

Louvain School of Management

What is the impact of prosumers supporting schemes and of the electricity price structure on the penetration of residential distributed renewable energy in Europe?

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Abstract

Climate change and the ever-growing increase in energy demand have led modern societies to look for alternative ways of supplying energy, including distributed renewable energy (DRE). Owners of small-scale DRE, mostly photovoltaic installations, the so-called prosumers, are expected to play a major role in the transition to low-carbon societies. However, it is still difficult for regulators to assess the impact of support mechanisms, especially feed-in tariffs and net metering, at a residential level. Understanding how these individuals respond to price signals is thus of uttermost importance. Through a regression model, this thesis quantifies the effectiveness of these support schemes and evaluates the impact of the electricity price components on the penetration rate of prosumers in Europe.

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List of abbreviations

BIC	Bayesian Information Criterion
CHP	Combined Heat and Power
DG	Distributed Generation
DRE	Distributed Renewable Energy
EC	European Commission
EU	European Union
FiP	Feed-in Premium
FiT	Feed-in Tariff
IEA	International Energy Agency
LCOE	Levelized Cost of Electricity
NEM	Net energy metering
PV	Photovoltaics
RTP	Real-Time Pricing
SG	Smart Grid
SPE	SolarPower Europe
ToU	Time-of-Use
UoS	Use of System

1 Introduction

Energy is vital for socio-economic development and is regarded by many nations as strategic to their future as it constitutes a source of competitiveness and fosters their advancement (Zajączkowska, 2016). As modern societies face an ever-growing energy demand – a 30% increase is predicted between 2017 and 2040 (International Energy Agency (IEA), 2017) – several challenges surfaced, notably the forecasted depletion of traditional fossil energy resources and the consequences of environmental pollution but also rising electricity prices (Schleicher-Tappeser, 2012; Vahl, Rüther, & Casarotto Filho, 2013). Using renewable energy to generate electricity quickly emerged as one of the potential keys to mitigate the pressure of global climate change, meet energy demand and transform to a low-carbon society (Chen & Yin, 2016; Erbach, 2016b). For instance, it is predicted that, by 2050, photovoltaic systems can reduce more than 6 billion tons of CO₂ emissions per year, the equivalent of the total direct emissions of the worldwide transport in 2014 (IEA, 2014a). In 2015, the share of renewable energy in global electricity production was already estimated at 23% (IEA, 2017).

Conscious of the renewables' potential and of its role as the third-largest energy consumer (IEA, 2017), the European Union (EU) passed the Renewable Energy Directive establishing a common framework for the use of energy from renewables to limit greenhouse gas emissions and promote cleaner transport. With it, came for each Member State a binding target regarding the share of energy from renewable sources in its gross final consumption by 2020, between 10% for Malta and 49% for Sweden (European Commission (EC), 2014).

The large-scale deployment of distributed renewable energy (DRE) as an alternative to the traditional electricity supply system is among the various solutions implemented by national governments to meet their target. Smaller and located close to the end-users, these decentralized generators are transforming the power system by making the energy flow multidirectional and involving electricity consumers proactively. As a result, DRE can yield significant benefits in terms of energy efficiency and reduced carbon emissions (Wolsink, 2012).

At the residential level, the DRE market can be reasonably scaled down to owners of photovoltaic (PV) systems with two recent developments shifting public perception about the

technology: the drastic price reduction of the PV cells and the Fukushima nuclear accident (Schleicher-Tappeser, 2012). Their combined impact accelerated the advancement of the market which grew by an impressive factor of nearly 245 times between the start of the millennium and 2016, up to 306.5 GW total power installed worldwide. As such, solar is being considered today as the preferred renewable energy choice to combat global warming (SolarPower Europe (SPE), 2016).

As a consequence, the challenge faced by regulatory authorities became to design the right incentivizing policies targeted at the owners of these PV systems, the so-called prosumers—a term coming from the contraction of producer and consumer since these individuals both produce and consume electricity (Bonbright, Danielsen, & Kamerschen, 1961).

Much is expected from these prosumers as they have the potential to harness demand flexibility, improve the integration of intermittent solar energy and achieve low emissions without the excessive costs related to network reinforcement and the supply of electricity by reserve generators (Osenia & Pollitt, 2017).

In 2015, feed-in tariffs (FiTs) and net energy metering (NEM) with self-consumption were the two main supporting mechanisms in place in the world representing together 78.2% of all active schemes (SPE, 2015). **The objective of this research is thus, first, to compare the impact of these policies on prosumers' penetration rates.**

When considering the promotion of PV, regulators should assess the behavior of the electricity market characterized by uncertainties in demand and supply (Vahl et al., 2013). In fact, most consumers interact with the market only through the price they pay for the delivery of electricity. As a consequence, good tariff design is crucial to provide users with the right signals (Reneses & Rodríguez Ortega, 2014). **Understanding how incentives conveyed through prices change when electricity tariff structure is altered is the second objective of this research.**

In fact, authors found that retail rate design and supporting schemes can affect PV deployment dramatically (Darghouth, Barbose, & Wiser, 2011; Darghouth, Wiser, Barbose, &

Mills, 2016; Dupont, De Jonghe, Olmos, & Belmans, 2014) and this thesis attempts to quantify these impacts.

The scope of this study is limited to countries located in Europe as the electricity network and grid organization can vary significantly between continents. Furthermore, prosumers are restricted to residential owners of PV cells as this sub-market is driven by different factors than commercial or utility-scale PV. Additionally, solar PV systems were considered representative of DRE given that power generated from other renewable sources is negligible at the residential level. Finally, only feed-in tariffs and net metering supporting schemes are studied. The research question formulated is the following:

What is the impact of prosumers supporting schemes and of the electricity price structure on the penetration of residential distributed renewable energy in Europe?

The organization of the rest of this thesis is as follows. First, a literature review is performed to assess what is currently known over electricity prosumers, electricity tariff design and compensation schemes. This section ends with the description of the hypotheses posed. Second, the data and model used are exposed and commented. Third, findings are analyzed in light of the hypotheses. Finally, the results are discussed in view of limitations and a conclusion of the research is presented.

2 Methodology

2.1 The electricity system

Despite minor differences between European countries due to local specificities, the traditional electricity system is operated almost identically everywhere and consists of two components: the physical grid for generation, transport and use, on the one hand, and the electricity market on the other (Erbach, 2016b; Rodríguez-Molina, Martínez-Núñez, Martínez, & Pérez-Aguilar, 2014).

On the one hand, the physical grid allows the effective flow of electricity and consists of generators and transport systems, which comprise both systems for transmission over long distances and systems for distribution to residential and industrial consumers of electricity.

On the other hand, the electricity market is the trading place for electricity and allows the flow of money between the various actors operating on the physical grid which are composed of (Erbach, 2016b):

- Electricity generators, who run large power plants (e.g. GDF Suez) or smaller-scale installations (e.g. residential owners photovoltaic cells).
- Electricity suppliers, who buy electricity on the wholesale market from generators and sell it to consumers (e.g. Engie Electrabel, Luminus).
- Private or commercial consumers, who consume electricity and pay suppliers.
- Transmission system operators (TSOs), who carry electricity at high voltages (up to 1 million volts) and over long distances. They are remunerated for transporting the electricity and for ensuring a large part of the system stability (e.g. Elia System Operator SA);
- Distribution system operators (DSOs), who carry electricity at lower voltages and over the short distance distribution network. They are remunerated for building the local grids, delivering electricity to consumers, installing electricity meters and communicating the consumption to the energy suppliers (e.g. ORES, Eandis) (Erbach, 2016b).
- Independent (regional) or national regulators, who define regulations and oversee the functioning of the market (e.g. CWaPE, ENTSOs).

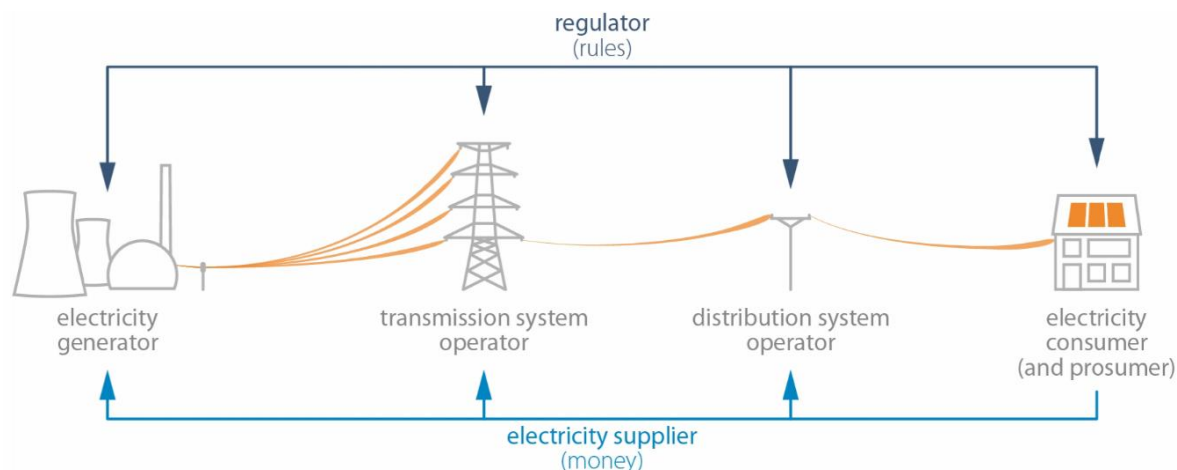


Fig. 1. Schematic overview of the electricity system. Reprinted from (Erbach, 2016b, p. 3).

The EU enactment of the liberalization directives in the 1990s laid the foundation of the semi-regulated modern electricity market. The legislation requires Member States to transpose them into national law and, as a consequence, the liberalization process has reached disparate stages depending on the country but, in general, the electricity system is divided into two parts. On the unregulated side of the market, suppliers and generators actively compete in an economic space where most of the switching costs and barriers to entry have been removed. A diverse and differentiated offer (locally produced, green, cost-efficient energy, etc.) is available to consumers who can also become electricity producers themselves. On the regulated side, operators of the network (i.e. DSOs and TSOs) evolve in a non-competitive market and allow third parties access to their infrastructure (Bellekom, Arentsen, & van Gorkum, 2016; Dupont et al., 2014).

Two fundamental technical properties characterize the modern electric grid (Erbach, 2016b):

- The balance between supply and demand of electricity must always be ensured to avoid system failures (e.g. blackouts). Tools such as reserve generators, demand response and energy storage can be used in case of scarcity of energy.
- The electricity follows the path of least resistance and, as a consequence, consumers receive electricity from mixed sources.

In the traditional grid, electricity flows from large central generators, mostly running on fossil fuel, through TSOs and is delivered by DSOs to the end-users. Today, the recent

development of the smart grid (SG) is rapidly changing the way the system is operated (Agrell, Bogetoft, & Mikkers, 2013).

A definition of the SG is given by the ERGEG (2010, pp. 18–19):

An electricity network that cost efficiently can integrate the behavior of all users connected to it – generators, consumers and those that do both – in order to ensure a sustainable power system with low losses and high levels of quality, security of supply and safety.

In the SG, electricity is also produced by smaller and distributed generators (i.e. prosumers), often from renewable sources, who consume part of their production for their own use and redistribute the rest through the grid to other consumers (Rodríguez-Molina et al., 2014). As a consequence, electricity, information and money flows become multi-directional with the help of advanced metering systems (Flaute, Großmann, Lutz, & Nieters, 2017; Rodríguez-Molina et al., 2014; Shandurkova, Bremdal, Bacher, Ottesen, & Nilsen, 2012).

The concepts of distributed generation (DG), prosumers and more specifically distributed renewable energy (DRE) are now explored more deeply as it is crucial to understand their role in the grid before diving into the problematic linked tariff design and prosumers supporting schemes.

2.2 Distributed Renewable Energy

A general definition for DG is given by Ackermann, Andersson, and Söder (2001, p. 195): DG is an “electric power generation within distribution networks or on the customer side of the network”. The implication of DG for the electricity system is that the energy flow becomes multi-directional. An increased interest has been shown towards DG in the recent years with the transformation from the traditional electric grid to the SG in which DG is expected to play a prominent role (Geelen, Reinders, & Keyson, 2013).

Parmesano (2003) identified the key features of DG:

- It is located near the electricity load or end-users (Ackermann & Knyazkin, 2002; Wolsink, 2012).
- It has a smaller capacity than classic centralized generators.
- It may supply excess power into the grid (Vahl et al., 2013).
- It can involve a renewable energy source (i.e. DRE).
- It can be a combined heat and power (CHP) facility to produce heat besides electricity.
- It does not necessarily belong to the local larger generators.

Ruester, Schwenen, Batlle, and Perez-Arriaga (2014) class DG as part of a broader category of Distributed Energy Resources which also encompass local storage, electric vehicles and demand response besides DG. The latter is, in fact, a broad concept ranging from “1 kW PV installation, 1 MW engine generators to 1000 MW offshore wind farms” (Singh, 2009, p. 1). An overview of various DG facilities and their production capacity is provided by Vahl et al. (2013) and by Singh (2009). An extensive review of DG benefits is given by Iannucci, Cibulka, Eyer, and Pupp (2003) while an examination of the challenges caused by DG to the network is explored by Picciariello, Reneses, Frías, and Söder (2015) and by Singh (2009).

The focus of this thesis is on a specific segment of DG known as distributed renewable energy (DRE) which is defined as DG from renewable sources: hydropower, wind, solar, biomass, geothermal, and ocean energy (Sun & Zhang, 2012; Wolsink, 2012). Owners of a DRE installation can also be referred to as prosumers¹ – the term comes from the contraction of producer and consumer since these individuals both produce and consume electricity (Bonbright et al., 1961).

As explained in the introduction, the scope of this thesis covers residential prosumers. In other words, the focus is put on households with a small-scale electricity generator installed locally. Even within residential prosumers, prosumption patterns vary considerably, both for consumption and production, depending on the technology available and storage possibilities (Flaute et al., 2017). A review of each renewable source is given in the next few paragraphs and

¹ The terms DRE and prosumer will now be used interchangeably depending on whether the focus is put on the installation (DRE) or on its owner (the prosumer).

it is shown that small-scale domestic DRE can be reasonably reduced to small photovoltaic systems.

In theory, all renewable sources of energy could be used in a residential electricity generator. However, in practice, the typical residential prosumer has very limited possibilities to produce a significant amount of electricity at home given today's commercially available technologies, solar PV being the largely dominant solution.

Biomass supplied a total primary energy equal to 62.5 EJ in 2016 and consists of converting biomass feedstocks such as wastes, residues and crops into heat, electricity, fuel or a combination of these. In the residential sector, the biomass energy is mostly limited to burning solid biomass to provide heat for cooking and for space and water heating. Production of fuels requires complex large-scale chemical pathways inaccessible to residential prosumers due to economic reasons. Production of electricity from biomass is only produced by utilities by swapping coal for biomass in traditional heat plants as the technology is expensive and heavily regulated in Europe (IRENA, 2018; REN21, 2017).

Geothermal energy can also be converted into heat or electricity and production of energy from this source amounted to 567 PJ in 2016. Similar to the biomass energy, geothermal energy is only used for heat at the residential level, mainly for heating swimming pools, space heating such as for greenhouses and hot water supply. Electricity from geothermal energy is only produced in large-scale plants as the technology requires heavy capital investments unaffordable for a typical household (IRENA, 2018; REN21, 2017).

Global hydropower generation was estimated to 14.8 EJ in 2016 (REN21, 2017) and mostly consists of reservoir schemes “that store water behind the dams in order to de-couple generation from hydro inflows” (IRENA, 2018, p. 116). Residential hydropower up to 100 kW is limited to owners of a property with a stream, creek or river and is mostly used in remote areas not connected to the conventional grid (IRENA, 2012).

Ocean power installed in 2016 amounted to 536 MW, more than 90% of which was brought by two tidal barrage facilities: the 254 MW Sihwa plant in the Republic of Korea and the 240 MW La Rance tidal power station in France. Indeed, most of the ocean energy facilities

are still in pre-commercial and development mode, thus not available to residential consumers. Moreover, the share of households with enough ocean access is negligible (REN21, 2017).

Wind power represents the second-largest annual market with 487 GW cumulative capacity installed in 2016. Wind potential varies largely on the location and today's technology requires sizeable wind turbines to offer attractive profitability. As such, the wind energy market for the residential segment is very limited with mostly small wind turbines installed for remote off-grid households (REN21, 2017).

Concentrating solar power (CSP) can also be used to generate electricity and the total cumulated capacity amounted to 4.8 GW in 2016. The technology consists of mirrors reflecting the power of the sun on a tower to produce superheated steam and requires huge fields for deployment to be economically viable (REN21, 2017).

Solar photovoltaic (PV) cumulative electrical capacity installed totaled to at least 306.5 GW in 2016. Never before more solar power has been installed in a single year than in 2016 and for the first time, PV left behind wind energy in terms of annual installations (SPE, 2016). PV development has been impressive and grew by a factor of nearly 245 times between the start of the millennium and 2016 (SPE, 2016). Europe was the first to pass the 100 GW milestone but was quickly surpassed by Asia, led by China (REN21, 2017).

PV installations come in every size, from systems of 1 kW up to 1500 MW with the Tengger Desert Solar Park in China being the largest PV system in the world at this date. While small-scale distributed PV systems led the development of the technology in the 90s and early 2000, economies of scale and uncapped incentives fostered the development of large-scale systems which were easier to establish than a distributed PV rooftop market (SPE, 2016) and quickly enjoyed a lower levelized cost of electricity (LCOE) than new CCGT, coal and nuclear power plants (Fig. 2 and Fig. 3).

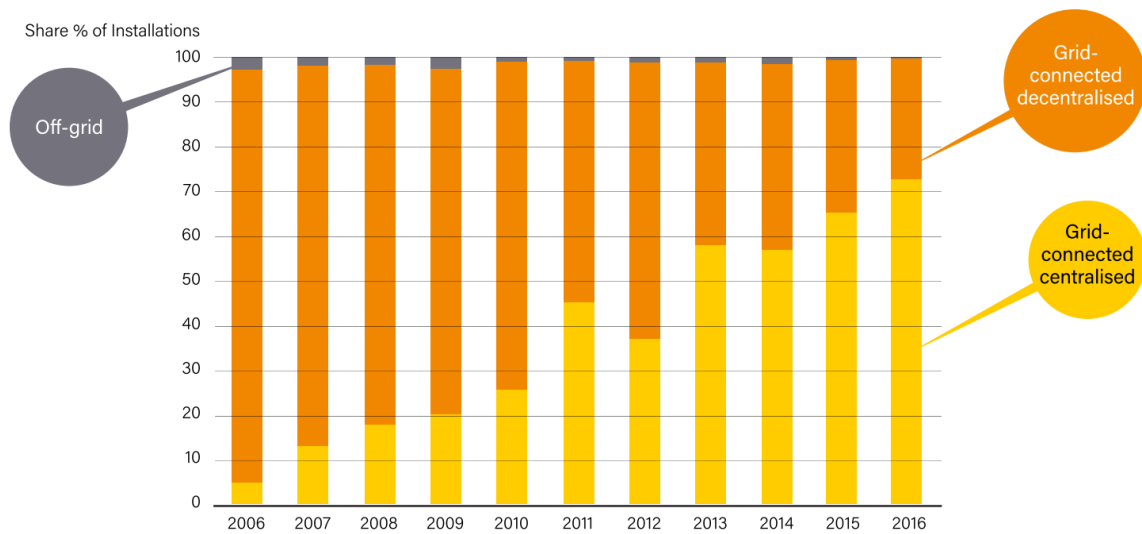


Fig. 2. Solar PV global additions, 2006–2016. Reprinted from (REN21, 2017, p. 67).

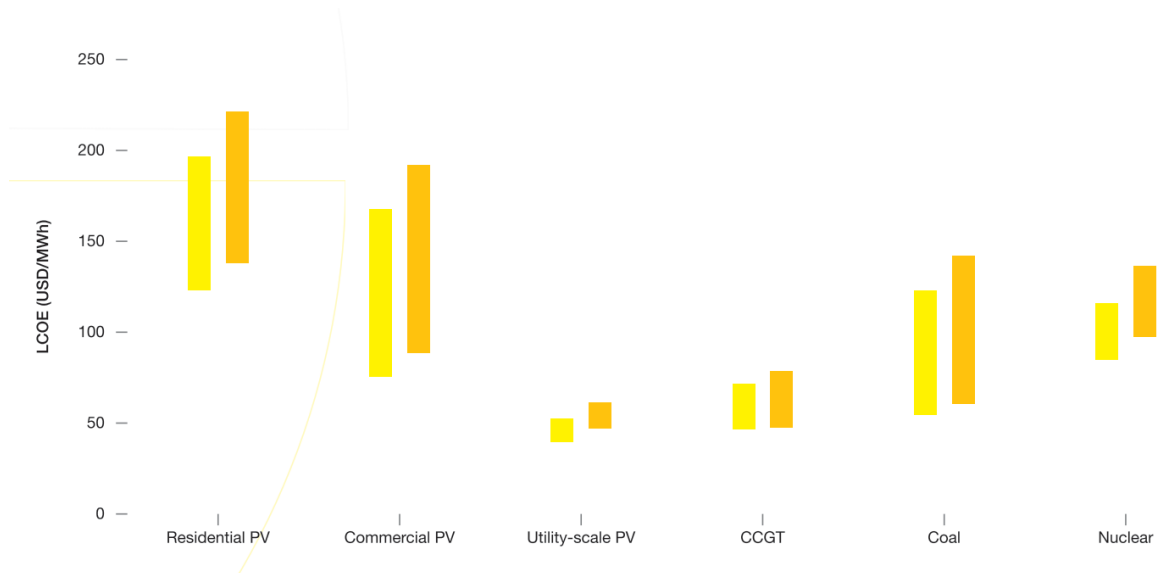


Fig. 3. Cost of generation for various sources. Reprinted from (SPE, 2016, p. 9).

Nevertheless, small-scale installations up to 10 kW are still very attractive to households either as rooftop or as ground-mounted systems. Compared to all other power generation technologies, Schleicher-Tappeser (2012) makes the case for PV as the most promising one through four characteristics that set it apart. First, PV is extremely reliable as they are durably encapsulated and fixed on a support with no moving parts, no need of fuel and little maintenance required over their lifetime of more than 20 years. Second, PV cells can be mass produced with significant economies of scale and learning curves similar to other components manufactured by the semiconductor industry. Third, the technology is remarkably

scalable as the transformation of sunlight into electricity occurs at microscopic levels with cost differences between scales only attributable to mechanical and electrical integration differences. As such, PV cells allow consumers of all sizes to produce power by themselves and as a consequence, these prosumers begin operating with a new bottom-up control logic. Fourth, PV enjoys innovation cycles up to ten times shorter than for conventional power plants.

Overall, PV represents one of the most promising technologies in the field of renewables and as REN21 (2017, p. 22) puts it: “solar PV leads the way in power generating capacity and is considered a cost-competitive source of new generation in many emerging markets across the world”. As a result of this analysis, residential DRE can be approximated to owners of a small-scale PV system².

2.3 Prosumers

Four categories of drivers can be identified which led to the substantial increases penetration of residential prosumers recently (Flaute et al., 2017; IEA-RETD, 2014; Singh, 2009):

- Environmental: there has been both political and individual effort to increase production from renewable energy instead of large polluting plants in light of increasing environmental concerns and awareness (Chen & Yin, 2016; Lopes, Hatziargyriou, Mutale, Djapic, & Jenkins, 2007; Pepermans, Driesen, Haeseldonckx, Belmans, & D’haeseleer, 2005; Picciariello, Vergara, Reneses, Frías, & Söder, 2015).
- Commercial: smaller residential generators have gained popularity because of their improved quality and reliability in a still uncertain electricity market (Pepermans et al., 2005). As a consequence, a positive return on investment in DRE, supported by government policies (see section 2.6.2) has largely contributed to the large-scale deployment of DRE (Islam & Meade, 2013). The declining investment cost of installations, up to 80%, and the rising electricity prices both played a role in increasing the economic attractiveness of PV for small-scale residential prosumers (IEA-RETD, 2014; Jäger-Waldau, 2016). The return itself depends on the prosumer behavior

² If not specified, DRE will now refer to small-scale PV installations and prosumers will refer to residential prosumers owners of these PV systems.

regarding the trade-off between “avoiding costs from consumption and maximizing earning from power injection” (Rodríguez-Molina et al., 2014, p. 6161).

- Behavioral: affinity with technology and energy (Islam & Meade, 2013) as well as increased concerns about the security of supply and power outages may also have contributed to shape the mind of prosumers (IEA-RETD, 2014; Leenheer, de Nooij, & Sheikh, 2011; Michelsen & Madlener, 2017).
- National: political attention given to energy security through diversification of energy sources and competition support, total rooftop space available, share of building owners vs. renters, and electricity demand trends can also explain the diffusion of prosumers (IEA-RETD, 2014).

Flaute et al. (2017) believe that prosumers are economically relevant since 2012 and Rodríguez-Molina et al. (2014, p. 6142) add that they are now “the most important value creators within the smart grid” by switching from a passive to an increasingly more active role (Geelen et al., 2013). Indeed, not only do they consume, produce and store energy but they also participate in the economic and technological optimization of electricity consumption while engaging in value creation for electricity services (Rodríguez-Molina et al., 2014).

However, the prosumers’ effective impact on the SG, especially in relation to managing the balance between supply and demand (Geelen et al., 2013) depends on prosumers’ autarchy level defined as the percentage of their electricity consumption that is self-produced (Flaute et al., 2017). Moreover, in order to become a mass phenomenon, low-risk integrated and standardized DRE solutions still have to be proposed to bridge the actual gap between technology providers and policymakers (Geelen et al., 2013; Schleicher-Tappeser, 2012).

Depending on the grid configuration and management, owners of a DRE installation can bring several advantages to the electricity system:

- Many centralized generators still produce energy through fossil fuels and, as a consequence, prosumers have a positive environmental benefit by increasing penetration of renewables which in turn reduces carbon emissions (Wolsink, 2012). This is important for authorities trying to reach their target in renewable energy set by the Renewable Energy Directive (EC, 2014).

- Prosumers can relieve the grid load from their self-consumption (Flaute et al., 2017). This is valuable for utilities during peak times since prosumers can reduce congestion which can potentially result in lower end-user electricity prices (Firestone, Marnay, & Maribu, 2006).
- Prosumers add capacity to the grid at a zero-investment cost for the utility. Most of this electricity being generated through PV is called by utilities “a high load carrying capability” because the sun power is relatively easy to forecast in the longer term (Poullikkas, 2013, p. 2). Moreover, if the necessary reinforcements in the grids are made, DRE can defer further investment in capacity and transformers (Firestone et al., 2006; Méndez, Rivier, & Gómez, 2006; Poullikkas, 2013).
- Domestic DRE can improve overall electricity service quality (Poullikkas, 2013). Grid voltage can be strengthened by using prosumers’ installations (Frías, Gómez, Cossent, & Rivier, 2009; Leenheer et al., 2011). PV or micro-CHP seem to be particularly suitable for prosumers in that respect, especially if combined with a storage capacity (Shandurkova et al., 2012). Additionally, outage risk can be reduced in long distribution lines by avoiding that voltage falls behind a defined threshold in case of high loads (Baran, Hooshyar, Shen, Gajda, & Huq, 2011; Poullikkas, 2013). Moreover, if a single prosumer was to produce enough energy and stock it to satisfy its entire needs, it would improve the network’s reliability indices while he would be safely islanded during network outages (Firestone et al., 2006; Frías et al., 2009). Larger-scale islanding is also possible through peer-to-peer sharing within a community (Rathnayaka, Potdar, Hussain, & Dillon, 2011) which can, in turn, form a micro-grid (Vahl et al., 2013). Finally, prosumers can reduce line losses in general but Méndez et al. (2006) showed that it is not always straightforward and highly dependent on the situation.
- Flaute et al. (2017) found that prosumers can also have a slight positive macroeconomic effect by fostering investments in electricity generators which can, in turn, stimulate economic growth.
- Prosumers can lower the cost of electricity and create new sector jobs (Zajęczkowska, 2016).

Prosumers also pose some challenges to the electricity supply chain and more specifically to the organization of the traditional power grid:

- Prosumers increase the complexity of the system because they do not have a similar consumption pattern than regular grid users (Flaute et al., 2017).
- DRE is still heavily dependent on weather conditions in the short term and since the balance between supply and demand must be ensured at all time (Erbach, 2016b), DRE can introduce instability if directly integrated into the grid. Estimates of DRE capacity self-utilization factors spread from 17% to 90% (Huld, Ruf, & Heilscher; Singh, 2009) due to the mismatch between consumption and production times (Schleicher-Tappeser, 2012). As a result, the intermittency of the power sources is still too much of a hurdle to reach high levels of penetration without being backed by centralized fossil plants given the current technology state (Schleicher-Tappeser, 2012; Vahl et al., 2013).

This last issue is strengthened under the “priority dispatch” European policy which gives the priority to renewable-based energy over other plants. Indeed, if electricity demand is low and weather favorable to DRE, the spot price of electricity might drop below zero since TSOs must accommodate all green energy produced (Oggioni, Murphy, & Smeers, 2014).

To counter this problem, the emerging technology of Distributed Hybrid Energy System attempts to take advantage of complementarities between different power sources such as solar and wind to mitigate this instability (Sun & Zhang, 2012). Furthermore, advances in storage capabilities are expected to reduce this intermittent dependency by improving self-utilization while providing optimization possibilities for prosumers during peak periods (Erbach, 2016b; Nieto, 2016; Schleicher-Tappeser, 2012; Vahl et al., 2013). Moreover, storage is predicted to increase stability and reliability of the grid (Sovacool & Hirsh, 2009; Vahl et al., 2013). Significant deployment of enhancing renewable energy behind-the-meter storage (Bellekom et al., 2016) can either be in the form of Vehicle-to-grid (V2G) using the large batteries inside electric vehicles (Schleicher-Tappeser, 2012; Sovacool & Hirsh, 2009) or in the form of regular larger residential batteries whose cost is currently decreasing for individuals thanks to firms like Tesla (Erbach, 2016b; Nieto, 2016).

2.4 Social welfare considerations

As stated earlier, national regulatory authorities need to design the right policies which stimulate prosumption penetration in order to meet their target regarding the share of energy from renewable sources in gross final consumption. In that respect, it is useful to first distinguish between the two different types of regulators, regional or national, their motivations and the challenges they face.

On the one side, regional and European independent regulatory bodies instituted after the enactment of the liberalization directives are actively coping with the changing electricity market and transition to the SG. For example, the Agency for the Cooperation of Energy Regulators (ACER) takes care of promoting cooperation between national regulatory authorities, monitoring progress in the implementation of network development plans, monitoring the internal markets, elaborating rules for the operation of the electricity transmission network, coordinating grid operation through the exchange of operational information and developing common safety and emergency standards and procedures (Erbach, 2017). Another example is the European Network of Transmission System Operators for Electricity (ENTSO-E) who acts as a coordinating body for TSOs. These regulators are expected to play an important role in the transition towards the SG which requires large infrastructure investments. According to Agrell et al. (2013), regulators should find a focal point, integrate performance assessment externalities and avoid wide delegation to maximize the social welfare of further investments in the grid.

On the other side, national regulators strive to achieve the maximum social benefit. The potential advantages brought by prosumers described earlier can contribute to improve the social welfare in various ways. However, prosumers must be incentivized through efficient policies at an individual level and a form of coordination between grid operators and self-interested prosumers is needed for the grid to achieve efficient global performance. As documented by Chen and Yin (2016), experiences in Australia, United States, Japan, Europe has indicated that well-designed policies are an effective tool to foster the development of renewable distributed energy generation. Understanding the motivations of individual prosumers is thus of uttermost importance in order to align their behavior and the benefits they can bring to the grid while proactively coping with the associated challenges (Rodríguez-Molina et al., 2014; Schleicher-Tappeser, 2012).

Practically, the trade-off faced by regulators is to conciliate short-term and long-term objectives (Rodríguez Ortega, Perez-Arriaga, Abbad, & González, 2008; Ruester et al., 2014; Strbac & Mutale, 2005). On the one hand, incentives directed at prosumers aim to mobilize short-term investments in DRE despite the large upfront cost and its related risk (Chen & Yin, 2016; Lesser & Su, 2008; Sioshansi, 2016). On the other hand, long-term objectives contributing to the social welfare include technology cost reductions and increased competitiveness of DRE through economies of scale (Lesser & Su, 2008; Sioshansi, 2016), sustainable energy concerns, grid stability (Flaute et al., 2017) and grid enhancements within costs management (Agrell, 2015). With respect to this conciliation process, Chen and Yin (2016) argue that eliminating information asymmetries between all parties is key to fulfill both short- and long-term objectives.

As a consequence, regulators have come up with a series of incentivizing mechanisms directed at prosumers which differ by how they achieve to reduce the investment's cost and risk while satisfying the long-term concerns (Sioshansi, 2016). Three types of stimulating instruments have been used so far: prosumer-tailored supporting schemes, direct subsidies and tax exemptions (Poullikkas, 2012). These alternative policies can have very different levels of success (Sioshansi, 2016) and DRE penetration rate was identified as an important decision factor when choosing which mechanism to implement (IEA-RETD, 2014; Vahl et al., 2013). The focus of this thesis is on the first only, also referred as prosumers compensation tariffs, as it is the only type of incentivizing schemes directly related to electricity prices. The most common supporting schemes (i.e. feed-in tariffs and net metering) are explored in more details in section 2.6.2.

2.5 Electricity tariffs guiding principles

In order to properly understand how these supporting schemes tailored at prosumers are built, it is useful to expose first the principles on which any electricity tariff is built.

Perfectly competitive markets lead in theory to efficient economic pricing but in the case of the semi-regulated electricity market, regulators play a major role in designing the Use of System charges relating to the transport on the grid (see section 2.6.1.3) (Vahl et al., 2013). The principles of public utilities first stated by Bonbright in 1961 still constitute today the fundamental guidelines for electricity tariff design despite the liberalization of the market in the

90s (Dupont et al., 2014). They guide regulators in their tariff design decisions, especially when faced with disruptive events such as the rise of prosumers. While a tariff respecting perfectly all 10 principles represents an ideal tariff, in practice, the principles often conflict with each other and this objective is hardly reachable.

Some of these principles and conflicts are particularly relevant for DRE integration into the grid: allocative efficiency, cost recovery, cost causality and equity (Picciariello, Reneses, et al., 2015). In the next paragraphs, a quick overview of these four principles is given as they will often be referred to in the following sections. The remaining guiding principles and the main arising conflicts can be found in the work of Reneses and Rodríguez Ortega (2014).

Under allocative efficiency, “all customers see economically efficient price signals for usage and distributed generation investment decisions, by time of day and season” (Nieto, 2016, p. 34) and are “being charged according to how much they value the service they receive” (Picciariello, Reneses, et al., 2015, p. 372).

Cost recovery implies that all actors must recover their total cost of operating the grid (Dupont et al., 2014; Rodríguez Ortega et al., 2008). This is particularly critical for DSOs who face revenue decreases and unexpected costs with the increased penetration of prosumers (see section 2.6.2.4) (Dupont et al., 2014).

The cost causality principle, also known as the cost reflectivity principle, states that tariffs must accurately reflect each grid user impact on the network costs (Picciariello, Reneses, et al., 2015; Picciariello, Vergara, et al., 2015). In other words, users must pay for the costs they cause to receive electricity and the costs of injecting their surplus into the grid. Due to the shared aspect of the grid and the semi-regulated nature of the market, it is not straightforward to identify and allocate costs to the right users (Sakhrani & Parsons, 2010) but Nieto (2016) made a great work of mapping out which cost categories and components should be recovered through which revenue stream in a perfect theoretical approach of the cost causality principle. In theory, following this principle leads to the avoidance of cross-subsidization (see section 2.6.2.4). However, DRE put cost causality under stress since the prosumers’ varying injected electricity price is not reflected in traditional tariffs (Dupont et al., 2014).

The equity principle states that there should be no discrimination between grid users by charging “each consumer the same amount for using the same good or service, independently of the electricity’s use and of the customer’s characteristics” (Picciariello, Reneses, et al., 2015, p. 372; Reneses & Rodríguez Ortega, 2014).

Besides adding complexity to the respect of these principles, DRE also exacerbates existing conflicts between them:

- Sending the appropriate signals to prosumers increases the risk for grid operators of not recovering their costs, intensifying the conflict between the allocative efficiency and cost recovery principles (Reneses & Rodríguez Ortega, 2014).
- Allocating the costs incurred by the operator to the user who caused it conflicts with ensuring simultaneously cost recovery for the grid operators as prosumers engender the same costs as any user but do not contribute accordingly (see section 2.6.2.4) (Frías et al., 2009; Reneses & Rodríguez Ortega, 2014).
- Cost causality often conflicts with the allocative efficiency principle and this is the reason why this trade-off has received a lot of attention in the literature (Rodríguez Ortega et al., 2008). In 1989, Hausman and Neufeld detailed the problematic extensively by opposing rate engineers designing meticulous tariffs to reflect costs with the best approximation and economists trying to influence customers’ behavior in order to better utilize idle plant capacity. Today the issue is still the same with economists trying to stimulate prosumers penetration.

Therefore, regulators and grid operators must prioritize certain principles and their informed decisions depend on the regulatory and political context (Rodríguez Ortega et al., 2008; Ruester et al., 2014; Sakhrani & Parsons, 2010). For example, DSOs usually prioritize efficiency, regulators have redistribution concerns as well as a focus on sending appropriate signals to develop the DRE market. Theoretically, significant penetration of small domestic DRE can either have a positive or negative impact on grid costs depending on their deployment rate, location, concentration, size and generation technology. As a consequence, prosumers have led regulators to seek new cost allocation methodologies respecting the guiding principles as much as possible (Picciariello, Reneses, et al., 2015).

2.6 Electricity retail rate structure

A retail tariff for prosumers is usually designed by combining three elements (see Fig. 4): between one and all of the possible types of charges described in section 2.6.1.3 (i.e. volumetric, capacity and fixed charges), one of the compensation schemes mentioned in section 2.6.2 (i.e. feed-in tariffs or net metering) and as many charging computation methods as desired described in section 2.6.3 (i.e. time-based tariffs, marginal or average pricing, block tariffs, location-based tariffs). The rest of this literature review explores each of these elements succinctly.

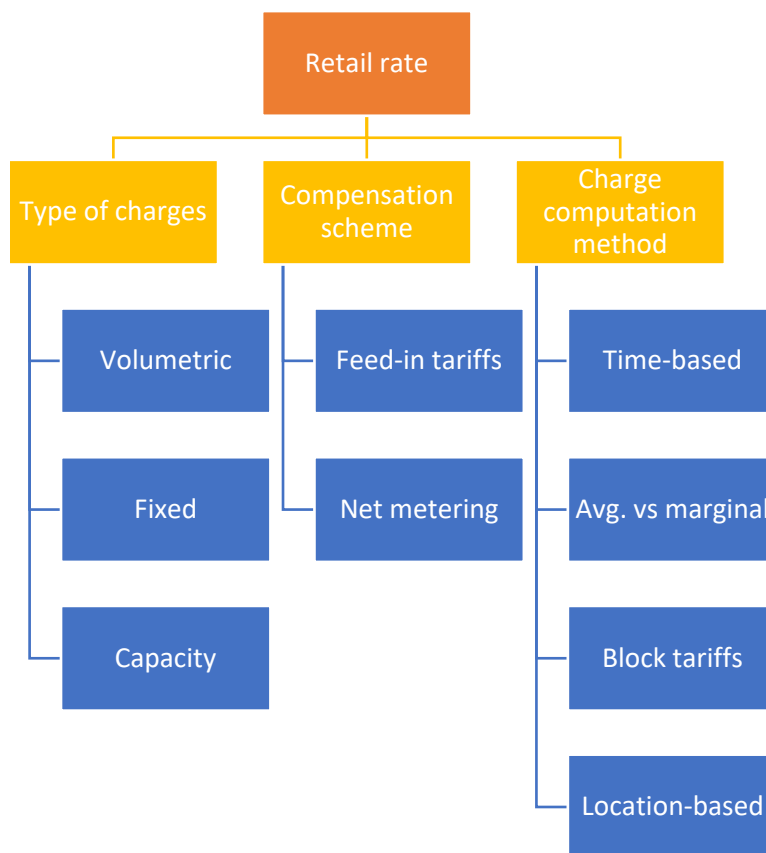


Fig. 4. Structure of an electricity retail rate.

2.6.1 Types of charges

Before diving into the first element, the different types of charges, a review of the grid operators' costs is given to properly understand why prosumers pose a new challenge to the grid.

2.6.1.1 Cost structure

Dupont et al. (2014) developed a simple framework to classify costs related to the electricity system: cost components and cost categories. Cost components include generation, transmission, distribution, and retail. Cost categories cover operational costs (i.e. variable and changing with the quantity of electricity delivered) and investment costs (i.e. fixed cost independent of the short-term demand variations) (Darghouth, Barbose, & Wiser, 2014; Nieto, 2016).

This electricity costs classification can be further analyzed by cost driver types (Dupont et al., 2014; Reneses, Gómez, Rivier, & Angarita, 2011):

- Costs driven by energy usage expressed in kilowatt hour, for example, the generation fuel costs. Electricity production must be supplied in (near) real-time and is for the moment largely non-storable. Therefore, energy usage costs may widely vary at different locations and depends on the technology used for generation. The further the customer, the higher the costs associated with lost energy, congestions, service quality, etc. (Osenia & Pollitt, 2017; Reneses & Rodríguez Ortega, 2014). These usage costs are also subject to important economies of scope and scale which explain why large centralized generators have been used historically.
- Costs driven by peak periods expressed in kilowatt faced to ensure the critical constant balance between demand and generation. During peak periods, costly and less efficient backup generators must be activated to meet the high customer demand (Osenia & Pollitt, 2017). Moreover, network losses, which constitutes a heavy component of network operating costs are also higher during peaks (Mutale, Strbac, Curcic, & Jenkins, 2000).
- Costs driven by the number of customers and independent of energy usage or peak periods (Weston, 2000). Examples are one-time connection costs to the grid, investments in supplementary generation and network reinforcements, maintenance costs and commercial costs such as the metering, billing and customer support (Dupont et al., 2014; Gautier, 2015; Nieto, 2016; Reneses & Rodríguez Ortega, 2014).

2.6.1.2 Wholesale and retail electricity prices

An important distinction to make at this point is the one existing between the wholesale and retail price of electricity. On the one hand, the wholesale electricity market involves large power plants like nuclear generators and wind farms selling raw electricity to suppliers. As intraday demand varies a lot and different technologies can have very different costs, the price of electricity on the wholesale market is strongly variable with price even dropping below zero in the case of excess supply. The wholesale market can either be in the form of an exchange market, where around 30% of the energy consumption in EU is traded (e.g. EEX, Powernext, NordPool, etc.), or in the form of an over-the-counter market where large transactions between private parties take place (usually facilitated by large brokerage firms). Depending on their timescale, wholesale markets can range from real-time balancing markets to long-term contracts. As a consequence, wholesale electricity can either be traded on spot or futures markets given that transactions on the wholesale market often contract an electricity quantity to be delivered in the future. Finally, wholesale prices are not uniform across EU Member States and prices can differ by up to a factor three, creating price competition between states. (Erbach, 2016b; Market Observatory for Energy of the European Commission, 2016; Rademaekers, Slingenberg, & Morsy, 2008; Rathnayaka et al., 2011; Vahl et al., 2013).

On the other hand, the retail electricity market is where transactions between grid end-users and suppliers take place. Retail prices are often fixed in longer-term contracts and are more stable (Rathnayaka et al., 2011). However, retail prices are now switching to more varying schemes incorporating some variability of the wholesale price (see section 2.6.3.1) due to the inflexibility and associated problems caused by long-term fixed retail price contracts.

The difference between the wholesale and retail prices can be explained as follows. Suppliers buy electricity on the wholesale market, add their margin and sell it back to consumers. Moreover, TSOs and DSOs also charge the end-user for using the grid and its infrastructures. Finally, taxes can also be levied at this stage and included in the retail price. However, grid usage costs constitute a much bigger portion of the supplier costs than the volumetric cost of electricity bought from the wholesale market creating a significant gap between the wholesale and retail price (Gautier, 2015; Rodríguez Ortega et al., 2008; Schleicher-Tappeser, 2012). This price gap represents a valuable window of opportunity for prosumers. Indeed, they can inject their surplus energy directly on the retail market and receive

the higher retail price for it while conventional large producers have to compete with the wholesale price (Schleicher-Tappeser, 2012).

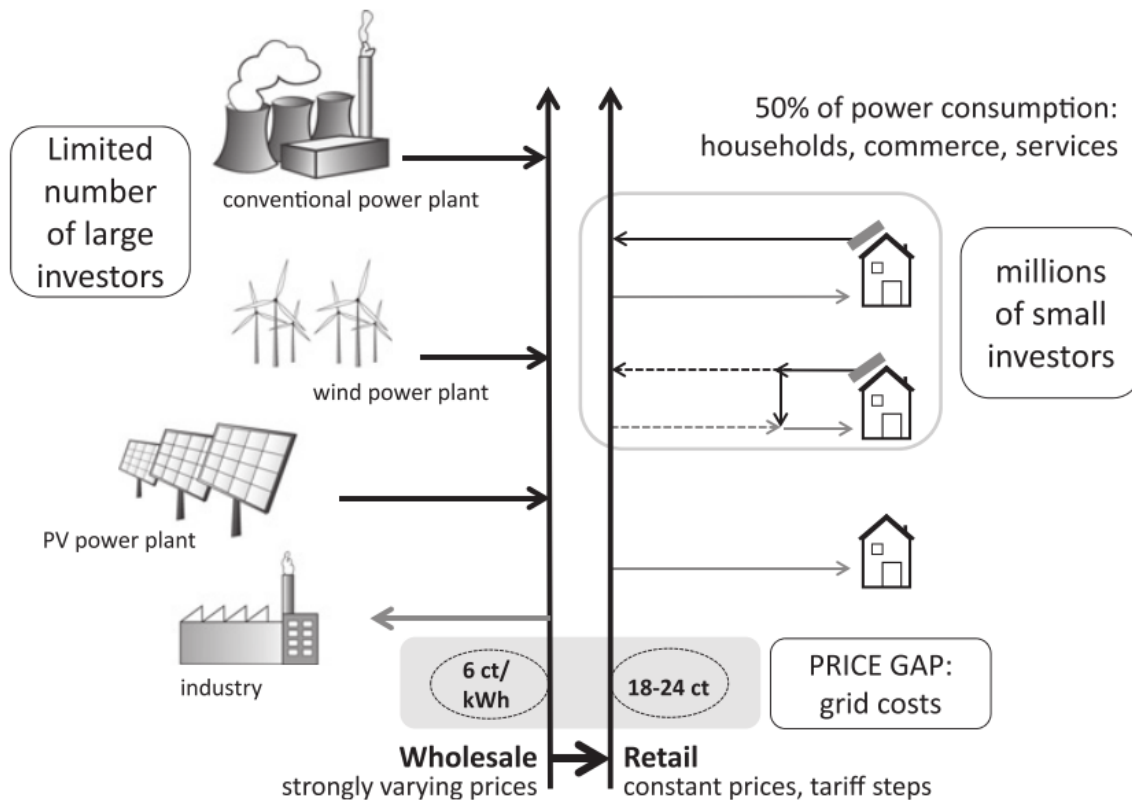


Fig. 5. Wholesale vs. retail market. Reprinted from (Schleicher-Tappeser, 2012, p. 66).

2.6.1.3 Revenue structure

In Europe, retail electricity prices for consumers consist of different price components (EC, 2014):

- The energy component covers the wholesale element to deliver electricity on the one hand (construction, operation and decommissioning of electricity generating units, maintenance, refurbishment, fuel and carbon as well as costs related to the operation of wholesale trading activities for electricity) and the retail element on the other (supplier's margin, portfolio management, personnel, IT, overheads, insurance for imbalance)
- The network component or Use of System (UoS) charges cover costs related to the infrastructure needed for transmission and distribution, i.e. maintenance and grid expansion, system services, network losses and other charges such as (but not limited

to) stranded costs, public service obligations, policy support to certain technologies. Connection charges are also part of the UoS charges and are paid only once in order to connect physically the user to the grid (Frías et al., 2009). Depending on what covers connection charges, three types can be distinguished: shallow, deep and shallowish charges. The distinction considers whether the connection charges incorporate only the direct connection cost or the associated reinforcement of the network cost as well (Cossent, Gómez, & Frías, 2009; Frías et al., 2009; Picciariello, Reneses, et al., 2015; Reneses & Rodríguez Ortega, 2014). Retail tariffs charges are paid by grid users periodically usually only to suppliers but UoS charges are then redistributed to grid operators (DSOs and TSOs) to recover the above-mentioned fixed and variable costs of grid infrastructure, operation and maintenance plus a fair rate of return depending on the degree of regulation (Darghouth et al., 2014; Sakhrani & Parsons, 2010).

- Various taxes and surcharges which can be levied on any of the above-mentioned charge components (Rodríguez Ortega et al., 2008).

Electricity price components are collected through three possible types of charges (Firestone et al., 2006; Picciariello, Reneses, et al., 2015; Reneses & Rodríguez Ortega, 2014; Rodríguez Ortega et al., 2008):

- Fixed charges in €/period: invariant fees, levied to recover the infrastructure supply and delivery costs regardless of the user electricity's consumption.
- Volumetric charges in €/kWh/period: proportional to the electricity consumed by a grid user, and initially intended to cover the variable costs linked to the energy production and transport which are highly varying during the day.
- Capacity charges in €/kW/period, also referred to as demand charges: collected on the maximum power used during the considered period, or more rarely on the contracted or installed capacity, regardless of the duration or frequency of that level of consumption. It is designed to cover the fixed costs of the network infrastructure shared with other users, proportionally to the capacity that each of them requires. Demand charges are not levied in every country and prosumers are sometimes exempted to pay them depending on the local regulations (Cossent et al., 2009; Picciariello, Reneses, et al., 2015). Nevertheless, capacity charges are being

considered as a potential solution to the cost allocation problem faced by utilities due to the large-scale penetration of DRE and is explored in section 2.6.2.5.

2.6.2 Prosumers compensation schemes

2.6.2.1 Introduction

Since their deployment in the late 19th century, electricity systems face the problems of non-trivial sunk capacity costs with non-storability and periodic demand (Simshauser, 2016). As explained in the section related to costs, distributing energy requires delivering energy but also capacity. Historically, both have been recovered through mostly volumetric charges (Gautier, 2015; Sakhrani & Parsons, 2010), partly because they were simple to implement with electromechanical induction meters and easily understood by customers. It was assumed that capacity and volume were proportional, however, consumption patterns have later proven that this was largely wrong: two customers may have the same level of electricity consumption but one with a peaky profile causes much more costs on the grid than another with a flat load profile (Reneses & Rodríguez Ortega, 2014; Sioshansi, 2016; Vahl et al., 2013). Moreover, regulators considered volumetric charges as a fair mechanism since it allowed to discriminate against more and less wealthy customers.

Under more recent environmental pressures, regulators have prioritized incentivizing tariffs speeding up renewables' penetration instead of both allocative efficiency and cost causality (Brown & Lund, 2013). Initially ignoring the challenges that prosumers posed to the grid, regulators designed these schemes to “create demand that otherwise would not exist whatsoever or would not exist at desired levels under current market conditions” (Lesser & Su, 2008, p. 983). As a consequence, the viability of the historical cost recovery mechanism is threatened (Sioshansi, 2016) because volume-based retail tariffs combined to these incentivizing schemes do not reflect the variable, uncontrollable and unpredictable nature of DRE which depends on weather conditions (Dupont et al., 2014).

While there is no evidence whether DRE has a positive or negative impact on the distribution network system costs (Frías et al., 2009), a consensus has emerged about the fact that higher penetration rates lead to a higher impact on DSOs' ability to recover their costs (Cossent et al., 2009). Moreover, the influence of DRE on DSOs' costs is exacerbated if

prosumers combine self-production with storage and peer-to-peer supply (Bellekom et al., 2016).

Concerned with this issue, many authors tried to design alternative retail tariffs adapted to DRE in order to integrate the cost causality and allocative efficiency principles while maintaining sufficient short-term individual incentives (Cossent et al., 2009; Picciariello, Reneses, et al., 2015).

The most common compensation schemes for residential prosumers are feed-in tariffs (FiTs) and net energy metering (NEM) since they represent together 78.2% of all active schemes (Sioshansi, 2016; SPE, 2015). Both are presented in the next sections as they constitute the second element of every electricity retail rate tailored at prosumers. Other incentivizing schemes have been introduced by regulators such as quota-obligations, tendering systems and Renewable Portfolio Standards but since these schemes are more designed to stimulate larger industrial prosumers, they are beyond the scope what is investigated in this thesis. Moreover, according to Sioshansi (2016), such solely quantity-based schemes tend to perform worse than those both quantity and price-based such as FiTs and NEM.

Only the key features of FiTs and NEM are presented here but Hughes and Bell (2006) propose a full taxonomy and distinguish between 16 distinct variations of these two compensation schemes. An alternative proposal, demand charges, is also discussed in light of the difficulties linked to FiTs and NEM.

2.6.2.2 Feed-in tariffs

According to Couture and Gagnon (2010, p. 955), “the central principle of feed-in tariff policies is to offer guaranteed prices for fixed periods of time for electricity produced from renewable energy sources”. All feed-in tariffs possess two fundamental features: a guaranteed price and a guaranteed purchase of the kWh produced by a qualifying RES (Lesser & Su, 2008; Sioshansi, 2016; Umamaheswaran & Rajiv, 2015).

The number of years during which the price is guaranteed by FiTs usually ranges from 8 to 15, but sometimes to as many as 20 or 30 years depending on the local regulations (Lipp, 2007). The amount of the FiT relies on the economic value given to small-scale DRE by local authorities and can be based on net loss reductions, capacity requirement reductions, emissions

reductions, incentivizing premiums and other costs and benefits (Picciariello, Reneses, et al., 2015).

While the tariff is guaranteed, its rate usually declines over time to account for the maturity and cost improvements of the concerned technology. As a consequence, FiTs allow for discrimination among different renewable solutions such as PV and wind turbines. Depending on the technology, the size of the installation, the quality of the resource and the location, the FiT offers a different price for each kilowatt hour injected into the grid (Couture & Gagnon, 2010; Lesser & Su, 2008; Lipp, 2007).

The guaranteed aspect of FiTs plays a major role in incentivizing DRE penetration since expectations about the future electricity price dictate potential savings and investment recoveries that prosumers can hope for (Flaute et al., 2017).

FiTs can be measured on a net or gross basis. With gross measurement, the prosumer is paid the tariff for all the energy produced, regardless of whether part of it is injected into the grid or not. Gross FiT can also be referred as net billing (not to confuse with net metering) or value of solar (VOS) tariffs where the prosumer is charged all the electricity consumed and obtains payment for all the electricity produced (Hughes & Bell, 2006; Nieto, 2016). Gross FiTs are useful in countries where retail tariffs are not high enough to stimulate prosumers and larger incentives are needed to increase DRE penetration (Nieto, 2016). In contrast, net FiTs are offered only for the amount of energy injected into the grid after self-consumption (Rathnayaka et al., 2011).

FiT policies exist since the late 70s in the US and have undergone multiple deployment waves with variable efficiency until today. An exhaustive history of FiTs across the world can be found in the work of Sioshansi (2016).

Several mechanisms have been used in the past to fund FiTs but ultimately it is the electricity consumers who carry the burden of the FiT. Indeed, taxes are usually raised on electricity consumption which leads to a tariff increase for regular consumers and can have several negative consequences with the larger deployment of DRE (see section 2.6.2.4). Another alternative is to force suppliers to pay the FiT who then charge increased retail prices to all electricity consumers to recover their additional cost. Suppliers can sometimes pass the

cost burden to DSOs and TSOs but these will eventually raise what they charge suppliers for using the grid who will ultimately pass it again on to consumers through increased prices (Butler & Neuhoff, 2008; Erbach, 2016a).

The main advantage of FiTs is the security of payments they provide by guaranteeing the price and quantity at which the electricity produced is sold. By effectively managing revenue risk for a DRE system with security over future cash flows, investors can be remunerated according to their actual cost and the associated upfront investment (Couture & Gagnon, 2010; Lipp, 2007; Sioshansi, 2016). Small-scale roof-top installations and micro-installations often receive additional support from policymakers allowing “hundreds of thousands of small solar power producers to enter the electricity market since low risks, low transaction costs and high transparency make investments easily calculable for investors and banks” (Schleicher-Tappeser, 2012, p. 65). Besides lowering the electricity bill of prosumers, FiTs also benefit all electricity consumers by lowering the investment cost of utilities in extra capacity which is eventually spread across all grid users (Schleicher-Tappeser, 2012; Zajączkowska, 2016).

This mechanism of easily scalable FiTs has encouraged a rapid and sustained deployment of renewables at the consumer level making “well-adapted feed-in tariff regimes [...] generally the most efficient and effective support schemes for promoting renewable electricity” in their early stages (Couture & Gagnon, 2010; European Commission, 2008). However, experts point out that FiTs have incentivized large DRE development, but often at a high cost (Buchan, 2012).

Couture and Gagnon’s (2010) extensive research on how different FiT models have varying impacts on investor risks, renewables' deployment and efficient electricity generation provide more details on the specific benefits of FiTs’ variations. Their results are based on the current DRE higher penetration environment and with the objective of ensuring a sustainable flexible pricing for DRE in the future. Another recent study by Sioshansi (2016) also demonstrates that combined quantity- and price-based models such as FiTs tend to work better than those based only on quantity.

The main difficulty of FiTs is to set the right guaranteed price and its decreasing rate during the right amount of time. The lack of information on the level and trend of the production

costs for both renewable and fossil energy, on the required mix of technologies and on the wholesale and retail electricity prices in the future makes it difficult to set an efficient FiT, especially in a deregulated market (Couture, 2010).

On the one hand, too high FiTs may overcompensate prosumers at the expense of consumers or taxpayers, an issue known as cross-subsidization (see section 2.6.2.4) which can result in welfare loss and rewarding inefficient DRE. Moreover, if the FiT duration is overestimated, these perverse effects will strengthen over time. Still, consumer-funded FiTs correspond to the European directives towards Member States (Erbach, 2016a).

On the other hand, too low FiTs might simply make the incentive policy ineffective in its goal to foster renewable deployment (Lesser & Su, 2008; Schleicher-Tappeser, 2012; van der Linden et al., 2005).

It has been suggested that market-determined FiTs can tackle this “guess-work” issue by being more efficient in rapidly expanding DRE markets than calculated FiTs (Bell & Foster, 2017; Langniß, Diekmann, & Lehr, 2009). These results are supported by Lesser and Su’s (2008) work who suggested a two-part market-based FiT. A particular application of these results is the feed-in premium (FiP) scheme which provides a premium on top of the electricity market price with a potential price cap. The transition from FiTs to FiPs has since been encouraged by the European directives (Erbach, 2016a). However, Couture and Gagnon (2010) argue that market-independent FiTs are more effective in deploying lower-cost renewable energy than market-dependent models as the fixed-price reduces the risk associated with the investment.

Another risk linked to FiTs is its negative interaction with other supporting schemes as in Denmark where a change of policy from FiTs to tradable green certificates (TGCs) in 2004 led to a collapse of the wind market (Lesser & Su, 2008).

After several successful years of PV growth in its early stage mainly attributable to FiT policies (Couture & Gagnon, 2010), decreasing installation costs as well as increasing retail electricity price, many countries have reached “grid parity” or will reach it soon. Grid parity is an important milestone for the further development of domestic renewable energy generation as it is considered to indicate cost neutral DRE installations based on the LCOE compared to

the retail price (Breyer & Gerlach, 2013). As a consequence, preferential rates such as FiTs were significantly lowered or even abolished as their role in the PV deployment had ended since DRE had become competitive on the market (Flaute et al., 2017; Vahl et al., 2013). Although, Hirth (2015, p. 1) argues that grid parity is a “flawed metric for economic assessment, as it ignores grid fees, levies, and taxes” and should be used carefully to take policy decisions.

2.6.2.3 Net metering

An alternative incentivizing policy that attracted policymaker’s interest in their effort to maximize the social benefits of residential DRE (Breyer & Gerlach, 2013) is net energy metering (NEM). This compensation scheme can be effectively leveraged during the post-FiT transition period and before the effective large-scale deployment of storage solution at prosumers’ homes (Christoforidis et al., 2016).

Net metering is a supporting scheme which allows prosumers to receive compensation for the injected electricity from renewable-based electricity generation at the full retail electricity price. The main benefits for the prosumers are a reduced electricity bill at the end of the metering cycle and therefore incentivized DRE installations. The reason why utilities have used NEM in the last few decades, firstly in the United States, is because it provides a simple, low cost, and easy practice to handle PV residential systems (Darghouth et al., 2011; Darghouth et al., 2016; Poullikkas, 2013).

NEM systems also possess the two fundamental characteristics of FiTs: a guaranteed purchase of the additional kWh produced and at a guaranteed price which is the retail price of electricity. The main difference with FiTs is that the buying and selling prices are identical for the prosumers and fixed by the supplier usually based on market-mechanisms instead of being fixed by regulators (Sioshansi, 2016).

Net metering uses a meter capable of spinning in both directions to measure the net amount of energy exchanged between the prosumer and the grid. If the prosumer is producing more than he consumes, the additional electricity is sold to the grid operator and its meter spins backward to reflect the energy being sold. If the prosumer is consuming more than he produces, he receives supplementary electricity from the grid and its meter spins forward to reflect energy being bought. At the end of the period, the prosumer is only charged the net energy sales and if a simple bidirectional meter is used, it is impossible to determine how much power was

produced and how much was consumed during the period (Hughes & Bell, 2006; Poullikkas, 2013; Sioshansi, 2016).

If at the end of a billing period a production surplus remains, then the prosumer may (Hughes & Bell, 2006):

- Get paid for the surplus at utility’s avoidance cost rate or retail cost rate.
- Get its surplus transferred to the next period also called “rolling credits”.
- Lose its surplus.

In practice, utilities use renewable energy credits (REC) to keep track of the surplus energy (Hughes & Bell, 2006; Poullikkas, 2013).

Net metering has been introduced in various forms worldwide, with none being the actual norm (Christoforidis et al., 2016). Among these various NEM policies is the combination with time-based tariffs such as time-of-use tariffs and real-time tariffs (see section 2.6.3.1). In these schemes, NEM is evaluated by taking into account when the energy is produced or consumed, i.e. day or night and seasonal rates, and its subsequent retail price. Both the time of the day and the quantity consumed or produced are then reflected in the net metering bill, bridging some of the gaps with the respect of the cost causality principle (Poullikkas, 2013). Time-based net metering will be facilitated by the large-scale deployment of advanced metering infrastructures (Nieto, 2016). A study by Darghouth et al. (2014) showed that net-metered bill savings can be lower with time-based tariffs if PV’s penetration rate is high. Another study by Eid, Reneses, Frías, and Hakvoort (2014) on the impact of time-of-use net metering tariffs showed that larger billing cycles intensify NEM’s impact on the utility’s cost recovery. Furthermore, the authors present how different types of NEM alternatives impact the utility’s revenues, the policy objectives and the arising cross-subsidies between network users. Finally, Darghouth et al. (2014) determined that net metering might become a more costly policy to support in the future but remain a valuable tool to incentivize behind-the-meter PV as solar renewable generation increases further.

Block tariffs (see section 2.6.3.3) have also been combined with net metering. In another study, Darghouth et al. (2011) found that progressive block tariffs could impact up to four times more the bill savings from net metering.

2.6.2.4 Cross-subsidization and the utility death spiral

The main risk associated with net metering refers to the ability of the grid operators to recover their costs and the caused instability. As mentioned earlier, this danger is linked to the mismatch between the high fixed costs faced by grid operators and the (potentially large) volumetric prices charged to users. Grid costs are highly dependent on demand during peak and critical periods while most revenues are derived from flat-rate variable charges, violating the cost causality principle and putting cost recovery under stress. (Brown & Lund, 2013; Gautier, 2015; Rodríguez Ortega et al., 2008; Schleicher-Tappeser, 2012; Sioshansi, 2016). Integrating distributed generation through volumetric tariffs with NEM is the most relevant example of this issue. Indeed, prosumers receive the retail rate while they do not face the charges incurred at higher voltage levels which contradicts the cost recovery principle. Through their low net volume, prosumers contribute little to the grid's funding while potentially extensively using it (Eid et al., 2014; Gautier, 2015; Picciariello, Reneses, et al., 2015; Picciariello, Vergara, et al., 2015; Rodríguez Ortega et al., 2008). Moreover, prosumers on NEM schemes face largely reduced volumetric charges but reduce peak load only marginally since PV production peaks in the middle of the day while network costly peak periods occur generally during the early evening. The mismatch between PV production peaks and system peaks can be easily visualized in Fig. 6 (Simshauser, 2016). As such, prosumers produce more than they can consume at certain times of the day and reduce only marginally peak load (Flaute et al., 2017).

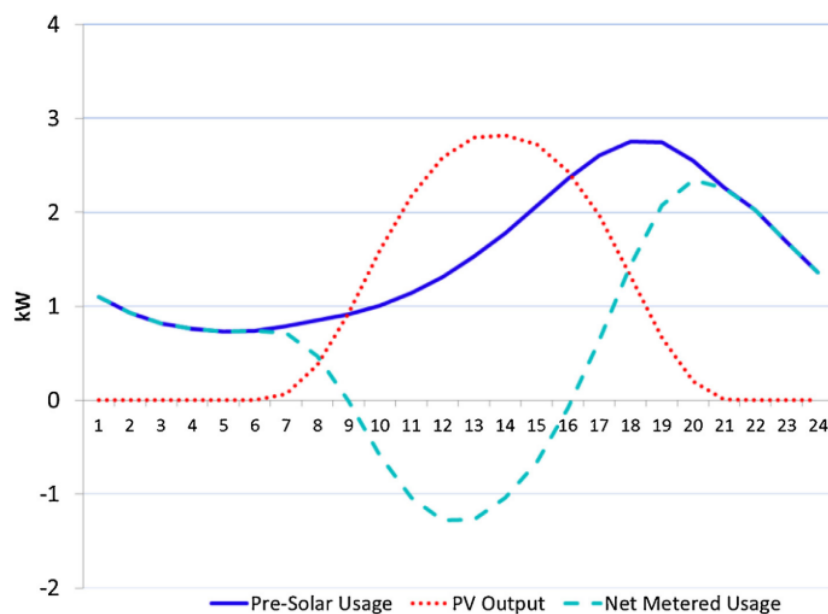


Fig. 6. Hourly load with and without PV. Reprinted from (Nieto, 2016, p. 32).

Confronted to this revenue erosion, grid operators have two options depending on the legislation. First, they can absorb the missing revenue as a loss which could be publicly funded through taxes on electricity consumption. Second, they can raise the kWh price on the volumetric charges. Indeed, due to the grid economies of scale, a drop in energy consumption results in a higher drop in revenues that can only be fixed through higher retail rates (Gautier, 2015). As it can be noted, the end result is the same in both options: an increased retail price for all electricity consumers. In practice, both solutions are implemented and charges are raised for all network users. As a consequence, non-prosumers with a larger consumption are affected more heavily by this volumetric rate increase than prosumers who caused this tariff increase. Some authors have also raised concerns about the fact that additionally, these non-prosumers are on average less wealthy than prosumers (Brown & Lund, 2013).

An extreme but straightforward example of the situation is the case of a prosumer connected to grid who produces all the electricity he needs. If only volumetric charges are in application, the DSO receives thus no payment from that customer but still had to incur the costs linked to the installation and maintenance of the contracted capacity in case of the prosumer deciding to rely on the grid. As a result, regular customers have to carry the entire burden of these costs through higher rates (Shandurkova et al., 2012; Sioshansi, 2016).

This phenomenon of a certain category of customers (i.e. prosumers) facing lower charges than others (i.e. regular customers) for similar network service is called cross-subsidization (Eid et al., 2014; Picciariello, Vergara, et al., 2015; Sakhrani & Parsons, 2010).

Cross-subsidization is not a problem per se and grid operators have been familiar with the concept for decades (Rodríguez Ortega et al., 2008). For example, rural and urban customers often pay the same retail price while remote rural customers cause higher investment costs to the DSO because of their smaller concentration than urban customers (Sakhrani & Parsons, 2010). Cross-subsidization becomes a problem when grid operators and users believe that the cross-subsidized class is being treated too generously and does not pay its fair share of the grid costs. It is then a violation of the equity principle and of the cost causality principle (Picciariello, Reneses, et al., 2015; Vahl et al., 2013). Another issue of cross-subsidization occurs when vertically integrated businesses use their revenues generated in the regulated market in order to cross-subsidize their unregulated operations, leading to unfair competition and entry blocking in the generation market (Willems & Ehlers, 2008).

Cross-subsidization can also have serious cost recovery implications when taking into account demand response. Indeed, with the tariff rise, investing in DRE has become even more financially attractive for non-prosumers (Cai, Adlakha, Low, De Martini, & Mani Chandy, 2013). As a consequence, a bigger share of regular users switches to prosumption. Facing lower revenues, the DSO has to raise his tariffs again and a negative feedback loop of increasing retail prices associated with increased DRE adoption ensues, referred to as the “utility death spiral” in the literature (Cai et al., 2013; Darghouth et al., 2016; Gautier, 2015; Ruester et al., 2014; Severance, 2011; Simshauser, 2016). Raskin (2014) defines the death spiral more formally as “a utopian (for customers) and dystopian (for utilities) near future in which electricity from the utility grid is widely displaced by distributed energy sources that supply electricity at prices below utility service from the electric grid”. As a result, retails tariffs can become unstable. According to Picciariello, Reneses, et al. (2015), the death spiral risk is even more serious when old meters are in use which can only provide the net accumulated consumption over long periods of time. The recent PV deployment is considered as the biggest threat today that could lead to a utility death spiral (Castaneda, Jimenez, Zapata, Franco, & Dyner, 2017). Castaneda et al. (2017) established that a death spiral occurs when the electricity PV cost, the electricity tariff and the PV adoption rate for customers are critical variables.

However, a study by Darghouth et al. (2016) suggests that the effect of the negative feedback loop can be moderated through an opposing force. When time-based NEM retail rates (see section 2.6.3.1) are used and the number of prosumers increases, the authors observe a shift in the timing of peak periods, reducing the bill savings and in turn, slowing down DRE adoption. Moreover, some authors have argued that the severity of the utility death spiral is overrated. Indeed, they refuse to see grid operators and suppliers as inert forces suffering from the death spiral but instead see them as dynamic market actors adapting their business models to respond efficiently to the new competition raised by prosumers (Costello & Hemphill, 2014; Graffy & Kihm, 2014; Laws, Epps, Peterson, Laser, & Wanjiru, 2017). In fact, Felder and Athawale (2014) showed that the death spiral is not a direct result of the disruptive competition from DRE owned by prosumers but rather a consequence from the inherent design of rate structures. Additionally, Laws et al. (2017, p. 639) demonstrated that a utility death spiral is highly unlikely and requires a rare combination of factors such as “high adoption rates, high utility costs, and favorable customer financial parameters such as the customer’s required rate of return”. Some DSOs have simply started to charge an injection fee to ensure they recover

their costs (Gautier, 2015). Castaneda et al. (2017) also identified backup fees, net billing and augmenting fixed charges as short-term solutions to the death spiral issue.

Using Australia as a case study, the death spiral has “resulted in network price increases of 112% in just five years in an ostensibly low inflation environment” (Simshauser, 2016, p. 109). However, Simshauser (2014) established that the Australian case was the consequence of misguided and overlapping policy failures.

As a conclusion, the death spiral risk seems to become a reality only when a series of circumstances are combined and is a complex phenomenon not directly resulting from an increased penetration of DRE.

2.6.2.5 Capacity charges

The challenges linked to FiTs and NEM have led authors to consider revalorizing capacity charges based on the energy capacity. As detailed in section 2.6.1.3, capacity charges are collected on the maximum power demanded, or more rarely on the contracted capacity or the installed capacity, used during the considered period, regardless of the duration or frequency of that level of consumption. Several authors propose a two-part tariff where some of the revenue acquired from volumetric charges is switched to capacity charges to improve the respect of the cost causality principle and avoid the utility death spiral described in the previous section (Darghouth et al., 2016; Eid et al., 2014; Gautier, 2015; Nieto, 2016; Sioshansi, 2016). In fact, these types of tariffs are already in application in most European countries (Refe, Mercados, & Indra, 2015).

The proposal of promoting capacity charges is not in conflict with the benefits of net metering as authors suggest the use of NEM for the volumetric part of the tariff to recover the per kWh variable cost and capacity charges for the second part of the tariff to recover the peak capacity cost. Capacity charges are more efficient under observed maximum capacity charging or net peak instead of contracted capacity and offer alignment with the equity principle because charges are identical for all grid users since they only depend on the peak demand (Eid et al., 2014; Gautier, 2015; Nieto, 2016; Sioshansi, 2016). Still, Lewis (1941) showed that individual peak demand is actually irrelevant when designing tariffs; only aggregate customer demand during system peak periods matters.

The main reasoning behind the implementation of capacity charges is to incentivize prosumers to reduce their contribution to system peak demand by using their DRE during peak periods. Consequently, both grid operators and prosumers cut down their cost linked to peak demand. (Sioshansi, 2016). Depending on the charge per kW and the cost during peak periods, the net effect of consuming self-produced energy during peak periods can be either positive or negative for grid operators. Furthermore, local storage could be incentivized through capacity charges as well since prosumers would self-consume from storage during peak periods if their generator is not producing enough to satisfy their needs (Eid et al., 2014). Finally, Simshauser (2016) compiled a list of various reasons to answer the question of why demand tariffs were not widely used in the past but many of the hurdles are now overcome in the modern grid, such as the availability of advanced metering technologies, making capacity charges more easily implementable.

2.6.3 Computation methods

The last element of electricity retail rates refers to the method used to compute electricity charges. Four alternatives are presented in this section: time-based tariffs, marginal or average pricing, block tariffs and location-based tariffs.

2.6.3.1 Time-based tariffs

Time-based tariffs have received significant attention in the literature and have been introduced by grid operators for more than 30 years in an attempt to reflect the high cost they incur during peak periods. In such schemes, the volumetric or capacity price of electricity differs according to the time of the day. System operators charge high prices during peak times in order to incentivize reduced consumption during these periods and avoid them the cost of operating costly backup generators (Osenia & Pollitt, 2017; Wang & Li, 2015).

Tariffs with a time-dependent volumetric component can be referred as dynamic pricing as they pass through at least part of the wholesale price volatility to final end-users. Dynamic time-based tariffs are opposed to fixed-priced tariffs which offer a fixed charge, regardless of changes in the market price, preventing customers from being exposed to the price volatility for a defined period of time. Every specified period, usually one year, the fixed-price charge is reevaluated in light of the current wholesale price to which they are often indexed to (Eurelectric, 2017).

Time-based tariffs can take several forms with the most common being time-of-use pricing (ToU), critical peak pricing and real-time pricing (RTP).

Time-of-use pricing is a tariff in which a few different energy prices are offered based on the time of the day. When these periods are determined according to peak and off-peak times, ToU pricing is also called critical peak pricing. Peak times can be evaluated by the grid operators over a single day or on the system's critical days and specific critical events during the year (Nieto, 2016).

Under ToU pricing, prices change at most a few times during the day, with a larger than an hour interval between changes. In contrast, real-time pricing tariffs are continuously and instantaneously adjusted depending on the wholesale price of electricity and therefore vary continuously over time. With RTP, prices change several times per hour and their availability to customers is expected to be promoted by the deployment of smart meters enabling effective data communication between suppliers and buyers (Osenia & Pollitt, 2017).

In short, ToU and RTP differ by the length of price blocks and price patterns but also by the advance notice of sending tariffs to users (Dupont et al., 2014). The choice between ToU and RTP depends on the available technology, their alignment with the different guiding principles and on their impact on demand response (Dupont et al., 2014).

The optimal dynamic rate design would be a RTP rate from the allocative efficiency principle point of view since it offers prices closer to marginal pricing (see section 2.6.3.2) (Dupont et al., 2014) but ToU pricing is the easiest implementation of demand response.

Besides requiring less demanding in technology requirements, ToU dynamic rates only modify the kWh or kW charge a few times a day at maximum. This is particularly suitable for entry-level customers who are used to a passive attitude towards electricity through flat rates. As they have little knowledge of tariffs, the less frequent tariff changes the less they have to respond to price signals (Nieto, 2016; Wang & Li, 2015).

As a consequence, Wang and Li (2015, p. 90) recommend a “step-by-step strategy: shift from the flat rate to a two- or three-tiered (on-peak, mid-peak, off-peak) ToU rate, and then proceed to more dynamic real-time pricing after consumers grow certain familiarity with such programs and consumption adjustments”. This is supported by Nieto (2016) who also

believes that a progressive approach from ToU to RTP rates would ease mandatory adoption rates and by Gautier (2015) who argues that consumers do not always react rationally to prices when they are too complex, as it is the case with electricity. Failure to facilitate the transition from ToU to RTP may result in customers switching back to a passive behavior, a phenomenon called “response fatigue” (Kim & Shcherbakova, 2011, p. 876).

If suppliers do not have the possibility to offer an RTP tariff because of regulations, social acceptability issues or the lack of advanced metering systems, ToU pricing can be proposed as a proxy to the allocative efficiency of RTP tariffs. In fact, Borenstein and Holland (2005) showed that well-designed ToU pricing can provide some of the allocative efficiency benefits of RTP. However, ToU pricing falls short of providing the right price signals to prosumers willing to inject their energy into the grid and consequently relieving the grid operators of part of the peak consumption demand. Borenstein (2002, 2005) also proved that RTP favors long-term efficient investment and the reduction of market power of grid’s actors. Lynham, Nitta, Saijo, and Tarui (2016) investigated the effect of displaying in-home the real-time information regarding electricity consumption and found that it can reduce consumption at peak times.

Moreover, the literature has tried to document the additional benefits of time-based tariffs, especially RTP tariffs, for residential DRE. The primary advantage for prosumers is that besides having efficient price signals on the consumption side, RTP also values efficiently their DRE resources. RTP pricing supports prosumers in their decision process of whether to store or inject their production into the grid and whether they should increase or decrease their on-site load. For instance, prosumers are given the financial incentive to inject their production at peak times when it is highly valued and grid costs are high, in turn reducing the peak load on the grid (Nieto, 2016; Shandurkova et al., 2012; Sioshansi, 2016).

Furthermore, change in the penetration rate of renewable energy could impact both the marginal cost of electricity and the hourly profile of wholesale electricity prices. These variations could then influence retail electricity prices and the temporal profile of time-differentiated rates and, as a consequence, the customer profitability of PV (Darghouth et al., 2014).

Two major difficulties arise with the introduction of time-based tariffs. First and inherent with the nature of the RTP tariff itself, is the addition of price uncertainty for grid users as it is not uncommon for wholesale energy prices to fluctuate by 100% or more within a single day (Borenstein & Holland, 2005). Borenstein (2007) proposed a hedging mechanism to overcome this difficulty by paying customers the “real-time price for any deviation between the contracted quantity and their actual consumption” (Sioshansi, 2016, p. 506).

Second, too-broadly designed ToU rates might fail to both preserve intra-class cross-equity and produce efficient energy conservation incentives. Peak periods, both on a day-scale and on a year-scale should only include the highest marginal-cost hours or months. When residential ToU rates peak periods cover too broad than necessary time frames, the peak per kWh price signal might get diluted and lose its efficiency (Nieto, 2016).

2.6.3.2 Marginal and average pricing

Marginal or average pricing is another computation option for volumetric charges. Darghouth et al. (2014, p. 291) propose a definition of marginal pricing: “under marginal cost pricing, the end-user is charged a rate that is commensurate with the cost of generating and delivering an additional unit of electricity at that time”. The other approach, average pricing, calculates the retail price based on average costs also referred as “embedded costs” by dividing the total cost by the total consumption of a user over a period.

Marginal pricing is often preferred by authors for two reasons: it supports the allocative efficiency guiding principle by promoting efficient energy consumption and production decisions by grid users. Indeed, under the assumption that prosumers are rational agents, marginal pricing sends the right signals to make efficient energy consumption and DRE investment decisions. Furthermore, efficient consumption patterns contribute optimally to system expansion and allocation which ultimately enables lower cost of service by grid operators (Nieto, 2016). However, to support allocative efficiency, marginal pricing requires the grid operators to perform a thorough cost analysis of the impact on costs of a customer addition or changes in its energy usage. Such cost analysis should incorporate the variation in costs caused by a user at different times of the day (see section 2.6.3.1) (Nieto, 2016).

In the case of electricity networks, the theoretical optimal marginal price corresponds to the electricity nodal prices (Perez-Arriaga, Rubio, Puerta, Arceluz, & Marin, 1995; Rudnick, Palma, & Fernandez, 1995).

It should be stressed at this point that marginal pricing only does not allow the grid operator to recover its fixed costs which would have to be financed by public authorities through taxes (Hotelling, 1938). A solution to this problem was proposed by Coase (1946): a two-part tariff consisting of a fixed and variable part to recover marginal costs and fixed costs respectively. This kind of two-part tariff is used in several European countries (Refe et al., 2015).

Despite these academic recommendations in favor of marginal pricing, Nieto (2016) notes that many grid operators still use average cost to allocate revenue requirements because of its ease of implementation because it provides minimal changes in tariff structures. However, average pricing fails to use prices as an effective signal for efficient consumption and investment decisions (Commission for Energy Regulation, 2004).

2.6.3.3 Block tariffs

Another existing computation option for electricity rates refers to block tariffs. In this volumetric pricing scheme, the retail electricity unit price increases or decreases as the consumption does. The first block unit is then priced lower or higher compared to the subsequent consumption block(s). Both increasing and decreasing block tariffs have been introduced in the past in the electricity retail market in an attempt to shape demand response. In the case of increasing or progressive block tariff, a low- (or zero-) priced block(s) to cover basic or essential energy use can be imposed by the government. Such zero-priced block was proposed by Wallonia but was eventually refused. Regulators consider increasing block tariffs as a fair mechanism since it allows to discriminate between more and less wealthy customers. Indeed, if volumetric distribution charges are meant to recover both fixed and variable costs, a large consumer can end up paying much less per kWh than a small consumer if flat-rate volumetric charges are used to recover both costs. The main objective of such block tariff design is to reduce the consumption of larger energy users while ensuring cost recovery by the DSO (Gautier, 2015; Osenia & Pollitt, 2017; Reneses & Rodríguez Ortega, 2014).

Gautier (2015) illustrates with empirical data the reasoning behind this mechanism of incentivizing large users to reduce consumption. However, Ito (2014) showed that switching from a linear increasing tariff to a block tariff increases the global consumption. Referring to the previous section, the cause of this consumption's increase originates in users responding to average price instead of marginal price when block tariffs are present. Hard to understand monthly bills and the need for real-time meters to measure consumption make the cognitive cost of deciphering marginal price substantial. Those two reasons do not apply to average pricing to which user respond better.

2.6.3.4 Location-based tariffs

An alternative rate computation method allowing for differentiation is location-based design. As mentioned earlier, energy usage costs may widely vary at different locations and depends on the technology used for generation. The further the customer from the generation point, the higher the costs associated with lost energy, congestions, service quality, etc. (Osenia & Pollitt, 2017; Reneses & Rodríguez Ortega, 2014).

With location-based tariffs, the retail rate can be dynamically set based on the location of the user, integrating the local balance of supply and load in the zone. While it is still mostly at an experimental stage for the moment, location-based pricing will be an essential element of the SG where time- and location-dependent grid costs are reflected in the retail price faced by all users, including DRE owners (Cossent et al., 2009). Smart meters are also expected to facilitate the implementation of location-based tariffs (Osenia & Pollitt, 2017).

However, grid operators should first investigate whether usage and system peak costs are driven by local or global consumption. If costs are driven at the local level, location-based pricing would allow grid operators to better allocate costs to users who cause them and get closer to tariffs respecting the cost causality principle (Dupont et al., 2014).

2.7 Hypotheses

In light of the literature review carried out above, the following research question was investigated:

What is the impact of prosumers supporting schemes and of the electricity price structure on the penetration of residential distributed renewable energy in Europe?

The research question was broken down into three hypotheses in order to provide it with a more refined answer. To test their validity, two important aspects of electricity tariffs developed above were studied from an empirical data point of view: the impact of the tariff price components (energy, network and taxes) and of prosumers compensation schemes (FiTs and NEM) on the penetration of PV in European countries. This choice is motivated by the fact that future adoption of distributed PV is highly sensitive to retail rate structures (Darghouth et al., 2016) and to prosumers supporting schemes (Chen & Yin, 2016).

First, governments have designed specific policies to incentivize a prosumer behavior among their population. Two of these prosumers schemes widely covered in the previous section are feed-in tariffs and net metering. These schemes have benefits, pose challenges and can offer complementarities but ultimately, their efficiency towards the goal of increasing the prosumer population depends on each country's specificities (political, socio-economic, technological and environmental). Nonetheless, it has been stated earlier that net metering can be effectively leveraged during the post-FiT transition period and before the effective large-scale deployment of storage solutions at prosumers' homes (Christoforidis et al., 2016). Given the current relatively high deployment of prosumers in Europe, the first hypothesis (*H1*) poses that the effectiveness of NEM is greater than FiTs in Europe.

H1. Net metering is more efficient than feed-in tariffs as a supporting scheme in increasing the penetration of prosumers in Europe.

Second, cross-subsidization of prosumers from consumers of electricity can lead to the “utility death spiral”. The main assumption for such a situation to occur is that some of the network costs incurred by DSOs and TSOs are at least partially charged on a volumetric basis. In fact, a recent study conducted by Eurelectric (2013) on 19 European countries showed that in all of them, network tariffs were partially volumetric. However, the share of total network

costs ascribable to the transmission and distribution activities varies considerably across EU Member States (Picciariello, Reneses, et al., 2015). Under this condition of volumetric charges, a higher level of prosumption can create a negative feedback loop of increasing prices for all grid users (Cai et al., 2013). As such, the second hypothesis (*H2*) states that electricity price increases are higher when a net metering scheme is in application.

H2. The network electricity price component is subject to higher increases under the application of a net metering scheme.

Third, environmental pressures have led to an increased attention towards renewable energies. For instance, international climate agreements such as the Kyoto and Paris agreements force abiding countries to reach targets in the renewable energy sector. In the European Union, the renewable energy directive sets targets on the final energy consumption from renewable sources by 2020 for each Member State. More broadly, renewable energy targets were in place in 176 countries in 2016 (REN21, 2017). As a consequence, the renewable energy market has grown massively in the recent years with the help of political effort (Sioshansi, 2016). Indeed, global renewable energy production went from 800 GW in 2004 to 2,017 GW in 2016 (REN21, 2014, 2017). As such, a political trend could be playing a role in the increase of prosumers in Europe in the last few years. In fact, authors agree that both political and individual efforts are among the main drivers to increase production from renewable energy in light of increasing environmental concerns and awareness (Chen & Yin, 2016; Lopes et al., 2007; Pepermans et al., 2005; Picciariello, Vergara, et al., 2015). Thus, the third hypothesis (*H3*) states that there exists such political trend playing a role in the deployment of residential PV.

H3. Environmental and political pressures contributed to the increase of prosumers penetration in Europe.

3 Data

In order to test these three hypotheses, empirical data was collected. However, little public data is available on the penetration level of residential prosumers in Europe, even less on the presumption behavior (Council of European Energy Regulators, 2017). Indeed, it is not mandatory for prosumers to declare their presumption level in every Member State or even the fact that they have an electricity generator behind-the-meter. Even when they do declare it, specific data is often privately owned by the DSO or the supplier in charge of the grid user. Furthermore, old meters are still used in some countries which can only provide the net accumulated consumption with no distinction between consumption and injection of electricity. Also, it was explained in section 2.2 why residential prosumers can be reduced to owners of PV systems. As a result, PV capacity installed was used as a proxy to quantify penetration of small-scale residential prosumers across Europe.

This data was retrieved from the annual survey country report made by the IEA (2018). Since the objective is to analyze the impact of prosumers as a distributed resource of the smart grid, stand-alone off-the-grid PV installations are abstracted from the data. The period covered in the observations ranges from 2007 to 2016.

Ten EU Member States have reported sufficiently precise data over their grid-connected distributed installed PV power and constitute the basis for the analysis: Austria, Belgium, Germany, Denmark, France, Italy, Norway, the Netherlands, Portugal and Sweden.

Electricity prices were retrieved from Eurostat (2018a), using end-of-year data. As the average price paid by kWh depends on the consumption level, Eurostat (2018a) distinguishes five consumption profiles of residential users ranging from band-DA to band-DE. The “medium” consumption profile (band-DC) was used to retrieve electricity prices as it corresponds to a household consuming between 2500 and 5000 kWh per year. This range has been chosen because it includes the average and median consumption amount of European citizens (4.6 and 4.2 MWh respectively) and because it is the standard band used in European Commission’s reports on electricity prices (Erbach, 2016b; European Commission, 2014, p. 7).

Moreover, using the Euro or local currencies to report electricity prices would make comparisons between countries irrelevant due to different purchasing powers. As a

consequence, electricity prices were reported using the Purchasing Power Standard (PPS), an artificial currency unit developed by the European institutions and which can buy the same amount of goods and services in each member state. As such, this unit of measurement directly takes into account the impact of inflation and interest rates on prices and, as a consequence, these macroeconomic effects were not analyzed through the model.

Eurostat also provides details on the price components of electricity. As such, a breakdown of the total electricity price in three components was retrieved for a more detailed analysis: energy and supply, network, taxes and levies.

The specific conditions and incentives fostering electricity prosumption are extremely country specific with many types of different policies existing. However, common schemes can be observed such as FiTs, net metering, subsidies, green certificates policies, etc. (Poullikkas, 2012). As such, a binary variable indicating the presence of a supporting scheme, either FiTs or NEM, in each country in a given year was created based on the policies database provided by the European Commission (2018).

Considering domestic PV power installed alone could hide larger issues linked to the global PV market in general. As a consequence, the yearly production of industrial PV plants was also retrieved from Eurostat (2018c).

As a summary, the full list with the description of variables used in the models is available in Table 1.

Table 1. List of variables used and their description.

Name	Description/Formula
<i>capacity</i>	Cumulative distributed residential PV capacity installed in MW
<i>centralized_production</i>	Total electricity produced from utility-scale PV in TOE
<i>country</i>	Country of the observation
<i>energy_supply</i>	Price in PPS/kWh of the energy and supply component of the total electricity price for the given year for a “band-DC” household
<i>fin_network</i>	1 = Main support scheme for PV financed through network costs 0 = otherwise
<i>fin_taxes</i>	1 = Main support scheme for PV financed through taxes 0 = Otherwise
<i>fit</i>	1 = Feed-in tariff in application during the given year 0 = No fit in application
<i>ind_elec_price</i>	Total electricity price for industrial customers
<i>nem</i>	1 = Net metering in application during the given year 0 = No net metering in application
<i>network</i>	Price in PPS/kWh of the network costs component of the total electricity price for the given year for a “band-DC” household
<i>population</i>	Reported population in the country in the year of the observation
<i>taxes_levies</i>	Price in PPS/kWh of the taxes and levies component of the total electricity price for the given year for a “band-DC” household
<i>year</i>	Year of the observation
<i>log_capacity</i>	$= \log(capacity)$
<i>log_centralized_production</i>	$= \log(centralized_production)$
<i>penetration</i>	$= capacity/population$
<i>log_penetration</i>	$= \log(penetration)$
<i>fin_taxes_price</i>	$= fin_taxes * taxes_levies$
<i>fin_network_price</i>	$= fin_network * network$
<i>trend</i>	$= year - 2016$

The level of PV capacity installed in a given year varies greatly depending on the country considered (see top graph in Fig. 7). The first action that can be taken to make a comparison between countries more meaningful is to divide the domestic capacity by the total population of the country in the given year to obtain a *penetration* rate in MW/person (see middle graph in Fig. 7). Population statistics can be retrieved from Eurostat (2018b). Second, a logarithmic transformation of the variable *penetration* was applied to highlight more differences between countries (see bottom graph in Fig. 7).

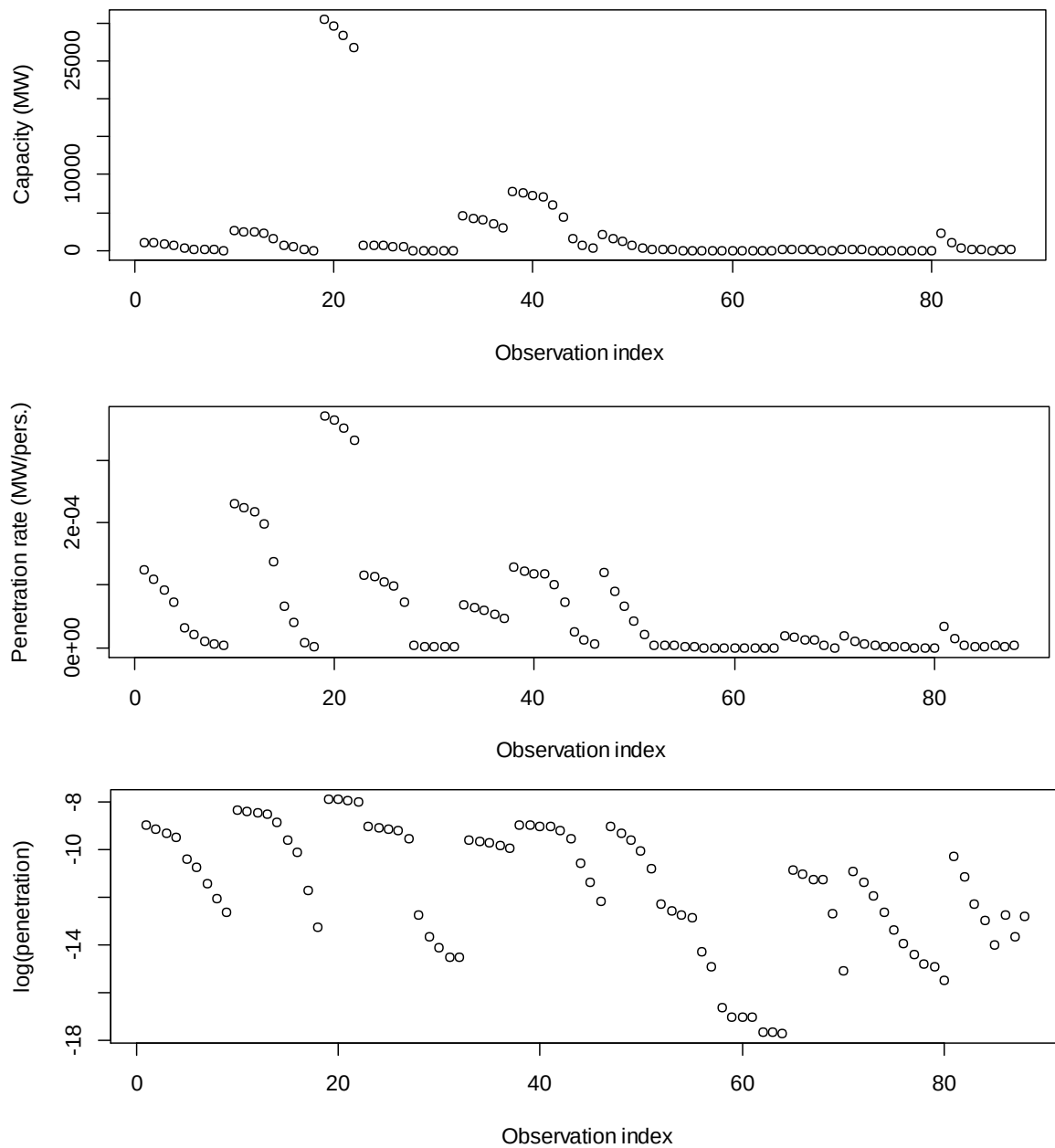


Fig. 7. Transformation of the dependent variable.

Similarly, a logarithmic transformation of the total centralized production of PV plants (*centralized_production*) was used to stay consistent (*log_centralized_production*). Furthermore, three variables were calculated based on other ones: *fin_taxes_price*, *fin_network_price* and *trend* (see Table 1). Table 2 provides descriptive statistics for all the variables used.

Table 2. Descriptive statistics for the variables used

Statistic	N	Mean	St. Dev.	Min	Max
energy_supply	81	0.062	0.022	0.024	0.110
fit	88	0.580	0.496	0	1
nem	88	0.477	0.502	0	1
fin_taxes_price	87	0.051	0.050	0.000	0.160
fin_network_price	81	0.020	0.029	0.000	0.091
log_capacity	88	4.914	3.203	−2.303	10.323
log_centralized_production	88	1.855	2.828	−1.609	8.111
trend	88	−4.330	2.904	−9	0
penetration	88	0.0001	0.0001	0.00000	0.0004
log_penetration	88	−11.607	2.627	−17.687	−7.901
year	88	2,011.670	2.904	2,007	2,016
capacity	88	2,354.111	6,095.931	0.100	30,439.000
centralized_production	88	279.418	759.317	0.000	3,329.900
fin_network	88	0.318	0.468	0	1
fin_taxes	88	0.682	0.468	0	1
ind_elec_price	87	0.121	0.045	0.058	0.207
network	81	0.053	0.012	0.034	0.091
population	88	24,630,296.000	25,672,567.000	4,681,134	82,175,684
taxes_levies	87	0.067	0.038	0.026	0.160

4 Application

4.1 Model specifications

A multiple linear regression model was used to infer conclusions about the penetration rate of prosumers depending on the level of electricity price components and supporting schemes in European countries. The choice for a regression model was guided from the fact that these models allow for easy testing of the variables' impact on the outcome. The model's summary can be found in Table 3.

Model 1 (*M1*):

$$\begin{aligned} \log_penetration \sim & \text{fit} + \text{nem} + \text{fin_taxes_price} + \text{fin_network_price} \\ & + \log_centralized_production + \text{trend} + \text{fin_network_price} * \text{nem} \end{aligned}$$

Table 3. Summary of *M1*.

	Model 1	Coefficients
(Intercept)	−14.58*** (0.63)	$\widehat{\beta}_0$
fit	0.97** (0.35)	$\widehat{\beta}_1$
nem	0.87* (0.44)	$\widehat{\beta}_2$
fin_taxes_price	19.91*** (5.08)	$\widehat{\beta}_3$
fin_network_price	34.55* (13.36)	$\widehat{\beta}_4$
log_centralized_production	0.47*** (0.08)	$\widehat{\beta}_5$
trend	0.27*** (0.07)	$\widehat{\beta}_6$
nem:fin_network_price	31.48* (13.72)	$\widehat{\beta}_7$
R ²	0.76	
Adj. R ²	0.74	
Num. obs.	81	
RMSE	1.38	

*** $p < 0.001$, ** $p < 0.01$, * $p < 0.05$

All coefficients in model *M1* are significant at least at the 5%-level suggesting that all predictors contribute to explain the variability in *log_penetration*. Logically, the null hypothesis of F-statistic testing the non-significance of all predictors is rejected with a p-value $< 2.2\text{e-}16$.

The reason for the presence of the interaction term between *nem* and *fin_network_price* is to make inferences regarding the second hypothesis over the death spiral possible (details are discussed in section 5).

4.2 Model fit

Several indicators were used to select among sub-models and decide on the six predictors involved in the final model: the adjusted R-squared, Mallows' C_p and the Bayesian information criterion (BIC). Three other variables than those used in the models were potential predictors: *country*, *ind_elec_price* and *energy_supply*.

First, the adjusted R-squared equals 0.74, indicating that a fair share of the variation in the data is explained without overfitting the data which can happen when looking at the non-adjusted R^2 .

The evolution of the blue curve in Fig. 8 shows that the maximum for the adjusted R^2 is reached at around six variables. The adjusted R^2 penalizes for adding variables that are not useful to explain additional variation in the model. It can be seen from the graph that there is no more improvement in the indicator after six predictors.

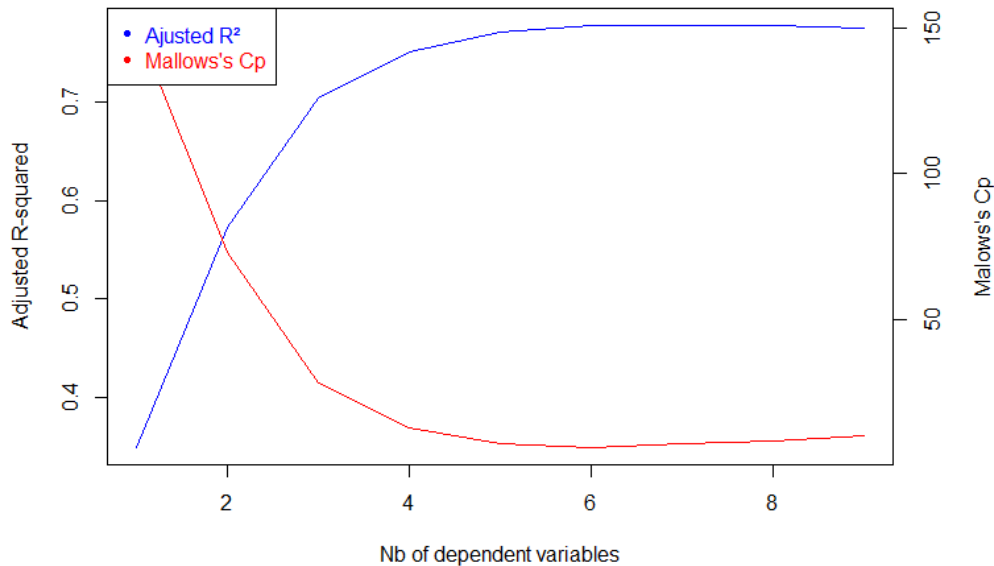


Fig. 8. Evolution of the adjusted R^2 and C_p for an increasing number of parameters.

Second, Mallows' C_p , was also used to assess the fit of the model and the selection of the number of predictors (Mallows, 1973). The smaller the value of the C_p , the more precise the

model is. As can be seen from Fig. 8, the C_p follows an opposite trend to the adjusted R^2 : first, a strong increase in precision up to three predictors; second, a continuous smaller but significant increase up to six predictors; third, a loss in precision if further variables are added.

Third, the BIC can also be used to select among models with different numbers of predictors. As expected, the BIC follows a very close pattern to Mallows' C_p which confirms the selection of six variables for the model.

Fourth, both the above-mentioned indicators and data logic were used to select the six predictors of the model. For example, in order to make a comparison between supporting schemes meaningful, if either the variable *fit* or *nem* was selected by the indicators, the other one was automatically forced into the model as well.

Finally, various control variables relating to the economy in general were used while building the model. Only one, the total electricity produced from utility-scale PV in TOE in a given year, *centralized_power*, was kept in the models due to its high significance after applying a logarithmic transformation (*log_centralized_power*) to stay consistent with what had been done for the *penetration* variable (see section 3). Its inclusion in the model is discussed further in section 6.3.1 regarding the limitations of the predictors.

4.3 Validity

4.3.1 Linear relationship

A multiple linear regression model assumes a linear relationship to be present between the independent variable (*log_penetration*) and the dependent variables. Scatter plots can effectively test for this assumption with a quick glance. Looking at Fig. 9, we can reasonably assume that there is some kind of linear relationship between the dependent variable and the independent ones³.

³ Binary variables (*fit* and *nem*) have been abstracted as their scatterplot can be meaningless and *fin_network_price* and *fin_taxes_price* have been summed up into *fin_price* as they are complementary by definition.

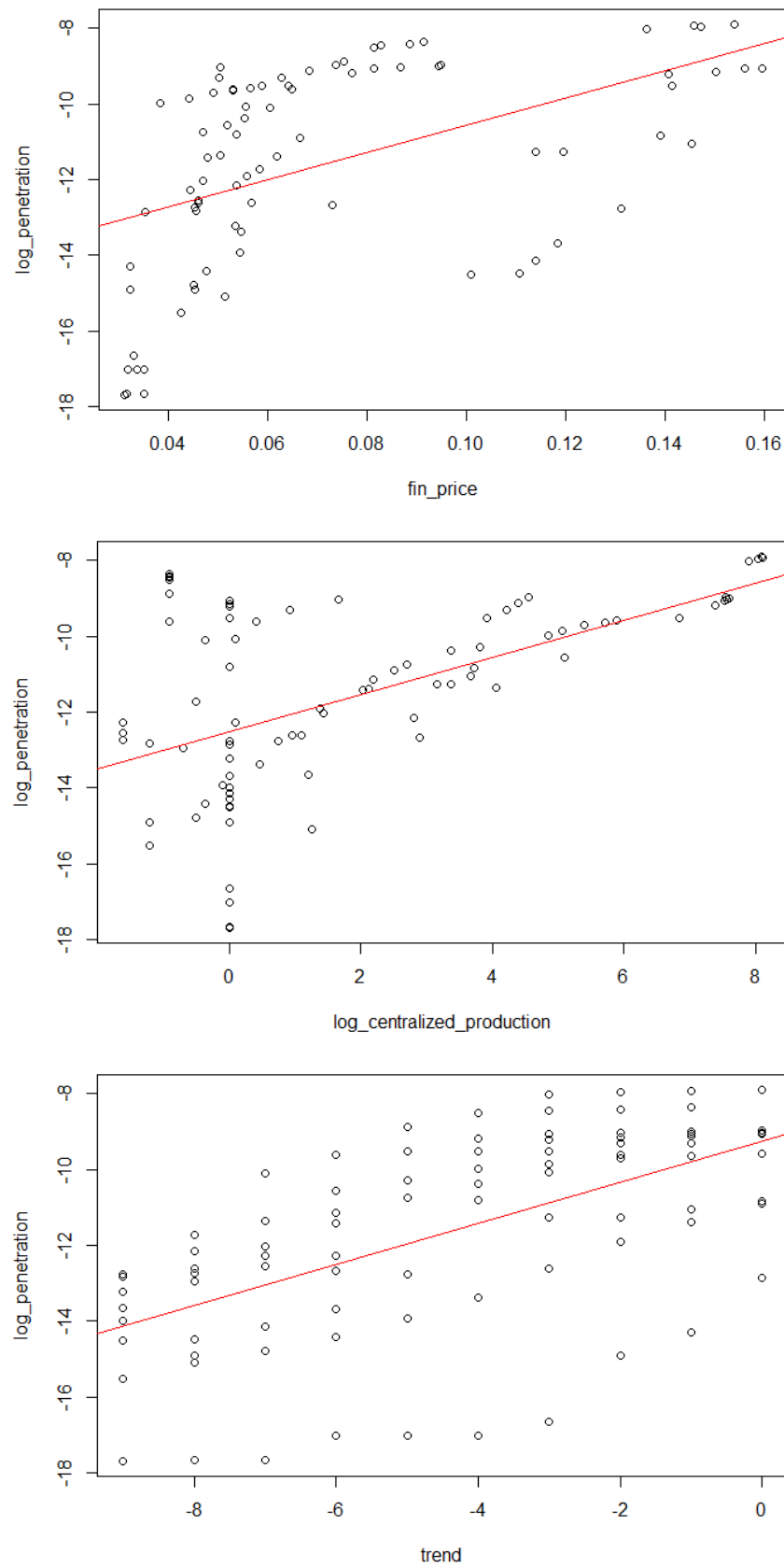


Fig. 9. Linear relationship between independent variables and the dependent variable.

It is also important to check for outliers which could distort the regression estimators. A robust regression model was fitted to the same data and using the same predictors⁴. It revealed that observations for Sweden between 2011 and 2016 were considered as outliers. However, the robust regression did not yield estimators of coefficients much different from the normal regression and an analysis of the outliers did not reveal any data evidence supporting the removal of these observations from the dataset. As a consequence, it was decided to keep these observations in the dataset.

Table 4. Comparison of *M1* with a Robust Model.

	Robust Model	M1 w/ interaction
(Intercept)	-14.32*** (0.46)	-14.53*** (0.65)
fit	2.12*** (0.40)	1.01** (0.36)
nem	1.55*** (0.25)	1.38*** (0.39)
fin_taxes_price	11.41** (3.71)	18.15*** (5.17)
fin_network_price	66.39*** (7.07)	54.98*** (10.24)
log_centralized_production	0.41*** (0.05)	0.45*** (0.08)
trend	0.40*** (0.03)	0.29*** (0.07)
Num. obs.	81	81
R ²		0.75
Adj. R ²		0.72
RMSE		1.42

*** $p < 0.001$, ** $p < 0.01$, * $p < 0.05$

4.3.2 Normality

Normality of the residuals of the model is an important assumption to ensure the validity of tests made on coefficients. First, looking at the QQ-plot and histogram of the residuals did not reveal clearly whether normality could be assumed (see Fig. 10 and Fig. 11).

⁴ The interaction term was suppressed as it caused the robust model to not converge.

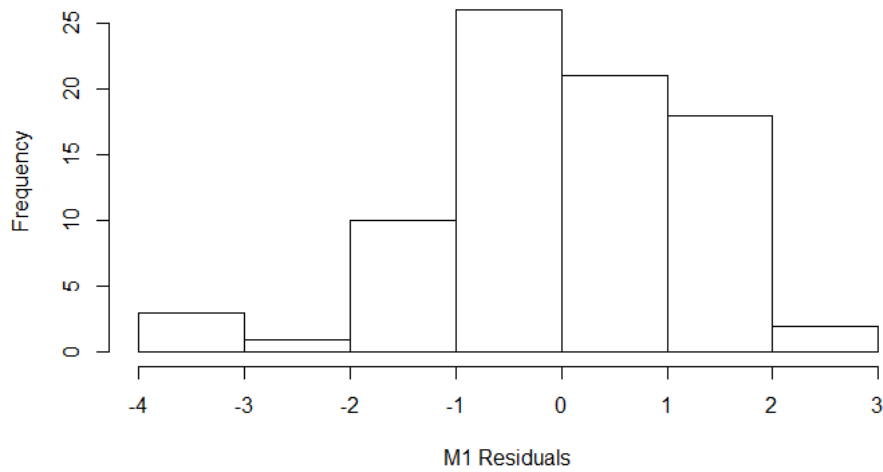


Fig. 10. Histograms of *M1*'s residuals.

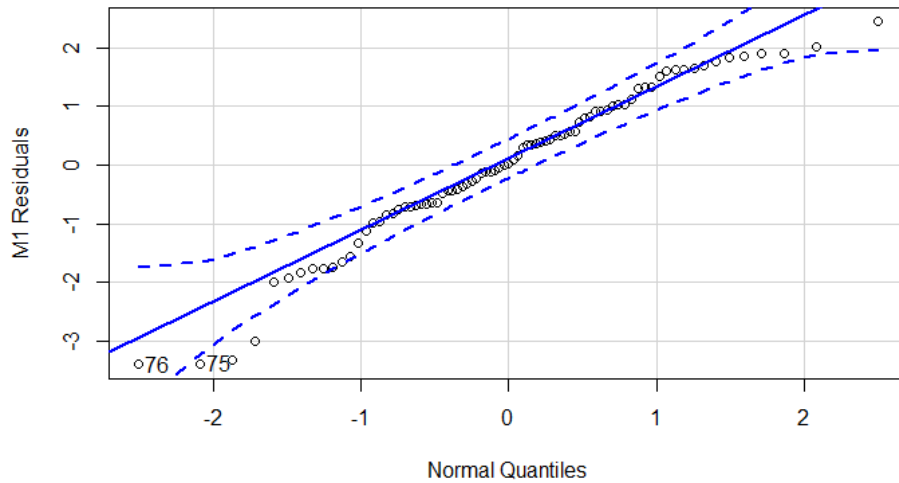


Fig. 11. QQ-Plot of *M1*'s residuals.

Second, the Shapiro-Wilk test of normality was used as Monte Carlo simulation has found that this test has the best power for a given significance (Mohd Razali & Yap, 2011). The p-value for this test is 0.03, rejecting the null hypothesis of normality at a 5% significance level.

Observations 75 and 76 identified correspond to Sweden for the years 2011 and 2012 respectively, which can explain why they were also identified by the robust regression as outliers. Nonetheless, it was decided to keep them in the dataset as supporting evidence to remove them was missing (see section 4.3.1).

However, Van Bellegem (2015) demonstrates that tests such as t-tests and F-tests are approximately valid for a dataset of a finite size such as this one and that the error in those tests gets smaller as the size of dataset increases. Tests were thus conducted as if the normality assumption was respected.

4.3.3 Multicollinearity

Multicollinearity occurs when the independent variables are too highly correlated with each other and can cause estimators to switch signs, have unusually high magnitudes or illogic signs (Van Bellegem, 2015). The Variance Inflation Factor (VIF) was used to test the presence of multicollinearity. If the VIF is more than 10, multicollinearity is strongly suggested. For *M1*, $VIF = 4.21$, indicating some small signs of multicollinearity but no strong evidence to reject the model.

4.3.4 Heteroskedasticity

Linear models assume the presence of homoskedasticity. Heteroskedasticity, on the contrary, occurs when the variance of the error terms differs across observations (Van Bellegem, 2015).

The Breusch–Pagan test can be used to investigate the null hypothesis of homoskedasticity (Breusch & Pagan, 1979). The test statistic obtained equals 14.0 with a p-value of 0.05. This led to the null hypothesis being rejected. As a consequence, further tests were conducted using White’s estimator of the variance to avoid coming to the wrong conclusions due to the presence of heteroskedasticity (see Table 5) (White, 1980).

Table 5. White’s estimator of the variance.

	(Intercept)	fit	nem	fin_taxes_price	fin_network_price	log_centralized_production	trend	nem:fin_network_price
(Intercept)	0.260	-0.024	-0.015	-1.338	-3.389	-0.011	0.014	0.539
fit	-0.024	0.135	0.040	-0.510	-0.108	-0.005	0.005	0.458
nem	-0.015	0.040	0.107	-0.368	0.671	-0.004	0.007	-1.387
fin_taxes_price	-1.338	-0.510	-0.368	18.315	22.329	0.015	-0.075	-4.043
fin_network_price	-3.389	-0.108	0.671	22.329	82.452	0.129	-0.066	-46.675
log_centralized_production	-0.011	-0.005	-0.004	0.015	0.129	0.002	-0.001	0.036
trend	0.014	0.005	0.007	-0.075	-0.066	-0.001	0.002	-0.089
nem:fin_network_price	0.539	0.458	-1.387	-4.043	-46.675	0.036	-0.089	74.824

4.3.5 Autocorrelation

The observations collected are obviously autocorrelated as they constitute time series for each country studied. By definition, the cumulative capacity of a given year for a specific country takes into account the cumulative capacity of the previous years. The Durbin-Watson's test of autocorrelation confirmed this characteristic of the data. As expected, the test value is 0.373 with a p-value $< 2.2e-16$, rejecting the null hypothesis of absence of autocorrelation.

Introducing a country-specific “trend” variable could be used to correct for this autocorrelation but this suggestion has not been pursued in this thesis as such variables would capture too much of the variability for each country. Instead the panel-wide *trend* variable was used but it does not correct for autocorrelation.

5 Analysis

This section presents the main findings related to the model and the consequences regarding the validity of the hypotheses posed.

Looking at the main effect of the estimated coefficients of *fit* and *nem*, it can be seen that both are significative at a 5%-level and that both are positive indicating an increase in penetration rate if a supporting scheme is in application⁵. This result is supported by Dusonchet and Telaretti's (2015) findings who showed that the best profitability for a PV system owner is obtained in countries where an electricity compensation scheme is in place. Indeed, a better profitability of PV systems leads to more economic incentives towards electricity consumers to adopt a prosumer behavior.

The estimated coefficients $\widehat{\beta}_1$ and $\widehat{\beta}_2$ yield the values of 0.97 and of 0.87 for *fit* and *nem* respectively. In other words, the model predicts that the presence of a FiT or NEM supporting scheme increases the predicted *log_penetration* by the estimates of the coefficients. As the transformation from *penetration* to *log_penetration* is not linear but logarithmic, the increase in *penetration* due to the presence of a supporting scheme is dependent on the fitted value of each observation and equals:

$$e^{\widehat{\beta}_x + \text{fitted_value}} - e^{\text{fitted_value}}$$

where *fitted_value* is the predicted value by *M1* of the observation and $\widehat{\beta}_x = \widehat{\beta}_1$ or $\widehat{\beta}_2$.

However, the ratio of this increase in *penetration* over the initial *penetration* level is a constant and is equal to:

$$\frac{e^{\widehat{\beta}_x + \text{fitted_value}} - e^{\text{fitted_value}}}{e^{\text{fitted_value}}} = \frac{e^{\widehat{\beta}_x + \text{fitted_value}}}{e^{\text{fitted_value}}} - 1$$

The value of this constant is 1.65 and 1.39 for $\widehat{\beta}_1$ and $\widehat{\beta}_2$ respectively.

⁵ Both supporting schemes can also be in application simultaneously as it happened at some point in Denmark and Italy.

The presence of a feed-in tariff increases the penetration rate of residential PV by 165% and of a net metering scheme increases the rate by 139%.

Regarding the comparison between the magnitude of the coefficients, a statistical test of linear restriction was conducted to assess whether the difference between the two coefficients was significative or not:

$$H_0: \beta_1 = \beta_2$$

$$H_a: \beta_1 \neq \beta_2$$

$$T = \frac{\widehat{RSS}_0 - \widehat{RSS}_1/r}{\widehat{RSS}_1/(n - K)} \sim F_{n-K}^r$$

where β_1 and β_2 are the real coefficients of *fit* and *nem* respectively, $\widehat{RSS}_0$ is the sum of residuals in the restricted model and $\widehat{RSS}_1$ is the sum of residuals in the full model, r and K the number of rows and columns in the restriction matrix respectively. The test is also corrected using White's estimator of the variance due to the presence of heteroskedasticity in the model (see section 4.3.4).

The result of the test was $T = 0.053$, with an associated p-value of 0.82, leading to a non-rejection of the null hypothesis at a 5%-level of a significative difference in the real coefficients.

It cannot be stated that coefficients *fit* and *nem* are statistically different from one another and that a supporting scheme is more effective than another using the mere presence of a supporting scheme as efficiency indicator. As a consequence, the first hypothesis cannot be validated using this result.

However, the presence or not of a supporting scheme is not the only indicator of its efficiency. Another method is to look at the cost per added capacity of such schemes. In that respect, the coefficients of *fin_taxes_price* and *fin_network_price* are insightful. Both are positive and significant indicating that increases in these electricity price components have an encouraging effect on the penetration of PV. More specifically, for an additional 0.01 PPS/kWh

passed on taxes or network charges, $\log_penetration$ rises by $\widehat{\beta}_3/100$ or by $\widehat{\beta}_4/100$, i.e. 0.199 or 0.345 respectively.

As the transformation from $penetration$ to $\log_penetration$ is not linear but logarithmic, the increase in $penetration$ for an additional 0.01 PPS/kWh is dependent on the fitted value of each observation and equals:

$$e^{\frac{\widehat{\beta}_x}{100} + fitted_value} - e^{fitted_value}$$

where $fitted_value$ is the predicted value by $M1$ of the observations and $\widehat{\beta}_x = \widehat{\beta}_3$ or $\widehat{\beta}_4$.

However, the ratio of this increase in $penetration$ over the initial $penetration$ level is a constant and is equal to:

$$\frac{e^{\frac{\widehat{\beta}_x}{100} + fitted_value} - e^{fitted_value}}{e^{fitted_value}} = \frac{e^{\frac{\widehat{\beta}_x}{100} + fitted_value}}{e^{fitted_value}} - 1$$

The value of this constant is 0.220 and 0.413 for $\widehat{\beta}_3$ and $\widehat{\beta}_4$ respectively.

An additional 0.01 PPS/kWh passed on taxes or network charges increases the penetration rate by 22.0% and 41.3% respectively.

A similar test of linear restriction to the one used earlier was conducted to verify whether the coefficients significantly differ from one another:

$$H_0: \beta_3 = \beta_4$$

$$H_a: \beta_3 \neq \beta_4$$

$$T = \frac{\widehat{RSS}_0 - \widehat{RSS}_1/r}{\widehat{RSS}_1/(n - K)} \sim F_{n-K}^r$$

where β_3 and β_4 are the real coefficients of fin_taxes_price and $fin_network_price$ respectively.

The result of the test is $T = 2.55$, with an associated p-value of 0.114, leading to a non-rejection of the null hypothesis and to the implication that it cannot be proven that the real coefficients are different from each other.

It cannot be stated that supporting schemes financed through taxes or network charges are cheaper than the other when looking at the main effects only. As a consequence, the first hypothesis can still not be validated using this alternative result.

The second hypothesis investigates the interaction between the presence of a net metering scheme and network charges under the assumption of partially volumetric charges. The interaction term $fin_network_price * nem$ is positive, significant and estimated at 31.48 with both $fin_network_price$ and nem estimated coefficients remaining positive and significant. In other words, the total increase in $log_penetration$ for an additional 0.01 PPS/kWh of network charges when a NEM is in application amounts to $34.55/100 + 31.48/100 = 0.660$.

The second hypothesis is thus not validated: the network electricity price component is not subject to higher increases under the application of a net metering scheme, it is actually subject to lower increases for an equal amount of increase in $log_penetration$.

On the one side, this evidence is supported by authors suggesting that the death spiral is an exaggeration in the current system and an outdated model to assess today's situation (Costello & Hemphill, 2014; Graffy & Kihm, 2014). Moreover, the result is also backed by scholars who showed that even in the case of high PV adoption, a utility death spiral is unlikely (Laws et al., 2017). A potential explanation could be that the European countries evaluated have in place one of the mechanisms proposed to avert the death spiral in the short-term, namely backup fees, net billing and sufficiently high fixed charges (Castaneda et al., 2017), while most studies were performed in the US where those mechanisms are rarer.

Furthermore, another and similar test of linear restriction was constructed to compare the effectiveness of schemes financed through network charges with schemes financed through increased taxes when looking at the cost per increase in penetration rate and taking into account the interaction this time:

$$H_0: \beta_3 = \beta_4 + \beta_7$$

$$H_a: \beta_3 \neq \beta_4 + \beta_7$$

$$T = \frac{\widehat{RSS}_0 - \widehat{RSS}_1/r}{\widehat{RSS}_1/(n-K)} \sim F_{n-K}^r$$

where β_7 is the real coefficient of *fin_network_price * nem*.

The result of the test yields a $T = 38.07$ and a p-value = 3.45e-08, leading to the rejection of the null hypothesis. As a consequence, supporting schemes financed through network charges are more effective than those financed through taxes if a net metering scheme is in application. In other words, the total increase in *log_penetration* for an additional 0.01 PPS/kWh of network charges when a NEM is in place amounts to 0.660, higher than the single main effect of 0.346 without a NEM.

An analysis of the evolution of the price components of electricity (energy and supply, network and taxes and levies) for different countries revealed that, in general, either the network or the taxes and levies components of electricity increase significantly with the introduction of either a feed-in tariff or a net metering scheme for residential owners of photovoltaic systems. This observation is consistent with the literature about the financing of prosumers supporting schemes. Indeed, it is always ultimately the consumer of electricity who pays for the financing of the supporting scheme through higher electricity prices (Gautier, 2015). In general, as FiTs are organized at the state level, the increase in price is passed on the taxes and levies component. On the contrary, NEM schemes are usually administered by DSOs (and TSOs) and the price increase is passed on the network component. This affirmation was observed in the data (see Fig. 12).

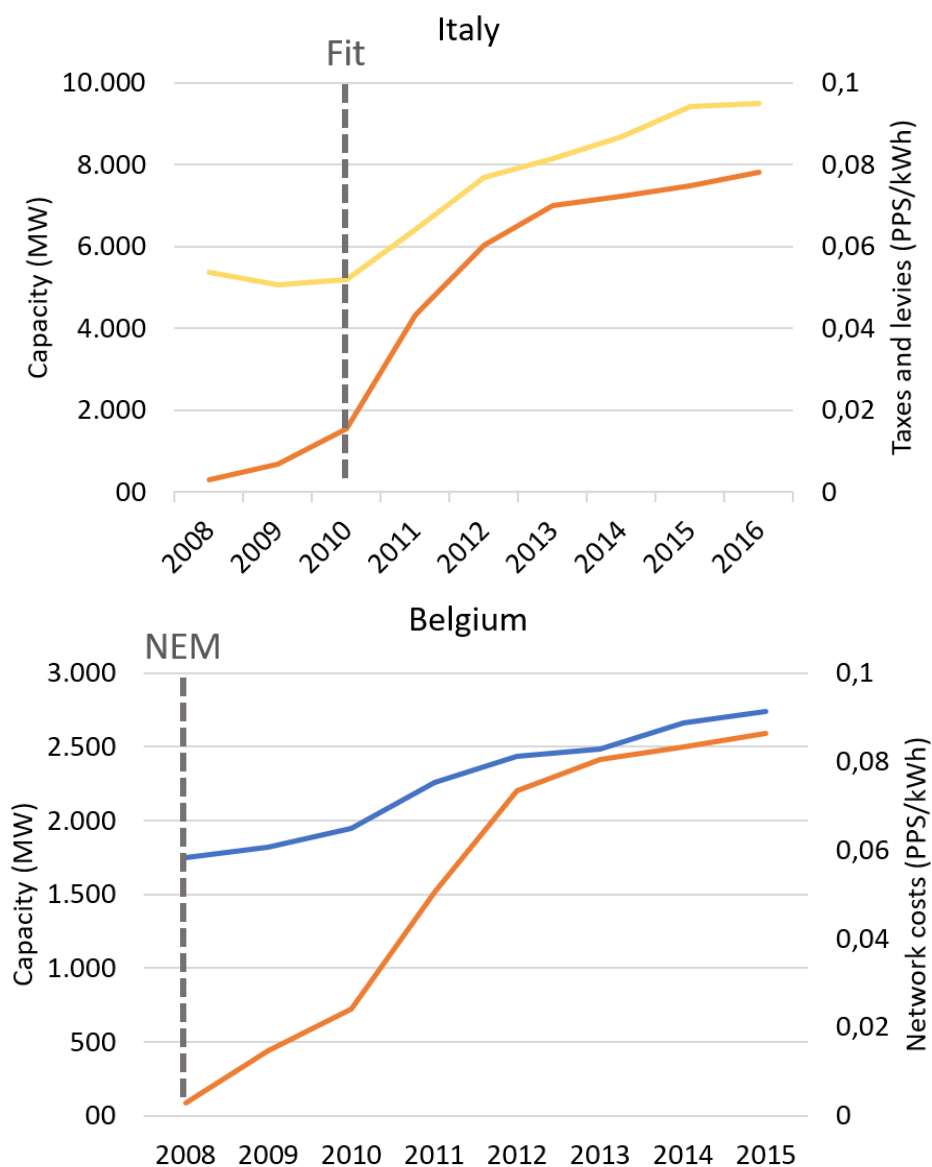


Fig. 12. Effect on price components of the introduction of supporting schemes.

As a consequence, the conclusions made so far about the first hypothesis can be reviewed if we take into account that NEM schemes are financed through taxes. Indeed, it can now be stated that NEM is a cheaper supporting scheme than FiTs at the marginal increase rate in penetration of PV given the last test performed.

The first hypothesis can now be validated: net metering is more efficient than feed-in tariffs in increasing the penetration of prosumers when using the cost per added penetration and assuming that net metering schemes are financed through network charges.

This finding is in line with the literature suggesting that net metering can be effectively leveraged during the post-FiT transition period and before the large-scale deployment of storage solutions at prosumers' homes (Christoforidis et al., 2016). Indeed, at this stage, the market forces are progressively replacing the government costly efforts to foster PV through FiTs in the early stages (Couture & Gagnon, 2010). In fact, the European Commission (2013) recommends that FiTs be phased out in favor of more market-driven instruments such as NEM and feed-in premiums. This recommendation is also supported by (Bell & Foster, 2017). However, Poullikkas (2013) found opposite results in his study comparing the effectiveness of NEM and FiTs when taking the electricity bill into account.

The third and last hypothesis investigates the presence of a trend towards increased renewable energies, especially photovoltaics at a residential level, due to political and environmental pressures in the light of climate change. Looking at the model, it can be seen that such trend does exist given the estimated coefficient of *trend*, $\widehat{\beta}_6$, equal to 0.269, significative and positive as expected. In other words, for each additional year, the estimated coefficient gives the marginal increase in *log_penetration* that can be attributed to political and environmental pressures.

The third hypothesis can be validated: environmental and political pressures contributed to the increase in penetration of prosumers in Europe.

This is no surprise in light of the EU's renewable energy directive setting a binding target of 20% final energy consumption from renewable sources by 2020.

While this estimate can be interpreted as an average trend across the European countries taken into account in this study, it should not be forgotten that currently no universal policy exists regarding the harmonization of the respective legislation of the EU Member States in the field of renewables (Christoforidis et al., 2016). Indeed, national efforts vary widely across Europe with national targets of renewable energy ranging between 10% for Malta and 49% for Sweden. In fact, Ruester et al. (2014, p. 236) argue that there is no need for such an EU-wide harmonization but that instead, the EU should “set certain minimum requirements in a few key regulatory aspects, and publish guidelines to encourage good regulatory practice”.

6 Discussion and Conclusion

6.1 Results

Climate change and the ever-growing increase in energy demand has led modern societies to look for alternative ways of supplying power. Using renewables to generate electricity quickly emerged as one of the potential keys to mitigate the pressure of global climate change, meet energy demand and transform to a low-carbon society (Chen & Yin, 2016; Erbach, 2016b). Among other things, regulators are trying to foster the large-scale deployment of distributed renewable energy as an alternative to the traditional electricity supply system which has the potential to harness demand flexibility, improve the integration of intermittent solar energy and achieve low emissions (Osenia & Pollitt, 2017). As documented by Chen and Yin (2016), experiences in Australia, United States, Japan, Europe has indicated that well-designed policies are an effective tool to foster the development of renewable distributed energy generation. Understanding how consumers and producers of small and distributed generators, the so-called prosumers, react to price signals and to these supporting schemes is thus of uttermost importance.

The analysis conducted above showed that both feed-in tariffs and net metering schemes have a positive and considerable effect on the penetration of prosumers. However, no significant difference between the main effect of feed-in tariffs versus net metering was found. Similarly, electricity price increases passed on network costs or taxes have a positive effect on the penetration of prosumers but a closer look at the cost per marginal increase in penetration revealed no significant difference between policies financed through network charges and those financed through taxes and levies, looking at the main effect only. Still, feed-in tariffs are most often financed through taxes while net metering policies are usually financed through network charges. Using this observation, it was then showed that net metering is a more effective policy in terms of cost than feed-in tariffs, taking the interaction effect between net metering and network charges into account. This is in line with the literature and the European Commission's (2013) recommendations of phasing out feed-in tariffs in favor of more market-driven schemes given the fact that Europe has reached a significant level of PV deployment (Bell & Foster, 2017; Christoforidis et al., 2016; Couture & Gagnon, 2010).

Additionally, it was found that the network electricity price component is not subject to higher increases under the application of a net metering scheme in presence of volumetric charges, it is actually subject to lower increases. This is supported by authors suggesting that the “utility death spiral” is an exaggeration in the current system and an outdated model to assess today’s electricity system (Costello & Hemphill, 2014; Graffy & Kihm, 2014). Moreover, the result is also supported by findings demonstrating that even in the case of large PV adoption, a utility death spiral is unlikely (Laws et al., 2017) thanks to possibly backup fees, net billing and sufficiently high fixed charges in the countries studied (Castaneda et al., 2017).

Moreover, results showed that environmental and political pressures successfully contributed to the increase of prosumption in Europe which is no surprise in light of the EU’s renewable energy directive setting a binding target 20% of the final energy consumption coming from renewable sources by 2020.

6.2 Contributions

Literature concerning European climate and energy policies is extensive and this thesis contributes to it by quantifying the impacts on prosumption levels of two supporting schemes, namely feed-in tariffs and net energy metering. The findings based on a linear regression on empirical data from European countries provide assistance to regulators in the process of implementing one of these policies.

This thesis also contributes to the literature on electricity tariff design by providing an analysis of the impact of electricity price components on PV penetration. Policymakers can use the results presented to understand more deeply the consequences of passing electricity price increases through taxes and levies or network charges. Overall, the findings can help network operators and regulators in charge of tariff design to construct more effective rates that foster the development of the electricity market in the direction which supports their priorities.

6.3 Limitations

In this last section, the results obtained are discussed in light of several limitations relating to the predictors used, the model structure, its predictivity and the data collected.

6.3.1 Predictors

The first limitation of this thesis regards the choice and building of the predictors used in the model. First of all, the independent variables indicating the presence of a supporting scheme, *fit* and *nem*, were computed as binary variables. However, Hughes and Bell (2006) documented at least 16 distinguishable forms of FiTs and NEM schemes with local variations existing in every country. Moreover, the timing and intensity of those schemes can differ significantly as one can see from the policies database provided by the European Commission (2018). As such, the choice for a binary variable was a simplification made for statistical purposes and given the limited amount of data available but certainly masks some of the potentially explanatory complexity behind these realities. In fact, rare are the policies which directly produce a considerable effect on the very short-term. Instead, the market needs to adapt and support schemes must be accessible in practical terms by the targeted group. Indeed, there could be a significant time between the introduction of a supporting scheme and its actual usage by the population but the date of entry into force of the relating legislation was used for the analysis. Another approach that could have been followed is the one used by Santamaria, Trujillo, and Hernandez (2016) who propose an index to compare different countries' state of regulation and policies regarding the promotion of distributed generation and taking into account several more detailed aspects.

Second, only two among many supporting schemes for PV have been investigated in this study. Indeed, investment grants, tax exemptions, green certificates, etc. could also play a role in the deployment of PV as some of them were in application in Europe at the same time than FiTs and NEM. However, the choice of reviewing these two only was driven by the fact they are those to which residential prosumers are the most often exposed – they represent together 78.2% of all active schemes (SolarPower Europe, 2015) – and by the fact that they have an immediate dependency on electricity prices.

Third, some attention should be dedicated to the variables *log_centralized_power* and *trend*. Indeed, their significance should be commented as compared to the other variables, they

do not relate directly to energy pricing or supporting schemes. The decision to integrate the centralized production in the model was supported by two facts. First, the share of centralized power increasing massively in the recent years and progressively replacing distributed power that used to dominate the market in terms of installed capacity (see Fig. 2 pg. 10). Second, growing markets and escalating competition have contributed to an unprecedented price decline which led the LCOE of utility-scale PV to be much cheaper than residential PV (Fig. 3 pg. 10). The IEA's long-term scenario for 2050 predicts that the worldwide capacity for solar PV would reach 1,000 GW (International Energy Agency, 2014b). A supposition that would need to be further investigated is that the variable *log_centralized_power* reflects the global market for the PV technology to which residential PV is inevitably linked. Similarly, it was hypothesized that the variable *trend* highlights environmental pressures from the political world. However, there could be a multitude of other explanatory variables hidden under this one. Another limitation linked to this variable is that it does not correct autocorrelation as it is panel-wide. As such, a model with country-specific "trend" variables could refine the findings of this thesis.

Fourth, as described in section 4.2 on the predictivity of the model, it can be dangerous to add too many dependent variables due to the risk of overfitting. This has motivated the choice to select (only) six variables linked to electricity price mechanisms and support schemes. However, a model is always an approximation of the reality and an infinity of other variables could be explaining the pattern of PV deployment. For instance, electricity computation methods, such as time-based tariffs, block tariffs and location-based tariffs, were investigated from a theoretical point of view in the literature but not integrated in the model. Furthermore, the impact of the share of different types of charges (volumetric, fixed or capacity) in the final tariff would also need to be empirically analyzed as they can modify the effectiveness of supporting schemes significantly. As the proportion of each type of charges can vary considerably between countries depending on the various actors of the local grid, getting country-wide data was difficult. Ultimately, it is the consumer who decides to install a PV system and, as a consequence, behavioral psychology certainly plays a role in the adoption of the technology. This aspect would also need to be investigated in further research.

6.3.2 Model structure

The second limitation of this paper concerns the model structure. First of all, an important assumption made with the model used is that there exists a linear relationship between

the dependent variable and the independent ones. However, this assumption can be questioned and non-linear configurations might deliver more insightful results. Moreover, the model and hypotheses built were based on parametric statistics with their underlying assumptions. As such, a more robust and explanatory model could be based on non-parametric statistics to infer conclusions. This could be useful as the data collected was proven to be not normally distributed, violating an important assumption of regression models. Furthermore, a robust model was built to test the validity of the normal model but the interaction term had to be suppressed due to non-convergence when it was included in the model. This observation needs refinement in order to understand why the full model does not converge when tested through a robust regression. As a consequence of these model structure limitations, the whole validity of the model used and the derived inferences can be questioned as other configurations might have yielded different results.

In general, the statistical methods used in this thesis are mostly limited to the materials covered in the Business Engineering curriculum (Bachelor's and Master's) of the Université Catholique de Louvain. As such, students and scholars with a superior knowledge of statistics may find more valid findings than those presented here. Indeed, the goal of this thesis was not to build the best statistical model as it may be the case in other faculties dedicated to statistics but rather to present a research contributing to management practices.

6.3.3 Predictivity

The third limitation regards the fact that the model is useful for understanding past level of PV development but that precautions should be taken concerning its predictive capabilities for future PV penetration levels. For instance, the model forecasts that if the electricity price skyrockets, so will adoption of residential PV. While this could make sense, a quantitative study found that “without a major technological breakthrough, it will be quite costly to drive up the share of solar power beyond 10% or 15% of Northwestern Europe's electricity consumption, even if equipment costs keep falling” (Hirth, 2015, p. 14). Similarly, the variable *trend* should not be interpreted as the fact that countries will ultimately reach 100% penetration rate of PV. In fact, Hirth (2015) has reservations about some of the very ambitious European policy targets for renewable energy and there is significant disagreement in the community over the share of renewable reachable in the future (Singh, 2009). An alternative

modeling that could solve these concerns would be using non-linear configurations which might deliver more insightful results for the future penetration levels.

Also, the dataset regrouped data out of Europe only. Inferences from the model should be extended to other continents with care, especially to the US, where the electricity system, prices and supporting schemes rely on different mechanisms and dynamics.

Finally, the model rejected the presence of a utility death spiral. However, there are several ways of modeling this conceptual effect and the interpretation made through the linear model and network prices might not be accurate enough. For example, Picciariello, Vergara, et al. (2015) used a methodology based on different scenarios to quantify this influence.

6.3.4 Data

The fourth and last limitation of this paper relates to the data collected. Indeed, the accuracy of the data used could be questioned as governments do not always have a precise idea of the number of prosumers or the total installed PV capacity on their territory. This is confirmed as authorities modified later up to 10% their previous estimations of distributed PV power in the annual survey country reports made by the International Energy Agency (2018). Furthermore, electricity prices were retrieved for a “medium” consumer but other consumption and production patterns exist. Finally, the amount of data remains limited and additional observations would be needed to make inferences more robust, especially given that some include close-to-zero PV capacity. Observations from a dataset of countries with mature PV development only could deliver more precise insights.

7 Bibliography

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