System contributions of residential battery systems: New perspectives on PV self-consumption

Hyun Jin Julie Yu [a,b,*]

[a] Institute for Techno-Economics of Energy Systems (I-tésé), Direction des énergies (DES), French Alternative Energies and Atomic Energy Commission (CEA Saclay), France
[b] Chaire of European Electricity Markets (CEEM), Paris-Dauphine University Paris, France

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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 shaving) 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 towards 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 (Yu, 2018). 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 and 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 shaving) 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

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* Corresponding author at: Institute for Techno-Economics of Energy Systems (I-tésé), Direction des énergies (DES), French Alternative Energies and Atomic Energy Commission (CEA Saclay), France.
E-mail address: julie.yu@cea.fr.

[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.

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 integration efforts need to be considered to assess economic value of these variable energy sources in power systems (Keppler and 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 and Hiralal (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. 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 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. 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). 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. 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.

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 2018, 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 a significant increase in renewable energies (See Fig. 1). 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.

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
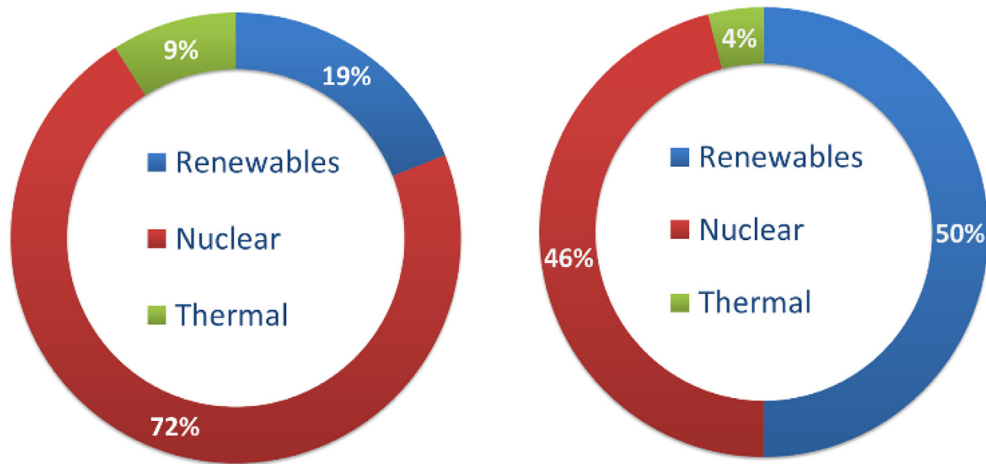
Fig. 1. French power supply mix (2016, 2035) (RTE, 2016).

and 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 shaving 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 shaving 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.

Fig. 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 about 65% throughout the year (100% = 1 full cycle per day). As Fig. 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.

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 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 (See Fig. 4 and Fig. 5).

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 (Fig. 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.

There are alternative options for power system balancing. For example, demand response (DR) leads to changes in the power consumption
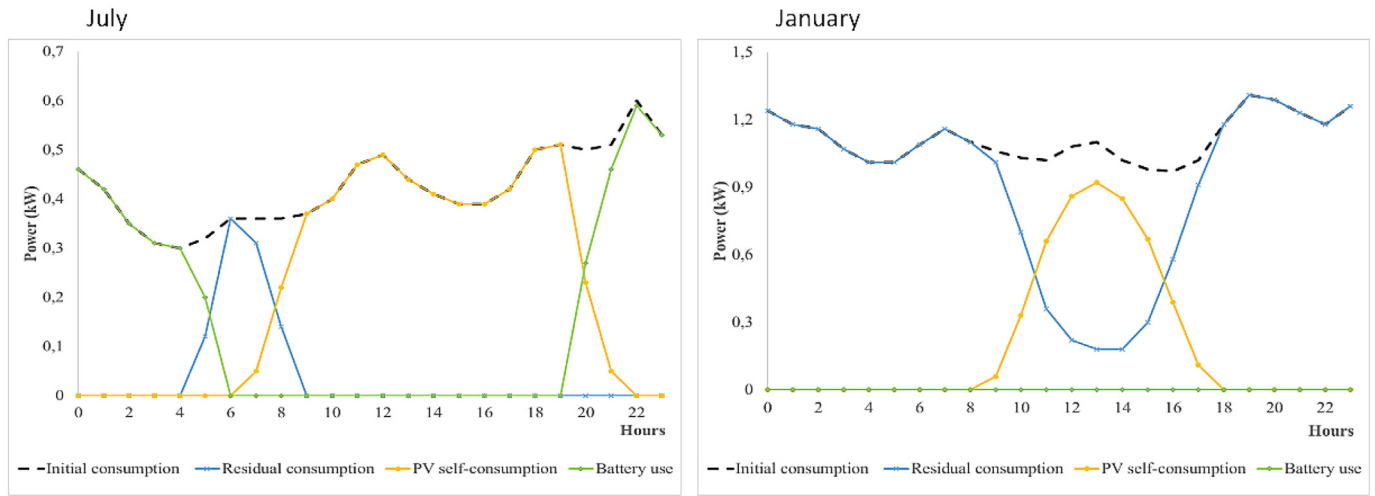
Fig. 2. Mechanisms of PV self-consumption based on a residential PV system (3kWp) with Li-ion batteries (4kWh capacity) (author's calculation based on the average energy profiles).
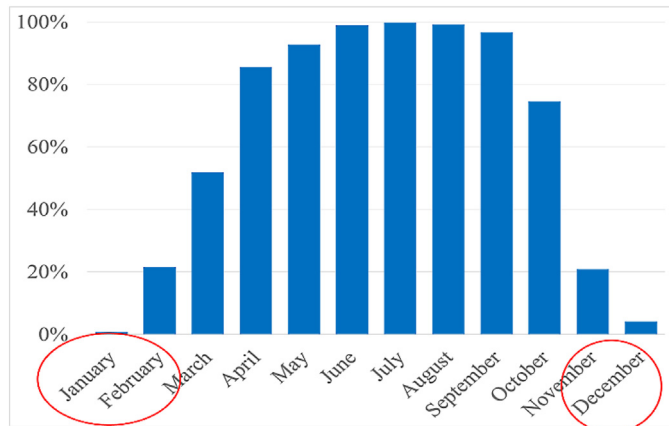

Fig. 3. Average battery use by month (2015 to 2019).

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 a 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 (Fig. 7).

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 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
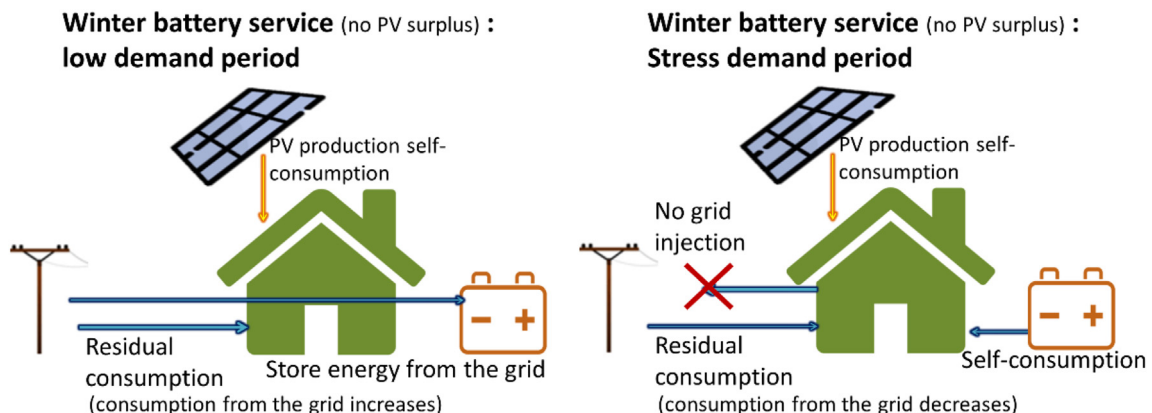

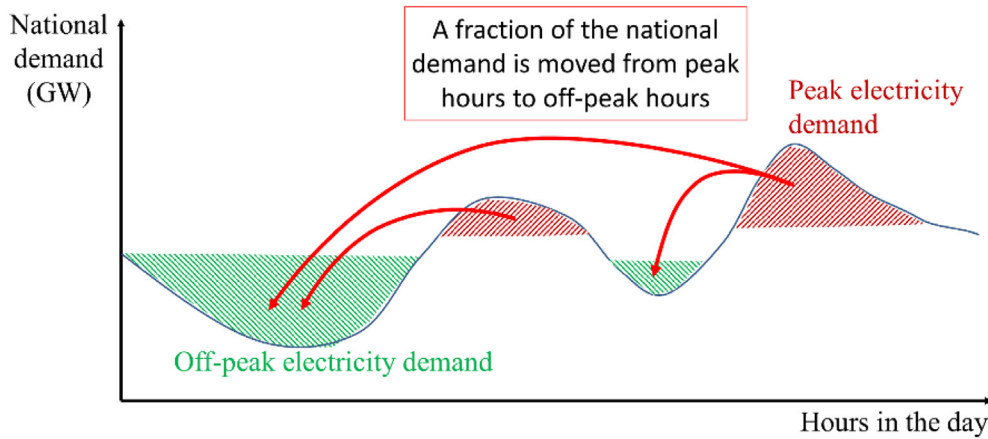**Fig. 4.** Grid services from residential batteries.

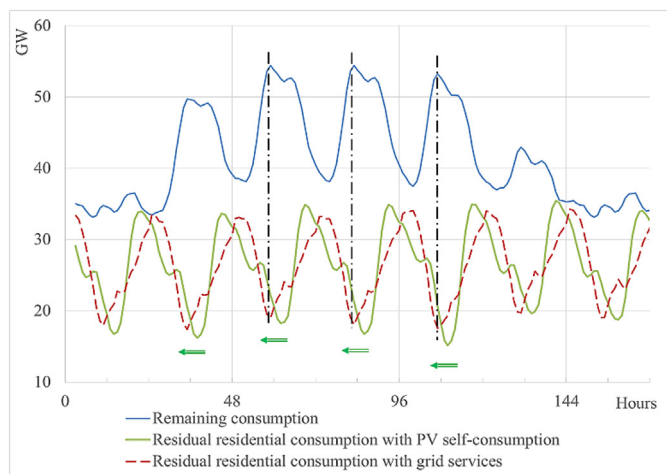**Fig. 5.** Potential energy shifting through the use of residential batteries.

Fig. 6. Targeted changes in the residential residual consumption to minimize peaks.

- Reference case: 2019 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

The French transmission and distribution system operators (Réseau de transport d'électricité (RTE) and Enedis) provides open platforms for their energy system database (RTE, 2020; Enedis, 2020). 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 years of 2015 to 2019.

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 2019 as a reference case with a cumulative installed

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.
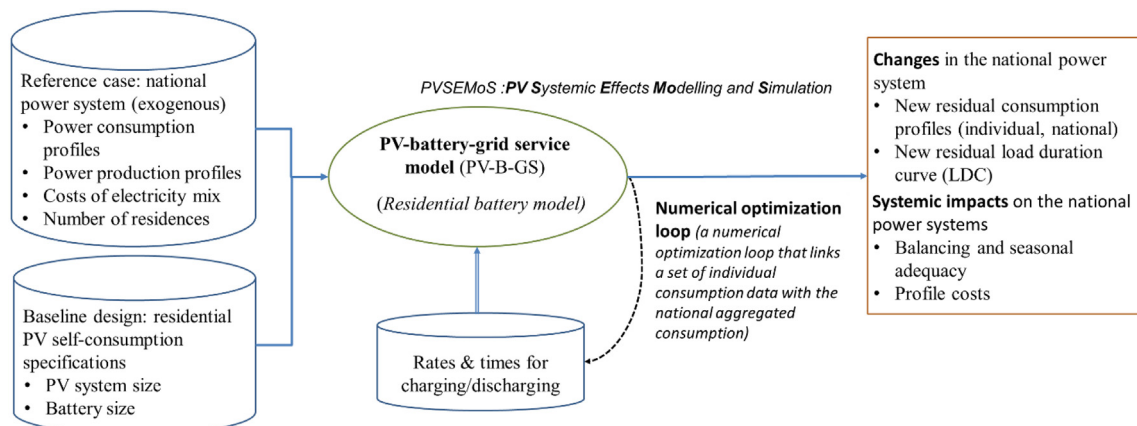
Our analysis is based on three scenarios:

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

PV capacity of 6.5 GWp (around 2% of the domestic power consumption). At first, we assumed that the 18.8 million individual houses[2] were equipped with the 3 kWp PV system coupled with the 4 kWh battery[3] as an enveloping case. 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 then 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 2019 provided by RTE was used as the baseline for our simulation, i.e. 470 TWh. As Table 1 shows, the residual consumption of the current mix, excluding wind and PV production, represents 424 TWh (2019). 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.

RTE provides hour-by-hour consumption data by segment of consumption. The residential consumption represented 148 TWh (35% of the total consumption) in 2019.

The French residential consumption represents 27 million residences including 18.8 million individual houses (see Fig. 8).[4] 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.

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[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 2019. 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.

[4] The average yearly residential consumption is 148 TWh / 27 million = 5480 kWh/year.

Table 1
Current electricity consumption and PV production.

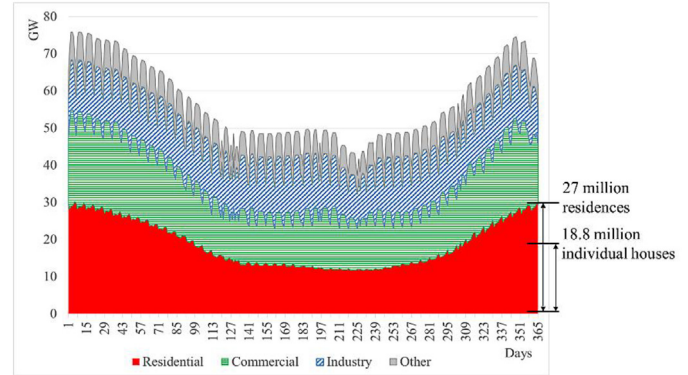| Current situation	2019
Total consumption	470 TWh
PV production	11.6 TWh
Residual consumption	424 TWh

Fig. 8. Annual consumption profiles by sector (2015).

In our model, we considered that the battery production can only be 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.

Fig. 9 shows the hour-to-hour daily grid demand for January, the month during which the annual peak was reached in 2019. The dashed line shows the real load consumption profile without PV self-consumption 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
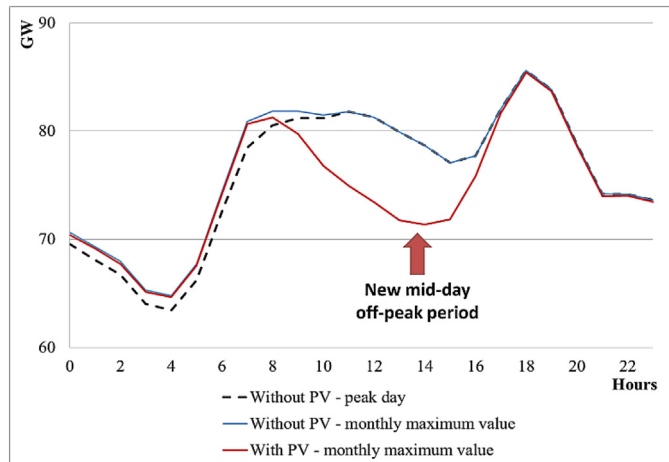
Fig. 9. Example of hour-to-hour daily national load consumption values (peak day and monthly maximum values) in January 2019 in France.

maximum load consumption for each hour of the day throughout the month without PV self-consumption while the red line shows the maximum load consumption with PV self-consumption. As Fig. 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 Fig. 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

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
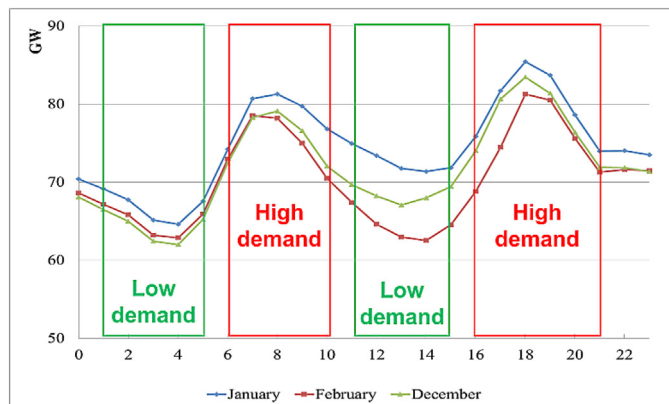
charging and discharging decision (e.g. risks related to concurrent automatic charging).

It is important to note that daily peak demand hours can be changed depending on how the battery charging or discharging rate is defined. As Fig. 11 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, we use our numerical optimization tool to set the rates and we decided to fix a rate of 0.3 kWh/h for charging and 0.35 kWh/h for discharging in our simulation model (see Fig. 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.

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 2 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.

We thus decided to focus on the smoothing effects. Fig. 13 illustrates the residential load profile (blue) according to two different scenarios. We used the daily profile of 24 January 2019 (the annual peak). We can see that the grid service model modifies the load profile. The left

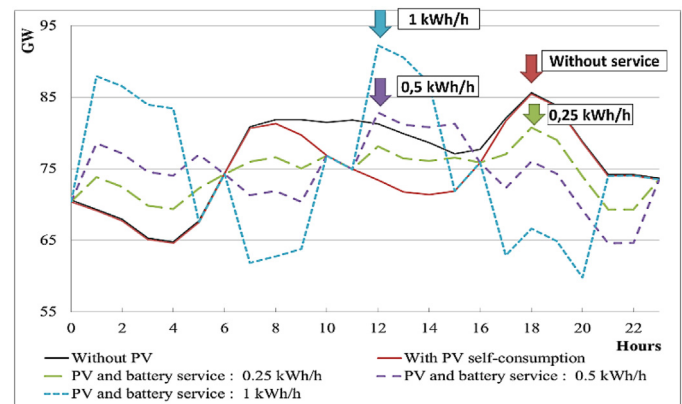**Fig. 10.** Example of maximum national demand for each hour of the day with PV self-consumption for December, January and February 2019.

Fig. 11. Examples of impacts of charge and discharge rates on the national demand profile in January 2015.
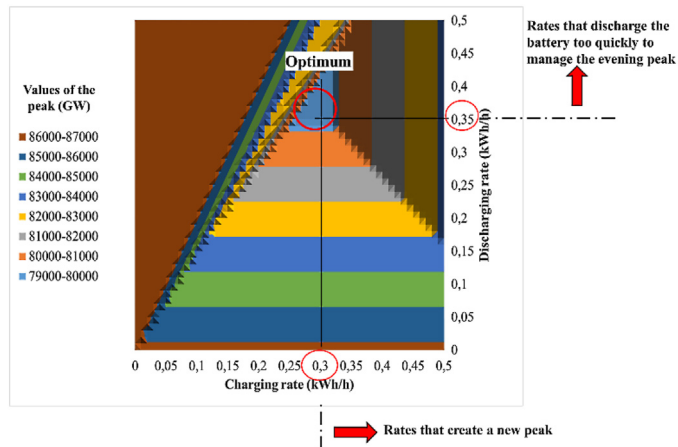
Fig. 12. Results of battery charging and discharging rates obtained by the optimization loop for 2019.

Table 2
Impact on the total electricity consumption in 2019.

	Current	PV self-consumption with batteries (10% PV integration, PV-B or PV-B-GS scenario)
Total consumption	470 TWh	470 TWh
PV production consumed	11.6 TWh	62 TWh
Residual consumption (excluding wind)	425 TWh	374 TWh

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.

Fig. 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 could smooth the daily load variation, which means less balancing efforts. Fig. 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 3.6 GW (February) to 8.2 GW (January) for the years 2015–2019 (Table 3). We find that the new grid service model helps flatten the daily load curve for all the months (December, January and February) in question.

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 Annexes). The virtual mix that we use 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 based on the minimum costs of power generation to meet the annual electricity demand. Table 4 shows the annual full load hours and capacities of dispatchable plants in the optimal power mix in 2019 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. oil combustion turbine).

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 15.9 GW to 10.1 GW.[5]

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

Fig. 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. This 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 2019 (425 TWh in 2019) while the red dotted line represents the new residual load curve after adding a new installed solar PV capacity of 56 GWp 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. 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 500 h and 2500 h).

Fig. 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 6.4 GW from 86.2 GW with the PV-B scenario to 79.8 GW with the PV-B-GS scenario.

We have analysed the years of 2015 to 2019 based on the same battery parameters. The following Table 6 demonstrates the reduction of annual peak:

A discernable peak reduction appears for each year. 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 7 illustrates the projected PV self-consumption deployment by 2035 in France.

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.

Fig. 18 shows the aggregate result of annual peak shaving 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. However, the annual peak shaving impact is significantly greater in the beginning of the PV

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[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.
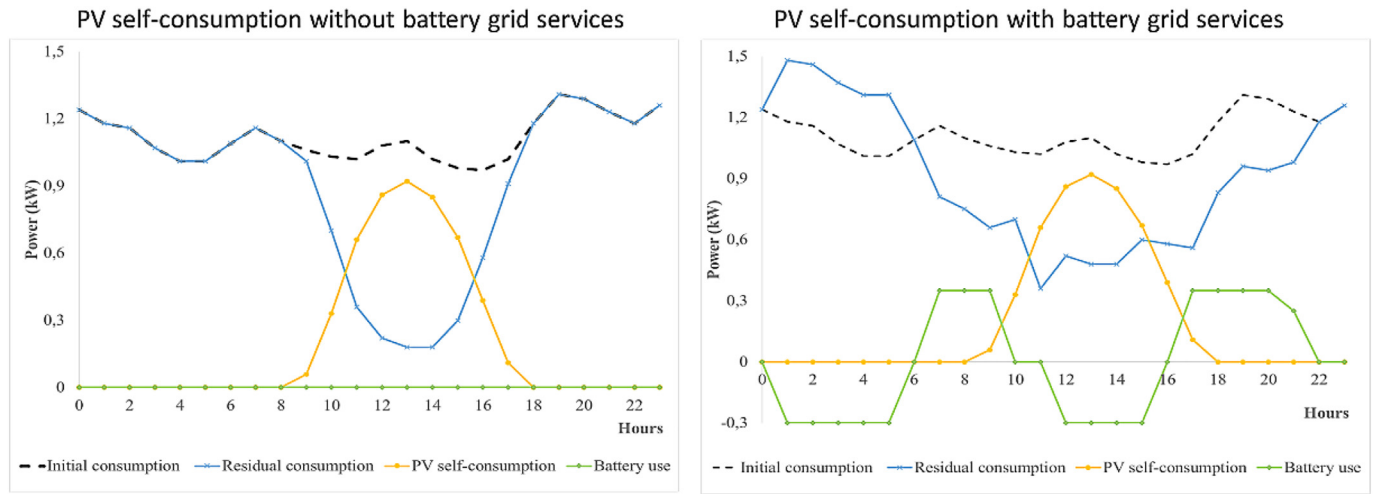
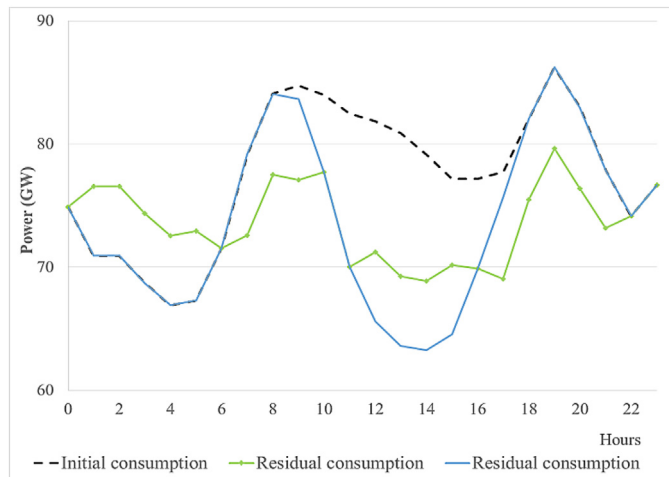**Fig. 13.** Residential profiles without (left) and with grid services (right): 24 January 2019 (annual peak).

Fig. 14. National consumption profiles based on the example of 24 January 2019 (peak day).
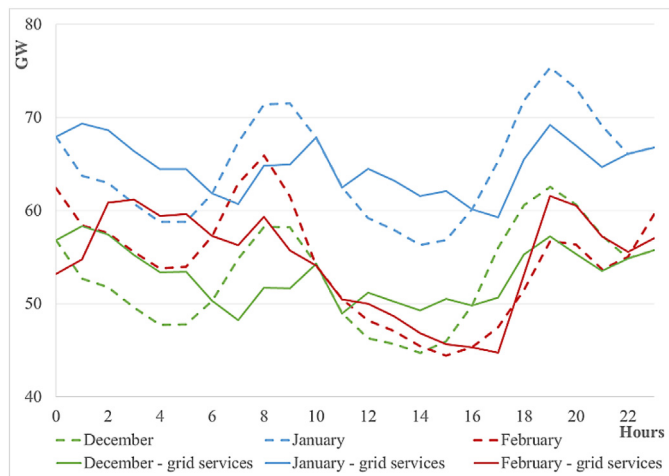

Fig. 15. Grid services to smooth the daily load variation (December–January–February).

Table 3
Average gains in daily balancing for the years 2015 to 2019.

Average consumption variation	PV-B scenario	PV-B-GS scenario	Delta
December	17.7 GW	10.7 GW	−7GW
January	18.5 GW	10.3 GW	−8.2 GW
February	20 GW	16.5 GW	−3.6 GW

diffusion with fewer batteries. For example, according to RTE's projection, the required back-up capacity can be reduced to 82.7 GW based on only around one fifth of the maximum storage capacity (15.3 GWh) (cf. 79.8 GW with the maximum uptake).

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 4 and Table 5). We concluded in the previous section that the new grid service model changes the optimal 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) (eq. 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)

$\overline{E}_{total}$: Power system's annual power demand (exogenous factor)
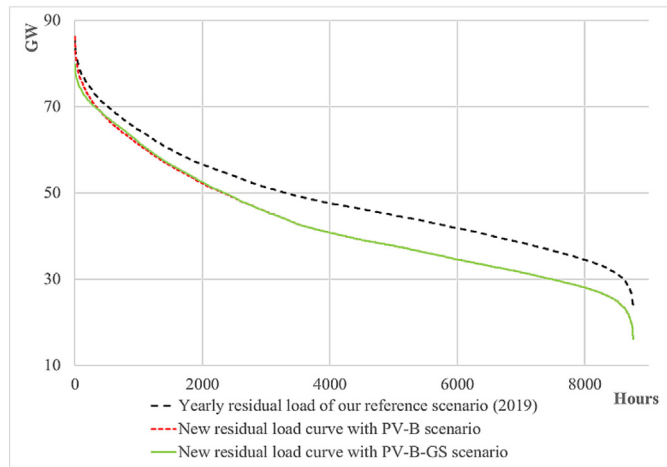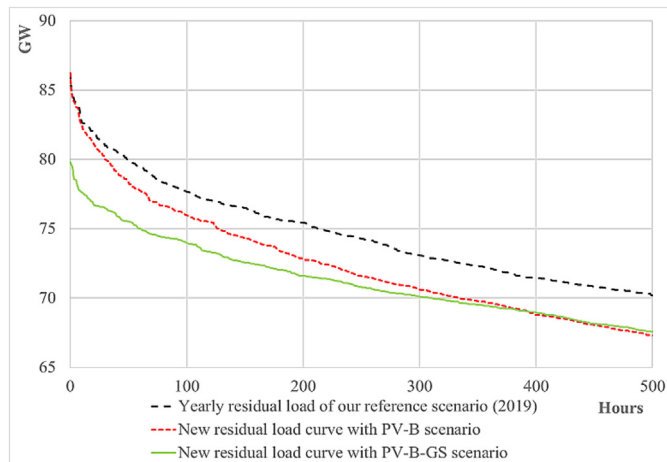
Table 4

Optimal power generation mix and yearly full load hours of dispatchable capacities – Reference scenario with virtual electricity mix in 2019.

Dispatchable capacities	Supply		Demand (Current residual load: 425 TWh)	
	Full-load hours/year (optimal)	Dispatchable capacities (GW) (optimal)	% of total residual demand	% of total demand
Nuclear	4981 h–8760 h	44.9	86.7%	78.3%
Coal	3765 h–4981 h	3.5	3.2%	3.2%
Combined-cycle gas turbine (CCGT)	318 h–3764 h	24.5	9.45%	8.5%
Combustion turbine (CT)	0 h–317 h	13.4	0.3%	0.3%

Table 5

Optimal power generation mix and yearly full load hours of dispatchable capacities.

Dispatchable capacities	Supply Dispatchable capacities (GW) (optimal)		Demand % of total demand	
	PV-B	PV-B-GS	PV-B	PV-B-GS
Nuclear	37.8	37.8	65.3%	65.4%
Coal	3.8	3.8	3.5%	3.5%
Combined-cycle gas turbine (CCGT)	28.7	27.8	10.4%	10.4%
Combustion turbine (CT)	15.9	10.3	0.3%	0.2%

Fig. 16. Changes in the load duration curve.

Fig. 17. Focus on the annual peak period of the load duration curves.

Table 6

Reduction of annual peak for years 2015 to 2019.

Year	2015	2016	2017	2018	2019
Residual peak PV-B (GW)	86.9	86.8	92	89.7	86.2
Residual peak PV-B-GS (GW)	80.4	83	85.4	86.6	79.8
Peak reduction PV-B-GS (GW)	6.5	3.8	6.6	3.1	6.4

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

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 2019 data was used as a baseline to calculate the profile costs. Our analysis considered the current residual demand as a reference. The defined optimal mix according to the different scenarios from the previous section was also used to calculate the profile costs (Ueckerdt et al., 2013). As seen in Fig. 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 8 shows the profile costs of 56 GWp PV integration depending on the defined scenarios. According to our analysis, the additional cost per each MWh of new PV production ($/MWh PV) amounts to $26.1/MWh under the PV-B scenario with no grid service. However, this cost can be reduced by around 33% to $17.6/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 $480 million 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.

Fig. 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

Table 7
Parameters of sensitivity analysis.

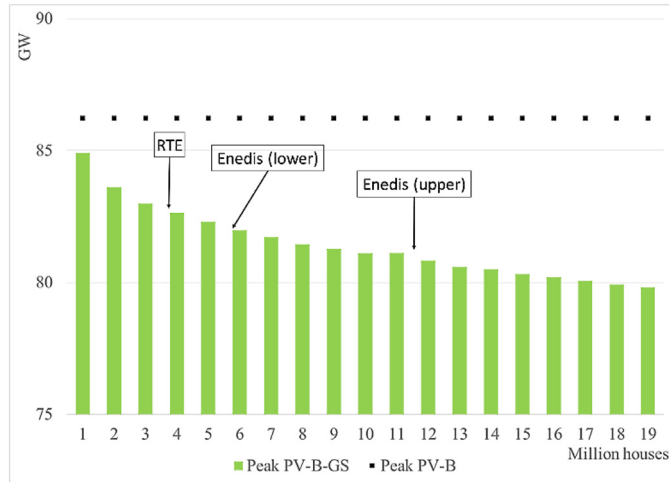|	Number of houses with PV self-consumption in 2035 (million houses)	Aggregate capacities of batteries (GWh)	Optimal rates of charging / discharging (kWh/h)
Base case (maximum uptake)	18.8	75.2	0.3 / 0.35
Enedis (upper)	11.6	46.4	0.35 / 0.45
Enedis (lower)	5.8	23.2	0.55 / 0.75
RTE	3.8	15.3	0.65 / 0.95

Fig. 18. Sensitivity analysis of annual peak shaving impact on a national level.

Table 8
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)	1.47	26.1
PV-B-GS (grid service)	0.99	17.6

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 for the diffusion of under around 5 million houses since the proposed grid service model can optimally increase the efficiency of the power system compared with the reference scenario.

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. 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 9. 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.

There is a clear gap between household investment and savings in electricity bills in locations with low levels of PV output. 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.

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 $181/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 $0.26/ kWh for power replacement of 688 kWh/year 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. Fig. 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
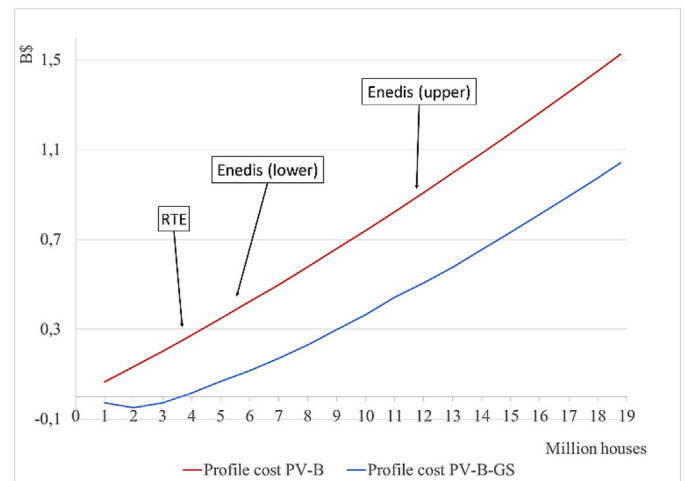

Fig. 19. Sensitivity of profile cost estimates.

Table 9
Discounted annual cost of the investment and battery service remuneration.[a]

	Energy output kWh/kWp	Discounted annual costs of the investment ($) (a)	Discounted annual gains from avoided grid consumption by PV self-consumption ($) (b)	Gap between a & b ($)	Discounted annual gap ($)	Remuneration of the power displaced
Paris	1,000	10,723	7,092	−3631	181	0.26 $/kWh
Average in France	1,100	10,723	7,801	−2922	146	0.21 $/kWh
Bordeaux	1,270	10,723	9,007	−1716	86	0.12 $/kWh
Nice	1,460	10,723	10,355	−368	18	0.03 $/kWh

[a] 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 $2/Wp, building integration (BIPV) for residential rooftops using c-Si PV technology (IEA PVPS, 2019) Potential PV power output: provided by PVGIS (JRC European Commission, 2020) 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, 2013) The LCOE of residential PV systems with batteries divided by the ratio of self-consumption.
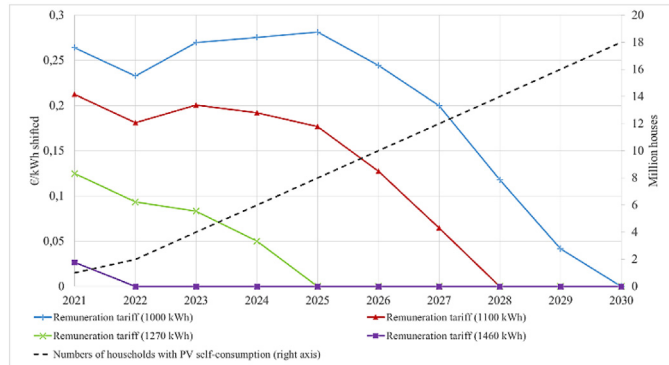

Fig. 20. Sensitivity of the grid service tariffs to break-even the investment for the energy output.

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 all over France around in 2030. Once breakeven is achieved, the additional gains can be used for other segments such as grid financing.

The remuneration system can be designed based on the contribution to the grid services. Fig. 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 Fig. 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 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 time 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 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 in order 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). We can design more sophisticated solutions that can smooth the start and end of battery charge and discharge. Based on institutional support, we can develop refined remote control systems (e.g. time-based by geographical 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
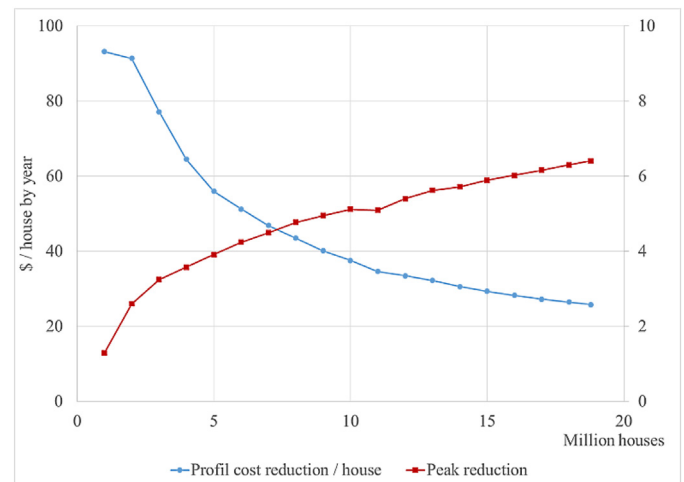

Fig. 21. Sensitivity of the peak shaving impact and profile cost reduction according to PV diffusion.

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.

Annexes

• 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.

• Modelling grid services and the optimization loop

The loop used to determine the optimal parameters depends on the battery charging/ discharging times and the battery charging/ discharging rates. 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 $\widetilde{e}_{H,PV}$ 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: $\widetilde{E}_{R,PV} = \widetilde{e}_{H,PV} \times Nb_H + e_R \times (Nb_R - Nb_H)$.
4. Reintegrate the new residential consumption profile into the total demand: $\widetilde{E}_{Tot,PV} = \widetilde{E}_{R,PV} + (E_{Tot} - E_R)$.

5. Use a loop to identify the optimal parameters that minimize the peak: $\widetilde{E}_{Tot,PV}^{opt} \mid \forall \widetilde{E}_{Tot,PV}$, $\max(E_{Tot,PV}) - \max\left(\widetilde{E}_{Tot,PV}\right) \leq \max(E_{Tot,PV}) - \max\left(\widetilde{E}_{Tot,PV}^{opt}\right)$. 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:

$$S_c^{opt}, S_d^{opt}, t_c^{opt}, t_d^{opt} \mid \forall \{S_c, S_d, t_c, t_d\},$$

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

With

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

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[7]
• Table 10 shows the investment and variable costs of different power plants used in the virtual mix (Petitet et al., 2016)

Table 10
Investment and variable costs of the virtual electricity mix technologies.**

	Nuclear	Coal	CCGT	Combustion turbine (oil)
Investment (k€/MW)	3,910	1,400	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 (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.

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