New perspectives on solar photovoltaic (PV) self-consumption

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Abstract
France aims to boost the share of solar power generation in its electricity mix by 2030. 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, high penetration of distributed solar PV provokes a significant impact on the stability of electricity. The major systemic issues concern seasonal back-up power system associated with variable PV integration. Policymakers thus need to work on systemic solutions (e.g. load management, peak saving) to support the large-scale integration of variable solar power. In this regards, this study aims to propose an innovative load management model based on the secondary application of residential batteries already installed for PV self-consumption. We performed a prospective economic analysis to identify potential system contribution of French residential PV-battery systems in 2030. The aim is to reduce systemic impact of distributed solar PV system integration thanks to collective use of distributed residential batteries for load management when they are not in use in winter. A sensitivity analysis has been conducted based on different projections of residential PV self-consumption in 2030 (RTE, Enedis). Our study then concludes with key messages and policy recommendations.

1 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 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). The market dynamics of the PV sector coupled with lithium-ion (Li-ion) batteries 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[1] associated with variable PV integration (Pudjianto, et al., 2013; Keppler & Cometto, 2012). France has higher back-up power costs compared with other regions as France's annual electricity consumption peaks occur in the winter evenings. This means that the massive and rapid integration of PV without strategies can affect more significantly the energy system. Policymakers thus need to work on systemic solutions (e.g. load management, peak saving) to support large-scale integration of variable solar power. This study aims to propose an innovative load management model based on the secondary application of residential batteries already installed for PV self-consumption. We performed a prospective economic assessment to analyse maximum systemic contribution of distributed PV-batteries based on French energy transition scenarios in 2030. The aim is to increase the load flexibility associated with high penetration of distributed PV systems thanks to collective use of residential batteries of self-consumption when they are almost not in use in winter.

2 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 potential 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. The system

1 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.

integration efforts need to be considered to assess economic value of these variable energy sources in power systems (Keppler & Cometto, 2012; Hirth, 2014; Haas, et al., 2013; Pudjianto, et al., 2013)

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 study 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, 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.

Yu (2018) attempts to conduct a system-wide economic analysis of residential PV system consumption coupled with batteries. 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 PV-battery 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 (Coffman, et al., 2017; Li, et al., 2017). However, numerous studies focus on the 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. Moreover, 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). 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. It is important to note that back-up capacities to serve yearly load peak demand is essential issue to maintain the security of the power system. However, existing studies that examine the possible utilization of residential batteries are mostly based on short-term perspective even though some articles indicate the concept of systemic values without detailed optimization modelling. In addition, 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 of flexible load management 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.

3 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 2035 from the current 75% as part of its energy transition strategy. 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 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.

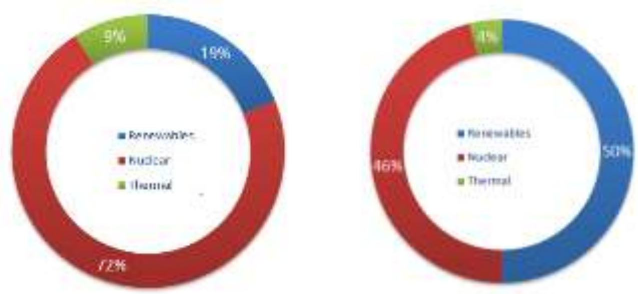

Figure 1: French power supply mix (2016, 2035) (RTE, 2016)

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). 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 Research objectives

This article proposes a new grid service model for flexible load management to support French energy transition policy plans that increase variable solar energies in the future power system. The study is based on collective use of residential batteries used for PV self-consumption for peak saving during winter months (December to February) when they are almost not in use. During this period, the residential battery capacity for self-consumption is not essential for small residential systems (3kWp) because the PV production rarely exceeds the consumption in winter in France. Since the annual power demand peak in France occurs in the winter evening, our grid service model of daily peak saving would directly reduce French annual load peaks. In this regard, this study evaluates the potential systemic benefit of secondary-use application of French residential PV-batteries in 2030.

This study adopts a numeric simulation model based on empirical French data (RTE and Enedis) to evaluate the potential benefits of collective use of distributed residential batteries. This article thus attempts to address the following questions.

- What are the potential systemic benefits (daily balancing and annual back up) from the secondary-use application of French residential batteries of PV self-consumption in 2030?
- What economic benefits will result from using the presented 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.

4 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.

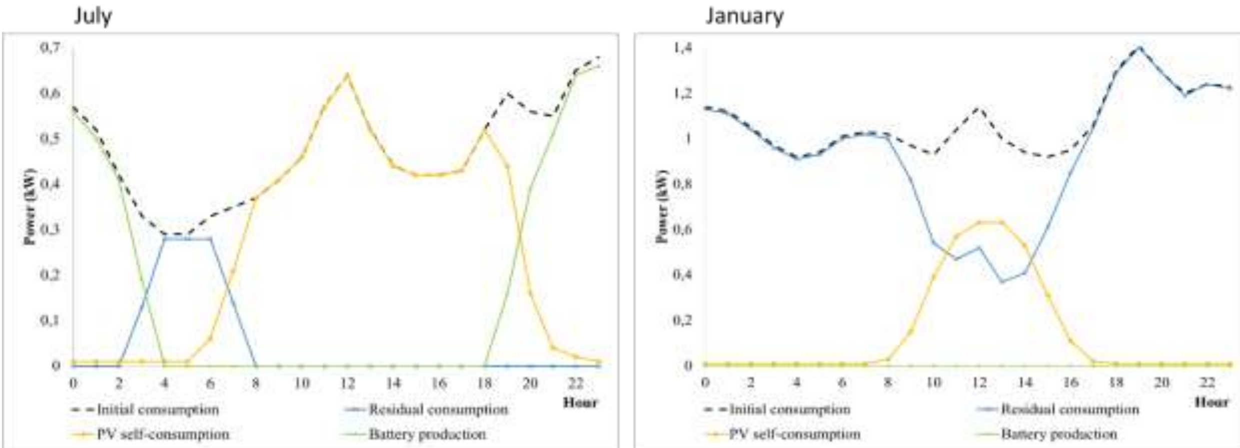

Figure 2: Mechanisms of PV self-consumption based on a residential PV system (3kWp) with Li-ion batteries (4kWh capacity) (author's calculation based on the average energy profiles)

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.

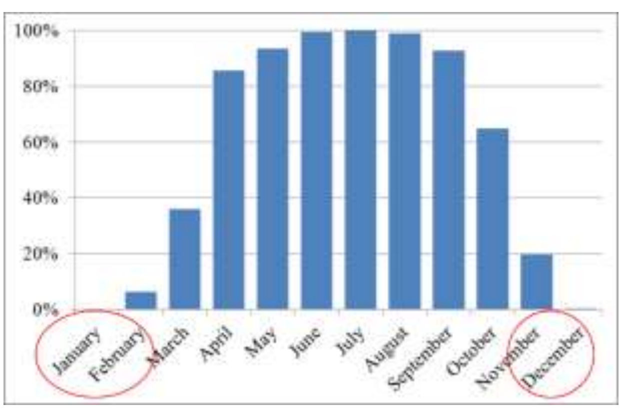

Figure 3: Battery use by month

The purpose of the model is to optimize the use of residential batteries throughout the year to create a secondary-use application for batteries to smooth the power demand and to address the back-up issue of PV integration in France.

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. 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 without additional systemic costs induced by grid injection.

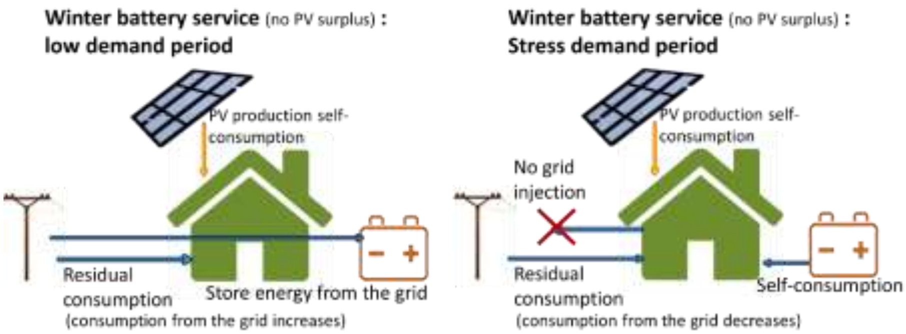

Figure 4: Grid services from residential batteries

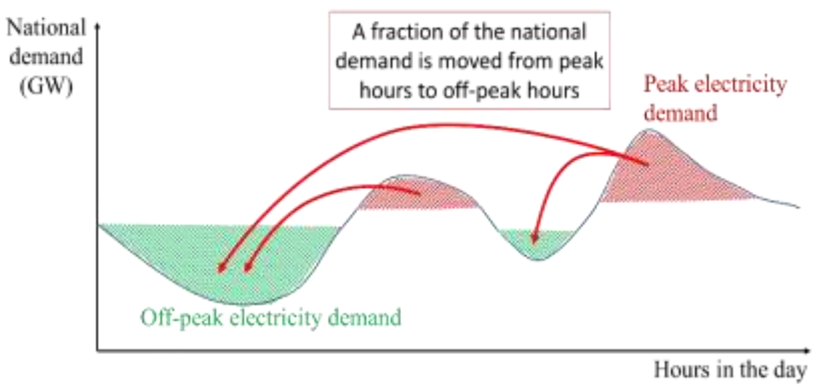

Figure 5: Potential energy shifting through the use of residential batteries

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 national 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.

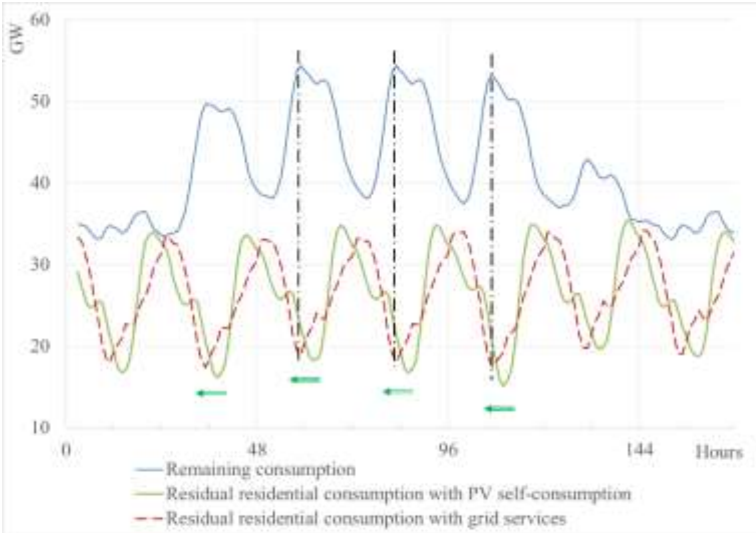

Figure 6: Targeted changes in the residential residual consumption to minimize peaks

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.

The methodological approach to develop the grid service model and data provided are explained in detail in the following sections.

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.

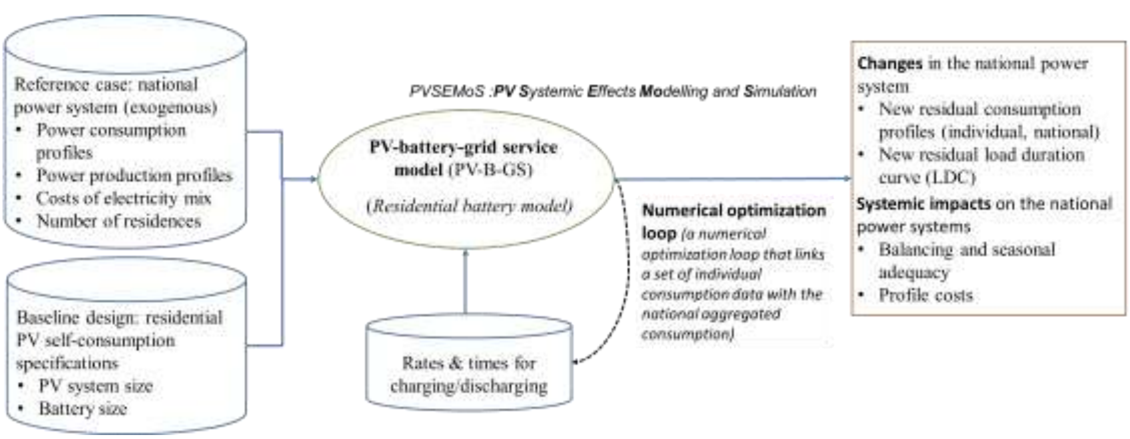

Figure 7: Logic flow diagram of the PV-B-GS (PV-battery-grid service) model

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 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:

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

4.3 Data and assumptions

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.

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 model developed in the author's previous article (Yu, 2018). 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[2] (Nb_H) were equipped with the 3 kWp PV system coupled with the 4 kWh battery[3]. 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. The ensuing PV production 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 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 put aside. 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 consumption profile

The total consumption in 2015 provided by RTE 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.

Table 1: Current electricity consumption and PV production

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

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).

Table 2: French electricity consumption by segment in 2015

	Residential	Industrial	Commercial	Other	Total

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

3 Residential PV production: This study is based on the real PV production profile in France in 2015. 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 also includes 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.

TWh	164	115	148	56	483
%	34%	24%	31%	11%	100%

The French residential consumption represents 27 million residences including 18.8 million individual houses. 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. Because of a lack of bottom-up data on different types of residences, 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.

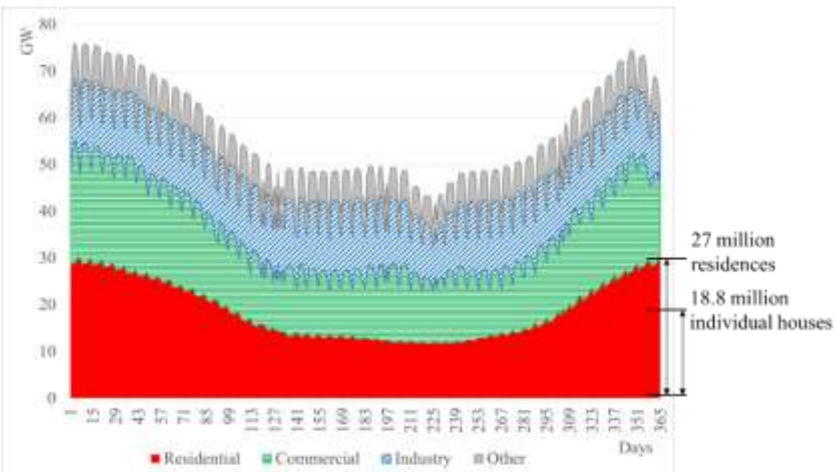

Figure 8: Annual consumption profile by sector

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.

5 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.

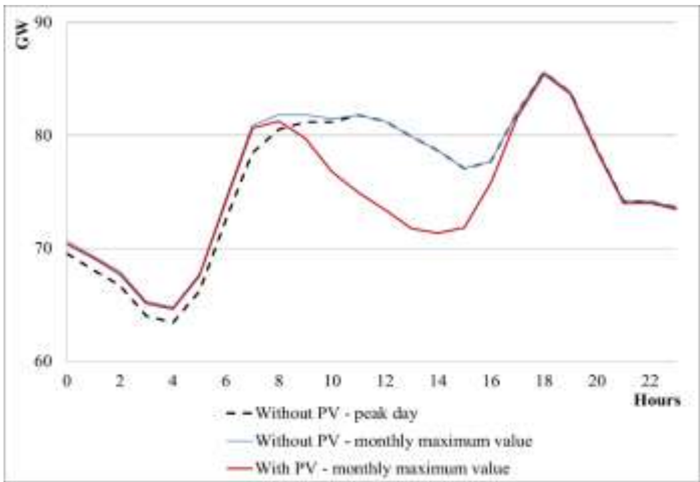

Figure 9: Hour-to-hour daily national load consumption values (peak day and monthly maximum values) in January 2015 in France

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. 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

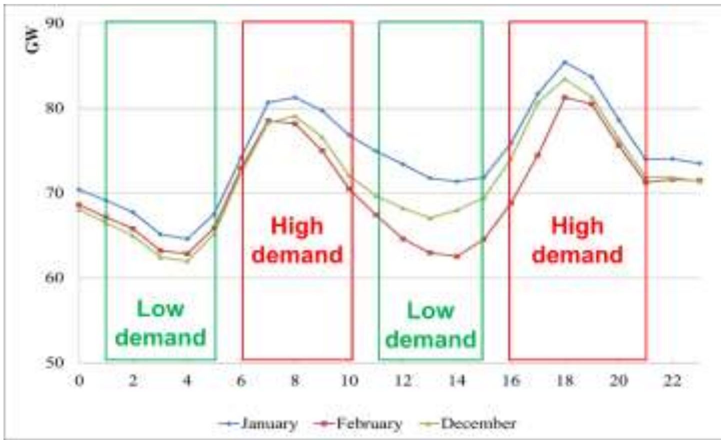

Figure 10: Maximum national demand for each hour of the day with PV self-consumption for December, January and February

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 rate is defined. For example, a rate of 1 kWh per hour can lead to new demand peaks during the night and at midday. 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. We use our numerical optimization tool to set the rates. Based on the results from 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).

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 and to handle issues related to frequency variations. 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.

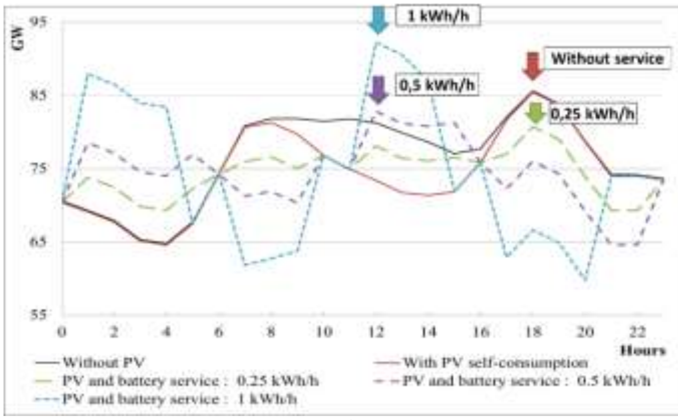

Figure 11: Impact on the national demand profile in January

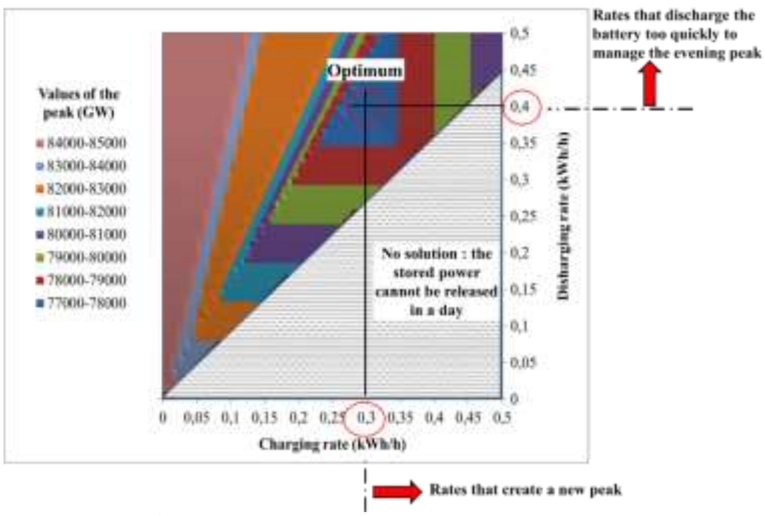

Figure 12: Results of battery charging and discharging rates obtained by the optimization loop

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 3 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 national peaks to other time zones. The algorithm of the numerical simulations validates this effect.

Table 3: Impact on the total electricity consumption

	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

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 service 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 residential consumption during the peak at night is higher, but it should be noted that this happens during a low national demand period.

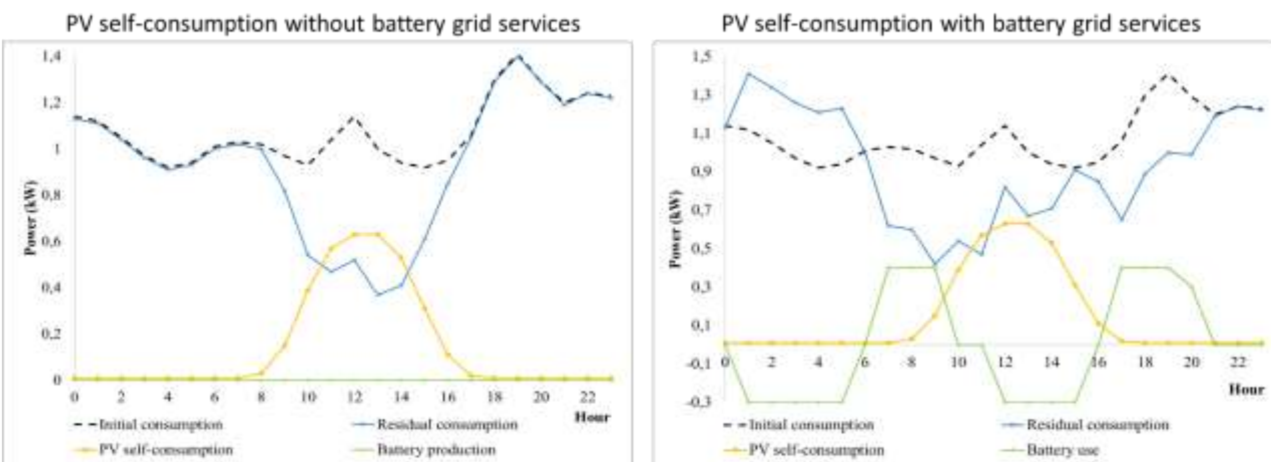

Figure 13: Residential profiles without (left) and with grid services (right): 4 January 2015 (annual peak)

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 4). We find that the new grid service model helps flatten the daily load curve for all months (December, January and February) in question.

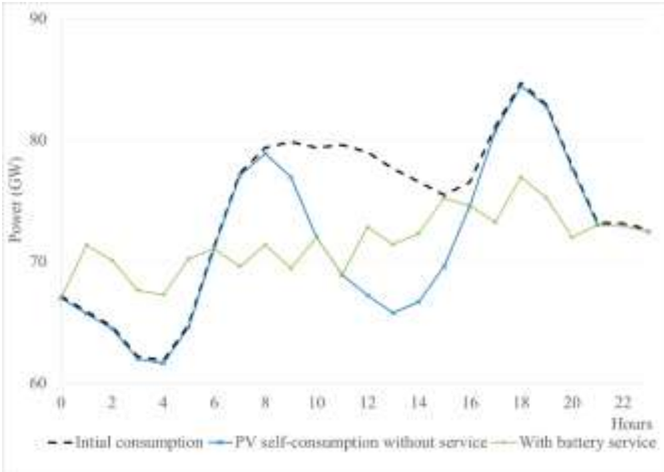

Figure 14: National consumption profiles based on the example of 4 January 2015 (peak day)

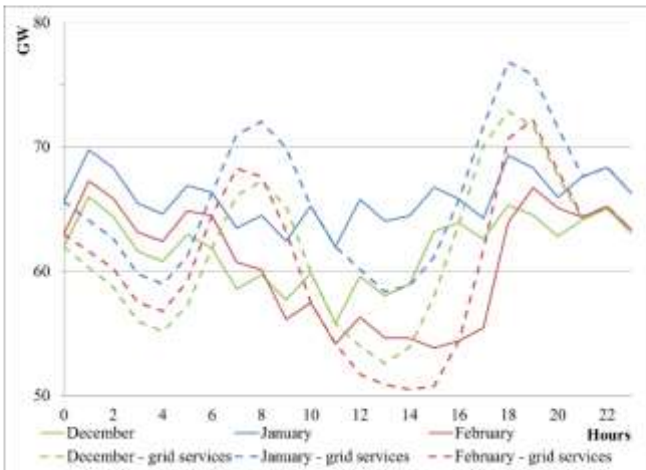

Figure 15: Grid services to smooth the daily load variation (December-January-February)

Table 4: Average gains in daily balancing

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

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 □). 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 5 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).

Table 5: Optimal power generation mix and yearly full load hours of dispatchable capacities – Reference scenario with virtual electricity mix in 2015

	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%

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. The optimal power supply mixes are different between two scenarios depending on whether the grid service model is used. 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[4].

We can evaluate the systemic and economic impact on the mix based on this result.

Table 6: 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	82.6%	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-GS

	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%

[4] 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.

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).

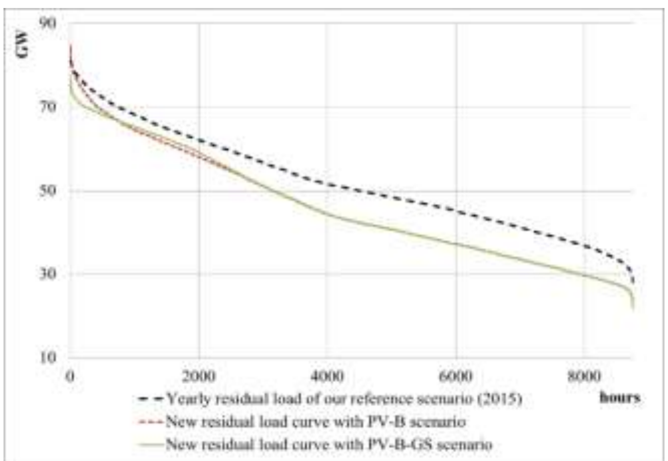

Figure 16: Changes in the load duration curve

Figure 17 provides a close-up of three curves with focus on the annual peak period. 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.

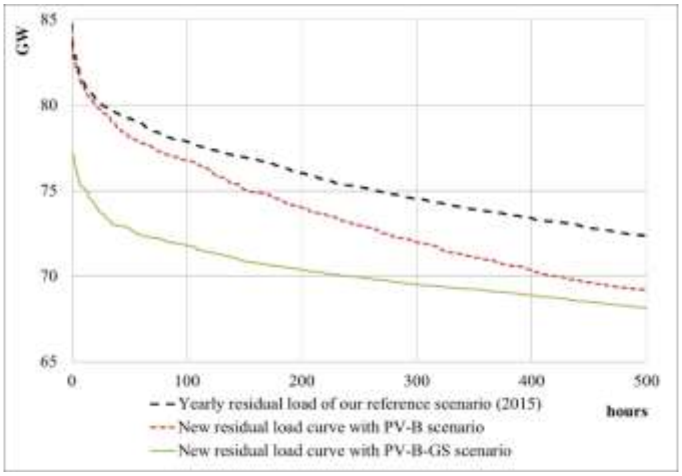

Figure 17: Focus on the annual peak period of the load duration curves

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 8 illustrates the projected PV self-consumption deployment by 2035 in France.

Table 8: Parameters of sensitivity analysis

	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

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.

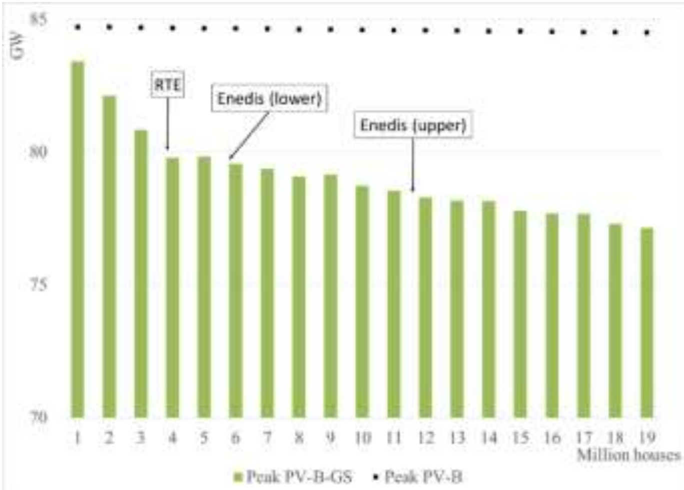

Figure 18: Sensitivity analysis of annual peak saving impact on a national level

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. 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 5 to
Table 7). We have demonstrated the extent to which the grid service can reduce peaks in demand for the French electricity 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[5]).

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

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 according to the different scenarios from the previous section was also used to calculate the profile costs[6]. 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 9 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.

Table 9: Profile costs based on two scenarios

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

[5] 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)

[6] The mathematical expression to define the production costs of the optimal residual mix is described in (2):

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

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 $\mathrm{T(q, E_{VRE})}$

PV-B-GS (grid service)	0.9	17

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.

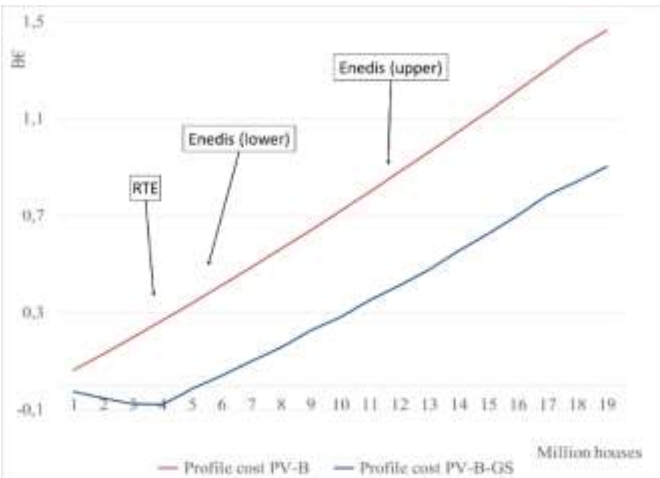

Figure 19: Sensitivity of profile cost estimates

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 10. 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.

Table 10: Discounted annual cost of the investment and battery service remuneration

	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

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.

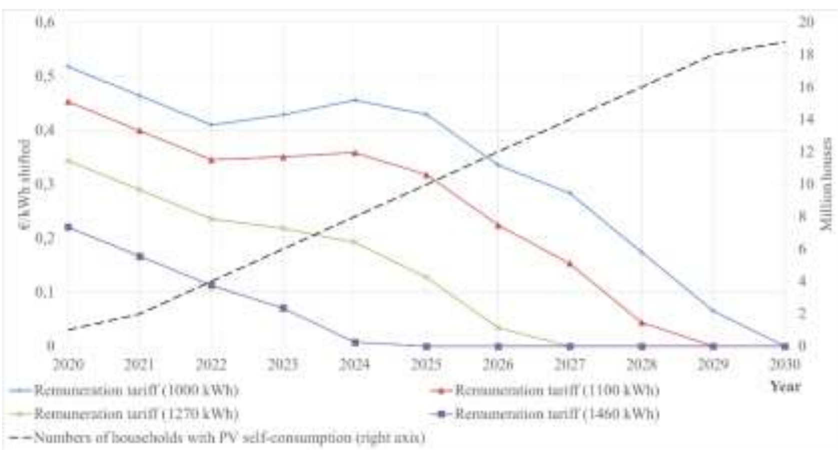

Figure 20: Sensitivity of the grid service tariffs to break-even the investment for the energy output

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

[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.

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.

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.

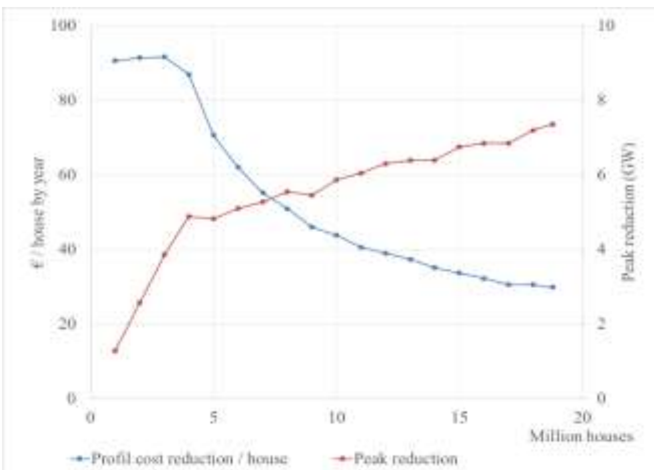

Figure 21: Sensitivity of the peak shaving impact and profile cost reduction according to PV diffusion

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

[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.

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 by acting as a load management operator.

6 Conclusion and policy implications

As demand for the residential PV self-consumption grows worldwide, we have proposed a new grid service model of flexible load management by assigning a secondary application to residential batteries for PV self-consumption. 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. Intermediate load management operators may facilitate the operation process.

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 that can lead to quick frequency variations). 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.

Therefore, we suggest enhanced market design (grid service-based tariffs, auction-based mechanism) and system process (intermediate load operators, aggregators) that allow grid operators to realise the proposed load management model. In addition, revenue created from this approach can help enhance the economics of distributed PV systems and facilitate the energy transition pathway. Policy makers can thus prepare proper economic models and institutional incentives to promote the proposed application of distributed PV batteries for flexible load management in accordance with the national plan of solar energy development.

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Annexes

- Analysis of systemic effects

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 11 shows investment and variable costs of different power plants used in the virtual mix (Petitet, et al., 2016).

Table 11: Investment and variable costs of the virtual electricity mix technologies

	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
CO2 intensity (tCO2/MWhe)	0	0.8	0.35	0.8

**The assumed carbon price was €30.5/ t CO2, 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.

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