CHAIRE EUROPEAN ELECTRICITY MARKETS
Fondation Paris-Dauphine

Working Paper #27

A PROSPECTIVE ECONOMIC ASSESSMENT OF RESIDENTIAL PV SELF-CONSUMPTION WITH BATTERIES AND ITS SYSTEMIC EFFECTS, AND THE IMPLICATIONS FOR PUBLIC POLICIES: THE FRENCH CASE IN 2030

Hyun Jin Julie YU

15.06.2017

DAUPHINE UNIVERSITÉ PARIS

Chaire de recherche soutenue par

RTE, EDF, EPEXSPOT, GROUPE Caisse des Dépôts

A PROSPECTIVE ECONOMIC ASSESSMENT OF RESIDENTIAL PV SELF-CONSUMPTION WITH BATTERIES AND ITS SYSTEMIC EFFECTS, AND THE IMPLICATIONS FOR PUBLIC POLICIES: THE FRENCH CASE IN 2030

Hyun Jin Julie YU[1]
15 Juin 2017

Abstract
Over the last decade, the price of PV modules has fallen largely due to the globalisation of the PV sector. If residential PV systems coupled with batteries become economically competitive in the near future, end-users will be willing to switch to the self-consumption of PV electricity instead of using power from the network. If the transition of PV self-consumption in the residential sector occurs massively or suddenly, the national energy system would be faced with a radical change. This article analyses the economic feasibility of French residential PV systems combined with Li-ion batteries in 2030 to anticipate the possible change in future energy systems. It also includes a stakeholder analysis with respect to the PV self-consumption model to analyse the systemic effects of PV integration into the electricity system. Our study provides a theoretical explanation of the impact on the current electricity market and quantifies the expected impact on the most influential stakeholder group. The ultimate objective is to help policymakers forecast possible scenarios for PV self-consumption so they can prepare for the future transition with strategic actions. By way of conclusion, we discuss the policy implications and elaborate policy recommendations based on the results of this study.

Keywords: Economic analysis, Energy policy, Photovoltaic (PV) self-consumption, PV residential systems with batteries, Stakeholder analysis, Systemic effects

1. INTRODUCTION

The PV sector has demonstrated visible progress over the last decade, reaching more than 300 gigawatts (GW) of installed capacity in 2016 (IEA PVPS, 2002 to 2015; Solar Power Europe, 2017). The reduced cost of PV modules has helped enhance the economic competitiveness of PV systems. End-users have economic incentives to adapt the mode of self-consumption of PV electricity when it helps them to reduce their electricity bills compared with the conventional way of purchasing electricity from the grid.

The ratio of self-consumption, which defines the rate between onsite consumption and the total production of the system installed on the site, is a very important factor in terms of defining the economics of the self-consumed model of PV power. The weak correlation in the separate residential sector can be increased via some methods; e.g. demand response, utilisation of smart electric home appliances, or storage solutions

[1] Institute for Techno-Economics of Energy Systems (I-tésé)
Strategic Analyses Department (DAS)
French Alternative Energies and Atomic Energy Commission (CEA Saclay)
Paris-Saclay University (UPSay)
julie.yu@cea.fr
Laboratory of Economics (LEDa), Centre of Geopolitics of Energy and Raw Materials (CGEMP)
Chair of European Electricity Markets (CEEM)
Paris-Dauphine University Paris, France
pareo0530@gmail.com

like batteries. The capital costs of lithium-ion (Li-ion) batteries are expected to come down over the next years (Deutsche Bank, 2016; Beetz, 2015). This possible cost reduction makes the large-scale deployment of PV systems in the residential sector a feasible solution.

If residential PV systems coupled with batteries become economically competitive with a high ratio of self-consumption in the near future, end-users will be willing to switch to the self-consumption of PV electricity instead of using power from the network. **A rupture (or radical change) could impact the national power system if the transition of PV self-consumption in the residential sector occurs massively or suddenly.** Such change will influence the interests of the electricity market stakeholders and can be the problematics for the national energy system. Policymakers would therefore have to focus on an optimal mix of PV power to achieve a careful balance with the other energy technologies and grid financing. This is why policymakers need to understand the timing of this transition in order to detect any changes and to anticipate any transformation.

In this context, this study sets out to forecast any radical changes in the residential sector and discuss the role of policy. The article assesses the future economic attractiveness of French residential PV systems coupled with lithium-ion (Li-ion) batteries; it employs the learning curve approach to estimate the critical moments of this transition to PV self-consumption. The study has chosen an **unfavourable French case** where the electricity tariffs are relatively low and the PV system prices are higher compared with its neighbouring countries, so as to give a late threshold. The ultimate objective is to help policymakers forecast possible scenarios for PV self-consumption so they can prepare for the future transition with strategic actions.

2. RESEARCH CONTEXT AND QUESTIONS

2.1 Solar PV energy in power systems according to IEA scenarios in 2030

The Paris Agreement defined the international climate objectives to keep the mean global temperature rise to well below 2 degrees above pre-industrial levels and to limit the temperature rise even further to 1.5 degrees above pre-industrial levels (UNFCCC, 2015).[2] Solar PV energy is highlighted as a solution making it possible to meet such objectives. According to the IEA hi-renewable (hi-Ren) scenario, 16% of the global electricity will be supplied by solar PV power by 2050. This study was based on two IEA energy scenarios (IEA, 2014; 2014b) to estimate the PV system prices in 2030: 2DS and hi-Ren. The IEA 2 degree scenario (2DS) proposes a radical energy system transformation to achieve the goal of a mean global temperature rise limited to 2°C by 2100 (IEA, 2014b). Furthermore, the IEA hi-Ren scenario[3] suggests that even greater efforts are required to shift to a low-carbon energy system based on the larger integration of renewable energies.

Table 1 illustrates the IEA solar PV goals with respect to PV installed capacity and PV electricity generation by 2030 and 2050. Supported by the political efforts of many countries aiming to reduce their carbon footprint or to increase their energy independence, the PV sector is currently on track to meet the 2DS target (IEA, 2016, p. 88).

[2] Articles 2 and 4.

[3] The scenario is a variant of the 2DS model, assuming the slower deployment of nuclear energy, the delayed introduction of carbon capture and storage (CCS) technologies and the more rapid deployment of renewables, notably solar and wind energies.

	Actual	2DS		Hi-Ren	
Year	2015	2030	2050	2030	2050
Installed PV capacity	227 GW	841 GW	2785 GW	1721 GW	4674 GW
PV electricity generation	285 TWh	1141 TWh	3824 TWh	2370 TWh	6300

Table 1: IEA's solar PV targets for 2030 and 2050

2.2 Residential PV system's economic competitiveness in France

The rapid decline in PV system costs is closely associated with the economics of PV self-consumption. Over the past few years, the PV market has largely gained in price competitiveness. Faced with the globalisation of the sector, the reduced cost of PV modules has helped improve the economic competitiveness of PV systems (Yu, et al., 2016). Figure 1 indicates the historical variations in the PV residential system prices in several countries (IEA PVPS, 2002 to 2015).

The current costs of French residential PV systems vary depending on the type of system: building-integrated PV systems (BIPV) at \$2.67/Wp[4] and the building-attached PV systems (BAPV) at \$2.05/Wp in 2015 (the BIPV cost is 30% higher than the BAPV cost for existing buildings) (IEA-PVPS France, 2016). French PV system prices are higher compared with its neighbouring countries and the electricity tariffs are relatively low. Since this article is based on an unfavourable French case, our economic calculation gives a late threshold of the PV self-consumption. In our study, the PV system prices in 2030 were estimated by means of the learning curve approach based on the PV installation targets proposed by the IEA energy scenarios (cf. 3.2.2).

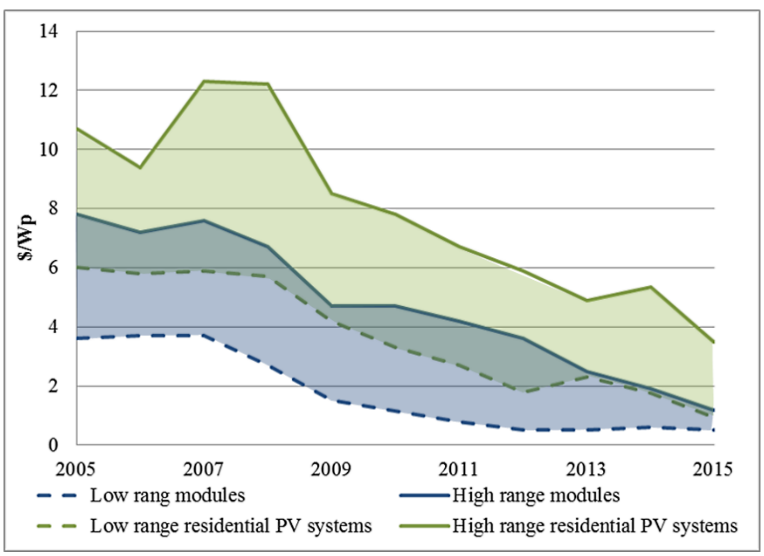

Figure 1 : Historical variations in the PV residential system prices in several countries
(Author's elaboration based on IEA PVPS data)

[4] ~ €2.4/kWh.

2.3 Impacts of cost dynamics of Li-ion batteries on the residential PV self-consumption

2.3.1 Li-ion batteries costs and the prospect

The study aims to define the future economic feasibility of residential PV systems. It is thus important to examine the trends of battery cost as **a complementary measure** to increase the ratio of self-consumption. This article has considered lithium-ion (Li-ion) batteries, one of the most developed storage technologies with potential cost reduction by economies of scale in the near future. They have demonstrated a rapid change with the development of mobile devices over the past decades, leading to the remarkable reduction in their volume and price. The development of Li-ion batteries is still driven by mobile device needs, and the emerging electrical vehicle (EV) markets accelerate the progress. The ability of Li-ion batteries to be coupled directly with distributed PV systems can give a comparative advantage to the residential systems if economically feasible. Many other promising storage technologies exist, however, the analysis with Li-ion batteries can provide a basic scenario to define the potential opportunities for the large deployment of PV systems coupled with batteries in the future electricity mix.

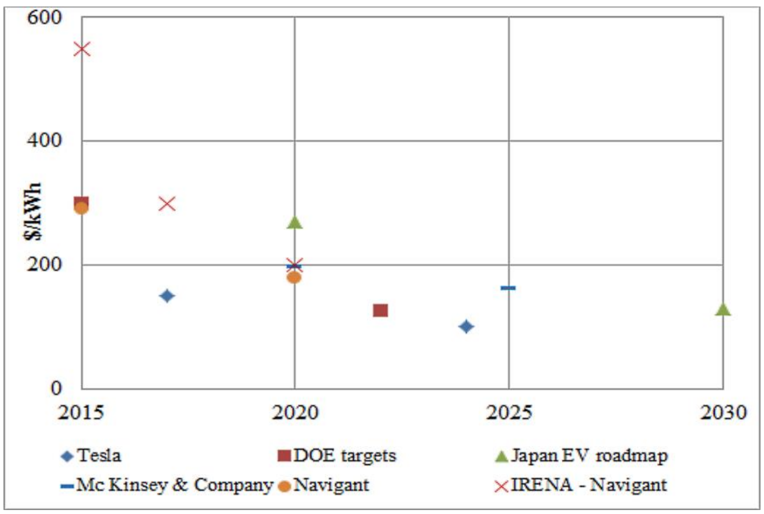

Figure 2: Li-ion battery price projections (Author's elaboration based on several studies)

Figure 2 displays the different projections of the Li-ion battery prices[5]. The estimated battery price would drop below $200/kWh between 2020 and 2025. In addition, the price would fall further between $100/kWh and $150/kWh in 2030 with a stabilised price. These reduced battery prices would bring synergies related to the residential or commercial usage of the PV systems. In this regard, our calculation considered a price of $500/kWh in 2015 and a price of $150/kWh in 2030.

[5] Tesla proposed a battery system for residential usage in 2015; the price of Tesla's Powerwall is $3,500 for 10 kWh and $3,000 for 7 kWh (Tesla motor). If the installation cost is included, the Deutsche Bank estimated the cost of the battery at $500/kWh (Deutsche Bank, 2016). According to the Deutsche Bank's report, Telsa's price will be reduced by 57% to $150/kWh in 2017 and by 71% to $100/kWh in 2024 (Deutsche Bank, 2015). The Japan EV roadmap aims to reduce the battery price to $270/kWh in 2020 and $130/kWh in 2030 (The committee on climate change, 2012). Furthermore, Mc Kinsey & Company expected the price of Li-ion battery packs to reach $197/kWh in 2020 and $163/kWh in 2025 (Hensley, et al., 2012).

2.3.2 Increased ratio of PV self-consumption thank to the usage of batteries

The poor correlation of PV self-consumption in the residential sector can be improved by combining with the storage systems. The continuous price decline in both Li-ion batteries and PV systems can accelerate the distributed PV diffusion process. Figure 3 illustrates the principal of using the residential PV batteries. They allow storing the electricity not consumed in order to release it when there is demand. It is important to well define the optimum system size to achieve a significant level of PV self-consumption in the residential sector. A small-sized PV system compared with the electricity demand profile is more likely to be completely self-consumed without storage solutions, but the gains with respect to the total onsite consumption will be small. However, a large-scale PV system will require a large amount of storage capacity leading to high capital costs. Various literatures have defined the optimal sizes of batteries combined with distributed PV systems. There are still very few articles and research available specifically related to the French context.

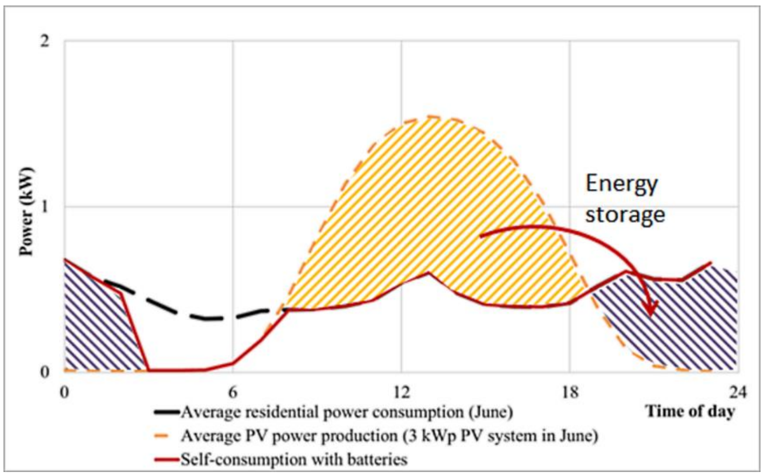

Figure 3: Principal of using the residential PV batteries

Our study considered the use of 3 kWp PV systems, which are commonly installed in the residential sector. This article was based on a few German studies although France uses more energy in the residential sector because of the high rate of electrical heating. However, this difference was ignored in our study to obtain a more penalising case (French data can increase the ratio of PV self-consumption in our model). Based on our analysis of several German studies (Weniger, et al., 2014; Huld, et al., 2014; Partlin, et al., 2015), it was assumed that the combination of 3 kWp PV systems with 4 kWh Li-ion batteries provided an optimal solution up to 80% PV self-consumption for an average household that consumes around 4000 kWh/year of electricity.

2.4 Research objectives and questions

Until recently, the objective of PV diffusion policies was mainly to create the market to help reduce the PV costs along with technological progress and industrialization. PV market development in the near future will present a very different aspect as a result of the sharp decline in the prices of PV systems and related products like lithium-ion batteries as well as associated services. The combined PV systems with batteries increase the ratio of self-consumption of distributed energy supply and open up new opportunities for associated services. The demand for electricity is price-inelastic and minimizing the costs is a way of maximizing the utility of end-users.

In this regard, this study first determines **the economic attractiveness** of PV self-consumption model combined with lithium-ion batteries in the residential PV sector in 2030. Our study was based on the current market design. The objective of this article is to predict any possible radical changes in the near-future energy system by PV self-consumption in France. The large penetration of PV power driven by the cost reduction of PV power may in fact result in higher systemic costs. Therefore, the article also examined the systemic effects and potential risks caused by a massive transition towards PV self-consumption. We considered a time horizon to 2030. This article attempted to address the following questions.

- What costs for French residential PV self-consumption systems coupled with lithium-ion batteries in 2030?
- What potential aggregate demand for residential PV self-consumption in France?
- What systemic effects under different scenarios?

At the end of this article, we discussed the policy implications and elaborate policy recommendations based on the results of this study.

3. MODELLING METHODOLOGIES

3.1 Schematic dynamic model of residential PV self-consumption with batteries

A schematic dynamic model of residential PV self-consumption was developed in order to analyse the pattern of consumer behaviour and ripple effects in case the PV power generation costs become more attractive in the near future. The current energy system is composed of several groups of stakeholders. It is important to give an overall understanding of stakeholder viewpoints in the electricity systems when the transition toward PV self-consumption happens.

End-users (***prosumers***) have economic drivers to install PV systems for their own use when it allows them to reduce their electricity bill or make money from the PV system installation. We evaluated the household profitability of the investment in PV systems. The profitability compares the generation costs of the self-consumed PV electricity to the residential electricity tariffs. The aim is to anticipate the critical timing of transition to PV self-consumption. As Figure 4 shows, we identified important drivers of the solar PV economics. However, the PV self-consumption diffusion changes the existing electricity market mechanism by influencing other stakeholder interests. Stakeholders (in particular, *latent group*[6]) who have little interest in the PV sector but have the power to cause major disruptions to the PV development should be closely examined. When the PV policies to promote self-consumption are expected to conflict with the interests of these stakeholders, they will strongly oppose the policy-making process and disturb the development of the PV self-consumed model (Energy and Policy Institute, 2014). For example, a large diffusion of PV self-consumption can reduce revenues of **conventional power production companies** and **grid operators** (Ueckerdt, et al., 2013; Yu & Popiolek, 2015) as fewer PV self-consumers buy electricity from the grid.

[6] Latent group has low interest in the subject and high power in the electricity systems. Refer to a stakeholder analysis of PV self-consumption, author's article (Yu & Popiolek, 2015).

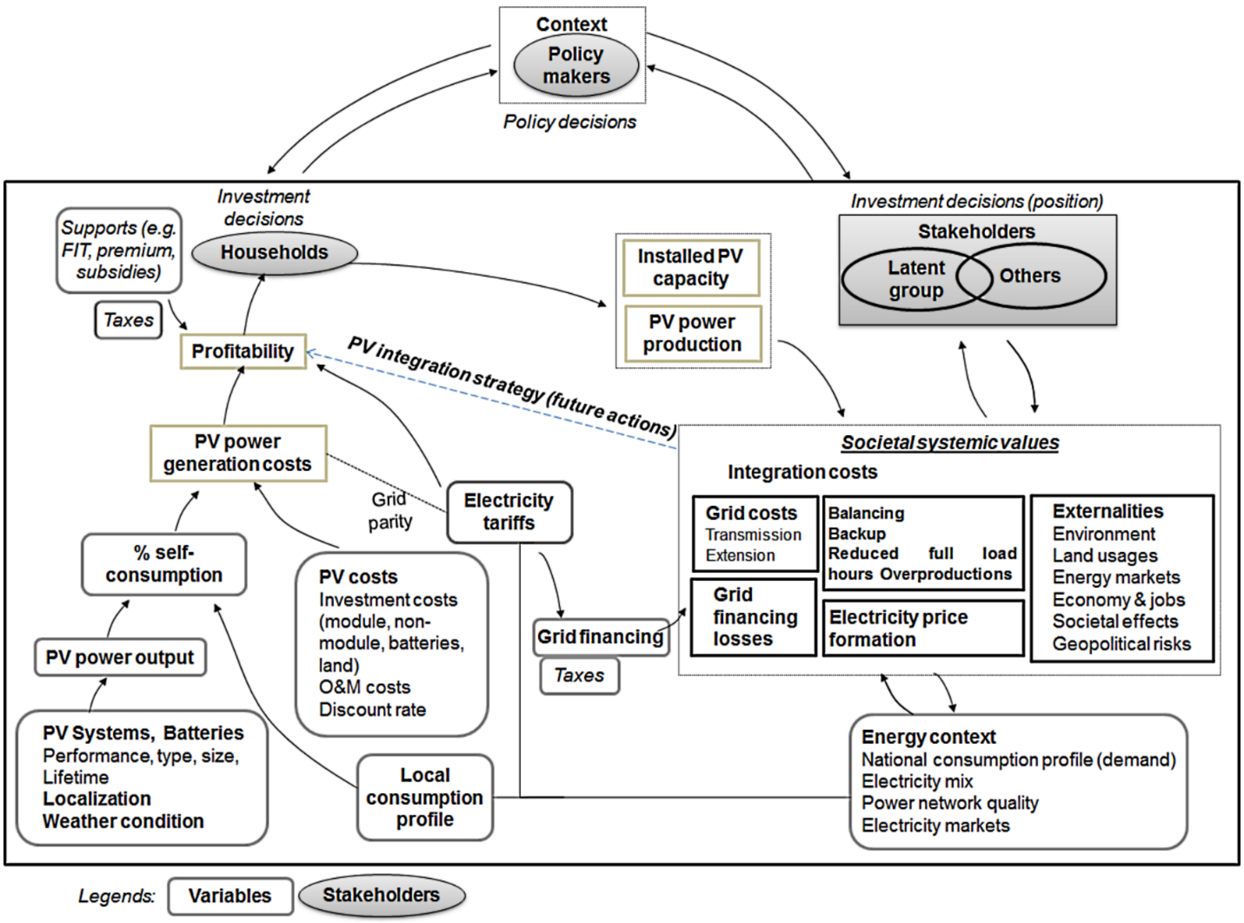

Figure 4: Schematic dynamic model of residential PV self-consumption (Author's elaboration)[7]

The remaining part of this article addressed **perspectives of different stakeholders** in the electricity systems. This article first determined the economic attractiveness of PV self-consumption according to **household perspective** to understand an individual investment decision making. The article then figured out how the PV dynamics change the existing electricity market mechanism (systemic effects) and influence other stakeholder interests (**the perspective of latent group**). This ultimately aimed to help **policymakers** predict any possible radical changes in the future energy system by residential PV self-consumption and prepare strategic actions to address them.

3.2 Drivers of household investment decisions

3.2.1 Profitability of households

The **profitability** is a crucial determinant of household investment decision making when predicting future demand for PV self-consumption. Electricity end-users will become PV prosumers if the investment in PV systems for self-consumption leads to the savings on the electricity bill or a positive return on investment (ROI). In our model, the profitability compares the generated earning by PV self-consumption to the total expenses and other relevant costs (including tax, if applicable) incurred during a specific period of time. The earning normally includes not only the avoided electricity bills but also concerns revenues from selling the surplus of electricity or political support (e.g. PV self-consumption bonus or green certificates).

[7] The basic structures and specific explanation of the schematic model are described in author's academic thesis (Yu, 2016).

We defined the profit investment ratio (PIR)[8] [9]as below:

$$\Pi = \frac{Present\ value\ of\ cash\ flow\ in\ the\ year\ N}{Initial\ investment\ required} = \frac{\sum_{t=1}^{N} \frac{(\alpha E_{PV}^{t} \times (P_E + p_A) + (1-\alpha) E_{PV}^{t} \times P_G) \times (1-\tau)}{(1+r)^t}}{\sum_{t=1}^{N} \frac{I_{PV}^{t} + O\&M^t}{(1+r)^t} - subsidies} \quad (1)$$

If the model considers no value for the excess PV electricity and excludes tax, premium and subsidies, we can simplify the equation as below.

$$\Pi = \frac{\alpha \sum_{t=1}^{N} \frac{E_{PV}^{t}}{(1+r)^t} \times P_E}{\sum_{t=1}^{N} \frac{I_{PV}^{t} + O\&M^t}{(1+r)^t}} = \frac{P_E}{\frac{1}{\alpha} LCOE} \quad (2)$$

The break-even indicates the critical point at which it becomes relevant for households to install PV systems to reduce the energy bills. The investment will be considered when the index is greater than 1. The timing of break-even is directly related to the position of government on the PV self-consumption. For example, if the government prepares appropriate policy support and the institutional framework to provide favourable conditions for residential PV self-consumption, it can advance the break-even point and vice versa.

The definition of grid parity (or socket parity) needs to be revisited to discuss the breakeven of residential PV self-consumption (Equation 2). Grid parity often indicates a milestone for the PV diffusion (Breyer, et al., 2009). It happens when PV generation cost intersects with the price of retail electricity tariffs. The PV grid parity for the residential sector was reached in some countries as a consequence of increasing residential electricity tariffs and reducing PV systems prices (Weniger, et al., 2014). However, electricity retail tariffs often include grid management costs and taxes. However, the comparison remains still important when discussing the momentum of residential PV self-consumption growth.

In addition, the **household electricity tariff** is a critical parameter to calculate the expected revenues of household (e.g. bill savings) (Masson, et al., 2014). We thus compared the results with the estimated price of electricity in 2030 to anticipate the future demand. The methodological approach and data provided were described in greater detail in the next section.

[8] A modification of the net present value method.

[9] With

E_{PV}^{t} : PV electricity produced in the year t,
α : Self-consumption ratio,
P_E : Electricity prices in case of self-consumption ($\alpha E_{PV}^{t} \times P_E$: electricity bill saving in the year t),
p_A : Self-consumption premium,
P_G : Purchase price of PV electricity surplus sent to the grid,
τ : Tax on PV electricity revenues,
I_{PV}^{t} : PV system investment in the year t,
$O\&M^t$: Operation and maintenance costs in the year t (including the replacement of batteries),
r : Discount rate.

3.2.2 Method for calculating the LCOE of solar energy

The Levelized Cost of Electricity (LCOE) represents the lifecycle cost per kilowatt-hour (KWh) of building and operating power generation asset. The resulting value indicates a break-even value that an investor would need to obtain per-kilowatt-hour (kWh) as the minimum sales revenue over the lifetime in order to justify the entire investment of a particular power generation facility (Reichelstein & Yorston, 2013). Solar PV power is commonly priced as LCOE ($/kWh) in many international studies (Fraunhofer ISE, 2015; IEA, 2014; IRENA, 2015; EPIA, 2014) and scientific articles (Candelise, et al., 2013; Hernández-Moro & Martínez-Duart, 2013; Reichelstein & Yorston, 2013) to follow the progress of the PV technologies.

Key inputs to calculating the LCOE include investment and variable operations and maintenance (O&M) costs, fuel costs, financial costs, electricity output, plant lifetime and system performance. Solar PV system costs are one of the important levers to calculate solar LCOE. The energy production is calculated based on various parameters such as lifetime, localization, weather conditions, module efficiency, installation specification, and system performance. In our study, we added the costs of batteries[10] to evaluate the combined PV system costs for residential PV self-consumption. A simplified LCOE equation[11] for residential PV with batteries is indicated as below.

$$LCOE\ of\ the\ PV\ system\ with\ batteries = LCOE_{PV} + LCOE_{battery}$$

$$= \frac{\sum_{t=1}^{n} \frac{I_{PV}^t + O\&M_{PV}^t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_{PV}^t}{(1+r)^t}} + \frac{\sum_{t=1}^{n} \frac{I_{battery}^t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_{PV}^t}{(1+r)^t}} \qquad (3)$$

The LCOE method includes a high degree of sensitivity to the initial assumptions and parameters. Our study thus conducted **a sensitivity analysis** (Hernández-Moro & Martínez-Duart, 2013) of the PV cost assessment. However, as the electricity system is very constrained, the large penetration of variable and non-dispatchable electricity sources influences the balance of the whole electricity system. The LCOE methodology is thus **incomplete to evaluate the market value of intermittent renewable energies like solar** (Borenstein, 2012; Joskow, 2011; Keppler & Cometto, 2012; Hirth, 2014; Hirth, et al., 2015; Ueckerdt, et al., 2013). However, the LCOE approach can be used to estimate the profitability of residential PV self-consumption model. The evaluation perspective can be broadened to include systemic effects of PV integration for the comprehensive economic value assessment of PV electricity in a society. They were further discussed in the section 3.3.

3.2.3 Dynamics of PV costs and the utilization of experience curve to project PV cost reductions

In this study, the experience curve method was used to estimate the PV price trajectories. The experience curve is an empirical approach to project a cost reduction in industries. The diffusion and adoption of technologies depend on how further costs are reduced through innovation and experience accumulation (Arrow, 1962). The experience curve (Yelle, 1979), also known as a learning curve, describes the correlation

---

[10] The battery yield losses were ignored.

[11] With:

- I_{PV}^t : Investment in PV systems in the year t,
- $I_{battery}^t$: Investment in batteries in the year t,
- $O\&M_{PV}^t$: Operation and maintenance costs in the year t,
- E_{PV}^t: PV electricity produced in the year t,
- r: Discount rate.

between the reduction in production costs and the level of experience (van den Wall Bake, et al., 2009; Byrne & Kurdgelashvili, 2011; Boston Consulting Group, 1972; Abell & Hammond, 1979; Sharp & Price, 1990). The general rules for the experience curve[12] is that the cost goes down by a constant percentage (the learning rate) with each doubling of the total number of units produced. The experience curve is usually used for long-term strategic analysis rather than short-term tactic review; experience curve~~s~~ can be used to project future cost trends based on past cost reductions (Byrne & Kurdgelashvili, 2011).

PV modules have demonstrated a consistent feature of learning-by doing over the last decades. The global PV module market now takes advantage of the cumulative knowledge stock and experience, thereby sharing a similar price around \$0.5/Wp in 2016 (PV magazine, 2016; IEA PVPS, 2016). The positive correlation between the module price drop and the size of the cumulative installations has been demonstrated in many studies, with the PV module's learning rate ranging between 18% and 22% in most literature (Timilsina, et al., 2012; Reichelstein & Yorston, 2013; IEA, 2014; Kersten, et al., 2011). However, the learning experience for complete PV systems is usually considered slower than that for the modules because of local variations in non-module costs (Yu, et al., 2015). We thus considered that the observed 'learning-by-doing trend' of solar PV technologies would remain regardless of the PV trajectory in the future system.

As indicated, our calculation is based on the IEA scenarios, which forecast world PV installations in 2030 with a focus on 2-degree scenarios (2DS) and hi-Renewable scenarios (hi-Ren).[13] We calculated the PV system prices in 2030 by using the learning curve with a learning rate of 18% (IEA, 2010, p. 18).

3.3 Systemic effects of PV integration in the electricity systems

3.3.1 Definition of systemic effects

A shift towards PV self-consumption in the residential sector will involve systemic effects in the power systems. The integration of PV power into the existing electricity systems requires efforts with additional costs (integration costs). These efforts include not only an engineering perspective to ensure the operation of all physical systems but also economic aspects in regard to systemic value of PV integration. The value evaluation of PV power in a society needs to be discussed in a more comprehensive manner by taking into account systemic effects involved.

---

[12] The **mathematical model** is described in equations (4) and (5).

$$\mathbf{C_t = C_0 \times \left(\frac{X_t}{X_0}\right)^{-b}} \qquad \textbf{(4)}$$

$$\mathbf{LR = 1 - 2^{-b}} \qquad \textbf{(5)}$$

With:

C_t: Cost of unit production at time t (\$/W), $\mathrm{X_t}$: Cumulative production at time t (W)

b: Experience index: this is used to calculate the relative cost reduction ($1\text{-}2^{-b}$) for each doubling of the cumulative production

LR : The learning rate: the fractional reduction in price expected as the cumulative production double

Initial condition:

C_0 : Reference cost, $\mathrm{X_0}$: Reference cumulative production.

[13] The study excludes the 6DS scenario. 6DS is a base-case scenario based on the condition that the current trends continue; it projects that the energy demand will increase by more than two-thirds between 2011 and 2050. In addition, associated CO_2 emissions are expected to rise even more rapidly, pushing the global mean temperature up by 6°C.

The systemic effects of variable PV integration can be classified into three levels. The first level concerns impacts on the **technical aspects like infrastructure, grid and electricity production mix** to maintain the operation of electricity systems. The second level of systemic effects is **indirect financial impacts related to regulatory mechanisms of electricity systems,** for example, electricity tariff system and electricity price formation. The last level involves **different types of externalities of PV integration into the society**. Various positive or negative aspects which influence on the national system and social welfare should be considered: i.e. environment, technology, economy, jobs and strategic position. The higher the level of systemic effects is, the broader scope of analysis is expected because of diverse correlation with other contextual, social or systemic variables.

In this context, our study was completed by a systemic analysis of integration costs with respect to PV penetration into the electricity system. This is an important step in understanding stakeholders' perspectives in relation to our PV self-consumption transition scenario. It helps policymakers prepare actions to counter any risks created by these stakeholders. Our study mainly focused on the systemic effects of PV integration related to power systems and the third level is beyond the scope of the study.

3.3.2 Integration costs

The systemic effects directly connected with power system mainly concern the intermittency of PV power and unique characteristics of electricity supply-demand mechanism. The variable PV electricity is not dispatchable and is not able to meet the electricity demand at all seasons of the year. The value of electricity varies according to time of production and location because of the unique feature of electricity mix. The integration of PV into the existing grid system requires additional efforts to deal with its intermittency compared with dispatchable technologies. A reflection on the integration efforts for PV penetration and dynamic impacts on the electricity systems has been provided by various studies (Borenstein, 2012; Joskow, 2011; Keppler & Cometto, 2012; Hirth, 2014; Hirth, et al., 2015; Ueckerdt, et al., 2013).

Keppler and Cometto (2012) largely divided the systemic costs (**grid-level costs**) of PV integration into two parts: 1) additional investments to extend and upgrade the existing grid, and 2) the costs for increased short-term balancing and for maintaining the long-term adequacy of electricity supply to integrate variable energies. **Short-term balancing** concerns the second-by-second balancing of electricity supply and demand (e.g. real-time adjustment, day-before forecasting). It is closely related to the accuracy of the weather forecast and the predictability of supply and demand. The improved forecast and prediction would decrease uncertainty on the production planning and would enhance the management of the production capacities for a day. More importantly, the level of flexible capacity in the electricity mix and the size of the interconnected electricity system influence the balancing task in terms of the instantaneous adjustment to match changes in demand. Therefore, countries that have a large share of flexible technology capacities (e.g. hydropower) in their energy mix need less balancing costs.

Intermittent PV systems require the **long-term dispatchable back-up capacity** to meet the electricity demand at all times (Pudjianto, et al., 2013; Keppler & Cometto, 2012). Non-dispatchable energies like PV contribute very little to generation system adequacy in Europe (the capacity credit of PV power in France is very low). The long-term back-up costs include investment and operation and maintenance costs to give additional adequacy capacities (demand increase) or to keep existing capacities available (constant demand); these costs are necessary to maintain a certain level of system reliability when variable energies are integrated into the electricity mix. The back-up costs account for the large fraction of the grid-level costs.

In another study, Ueckerdt *et al*. (Ueckerdt, et al., 2013) introduced the notion of **system LCOE** to evaluate the integration costs of intermittent energies. Ueckerdt *et al*. decomposed the **integration costs** into grid costs (network costs), balancing costs (supply & demand) and profile costs (a sum of adequacy, full-load hour reduction and overproduction of variable electricity). The study is based on the **load duration curve approach**. The load duration curve method involves ranking the required power capacity for each unit of time (hour-to-hour) in decreasing order. **A residual load duration curve** can be obtained by subtracting the power generation from variable wind or PV resources. The optimal mix can be obtained by taking the minimum power generation costs into account to meet the annual electricity demand. The most critical segment of integration costs (variability) concerns **profile costs** and balancing costs is of secondary economic importance. The reduced rate of utilization of conventional dispatchable plants led by high penetration of renewable energies is the key issue when assessing the integration costs (Hirth, et al., 2015). Ueckerdt *et al.* (2013) provided a mathematical method (Equation 6)[14] to quantify the integration costs.

$$\mathrm{C_{int}} = \mathrm{C_{grid}} + \mathrm{C_{balancing}} + \mathrm{C_{profile}} \quad \text{With} \quad \mathrm{C_{profile}} = \mathrm{C_{resid}} - \frac{\mathrm{E_{resid}}}{\bar{\mathrm{E}}_{\mathrm{total}}}\mathrm{C_{total}}(0) \qquad (6)$$

They provided an in-depth insight into the evaluation of integration cost of variable energies by differentiating the timeframe of integration. The study explained the differences between short-term (ST) and long-term (LT) perspective of variable renewable energy (VRE) integration. The short-term perspective represents a fast deployment of VRE without adaptation. The conventional dispatchable capacities remain unchanged after introducing VRE. In contrast, the long-term perceptive assumes an accomplishment of the power system transition. The dispatchable capacities have time to fully and optimally adapt to the integration of VRE with a new long-term equilibrium (**optim**). Ueckerdt *et al.* proposed new mathematical expressions to calculate profile costs according to these two cases (Equation (7) and (8)) [15]. They allow to

---

[14] With:

C_{int} : Integration costs of variable renewable energies (VRE),

$\mathrm{C_{grid}}$: Costs of grid extension and upgrading, $\mathrm{C}_{balacing}$: Balancing costs, $C_{profile}$: Profile costs,

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}: The resulting residual load with VRE (provided by dispatchable power plants),

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

[15]

$$\mathbf{C_{resid}^{optim}} = \int_{\mathbf{0}}^{\mathbf{q_{peak}}} \mathbf{T}(\mathbf{q}, \quad \mathbf{E_{VRE}})\mathbf{C_{min}}(\mathbf{T}(\mathbf{q}, \quad \mathbf{E_{VRE}}))\,\mathbf{dq} \qquad (\mathbf{7})$$

With

- C_{resid}^{optim} : Costs of residual system after VRE integration in a <u>**long-term**</u> perspective (the mix adapts in response to the transformation with VRE integration),
- E_{VRE}: Power generation from VRE
- q_{peak} *:* Annual peak demand of electricity,
- $T(q, E_{VRE})$: Full-load hours for power demand q,
- $C_{min}(T(q,\ E_{VRE}))$: Generation costs from the cheapest production capacity (i.e. nuclear, gas and coal) to operate a full-load hours of $\mathrm{T}(\mathrm{q}, \mathrm{E_{VRE}})$.

evaluate effects of PV integration according to the different speed of integration, the short-term and long-term. Our study quantified PV integration costs based on this mathematical approach.

3.3.3 Other financial impacts

As seen, the PV integration into the existing electricity mix reduces the operation hours and the capacity factor of dispatchable conventional plants and eventually influences their profitability. This issue is critical because they are compulsory to maintain the security of electricity systems. The negative financial impacts on existing dispatchable capacities can be discussed related to the **current electricity price formation**. The current management of the electric power system ranks the capacities in ascending order of marginal costs of production (merit order). The ranking is organised on the basis of the day-ahead declaration of available capacities. The electricity price is determined by the highest marginal costs of production units to satisfy the demand. The price is imposed to all other producers. The base-load capacities have low variable costs and they are ranked first (e.g. run-of-the-river hydroelectricity, nuclear). The peaking capacities have high variable costs and they are ranked last (e.g. oil, gas).

PV electricity with low marginal costs is ranked first in the merit order before base-load capacities and the merit order shifts to the right. However, the electricity demand is inelastic; the price variability does not have much impact on consumption. Therefore, the electricity price is reduced with the same demand curve (Haas, et al., 2013; Commissariat Général à la Stratégie et la Prospective (CGSP), 2014). It raises an issue with the payment of the initial investment (*losses of infra marginal rent*). In addition, in terms of the temporarily reduced demand, it is sometime technically too difficult to shut down a capacity for only a short time. This occurs when PV production is maximum (i.e. summer daytime). In extreme cases, the market price can be negative. It also concerns the reduced use of the peak capacities that in turn reduces the revenues of conventional power plants. With the deterioration in the peak coefficient[16], the extreme peaking capacities become an issue since they cannot cover their fixed costs (Hogan, 2005) (the missing money). This would thus exacerbate the problem in terms of future investment choices; investors are reluctant to build conventional plants because of the uncertainty in recovering the capital invested. This threatens the energy supply security.

$$\mathbf{C^{ST}_{resid}} = \sum_{\mathbf{te}} \int_{\mathbf{q_{te,min}}}^{\mathbf{q_{te,max}}} \mathbf{T}(\mathbf{q}, \quad \mathbf{E_{VRE}})\mathbf{C_{te}}(\mathbf{T}(\mathbf{q}, \quad \mathbf{E_{VRE}}))\,\mathbf{dq} \qquad (\mathbf{8})$$

With

- C^{ST}_{resid} *:* Costs of residual system after VRE integration in a **<u>short-term</u>** perspective (The dispatchable capacities remain unchanged, the mix is not able to adapt in response to the transformation),
- te : Considered dispatchable power generation technologies (i.e. nuclear, gas and coal),
- $q_{te,min}$ and $q_{te,max}$: The lower bound and the upper bound of the zone powered by technologies te respectively, on the vertical axis of residual load duration curve,
- $T(q, E_{VRE})$: Full-load hours for power demand q ,
- $C_{te}(T(q,\ E_{VRE}))$: Generation costs of technologies te with a full-load hour value of $T(q, E_{VRE})$.

[16] The peak coefficient is the ratio between the average hourly production during the year and the peak production (Heinen, *et al.*, 2011).

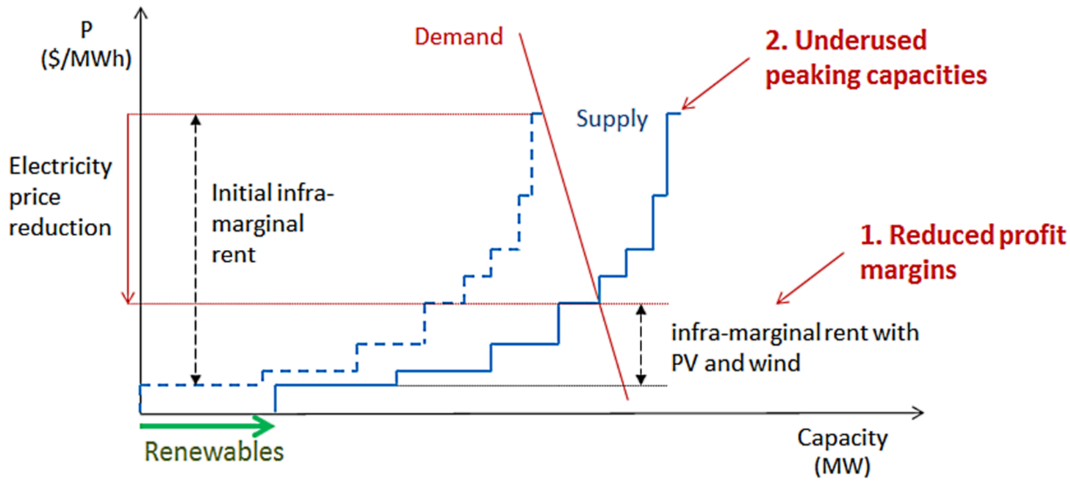

Figure 5: Merit order and electricity price formation

Another issue should be discussed with regard to **electricity tariffs**. The shift to PV self-consumption induces loss of grid operator revenues (Yu & Popiolek, 2015). Electricity retail tariffs are often composed of various costs like electricity generation, grid management and taxes. The maximum grid capacity must be kept to maintain the security of power supply because of a low capacity credit of PV. Grid operators will have more activities to manage the integration of variable PV energies and it is important to secure budget for grid financing. However, risks exist related to electricity tariffs because hidden losses of stakeholder's revenues occur when fewer consumers purchase the electricity from the grid.

4. RESULTS AND DISCUSSIONS

4.1 What costs for French residential PV self-consumption systems in 2030?

4.1.1 Prospect for PV system cost reductions

In order to project the PV power generation costs in 2030, we first estimated the PV residential system costs in 2030 using Equations (4) and (5). As indicated, our calculation was based on the costs of two types of French residential PV systems using c-Si PV technology, i.e. BIPV system cost of $2.67/Wp and BAPV system cost of $2.05/Wp and a learning rate of 18% (IEA, 2010, p. 18). **Table 2** presents the projected costs of residential PV systems in France in 2030.

	2015	IEA scenarios for 2030	
		2DS	Hi-Ren
World PV cumulated installations (GWp)	227	842	1721
BIPV system cost ($/Wp)	2.67	1.83	1.49
BAPV system cost ($/Wp)	2.05	1.41	1.15

Table 2 : Estimated residential PV system costs in 2030 based on the IEA scenarios

4.1.2 Prospect for PV LCOE with batteries in the French residential sector in 2030 and profitability

We calculated the French residential PV LCOE[17] combined with batteries in 2030. In order to define the investment costs, the costs of 4 kWh batteries were added to the estimated costs of the 3 kWp BIPV systems (**Table 3**). For example, the costs would be around US$ 5100 in 2030 in order to acquire a 3 kWp BIPV PV system with 4 kWh batteries according to the Hi-Ren scenario.

Material costs	2015	IEA scenarios for 2030	
		2DS	Hi-Ren
4 kWh batteries	US$ 2000	US$ 600	US$ 600
3kWp BIPV systems	US$ 8010	US$ 5504	US$ 4485
3kWp BAPV system	US$ 6150	US$ 4226	US$ 3443

Table 3 : Estimated costs of 3 kW PV systems coupled with 4 kWh batteries in 2030 (based on the IEA scenarios)

Figure 6 shows the calculated PV LCOE of 80% self-consumption in 2030 according to different scenarios. In addition, the profitability of PV systems with batteries was considered. As explained, the profitability ratios compare the LCOEs of PV systems[18] with batteries to the residential electricity tariffs. It implies the critical point at which it becomes relevant for households to install PV systems to reduce the energy bills. **We compared the results with the estimated price of electricity in 2030**. Our study was based on the current market design. We thus assumed that the electricity tariffs increased by 2% per year until 2030. The electricity tariffs for households in 2015 were $US 0.18/kWh in France (€0.1624/kWh) (Eurostat, 2016). If we consider a 2% increase by year, the household tariffs in 2030 will be $ US 0.243/kWh in France. However, a high level of uncertainty exists when there are radical changes in the market system.

It should be noted that the considered PV systems with batteries are currently far from the break-even point in France, but **they would become competitive in France by 2030 under all IEA scenarios.** However, if the global number of PV installations grows faster than the assumptions based on the IEA scenarios or if **targeted policies to reduce soft-costs** are implemented, residential PV systems with batteries can become profitable in France before 2030 (Figure 6), especially in the southern part of France **with higher insolation**. This will be further explained in the sensitivity analysis in the next section.

In addition, battery prices are expected to continue to decline. Our analysis showed that battery prices will represent a small fraction of the PV power production costs of residential PV systems combined with batteries. Based on the 2DS scenario, it will only account for about 13% of the PV power production costs amounting to only c$3.2/kWh in 2030. With a self-consumption rate of around 80%, the surplus electricity

---

[17] In order to calculate the LCOE of French residential PV self-consumption model in 2030, we referred to the following data and assumptions.

- PV system price: 1.83€/Wp, building integration (BIPV) for residential rooftops using c-Si PV technology.
- Potential PV power output: 1000 kWh/kWp/year provided by PVGIS[17] (JRC European Commission) (almost equivalent to the irradiation of Paris, lower bound for France) based on optimal positioning, c-Si cells, and estimated system losses of 14%.
- O&M: 1.5% of PV system price.
- Lifetime: 20 years of lifetime for the PV system and 10 years for the battery. We considered the repurchase of batteries with the same costs of replacement.
- A discount rate of 5% is used to consider the weighted average costs of capital (WACC) for the respective investment (European Commission, 2013; Fraunhofer ISE, 2013).

[18] The LCOE of residential PV systems with batteries divided by the ratio of self-consumption.

is small. If PV policies aim to promote self-consumption, it is also conceivable to establish a mechanism for reselling the 20% surplus to the network in order to enhance its economics.

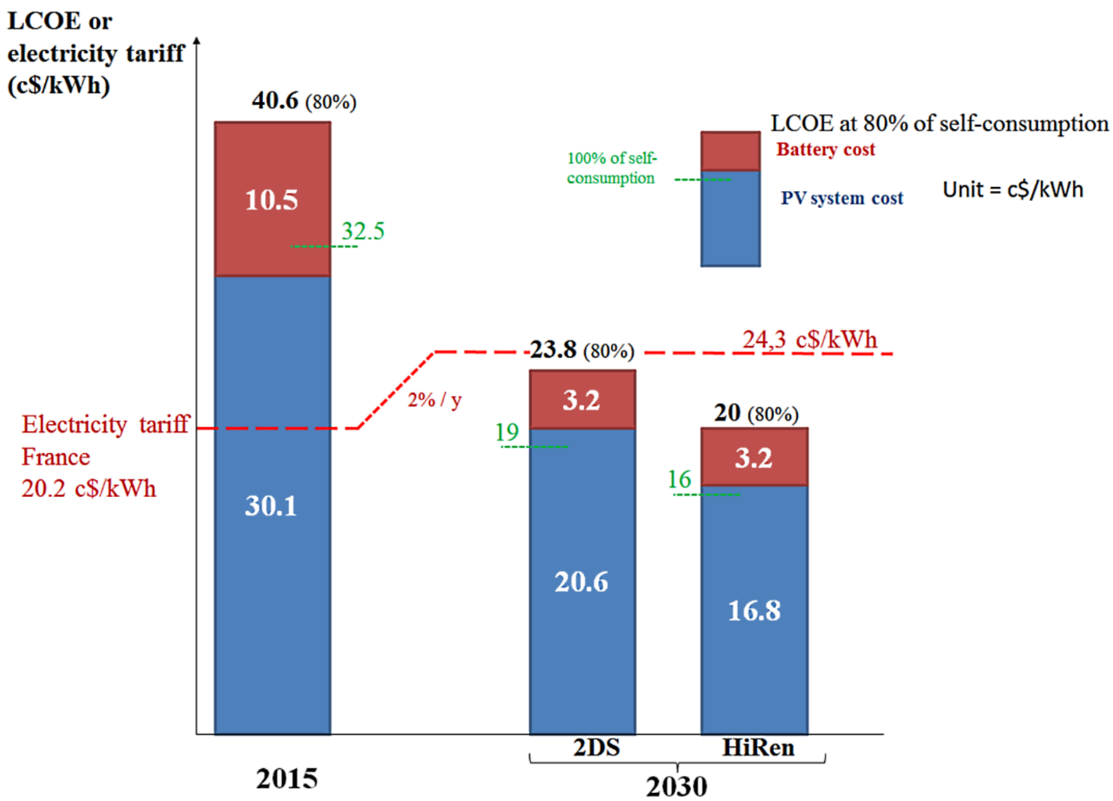

Figure 6: Economic attractiveness of French residential PV systems coupled with lithium-ion batteries in 2030[19]

4.1.3 Sensitivity analysis of residential PV LCOEs in 2030

We conducted a sensitivity analysis for eight of the most crucial parameters that define the LCOE estimates of PV systems with batteries in the French residential sector. The analysis using a spider chart is shown in Figure 7. Each line represents one of the parameters which vary the nominal values according to different ratios. The 2DS scenario was used to calculate the base-case values. The chosen criteria are indicated in **Table 4**.

[19] Assumptions for LCOE calculations: an irradiation of 1000 kWh/kWp/year, WACC=5%, a 20-year lifetime for the PV system and a 10-year lifetime for the Li-ion battery system.

Criteria	Nominal values	Ranges	
		Minimal values (-40% by default)	Maximal values (+40% by default)
PV system price	$1.83/Wp	$1.1/Wp	$2.56/Wp
Batteries price	$150/kWh	$90/kWh	$210/kWh
Energy output	1000 kWh/kWp	800 kWh/kWp	1400 kWh/kWp
Lifetime	20 years	12 years	28 years
Discount rate	5%	3%	7%
Learning rate	18%	11%	25%
Self-consumption level	80%	48%	100% (+20%)
Dollar/Euro exchange rate	0.9	0.72 (-20%)	0.99 (+10%)

Table 4: Parameters of the sensitivity analysis

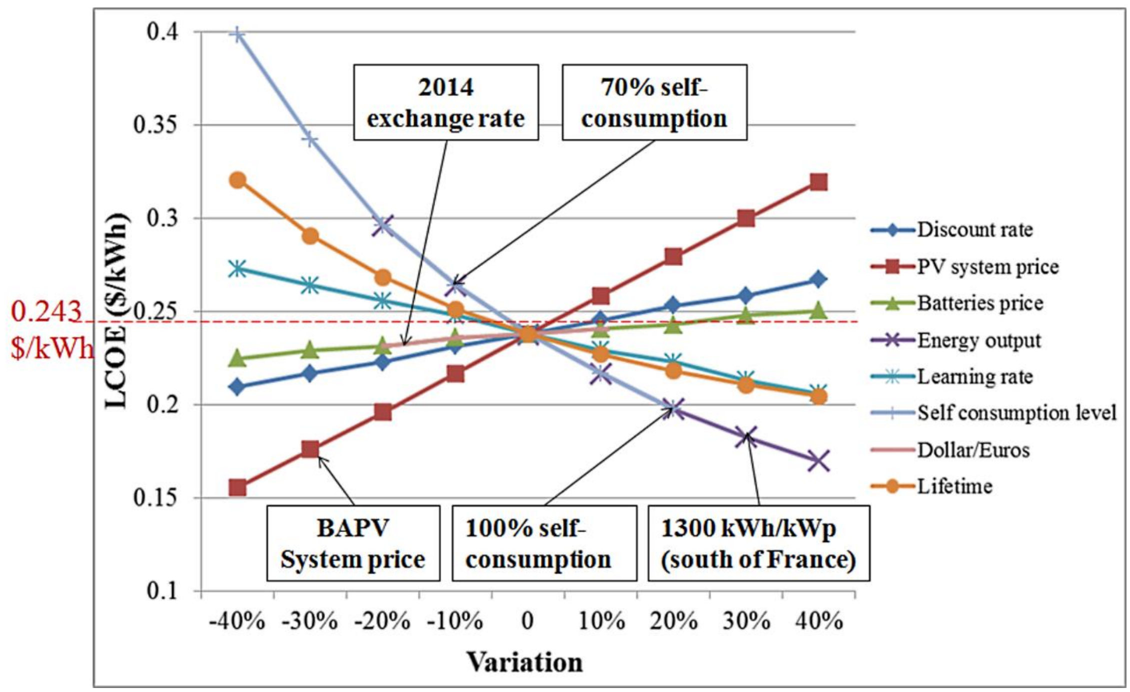

Figure 7: Sensitivity analysis of PV LCOE estimates

The slope of the line indicates the sensitivity of the PV LCOE estimates to the each parameter. The degree of sensitivity differs among these variables. **The PV system price, the energy output (insolation) and the self-consumption ratio** have the greatest influence on the PV LCOE estimates. In contrast, the discount rate, the learning rate and the battery costs have a relatively low impact when it comes to defining the PV LCOE among the criteria we have chosen. For example, the battery costs have a relatively small impact because they get a low share of the future PV system prices.

Figure 7 shows that our base case is a lower bound case. The PV energy output was estimated based on the location of Paris, yet the conditions are much more favourable in southern France. In addition, French residential PV system prices are usually higher because of building-integrated PV systems (BIPV), yet building-attached PV systems (BAPV) are currently 30% cheaper (IEA-PVPS France, 2016).

Table 5 indicates the sensitivity of the profitability of PV systems with batteries. As previously explained, the profitability ratios compare the LCOEs to the residential electricity tariffs to anticipate the critical timing of transition to PV self-consumption. However, estimating the residential electricity tariffs does involve a certain level of uncertainty. The sensitivity analysis of the electricity tariffs can thus provide a comprehensive comparison. An annual increase of 2% was considered as the base scenario in our calculation.

Electricity price variation	**-40%**	**-30%**	**-20%**	**-10%**	**0%**	**+10%**	**+20%**	**+30%**	**+40%**
Electricity price	0.146	0.170	0.194	0.219	0.243	0.267	0.292	0.316	0.340
Profitability with LCOE = 0.238 $/kWh	0.61	0.71	0.82	0.92	1.02	1.12	1.23	1.33	1.43

Table 5: Profitability sensitivity (2DS scenario)

4.2 Risks of transitioning to PV self-consumption and systemic effects

4.2.1 Risks of transitioning to PV self-consumption

We have concluded that PV systems would become profitable for individual investors in France by 2030 under the IEA scenarios in question with a self-consumption rate around 80% led by the use of batteries. It is possible to advance the time if the economic analysis considers more favourable assumptions and input data (e.g. insolation in Southern regions, BAPV systems).

A simple calculation gives **an upper limit of development opportunities in the French residential sector** based on the coupling of PV systems with batteries. France has 33.4 million residential buildings, including 18.8 million individual houses (ADEME, 2013, p. 36), and the residential and tertiary sectors account for 44% of the national electricity consumption. If PV self-consumption in the residential sector helps reduce the energy bills of households, **a massive and rapid transition towards PV self-consumption can occur in the near future.**

If 18.8 million individual houses installed a PV system with an average capacity of 3 kWp, it would represent a potential additional installation of approximately 56 GWp producing PV electricity of about 46 TWh[20] per year. This accounts for around 10% of the French electricity consumption, which was 476 TWh in 2015 (RTE, 2016).

As explained in section 3.3, the network should meet demand that can be requested when PV power plants are unavailable. The massive integration of PV power into the power system thus includes risks that are mainly related to grid management because of intermittency issues. This also includes **risks** of seeing the **sub-optimisation of electricity system** with the **massive and uncontrolled deployment of PV self-consumption**. In this regard, the government aspires to well anticipate all kinds of risks related to PV development in the future to avoid negative consequences. We thus analysed the systemic effects of PV integration into the electricity system in the following section. This approach helps policymakers prepare strategies to mitigate risks related to the PV self-consumption growth in the future.

4.2.2 Systemic effects of PV integration

We attempted to quantify the reduction in the load duration curve of the existing power capacities influenced by the demand growth for PV electricity in the French residential sector and the resulting profile costs.

[20] 80% x 56 GWp x ~1000 kWh/kWp/year.

This study has taken two variables, **the speed of PV integration** and the **use of batteries**, to determine different scenarios in terms of adding 56 GWp installed capacity of PV power (the defined aggregate demand). Four scenarios can be considered (Figure 8)[21]. Our residential PV self-consumption model with batteries concerns scenarios SR and scenario SP.

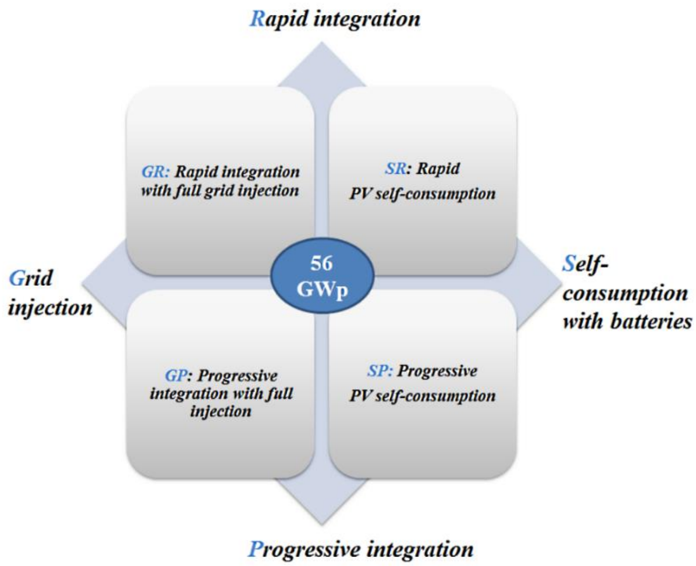

Figure 8 : Scenarios for PV integration in the electricity systems

1) Residual load duration curve

As a baseline for the study, our simulation was based on the French PV cumulative installation capacity of 6.5 GWp in 2015, representing 1.6% of the domestic consumption (IEA PVPS, 2016). We then assumed that the maximum possible PV capacity, which was identified in the previous section (56 GWp), was added in the French electricity mix. We considered that wind production remained constant since the analysis of wind power integration falls outside of scope of this article. The estimated PV production is based on the extrapolation of the current hourly PV production data of RTE (French transmission system operator)[22]. This will induce a significant reduction in the residual load supplied by conventional power plants. Figure 9 indicates the yearly load duration curve (**black line**) and the residual load curve without PV and wind in the French electricity mix (**blue dotted line**) in 2015. The **red dashed line** represents the future residual load curve after adding a new installed solar PV capacity of 56 GW without batteries. The **orange line** indicates it for the residential PV self-consumption model with batteries. The residual production of the current mix represents 506 TWh[23] (2015), which will be reduced to 460 TWh according to our transformation scenario S (PV self-consumption with avoided grid injection), and to 445 TWh according to our scenario G (full grid injection).

[21] **Speed R**: Rapid integration of PV power, uncontrolled installations (i.e. installation peaks), **Speed P**: Progressive integration of PV power (i.e. constant PV installations), **Usage G**: PV integration without batteries, full grid injection (i.e. utility-scale PV deployment), **Usage S**: residential PV self-consumption with batteries, no grid injection (~ 80% of self-consumption ratio, our PV self-consumption model).

[22] From 6.5GWp in 2015 to 62.5 GWp in 2030

[23] We included losses and exports compared with consumption. Our simulation was based on the electricity production data (assumption: production=demand). The total production in 2015 was 533 TWh.

As Figure 9 indicates, the capacity of base-load power plants that operate continually during the year will be reduced after 56 GW of new capacity added. On the other hand, the increasing share of solar power in the system does not contribute to reduce the annual peak demand in France because of the low capacity credit. As Figure 9 demonstrates, the peak demand stays constant at 86 GW; about 6 GW of the peaking units are used for less than a hundred hours. Therefore, the induced shift to PV power reduces the profitability of the existing power plants and some producers will have difficulties recovering their investment in the facilities.

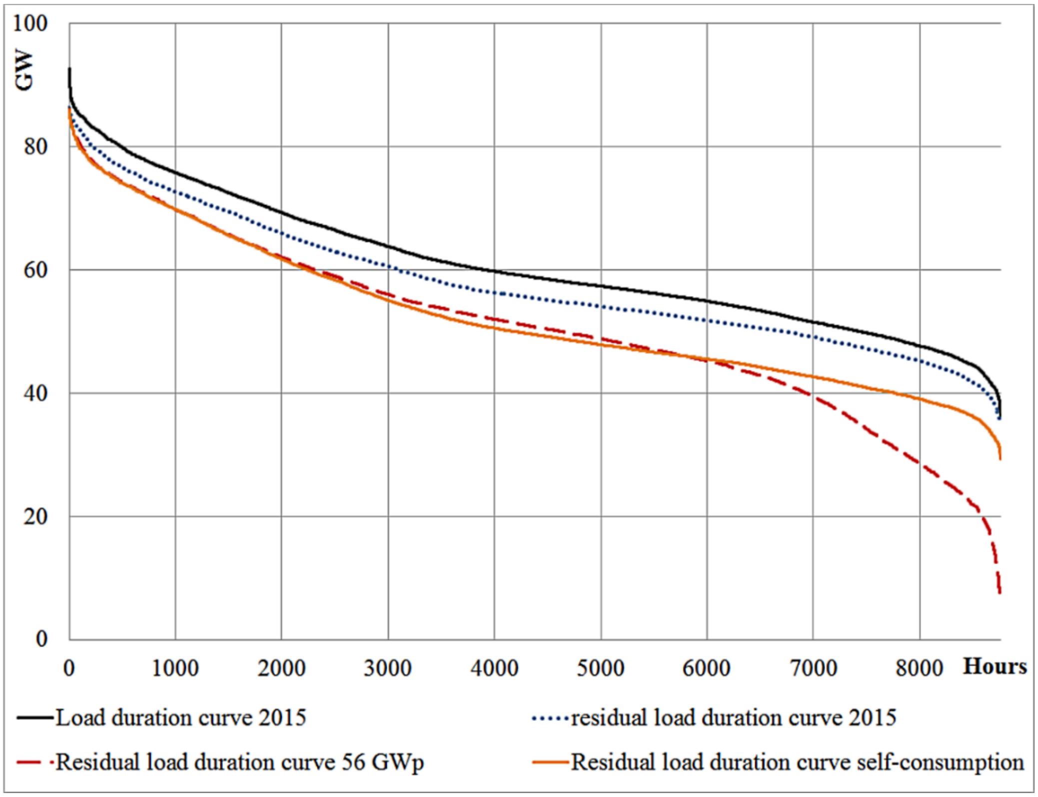

Figure 9: Residual load duration curves

2) The optimal power generation mix

We can draw the optimal power generation mix with respect to defined scenarios. The analysis was conducted based on **a virtual electricity mix**,[24] which is composed of a number of dispatchable capacities to satisfy the annual power demand (cf. **Table 6**). The system usually includes nuclear or coal for baseload generating units, coal or gas for intermediate load and combustion turbines for peak load units. The assumed carbon price is 20€/ t CO_2.

[24] The French electricity mix has a large share of hydraulic power. However, this approximation based on a virtual electricity mix is commonly used in many studies of French electricity mix (République Française, 2009).

	Nuclear plants	Coal plants	Combustion turbines (CT) (oil)	Combine cycle gaz turbines (CCGT)
Investment (k€/MW)	3910	1400	500	800
Lifetime (years)	50	40	25	30
Annual O&M (k€/MW/year)	75	30	10	20
Annualized fixed costs (k€/MW)	395	147	57	91
Variable costs (€/MWh)	10	42	162	66
CO_2 intensity (t/MWh)	0	0.32	0.27	0.27

Table 6: Investment and variable costs of the virtual electricity mix technologies

As seen, the defined aggregate demand of 56 GW PV capacity is equivalent to 10% of the electricity demand in France. The annual power demand and wind power were assumed constant within the simulation. **Table 7** indicates annual full-load hours of dispatchable capacities in the optimal mix of power generation and the consequences of a rapid integration of PV power. According to our self-consumption model with batteries, the batteries are charged up to the maximum capacity (4 kWh) in case there is a surplus[25] of PV electricity and discharged when consumption exceeds production. In our study, we also assumed that the excess PV power will be lost once batteries are fully charged.

The rapid penetration of PV power decreases the yearly full load hours of existing conventional capacities and induces a **sub-optimisation of the electricity mix**.

10% PV penetration (Rapid)	**Optimal mix of power generation (virtual electricity mix in 2015)**		**Rapid integration case: Reduction of full load hours (56 GW added capacity)**	
	Dispatchable capacities (GW) (Optimal)	**Full-load hours / year (Optimal)**	**Reduced full load hours/ year (Scenario Grid injection)**	**Reduced full load hours/ year (Scenario Self-consumption)**
Nuclear	50.8	Over 6438	Over 4356	Over 3916
Coal	18.9	1450 to 6438	1007 to 4356	1020 to 3916
Combine cycle gaz turbine (CCGT)	8.5	357 to 1450	196 to 1007	179 to 1020
Combustion turbine (CT)	8.1	0 to 357	0 to 196	0 to 179

Table 7: Optimal mix of power generation and reduction of annual full load hours of dispatchable capacities

The simulation gives different results in case the PV integration to achieve the same level of PV penetration is conducted in a progressive manner. The power generation mix will obtain a new long-term equilibrium (*optim*). **Table 8** shows new optimal capacities of dispatchable units in terms of scenario with full grid

[25] The profitability of residential PV self-consumption model can be greatly improved if the excess PV power is sent out to the grid with financial benefits. In this case, however, the profile costs can be increased because the surplus of PV power is mainly produced during a few days in the summer. The impacts vary according to the way of controlling batteries. This analysis is out of scope of the article.

injection (Scenario G) and scenario with self-consumption (Scenario S). For both scenarios, the PV integration decreases the nuclear capacities around by 15% and increases capacities of peaking units (i.e. by around 26%-30% for combustion turbine).

	Optimal mix of power generation (virtual electricity mix in 2015)		**Progressive integration case: reduced optimal capacities of dispatchable units**	
	Dispatchable capacities (GW) (Optimal)	**Full-load hours / year (Optimal)**	**Scenario Grid injection, GW**	**Scenario Self-consumption (no grid injection), GW**
Nuclear	50.8	Over 6438	43.1	44.4
Coal	18.9	1450 to 6438	23	21.7
Combine cycle gaz turbine (CCGT)	8.5	357 to 1450	9.7	9.5
Combustion turbine (CT)	8.1	0 to 357	10.2	10.5

Table 8 : Dispatchable capacities in the optimal mix of power generation

The increasing level of renewable energy integration tends to decrease the market size and the revenues of conventional power producers. The French power system comprises a high share of nuclear power, representing 63.1 GW in 2015. Nuclear power supplied 76.3% of the French domestic electricity production in 2015 (RTE, 2016). If we assumed a constant level of nuclear power plant availability[26] in a year at 80% (CRE, 2016), the available nuclear capacity is 50.5 GW and it is almost equal to the nuclear capacity of our virtual electricity mix (50.8 GW).
We estimated the losses of French nuclear power production; our calculations considered the nuclear power production in 2015 (434 TWh) as a baseline of comparison.

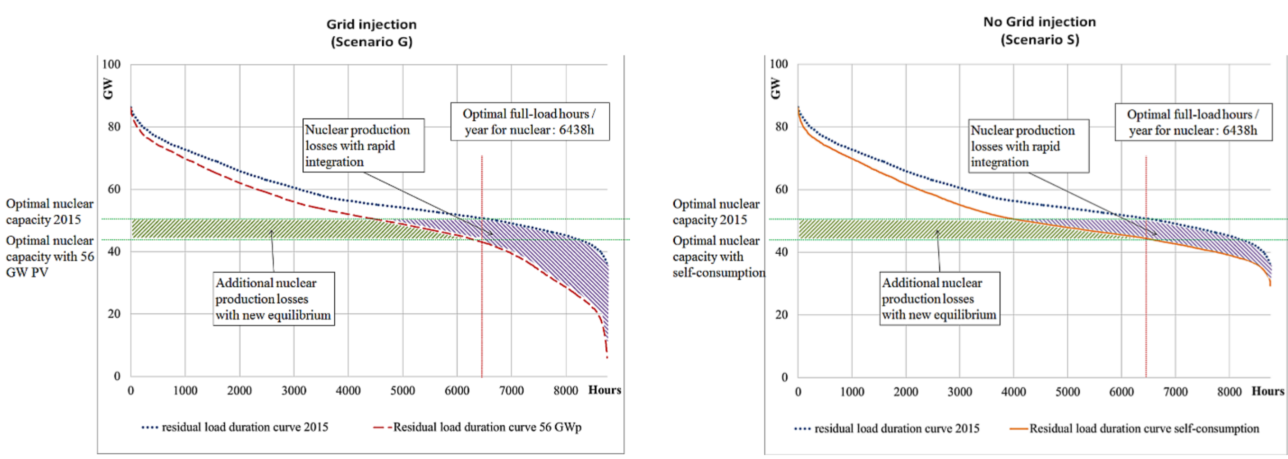

Figure 10 : Nuclear power production losses based on different scenarios

[26] Availability was measured based on the availability factor that indicates the average availability of the nuclear power plants in a year. This coefficient takes into account the capacities that cannot produce because of maintenance.

Nuclear power production (TWh/year)	Grid injection (Scenario G)	No Grid injection (Scenario S)
Speed Rapid (R)	394 (-9.2%)	412 (-5%)
Speed Progressive (P)	352 (-18.8%)	379 (-13%)

Table 9: Nuclear power production losses based on different scenarios

Based on our residential PV self-consumption model with batteries (Scenario S), the power production from nuclear plants will be reduced between 22 TWh (-5%) and 55 TWh (-13%). These impacts will intensify under the scenario without batteries (Scenario G); the residual load duration curve will become steeper and nuclear capacities operate much fewer hours per year than the optimal level.

3) Integration costs of PV power

Based on the obtained results, we attempted to quantify **the integration costs of PV power in the electricity mix** according to the defined scenarios. Our analysis assumed that the PV integration costs are composed of grid-related costs, balancing costs and profile costs.

Grid related-costs and balancing costs

The direct costs of PV integration concerns grid-related costs (i.e. grid reinforcement or extension) and the short-term balancing costs. A number of studies estimated these costs (Keppler & Cometto, 2012; Pudjianto, et al., 2013). For example, at 10% PV penetration level in France, the grid-related costs mainly for utility-scale PV plants were estimated around 5.8$/MWh and the balancing costs around 2 $/MWh (Keppler & Cometto, 2012) without PV integration strategy. The grid-related costs will become almost null under residential PV self-consumption model with batteries if it enables to avoid important injection of electricity into the electrical grid. The short-term balancing costs can be minimized through a geographic spread method; this reduces the uncertainty in the forecasts of PV power production (statistical effects).

	Grid injection (Scenario G)	**No Grid injection (Scenario S)**
Grid-related and balancing costs	~8 $/MWh	~0 $/MWh

Table 10: Grid-related costs and balancing costs

Profile costs

We adopted the method proposed by Ueckerdt *et al*. to quantify the integration dynamics caused by residential PV self-consumption model. The mathematical expressions (7) and (8) were used to calculate the profile costs ($C_{profile}$), which account for the significant part of PV integration costs (C_{int}).
We took the date of 2015 as a baseline to estimate the **profile costs**. We assumed that the annual power demand ($\bar{E}_{total}$) in 2015 is equal to the residual electricity production in 2015 (this included losses, exportations and storage but excluded wind and solar productions). In order to calculate $C_{tot}(0)$ and $C_{profile}$, the virtual electricity mix was considered. **Table 11** shows the profile costs of 56 GW PV integration depending on different scenarios. The annual total profile costs and the unit costs per megawatt-hours ($/MWh)[27] were presented.

[27] The total profile costs / PV power sent to the grid (Scenario G) or self-consumed (Scenario S). As indicated, we considered a total of 46 TWh for PV self-consumption model (a surplus is lost) and a total of 61 TWh for PV deployment without batteries.

Profile costs	Grid injection (Scenario G)		No Grid injection (Scenario S)	
Unit	**Billion € / year**	**€/MWh PV**	**Billion € / year**	**€/MWh PV**
Speed Rapid (R)	2.3	33.1	1.4	25.7
Speed Progressive (P)	2.0	29.3	1.0	19.3
Reduction ratio (R vs. P)	-13%	-11%	-29%	-25%

Table 11: Profile costs based on different scenarios

According to our analysis, the maximum additional costs per each MW installed amount to 33.1 €/MWh under Scenario G with a rapid integration of PV power. The price can be almost halved to 19.3 €/MWh if a progressive PV integration based on our PV self-consumption model with no grid injection occurs. It is important to notice that **the speed of PV integration** is significant factor to determine the profile costs. The rapid integration is more costly than the progressive deployment option: about 13% higher for PV integration with grid injection (Scenario G) and about 29% higher for residential PV self-consumption with batteries (Scenario S). As seen in Figure 9, the PV integration with grid injection (Scenario G) has a much steeper load duration curve than residential PV self-consumption with no grid injection for base load units. When the residual load duration curve falls below zero, the overproduction occurs during the year (PV power supply exceeds the load). According to Ueckerdt and al. (2013), this phenomenon is the most expensive part of PV integration costs. **Our residential PV self-consumption model with batteries enables to obtain higher levels of PV penetration before the overproduction happens.** Therefore, it is important to take into account the integration costs with regard to PV deployment decision.

4) Other financial impacts

Indirect financial impacts related to regulatory mechanisms of electricity systems

Figure 11 presents the total current electricity consumption, PV production without storage and PV production with batteries for 80% self-consumption for the week of 1 August in 2015. With a high penetration of variable PV power, **negative prices** can be observed because of the excess power production. As shown in Figure 11, our residential PV self-consumption model with batteries significantly reduces the risks related to negative prices.

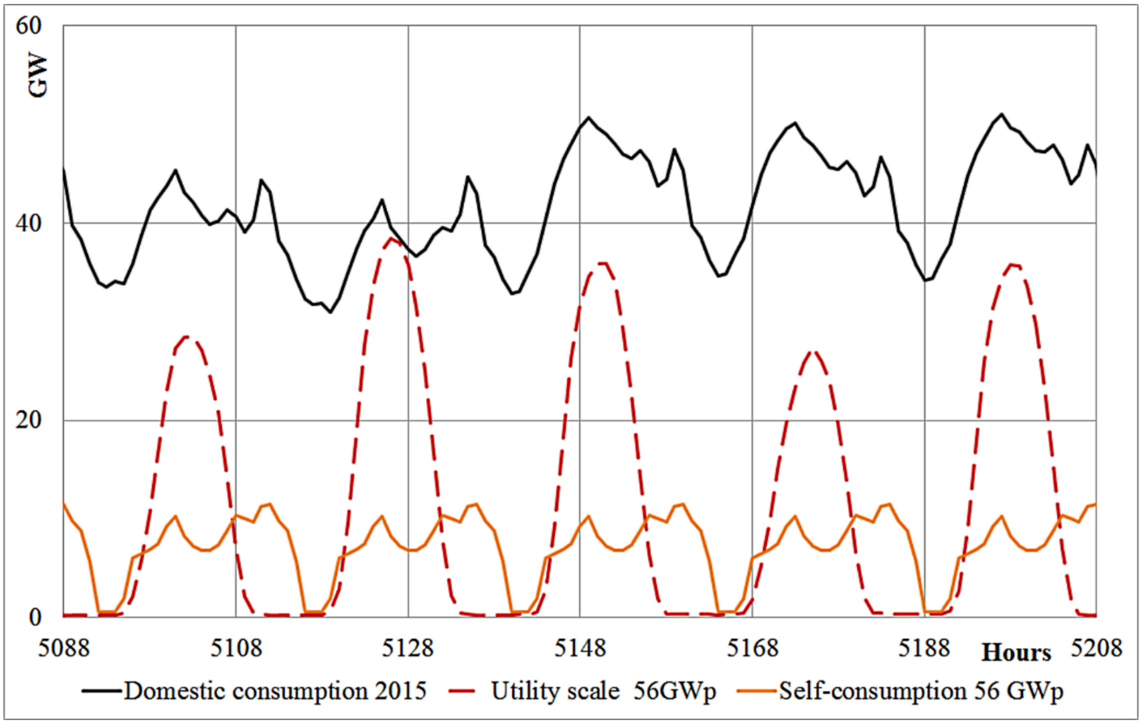

Figure 11: PV production without batteries, PV production with batteries and demand for the week of 1 August
(Author's elaboration based on data of RTE)

Grid financing loss

Based on our PV self-consumption model, there is no PV production surplus injected into the grid. However, the grid should be sized to provide the maximum residual demand. As said, the residential peak demand in France occurs in the evening when the PV capacities do not produce the power.
French electricity tariffs consist of several parts mainly related to the energy costs (electricity), the grid cost for electricity delivery (user fee for the electrical public network known as TURPE[28]) or taxes. TURPE represents 90% of the grid operator's revenue (Enedis). TURPE is calculated taking into account both fixed and variable costs which depend on the subscription type, the options taken, and the consumption profile. There are other segments in the retail electricity rates; different taxes and fees are added to these tariffs (CRE, 2016). The diagram in Figure 12 shows the price breakdown of the average residential electricity rates in France in 2015.

[28] French abbreviation for Tarif d'Utilisation des Réseaux Publics d'Electricité

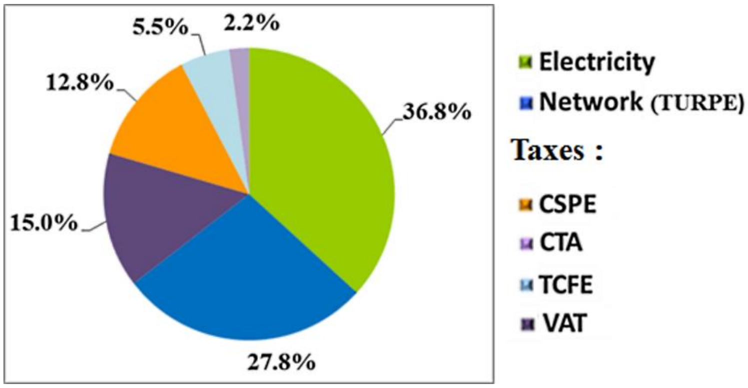

Figure 12: Price breakdown of the average residential electricity rates in France[29] (2016) (CRE, 2016)

The grid financing losses can be roughly estimated thanks to the structure of the electricity price. **The use of the PV self-consumption model will bring about some changes in electricity tariffs because fewer customers buy electricity from the grid with the PV self-consumption.**
Referring to the current electricity tariffs, around 28% of electricity tariffs in France are used for grid funding and this amounts to around c$5/kWh.[30] In this regard, if all the individual households in France install PV systems with batteries, we can expect a loss of grid funding amounting to $2.3 billion/year.[31] If the loss of network funding is equally distributed to end-users of electricity from the grid, the cost will be around c$0.5/kWh[32].

In this regard, the impact on the network cannot be ignored with regard to PV integration. Therefore, it is important to get the grid operators strategically engaged in the planning process of PV integration into the energy systems. Under the PV self-consumed model, preparing a fair scheme for grid cost recovery is necessary to justify the development of this model (IEA, 2014; 2014b; IEA-RETD, 2014). **The redesign of electricity tariffs** can be taken into account: for example, **the rise in the fixed tariffs to finance the grid** or the **implementation of a floating time-based pricing to adjust to the real use of the grid**.

5. CONCLUSIONS AND POLICY IMPLICATIONS

This study has shown that **PV self-consumption with batteries could become profitable for individual investors in France before 2030.** The demand in the residential sector would thus be natural in the near future in France. It is also possible to advance the timing by improving the PV economic competitiveness (e.g. non-module sector). The transition to PV self-consumption provides many opportunities for PV development with advantages (e.g. no grid reinforcement needed and no new land usage).
However, as previously indicated, the possible expanded PV integration through a self-consumption model raises **new issues related to changes in interests of stakeholders in the electricity systems.**
First, it must not be forgotten that PV self-consumption induces losses in terms of the **impact on the power system and network management. The development of self-consumption must be associated with grid**

[29] Contribution to Electricity Public Services (CSPE): French abbreviation for Contribution au Service Public de l'Electricité, Transmission Tariff Contribution (CTA): French abbreviation for Taxe sur la Consommation Finale d'Electricité, Tax on Final Electricity Consumption (TCFE): French abbreviation for Taxe sur la Consommation Finale d'Electricité, Value Added Tax (VAT).
[30] Electricity tariffs for households in 2015 were $US 0.18/kWh in France.
[31] 46 billion kWh x c$5/kWh
[32] $2.3 billion / (476 TWh – 46 TWh), we considered the consistent demand of electricity ($\overline{\mathrm{E}}_{\mathrm{total}\,2015}$=$\overline{\mathrm{E}}_{\mathrm{total}\,2030}$).

financing reform. For example, a time-based grid-usage pricing system can provide economic incentives to develop the distribution of a storage solution or promote the demand management.

Secondly, it has **a negative impact on long-term investment choices in the electricity sector.** Policymakers will have to prepare this change to maintain the security of the energy system. It is thus important to prepare a long-term vision for PV policy in accordance with the current energy mix and the national energy scenarios for the transition to PV self-consumption. It should enable concerned stakeholders to have enough time to adapt to the new situation and to enter into new markets or expand new business.
As explained, it is more risky and costly for the national energy systems to have a system enabling the rapid deployment of PV power or uncontrollable PV installation peaks in a short-term period. **PV integration needs to be progressed based on gradual changes in the mix led by the systemic energy system plan.** In this regard, the energy policies can first focus on targeted sectors or niche markets to progressively start installing PV for self-consumption. The **early encouragement** of PV self-consumption can be **intentionally** planned to secure the **constant growth** model of PV installations. Afterwards, the speed of PV installations can be managed strategically to obtain an optimal mix of the energy systems in the **long-term perspective**.

In this respect, it is worth highlighting the change in the characteristics of PV policies. In the past, PV policies mainly aimed at creating the market with aid to support the PV innovation trajectory so as to reduce its costs. However, the future PV policy should focus more on PV integration to find optimal strategies in terms of the PV power's systemic impacts on the future power systems as PV penetration becomes significant. The current power market design and power system should be modified to better adjust to the possible transformation with high penetration of PV power in the future. The organisational changes should take place under the new regulatory system to introduce new business practices and grid models. As seen in our study, the critical timing is situated in the near future supported by enhanced price competitiveness of PV systems and associated solutions like batteries or digitalisation. When the policy presents a clear and long-term vision, utility generators will also explore new business opportunities by diversifying their business model to react to the market situation change. This long-term vision can be also discussed connected with the national plans to develop associated industries of PV integration.

In conclusion, regarding the policy-maker's perspective, it is thus extremely important to have **a regular and progressive policy** when transitioning to PV self-consumption in the future with the objective to allow enough time for concerned stakeholders to adapt to the new market situation and to reduce the negative impact on the electricity mix by adapting to the age of production capacity in use. How policymakers prepare for this change with a proper institutional framework supported by long-term vision affects the success of PV integration. The future PV policy should be decided based on a systemic perspective taking into account the costs for the whole energy sector.

Acknowledgements
The author is grateful to Dr. Nathalie Popiolek (Senior Expert) at the CEA, Prof. Dr. Patrice Geoffron and Prof. Dr. Jan Horst Keppler at the Paris-Dauphine University for their valued discussion and support. This paper has benefited from the support of the Chaire European Electricity Markets (CEEM) of the Paris-Dauphine Foundation, supported by RTE, EDF, EPEX Spot and the Groupe Caisse des Dépôts. The views and opinions expressed in this paper are those of the author and do not necessarily reflect those of the partners of the CEEM.

References

Abell, D. F. & Hammond, J. S., 1979. *Strategic market planning : problems and analytical approaches.* Englewood Cliffs, N.J.: Prentice-Hall.

ADEME, 2013. *Bâtiment édition 2013 - Chiffres clés,* s.l.: s.n.

Arrow, K., 1962. The Economic Implications of Learning by Doing. *The Review of Economic Studies,* 29(3), pp. 155-173.

Assoa, Y. B. & Gaillard, L., 2013. *Building integrated photovoltaic systems and related project works in France.* Lyon, s.n.

Beetz, B., 2015. *Li-ion battery costs to fall 50% in next 5 years, driven by renewables.* [Online] Available at: https://www.pv-magazine.com/2015/11/19/li-ion-battery-costs-to-fall-50-in-next-5-years-driven-by-renewables_100022051/#ixzz4NR9jiC81
[Accessed 24 February 2017].

Borenstein, S., 2012. The private and public economics of renewable electricity generation. *The Journal of Economic Perspectives,* 26(1), pp. 67-92.

Boston Consulting Group, 1972. *Perspectives on experience.* 1st ed. s.l.:Boston Consulting Group.

Breyer, C. & Gerlach, A., 2013. Global overview on grid-parity. *Progress in photovoltaics: Research and Applications,* 21(1), pp. 121-136.

Breyer, C. et al., 2009. *Grid-parity analysis for EU and US regions and market segments–Dynamics of grid-parity and dependence on solar irradiance, local electricity prices and PV progress ratio..* Hamburg, Germany, s.n., pp. 21-25.

Bryson, J. M., 2004. What to do when stakeholders matter: stakeholder identification and analysis techniques.. *Public management review,* 6(1), pp. 21-53.

Byrne, J. & Kurdgelashvili, L., 2011. The role of policy in PV industry growth: Past, present and future. In: *Handbook of Photovoltaic Science and Engineering, Second Edition.* s.l.:John Wiley & Sons, Ltd, pp. 39-81.

Candelise, C., Winskel, M. & Gross, R. J., 2013. The dynamics of solar PV costs and prices as a challenge for technology forecasting. *Renewable and Sustainable Energy Reviews,* Volume 26, pp. 96-107.

Cany, C. et al., 2016. Nuclear and intermittent renewables: Two compatible supply options? The case of the French power mix. *Energy Policy,* Volume 95, pp. 135-146.

Commissariat Général à la Stratégie et la Prospective (CGSP), 2014. *The crisis of the European electricity system : Diagnosis and possible ways forward,* s.l.: s.n.

CRE, 2014b. *Marché de détail: Observatoire des marchés de l'électricité et du gaz naturel, 2nd quarter 2014,* s.l.: s.n.

CRE, 2014. *Délibération de la Commission de régulation de l'énergie du 15 octobre 2014 portant proposition relative aux charges de service public de l'électricité et à la contribution unitaire pour 2015,* s.l.: s.n.

CRE, 2016. *Le fonctionnement des marchés de gros de l'électricité, du CO2 et du gaz naturel: rapport 2015-2016,* s.l.: s.n.

CRE, 2016. *Marché de détail: Observatoire des marchés de l'électricité et du gaz naturel, 1st quarter 2016,* s.l.: s.n.

Deutsche Bank, 2015. *Crossing the Chasm: Solar grid parity in a low oil price era,* s.l.: s.n.
Deutsche Bank, 2016. *Welcome to the lithium ion age - Lithium 101,* s.l.: s.n.
Direction de l'information légale et administrative de la République Française, 2014. *Journal officiel de la République Française, Texte 10 sur 97,* s.l.: s.n.
Direction Générale du Trésor de la République Française, 2013. *Comparaison des prix de l'électricité en France et en Allemagne,* s.l.: s.n.
EDF, n.d. *All about my bill: Taxes and contributions.* [Online]
Available at: http://residential.edf.com/self-services/my-bill/all-about-my-bill/taxes-and-contributions-details-293136.html
[Accessed 10 Apr. 2015].
Enedis, n.d. *Network Tariff.* [Online]
Available at: http://www.enedis.fr/network-tariff
[Accessed 24 Feb. 2017].
Enerdata, 2013. *EDF will receive €3.9bn compensation for CSPE deficit (France).* [Online]
Available at: http://www.enerdata.net/enerdatauk/press-and-publication/energy-news-001/edf-will-receive-39bn-compensation-cspe-deficit-france_15717.html
[Accessed 10 Apr. 2015].
Energy and Policy Institute, 2014. *Attacks on renewable energy standards and net metering policies by fossil fuel interets & front groups 2013-2014,* s.l.: s.n.
Epexspot, n.d. *Day-ahead fixing.* [Online]
Available at: https://www.epexspot.com/fr/donnees_de_marche/dayaheadfixing/auction-table/2016-11-22/FR
[Accessed 24 Feb. 2017].
EPIA, 2012. *Connecting the sun: Solar photovoltaics on the road to large-scale grid integration,* s.l.: s.n.
EPIA, 2013. *Self-consumption of PV electricity,* s.l.: s.n.
EPIA, 2014. *Global market outlook for photovoltaic 2014-2018,* s.l.: s.n.
Esnault, B., 2014. *Transition énergétique, les enjeux économiques et institutionnels de l'intégration dans les réseaux.* s.l., Les transitions énergétiques dans l'Union Européenne.
European Commission, 2013. *JRC scientific and policy reports: Photovoltaic Electricity Cost Maps,* s.l.: s.n.
Eurostat, 2016. *Electricity prices components for domestic consumers - annual data (from 2007 onwards) [nrg_pc_204_c].* [Online]
Available at: http://appsso.eurostat.ec.europa.eu/nui/show.do
[Accessed 05 Mar. 2017].
Fraunhofer ISE, 2013. *Levelized cost of electricity: Renewable energy technologies,* s.l.: s.n.
Fraunhofer ISE, 2015. *Current and future cost of photovoltaics - Long term scenarios for market development, system prices and LCOE of utility-scale PV systems,* s.l.: s.n.
Haas, R., Lettner, G., Auer, H. & Duic, N., 2013. The looming revolution: How photovoltaics will change electricity markets in Europe fundamentally. *Energy,* Volume 57, pp. 38-43.
Heinen, S., Elzinga, D., Kim, S. K. & Ikeda, Y., 2011. *Impact of smart grid technologies on peak load to 2050,* s.l.: IEA.
Hensley, R., Newman, J. & Rogers, M., 2012. Battery technology charges ahead. *McKinsey quarterly*, Jul., p. 4.
Hernández-Moro, J. & Martínez-Duart, J. M., 2013. Analytical model for solar PV and CSP electricity costs: Present LCOE values and their future evolution. *Renewable and Sustainable Energy Reviews,* Volume 20, pp. 119-132.
Hirth, L., 2014. *The economics of wind and solar variability: How the variability of wind and solar power affects their marginal value, optimal deployment, and integration costs,* Berlin: Thesis dissertation, Technische Universität Berlin, Fakultät VI.

Hirth, L., Ueckerdt, F. & Edenhofer, O., 2015. Integration costs revisited–An economic framework for wind and solar variability. *Renewable Energy,* Volume 74, pp. 925-939.
Hogan, W. W., 2005. *On an "Energy only" electricity market design for resource adequacy.,* s.l.: s.n.
Huld, T., Ruf, H. & Heilscher, G., 2014. *Self-consumption of electricity by households, effects of PV system size and battery storage.* Amsterdam, NL., 29th European Photovoltaic Solar Energy Conference (EU PVSEC).
IEA PVPS, 2002 to 2015. *Trends in photovoltaic applications,* s.l.: s.n.
IEA PVPS, 2014. *Transition from uni-directional to bi-directional distribution grids: Management summary of IEA Task 14 Subtask 2 – Recommendations based on global experience,* s.l.: s.n.
IEA PVPS, 2015. *Trends in photovoltaic applications.* s.l., s.n.
IEA PVPS, 2016. *Review and analysis of PV self-consumption policies,* s.l.: s.n.
IEA PVPS, 2016. *Trends in photovoltaic applications,* s.l.: s.n.
IEA, 2010. *Technology roadmap: Solar photovoltaic energy,* s.l.: International Energy Agency.
IEA, 2014b. *Energy technology perspectives 2014: harnessing electricity's potential,* s.l.: s.n.
IEA, 2014. *Technology Roadmap: Solar Photovoltaic Energy,* s.l.: International Energy Agency.
IEA, 2016. *Energy technology perspectives.* s.l., s.n.
IEA-PVPS France, 2016. *Photovoltaic power applications in France: National survey report 2015,* s.l.: s.n.
IEA-RETD, 2014. *Residential prosumers-drivers and policy options,* s.l.: s.n.
IRENA, 2015. *Renewable power generation costs in 2014,* s.l.: s.n.
Joskow, P. L., 2011. Comparing the costs of intermittent and dispatchable electricity generating technologies. *The American Economic Review,* pp. 238-241.
JRC European Commission, n.d. *Photovoltaic Geographical Information System - Interactive Maps.* [Online] Available at: http://re.jrc.ec.europa.eu/pvgis/apps4/pvest.php?lang=en&map=europe
[Accessed 10 Apr. 2015].
Keppler, J. H. & Cometto, M., 2012. *Nuclear energy and renewables: System effects in low-carbon electricity systems,* Paris, France: Nuclear Energy Angency, OECD.
Kersten, F. et al., 2011. *PV learning curves: past and future drivers of cost reduction.* Hamburg, 26th EU PVSEC conference.
Masson, G. et al., 2014. *PV Development as Prosumers: the Role and Challenges Associated to Producing and Self-Consuming PV Electricity.* Amsterdam, The Netherlands, s.n., pp. 3909 - 3929.
Matallanas, E. et al., 2011. *Analysis of the Self-Consumption Possibilities in Small Grid-Connected Photovoltaic Systems in Spain.* s.l., 26th European Photovoltaic Solar Energy Conference (EUPVSEC).
Mc Kinsey & Company, 2012. Battery technology charges ahead. *McKinsey quarterly*, July, p. 4.
Neij, L., 1997. Use of experience curves to analyse the prospects for diffusion and adoption of renewable energy technology. *Energy Policy,* 25(13), pp. 1099-1107.
Partlin, S., Thierschmidt, T., Kever, F. & Rothert, M., 2015. *Optimised Storage for increased PV Self Consumption,* s.l.: s.n.
Percebois, J., 2012. *Les nouvelles contraintes pour le mix électrique en France.* s.l., s.n.
Pudjianto, D., Djapic, P., Dragovic, J. & Strbac, G., 2013. *Grid Integration Cost of PhotoVoltaic Power Generation,* London: Energy Futures Lab, Imperial College.
PV magazine, 2016. *Module Price Index.* [Online]
Available at: https://www.pv-magazine.com/features/investors/module-price-index/
[Accessed 28 04 2017].
Reichelstein, S. & Yorston, M., 2013. The prospects for cost competitive solar PV power. *Energy Policy,* Volume 55, pp. 117-127.
REN21, 2014. *Renewables 2014 – Global status report,* s.l.: s.n.
République Française, 2009. *Programmation pluriannuelle des investissements de production électrique, période 2009 - 2020,* s.l.: s.n.

RTE, 2016. *Bilan electrique2015,* s.l.: s.n.
RTE, n.d. *Eco2mix RTE.* [Online]
Available at: http://www.rte-france.com/fr/eco2mix/eco2mix
[Accessed Jun. 2015].
Sharp, J. A. & Price, D. H. R., 1990. Experience curve models in the electricity supply industry. *International Journal of Forecasting,* 6(4), pp. 531-540.
Solar Power Europe, 2017. *Q4/2016 & full year: Developments in European solar market & beyong,* s.l.: s.n.
Tesla motor, n.d. *Powerwall: Tesla home battery.* [Online]
Available at: https://www.teslamotors.com/powerwall
[Accessed 20 12 2015].
The committee on climate change, 2012. *Cost and performance of EV batteries,* Cambridge: Element Energy Limited.
Timilsina, G. R., Kurdgelashvili, L. & Narbel, P. A., 2012. Solar energy: Markets, economics and policies. *Renewable and Sustainable Energy Reviews,* 16(1), pp. 449-465.
Ueckerdt, F., Hirth, L., Luderer, G. & Edenhofer, O., 2013. System LCOE: What are the costs of variable renewables?. *Energy,* Volume 63, pp. 61-75.
UNFCCC, 2015. *Adoption of the Paris agreement - FCCC/CP/2015/L.9/Rev.1,* s.l.: s.n.
van den Wall Bake, J. D. et al., 2009. Explaining the experience curve: Cost reductions of Brazilian ethanol from sugarcane. *Biomass and Bioenergy 33(4),* pp. 644-658.
Weniger, J., Bergner, J., Tjaden, T. & Quaschning, V., 2014. *Economics of residential PV battery systems in the self-consumption age.* s.l., 29th European Photovoltaic Solar Energy Conference and Exhibition (EUPVSEC).
Yelle, L. E., 1979. The learning curve: Historical review and comprehensive survey. *Decision Sciences 10 (2),* pp. 302-328.
Yu, H. J. J., 2016. *PhD Thesis: Public policies for the development of solar photovoltaic energy and the impacts on dynamics of technology systems and markets,* s.l.: Paris-Dauphine University.
Yu, H. J. J. & Popiolek, N., 2015. *Challenges and Opportunities of Photovoltaic (PV) Growth with Self-consumption Model.* Antalya (Turkey), 38th International Association for Energy Economics (IAEE) International Conference.
Yu, H. J. J., Popiolek, N. & Geoffron, P., 2015. *A Comprehensive Approach to Evaluate PV System Prices and Opportunity for PV Policy.* Lisbon, Portugal, s.n.
Yu, H. J. J., Popiolek, N. & Geoffron, P., 2016. Solar photovoltaic energy policy and globalization: a multiperspective approach with case studies of Germany, Japan, and China. *Progress in Photovoltaics: Research and Applications,* 24(4), p. 409–587.