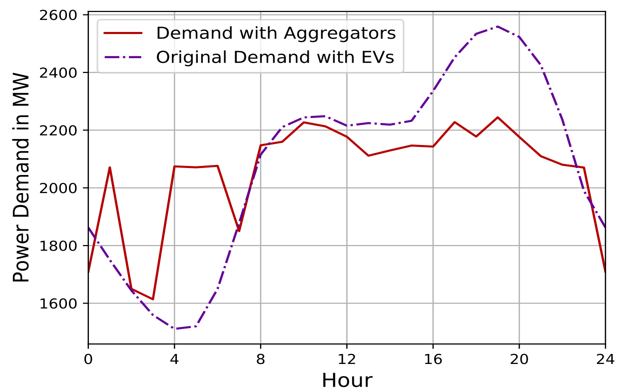


Fig. 7. Resulting power demand with aggregators using spot price

In this case, the total generation cost is 891.754,056 USD/day, just 12% more than the case without EVs in the system. In particular, from this cost, aggregators should pay 130.962,71 USD/day for the energy used in mobility services.

For characterize the aggregators' operation is important to consider the SoC evolution in the EV batteries. In figure 8 is possible to see it, for a vehicle plugged between 10:00 p.m. and 7:00 a.m. its SoC will increase no matter if it's already superior than 80%. On the other side, if a vehicle is plugged in to the grid after 7:00 a.m. it will only recharge if its SoC is lower then 80%, otherwise it'll give energy to the grid.

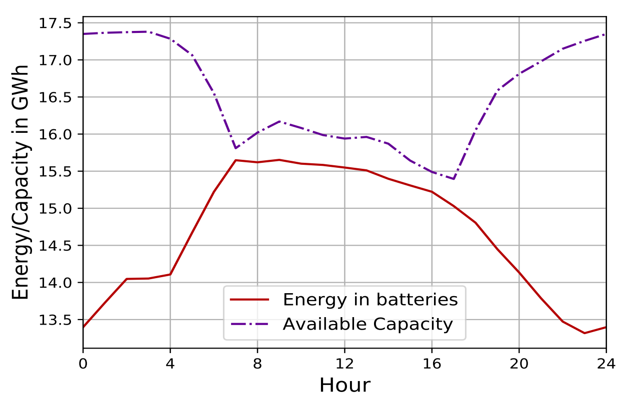


Fig. 8. SoC evolution in the batteries

B. Results in the IEEE RTS using nodal marginal prices

In this case, the solution reached doesn't guarantee to be the global optimum due to the algorithm used. So, the flattening factors are different in each bus even when exist a proportional capacity to storage energy in all of them. Here below, in figure 9 is shown the resulting load profile for the bus 15 which have one of the lowest flattening factor.

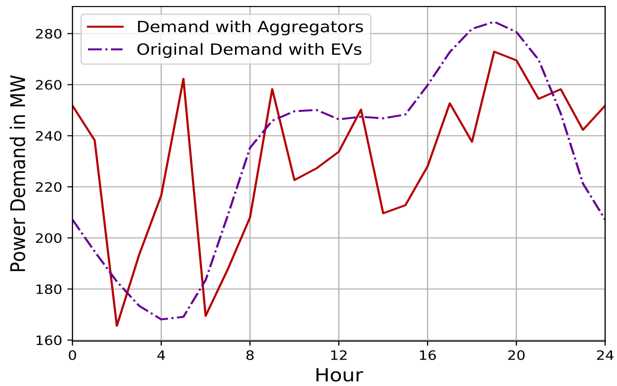


Fig. 9. Resulting power demand for the bus 15 in the IEEE RTS

Considering that the initial V/P ratio in all buses is 0,59, table III indicates that aggregators achieve an almost flat power demand in several buses. Unfortunately, the buses with the biggest loads reached very low flattening factors.

TABLE III
FLATTENING FACTORS FOR THE LOADS IN THE IEEE RTS

bus	FF	bus	FF	bus	FF
1	12,7%	7	33,2%	15	2,7%
2	31,9%	8	12,4%	16	46,5%
3	1,1%	9	12,8%	18	5,9%
4	17,5%	10	13%	19	4,4%
5	64,3%	13	2,7%	20	48,4%
6	13,7%	14	7,4%		

In this case, the total generation cost is just 629.519,11 USD/day, and from this, 102.406,55 USD/day should be payed by aggregators for the energy of the EVs.

Finally, the figure 10 shows the energy evolution in the batteries plugged in to the bus 15. In this context, aggregators recharge the available batteries only after 10:00 p.m. So, the batteries are giving energy to the grid during all sunshine h

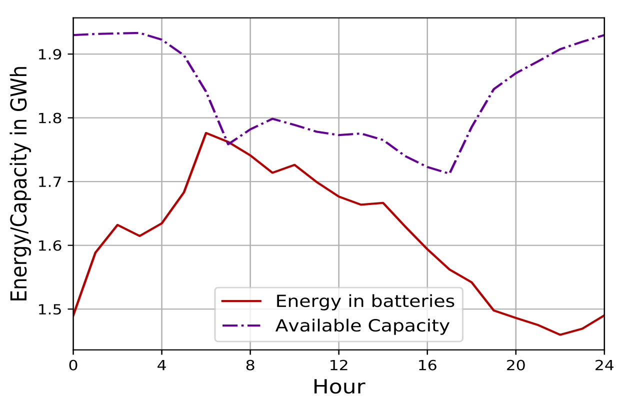


Fig. 10. SoC evolution for the batteries in bus 15

C. Results in the colombian power system

In this case, aggregators require to use the 30% of the available capacity in batteries for flattening the load profile, because the size of the EV fleet is similar to the previous one but the energy demand in this power system is bigger. As can be seen in figure 11, it exists an evident demand shift from the peak hours to the valey hours.

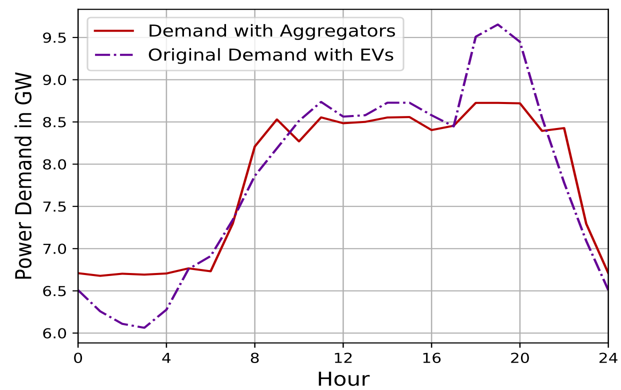


Fig. 11. Resulting power demand in the colombian power system

In the case without aggregators, presented in section III, the V/P ratio is 0,63, instead, when adding the aggregators the V/P ratio rise to 0,76. Consequently, the flattening factor achieved is 21,8%

Turning now to the costs, with aggregators the total generation cost is 20.829'371.582 COP/day, just 0,8% higher than the case without EVs in the system. From this total cost, the aggregators must pay 113'648.173 COP/day for the energy used in mobility services.

Finally, the evolution of the energy in the batteries along the day is presented in figure 12. As shown, if a vehicle is plugged in between 12:00 p.m. and 7:00 a.m. its SoC only can grow, even if it's already higher than 70%. Whereas, if a vehicle is connected between 6:00 p.m. and 10:00 p.m. it only can recharge if its SoC is under 70%. It should be highlighted that when the energy grows at the same time as the available e-storage capacity, it isn't just because the aggregator is buying energy, it could be also because there are vehicles getting plugging in to the grid with remaining energy in their batteries.

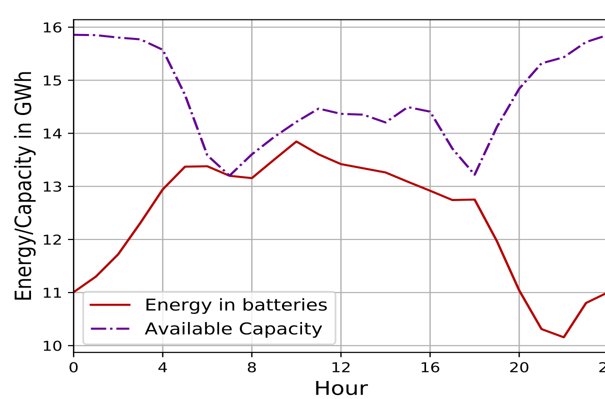


Fig. 12. SoC evolution in the batteries

V. Challenges in the real implementation

Implementing demand aggregators is an effective solution for reducing negative impacts of uncoordinated charge of the EVs. However, there are still several obstacles to enable their operation in a real market. Here below, are exposed the main challenges like: chargers coverage, battery costs and dependency on the users behavior, with the aim to suggest solutions and to analyze aggregators' viability in the near term.

A. Chargers coverage

In the results of section IV, is highlighted that aggregators doesn't require a great percentage of the batteries capacity to flatten the load profile. So, most energy will be available for mobility services. The problem is that chargers coverage must allow the EV owners to plug their vehicles in anyplace at anytime.

When the energy demand of the EVs grows, there will be distribution systems operators interested in increasing chargers coverage. Unfortunately, it'll be necessary more than one charger per vehicle and a large coverage in public and private places. Besides, it'll be indispensable a robust telecommunication network to build a smart grid suitable for demand aggregators. In other words, it'll be necessary a huge investment in the distribution grid.

According to cost studies for electric vehicles, nowadays they're competitive in some market segments against traditional ICE cars [40]. So the subsidies that are aim to increase the penetration of EVs [41] could be bad focused in the near future, when the biggest barrier for the users to buy an EV won't be the initial investment, but the practicality of its usage.

In addition, the chargers infrastructure is a common pool resource and implies decreasing average costs for its owner; so, it should be property of the DSO because it's already a monopolist. In this way, the public policy in near future should not only reformulate EV market growth subsidies, but also motivate grid operators to invest in EV chargers.

B. Battery costs

For making interesting to the EV owners the subscription of their assets to a demand aggregator, they must be compensated by the degradation of their batteries. Nevertheless, before agreeing a compensation value, it's important for the owners to understand that batteries' life time depends on many factors like the time of use and environmental conditions, but aggregators' operation only affect the charging/discharging cycles. In this way, aggregators shouldn't pay for a battery if it last more than the guaranteed life time given by the manufacturer.

At the other side, aggregators will need to forecast the battery costs before agree on when and how much they'll compensate to the owners. In this matter, is suitable to analyze battery price projections for EVs [42], like the ones from Bloomberg [43], McKinsey & Co. [44], MOBI group from Vrije University [45], US Energy Department [46], World Energy Council [47], and US. Energy Information Administration [3].

The battery cost data have a clear logarithmic trend in all cases. Thus, it's possible to estimate that the price will be between 13,5 and 161 USD/kWh by 2035 using curve fitting. Next, in figure 13 are summarized the cost projections

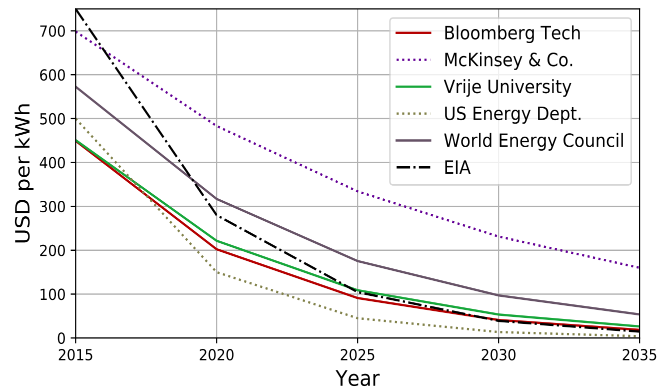


Fig. 13. Battery costs projections

Taking into account that lithium cost constitute close to 50% of the batteries price [48], it's possible that batteries' price drop suddenly if this material is changed for a cheaper one. In fact, this is a possible scenario due to the scarcity of the material [49].

C. Dependency on the EV owners behavior

As stated before, the battery degradation not only depend on the action of the aggregators, but also in the usage of the vehicle. So, to approximate the degradation of the 400.000 batteries incorporated in the colombian power system, it'll be used the five most commons usage patterns from the mobility survey in Bogota 2015 [17].

The operational conditions of the batteries shouldn't change if the battery is managed by the aggregator or by the EV owner. In consequence, it's possible to simplify the problem and assume that batteries' life time depends only of the depth and the number of charging/discharging cycles [50].

From mobility surveys it's known the time and distance of each trip, and with this information is posed an ever-increasing demand. This doesn't correspond with a real driving cycle, but it allows to make an approximation of the evolution of the SoC. Nevertheless, in a more detailed model it would be necessary to match the slopes of the SoC with a real driving cycle because the discharging current is a determinant factor in the battery's durability.

In this anallysis, they are all Li-ion batteries, because it's the most common technology used in EVs [51]. For these, the expected value of complete charging/discharging cycles is 1000, before their capacity is depleted 20% [52]. Using this value and the curves of depth vs number of charging/discharging cycles for the cells is possible to estimate the years that the batteries will last.

Following up, in figure 14, is presented the most common usage pattern of the vehicles in Bogota, and the evolution of the SoC in both cases: with and without aggregators. This vehicle is assumed to be Nissan Leaf 2017 because, in the selected vehicles, it's the one with less battery capacity and for this very reason is the worst case for aggregators. As can be seen in the Wohler curves for Li-ion cells [52], smaller batteries will have more degradation with the same discharging cycles.

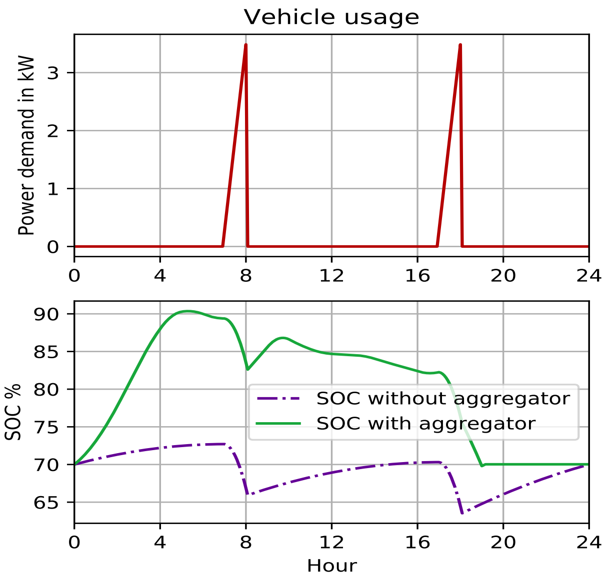
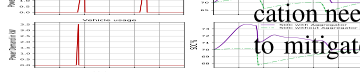
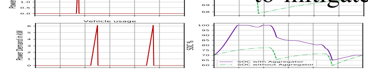
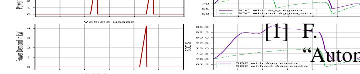
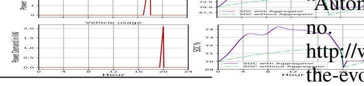


Fig. 14. (a) EV power demand (b) SoC evolution for the most common usage pattern in Bogota

Previous figure presents a possible way in what aggregators could achieve the operation showed in section IV for the colombian case, using 30% of the batteries' capacity. But it isn't the only way they can accomplish that result.

In table IV is the expected life time of the batteries for the five usage patterns, ordered from the most common to the least, with and without the action of aggregators. Due to the aging of the materials it isn't expected that the cells last more than 10 years [51], so the results are limited to this value.

TABLE IV
EXPECTED LIFE TIME OF THE BATTERIES IN YEARS

User	Life time without aggregators	Life time with aggregators	Usage pattern
1	10 years	6.85 years	
2	10 years	10 years	
3	8,22 years	4,122 years	
4	10 years	10 years	
5	10 years	10 years	

As shown, in cases 1 and 3 , the degradation caused by the aggregator reduce the life time almost to the half. Meanwhile, in the other cases the battery can last more than 10 years. Hence, aggregators should pay different percentages to each user and an average of 15% of the total batteries.

As mentioned before, the battery costs for EVs have a decreasing tendency, so it's convenient for the aggregators to agree the payment of the batteries at the end of their life time. For the colombian case, is estimated that if aggregators start their operation in 2030 they should pay between 4 and 374 millions of USD in batteries before 2040.

Finally, is important to mention that here aren't measured all the benefits produced by aggregators to power systems, and those services can produce more profits than just buy and sell energy. At the end, aggregators will depend on how the policy allow them to contract their services to surpass all the challenges. For example, the biggest saving produced by reduce load peaks is in the avoiding costs of generation and transmission expansion, so transfer part of that saving to aggregators will make them highly profitable.

VI. Conclusions

Results obtained in section III show that uncoordinated charge of EVs cause an increase in the load profile peak, so it increase the total cost of generation in the short term. Also, in the long term this effect causes costs overruns because it will be needed more power plants and more transmission lines for supplying only the demand peak.

Predicting these negative impacts allows to formulate solutions and to be ready before they appear. With this in mind, implementing demand aggregators have demonstrated to be an adequate solution to flatten the daily load profile and also to have more EV on the roads. Actually, it's a more effective method than other demand response programs because it take away the decision of when to recharge the EVs from their owners.

Aggregators will need to manage a percentage of the batteries capacity to flatten the daily load profile depending on the fleet size, vehicle types, and the power system size. In the case studies presented in section IV, the new agents doesn't need more than 30% of the batteries capacity in a fleet of 400.000 EVs which is a good result because most of the energy can be used in mobility affairs.

However, nowadays aggregators can't come up as a market solution due to high costs of batteries that make unfeasible their use for providing services to power systems. Additionally, considering problems of chargers coverage and telecommunication needs, aggregators will need a huge amount of resources to mitigate the negative effects of transport electrification.

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