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SYSTEM CONTRIBUTIONS OF RESIDENTIAL BATTERY SYSTEMS: NEW PERSPECTIVES ON PV SELF-CONSUMPTION

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Abstract

The market dynamics of the PV sector and coupled Li-ion batteries are likely to enhance the economics of residential PV self-consumption in the near future. When PV self-consumption systems become economically competitive, end-users will be willing to switch to PV self-consumption instead of using power from the grid. However, the large penetration of PV systems in the electricity mix provokes systemic effects (e.g. additional costs related to the integration of PV into the existing electricity system). The majority of the systemic costs concern the back-up power system associated with variable PV integration. These costs vary from one country to another because of the different energy profiles. France has higher back-up power costs compared with other regions (e.g. California) since France's annual electricity consumption peaks occur in the winter evenings. This means that the massive and rapid integration of PV without systemic strategies can affect the energy system and stakeholders. In this context, this study proposes an innovative grid service model based on the secondary application of residential batteries installed for PV self-consumption. Our optimization model to minimize the cost of residential PV self-consumption deployment at the system level is based on the strategic utilization of residential batteries when they are not in use in the winter months. Our study identifies potential opportunities for the strategic utilization of residential battery systems in France to reduce systemic costs in line with the large diffusion of PV self-consumption in the future. Our study also identifies optimal grid service conditions and evaluates the extent to which this model can reduce PV integration efforts (e.g. balancing and seasonal back-up capacities). We performed an economic analysis to calculate the savings made in terms of PV integration costs and the benefits resulting from the secondary use of batteries. Our study then concludes with several key messages and policy recommendations to prepare the proper institutional and political strategies.

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I. INTRODUCTION

The electricity system is in the process of transforming from traditional models to a decarbonized system spurred on by a rapid increase in renewable energy technologies and associated solutions. The large-scale diffusion of distributed storage accelerates the decentralization of electricity systems and allows customers to participate in the market more proactively. The market dynamics of the PV sector coupled with lithium-ion (Li-ion) batteries will enhance the economics of residential PV self-consumption. PV self-consumption systems will become economically competitive in the near future without subsidies. End-users will be willing to switch to PV self-consumption instead of using power from the grid when there is an economic incentive.

However, the large penetration of PV systems in the electricity mix provokes systemic effects (e.g. additional costs related to the integration of PV into the existing electricity system). The majority of systemic costs concern the back-up power system associated with variable PV integration. However, these costs vary from one country to another because of the different energy profiles. France has higher back-up power costs compared with other regions like California as France's annual electricity consumption peaks occur in the winter evenings. This means that the massive and rapid integration of PV without systemic strategies can affect the energy system and stakeholders.

In this context, this study proposes an innovative grid service model using residential battery systems to address the systemic effects that can arise due to the large integration of PV power. In this article, we have defined the market demand of residential PV self-consumption systems with batteries without political support: French data was used for modelling purposes. This study considers that the combination of 3 kWp PV systems (commonly installed in the residential sector) with 4 kWh Li-ion batteries provides an optimal solution up to 80% PV self-consumption for an average household in France. The use of residential batteries for grid services produces a range of systemic and economic benefits. This article identifies opportunities for the strategic usage of residential battery systems. Our model suggests the strategic utilization of residential batteries when they are not in use in the winter months. This article demonstrates how this innovative mode of battery usage reduces the systemic effects of PV integration. For example, we evaluated the extent to which this model can address the systemic effects with regard to balancing and seasonal back-up capacities. We then give our economic analysis of the grid service model. Our study concludes with several key messages and policy recommendations to prepare the proper institutional and political strategies.

II. LITERATURE REVIEW

The purpose of this article is to amplify the synergy of PV-battery systems for PV self-consumption in order to reduce the systemic effects provoked by the large penetration of PV power. Our literature review focuses on the coupling of PV systems with battery energy storage for decentralized systems.

The fundamental limitations of integrating solar PV into a traditional electric power grid lie in the mismatching of the PV supply and electricity demand. The integration of non-dispatchable variable energies like solar and wind into an electric power system is a complex task because of uncertainty and intermittency factors. However, conventional baseload generators are limited when it comes to responding to rapid load changes. A systemic approach including system integration efforts is necessary to assess the economic value of these variable energy sources in the power systems (Keppler & Cometto, 2012; Hirth, 2014; Haas, et al., 2013; Pudjianto, et al., 2013) PV technologies can be easily combined with other technology solutions as solar power can be produced without geographical restrictions. The combined effects of independent technologies can sometimes create synergies to overcome systemic challenges and lead to a disruptive force in the energy system transformation. For example, energy storage has a key role in decarbonizing the energy system since it results in the better integration of a high share of renewable energies into the electricity system by helping improve grid stability and flexibility.

Numerous articles in the literature analyse the economics of PV-storage-systems influencing the decision to invest in batteries. Abdin and Noussan (2018) evaluate the installation of power storage systems in Italian residential buildings combined with existing PV systems from both an energy and an economic angle. The article concludes that the current investment in energy storage is not attractive for residential users compared with net metering. Hassan *et al.* (2017) develop an optimization model of the PV-battery system under a FIT incentive to maximize revenue streams in the UK. These authors point out that it is preferable to charge batteries when the PV power production is at its maximum and to move to grid charging when PV generation drops and the wholesale electricity tariff is low. This study indicates that the battery unit cost of £138/kWh is the breakeven point for battery adoption. However, it seems that battery adoption without political support (e.g. FIT incentives or subsidies) still has a way to go. The decline in battery prices will increase the adoption of PV systems coupled with batteries with good payback periods. The authors mentioned that the effect of large-scale connection to a local distribution network would be discussed in a future article.

In another study, Pena-Bello *et al.* (2017) describe an optimization method for different types of applications based on PV with grid charging, tariffs and battery capacities. The article concludes that the investment of households in batteries to couple with existing PV systems is not yet economically viable in Switzerland regardless of the tariff structure and battery price. The study also indicates that a small battery capacity for PV self-consumption is only preferable under a single flat tariff and that investment in a storage capacity for the sole purpose of demand-load shifting is not attractive for households in Switzerland. With a dynamic tariff, batteries should perform both PV self-consumption and demand-load shifting simultaneously to increase the economic attractiveness. The economics of residential batteries can be enhanced by including additional functions such as system-wide demand peak shaving or frequency control together with PV self-consumption and demand load shifting.

Davis *et al.* (2016) focus on the economics of residential batteries alone. This study evaluates the uptake of batteries in UK households related to time-based electricity tariffs. It suggests adding batteries to the UK residential sector to displace the daytime peaks of the domestic electricity demand; batteries are charged with the excessive electricity in times of low demand when electricity is cheap, and then the electricity is drawn from the batteries instead of the national grid when electricity is expensive (peak demand time). However, in terms of deciding whether to invest in batteries or not, it would not be economically feasible for UK homeowners to install batteries at the current prices. Therefore, government subsidies are needed until the price drops based on economies of scale. However, the economic side of this article barely includes the systemic effects of residential batteries on the overall power system. Moreover, Denholm *et al*. (2013) explain that power storage provides a number of systemic benefits as it flattens the consumption variation. However, despite these systemic benefits, the authors conclude that the revenue generated by the use of storage is less than the net benefit offered by the system under the current electricity market model because of the decrease in the price differential of on/off-peak period. There are therefore a number of issues to overcome in order to correctly integrate the storage system into the current power system.

Some studies are based on a longer-term perspective. Sadiqa *et al.* (2018) analyse the potential role of storage technologies in Pakistan by 2050. Storage technologies will play an important role in increasing the share of renewable energies (in particular solar) in the system, i.e. batteries on a daily basis, gas storage for a long-term solution. The article concludes that hybrid PV with batteries would be the least expensive option to supply power until 2050.

Yu (2018) attempts to conduct a system-wide economic analysis of residential PV system consumption coupled with batteries. The author develops a prospective economic analysis model of residential batteries coupled with a PV system in France in 2030. The economic calculation is based on prospective prices for both technologies without political financial incentives to anticipate the market demand. The study quantifies the systemic effects (integration costs) of residential PV systems with distributed batteries on the French electric power system. It demonstrates the functionality of batteries for residential PV self-consumption from both an economic and systemic perspective. The article concludes that residential PV self-consumption combined with Li-ion batteries could be profitable without any subsidies for an individual investor before 2030 in France. In addition, this combination will generate fewer systemic effects on the national power systems compared with centralized PV deployment with full grid injection. However, the article indicates that the coupling system still needs a back-up solution to address the annual peak during the winter evenings.

The systemic advantage of batteries for grid management is widely discussed in with respect to coupling models for PV and electric vehicles (EV) (Richardson, 2013). Many articles focus on the economic and environmental aspects of PV-EV coupling models. For example, Coffman *et al.* (2017) discuss the interactions between EV and PV adoption from a total-cost-of-ownership (TCO) and an environmental perspective; they indicate the great potential to reduce CO_2 emissions in the transportation sector if households were to switch to EVs in conjunction with recharging from home PV systems. Li *et al.* (2017) show a positive correlation between the increase in renewable energies and the EV demand (a one percent increase in renewables would lead to an approximate 2–6% increase in EV demands). This implies a possible market synergy between solar and batteries. However, numerous studies focus on another core functionality of the coupling model, which concerns the systemic benefits to facilitate the integration of variable energies into the power system (Mohamed, et al., 2014; Tan, et al., 2016; Hu, et al., 2016; Bhatti, et al., 2016; Richardson, 2013; Habib, et al., 2015). EVs can significantly reduce the amount of excess renewable energy produced in an electric system (Richardson, 2013) and a storage bank can help smooth the intermittent variable solar and wind power productions. Habib *et al.* (2015) analyse the advantages of EVs with vehicle-to-grid (V2G) application in the power system. V2G can provide a solution for variable renewable energies with ancillary services in a power system (including spinning reserve, voltage control and frequency control). Nunes *et al*. (2016) analyse the relevance of using vast car park for installing solar carports for EVs. EVs can play a vital role in providing grid services and solar car park can be aggregators of EVs in the power system. However, the integration of EVs based on random charging will largely influence the power system with significant challenges such as load balancing, overload, or power quality degradation. A controlled charging algorithm that minimizes the voltage variations can mitigate the voltage quality problems caused by EV charging (Dubey & Santoso, 2015). However, challenges do exist regarding the degradation of batteries from the charging/discharging cycles for grid services (Bishop, et al., 2013) and smart communication systems between EV and the grid (Bhatti, et al., 2016). Poullikkas (2015) asserts that smart charging with dynamic communication systems between EVs and the grid is needed for an effective V2G model. If the right systems are properly implemented, the excess EV battery capacity can be used to export power back to the grid and to supply power during peak hours (López, et al., 2013). It is necessary to include key aspects such as pricing design, non-pricing incentive, and regulations for EV modelling if we wish to determine the impact on charging behaviours (Bhatti, et al., 2016). EVs can be automatically charged as soon as they are connected to the charging station or the charging mode can be programed based on certain criteria such as the energy price or availability of renewable, or both approaches can be used concurrently (Xydas, et al., 2016). However, studies on the impact of EV charging on the distribution network mostly concern the daily balancing solution rather than the long-term seasonal perspective. Anuj Banshwar *et al*. (2017) describe the prospects of the energy and ancillary service markets with the participation of renewable energies. The authors clarify the main ancillary services in the electricity market as frequency control services, voltage control services and emergency services (Banshwar, et al., 2017; Cappers, et al., 2013). The article recommends changing the market designs and rules of the current market to integrate significant variable energies with ancillary services.

As we have seen, existing studies that examine the possible utilization of residential batteries are mostly based on short-term timelines even though some articles indicate the concept of systemic values without detailed optimization modelling. In addition, it is essential to take into account the annual back-up capacities required to meet the seasonal load peak demand in order to maintain the security of the power system. However, there is no literature that models the use of batteries directly from residential PV systems with the objective of addressing the back-up issue in France. Therefore, this subject merits further investigation in order to evaluate the systemic values and potential application of PV self-consumption combined with residential batteries. In this context, the purpose of our study is to recommend a new grid service model by introducing a secondary application of residential batteries installed for PV self-consumption. The model can provide systemic benefits in line with the large diffusion of residential PV self-consumption and thus help reduce the annual back-up costs.

III. RESEARCH CONTEXT

3.1. French power systems

Nuclear power has long played an important role in the national electricity sector in France. In 2012, France decided to reduce the share of nuclear energy in the national power production to 50% by 2025 from the current 75% as part of its energy transition strategy. However, the French government has recently pushed this target from 2030 to 2035 because it is proving unrealistic and not possible without increasing France's CO_2 emissions (De Clercq & Rose, 2017). In this context, RTE proposed four different scenarios to achieve the 50% reduction target by 2035 (RTE, 2017). The simulations rely on a stable or decreasing electricity consumption. These scenarios lead to strong growth in renewable energies to build a future French electricity system, the massive deployment of electric vehicles and a rapid increase in the self-consumption of electricity. For example, RTE's Ampère scenario plans for a reduction to 50% of nuclear power by 2030, based on the closure of 18 of the 58 reactors currently in operation and with a significant increase in renewable energies. In this scenario, the PV electricity supply will be increased from the current 2% (8.7 TWh) to around 12 % (58 TWh) in 2035. All scenarios expect a significant increase in residential PV self-consumption.

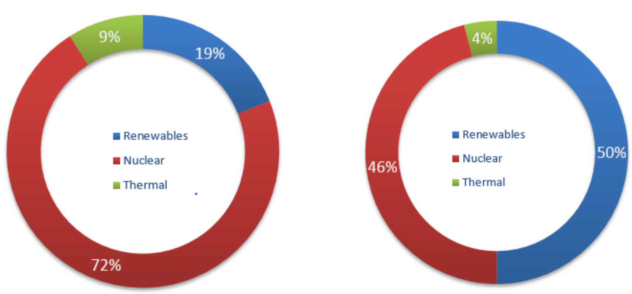


Figure 1: French power supply mix (2016, 2035) (RTE, 2016)

The residential sector accounts for one third of the current national power consumption in France. The transition towards PV self-consumption will accelerate the decentralization of the French power system. However, France has its annual peak demand in the winter evenings due to the high power consumption of electric heating. Electric power systems need to satisfy demand at all times and variable energy sources like solar power require a back-up capacity to provide system security. However, solar energy has an almost zero capacity credit in France when the peak demand occurs in the winter evenings (Keppler & Cometto, 2012). This implies that a significant modification of the residential consumption profile could lead to an important change in the national load profile. Therefore, the transition towards more variable solar energy sources in the electric power system will require an effective development of flexibility (e.g. storage, demand response, control of recharging of electric cars (RTE, 2017)) to guarantee system security.

Taking into account the growing demand for residential PV self-consumption, it is important to find a way to meet the seasonal demand peaks in the winter months with regard to a large-scale PV penetration in the French electric power system. Our research therefore sets out to address these systemic challenges.

3.2. Residential PV self-consumption and systemic effects

The combination of a rapid reduction in PV power costs, the decreasing feed-in-tariff and the increasing retail electricity prices for household customers leads to a transition toward PV self-consumption (Merei, et al., 2016; IEA-RETD, 2014). In this context, grid parity occurs when the PV power generation costs intersect with the price of retail electricity tariffs, thus indicating a milestone for PV development. Grid parity for the residential sector has already been reached in many countries. However, this approach is economically misleading as grid parity refers to the electricity tariffs, which also include grid management costs and taxes (Yu, 2018). In addition, this calculation of grid parity assumes the full consumption of PV electricity. In this context, residential PV self-consumption is still invalid without subsidies and additional PV integration efforts. Nevertheless, end-users would be willing to switch to PV self-consumption instead of using power from the grid when there is an economic gain for them. In this case, the transition towards PV self-consumption can provoke a radical change in the national power system when the transition occurs massively and suddenly. For this reason, it is important to predict the dynamics of future electric power systems led by subsidy-free PV development.

As indicated, the author previously developed a residential PV self-consumption model with batteries in France in her article to conduct a prospective economic analysis of residential PV systems with batteries in France in 2030. The aim was to predict the subsidy-free market demand for residential PV self-consumption based on the market dynamics of the PV sector coupled with Li-ion batteries. The article indicates that French residential PV systems combined with Li-ion batteries could become profitable without subsidies for individual investors before 2030 under the IEA scenarios in question with a self-consumption rate around 80% led by the use of batteries (Yu, 2018).

However, the increased share of intermittent and non-dispatchable PV power in the national power mix should be accompanied by additional efforts to secure the balance of the system. The article demonstrated a risk of observing sub-optimization with the massive and uncontrolled deployment of PV self-consumption. The systemic effects vary according to different integration options. The article concluded that the scenario of progressive PV integration based on our PV self-consumption with no grid injection by using residential batteries offers the least expensive integration option (Yu, 2018). In addition, the residential PV self-consumption model with batteries makes it possible to obtain a higher level of PV penetration before overproduction[2] occurs, i.e. when the PV power supply exceeds the load.

The study also indicates that regardless of the PV deployment decision, there is no gain regarding the seasonal back-up costs. Non-dispatchable PV power contributes very little to power generation system adequacy in Europe and the long-term back-up costs concern the investment, operation and maintenance costs to meet the demand at all times. Furthermore, the back-up costs

[2] According to Ueckerdt *et al*. (2013), this phenomenon represents the highest fraction of PV integration costs.

account for a large fraction of the grid-level integration costs (Pudjianto, et al., 2013; Keppler & Cometto, 2012).

In this regard, this study adopts the author's previously developed PV self-consumption model coupled with batteries to find a way to reduce PV integration costs by contributing to the long-term back-up capacities. Residual load duration curves have been plotted to assess the systemic benefits of our battery model with grid services to the French national power mix.

3.3. Research objectives

The purpose of this research is to determine a way of reducing the integration efforts of large-scale PV penetration through residential PV self-consumption systems with batteries. The study proposes a strategic utilization of residential batteries to provide new grid services (PV-battery-grid service model). This study thus attempts to evaluate the systemic value of the secondary-use application of residential batteries coupled with PV systems in France.

As explained, we need an annual back-up power capacity to address the variability characteristics of solar power as the seasonal electric demand peak in French occurs in the winter evenings. Therefore, the study considers the winter period (December to February). During this period, the residential battery capacity coupled with PV systems for self-consumption is not essential because the PV production of small residential systems (3kWp) rarely exceeds the consumption in winter in France. This article proposes a grid service model to help improve the flexibility of the residential PV system coupled with Li-ion batteries in the electric power system.

In our study, we have developed a numeric simulation model based on empirical French data (e.g. RTE) to evaluate the functionality of secondary-use application of residential batteries, as well as to define the optimal conditions for designing an optimal grid model. This article thus attempts to address the following questions.

- What are the conditions for optimal battery use of grid service (speed, time)?
- What are the potential systemic benefits (daily balancing and annual back-up) from the secondary-use application of residential batteries of PV self-consumption in France?
- What economic benefits will result from using this grid service model?

At the end of this article, we discuss the policy implications and give a few policy recommendations based on the results of this study.

IV. METHODOLOGIES AND DATA

4.1. Utilization of batteries from residential PV self-consumption systems

The functionality of batteries is important to understand before discussing our battery grid service model of PV self-consumption. The utilization of batteries for residential PV systems makes it possible to store the surplus PV electricity during the daytime and release the stored excess power when needed. Coupling with batteries provides a higher ratio of PV self-consumption in the residential sector.

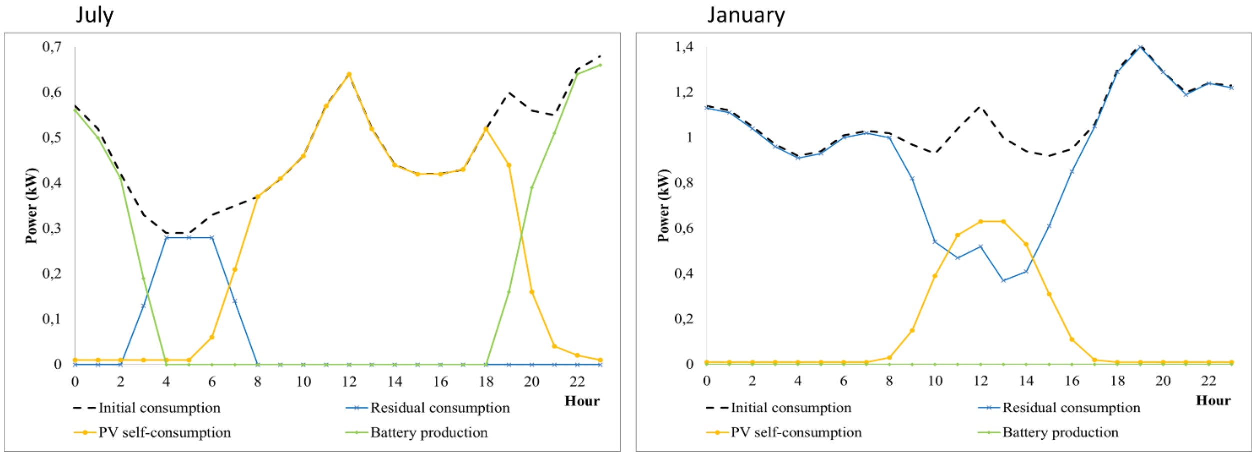


Figure 2: Mechanisms of PV self-consumption based on a residential PV system (3kWp) with Li-ion batteries (4kWh capacity) (author's calculation based on the average energy profiles)

Figure 2 explains the mechanisms behind the use of batteries coupled with a PV system in the residential sector. When PV systems produce more than the necessary residential consumption, the surplus is stored within the range of the defined battery size. The stored electricity is released when consumption exceeds the PV production. We consider that there is no grid injection to avoid additional systemic effects (grid overload, electricity overproduction, etc.). PV self-consumption happens during the day and the battery-stored electricity is used in the evening and at night. However, battery usage is impacted by seasonal differences: batteries are almost never used in January while households use stored electricity between 6 pm and 3 am in July.

According to our analysis for all seasons, the average usage rate of the 4 kWh residential batteries coupled with a 3 kWp PV system is 58% throughout the year (100% = 1 full cycle per day). As Figure 3 illustrates, the use of batteries becomes almost null during the winter months because the PV production decreases despite the increase in the residential power consumption.

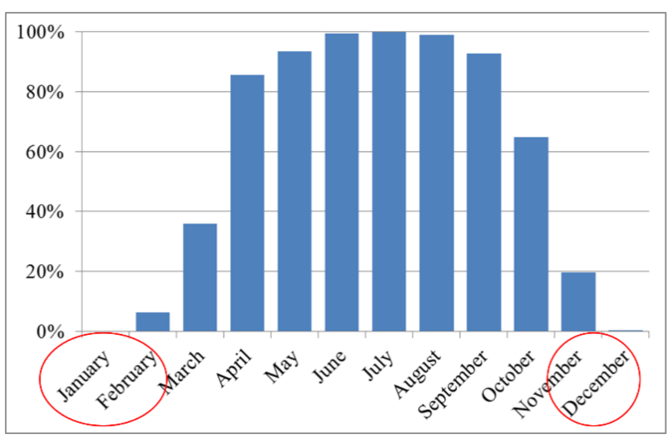


Figure 3: Battery use by month

Power system in France is faced with the fundamental issue of how to smooth the power demand and to address the back-up issue of PV integration in France. This article aims at finding a solution to these issues by using the installed battery systems for PV self-consumption. The idea is to optimize the use of residential batteries throughout the year to create a secondary-use application for batteries.

As the use of residential batteries to manage PV production in the winter is almost null, our battery model proposes a new grid service model by using the installed capacities of residential batteries only during the winter months when the demand peaks occur in the French power systems. The purpose of the model is to flatten the national load profile over the day in the winter months based on the secondary-use application of residential batteries. Households consume power from the grid to charge batteries during off-peak electricity demand hours. During peak hours, the stored electricity can be released for residential self-consumption without grid injection. By doing so, residential batteries make it possible to shave peak demand in the day.

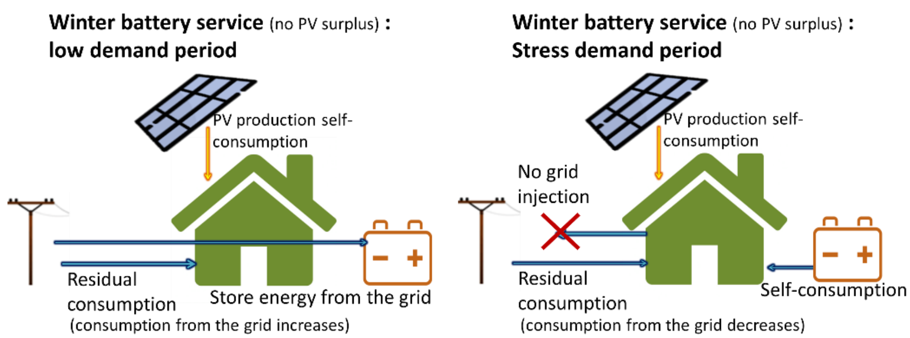


Figure 4: Grid services from residential batteries

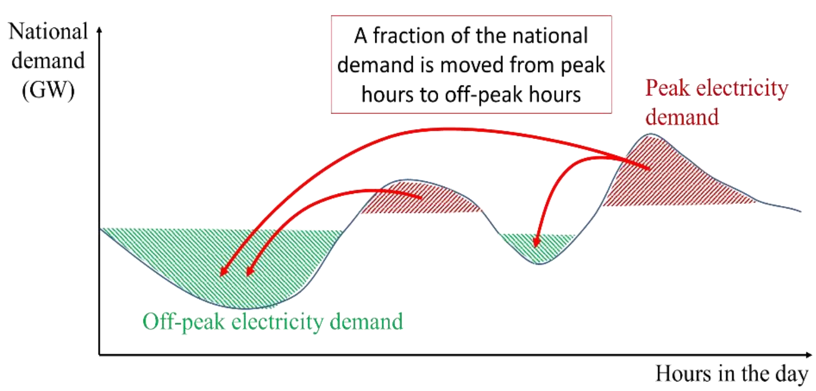


Figure 5: Potential energy shifting through the use of residential batteries

The ultimate objective of the study is to achieve optimal use of residential batteries in a way that changes the residential power consumption profile to balance the remaining consumption variations (non-residential: industrial, commercial, etc.). When the remaining consumption is high, the residential consumption should be reduced, and when the remaining consumption is low, the residential consumption can be increased (Figure 6). This approach can help reduce PV integration costs because it reduces the national electricity demand peak without additional installation. In addition, this can enhance the economics of battery investment.

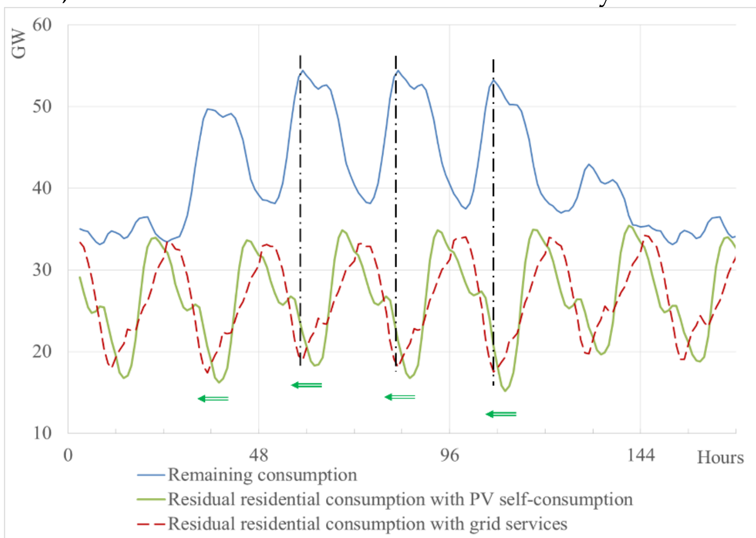


Figure 6: Targeted changes in the residential residual consumption to minimize peaks

The methodological approach to develop the PV-battery-grid service model and data provided are explained in detail in the following sections (4.2-4.4).

4.2. Schematic model of PV batteries with grid service

We developed an optimization model of the PV-battery-grid service (PV-B-GS) to increase the systemic value of residential PV self-consumption in France. This involved developing a numeric simulation tool that defines the mechanism behind the optimal use of residential batteries for peak shaving. The following schematic (conceptual) diagram explains the logical flow of our model.

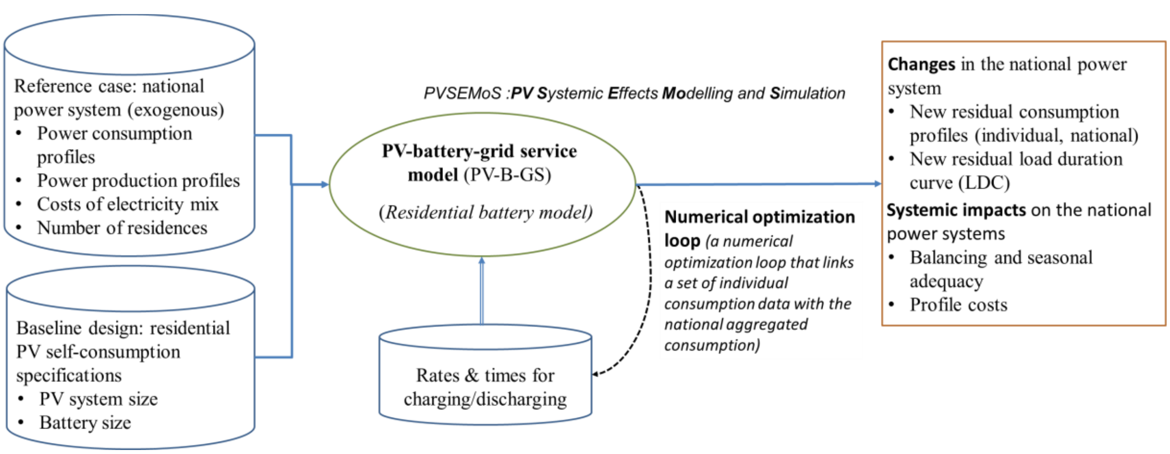


Figure 7: Logic flow diagram of the PV-B-GS (PV-battery-grid service) model

This PV-B-GS model has been developed based on PV self-consumption systems coupled with Li-ion batteries in the French residential sector. We first defined the input data of the PV-battery system specifications to design the French residential PV self-consumption model. The French

transmission system operator (RTE, Réseau de transport d'électricité) provides an open platform for its energy system database (RTE, 2018). Our simulation thus uses exogenous data based on the national hour-by-hour power consumption by segment and the national PV hour-by-hour production from RTE. The model uses the hour-to-hour dataset for the entire year of 2015.
The optimization model considers the residential battery charging/discharging rates and times as variable parameters in order to determine the optimal conditions. The model aims at minimizing the national demand peaks, and the optimal parameters are defined via a numerical optimization loop that links a set of individual consumption data with the national aggregated consumption.

The scope of analysis includes the systemic effects resulting from the secondary-use application of residential batteries in the winter months. The systemic effects are measured with the numerical tool known as PVSEMoS (PV Systemic Effects Modelling and Simulation). PVSEMoS is a numerical simulation code that allows us to evaluate the systemic effects of integrating PV into the defined electric power systems on a national scale. By using this code, it is possible to estimate the systemic effects of the grid services provided to the French power system. This approach enables us to measure the aggregate systemic benefits of the secondary-use application of residential batteries in the national power system as it considers a high level of PV penetration with residential PV self-consumption systems.
Our analysis is based on three scenarios:

- Reference case: 2015 situation of PV integration (PV Ref.);
- Scenario 1: PV self-consumption with batteries (no grid injection) (PV-B model);
- Scenario 2: PV self-consumption with batteries + new grid services (no grid injection) (PV-B-GS model).

4.3. Data and assumptions

4.3.1. Baseline design of PV self-consumption with batteries

This article aims at developing a new grid service model using residential batteries to increase the flexibility of PV self-consumption. We first defined the residential PV-battery self-consumption model as a baseline. This study is based on the residential PV self-consumption model developed in the author's previous article. This study considers that the combination of 3 kWp PV systems (commonly installed in the residential sector) with 4 kWh Li-ion batteries provides an optimal solution up to 80% PV self-consumption for an average household. Our simulation takes the French situation in 2015 as a reference case with a cumulative installed PV capacity of 6.5 GW (around 2% of the domestic power consumption). We assumed that the 18.8 million individual houses[3] (Nb_H) were equipped with the 3 kWp PV system coupled with the 4 kWh battery. Based on these conditions, our PV self-consumption model assumed a total cumulated residential storage capacity of 75.2 GWh and an additional 56.4 GWp of PV capacity in the French power mix. This represents about 10% of the French power supply on the condition that the power demand remains constant in the future. We also considered that the excess PV electricity had no value and that there was no grid injection of the PV power production surplus. Since our battery model aimed to develop a secondary-use application of residential batteries of PV self-consumption, we excluded other ways of direct and instant use of the cumulative capacity of residential batteries

[3] Source: (ADEME, 2013) (the number of individual houses and the total number of residences in France).

to address the annual peak demand. We thus assumed no grid injection of battery-stored power for balancing (they are considered for onsite consumption). We also assumed that the battery response time is immediate and the frequency constraints are ignored. As this approach identifies the maximum uptake, we conducted a sensitivity analysis based on different assumptions of cumulated capacity to define the national systemic benefits of the secondary-use application of residential batteries. We considered the projections of RTE and Enedis: RTE considers that the self-consumption could concern up to 3.8 million houses by 2035 and Enedis assumes between 5.8 and 11.6 million consumers, for low voltage alone (CRE, 2018).

4.3.2. Residential PV production

This study is based on the real PV production profile in France in 2015. We used the PV power production in 2015 as the reference case for PV production. Various factors should be taken into account to produce accurate residential PV production curves. For example, solar PV production varies according to the location and system type or installation specifications. We have very limited access to the aggregated bottom-up dataset and there is no available data on the distribution of all the houses in France. It was thus not possible to define accurate residential PV production curves in relation to the location of residences in France. Our model thus assumed identical solar resources for all residences in our calculations (~1100 kWh/kWp/year). This assumption also ignores the smoothing effect induced by the geographical spread of PV production. However, as the article sets out to measure the systemic effects of our residential battery model on a national scale, we considered that this assumption was counterbalanced seeing that all the modified residential profiles are reintegrated on a national level. Therefore, to determine the PV production of an average residence, the national PV production profile was divided by the total installed capacity in France to obtain an average unit production profile by Watt peak (Wp) installed. The unit profile was multiplied by the installed residential capacity (3kWp) to simulate the residential behaviour.

4.3.3. Residential consumption profile

Our simulation is based on real national consumption data in 2015 provided by RTE. The total consumption in 2015 was used as the baseline for our simulation, i.e. 483 TWh. As Table 1 shows, the residual consumption of the current mix, excluding wind and PV production, represents 456 TWh (2015). The simulation considers the electricity consumption at its assumed constant level in the future. We also considered a constant share of wind since the analysis of wind power falls outside of scope of our study.

Current situation	2015
Total consumption	483 TWh
PV production	7 TWh
Residual consumption	456 TWh

Table 1: Current electricity consumption and PV production

RTE provides hour-by-hour consumption data by segment of consumption. The residential consumption represented 164 TWh (34% of the total consumption) in 2015 (Table 2).

	Residential	Industrial	Commercial	Other	Total
TWh	164	115	148	56	483
%	34%	24%	31%	11%	100%

Table 2: French electricity consumption by segment in 2015

The French residential consumption represents 27 million residences, including 18.8 million individual houses (see Figure 8). Our PV self-consumption model with battery grid services has been developed based on an individual house consumption profile equipped with a PV-battery system. The change in the national residual power consumption has been analysed based on changes in the residential electricity consumption profile in France. We decided to simulate the national systemic effects assuming that most residences in France shared a similar consumption profile. Our aim is to change the power consumption profile in the residential sector thanks to the use of batteries. The modified profile will change the national power consumption pattern, leading to peak shaving and less efforts for PV integration.

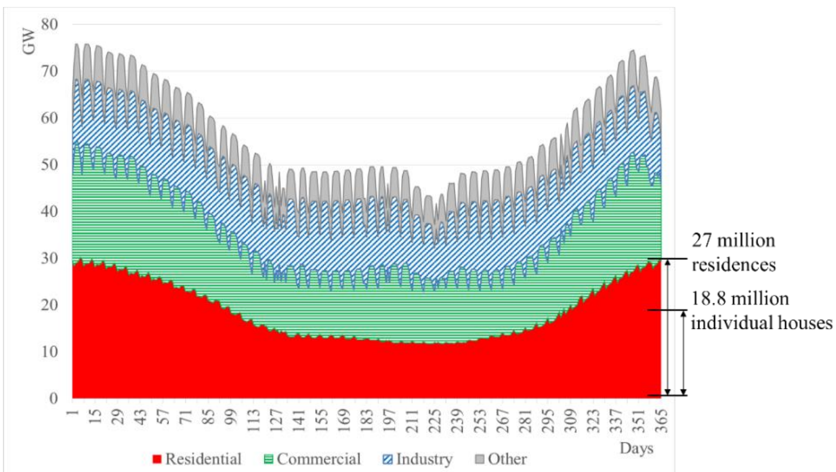


Figure 8: Annual consumption profile by sector

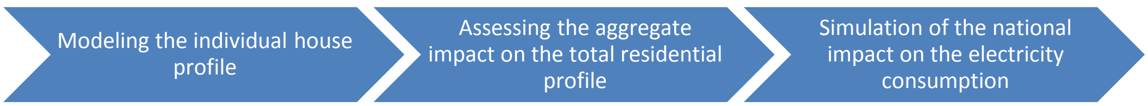
In our model, we considered that the battery production can be only self-consumed within the maximum consumption amount and that there was no grid injection to limit the negative effects on the grid. This is important for defining the battery parameters. However, this assumption introduces a limit on the battery-discharging rate that must be lower than the consumption of the residence; consequently, it introduces a limit on the amount of power that a house can shift thanks to batteries.

We also assumed that each PV system owner was connected to the grid, at which point the system operator can control residential battery charging and discharging. By doing so, the batteries considered as a whole can provide a considerable capacity enabling us to design a system balancing mechanism. We also considered that the residential PV systems with batteries were equipped with battery-management software and hardware to allow two-way power flows, and effective communication between residential systems and grid operators. The losses induced by power storage were also neglected.

4.4. Modelling methodologies

4.4.1. Simulation logic (PV-B-GS model)

This section describes the simulation logic of the PV-battery-grid service model. Based on the PV production and demand data described in the previous section, the electricity load profile and battery usage were simulated with an hourly dataset over an entire year of operation. The modelling methodology was used to assess the potential effects of grid operation with residential batteries. It includes the following steps:



The current situation was taken as a baseline case. Assuming large-scale PV integration based on residential PV self-consumption, we first modelled the individual house profile based on a PV self-consumption system with batteries (PV-B model). We then estimated the aggregate impact of PV self-consumption on the total residential profile and simulated the national impact on the electricity consumption. The same approach was used to model the case with grid services. We produced an individual house profile based on the PV-battery system with grid service. Next, the aggregate impact of the PV-B-GS model on the residential load profile and the change in the national power consumption were analysed. The final objective was to distinguish the function of battery grid services from the PV-battery system case with no grid service model. This analysis provided us with the basic data needed to define the systemic benefits of batteries and the economic gains of new grid model.

4.4.2. Modelling new residential consumption profiles

The following description presents the precise steps taken to integrate the new residential profile induced by our PV self-consumption model into the current consumption profile. We therefore proceeded as follows.

1. Split the total national consumption profile to determine the residential consumption profile $(E_R) : E_{Tot} = E_R + (E_{Tot} - E_R)$.
2. Define an individual house consumption profile e_H based on the total residential profile E_R. The average residential consumption profile is the national residential profile divided by the number of residences (Nb_R = 27 million) ($e_H = e_R = E_R / Nb_R$). The number of residences includes the number of individual houses (Nb_H = 18.8 million) and the number of other residences ($Nb_R - Nb_H$). Therefore, the total residential demand is $E_R = e_H \times Nb_H + e_R \times (Nb_R - Nb_H)$.
3. Replace the individual house consumption profile with the PV self-consumption $e_{H,PV}$ induced by our PV self-consumption model and reintegrate the new profile into the total residential consumption profile $E_{R,PV} = e_{H,PV} \times Nb_H + e_R \times (Nb_R - Nb_H)$.
4. Integrate the new residential profile into the total consumption profile $E_{Tot,PV} = E_{R,PV} + (E_{Tot} - E_R)$.

The same modelling process was applied to the scenario with grid services.

4.4.3. Modelling grid services and the optimization loop

Our battery service model aims at reducing the variation in the load profile which is why we used an optimization loop to define the key parameters to manage batteries (i.e. hours, rates) and to flatten the domestic power demand curves. We reviewed the national residual consumption profile for each month to determine the periods of low demand and high demand in a day. This basic step was used to define the optimal parameters of our battery model for grid services. The loop used to determine the optimal parameters depends on the battery charging/ discharging times and the battery charging/ discharging rates. Therefore, the objective of our optimization tool is to identify the optimal conditions in terms of battery charging/ discharging times and rates for national peak shaving. Our approach involved the following steps.

1. Define the periods of low and high demand on the total consumption profiles $E_{Tot,PV}$ during the day in winter.
2. Model the new profile of the modified household consumption due to the use of residential batteries $\tilde{e}_{H,PV}$ in winter with battery charging during national consumption off-peaks and battery discharging during national consumption peaks.
3. Aggregate the Nb_H household consumption profile on a national level: $\tilde{E}_{R,PV} = \tilde{e}_{H,PV} \times Nb_H + e_R \times (Nb_R - Nb_H)$.
4. Reintegrate the new residential consumption profile into the total demand: $\tilde{E}_{Tot,PV} = \tilde{E}_{R,PV} + (E_{Tot} - E_R)$.
5. Use a loop to identify the optimal parameters that minimize the peak: $\tilde{E}_{Tot,PV}^{opt} \mid \forall \tilde{E}_{Tot,PV}$, $\max(E_{Tot,PV}) - \max(\tilde{E}_{Tot,PV}) \leq \max(E_{Tot,PV}) - \max(\tilde{E}_{Tot,PV}^{opt})$.

For the step 5, we considered S_c as the battery charging rate, S_d as the battery discharging rated and $\{t_c, t_d\}$ as the periods of battery charging/discharging in a day. The objective function of optimization to define the parameters is described as below:

$$S_c^{opt}, S_d^{opt}, t_c^{opt}, t_d^{opt} \mid \forall \{S_c, S_d, t_c, t_d\},$$
$$\max(E_{Tot,PV}) - \max\left(\tilde{E}_{Tot,PV}(S_c, S_d, t_c, t_d)\right) \leq \max(E_{Tot,PV}) - \max\left(\tilde{E}_{Tot,PV}^{opt}(S_c^{opt}, S_d^{opt}, t_c^{opt}, t_d^{opt})\right)$$

With

$$\begin{cases} \tilde{E}_{Tot,PV}(S_c, S_d, t_c, t_d) = \tilde{e}_{H,PV}(S_c, S_d, t_c, t_d) \times Nb_H + e_R \times (Nb_R - Nb_H) \\ \tilde{e}_{H,PV}(S_c, S_d, t_c, t_d) = e_{H,PV} + B_c(S_c, t_c) - B_d(S_d, t_d) \\ B_c(S_c, t_c) = S_c \; if \; h_{day} \in t_c \; and \; day \in winter \; months, else \; B_c(S_c, t_c) = 0 \\ B_d(S_d, t_d) = \min(e_{H,PV}, S_d) \; if \; h_{day} \in t_d \; and \; day \in winter \; months, else \; B_d(S_d, t_d) = 0 \\ \sum_{h_{day} \; in \; each \; day} B_c(S_c, t_c) = \sum_{h_{day} \; in \; each \; day} B_d(S_d, t_d) \end{cases}$$

With:

- h_{day}: hours in a day
- B_c: power consumed by the batteries during grid charging
- B_d: power provided by batteries during discharging[4]

[4] The last equation examines if the power stored during a day is fully released in the same day.

4.4.4. Analysis of systemic and economic effects

The impact on the national power system was analysed based on a residual load duration curve approach. A residual consumption profile was obtained by subtracting the power generation from the variable wind and PV production. Battery use was also considered to define the residual consumption profile. In order to assess the systemic effects, the remaining required dispatchable power capacity for each unit of time can be ranked in decreasing order to obtain the residual load duration curve. Based on the results, we compared the effect on conventional power plants and the national mix.

In the next section, the PV-B-GS model first defines the optimal condition of charging and discharging strategies in order to maximize the systemic benefits of our grid model. Based on the results of new residual load duration curve modelling, we assessed the systemic effects with regard to balancing and seasonal adequacy according to different time series (daily and yearly). The proposed grid service model also enabled us to increase the utilization rate of batteries. We also measured the increase in asset utilization due to the new application of grid services. We then defined the economic gains based on the new residual curve produced by the grid service. The impact on the PV integration costs and back-up costs was calculated. We used the definition of the profile costs to calculate the savings in integration costs. We compared the cumulated costs to meet the residual power demand according to different scenarios with the cumulated costs to meet the same residual demand based on the current average production costs (profile costs, Ueckerdt *et al.* (2013)). For this reason, the calculation was based on a virtual electricity mix. Table 3 shows investment and variable costs of different power plants used in the virtual mix (Petitet, et al., 2016).

	Nuclear	Coal	CCGT	Combustion turbine (oil)
Investment (k€/MW)	3910	1400	800	500
O&M (k€/MW/year)	75	30	20	10
Lifetime (year)	50	40	30	25
Variable cost (€/MWhe)	10	37	64	157
CO_2 intensity (tCO_2/MWhe)	0	0.8	0.35	0.8

Table 3: Investment and variable costs of the virtual electricity mix technologies
**The assumed carbon price was €30.5/ t CO_2, equal to the carbon price of 2017.

Thanks to this data, we were able to determine the cheapest technologies during a given period of time (year) to obtain an optimal mix in France according to different scenarios. We also calculated the extent to which the grid service model provides financial incentives for investment in PV-battery systems for French households. The breakeven point was defined to quantify the impact of the grid model on profitability with regard to an individual investment. Finally, we were able to discuss the policy implications of our findings and provide some recommendations.

V. RESULTS AND DISCUSSIONS

5.1. Identification of parameters for optimal performance

The performance of grid services is related to how to the systems are configured. In order to design the optimal grid service model, we first estimated the necessary conditions for numerical simulation. Therefore, prior to obtaining the simulation results, we aimed at defining the basic parameters for our simulation.

5.1.1. Time-based charging and discharging of batteries

As indicated, the PV self-consumption model changes the demand profile of individual households and the aggregate profile will largely influence the national load profile.

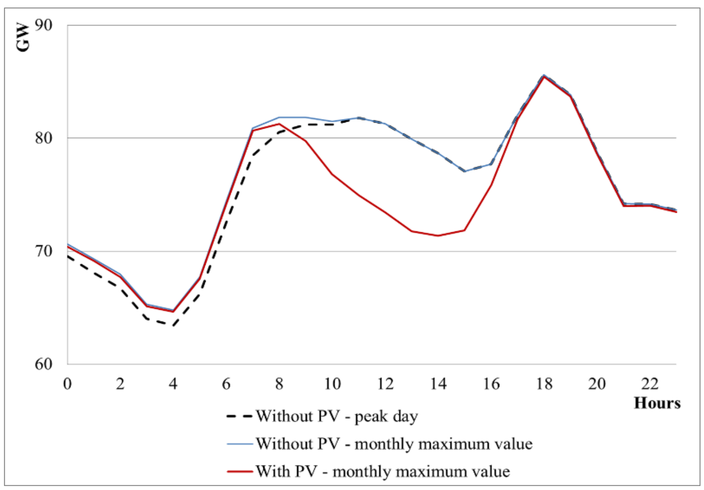


Figure 9: Hour-to-hour daily load consumption values (peak day and monthly maximum values) in January 2015 in France

The graph shows the hour-to-hour daily grid demand for January, the month during which the annual peak was reached in 2015. The dashed line shows the real load consumption profile without PV self-consumption (E_{Tot}) during the peak day. Since the study aims at reducing the national consumption peak, we needed to consider the maximum load consumption values because a change in the profile can move the peak to another day in the month. Therefore, the blue line shows the maximum load consumption for each hour of the day throughout the month without PV self-consumption ($E_{Tot}^{max,January}$) while the red line shows the maximum load consumption ($E_{Tot,PV}^{max,January}$) due to PV self-consumption coupled with batteries. As Figure 9 shows, PV self-consumption will lead to a new mid-day off-peak period and cause two peaks, namely the morning peak and evening peak.

By analysing the national profile of the residual load consumption, we obtained new load consumption profiles for the winter months (December, January and February). As Figure 10 indicates, the PV self-consumption model gives two periods of high power demand from the grid and two periods of low power demand from the grid.

Our grid service battery model aims at charging residential batteries from the grid during off-peak periods in order to release the stored power during the peak periods. Therefore, we decided to define the periods of residential battery charging and discharging based on the identified periods of high and low demand.

- Battery charging: from 1 am to 5 am, from 12 pm to 3 pm;
- Battery discharging: from 7 am to 9 am and 5 pm to 11 pm.

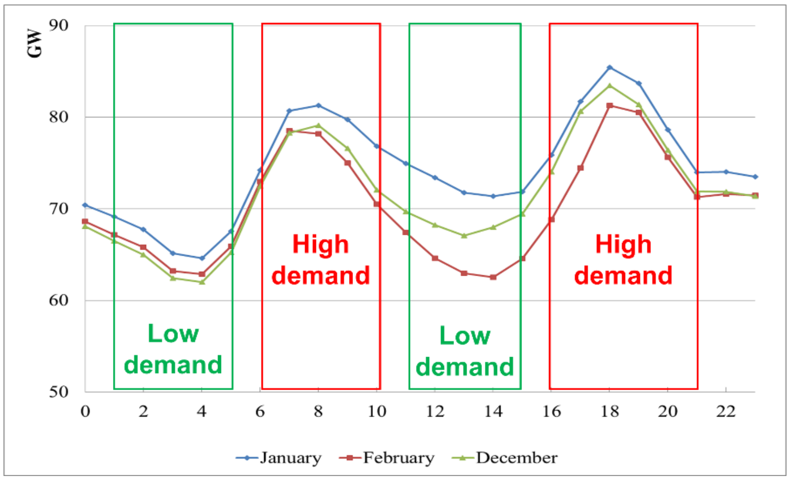


Figure 10: Maximum demand for each hour of the day with PV self-consumption for December, January and February

5.1.2. Battery charging and discharging rates

The battery charging and discharging rate is an important parameter to take into account if we intend to achieve the intended simulation results. We can expect a shift in the peak demand to different timeslots and a rapid change in the demand profile directly related to the battery charging and discharging decision (e.g. risks related to concurrent automatic charging).

Figure 11 demonstrated the different load profiles for the winter months based on different parameters (from 0.25 kWh/ hour to 1 kWh/ hour for charging and discharging). It is important to note that daily peak demand hours can be changed depending on how the battery charging or discharging batteries rate is defined. For example, a rate of 1 kWh per hour can lead to new demand peaks during the night and at midday. Therefore, based on this result, we decided to choose a fixed (controlled) battery charging/ discharging rate for our grid model since it enabled us to address risks of demand peak shifting. We use our numerical optimization tool to set the rates. As Figure 12 indicates, the increase in the battery-charging rate makes it possible to move a greater amount of energy and reduce the current peak demand until the load consumption for charging batteries starts to create a new peak. An increase in the battery discharging rate reduces the peak demand until the rate becomes too high and empties the battery too quickly to manage the evening peak. In this regard, our battery model aims at avoiding these identified risks. Based on the results from an optimization loop of our numeric simulation, we decided to fix a rate of 0.3 kWh/hour for charging and 0.4 kWh/h for discharging in our simulation model (see Figure 12).
In order to avoid risks related to the implementation of our grid model, relatively simple and standardized control systems were considered with the following functions:

- Automatic battery charging/ discharging based on the defined time slots;
- Possibility to set the battery charging/discharging rate to reduce the risk of generating other peaks.

In our study, we used basic nation-wide parameters for battery charging/ discharging times and rates. However, the model may need to liaise with a more sophisticated solution to smooth the start and the end of charging/discharging. We can design finest remote control systems (e.g. time-based by geographic areas) and sub-level management (e.g. collaborative actions with aggregators). Therefore, we need to work on methods to facilitate the systemic functionality of residential batteries, e.g. regional control system, smart charging and communication methods.

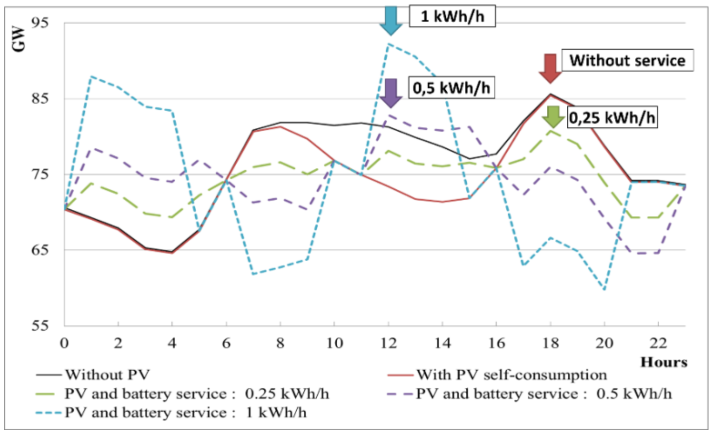


Figure 11: Impact on the national demand profile in January

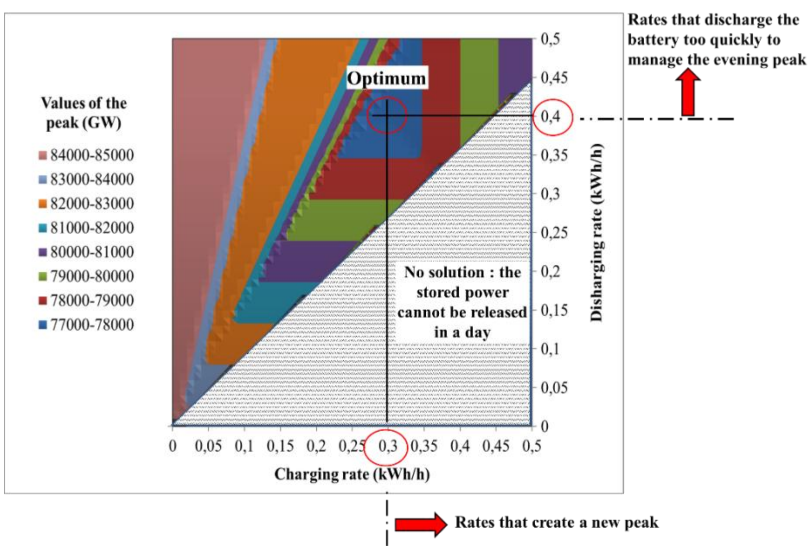


Figure 12: Results of battery charging and discharging rates obtained by the optimization loop

5.2. Systemic effects

5.2.1. Smoothing daily variations (peak shaving)

The systemic benefits of our grid service model were analysed based on the configuration with optimal parameters. Table 4 summarizes the impact of PV penetration on the total electricity consumption according to different scenarios. It should be noted that the PV-B-GS model does not make any changes to the residual load demand volume; the function of the grid service is to smooth daily variations by moving a fraction of the consumption during peaks to other time zones. The algorithm of the numerical simulations validates this effect.

	Current	PV self-consumption with batteries (10% PV integration)	
		PV-B scenario	PV-B-GS scenario
Total consumption	483 TWh	483 TWh	483 TWh
PV production consumed	7 TWh	60 TWh	60 TWh
Residual consumption (wind included)	456 TWh	403 TWh	403 TWh

Table 4: Impact on the total electricity consumption

We thus decided to focus on the smoothing effects. Figure 13 illustrates the residential load profile (blue) according to two different scenarios. We used the daily profile of 4 January 2015 (the annual peak). We can see that the grid model modifies the load profile. The left graph indicates the peak demand occurred in the evening of that day. However, on the right graph, we can see the decrease in the load demand in the morning and the evening and an increase during the night and at midday. The consumption during the peak at night is higher, but it should be noted that this happens during a low demand period.

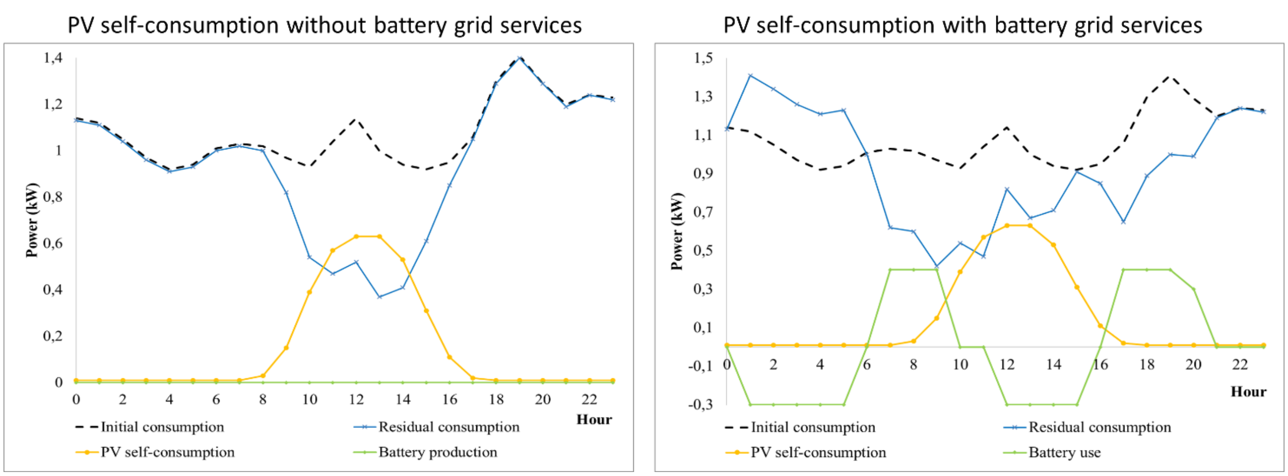


Figure 13: Residential profiles without (left) and with grid services (right): 4 January 2015 (annual peak)

Figure 14 shows the aggregate result on a national level for the peak day. There appears to be a flatter national profile for load consumption with a significant decrease in the evening peak. Therefore, we concluded that the PV-B-GS model can smooth the daily load variation, which means less balancing efforts. Figure 15 shows the average daily load consumption of December, January and February for two scenarios. We quantified the systemic benefit of our battery grid service model by comparing the maximum to minimum values of the average daily variation for each scenario. The average gain varies from 8.3 GW (February) to 10.7 GW (January) (Table 5). We find that the new grid service model helps flatten the daily load curve for all months (December, January and February) in question.

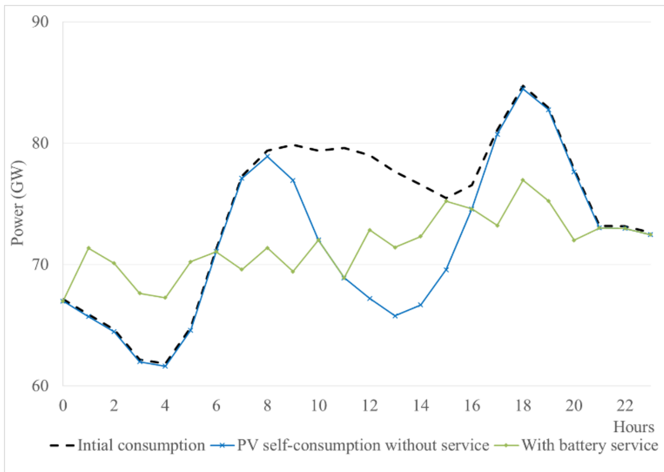


Figure 14: National consumption profiles based on the example of 4 January 2015 (peak day)

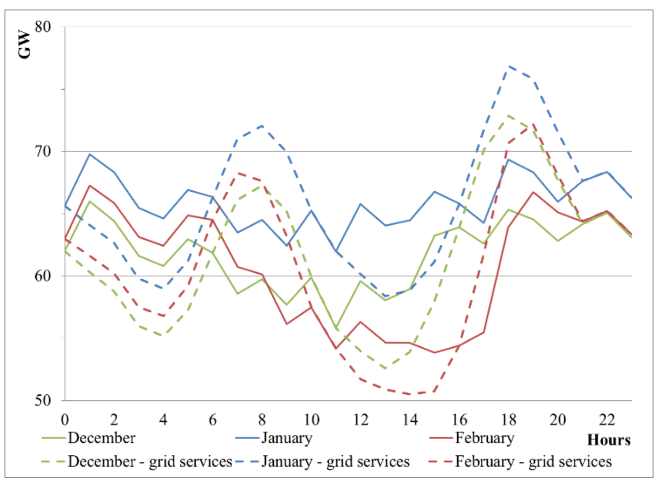


Figure 15: Grid services to smooth the daily load variation (December-January-February)

Average consumption variation	PV-B scenario	PV-B-GS scenario	Delta
December	20.3 GW	10.2 GW	-10.1 GW
January	18.5 GW	7.8 GW	-10.7 GW
February	21.7 GW	13.4 GW	-8.3 GW

Table 5: Average gains in daily balancing

5.2.2. Annual peak shaving

We will now demonstrate the extent to which the grid model can help reduce the required back-up capacity in the French electric power system. The optimal power mix gives different yearly operation times to each plant based on the virtual mix (see section 4.4.4). The system usually has nuclear and coal for baseload power units, coal or gas for intermediate loads, and combustion turbines for peaking units. The optimal mix can be defined on the basis of the minimum costs of power generation to meet the annual electricity demand. Table 6 shows the annual full load hours and capacities of dispatchable plants in the optimal power mix in 2015 considering a CO_2 price of €30.5/tCO_2. These generators have different investment costs and electricity generation costs. Nuclear power plants offer the cheapest solution if they operate over 5943 h throughout the year because they have high investment costs with low variable costs. However, most peaking units have low investment costs and high operational costs (e.g. natural gas combustion turbine). There are alternative options for power system balancing. For example, demand response (DR) leads to changes in the power consumption to better match the power demand for power supply profile. RTE estimated the demand response made available through tariff-based schemes at 800 MW in the winter of 2016-2017 (RTE). However, we considered that this point fell out of the scope of our study.

	Supply		Demand (Current residual load: 456 TWh)	
Dispatchable capacities	Full-load hours/year (optimal)	Dispatchable capacities (GW) (optimal)	% of total residual demand	% of total demand
Nuclear	4848h-8760h	48.8	87.5%	82.7%
Coal	4175h-4848h	2.2	2.1%	2%
Combined-cycle gas turbine (CCGT)	323h-4174h	23.3	10.2%	9.6%
Combustion turbine (CT)	0h-322h	10.4	0.2%	0.2%

Table 6: Optimal power generation mix and yearly full load hours of dispatchable capacities – Reference scenario with virtual electricity mix in 2015

The aggregate production of 56 GW PV based on PV self-consumption is equivalent to around 10% of the electricity demand in France. The integration of PV power into the power system will change the optimal condition of yearly full load hours of dispatchable capacities and the power production mix. The optimal capacities of dispatchable plants under these two scenarios have been changed. In the previous section, we concluded that the grid service made it possible to move a share of the peak demand to other time zones with a constant power consumption. The scenario with grid services requires less CCGT and combustion turbine (CT). The optimal capacity for the CT decreases from 12.9 GW to 7.7 GW[5].

[5] The coal production capacity is highly dependent on the carbon price. An increase in this price shifts a share of the coal production to CCGT and nuclear plants.

In this regard, we concluded that there was a difference in optimal power supply mixes between two scenarios depending on whether the grid service model was used. We can evaluate the systemic and economic impact on the mix based on this result.

	Supply		Demand (total residual load: 403 TWh)	
Dispatchable capacities	Full-load hours/year (optimal)	Dispatchable capacities (GW) (optimal)	% of total residual demand	% of total demand
Nuclear	4848h-8760h	41.2	82.6%	69%
Coal	4175h-4848h	2.3	2.6%	2.1%
Combined-cycle gas turbine (CCGT)	323h-4174h	28	14.5%	12.1%
Combustion turbine (CT)	0h-322h	12.9	0.3%	0.3%

Table 7: Optimal power generation mix and yearly full load hours of dispatchable capacities - Scenario PV-B

	Supply		Demand (total residual load: 403 TWh)	
Dispatchable capacities	Full-load hours/year (optimal)	Dispatchable capacities (GW) (optimal)	% of total residual demand	% of total demand
Nuclear	4848h-8760h	41.2	82.7%	69%
Coal	4175h-4848h	2.3	2.6%	2.2%
Combined-cycle gas turbine (CCGT)	323h-4174h	25.8	14.6%	12.2%
Combustion turbine (CT)	0h-322h	7.7	0.1%	0.1%

Table 8: Optimal power generation mix and yearly full load hours of dispatchable capacities - Scenario PV-B-GS

Figure 16 indicates the annual load duration curve for different cases. The load duration curve shows the required dispatchable power capacity needed to meet the power demand in descending order. The residual load duration curve can be produced to assess the contribution of our grid service model to the seasonal back-up capacity. The black line indicates the yearly residual load of our reference scenario in 2015 (456 TWh in 2015) while the red dotted line represents the new residual load curve after adding a new installed solar PV capacity of 56 GW based on PV self-consumption with batteries (PV-B). The green line represents the modified residual load curve by adding grid services to the PV self-consumption model (PV-B-GS).

We can see that PV self-consumption with no grid service results in a significant reduction in the residual load supplied by conventional power plants and the curve is steeper than the current residual load (see black dashed line vs. red dotted line). The grid service model creates a new shape that is flatter than the red dotted curve. As indicated, the difference in the residual load demand between two scenarios is null (the total residual load consumption stays the same at 403 TWh, 83.4% of the total demand of 483 TWh). However, the grid service model (green curve) requires less from conventional peaking units, which allows us to move a share of the residual power consumption during the highest demand period (between 0 h to 500 h) to different time zones (between 1000 h and 2500 h).

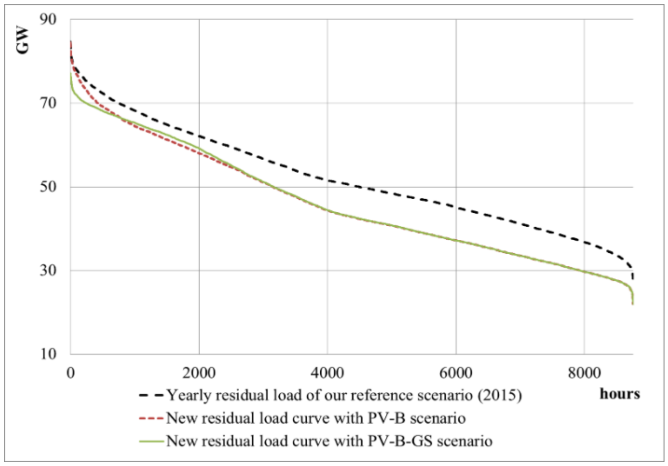


Figure 16: Changes in the load duration curve

Figure 17 provides a close-up of three curves with focus on the annual peak period. Referring to Figure 17, we can see that the proposed model with grid service makes it possible to reduce the required back-up capacity by 7.4 GW from 84.5 GW with the PV-B scenario to 77.1 GW with the PV-B-GS scenario.

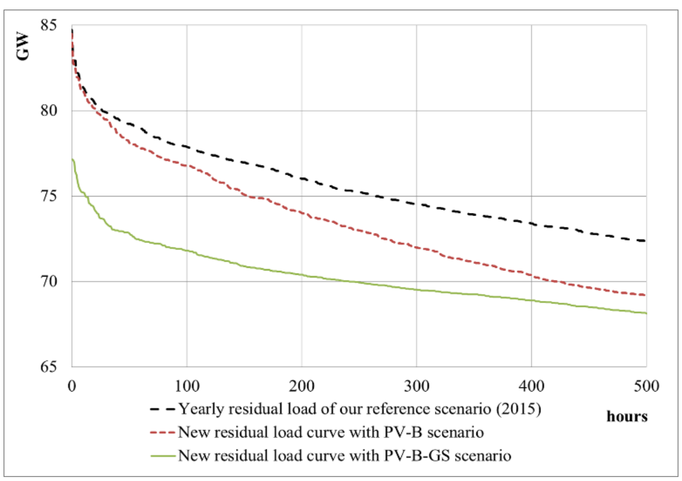


Figure 17: Focus on the annual peak period of the load duration curves

The economic effects induced by this modification in the power mix are calculated in the section 5.3.

5.2.3. Sensitivity analysis of systemic effects

The approach gave the maximum uptake of national systemic benefits. We thus conducted a sensitivity analysis with smaller uptakes based on different projections of the residential PV self-consumption by RTE and Enedis. Table 9 illustrates the projected PV self-consumption deployment by 2035 in France.

	Number of houses with PV self-consumption in 2035 (million houses)	Aggregate capacities of batteries (GWh)	Optimal rates of charging / discharging (kWh/h)
Base case (maximum uptake)	18.8	75.2	0.3 / 0.4
Enedis (upper)	11.6	46.4	0.35 / 0.55
Enedis (lower)	5.8	23.2	0.55 / 0.85
RTE	3.8	15.3	0.7 / 1.3

Table 9: Parameters of sensitivity analysis

We first fixed the optimal parameters for the best system configuration. The defined periods of residential battery charging and discharging were taken for the sensitivity analysis (see 5.1.1.). We then used our numerical optimization tool to set the optimal rates for each case to minimize the demand peak. For example, based on the results from an optimization loop, we decided to fix a rate of 0.7 kWh/hour for charging and 1.3 kWh/h for discharging to evaluate the case of RTE and smaller rates were fixed for the cases of Enedis.

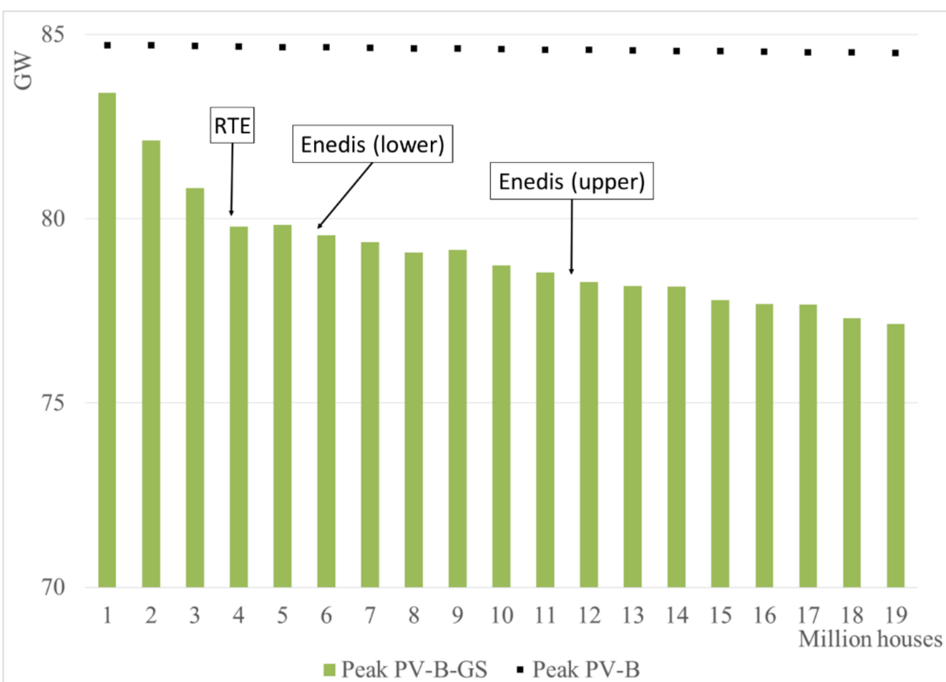


Figure 18: Sensitivity analysis of annual peak saving impact on a national level

Figure 18 shows the aggregate result of annual peak saving on a national level according to the progressive diffusion of PV self-consumption. We can see that the proposed grid service model enables to largely reduce the required back-up capacity almost for all cases. Another issue should be discussed with regard to the aggregate capacity of residential batteries. The annual peak shaving impact is significantly greater in the beginning of the PV diffusion with fewer batteries. For example, we have seen that the proposed grid model based on the maximum uptake (75.2 GWh) made it possible to reduce the required back-up capacity by 7.4 GW to 77.1 GW. According to RTE's projection, the required back-up capacity can be reduced to 79.8 GW based on around one fifth of the maximum storage capacity (15.3 GWh).

5.3. Economic analysis

5.3.1. Saving in PV integration costs

In this section, we attempt to calculate the economic effects of the grid service model by estimating the savings in PV integration costs. The integration of solar generators into power systems generates integration costs. Annual back-up costs are important economic issues with respect to increasing the fraction of variable renewable energies in a national electricity mix. We therefore defined the potential savings resulting from the implementation of the proposed grid service model.

We have identified the cheapest technologies for a given operating time of a year in order to obtain an optimal mix in France according to different scenarios (Table 6 toTable 7: Optimal power generation mix and yearly full load hours of dispatchable capacities - Scenario PV-B

). We have demonstrated the extent to which the grid service can save on back-up costs for the French electricity system. We now need to focus on peaking power plants that can follow the fastest variations in demand to maintain the power system. Assuming that combustion turbines operate as the peaking units, we can perform a quick calculation to estimate the economic gains achieved with respect to the annual peak demand. The previously defined 7.4 GW reduction in the annual peak demand leads to an approximate saving of €3.7 billion (500 k€ x 7400 MW) in power generation investment.

However, we concluded in the previous section that the new grid service model changes the power supply mix. The existence of the grid service model slightly changes the shape of the residual load curve. This also implies economic changes in the national power system. These economic gains or losses can be calculated by comparing the optimal power mix according to different scenarios. Ueckerdt *et al*. introduced the concept of profile costs. They can be calculated by comparing the cumulated costs to meet the residual power demand induced by PV penetration with the cumulated costs to meet the same residual demand calculated based on the current average production costs (Ueckerdt, et al., 2013; Yu, 2018) (equation 1[6]).

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[6] C_{resid} : All other costs for the residual system with VRE integration (including generation costs of dispatchable plants, costs for reserve requirements, balancing services, grid costs and storage systems).
$C_{total}(0)$: Total costs to meet a system's demand without VRE generation.
E_{resid}: Resulting residual load with VRE (provided by dispatchable power plants).
$\bar{E}_{total}$: Power system's annual power demand (exogenous factor).

$$\mathrm{C_{profile}} = \mathrm{C_{resid}} - \frac{\mathrm{E_{resid}}}{\overline{\mathrm{E}}_{\mathrm{total}}} \mathrm{C_{total}}(0) \qquad (1)$$

If the residual load duration curve is steeper than the current reference curve, the profile costs are positive and if the curve is flatter, the costs are negative. In addition, the profile costs are the most critical segment of integration costs (including the costs of grid reinforcement and balancing) with regard to the high penetration of variable power generation (Ueckerdt, et al., 2013). The 2015 data was used as a baseline to calculate the profile costs. Our analysis considered the current residual demand $\overline{\mathrm{E}}_{\mathrm{total}}$ as a reference. The defined optimal mix data according to the different scenarios from the previous section was also used to calculate the profile costs.
The mathematical expression to define the production costs of the optimal residual mix is described in (2):

$$\mathrm{C_{resid}^{optim}} = \int_0^{\mathrm{q_{peak}}} \mathrm{T}(\mathrm{q}, \quad \mathrm{E_{VRE}}) \mathrm{C_{min}}(\mathrm{T}(\mathrm{q}, \quad \mathrm{E_{VRE}}))\, \mathrm{dq} \qquad (2)$$

With

- C_{resid}^{optim} : Cost of the optimal residual system after VRE integration
- E_{VRE}: Power generation from VRE
- q_{peak} *:* Annual peak demand of electricity
- $T(q, E_{VRE})$: Full-load hours for power demand q
- $C_{min}(T(q,\ E_{VRE}))$: Generation costs from the cheapest production capacity (i.e. nuclear, gas and coal) to operate a full-load hours of $\mathrm{T}(\mathrm{q}, \mathrm{E_{VRE}})$

This defines the sum of the lowest production costs to meet the residual power demand. The profile costs can be calculated by comparing the two different load duration curves depending on the inclusion of the grid service. As seen in Figure 16, PV integration with no grid service model has a steeper load duration curve than the case with grid services. This indicates higher profile costs. Table 10 shows the profile costs of 56 GW PV integration depending on the defined scenarios. According to our analysis, the additional cost per each MW of PV installed (€/MWh PV) amounts to €27.7/MWh under the PV-B scenario with no grid service. However, this cost can be reduced by around 39% to €17/MWh based on our PV-B-GS scenario with grid services provided by the secondary-use application of batteries. The total savings based on our grid model amount to €560 billion per year. It is thus important to highlight that the proposed model can largely contribute to reducing PV integration costs. This facilitates a high level of PV integration based on PV self-consumption with much lower integration costs in the future.

Profile costs	Billion €/year (annual total costs)	€/MWh PV (Unit costs per megawatt-hours)
PV-B (no grid service)	1.46	27.7
PV-B-GS (grid service)	0.9	17

Table 10: Profile costs based on two scenarios

Figure 19 demonstrates the sensitivity analysis of PV profile cost estimates according to the level of PV self-consumption diffusion in France. We fixed optimal parameters of charging and discharging to maximize the peak reduction for each million houses equipped with PV self-consumption system coupled with the residential battery. We can see that the profile costs with grid services increase linearly with the PV-B scenario (no grid service).

However, it is interesting to note that the grid service model can sharply reduce the profile costs at the early phase of PV diffusion. They can be negative under around 6 million house diffusion since the proposed grid service model can optimally increase the efficiency of power system compared with the reference scenario.

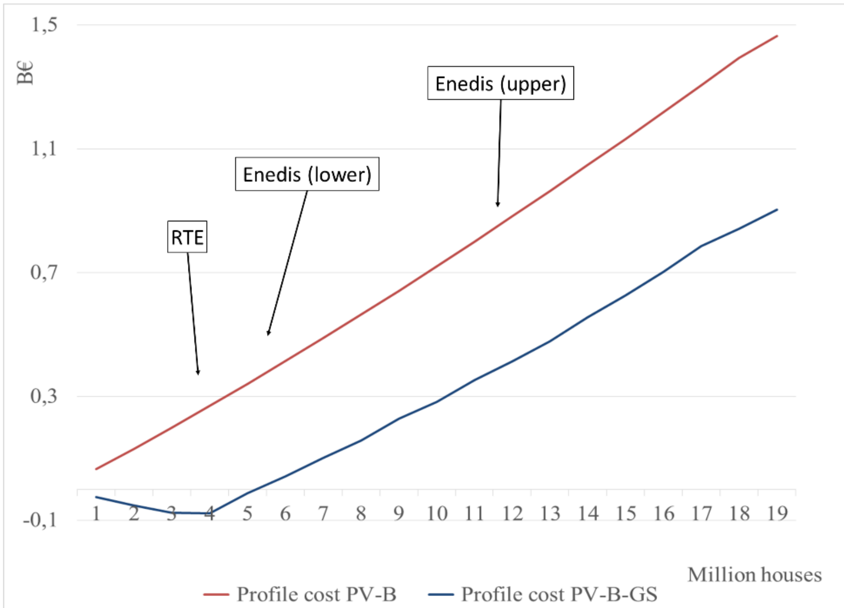

Figure 19: Sensitivity of profile cost estimates

5.3.2. Remuneration of grid services

Our battery model attributes a secondary-use application to the batteries. Since the aggregate capacity of residential batteries can provide grid services via the proposed PV-B-GS model, the value of residential batteries increases. Our simulation concludes that battery services during winter increase the battery use over the year to 74% from 58% with the baseline scenario based on PV self-consumption only. The new grid service can be implemented based on a new business model. We will discuss this aspect with respect to evaluating the investment decision. We will now define the extent to which the grid service model can help advance the break-even point for investment in residential PV-battery systems when a proper remuneration system is implemented. This analysis gives us an idea of the economic incentives needed for battery investment if policymakers plan to deploy more residential PV self-consumption with grid services.

Current French residential PV systems combined with Li-ion batteries are not yet profitable without subsidies for individual investors. Yu (2018) evaluated their profitability and concluded that residential PV-battery systems in France would become profitable for households before 2030 without subsidies. The discounted annual costs of the investment to install residential PV-battery systems in 2017 are shown in Table 11. These costs include the capex investment to acquire the system and the operation & maintenance costs over the system's lifetime. Based on the input data provided in the previous section, we defined these costs according to different locations in France.

Households are expected to make savings since they will purchase a smaller share of electricity from the grid by switching to PV self-consumption.

	Energy output kWh/kWp	Discounted annual costs of the investment (EUR) (a)	Discounted annual gains from avoided grid consumption by PV self-consumption (b)	Gap between a & b ($)	Discounted annual gap ($)	Remuneration of the power displaced
Paris	1000	12147	6741	-5406	270.3	0.56 $/kWh
Average in France	1100	12147	7415	-4732	236.6	0.49 $/kWh
Bordeaux	1270	12147	8561	-3586	179.3	0.37 $/kWh
Nice	1460	12147	9842	-2305	115.3	0.24 $/kWh

Table 11: Discounted annual cost of the investment and battery service remuneration
Data (see footnote)[7]

There is a clear gap between household investment and savings in electricity bills. If the grid service model covers a part of this gap, then PV investment coupled with batteries can become profitable earlier than the case without the grid service. This approach can promote PV-battery investment.

[7] We used the following data and assumptions to plot the PV production curve of PV self-consumption and the PV power generation costs:

- PV system price: €1.83/Wp, building integration (BIPV) for residential rooftops using c-Si PV technology (IEA-PVPS France, 2016).
- Potential PV power output: provided by PVGIS (JRC European Commission, n.d.) based on optimal positioning, c-Si cells, and estimated system losses of 14%.
- O&M: 1.5% of the PV system price (European Commission, 2013).
- Lifetime: 20 years for the PV system and 10 years for the batteries (Mundada, et al., 2016). We considered the repurchase of batteries with the same replacement costs.
- A discount rate of 5% was used to consider the weighted average costs of capital (WACC) for the respective investment (European Commission, 2013; Fraunhofer ISE, 2013).
- The LCOE of residential PV systems with batteries divided by the ratio of self-consumption.

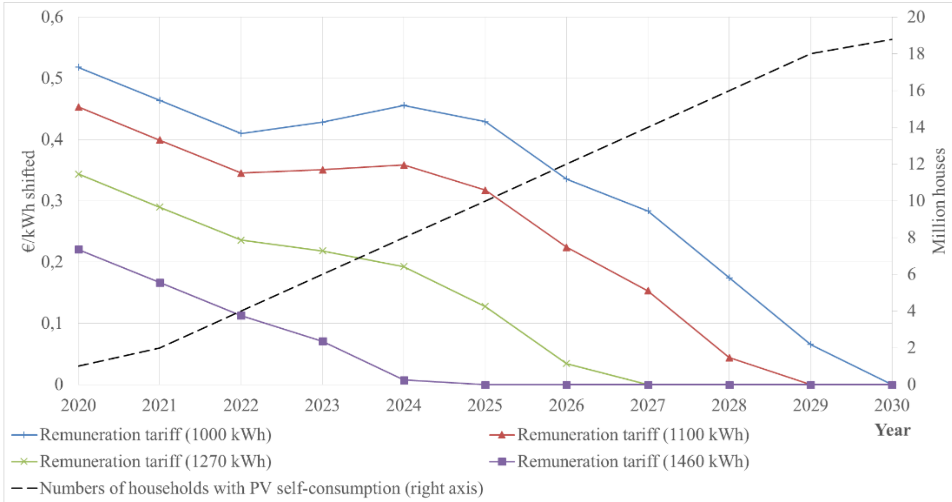

Figure 20: Sensitivity of the grid service tariffs to break-even the investment for the energy output

In order to define shortage, we defined the gap between the discounted annual total cost and the discounted annual total revenue over the lifetime of PV-battery systems. If the grid model generates additional revenues of around $270/year over 20 years, the PV-battery system in Paris become economically feasible for an individual investor. To guarantee this amount, a tariff can be fixed. For example, a tariff of $0.56/ kWh for power replacement of 486 kWh/year[8] makes it possible to achieve breakeven in Paris. When the calculations concern southern parts of France, the required tariffs for achieving a breakeven point are reduced thanks to the higher energy output.

PV system costs has been declining with globalization and this trend is continuing. In addition, the battery costs are expected to continue to decline in the next decades. The difference between investment and expected revenues will be decreased in the near future. We conducted a dynamic analysis for the required grid service tariffs to bridge the gap. We included the market dynamics in our analysis with regard to the progressive (linear) decrease in PV system costs and battery costs. In addition, we also considered that PV-battery systems progressively diffused in the residential sector until 2030. Figure 20 shows the sensitivity of the grid service tariffs to break-even the investment for the energy output. We can see that southern France requires lower tariffs and reaches the breakeven point earlier by benefiting from higher insolation. Assuming the demand for PV self-consumption grows in the near future, if the grid services were remunerated as proposed, the PV-battery systems would become profitable around 2024 in Nice. Once breakeven is achieved, the additional gains can be used for other segments such as grid financing.

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[8] If the grid model concerns18.8 million houses equipped with PV-battery systems, a power shift of 243 kWh (0.3 kWh/h x 9 h x 90 days) per each house leads to the best use of batteries to reduce the annual peak demand in the winter. In this case, based on our model, the use of batteries for the grid service is limited because their full utilization can provoke new demand peaks with aggregation effects of power consumption to charge batteries from the grid. However, if the model considers a small number of houses, the optimal utilization of batteries will be different. However, the battery charging rate is still limited because the power stored must be self-consumed in a day, and the storable power is limited by the consumption of the household during the battery discharge time. Therefore, our optimization grid service model defines a maximum rate of 0.6 kWh/h for charging and 1.3 kWh/h for discharging. This leads to a power displacement of about 486 kWh by year.

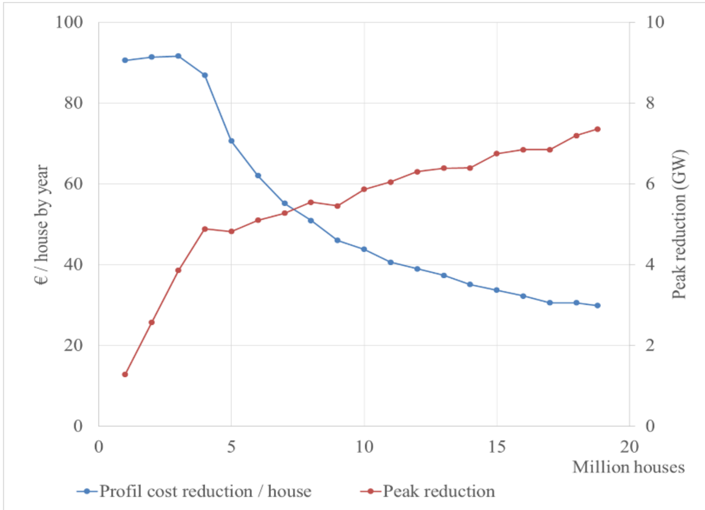

Figure 21: Sensitivity of the peak shaving impact and profile cost reduction according to PV diffusion

The remuneration system can be designed based on the contribution to the grid services. Figure 21 shows the sensitivity of the peak shaving and profile cost reduction according to the PV diffusion level. We have seen that the peak shaving impact is greater in the early PV diffusion despite less battery capacity to support power system. In this case, the systemic contributions of these batteries are greater than late entrants (a higher level of remuneration can be developed for early participation). Referring to Figure 21, a system design based on an initial target of around 6 million houses can be a reasonable objective of remuneration scheme. We need a scheme that encourages the investment in new battery capacity and the participation to the market mechanisms should be allowed. For example, the public authorities can ask RTE to organise auctions to secure a certain battery capacity during the winter months for annual peak shaving. The contracts can be defined between the owner and grid operators. The aggregator could become an agent to facilitate the business process between a number of battery owners and grid operators.

VI. CONCLUSION AND POLICY IMPLICATIONS

The market dynamics of the PV sector coupled with batteries will enhance the economics of residential PV self-consumption in the near future. PV self-consumption systems will become more economically competitive without subsidies. As demand for the residential PV self-consumption grows worldwide, we have proposed a new grid service model by assigning a secondary-use application to residential batteries for PV self-consumption in order to reduce systemic effects.

Our grid model uses residential batteries for PV self-consumption when they are not in use to store electricity from the grid with the objective of flattening the consumption profile. The expected effects concern the winter period because batteries are not usually used due to low PV power production and higher power consumption from households. It should be highlighted that the grid service model moves a share of the consumption during daily peaks and annual peak demand to other times zones when the national load demand is low, which reduces the additional efforts for PV integration to balance the system. We have concluded that our optimized residential PV self-consumption model with grid service increases the rate of battery use during winter and significantly helps address balancing and back-up issues. For this to be feasible, the model needs a relatively simple yet standardized control system that includes automatic operation based on optimal conditions (rates, times). In addition, policy can support the development of the model (e.g. regulation, standardizations). Regulations can be designed to allow grid operators to access the battery capacity to address seasonal peak demand.

However, possible risks with regard to the implementation of grid services can arise due to the rapid change in demand related to battery charging (concurrent automatic charging). More sophisticated solutions that smooth the start and end of battery charging/discharging should be possible. Based on institutional support, we can develop refined remote control systems (e.g. time-based by geographic areas) and sub-level management (e.g. collaborative actions with aggregators) to maximize the benefits of the grid service.

The aggregate use of residential batteries for PV self-consumption can potentially play an important role in improving the penetration of variable renewables like solar energy by providing an interesting back-up option for a country like France. The coupling price reduction of PV systems and residential batteries will significantly enhance the economics of our model in the next decade. In addition, the study was based on the current carbon price. If we consider higher carbon prices, the economic attractiveness of our model will be further increased. This helps to reduce additional investment in annual back-up capacities (peak generation units). Moreover, revenue can be generated when grid operators, aggregators or system providers are allowed to use the capacities of residential batteries based on our grid service during winter. This indicates that the grid service solution can enhance the profitability of residential PV self-consumption systems. New business models and further applications for other sectors can be further discussed based on our model. Policy makers can thus prepare proper economic and institutional incentives to promote the secondary application of batteries for PV self-consumption diffusion. Economic models and price mechanisms to motivate end-users should be studied. For this reason, the current electricity market mechanism needs to be reconsidered as the current pricing mechanisms are insufficient for implementing the grid service model to achieve peak shaving of the power demand. We recommend preparing institutional support through sustained dialogue between energy system stakeholders.

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