The Impact of Electric Vehicles Deployment on Production Cost in a Caribbean Island Country

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Abstract — **Rapid deployment of large shares of Variable Renewable Energy (VRE) is driving a shift in economics and operational practices of power systems around the world, creating the need for a more flexible and decentralized system. In this context, electric vehicles (EVs) are expected to play a significant role, as they can contribute to decarbonize the transportation sector while facilitating the integration of VRE. It is important to carefully plan for EV integration to make sure that they indeed facilitate the integration of VRE and maximize the benefits provided to the power system. This paper assesses the different impacts on production costs that electric vehicles could have depending on different charging profiles and considering the value added from allowing the EVs to provide energy and ancillary services to the grid. This paper shows how this can limit the total increase in production cost from charging EVs, raise the level of VRE integration into the system reducing curtailment, affect marginal cost of electricity and ultimately reduce the investment needed for grid connected storage using as a case study the Caribbean island of Barbados.**

Keywords- Variable Renewable Energy, Electric Vehicles, vehicle-to-grid, Small isolated power systems, Production cost modelling

I. INTRODUCTION

The operation of electric power systems is being transformed by the increasing penetration of Renewable Energy Sources (RES-E), which have become highly attractive due to their increased competitiveness and environmental benefits. Among these technologies, wind, solar PV and to a lesser extent run-of-the-river hydro (from now on referred as Variable Renewable Energy (VRE)) are characterized by intermittency and limited predictability in generation ahead of dispatch time. These characteristics are creating new challenges in electric power systems. Some of these implications are described in [1]. Here the authors divide the different VRE impacts based on the timescale studied. In the very short-term VRE can call for a higher reserve requirement, as also described in [2] by studying the impacts of high shares of wind generation in electric power systems. From short to medium term the impact becomes relevant for unit commitment, production costs and market prices. In this timescale, it is important to underline that although VRE reduce the overall supply costs, they might increase generation cost from thermal units by increasing cycling needs and reducing fuel efficiency [3]. Finally, in the long-term VRE might require new investments in flexibility options that can help to handle the increased variability in the residual load (load minus VRE generation), after unlocking the flexibility already existing in the power systems through regulatory measures and improved market design, as discussed in [4].

Over the last two decades, many countries and international institutions joined their efforts to fight climate change, with efforts being facilitated by the rapid increase in competitiveness of renewable energy. This global momentum culminated with the adoption of the Paris Agreement on December 2015 and its rapid ratification throughout 2016, where it was agreed to take the appropriate measures to limit the temperature increase of the planet in less than 2ºC, with efforts to limit it to less than 1.5ºC [5]. To reach this ambitious goal, renewable energy has been identified as the key solution. Renewable energy deployment has accelerated significantly in power sector due to the rapid cost reduction in solar and wind [6]. However, if the 2ºC goal has to be reached, decarbonisation must be achieved also in other sectors [7]. Among end use sectors, there is now an increasing interest in the transportation sector, which is characterized for being one of the most hydrocarbon dependent – and the most oil dependent - sectors in the global economy [8]. Many solutions have been proposed to decrease the emissions and turn this sector into a less oil dependent one. Among these solutions, electric vehicles (EVs) charged with electricity from renewable energy sources have become prominent thanks to technology advancement and cost reductions in renewable energy and electricity storage. The progress in EV development and deployment has made of vital importance to assess the impact that these vehicles could have on the grid if not carefully managed and how to turn this challenge into an opportunity to facilitate the integration of VRE. In recent year, this led to the proliferation of studies, starting by considering EVs as additional demand which is added to the power system demand based on when the EVs are expected to be recharged. For instance, the impact of Plug-in Hybrid Electric Vehicles (PHEV) on system demand using national household travel surveys to build the profiles is analysed in [9]. In [10] the authors go one step further considering whether EVs can foster renewable energy integration when connected to the grid using an island as a case study and creating different demand profiles depending on the service provided by EVs (energy arbitrage, spinning reserve…).

The exceptional opportunity provided by EVs for VRE integration is related to the fact that, when connected to the charger, they could act as grid connected storage units, potentially able to provide a broad range of services to the system if allowed to do so and appropriately compensated. This is what is generally referred to as Vehicle-to-Grid (V2G). Here EVs would not only absorb energy from the grid for charging but also discharge energy to the grid and provide ancillary services. For instance, in [11] a complete assessment of how V2G can help renewable energy integration and decarbonisation of road transport is presented, in [12] a model that analyse the impact of V2G on ancillary services market is described. Finally, some studies assess different types of modelling approaches, like in [13], where authors first assess the effects that EVs have on the grid if they are only able to charge and compare it with V2G.

The present paper analyses the impact of EVs in a small isolated power system with an expected high share of VRE. EVs will be first considered just as a static demand, according to three possible charging strategies, in order to identify the one with the lowest additional production cost for the power system. This is described in the Barbados energy roadmap developed by IRENA for the Government of Barbados [14]. This paper takes the roadmap as a base of comparison for assessing the potential benefits of introducing V2G. The approach is similar to the one presented in [15], where using PLEXOS the authors make a complete EVs assessment. However, the present paper adds a V2G analysis using additional modelling practices, such as the consideration of different charging strategies constraining the times at which EVs can be charged or the provision of ancillary services accounting for the limited energy of the resource. Section II describes the main elements of the Barbados roadmap, which is the base for the case study. Section III explains the methodology followed in this paper. Section IV present the application of the methodology to Barbados and Section V draws the conclusions.

II. CASE STUDY: BARBADOS

A. Barbados power system

Barbados, shown in Figure 1. , is a small island nation located in the Caribbean Sea. With a land area around 430 km^2, the population of this Small Island Developing State (SIDS) country is estimated at 284.800 inhabitants in 2016 [16].

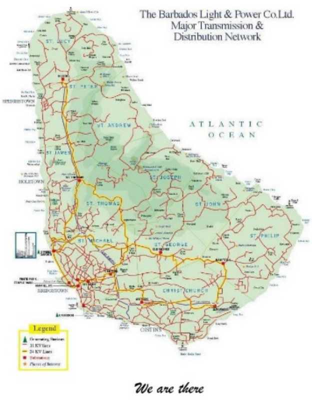


Figure 1. Barbados transmission and distribution network

According to [17], Barbados' peak electricity demand is 167.5MW and it is covered with 240MW of total installed generation. Most of this capacity is allocated across three thermal power plants (Spring Garden, Seawell and Garrison) which are owned by Barbados Light and Power Company (BLPC), the local power utility now part of the Emera Group. These three power plants are composed of steam turbines, internal combustion engines and gas turbines. As for the RES-E capacity, Barbados has currently one 10 MW utility-scale solar PV system (commissioned at the end of 2016 in St. Lucy) and ca. 20MW of distributed solar PV. Although wind power has been under discussion for a long time, no wind power generation is installed as of mid-2017. In the upcoming years, it is expected rapid increase in solar and wind deployment, as proposed in the Barbados energy roadmap developed by IRENA [14]. In the Wind and Solar Integration Study [18] developed by General Electric for the BLPC, a series of predetermined RES-E penetration scenarios is analysed in order to figure out how much VRE is the current system able to integrate, up to a maximum of 15.7% of annual electricity demand being supplied by solar and wind. The Barbados Energy roadmap goes well beyond this study in terms of scale of the renewable energy deployment considered, identifying a set of least-cost capacity expansion scenarios up to 2030, where in the Reference scenario solar and wind supply 64% of demand (and biomass an additional 12%, for a total RE share of 76%). The Reference scenario of the roadmap will serve as a base for the 2030 scenario that we present in this study, while the EV scenarios of the roadmap will serve as comparison with the V2G scenarios presented here. Generation, demand and power system data was obtained from [19]. Barbados is an ideal case study since it is one of the few small isolated power systems where EVs as well as solar PV are already being rapidly deployed, and where large shares of VRE and EVs are expected in the near future, therefore the analysis has immediate policy relevance, while constituting a technically-challenging case worth studying.

B. Electric vehicles estimation

Barbados, given its small land area, presents a great opportunity for the deployment of electric vehicles. The number of EVs in the island is expected to steadily grow until 2030. The number of EVs estimated to be on the road by 2030 is based on several assumptions, to address limitations in the available data from national statistics.

First, the number of cars per capita is assumed to remain the same in 2030 as it is today (0.27 cars per person). Assuming a slight population growth of 1.82% by 2030 [20] the total number of vehicles (electric and not) expected in 2030 was obtained.

Assuming that 50% of new car sales in 2030 are EVs, a logistic substitution model was used to calculate the growth from current share of new sales to the target share for 2030 [21]. Adding up the amount of new EVs expected to be sold each year, and assuming a constant share of vehicles being scrapped every year, 26,600 EVs are expected to be on the road by 2030.

As for the EVs characteristics, they are presented in TABLE I. .This data is based on a review of the EVs available on the market in 2016, and therefore conservative.

TABLE I. EVs BATTERY CHARACTERISTICS

Battery Capacity (kWh)	Range (km)	Efficiency (kWh/km)	Internal charger capacity (kW)
24	135	0.18	3.6

Finally, with the actual number of gasoline vehicles in Barbados and the gasoline consumption of the fleet, an average driving distance of around 40km per day per vehicle was estimated.

Taking all this into account, different scenarios were developed based on the charging profile and on the possibility to feed energy from the EV battery to the grid.

III. METHODOLOGY

A. *Barbados energy roadmap model*

The analysis of the different scenarios presented in the Barbados energy roadmap, which are used in the present paper, were performed with the PLEXOS[1] model.

First, a long-term capacity expansion analysis was performed by using different demand forecast scenarios. This analysis was used to determine how much additional generation of what type to add when and where to meet future electricity demand. This long-term analysis also reflects the cost of building additional resources (which varies by unit type and size), the estimated production cost of energy (which could vary by fuel price assumptions) and other associated long-term costs.

Second, the operational impact of each future scenario was analysed through detailed chronological modelling of the Barbados system, including modelling the unit commitment and economic dispatch (UCED) of the future resource mix. It is here where the impact of EVs on the electricity grid is analysed. The different modelling approaches that were adopted are explained below.

[1]The analyses were performed using the PLEXOS Integrated energy model software tool, copyrighted by Drayton Analytics Pty Ltd, Australia and Energy Exemplar Pty Ltd, Australia, pursuant to a Research End User License Agreement provided by Energy Exemplar. The model was calibrated against an earlier study performed by General Electric for Barbados Power & Light Company, which used the same software for the production cost modelling.

B. *Electric vehicles as a pre-calculated demand profile*

The first approach taken is to consider the energy required to charge EVs only as an increase in the total electricity demand of the power system, occurring at pre-determined times every day. In this case, EVs can only absorb energy from the grid for charging (chargers are unidirectional). Three scenarios were considered: (a) uncontrolled evening charging, which means that as soon as EVs owners arrive at home the car will start to charge at the nominal (max) power of the charger, (b) controlled night charging which basically means that smart chargers are deployed and the charging process is distributed during the night to avoid rough ramping (e.g. slower concurrent charging or scheduled charging managed by the utility to minimize contemporaneity factor), (c) sun hours charging, aligned with PV generation profile, which implies that the chargers are also deployed in public places to allow keeping the EVs connected to the charger during working hours and lunch break. This last scenario assumes that the charging profile has the same shape as clear sky solar PV output.

To model each of these scenarios, three different demand profiles were created. As explained before, it was considered that EVs in Barbados are driven for a daily average of 40 km which implies a total daily charge of 7.2 kWh per EV. We assume that all the EVs are used every day. In. Figure 2. , Figure 3. and **Fehler! Verweisquelle konnte nicht gefunden werden.** the three different demand profiles used are illustrated:

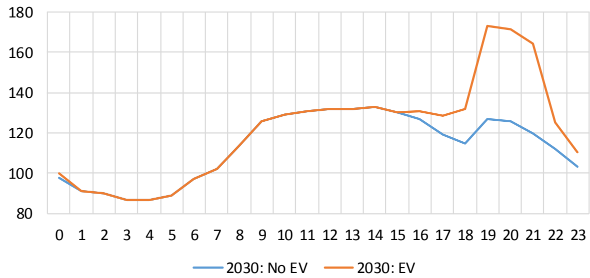


Figure 2. Demand profile for an uncontrolled charging during evening

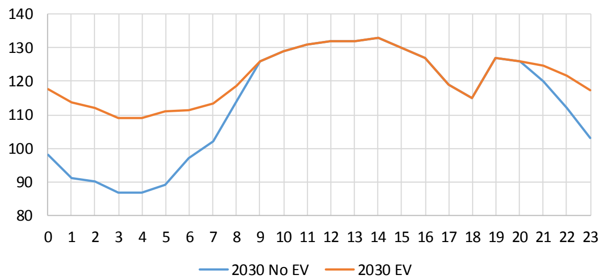


Figure 3. Demand profile for a controlled charging of EVs during night

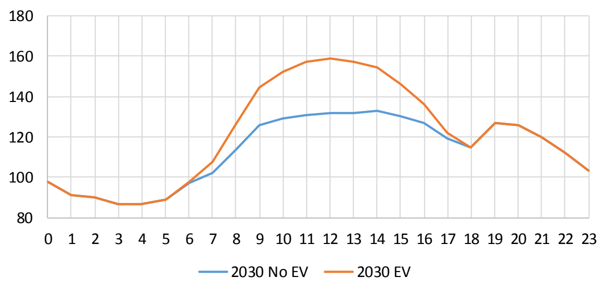


Figure 4. Demand profile for a controlled charging of EVs during the day

The results obtained from the simulations of these scenarios will serve as a base of comparison with the results from the V2G analysis. It is important to notice the potential impact on generation adequacy and production cost of profile a), and that in 2030 is possible that chargers will have a higher nominal capacity, making any challenge potentially arising from uncontrolled charging significantly worse.

C. *Electric Vehicles providing V2G services*

The additional analysis developed for this paper is the assessment of the impacts that electric vehicles could have if allowed to supply energy to the grid and provide ancillary services. For the purpose of the paper we will refer to it as Vehicle-to-Grid (V2G) [22].

1) Modelling approach

Modelling V2G is more complex than the previous approach and thus it requires a more detailed explanation. First of all, the tool used for the Barbados energy Roadmap, PLEXOS, does not offer a special EV module and that makes the analysis more challenging. After testing different feasible approaches, it was finally decided to model the fleet of electric vehicles as a single market participant that operates a grid connected battery energy storage system (BESS) and can provide different services. When EVs are connected to the grid, the battery is free to charge or discharge at every moment taking into consideration that at the moment of disconnection the battery must have at least a state of charge (SoC) of 70%, to ensure that it can be used for providing the main service of the EV, which is mobility. Once the EV is disconnected from the charger, the battery is discharged because of mobility usage. For an accurate representation, it is important that the discharge of the battery while the EV is disconnected from the charger should not affect the unit commitment or the marginal price of the system. To represent this, the discharge was modeled as a negative natural inflow that equals the energy consumed for mobility reasons (40km *0.018 kWh/km/EV/day). The maximum power of the battery was set to 0 during mobility hours, to make sure that the batteries from the EVs do not contribute to the provision of ancillary services when not connected to the grid.

2) Battery degradation

The main difference between a battery and other types of energy storage systems, such as pumped hydro storage (PHS), is that the batteries suffer a degradation that depends, among other factors, on how they are operated and the specific chemistry used. This parameter usually depends on the discharge current, the depth of discharge and temperature of operation, among other variables. Representing all these effects in a production cost model is very challenging and although some authors have addressed this issue [23], battery degradation will not be considered in the analysis carried out in this paper. However, this is a question that will be addressed in future research.

3) Services considered

According to [24], energy storage can play an important role in the provision of different grid services such as energy arbitrage, frequency and voltage regulation, black start, network investment deferral. Although [24] is focused on dedicated energy storage, some of the services described can also be provided by what authors refers as non-dedicated energy storage. This paper will therefore consider V2G providing two services. First, energy arbitrage will be analysed. By energy arbitrage is meant the absorption of energy generated by VRE when their production is high and therefore market price is low, to feed it into the grid when VRE generation is lower and prices are higher. Then, the combination of energy arbitrage and reserves provision will be analysed. Reserves will be considered as capacity (MW) and not as energy (MWh), but the model has been set up to take into account that EVs have limited energy in the provision of this service.

For both scenarios, a set of results will be presented.

IV. APPLICATION OF METHODOLOGY TO BARBADOS

The previously explained methodology was applied to Barbados to analyse the impact of electric vehicles in a small isolated power system with a high share of VRE. Following the different steps explained in the previous section, two different charging scenarios were analysed.

A. *Scenarios*

1) Reference

The reference scenario represents the least-cost capacity expansion option that results from the long-term simulations made in the Barbados energy roadmap for 2030.

Here the most relevant assumptions were the following:

- Demand reduction of 0.6% year on year from 2015 to 2030 due to energy efficiency improvements
- Fuel prices indexed on the New Policies Scenario from the IEA WEO 2015 [25]
- VRE deployment following the optimal solution of the capacity expansion model
- Battery Energy Storage System with a size 150MW/150MWh
- 30MW of demand response
- No EVs

The reference scenario will be used as a base case to compare with the EV deployment scenarios. In reality, a mix of the described scenarios is likely to take place, however for comparison and illustration we are considering them separately.

2) Night and evening charging

In these scenarios, it is assumed that all chargers are private-owned by households and EV owners connect their vehicles to the grid as soon as they arrive home and disconnect them early in the morning when they go to work. This implies that the number of chargers deployed must equal the number of EVs; however, this charging strategy ensures that every battery will be connected to the grid with the suitable charger. TABLE II. shows the involved investment cost in these charging scenarios, using [26] as a reference and reflecting the cost reductions which are likely to take place by 2030.

TABLE II. EV CHARGING INFRASTRUCTURE DEPLOYMENT COSTS: PRIVATE CHARGING

Nº of chargers deployed	Price per charger (USD)	Total Investment Costs (million USD)
26 600	1000	26.6

3) Day charging

Here the main assumption is that chargers are deployed only in public places and thus EVs are charged exclusively during the day coinciding with solar PV generation, as partly examined in the ongoing project SolarMiles [27]. This reduce the number of chargers needed but at the same time increases the complexity and cost of a single charging station. In these scenarios, it is assumed that only a 28% of the total EV fleet will be connected to the grid at the same time. Thus, both energy and power should be limited to a 28% of the total available in the V2G scenario to be able to compare with the EV static one.

The final number of charging stations in 2030 is therefore estimated at 7433. Using also [26] and assuming a reduction of investment costs due to economies of scale, TABLE III. presents the total capital cost that this scenario would imply:

TABLE III. EV CHARGING INFRASTRUCTURE DEPLOYMENT COSTS: PUBLIC CHARGING

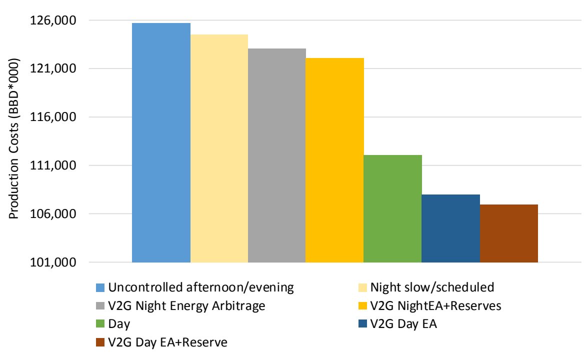
Nº of chargers deployed	Price per charger (USD)	Total Investment Costs (million USD)
7 433	1500	14.2

In both charging scenarios, depending on the type of charging strategy (uncontrolled, controlled unidirectional or controlled bidirectional) different results were obtained.

B. Results

1) Productions costs

The first expected outcome when coupling EVs with the grid is an extra cost added to the whole system because of the demand increase due to the charging process. In Figure 5. the impact on productions costs from different scenarios is shown. The figure is presented with the vertical axis starting at the reference scenario production costs of 101 Million BBD [2] /year. This way the reader can directly compare only the increase in production costs related to providing the same amount of energy to the same number of EVs in different scenarios, effectively comparing charging strategies.



[2] 1 USD = 2 BBD

Figure 5. Productions costs for different scenarios

It is immediately evident that the difference in cost among different charging strategies is significant, with a fivefold increase between the cheapest and the most expensive. The most expensive scenario is the uncontrolled charging one. This scenario assumes that all the EV fleet starts to charge at maximum power in the evening. This may create a flexibility problem, since the system will have to cope with a very high ramp which is typically produced not only by an increase of EV demand but also by a decrease of PV generation in the evening, as demonstrated by PG&E and BMW in North California [28], although this is not the case in Barbados due to a very flexible generation mix. The key challenge in this scenario would be on generation adequacy, potentially exasperated if faster chargers are deployed. This first scenario is then followed by the controlled charging scenarios, which are even cheaper if the charging process occurs during the day when EV demand coincides with PV generation. Finally, the most profitable scenarios would be those in which V2G services are provided and charging takes place during the day, being even more advantageous if EVs are allowed to provide ancillary services.

2) Impact on solar and wind curtailment

As mentioned in the introduction of this paper the deployment of EVs makes sense as long as these are charged with energy provided by VRE, otherwise all the additional demand coming from EV might be coming from additional fossil fuel based generation. One way to analyse if this is really happening is by measuring total VRE curtailment, which refers to the use of less wind or solar power than is potentially available at a certain time due to operational constraints [29]. Figure 6. shows VRE curtailment in different scenarios.

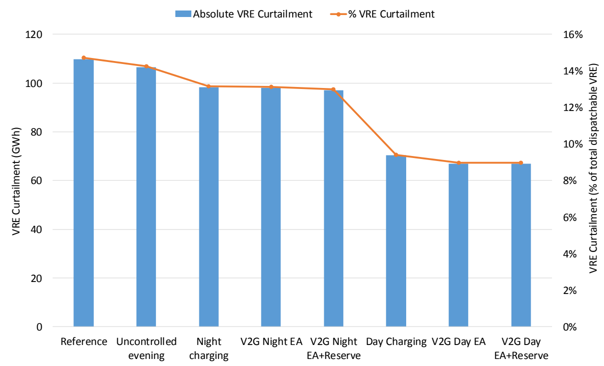


Figure 6. VRE Curtailment for different scenarios

In every scenario, VRE curtailment is lower than in the reference case, which means EVs are at least partially charged with VRE and are helping to integrate these sources into the system Among these scenarios, those in which V2G is considered, EVs can also act as dedicated energy storage by shifting VRE from overproduction periods to periods where expensive thermal units would be generating, reducing VRE curtailment, decreasing CO2 emissions and reducing the marginal price, as we will explain in the following section. It is also relevant here to highlight that the provision of ancillary services by EVs combined with energy arbitrage will have virtually no effect on VRE curtailment with respect the ‘energy arbitrage only’ scenario.

3) Marginal Cost of Electricity

The marginal cost of electricity production (short-run marginal cost in this case) is typically defined as the variable cost of the marginal generator, this is, the one that would respond to a demand change at a given time [30]. This cost is usually relevant in competitive markets, which is not the case of Barbados yet, but could also be interesting to analyse. In Barbados, the increase in total system demand added by EVs when charging, the energy arbitrage service provided by V2G and a set of other different factors, will cause changes in system marginal cost with respect the reference scenario. Figure 7. shows the yearly average marginal cost of electricity for every scenario.

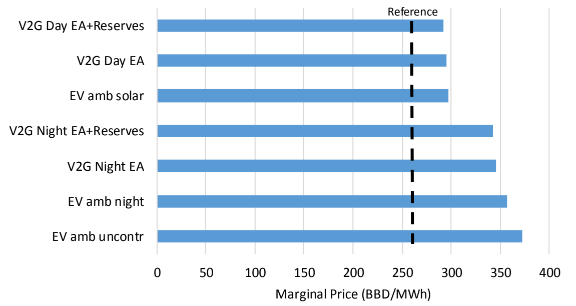


Figure 7. Yearly average marginal cost of electricity for different scenarios

The lowest price is the one from "day charging" scenarios since they use the solar PV production to charge the EVs and integrate a higher amount of renewable energy with zero marginal cost. This is followed by the "night charging" scenarios and the uncontrolled charging one. Among these, the average marginal cost of electricity obtained using V2G is lower than if EVs are modeled as a static profile, being even lower when electric vehicles are allowed to provide reserves. While the increase in average marginal cost might be seen as negative for the customer, it is important to note that in a market context this might make the difference between a viable generation project and an operational thermal generator, and a non-viable project or a decommissioned generator.

Apart from the yearly average price it is interesting to analyse the price spread by showing the average hourly price curves. Here, for simplicity reasons and because some scenarios yield very similar results only day charging, night charging, uncontrolled charging and reference will be presented as scenarios. Figure 8. shows average hourly marginal prices for each scenario described.

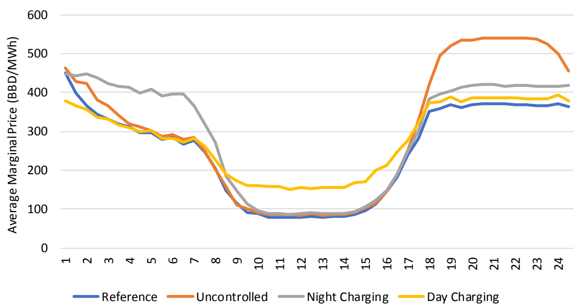


Figure 8. Average hourly marginal cost of electricity for a reduced set of scenarios

First of all, due to the high solar PV penetration, prices are lower in the middle of the day and higher at night in the reference scenario. The uncontrolled charging scenario as well as the night charging scenario increase the price spread and make the consumption of electricity during the day even more attractive (higher price during night). In case of day charging, the conclusions are completely different. Here the curve is flattened decreasing price spread and EV charging is more optimized from a system level perspective and from a market level perspective (it charges when prices are cheaper).

Finally, it is interesting to go deeper into the day charging scenario since some differences can be observed between EV static and V2G scenarios. This is shown in Figure 9.

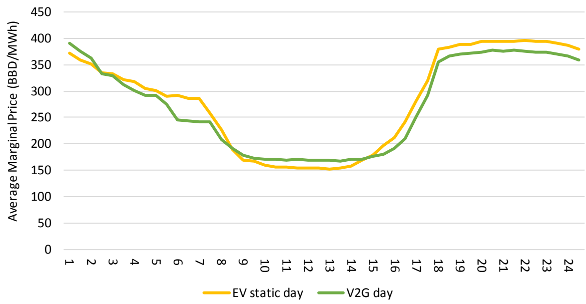


Figure 9. Average hourly marginal cost of electricity for day charging scenarios

In the V2G scenarios prices during sun hours are slightly higher but lower from 5am to 7am, while when modelling EV as a static profile prices are lower but only from 8am to 3pm. This difference can be explained because V2G allows for energy arbitrage, shifting some solar energy from the central hours to the first morning hours, when the sun is not completely shining yet and to the evening hours, when there is almost no sun. To demonstrate that this is actually happening Figure 10. shows how EVs are dispatched to perform energy arbitrage.

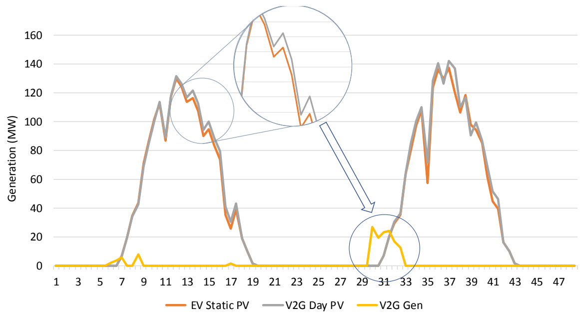


Figure 10. Representation of electric vehicles providing energy arbitrage while charging during the day

This figure shows that EVs with V2G capabilities can absorb a higher amount of PV generation that could be used at a latter point during the day (in this case first morning hours the next day)

In the night charging scenarios, V2G also does some energy arbitrage, however the effect on marginal price is negligible and it is not worth going into detail on this scenario.

4) Reduction on grid-connected storage investments

One possible indicator to assess the benefits of V2G is the amount of grid connected storage that could be avoided with respect the static EV scenarios, maintaining the same reliability level on the system. The methodology followed in this section is similar to the one followed in the calculation of the Effective Load Carrying Capability (ELCC) used in [31] to assess the capacity value of VRE. In this case the amount of non-supplied energy (NSE) will be used as a reliability index instead of the Loss of Load Expectation (LOLE). There are two main reasons that justify this index selection: (1) the LOLE obtained in the simulations is extremely small and PLEXOS identify it as 0 in many scenarios, thus making it impossible to carry out this type of analysis (2) PLEXOS does not take into account the amount of energy available in the storage when computing the LOLE, it only accounts for capacity installed in MW, which tends to overestimate reliability. On the other hand, the NSE is large enough to carry out the analysis and it considers both power and energy from storage.

The only scenario that reduces non-supplied energy and therefore could avoid storage investments is the day charging one. Evening and night scenarios increase non-supplied energy and therefore do not avoid grid-connected storage. In particular, the uncontrolled evening charging scenario quadruples non-served energy with respect to the Reference scenario because of the generation adequacy problem triggered by the increased evening peak demand. In this case, instead of avoiding grid-connected storage it would be necessary to increase the investment on generation capacity. Thus, only the day charging scenario was considered in this section. First the reference, day charging and V2G day charging scenarios were simulated to analyse the amount of NSE in 2030, which is shown in TABLE IV.

TABLE IV. NON-SUPPLIED ENERGY VALUES FOR THE DIFFERENT SCENARIOS CONSIDERED

Reference	EV day	V2G Day EA	V2G Day EA +R
0.2059	0.139	0.125	0.125

As expected, the reference scenario has the highest amount of non-supplied energy, followed by the EVs only charging and V2G. This already indicates that V2G can be more effective in reducing non-supplied energy. The reader may notice that the NSE in the V2G EA scenario and the V2G EA+R scenario are the same. This, however, does not mean that the avoided grid-connected storage is the same, as will be shown next. Once NSE from each scenario has been identified the next step is start removing grid-connected energy storage to increase NSE until it equals the reference scenario. In the Barbados energy roadmap a 150MW/150MWh battery is installed in 2030. In terms of power it is dimensioned this way to provide for instance black start services and potentially act as grid master through a grid forming battery inverter system. Since EVs are not expected to provide black start services it will be assumed that the power of the battery will not vary. Thus, only energy will be removed to increase the NSE of the system. In Figure 11. the grid-connected storage needed to maintain the same NSE amount from the reference scenario is shown.

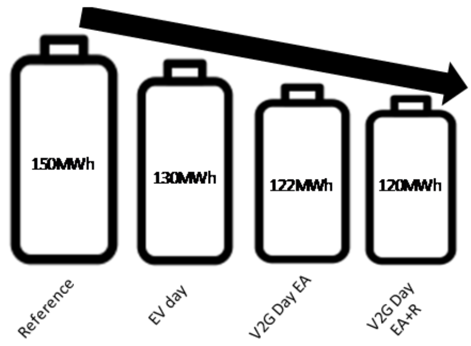


Figure 11. Grid-connected storage needed in different day charging scenarios

If EVs are modeled as a static profile 20 MWh of grid connected storage could be avoided, while if V2G services are considered this number increases to 28 MWh if only energy arbitrage is considered and 30 MWh if also the provision of reserves is considered. V2G services will then avoid the installation of a higher amount of grid connected energy storage, reducing total CAPEX of the system.

V. CONCLUSIONS

This paper presents a complete assessment of how the increasing deployment of electric vehicles in a small isolated island (Barbados) can affect the productions costs of its electric power system. To do so two alternative EV integration strategies are compared: (1) EVs considered as a pre-calculated demand profile which is added to the total power system demand, (2) EVs with smart charging providing V2G services.

With the first approach, it is shown that EVs can reduce VRE curtailment, increase average yearly marginal cost of electricity production and finally decrease the needs of grid-connected storage up to a 13% if EVs are charging during the day. The deployment of EVs is therefore beneficial for the island of Barbados even if they are only able to charge. However, it has been also demonstrated in this paper that the introduction of EVs providing different services can bring greater benefits. V2G increase in production costs less, since it allows for EVs to charge and discharge energy from the grid when marginal cost is lowest and highest respectively. V2G further decreases VRE curtailment facilitating the integration of these technologies, flattening and lowering the marginal prices and reducing the investment needs in grid-connected storage up to a 20% (50% more than with EV static) in case the charging takes place during the day.

This paper, however, have some limitations, of which the authors are aware and that set the scene for a follow up research agenda. As already introduced batteries are characterized by its degradation during operation, which should be something to take into account in future research. This paper is also not considering the impact on transmission or distribution grid or the CAPEX of grid integration measures that can be necessary in some scenario, due to unavailability of data in this specific case study, focusing only on generation cost. Further analysis could include this if a case study with adequate data available is identified.

Finally, the methodology devised in this paper could be applicable to other countries or regions, making the case for the application of this methodology to other jurisdictions that are currently considering how to best integrate the EVs that are expected to be deployed in the coming years.

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