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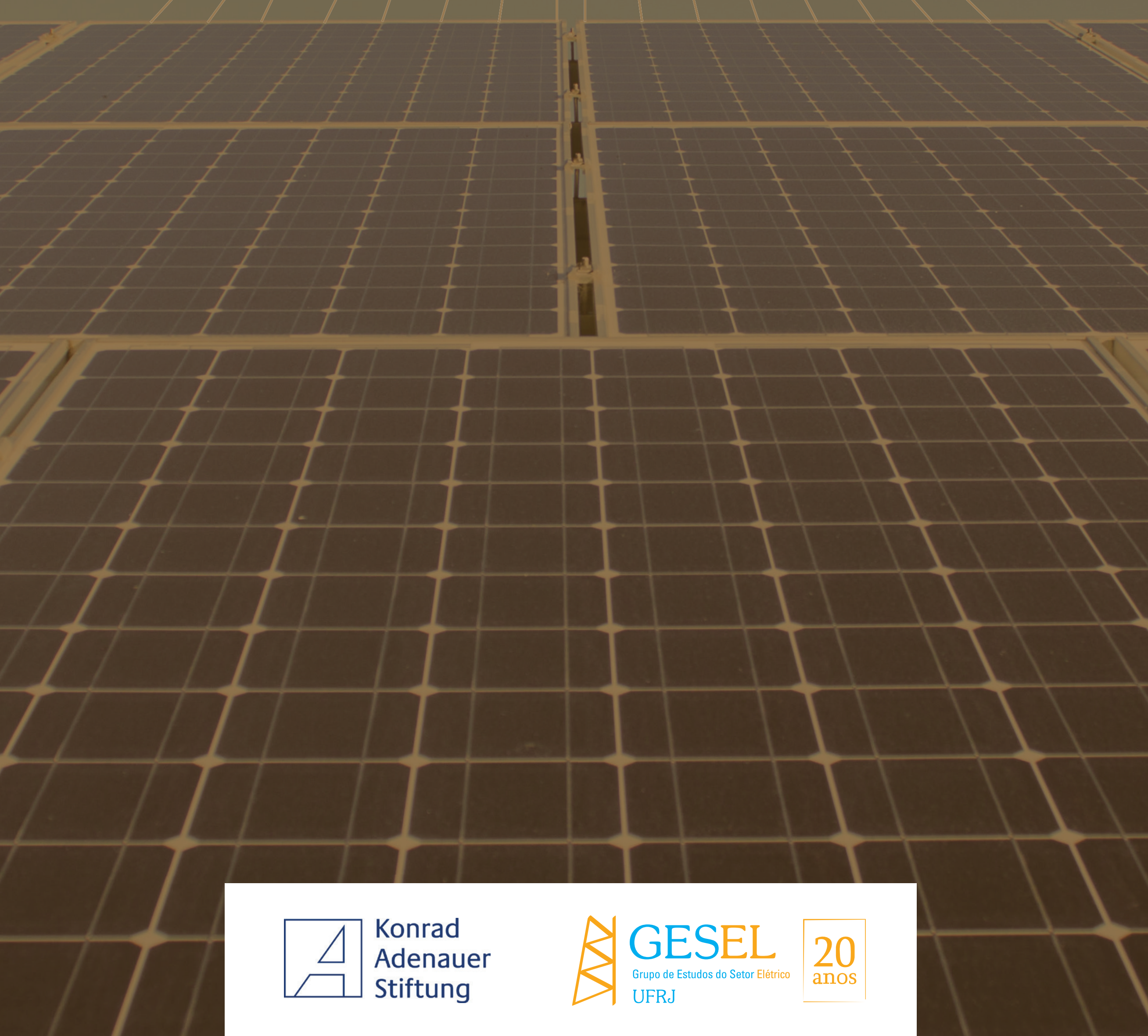
NIVALDE DE CASTRO AND GUILHERME DANTAS

DISTRIBUTED GENERATION:

INTERNATIONAL EXPERIENCES AND COMPARATIVE ANALYSES



Konrad Adenauer Stiftung

GESEL Grupo de Estudos do Setor Elétrico UFRJ 20 anos

Distributed Generation:
International Experiences and Comparative Analyses

Organizers
Nivalde de Castro and Guilherme Dantas

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Presentation EKLA-KAS

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Freedom, justice and solidarity are the basic principles underlying the work of the **Konrad Adenauer Foundation – KAS,** a political foundation, linked to the Christian Democratic Union (CDU) a political party in Germany (CDU). With more than 80 offices abroad and projects in over 120 countries, our goal is to make a unique contribution to the promotion of democracy, the rule of law and a social market economy. To promote peace and freedom, we encourage a continuous dialog at the national and international levels, as well as the exchange between cultures and religions.

Alongside the country-specific programs, developed by the country offices of the KAS in Latin America, there are cross-border regional programs with separate thematic focuses. One of these programs is the **KAS Regional Program "Energy Security and Climate Change in Latin America (EKLA)",** which has its headquarters in Lima, Peru.

The Regional Program EKLA has been designed as a dialogue platform, in order to provide impulse for political decision-making processes. This program understands itself as a consultative center for the coordination of the individual KAS country projects of the Latin-American continent, and supports the country projects with its expertise and network on this subject. Assuming the role of an initiator and consultant, it aims at complementing the activities of the country programs by means of regional networks, and providing the know-how and thus, enhancing their impact. This program organizes regional events, where experts and participants from Latin American countries have the opportunity to exchange ideas and experiences.

The global economy and society faces enormous ecological challenges. There is a need to react to climate change and the shortage of resources, as well as to the growing demand for energy, especially in emerging countries. Over the past years, KAS has already embraced these issues; however, the enormous importance and the urgency to react to these demands, led to the establishment of EKLA-KAS, which has the ability to concentrate exclusively on these subjects.

The Latin American region is ideal for the implementation of environmental projects due to the abundance of green energy sources such as sun, water, geothermal energy, wind, and biomass. To explore and develop this potential will help Latin America to satisfy its growing energy demand. In order to exploit the full ecologic potential of the continent, it is necessary to understand the current situation of its public policies. Hence, KAS supports this study, organized in cooperation with our partner, the **Electricity Sector Study Group (GESEL, in its Portuguese version) of the Institute of Economics of the Federal University of Rio de Janeiro (IE/UFRJ)**, aiming to facilitate the access to international experiences and best practices. Within the framework of this Project, an international workshop was organized in Rio de Janeiro, Brazil, in which energy experts debated the decentralization of electrical systems, impacts in the micro generation of electric network, and its economic-financial consequences for distributors.

We hope that this book will contribute to the process of further increasing electrical integration in the region, based on renewable sources. It is believed that this is a strategy that will bring security for the transition to a low-carbon energy mix, allowing mitigating climate change, while promoting sustainable social and economic development. The main goal is to offer subsidies and proposals for the authorities responsible for energy policies and for the members of the legislative branch, to formulate and implement public policies, regarding distributed energy generation. We would like to thank GESEL for their partnership, as well as all the researchers and authors who contributed to this publication. We wish you all a pleasant reading!

Foreword

Mauricio Tolmasquim
Full Professor of Energy Planning Program - PPE/COPPE/UFRJ

In 1876, Alexander Graham Bell spoke a few words to his assistant, who was listening in another room of the same device. 100 years later, on April 3, 1973, Martin Cooper, a senior engineer at Motorola, called a rival telecommunications company and informed them he was speaking via a mobile phone. Less than 30 years later, a Japanese firm released the first smartphones to achieve mass adoption. Since then, the population is using their phones for a variety of nontraditional phone activities, such as shopping, looking for a job, reading a book, accessing the banking account, and even to socialize with others.

As in the case of the communication sector, the electricity system is also in the middle of a transformation, thanks to technological disruptions. As the World Economic Forum has pointed out, there are clear indications that a broad global technological revolution has started, combining electrification, distributed energy resources and digitalization.

This technological disruption is occurring faster than in the communication sector. The adoption rate of these grid edge technologies is likely to follow the typical S-curve seen with previous technologies such as cell phones, TVs, and the internet. However, the time to reach the point of mass adoption has decreased to about 15 to 20 years.

For more than a century, most industrial, commercial and residential customers have plugged into energy sources that were centralized. Over the past decade, however, a shift has begun to occur. Many customers have taken advantage of the declining costs in distributed technologies for generating electricity and, in the future, storing electricity will also be economically viable.

Two good examples are the dramatic declines in the costs of photovoltaic systems and in batteries for vehicles and for stationary use. While the cost of solar panels has dropped almost unbelievably and the performance has been improving, the global panel installed capacity skyrocketed.

At the same time digital technologies increasingly allow devices across the grid to communicate and provide data useful for customers and for grid management and operation. Internet of the things, sensors and smart meters allows objects to be sensed or controlled remotely across existing network infrastructure, and creates opportunities for more direct integration of the physical world into computer-based systems and empowering the consumer.

Additionally, the rise of grid-edge technologies will enable customers to take the center stage of the electricity system. Under the right price signals and market design, customers will be able to produce their own electricity, store it and then consume it at a cheaper time or sell it. In the new energy reality, the consumer will have a key role in balancing the power system, facilitating the introduction of intermittent renewable energy in the system. Changes in behavior can have the effect of flattening peak loads, thus reducing the need for expensive, carbon-polluting peaking plants and network reinforcements.

The new technologies will transform the power grid from a one-way to a two-way system and the consumer from a passive to an active player. However, while the technological change is taking place rapidly, the required utility transformation and policy and institutional arrangements are evolving much more slowly.

Policy-makers will have to redesign the regulatory paradigm. They have to adapt the network revenue regulation model and tariffs. The price signal is fundamental to indicate when to consume. They have to take into account both utility and distributed energy resources to plan the power system. Policies and legislation should create a framework where consumers have incentive to increase their flexibility in energy consumption.

On the other hand, facing declining revenue as customers consume less and produce more of their own power, utilities are dealing with potential stranded assets. This means that the utilities will have to acknowledge the new reality of a digital consumer-empowered by embracing new business models.

The incumbent utility has to adapt. The range of possible services goes beyond what the utilities currently provide.

To manage this, utility executives need to understand how to integrate Distributed Energy Resources into the increasingly digital power grid. For utilities, successfully navigating the integration of these resources will require a well-measured approach to understand the impact of Distributed Energy Resources on the system, reinforcing the grid to accommodate and take advantage of the electricity that DERs can supply, and investigating growth opportunities originated from the popularity of distributed energy.

If utilities are not proactive, then they will be bypassed in favor of third-party energy providers. The age of passive consumers and old-fashioned utilities is over.

Contents

Introduction

Historically, electric power systems were developed based on centralized generation with transmission and distribution networks transporting energy to consumers. Therefore, it is observed that energy flows have a unidirectional trajectory. It is a standard that can be defined as "generation follows the electric charge".

Generally, this remains as the current operational paradigm. Within this logic, distribution concessionaires traditionally operate their networks passively. Basically, the distribution activities consist of planning the expansion of the network with load forecasting, making investments, and performing network maintenance procedures. Since the network operation is carried out in a passive way, there is no network operator function as is the case with the transmission segment. It is the paradigm known as fit-and-forget.

In recent years, the need to mitigate climate change has become a high priority of the contemporary international political agenda. With a share of fossil fuel (oil, gas, coal) exceeding 80% in its matrix, the energy sector accounts for more than 50% of global greenhouse gas emissions. Therefore, it is noticeable that the reduction of greenhouse gas emissions is directly related to the decarbonization of the energy sector through the constant search for energy efficiency gains and a greater use of renewable sources.

Due to its natural potentialities, of all sectors the electricity sector has the most favorable conditions for the diffusion of renewable sources. In this sense, it should be noted that many countries, especially the most developed ones, are making massive investments in renewable energy sources in the electric sector.

There has been an exponential expansion of energy generated by wind, which by the end of 2016 already had a global installed capacity of 486 GW, while in the year of 2000 this capacity was only 17 GW. The diffusion of wind power has been accompanied by significant reductions in the cost of technology. Between 2000 and 2016 there was a 25% reduction in the cost of investment in wind power plants – currently it is approximately US$ 2,000/kW installed. In general terms, it can be said that technological innovations and the gain of scale in the industry are increasing the competitiveness of wind power in relation to conventional sources.

More recently, there is an analogous process in the field of photovoltaic solar generation, which already has an installed capacity of more than 303 GW. This diffusion of solar photovoltaic generation is the result of the combination of incentive policies with a drastic reduction of the technology costs. From 2010 to 2015 the decrease in the cost of a photovoltaic system was of 65%.

Due to its modularity, solar photovoltaic generation can be installed in small systems in residential and commercial consumer units. These micro-generation systems enable energy consumers to also be producers, creating the concept of "prosumers".

This is an ongoing phenomenon in several develop countries. For example, in Italy microgeneration systems already account for 5% of total electricity consumption, while in Germany this share is 5,7%. The same trend can be seen in some regions of the USA. In California and Hawaii, the share of solar photovoltaic microgeneration in total consumption is respectively 3,2% and 6,1%.

From the perspective of the consumer, the attractiveness of the investment in a photovoltaic system is a function not only of the cost of the system, but also of the value of the electric energy tariffs. Therefore, the analysis is based on the comparison between the tariffs paid to energy distribution concessionaires vis a vis the cost of its own power generation.

The exponential growth of distributed generation systems in some regions is the most emblematic sign of a trend towards decentralization of electric systems. In a broader analysis, the diffusion of distributed energy resources (microgeneration, storage, demand response, electric vehicles) and equipped networks with a high level of automation and smart metering are also prospected. In this context, consumers will be more active in managing their demands and, at the same time, they will be injecting energy into the network. To deal with this new paradigm, distributors will have to effectively become network operators.

In addition to environmental benefits, it is recognized that the diffusion of photovoltaic solar generation has systemic benefits, both energetic and electric. However, it is necessary to be aware that there are also costs and risks. It is also necessary to consistently address the allocation of benefits, costs and risks among different agents in the electricity sector so that the insertion of solar generation in the Brazilian electricity system occurs consistently and sustainably.

However, it is well known that consumers units equipped with photovoltaic systems still need to be connected to the distribution network. This is not merely a need for backup. These consumers will effectively be supplied by the distribution network during most of the day. There is lack of perfect adherence between the generation of a photovoltaic system and the consumption of energy throughout the day. For that reason, the distribution network will assume the role of a "virtual battery" of photovoltaic systems. In this way, it can be said that the obligations of a distribution concessionaire in terms of the availability of a reliable network will not change significantly.

Although the distributor's duties tend stay unchanged, the same does not happen with their revenues. Considering that the tariff structure of the distribution sector is mostly volumetric and, as consequence, the revenues of a distribution concessionaire are directly related to the volume of energy delivered to consumers, the reduction of its energy market, related to the diffusion of distributed solar photovoltaic generation, may result in significant financial economic imbalances as the diffusion reaches significant levels. These impacts are especially severe in cases where the net metering compensation system and the regulatory guidelines do not provide mechanisms of protection to the distributor in relation to market risk. In any case, these imbalances must be considered during the distributor's tariff review. However, the process of tariff repositioning will be towards an increase in the level of tariffs, as to guarantee a volume of revenues that allows the economic and financial equilibrium of the distributor in a context of market reduction. Thus, it is clear that this process will be harmful to consumers who do not have photovoltaic systems.

The increase in tariffs has two effects. On one hand, it encourages new consumers to adopt photovoltaic systems. This effect ends up feeding back the process. On the other, consumers without financial conditions to install photovoltaic systems will end up having higher expenditures on the consumption of electricity. Therefore, consumers that do not have photovoltaic systems will be subsidizing consumers with such systems.

It should be noted that this discussion is already present in regions where distributed solar photovoltaic generation has already reached considerable levels of penetration. The establishment of capacity ceilings and/or mandatory payments of specific fees for the use of the network by consumers bearers of photovoltaic systems are already regulatory directives. Countries such as Italy, Portugal, Belgium, as well as the states of California, Nevada and Hawaii in the USA are perfect examples of measures in this direction.

The smart grid and distributed generation nexus

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Abstract

The transition towards a more decentralised electricity system, in which distributed generation is integrated at the distribution level, challenges the traditional electricity infrastructure value chain. The deployment of smart grids has been proposed as a pathway for successfully integrating and managing these variable distributed energy sources. This chapter explores the reinforcing relationship between smart grids and distributed generation. We provide key concepts of both smart grids and distributed generation. Furthermore, technical, regulatory, and economic challenges are described. Future development trajectories, investments, and research and innovation plans are discussed in the wider context of the energy transition in the United States and the European Union. As a result, this chapter emphasizes how smart grids and distributed generation can contribute to a future electricity sector that is more integrated, cost-effective, and cleaner. Supporting the diffusion of distributed generation vis-à-vis the electricity system infrastructure and vice-versa, can facilitate an energy transition that prepares society for future needs, while ensuring that present costs and quality of service are not disproportionally compromised.

1. Introduction

Global concerns with climate change impacts on our ability to sustain modern society living standards in a context of dwindling natural resources have contributed significantly to push for a transition towards sustainable energy systems. In this context climate and energy policies have been designed, implemented, evaluated and consequently redesigned, with the goal to reduce our anthropogenic greenhouse gas emissions, for which the electricity sector contributes to a large extent. The implemented policies, combined with technological innovation, are increasingly changing how electricity is generated, distributed, and consumed. These emerging electricity sector dynamics can be observed as the evolution towards smarter and more sustainable electricity systems. More sustainable due to the growth in the share of renewable energy, with emphasis on the role of distributed generation. Smarter given the integration of monitoring, automation, and control technologies that facilitate the collection and use of data for a more efficient use of resources. Drivers for this changes include (Järventausta et al., 2010):

- Increased penetration of distributed generation, mostly renewable, such as wind and solar photovoltaic;
- The ambition for market integration in the European Union and North America, considering high shares of renewable energy on their generation mix;
- The increased importance of pursuing energy efficiency and demand response actions;
- Increased power quality expectations, driven by consumer demand and regulatory actions;
- Economic incentives for better utilization of the electricity infrastructure, which are expected to go beyond investments into passive distribution assets;
- Aging electricity distribution infrastructure, requiring a renewal that is in line with the changes in electricity usage patterns;
- Regulators and implemented regulatory frameworks will increase efficiency demands, challenging electricity distribution business profitability, resulting in adaptation needs for both the long-term and short-term in terms of network management; and
- Growing risk for system disturbances, due to climate change, and societal dependence on electricity.

In this chapter, we focus on the energy transition in electricity distribution networks with an emphasis on the smart grid and distributed generation nexus. We explore key concepts pertaining to both smart grids and distributed generation. Furthermore, technical, regulatory, and economic challenges are described. Future development trajectories, investments, and research and innovation plans are discussed in the wider context of the energy transition.

2. Concepts and background

The use of concepts related with smart grids and distributed generation has increased, alongside efforts to promote an energy transition. In this section, we present key concepts, definitions and background information for a better understanding of the relationship between smart grids and distributed generation.

2.1. Smart grids

The shift from traditional electricity distribution systems, designed around unidirectional electricity flows, distributing electricity from high voltage transmission lines to end-users, to a system that supports flexibility, bi-directional electricity flows, and enables the integration of innovative energy sources as well as information and communication technologies encompasses the evolution toward smart grids. The International Energy Agency in its Smart Grids Technology Roadmap defines smart grids as:

> "[…] an electricity network that uses digital and other advanced technologies to monitor and manage the transport of electricity from all generation sources to meet the varying electricity demands of end-users. Smart grids co-ordinate the needs and capabilities of all generators, grid operators, end-users and electricity market stakeholders to operate all parts of the system as efficiently as possible, minimising costs and environmental impacts while maximising system reliability, resilience and stability." (IEA, 2011)

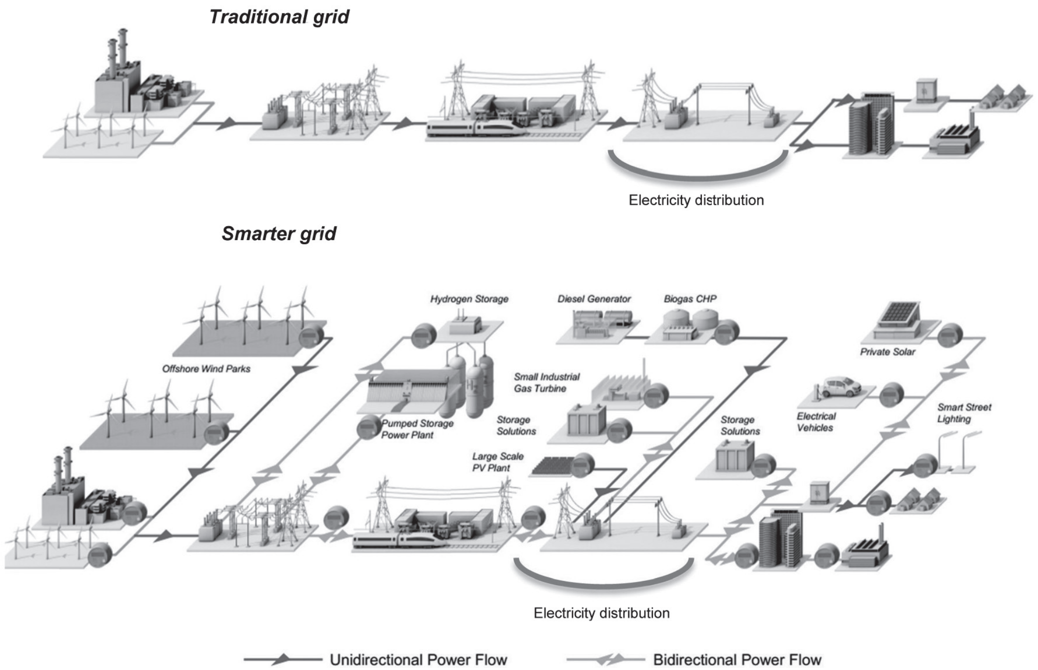
In a smarter distribution grid, digital and advanced technologies contribute to increase the monitoring and control capabilities of connected technologies, which include decentralised renewable electricity sources, electricity storage, electric vehicles and their charging infrastructure, smarter appliances, and demand response technologies. Moreover, advanced metering infrastructure enable remote data collection and create opportunities for increasing awareness on consumers electricity usage. The combination of the electricity infrastructure, with a layer of information and communication technologies aims to increase distribution system capabilities to handle the growth on distributed loads connected to the distribution infrastructure. Smart grids facilitate the diffusion of distributed renewable electricity generation by supporting the integration of end-user side generation from PV, wind, and small scale combined heat and power, complementing the role of conventional centralised power sources (IEA, 2011; IRENA, 2015). Smart grids will result both from the modernisation of existing systems, which will have to adapt given changes in electricity uses, as well as from the implementation of new systems that are designed for smart grid operations. Smart grids represent a transition toward new technologies, business processes, and distribution system operational management. Table 1 provides a perspective on the main differences between traditional grids and smarter electricity distribution grids.

Table 1. Traditional grid and smarter electricity distribution grid characteristics

Characteristics	Traditional grids	Smarter grids
Connected consumers participation	Consumers have limited access to information and are passive users of electricity, with a consumption-only role.	Consumers are involved and participate through demand response initiatives and by connecting distributed energy resources to the grid.
Distributed generation and storage integration	System designed for large central power plants, with significant barriers for the uptake of distributed generation.	Distributed energy resources, such as small-scale PV, wind, and micro CHP can easily be integrated into the grid, supporting the growth of renewable energy participation.
Enables business model, product, and market design innovation	Limited business models and market structures, resulting in limited opportunities for consumers to participate in electricity markets.	Well integrated electricity markets are adapted to allow for consumer participation, by creating market opportunities for demand response and distributed generation.
Supports the transition to a digital economy	System operation focused on outages reduction, characterised by slow response to quality of service issues.	Power quality becomes a priority, enabled by a layer of digital technologies, which contribute to faster response times and increased customer service quality.
Asset optimization and operational efficiency	Business processes have limited access to operational analytics.	Increased access to data and analytics contributes to fault prevention and minimises outages.
Self-healing capabilities	Focus on minimising damages after faults are detected.	Monitoring and control technologies contribute to automatic detection of issues, contributing to fault prevention.
Infrastructure resiliency	System is vulnerable to external attacks and natural disasters.	Resilient to attacks and natural disasters due to system restoration capabilities.

Source: US DOE (2008)

Smarter distribution grids are a key enabler for distributed generation integration (US DOE, 2009). The combination of smarter grid technology with increasing shares of distributed generation allows for more effective consumer demand management, as well as management of intermittent renewable electricity sources. The ability to integrate distributed generation in distribution networks has an impact on electricity sector stakeholders, namely: connected consumers, public utility commissions and regulators, as well as third party developers (US DOE, 2009). The changes for electricity sector stakeholders can be illustrated by considering the changes across the electricity value chain in a smarter grid context. Shifting from a unidirectional flow focused system, to a bi-directional electricity flow, ICT enabled framework creates new possibilities for existing system operations, standards, technologies, policies, and overall market design. Figure 1 represents the main changes between these two paradigms, while the electricity distribution activities under a traditional system operation are dedicated to ensuring electricity delivery, the situation under a smarter grid system operation incorporates new sources of power both at the distribution and at the consumer level.



Source: Geisler (2013)
Figure 1. Electricity system changes under smart grids

While the transition to smart grids is often policy-driven, as part of climate and energy policy packages, its delivery depends on the diffusion of technologies at the distribution level that enable new operational and asset management procedures from network operators. One of the first investments often pushed forward to enable smart grids is related to the metering infrastructure. A grid reliant on electromechanical or advanced meter reading hinders smart capabilities, as these two types of meters are only one-way communication based devices. Therefore evolving to an advanced metering infrastructure becomes relevant, to support two-way communication between distribution network system operators and connected grid users. This change gives distribution utilities the capability to be more active in system management, supporting load management, and improved quality of service (Farhangi, 2010).

According to IEA (2011) to the increased control capabilities, implementing advanced metering infrastructure contributes to:

- Implementation of price signals to promote time-of-use tariffs;
- Ability to gather and store granular data on connected user's electricity consumption and production when behind the meter distributed generation exists;
- Development of more detailed and accurate load profiles;
- Better maintenance and outage management operations;
- Remote service connection and disconnection;
- Identification of non-technical losses, and theft detection and
- Better cash flow management through automated collection of consumers' data.

Considering the main concepts, characteristics, and framework in which smart grids are evolving it is important to emphasise that smart grids represent in most cases an evolution through upgrades on existing electricity distribution systems, rather than a replacement of existing infrastructure. Smarter distribution grids will be achieved through the implementation of new technologies, processes, business models, and development of necessary capabilities to operate in a more interconnected, and digital environment (Farhangi, 2010).

2.2. Distributed generation

Distributed generation technologies are a key component of the energy transition, given their potential to be closer to the end-use loads, and connected to lower voltage distribution networks. As an electricity source, distributed generators are complementary to large central power plants, allowing for new applications and contributing to an increasing community of consumers that also produce electricity. Remarkably, distributed generation technologies supplied most of the electricity needs in the late 1800s and early 1900s, before large centralised power systems were deployed. In the 1950s distributed generation accounted to 10%, mostly used as a back-up source or in transportation, while in 2010 it accounted for 36% of power capacity additions (Pepermans et al., 2005; Owens, 2014).

The concept of distributed generation has often been loosely defined and associated with the idea of small-scale electricity generation (Pepermans et al., 2005). Additional characteristics include its installation close to the point of consumption, flexibility in terms of installation and network connection, and intermittency associated with the availability of the primary energy resource used for generation, in which case solar and wind are highly intermittent (Dulău, Abrudean, & Bică, 2014). The European Commission Joint Research Centre proposes the following definition:

> "Distributed generation is an electric power source, connected to the grid at distribution level voltages, serving a customer on-site or providing support to a distribution network." (L'Abbate et al., 2007)

This definition considers distributed generation in the context of its goal and installation location, capacity and voltage, and the area to which it delivers power. In terms of goal, distributed electricity generation units are deployed as a source of electric power, much like what is expected from large power plants. Regarding location, distributed generation is expected to be located close to where consumption occurs, and connected to the electricity distribution network, or on the consumer side of the meter, being in that case a behind-the-meter source of power. Power delivery area is also relevant, while distributed generation is expected to be located and consumed locally, resulting excess generation has to be delivered to the distribution network, thus requiring due consideration for system capacity. System capacity for distributed generation is associated with small generating units; this capacity depends on the technology being used. Table 2 provides a summary of distributed generation technologies and associated capacities in a distributed generation environment.

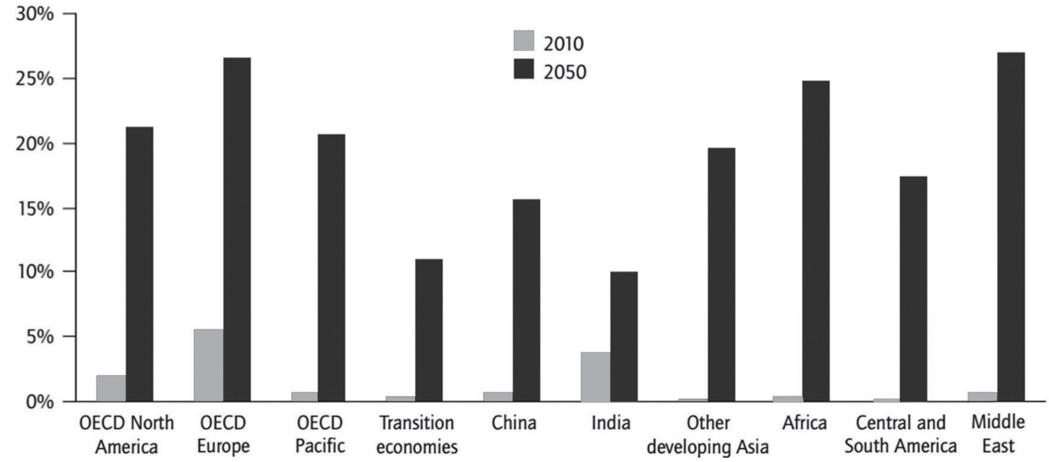
Table 2. Distributed generation technologies.

<table>
<tr><th>Distributed generation technology</th><th>Typical system capacity range</th><th>Fuel option</th></tr>
<tr><td>Reciprocating engines</td><td>20 kW – 20 MW</td><td>Diesel
Natural gas
Alternatives</td></tr>
<tr><td>Gas turbines</td><td>10 – 100 MW</td><td rowspan="2">Natural gas
Alternatives</td></tr>
<tr><td>Microturbines</td><td>30 – 250 kW</td></tr>
<tr><td>Fuel cells</td><td>5 kW – 5 MW</td><td>Hydrogen
Natural gas</td></tr>
</table>

Distributed generation technology	Typical system capacity range	Fuel option
Small hydro	1 – 100 MW	Renewable resource
Micro hydro	25 kW – 1 MW	
Solar PV	20 W – 100 kW	
Small wind	200 W – 3 MW	
Biomass gasification	100 kW – 20 MW	
Geothermal	5 – 100 MW	
Ocean energy	100 kW – 5 MW	

Source: (L'Abbate et al., 2007; Dulău et al., 2014; Owens, 2014)

The diffusion of distributed generation technologies, predominantly renewable sources such as PV and small wind, can impact electricity distribution network operations. Voltage profile changes can occur, resulting from the variations in electricity consumption and production, which differ from typical unidirectional networks. Power flows become progressively bi-directional, despite the overall goal of distributed generation being deployed for local consumption. Short circuits can occur more often, as well as load loss, and congestion in the system, all of which depend on generation and load levels. Moreover, power quality and service availability may be affected as more distributed generation plants are connected to the network (L'Abbate et al., 2007; Dulău et al., 2014). On the other hand, there are various benefits that must be considered. Being close to loads enables a better use of local energy sources, which results in access to low cost electricity for consumers connected to renewable electricity distributed generation. The growth on the share of renewable distributed generation contributes for fossil fuel consumption reduction, resulting in lower greenhouse gas emissions, thus benefiting the environment. Construction of distributed generation plants represents fewer burdens related to authorisation and permits when compared to large power plants, thus resulting in faster access to electricity. A higher number of distributed generation plants can result in congestion reduction upstream in the system, which can lead to investment deferral for higher voltage transmission lines. Besides, it can too contribute with ancillary services, leading to improved system security and service quality (L'Abbate et al., 2007). All things considered, distributed generation stands as a key enabler of emissions reduction on the scope of the energy transition, as well as a driver for increased energy security by contributing to fuel import reduction. Diffusion is expected to increase across regions as illustrated in Figure 2, which shows the levels of variable renewable electricity generation in 2010, as well as the projection for 2050. Distributed renewable electricity generation is a variable electricity source, given its dependence on climatic conditions, meaning that there is no possibility to guarantee that it will generate power at a certain time. Sources with this characteristic include wind, photovoltaic, small hydro, and tidal technologies (IEA, 2011).



Source: (IEA, 2011)
Figure 2. Variable renewable generation by region

The expected growth on distributed variable renewable generation further emphasises the relevance of deploying smart grids. Electricity distribution systems with distributed generation representing over 15% to 20% of total electricity generation capacity will experience significant operational complexities in a traditional network management approach. Smart grids can contribute to easing these difficulties by supporting control of variable generation, enabled through access to real-time data that supports system management, power and overall service quality and system flexibility (IEA, 2011; Buccella et al., 2014).

3. Integration and adoption challenges

3.1. System integration

The integration of distributed generation units into distribution grids impacts system operation. As most electric systems where not designed for high shares of distributed generation being interconnected, these may face additional challenges. However, as smart grids are deployed, these impacts will become part of normal business operations for distribution network companies. Different aspects lead to system impacts, including: the size of the distributed generation unit, the type of technology, the location and point of interconnection, to name a few (Basso, 2009). System impacts can manifest locally at the interconnection level and local distribution system, or span across the network to other areas, these impacts usually increase as the share of distributed generation expands. System impacts can be classified into (Basso, 2009):

- System protection and coordination;
- Unplanned island;
- Voltage related;
- Service quality and
- System capacity

The following sections present the main characteristics of the identified system impacts.

3.1.1. System protection and coordination impacts

Distribution system protection is essential for system operation, as well as to secure safety and quality. Safety devices are distributed through the electricity distribution system, including: feeder breakers at substations, line reclosers, and fuses. The integration of distributed generation calls for a reassessment of the system protection practices and devices installed for this purpose (Pepermans et al., 2005; L'Abbate et al., 2007; Basso, 2009; Martinez & Martin-Arnedo, 2009).

3.1.2. Unplanned island impacts

An unplanned distribution system island occurs when part of the system becomes separated from the rest, but the connected distributed generation units continue to deliver electricity to the islanded section to which they are connected. This type of impact can result in safety and quality issues. Furthermore, unplanned islands can put distribution utility workers at risk, if maintenance works are being conducted at the unplanned island location. Moreover, Basso (2009) argues that beyond personnel safety, an island can lead to equipment damage and increase outage time.

3.1.2. Voltage related impacts

Regulating voltage is an important part of electricity distribution system operations, as it is both a measure of quality of service, as well as a prerequisite for the adequate operation of local appliances, lights, and consumer electric powered devices. Given the importance of voltage regulation, distribution systems are equipped with voltage regulation devices to keep voltage as the required ranges. However, these technologies were designed for a unidirectional power flow system, which will require changes for system areas with reverse power flows originating from the increase in distributed generation (Azmy & Erlich, 2005; Basso, 2009; Ruiz-Romero et al., 2014).

3.1.4. Service quality

The impact of distributed generation for power quality becomes a concern in systems where contributions exceed 15%. For these cases the impacts include harmonics, direct current injection, and flickers (Pepermans et al., 2005; Basso, 2009; APPA, 2013). These impacts require the implementation of modern electronic devices to mitigate service quality disturbances (L'Abbate et al., 2007).

3.1.5. System capacity

The existence of distribution network capacity to handle distributed generation related power flows is an important aspect for successful system integration. Generally, constrains exist across distribution network segments on the level of distributed generation that can be interconnected without compromising operations. However, if distributed generation capacity and location is planned adequately, a higher number of interconnections should lead to congestion reduction. In any case it is important to study available system capacity (L'Abbate et al., 2007).

3.2. Economic and regulatory

The system impacts presented above are often connected with the economic and regulatory framework in which electricity distribution systems operate, which enhances the difficulties for integrating distributed generation. Distribution systems operate as regulated monopolies, to guarantee fair prices for access to the infrastructure, non-discriminatory access to the network, as well as high quality service and reliability standards (Scheepers et al., 2007).

Given their regulated activities, and the resulting constrains, economic challenges are often tied with regulatory barriers, which include:

- Lack of incentives for integration;
- Interconnection costs;
- Market access and
- Bureaucratic barriers for interconnection.

The following sections present the main characteristics of the recognized trials.

3.2.1. Lack of incentives for integration

The integration of distributed generation requires upgrades in the systems as well as in system management processes and operations. As regulated natural monopolies, electricity distribution companies can have limited incentives for investing in integration of distributed generation, as it can result in reductions on their efficiency indexes and consequently impact their financial performance.

3.2.2. Interconnection costs

Depending on the region, interconnection cost can result in negative signals for distributed generation diffusion. This can often occur in countries where national legislation has not yet been reformed for small-scale generation units to be connected to distribution networks.

3.2.3. Market access

Market access for small-scale distributed generators can be defiant in markets with high concentration, or where larger players have significant economies of scale, thus creating significant barriers for distributed generators to compete. Moreover, spot market trading fees are considerably high for small-scale generators.

3.2.4. Bureaucratic barriers for interconnection

Access to distribution networks for distributed generation interconnection can be challenging depending on national laws and existing processes for obtaining authorization. As interconnection procedures have been designed for larger power generators, existing bureaucracies have to be adapted to enable interconnection for small-scale distributed generators, at fair costs.

Table 3 summarises the main barriers for the diffusion of distributed generation, considering system, economic and regulatory impacts.

Table 3. Economic and regulatory barriers

Barrier type	Resulting consequences
Interconnection costs	High network access fees Discrimination for network access Lack of transparency in interconnection procedures
Distribution network constraints	Limited network capacity Extended delay for interconnection Maintenance costs Balancing costs
Network access bureaucracies	Complex authorisation procedures for interconnection
Lack of incentives for distribution system operators	Lack of capacity to invest in distributed generation integration Regulatory framework does not consider distributed generation related investments
Market access	Lack of transparency on market access procedures Disproportionately high spot market trading fees
Entry barriers	Established incumbents with strong market shares Difficult access to wholesale markets Lack of adapted mechanisms for distributed generation trading in the market
Benefits of distributed generation	Lack of understanding on associated benefits Uncertainty on the role of support mechanism Lack of rewards for integrating distributed generation

Source: (Scheepers et al., 2007)

3.3. Financial issues

Beyond distribution system related difficulties, those investing in distributed generation technologies, the owners, face also burdens associated with financing the investments for generation technologies. These include, according to the California Public Utilities Commission (2013):

- Financial incentives;
- Access to financing;
- Technology costs and
- Soft costs.

The following sections present their main characteristics.

3.3.1. Financial incentives

Financial incentives to support the diffusion of distributed generation technologies have been implemented across regions, due to the high upfront investment required, that otherwise would result in slow deployment rates. However, as technologies mature and their costs become closer to that of traditional electricity supply, the incentives start to become less attractive from a financial perspective. This transition from an incentive based policy framework to a market-driven framework can result in a slowdown in diffusion rates, and increase financing difficulties for those interested in a distributed generation installation (Rugthaicharoencheep & Auchariyamet, 2012; California Public Utilities Commission, 2013).

3.3.2. Access to financing

Financing instruments to support investment are critical to support distributed generation. The necessary technology requires a large investment upfront, which in the case of renewable distributed generation is mostly the only cost, apart from relatively smaller operation and maintenance expenditures throughout the lifetime of the system. The initial investment requirement can therefore act as a barrier for interested consumers. This issue can be overcome through the development of financing options tailored for distributed generation.

3.3.3. Technology costs

Equipment and technology costs are the main component of the investment necessary in a distributed generation installation, while incentives and financing instruments can contribute to offsetting part of the investment burden; this cost is still a barrier for diffusion. As adoption increases, and economies of scale at production are achieved the cost of the technology will further increase, which can contribute to reduce this hurdle.

3.3.4. Soft costs

Installing a distributed generation system encompasses a range of intangible costs. Soft costs in distributed generation installations include: permitting fees, to cover the process to obtain authorisation to install and connect the generation unit to the electricity distribution system; administrative costs, to cover all the aspects related with technology acquisition, application to incentive schemes, and other bureaucracies; financing and contract related costs; engineering and installation costs; grid connection fees, government taxes; and any other costs associated with the entire project from when the decision to install distributed generation is made until the unit goes online. These costs represent a significant barrier, and one that is often hard to forecast in the planning stage, as some of these are context specific and can vary across locations, given differences in local policies and regulations, as well as the maturity of the market where the distributed generation unit is being installed.

The described distributed generation obstacles provide a wide-ranging perspective on the areas where difficulties often arise, thus hindering its diffusion. However, the existence of system integration, economic and regulatory, and financial related barriers indicate also the possibilities for innovation and improvement in terms of technologies, business models and operational processes, policies, and overall market design.

4. Innovation and development

The potential benefits associated with the proliferation of distributed generation continue to motivate efforts to overcome existing diffusion challenges, some of which were discussed on the previous section. In this context, research and development (R&D) plays an important role driving innovation and progress to reduce barriers and increase integration. This section describes examples of R&D efforts in the United States and in the European Union, with an overview on their focus areas for development, roadmaps and allocated investments for innovation and development.

4.1. The United States Recovery Act Smart Grids Programs

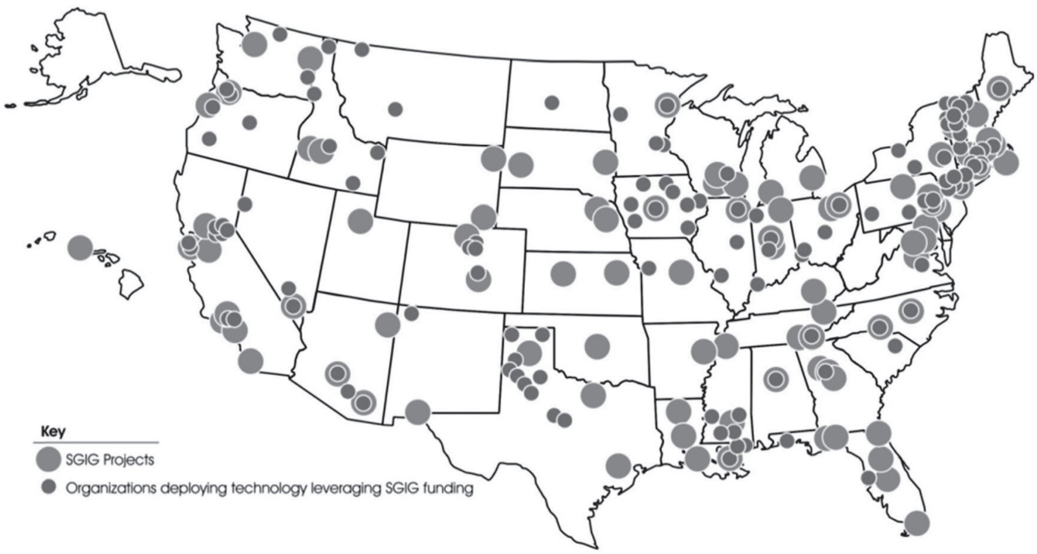
The US Recovery Act Smart Grid Programs enacted in 2009 as part of the post-crisis American Recovery and Reinvestment Act, included a total of 4.5 Billion US Dollars to support grid modernisation (US DOE, 2013). The program introduced two initiatives focusing on smart grids:

- The Smart Grid Investment Grant (SGIG), designed to support the deployment of available smart grid components to improve electricity system performance and
- The Smart Grid Demonstration Program (SGDP), designed for the evaluation of possible future applications for advancing grid operations, and integration of new distributed energy sources.

Moreover, programs focusing on workforce training for the future electric sector, cyber security, and renewable and distributed systems integration were also developed. These initiatives where assigned to the US Department of Energy Office of Electricity Delivery and Energy Reliability (US DOE, 2017c). Next, we describe the SGIG program in more detail, as the recipient of the largest share of the Recovery Act Smart Grids budget.

4.1.1. The Smart Grid Investment Grant (SGIG)

The SGIG aimed to contribute to the modernisation of the US electricity system. The program supported projects proposed by electricity providers. The areas of development targeted smart grid technologies and processes, flexibility capabilities development, interoperability, functionality, cyber security, situational awareness and operational efficiency (US DOE, 2017). This program received a budget of 3.4 Billion US Dollars, which were matched by 4.4 Billion US Dollars in private funds. Through this initiative 99 projects were supported, engaging 228 electric utilities and other stakeholders, as illustrated in Figure 3.



Source: US DOE (2013)
Figure 3. Supported projects and involved organisations.

For electricity distribution, the initiatives supported in this programme targeted the installation of systems for improved operations, including outage management technologies, voltage control devices, voltage regulators and sensors. The integration of these technologies gives network operators technical capabilities for fault detection, power flow control, and preventive maintenance, and overall increase of service quality and reliability (US DOE, 2013). Table 4 presents the investments on electric distribution automation equipment, and on distributed energy resource related technologies.

Table 4. Electricity distribution automation investments under SGIG

Electric Distribution Automation Assets	Investment
Automated feeder switches	$450,777,312
Automated capacitors	$121,911,889
Automated regulators	$18,480,004
Fault current limiter	$217,260
Feeder monitors	$101,533,161
Substation monitor	$118,513,082
Distribution automation/Substation communication networks	$526,743,581
Distribution management systems	$331,142,712
IT hardware, systems, and applications that enable distribution functionalities	$137,002,266
Other electric distribution automation related costs	$296,590,009
Total	**$2,102,911,277**
Electric Distribution Distributed Energy Resource (DER) Assets	**Investment**
Stationary electricity and energy storage devices	$3,285,403
EV charging stations	$5,536,573
Other DER related costs	$6,661,234
Total	**$15,483,210**

Source: US DOE (2017)

This five-year programme, implemented in 2009 through 2013, achieved progress on system reliability, reduction of operational costs through increased efficiency, shorter and less frequent outages, improved revenue streams, and to job creation for the participating entities. The SGIG framework contributed to smart grids innovation by developing capabilities, knowledge, and supporting experimentation in the following areas (US DOE, 2013, 2017):

- Participation of consumers in retail and wholesale electricity markets;
- Accommodation of centralised and distributed electricity generation sources;
- Integration of electricity storage;
- Supporting the development of innovative electricity products and services, as well as market designs;
- Ensuring power quality standards for different distribution system users and
- Increased optimisation of asset management and utilization, and efficiency performance.

This program reflects the added value of government and private sector joint actions to deliver a smarter, more distributed electricity sector for the United States. The focus of the program on distribution system automation technologies, and distributed energy resources innovations further reinforces the close connection of smart grids and distributed generation. The program described is an example of the efforts undertaken by the US Department of Energy on grid modernisation and electricity system transformation (US DOE, 2017b).

4.2. The European Electricity Grid Initiative (EEGI)

The European Electricity Grid Initiative (EEGI) was created in 2010 by the European Commission to focus on innovative R&D to support the transition of the electricity sector (EC, 2017a). The innovation and development strategy for this program included the following goals:

- Transport and distribute 35% of electricity from distributed generation and concentrated renewable sources by 2020, and the achievement of a fully decarbonized electricity sector by 2050;
- Integrate national networks to deliver a pan-European electricity network infrastructure, contributing to quality of service and consumer engagement;
- Accommodate adjacent developments, such as the electrification of transportation and
- Increase efficiency of electric grid operations, by reducing capital and operational expenditures.

The EEGI R&D budget for the period from 2013 through 2022 consisted of 2.1 Billion Euros, of which 1.1 Billion Euros were allocated for electricity distribution networks development and innovation. Table 5 presents the functional objectives for development for this area.

Table 5. EEGI electricity distribution investment plan

Area	Functional objective	Investment
Integration of smart consumers	Active demand for increased flexibility	€140,000,000
	Energy efficiency from integration with smart homes	€100,000,000
Integration of distributed energy resources and new uses	Integration of distributed generation	€170,000,000
	Integration of electricity storage	€100,000,000
	Infrastructure to host electric vehicles	€60,000,000
Network operations	Modelling and control of Low Voltage network	€150,000,000
	Automation and control of Medium Voltage network	€100,000,000
	Network management tools	€50,000,000
	Smart metering data processing	€100,000,000

Area	Functional objective	Investment
Network planning and asset management	New planning approaches to smart grids	€50,000,000
	Asset management	€50,000,000
Market design	Novel approaches for market design analysis	€20,000,000
	Total	**€1,090,000,000**

Source: European Electricity Grid Initiative (2013a, 2013b)

The activities included in this roadmap aim to:

- Improve network planning for transmission and distribution systems to optimize infrastructure investment;
- Improve system coordination techniques contributing to system security;
- Demonstrate the benefits resulting from improved conversion efficiency, resulting in loss reduction through increased local use of locally produced electricity;
- Demonstrate the benefits of renewable electricity distributed generation integration;
- Reduce electricity grid's environmental impacts;
- Demonstrate capabilities for small scale load and generation aggregation;
- Improve interaction between distribution system operators and
- Experiment and improve electricity market designs.

The presented EEGI is also one example of a European Union level initiative on innovation and development for smart grids. For an overview of the general progress of the EU in smart grid innovation the European Union Joint Research Centre contributes to identifying the smart grid R&D and demonstration effort through its Smart Grid Observatory reports (Catalin et al., 2014; Gangale, Vasiljevska, Covrig, Mengolini, & Fulli, 2017). Figure 4 illustrates the distribution of the 540 ongoing and completed smart grid projects across Member States.

Source: EC (2017b)
Figure 4 European Union R&D smart grid projects.

Building on the structured approach of the EEGI the EU has expanded its efforts in line with ambitious goals to decarbonize the electricity sector. For this purpose the European Technology and Innovation Platform on Smart Networks for the Energy Transition was established in 2016 (ETIP SNET, 2016). This new entity aggregates the efforts for delivering the energy transition for electricity networks from the EEGI by driving efforts toward: a reliable, economic, and efficient smart grid; storage technologies and sector interface; flexible generation; digitalisation of the network infrastructure and consumer engagement; and innovation in the business environment (ETIP SNET, 2017).

This section provided a transatlantic overview on efforts for delivering smart grids, in the United Stated and the European Union. The programmes described, which are but an example of ongoing efforts for achieving transformation in the electricity sector, have a clear concern for improving distribution networks amidst the increasing penetration of distributed generation, and distributed energy resources in general. Moreover, it is important to consider how research and development progress can be planned and implemented with joint efforts from government, and private entities, bringing together the broader economic development and social welfare concerns from of policy makers, with the practical challenges and ambitions of private enterprises, universities, and research labs, that work on the development and implementation of solutions for the obstacles associated with a smarter and more sustainable electricity sector.

5. Conclusion

The implications of the energy transition for the electricity sector are manifold. Changes in technology, policies, and how stakeholders are organised, all contribute to a complex system through which adaptation must occur. Through this chapter we aimed to focus on the smart grid and distributed generation nexus, by focusing on the conceptual framework around these two domains, followed by an overview on the challenges for integrating distributed generation, and a last section on innovation and development as a driver for progress. By combining these different building blocks, the reinforcement cycle between smart grids and distributed generation diffusion become evident. We explained how the future of the electricity sector grids is planned to achieve a standard where monitoring, control and automation are used to increase operational efficiency and service quality. In parallel, distributed generation was presented as a clean source of power in an environmentally constrained world. The synergy between these two domains can contribute to a future electricity sector that is more integrated, cost-effective, and cleaner. Supporting the diffusion of distributed generation vis-à-vis the electricity system infrastructure and vice-versa, can contribute to an energy transition that prepares society for future needs, while ensuring that present costs and quality of service are not disproportionally compromised.

The complementarities between smart grids and distributed generation span beyond the domains explored in this chapter. Additional aspects to consider include: integrated energy policy making, and the development of support mechanisms and market designs; the regulatory reform of the network industry, considering the impacts of smart grid and distributed generation diffusion as well as changes on consumers behaviour, technology costs and diffusion; and network industries role in the energy transition; and business model innovation and electricity utilities transformation, by identifying adaptation capabilities and how these are influenced by market and organisational factors.

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Diffusion of Microgeneration: Potential Economic and Financial Impacts Over Brazilian Distribution Utilities

Francesco Tommasso

Abstract

Microgeneration, which constitutes a part of a wider category of Distributed Generation (GD), challenges the traditional design and operation of the electric sector. Electric sectors were developed around the world over the paradigm of centralized generation. The diffusion of distributed generation brings new challenges that are not restricted to the electro-technical field, but affects several stakeholders through imbalances in regulatory frameworks. The development and maintenance of regulatory mechanisms that allow the economic attractiveness of the service's provision, without concomitantly generating onus to the consumers presents a great challenge. The entry of a phenomenon such as the diffusion of distributed generation, which significantly alters the operational and economic relations of the sector as a whole, especially of the distribution service, can result in imbalances involving many agents, if regulatory mechanisms do not adapt. The aim of this chapter is to analyze these potential financial-economic imbalances, applying microeconomic theory. The results of such analysis point to the potentiality of two main imbalances: one of financial order, which acts upon the cash flow of the utilities; and another one on market stability, affecting the economic logic of the distribution service.

Introduction

Microgeneration, which constitutes a part of a wider category of Distributed Generation (GD), challenges the traditional design and operation of the electric sector. Electric sectors were developed around the world over the paradigm of centralized generation. The diffusion of distributed generation brings new challenges that are not restricted to the electro-technical field, but affects several stakeholders through imbalances in regulatory frameworks.

One of the most important regulatory imbalances caused by the diffusion of DG is related to the nexus between compensation schemes and rate structure. Several incentive schemes around the world are used to stimulate the diffusion of distributed generation, seen as a clean source of energy, capable of reducing electricity losses. Some of these incentive scheme are meant to be temporary, other have a longer span, passing through several marginal transformations, as for example, the price of the compensation.

In Brazil the compensation scheme, the *Net Metering,* has proved itself as capable of incentivize and boost DG systems diffusion, remunerating the energy exported to the grid at retail levels and turning the distribution utilities into "virtual" and extremely efficient electrical batteries. However, the rate structure for low-tension consumers in Brazil is not adequate for dealing with the Net Metering compensation scheme, since their interactions might cause several side effects, whose costs, it might be argued, could overcome the benefits.

The present chapter aims to analyze some of the potential impacts that the distributed generation, with emphasis in microgeneration, which is the more adopted modality by low-tension consumers, might cause to some of the stakeholders.

Distributed Generation in Brazil

The DG in Brazil is regulated by the Brazilian regulatory agency, ANEEL, through Normative Resolution 482 (REN 482). The Resolution defines the distributed generation modalities, which can be defined as: (i) microgeneration – systems with installed generation capacity up to 75 kWp; or (ii) minigeneration - systems with installed generation ranging from 75 kWp up to five MWp (ANEEL, 2012.a).

Consumers can either install micro or minigeneration systems physically close to their own load, as, for example, employing a photovoltaic system on the rooftop of their houses and commercial buildings, or install such systems remotely, generating energy credits in a place to be spend on another. Additionally it is possible to share a minigeneration systems with other consumers (ANEEL, 2012.a).

The compensation scheme employed by ANEEL is the *Net Metering*, which allows for the utilization of the energy credits up to five years after their generation. It is defined according to REN 482 in the following terms:

> *For the purpose of compensation, the active energy injected into the distribution system by the consumer unit will be transferred as a free loan to the distributor, with the consumer unit having a credit in quantity of active energy to be consumed for a period of 60 months* (ANEEL, 2012.a, p. 5).

As July of 2017, more than 15.500 DG systems were already installed in Brazil. More than 97% of the total number of installations is photovoltaic, representing more than 72% of all DG installed capacity. Most of these are microgeneration systems – the average size of the photovoltaic DG systems is eight kWp. ANEEL projects more than 880 thousand installations until 2024, representing 3.2 GWp of installed capacity. The number of installations represents around 0.35% of the total projected number of residences and commercial buildings combined (ANEEL, 2017).

The Electricity Distribution Utilities in Brazil

In Brazil, the electricity distribution service is classified as a public service whose execution is subject to delegation through permissions or concessions. The technical and economic characteristics of the distribution service render it as a natural monopoly. In face of the negative social effects that monopolies can cause, the electricity distribution is a concession ruled by regulation, including rates regulation (CARVALHO FILHO, 2009).

Distribution utilities incur in operational expenditures (OPEX) and capital expenditures (CAPEX) to be able to supply the service in accordance with regulatory supply conditions. Both, OPEX and CAPEX are subject to the regulator's focalization and approval. However, the mechanisms that regulate the expenditures depends on their nature.

OPEX is regulated through a variation of a *yardstick competition*, in which ANEEL creates "utilities groups" in accordance with their technical and economic characteristics, aiming at creating groups of similar utilities that would allow direct comparison and competition. These benchmarks, which are created with the use of top-down methodologies, employing econometrics and other data analysis, define maximum OPEX levels for each of the utilities, using metrics adapted for each one of the groups in accordance with their characteristics (ANEEL, 2017.d).

CAPEX is regulated in a discrete fashion, with all the new capital investments being subject to analysis and approval. Only those that are approved join the regulatory capital and assets base. Assets in this base are remunerated in accordance with capital costs, which are calculated with the utilization of the WACC[1] methodology. Those assets not included in this base end up as financial loss to the utility (ANEEL, 2015.a).

The Electricity Distribution Utilities Rates in Brazil

Still, the utilities' OPEX and CAPEX do not totalize the costs. The utilities also have to pay for the energy and for the service of transmission and distribution of other utilities, which have direct participation in the operation of supplying electricity for the utilities' consumers. The energy purchase for supplying of its market is a utility's obligation. The market risk, of differences between actual and projected electricity demand is a utility's risk. One last cost group is related to electricity losses, which can be technical and non-technical (theft, fraud etc.) (ANEEL, 2017).

The revenue's volume needed to remunerate the sum of both the utilities' OPEX, CAPEX, electric losses and third parties payments is called Required Revenue. The Required Revenue is divided in two parcels: Parcel A and Parcel B. The Parcel A is the amount of revenues aimed at remunerating the utility's non-manageable costs – those related to energy purchase, transmission of energy and payment of charges. The Parcel's B revenues are directed to the payment of the utility's manageable costs, such as its CAPEX and OPEX (ANEEL, 2017).

The rates are then defined considering the Required Revenue and the total electricity demand for a year period. The Equation 1 illustrates a simplified scheme for the rate definition:

$$Equation\,1: \text{Rate} = \frac{Required\ Revenue}{Total\ Market\ Demand}$$

The rates are adjusted after some pre-defined period. There are two adjustment mechanisms: (i) the Annual Rate Readjustment; and (ii) Periodic Rate Revision.

The Annual Rate Readjustment, as the name suggests, occurs annually and aims at correcting Parcel's B real value, using price other indexes, and recalculate energy costs. The Periodic Rate Revision is a deep, technical revision of all the costs, that usually

1 Weighted Average Cost of Capital - See Damodaran (2014)

happens every four years. The Periodic Rate Revision is not unique, and it might be separated by costs subcomponents (ANEEL, 2017).

Potential Impacts of the Distributed Generation Diffusion over Distribution Utilities

There are two main potential impacts that might originate from the DG diffusion and must be taken into account: (i) short term decrease in the utilities' cashflows; and (ii) instability of the economic logic of the distribution utilities service.

The first might be seen as a short-term impact, acting over annual utilities operations and cashflow. The second one has a long-term nature, leading to an unstable equilibrium in the utilities business model, affecting several other stakeholders, including other captive consumers connected to the utilities.

Potential Impact over Utilities' Cashflow

As seen above, distribution utilities in Brazil have their costs remunerated through revenues from the payment of the electricity rates. The distributions utilities' revenues from the low-tension consumers are function of their energy consumption and of the average electricity rates payments. Although the Required Revenue is the revenue level that allows the full remuneration of the utilities costs, its effective achievement depends on several factors, since the rate is determined in advance and the energy consumption level is only know with certainty afterwards. The Required Revenue can be written as a function of the rate defined in the last rate adjustment (Defined Rate) and the total demand of electricity for a given group of consumers in a certain period, the consumers group in the present analysis is the low-tension:

$$Equation\,2: Required\ Revenue = Defined\ Rate\ x\ Demand\ of\ Electricity$$

It must be noted that the Defined Rate is, according to current rate design, function of the current total costs (or Required Revenue) and total electricity demand of the last twelve months (Reference Market) (ANEEL, 2017.e, p.3). Considering the real value of the Defined Rates, in order to the above Equation 2 be attained it is necessary that the total electricity demand for the last twelve months be the same for the following twelve.

It is, of course, never the case, and what effectively happens is that the Required Revenue is either surpassed or stays higher than the actual revenue. In both cases it affects the distribution utilities cashflow on the short term, even if such a revenue gap is later compensated taking in consideration the opportunity cost of such divergences.

Therefore, during periods in which there is electricity demand growth the effective revenue is higher than the Required Revenue and the distribution utilities receive higher than expected cashflows in the short term. The opposite happens if there is a fall in the electricity demand, and the Required Revenue is not reached, resulting in lower short term cash flows than expected.

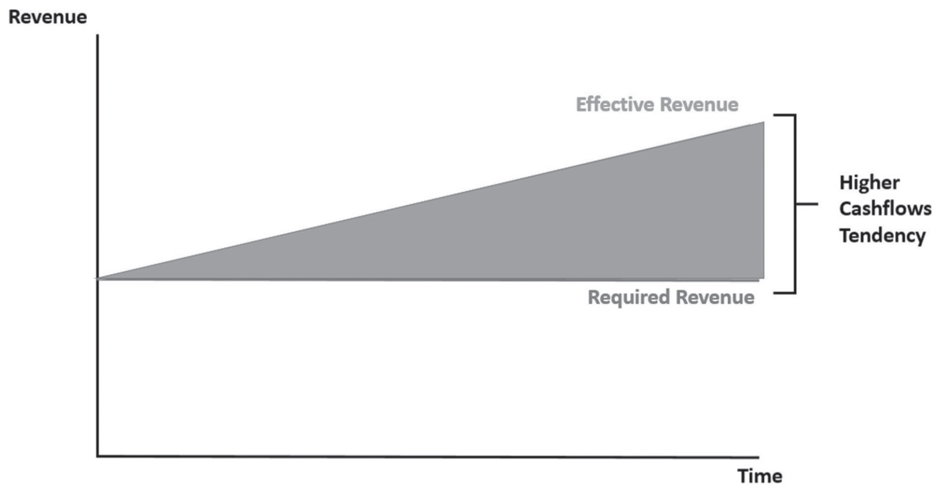
Observations of the *Ministério de Minas e Energia* (MME) annual electricity demand time series, considering a period that starts in 1970 and end in 2016, show that the compounded annual growth rate is 5.75%. The average yearly growth is 5.36%, with standard deviation of 3.9%. With the small exception of the four years, 2001, 2009, 2015 and 2016, all the other years presented electricity demand growth. It is possible to conclude that there is a tendency for the surpassing of the Required Revenue and higher short-term cashflows than expected.

However, the electricity demand is not the only variable that can show perturbation and present divergent values from those defined in Equation 2. Since there is inflation and the Defined Tariff is only corrected for inflation once a year, its real value decays daily and monthly, reaching its minimum right before the Annual Rate Readjustment. The loss of the rates real value implicates, *ceteris paribus*, in lower than expected real value cashflows. Considering the IGP-M[2] time series, which is a price index used to measure inflation, from 1996 to 2016 the average inflation was 8.77%. It presents a higher average than the growth of electricity demand of the above mentioned MME's time series. Nonetheless, the inflation affect is variable, affecting the months right before the next Annual Rate Readjustment more intently than those right after the last Rate Readjustment Period, resulting in a lower monthly average, at present value.

From the above analysis is plausible to conclude that there are two factors affecting the cashflows dynamics in the short term: (i) the tendency for electricity demand growth, that acts in a way of increasing the revenues volume; and (ii) the loss of the rates real value, in face of inflation, acting as a factor that tends to reduce the real value of the cashflows. Both factor act in opposite direction concerning the effect of the differences between the Required and the effective revenues. Figures 1 and 2 illustrate both effects over the period's revenue.

2 It is calculated by the Fundação Getúlio Vargas (FGV), and is a price index widely applied by the financial market in Brazil. It measures the prices behavior of good adquired by São Paulo and Rio de Janeiro families, with monthly income ranging from 1 to 33 minimum wages. Is is calculated between the 21th day of the previous month and 20th of the current.

Figure 1 – Example of a Relation Between Nominal Required Revenue and Nominal Effective Revenue – Demand Growth Effect



Source: Own Elaboration

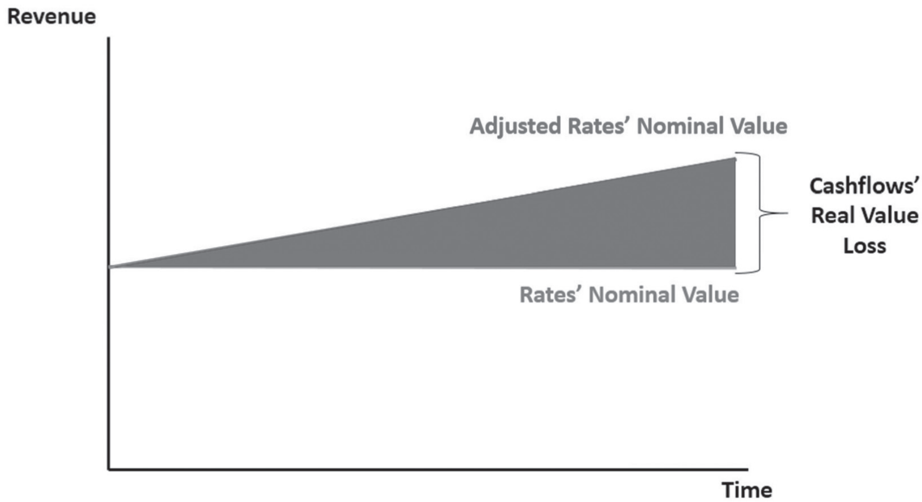
The Figure 1 above represents the dynamics between the Required Revenue and the effective revenue considering the growth in electricity demand. The vertical axis represents the revenues' volume and the horizontal axis represents the time, one year, which starts in the first day after the Annual Rate Readjustment and ends the day before the next Annual Rate Readjustment. If the horizontal axis is fractioned in twelve equal parts, they represent, approximately, each month of the year.

Since the electricity demand, in the above example, is for any of these periods higher than it was during last year's same period, the Required Revenue is consistently surpassed, resulting in higher than expected cashflows. The farther away from the last Annual Rate Readjustment, the stronger is the gap and higher is the cashflow. The green area in the Figure 1 represents the sum of higher cashflows.

This effect is corrected by what is called the *X Factor*, which is an index that measures among other things, the higher efficiency achieved (or lower average costs) from the growth in electricity demand. The X Factor contains a component called "P", this component is responsible for capturing such gains, and is calculated taking in consideration the variation in the number of consumer units and in the total electric power demand between the twelve months period (ANEEL, 2017.d). The application of the X Factor will be explicit further ahead.

The other, opposite effect, is the inflation, which reduces the rates' real value with the passing of time. The Figure 2 below illustrates the case using nominal rates and nominal cashflows in a market with no grow in electricity demand, in order to explicitly analyze the losses in real value. There are two cashflows levels: the one below, in blue, represents the cashflow of the nominal rates at their default level, defined in the last Annual Rate Readjustment; the above one, in red, represents the nominal level of cashflows in case they were continuously adjusted for inflation. The red triangle represents the loss of cashflow real value in the period.

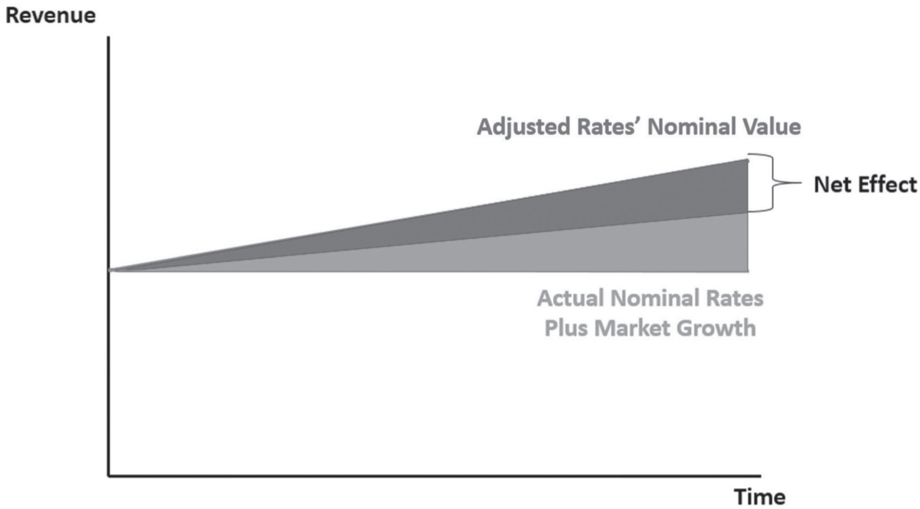
Figure 2 – Example of a Relation Between Fixed Nominal Cashflow and Adjusted Nominal Cashflow



Source: Own Elaboration

These temporary losses are then corrected in the Annual Rate Readjustment, using the IGP-M price index. The overlapping of both Figures 1 and 2 above allows for a graphical representation of the net effect that results from both factor interaction. If, for example, the effect of an increase in revenues is lower than the real value's loss effect, then the net effect can be represented as in the Figure XX below.

Figure 3 – The Net Effect of Inflation and Market Growth Over the Utilities Cashflow



Source: Own Elaboration

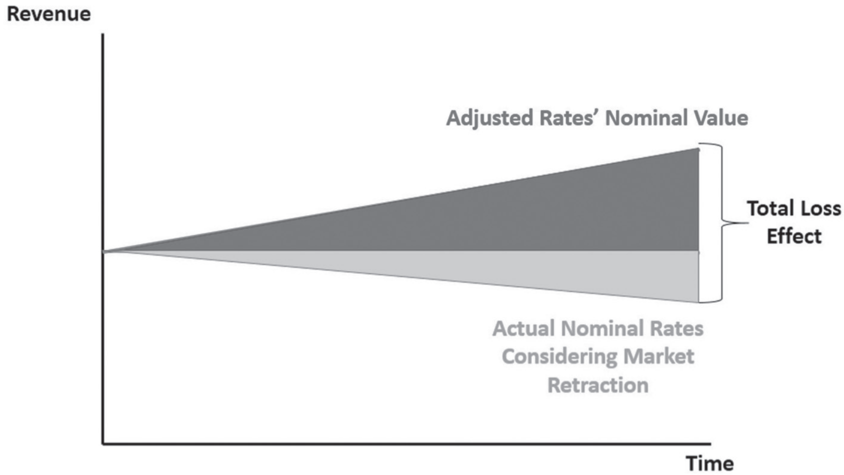
As shown in the Figure 3, the net effect is negative, and the effect over the volume of the real value cashflows is a reduction. This is case usually does not present a real problem, since both effects compensate each other up to a point and the net effect is reduced. During the Annual Rate Readjustment, the Parcel B (PB) readjustment is calculated as the following formula, which contains both indexes, the X Factor and the IGP-M price index (ANEEL, 2016.b):

$$Equation\,3 : PB_1 = PB_0 * (1 + IGPM - Factor\,X)$$

However, in case of an intense DG diffusion rate it might happen, especially during times of weak per capita electricity demand growth or for utilities operating in areas with slower per capita electricity demand, that both effects reinforce each other, with the market effect reaching negative values with de withdrawal of part of the demand being substituted by DG.

The sum of both effects might create a large gap between planned and actual cash-flows, creating potential operational restrictions. This risk is present even when they do not act in the same direction, but the market effect is strongly weakened. The extreme case is illustrated in Figure 4 below.

Figure 4 – Potential Reinforcing Market and Inflation Effects During High Rates of GD Diffusion



Source: Own Elaboration

Potential Impact over the Utilities Economic Logic

A strong rate of DG diffusion, in accordance to current regulation may lead to a permanent long-term economic impact. This potential impact concerns the low-tension consumers, for whom the electricity rate structure allocated all costs in volumetric logic.

The rate structure for the low-tension consumers group can be divided in the allocation of costs related to energy purchase by the distribution utilities and those related to the payment by the distribution utility for the services rendered by transmission and other distribution utilities, as well as the direct capital costs of the utility itself. Additionally, they have to pay for electric losses, technical and non-technical.

From the nature of the costs allocated to the consumers' rates is possible to analyze their behaviors under a scenario of strong DG diffusion. Energy costs are expected to fall, since distribution utilities will need to acquire less energy to supply their consumers, given that some of the energy supply will be accomplished by self-generation or by the consumption of the electricity exported to the grid by another's consumers DG system.

However, even if there is less demand for electricity from the grid, the physical distribution grids will not face costs reductions. The electricity will keep flowing though the distribution grid, from centralized generation to consumers or from consumers to other consumers. There is not any reason to justify the capital investment on the current grid, and even if this were possible, the sunk costs nature of such investment would not allow for disinvestment.

The transmission grids are designed for performing electric transmission of large energy volumes and face congestion very often. This will not change with the diffusion of DG, since their electric production is subject to variation and volatility, reinforcing the need for balancing mechanisms between geographically distant areas (IEA, 2014). So the costs will not be reduced with the DG diffusion.

The remaining non-energy cost component of the distribution utilities are the electric losses. The non-technical losses are largely independent of the DG diffusion by itself, however, as will be shown, average rates may increase with de DG diffusion and this may increase non-technical losses.

From the point of view of technical losses, the relation is less clear, and there are arguments that justify their reduction. This does not mean that they will fall in a faster pace than the reduction in demand for centralized generation (electricity sold from the distribution utilities). Sheikhi *et al.* (2013) show that the electric losses might even raise again with higher levels of DG diffusion, even if there are short-term reductions for lower diffusion rates.

In accordance to the above exposed, it is possible to represent the average electric rates for a given low-tension “consumer i” as a sum of three different costs groups, acting as function of the total demand and of the Reference Market. The components are: (i) energy - related to costs of electric power acquisitions made by the distribution utilities; (ii) physical transmission and distribution (from other utilities or their own) costs; and (iii) energy losses costs. The consumer’s i rate is expressed as Equation 4 below:

$$Equation\,4: \frac{EC}{RM} \cdot c(i) + \frac{PC}{RM} \cdot c(i) + \frac{EL}{RM} \cdot c(i)$$

Where, EC represents the energy acquisition costs; PC represents the physical transmission and distribution costs; EL represents the costs related to electricity losses, technical and non-technical; RM represents the Reference Market; and c(i) represents the consumption demand of electricity for the consumer i.

In addition, from the above analysis, the relationship of these three components can be expressed as:

$$\frac{\partial\, Energy\, Costs}{\partial\, Reference\, Market} = \beta$$

$$\frac{\partial\, Physical\, Costs}{\partial\, Reference\, Market} = -\frac{Physical\, Costs}{Reference\, Market^2} < 0$$

$$\frac{\partial\, Energy\, Loses}{\partial\, Reference\, Market} = -\frac{Non - Technical\, Loses}{Reference\, Market^2} + \gamma < 0$$

Both β and γ are positive scalars that represent the linear (simplified) relation between Energy Costs and the Reference Market as well as the one between Technical Loses and the Reference Market. Therefore, it is possible to obtain the following relation:

$$\frac{\partial\, Consumer's\, i\, rate}{\partial\, Reference\, Market} = -\frac{PC}{RM^2} - \frac{PC}{RM^3} - \frac{N - TL}{RM^2} - \frac{N - TL}{RM^3} < 0$$

Therefore exists an inverse relation between the low-tension consumers' rate and the Reference Market size, which may be reduced by a strong DG diffusion rate. Reductions in the Reference Market causes the average rate for these consumers to rise.

The reason for this is that several costs are not driven by energy consumption levels, as is the case for physical assets in the transmission and distribution grids or for non-technical losses. Volumetric rates, that allocates the payment of these costs in proportion to total electricity consumption, eliminates the contribution of DG adopters to the payment of these fixes physical cots, even though these adopters consumers remain connected and using the assets.

It must be noted that in this situation a cross-subsidy is created, with non-DG adopters paying for the almost totality of the costs of assets also being utilized by DG systems adopters. This cross-subsidy might carry an additional perverse distributional effect, characterized by high-income consumers, capable of acquiring photovoltaic systems, being subsided by consumers unable to adopt DG systems because of financial and economic restrictions.

A direct consequence of the raise in the average rates level for these consumers is the increase in financial attractiveness of a DG system adoption. One way of seeing this is through the effect it causes to the Net Present Value (NPV) of such an adoption. The NPV o the investment in a DG system may be expressed as:

$$Equation\, 5:\ \mathrm{NPV} = \sum_{j=1}^{n} \frac{g_j \cdot r_j}{(1+i)^j} - \sum_{i=1}^{n} \frac{m_j}{\left(1+i\right)^j} - \sum_{i=1}^{n} \frac{d_j}{(1+i)^j} - C$$

Where, g_j is the volume of electricity generated in the month j; r_j is the rate for the month j; m_j are the maintenance costs of the month j; d_j are the depreciation cost for the month j; i is the rate of discount; and C is the investment cost.

Raises in the rates lead to a higher NVP for any given DG system, as it can be obtained from the following relation:

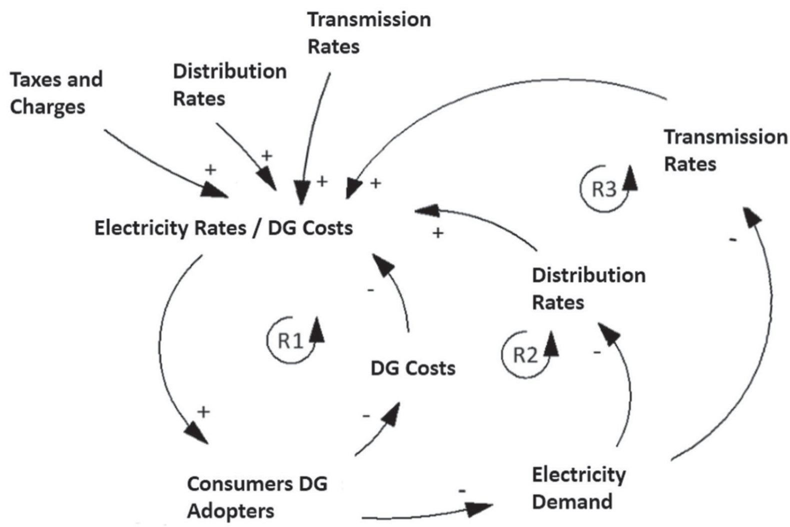
$$\frac{\partial NVP}{\partial r_j} = \sum_{j=1}^{n} \frac{g_j}{(1+i)^j} > 0$$

A raise in the NVP can lead some consumers for whom the previous results did not show high or even any attractiveness (the NVP was lower than zero) to adopt. Thus, in case of several consumers adopting DG systems in the period between Annual Rate Readjustments, they can raise the average rate through the reduction of the Reference Market, acting as an important incentive to promote the adoption of a new group of consumers for whom the NVP did not show enough attractiveness in the period before. These new adopting consumers might in turn act as the first ones, helping raise the average rate to a newer higher level, creating incentives for a new wave of adoptions and so on, in a cyclical process. This phenomenon can lead to a theoretical result known as "the death spiral" of the distribution utilities (COSTELLO & HEMPHILL, 2014).

According to Felder and Athawale (2014), this is not a new theoretical phenomenon. It has drawn the attention of economists since 1970, when was motivate by worries about the fall in the consumption level of oil during the decade's oil crisis in the USA, threatening to imbalance the electricity utilities (vertically integrated in many cases). However, the process did not happen and the conditions leading to its concretization were deemed improbable and of little verisimilitude (FELDER AND ATHAWALE, 2014).

In 2013 an article of The Wall Street Journal (DENNING, 2013) marked the beginning of a new wave of debates concerning the death spiral phenomenon, but this time motivated by other, technological factors, concerning the distributed generation. The nature of the death spiral in this new theoretic approach is the following, illustrated in Figure 5:

Figure 5 – Death Spiral General Scheme



Source: Adapted from Dyner *et al.*(2016)

This dynamic is supported by the following relation: raises in average level rates, caused by a previous wave of DG systems adoptions and consequential Reference Market size reduction, results in subsequent adoptions of DG systems, motivated by better NVP results, which in turn raises again the average electric rates, and so on. However, this simplified theoretical dynamic is not enough to determine the actual possibility of this happening.

The condition that would allow the above death spiral dynamic to happen has a strong relation with the price elasticity of the electric power provided by the distribution utilities. Henderson (1986) came to find out what was latter denominated *Henderson's Condition* by Costello and Hemphil (2014). The condition for the indefinite continuity of the spiral, or the Henderson's Conditions is given by the following inequality:

$$Inequality 1: e_p > \frac{P}{P - mc}$$

Where, e_p is the elasticity-price of the demand; P is the average rate level; mc represents the marginal cost.

This condition is similar to the monopolist's profits maximizing condition, which differs from the Henderson's Condition essentially for being an equality condition. Considering a monopolist whose profit function is:

$$Equation\,6: P(q)\cdot q - F - c(q)$$

Where, P(q) is the practiced price by the monopolist; q is the demand; F represents the fixed costs and c represents the marginal costs. The condition for profit maximization is:

$$P\cdot\left(1+\frac{1}{e_p}\right)=cm$$

It can be written in a way to resemble Henderson's Condition;

$$e_p=\frac{P}{P-mc}$$

What would happen if the monopolist under this equilibrium increases the price? Since the maximizing condition represents a situation where a reduction in the price would not compensate the increase in demand and vice-versa, a price increase would reduce de demand and costs that would more than compensate the increase in the price, leading to a lower profit. It can be seen in the following math relation, taking the derivate of the right side of the monopolists' profit maximization condition:

$$\frac{d}{dp}\left(\frac{P}{P-cm}\right)=-\frac{cm}{(p-cm)^2}<0$$

It implies that the right side of the profit maximization equation decreases when prices (or rates, in the case of the utilities) increase. What about the left side of the equation? Equation 7 represents the elasticity-price of the demand:

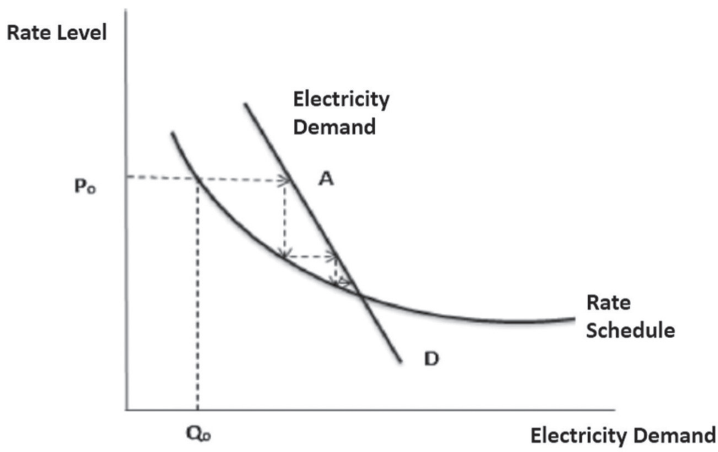
$$Equation\,7: e_p=\frac{\Delta q}{\Delta p}\cdot\frac{p}{q}$$

Raises in prices have the tendency to increase the elasticity-price of the demand since the relation $\frac{p}{q}$ increases and the impacts over the $\frac{\Delta q}{\Delta p}$ relation should be very intense in order to offset the impacts of the first relation. Even more when considering that consumers now face electricity supply alternatives, like DG.

Therefore, increases in the prices, or rates, would lead to a scenario characterized by Henderson's Condition. A utility under such scenario may end up in a death spiral, unable to reestablish a stable equilibrium. Unlike the monopolist in the example, utilities do not have full control over their rates – they provide a regulated public service with regulatory rates. Rates and demand levels are interdependent, and since public utilities are designed for efficient CAPEX and OPEX remuneration, it is possible to draw a mathematical relation between both.

Felder and Athawale (2014) call this relation "rate schedule", representing the minimal rates necessary for the proper provision of revenues, just enough to remunerate CAPEX and OPEX, for different demand levels. The rate schedule' curve inclination can be represented by right side of Henderson's Condition inequality. Considering the rate schedule and the electricity demand behavior, it is possible to understand graphically Henderson's Condition (FELDER AND ATHAWALE, 2014). Figure 6 presents the case of a utility acting on a market under stable equilibrium (absent of Henderson's Condition).

Figure 6 – Utility Operating on a Stable Equilibrium

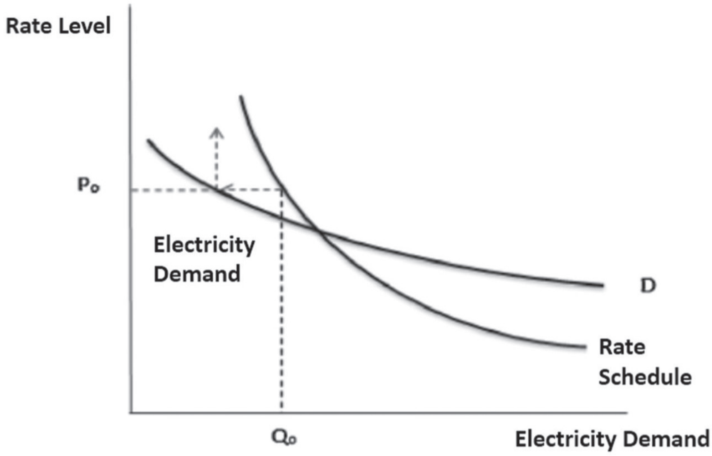


Source: Adapted from Costello & Hemphil (2014)

In the Figure 6 the rate schedule inclination (Henderson's Condition right side of the inequality) is lower than the electricity's demand (represented by the price-elasticity of the demand – left side of Henderson's Condition inequality). If the rate increases, a new equilibrium is found, with lower quantities and a higher rate. This equilibrium will can only be disturbed by variables outside of consideration in this analysis.

In case of a market in which the Henderson's Condition is already present, the dynamic can be observed from Figure 7 below. In this case, if the rate increases is not possible to obtain a new stable equilibrium. The price-elasticity of the demand is higher than the rate schedule inclination and quantities diminish in a faster pace than needed for setting a new equilibrium.

Figure 7 – Utility Operating Under an Unstable Equilibrium (Henderson's Condition)



Source: Adapted from Costello & Hemphil (2014)

In such a scenario, rate will raise year after year, with periodical market demand reductions, in face of the possibility for consumers to adopt DG. It must be noted that the implicit cross-subsidy will remain as long as DG adopting consumers stay connected to the grid without contributing to fixed physical costs payment.

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The impacts of micro distributed generation on distribution companies and mitigation measures: a case study of Italy and California.

Lorrane Camara

Abstract

A huge growth of residential households with photovoltaic distributed generation systems has taken place over the last few years, supported by consistent public policies and decreasing prices of photovoltaic systems. The increasing penetration of photovoltaic distributed generation, however, imposes huge challenges to the financial sustainability of electricity distribution companies. The reduction of retail electricity sales associated to traditional, volume driven, distribution tariffs, can lead to utilities' revenue erosion and cost-shifting from prosumers to non-photovoltaic customers. Therefore, as penetration of distributed photovoltaic distributed generation grows, distribution tariffs structure need to be reassessed in order to ensure that utilities can collect enough revenue to cover its costs, while avoiding allocative inefficiencies. In this sense, this chapter aims to discuss the negative impacts of DG diffusion on distribution utilities and non-photovoltaic consumers, analyze mitigation measures considered in the literature and present alternative tariff structures, such as capacity based and fixed charges, discussing pros and cons associated to each of them. Finally, the Italian and Californian cases, which are representative in terms of distributed generation diffusion level, are analyzed. In each case, the verified impacts and the mitigation measures being implemented are presented, corroborating the proposed discussion.

1. Summary

A huge growth of residential households with photovoltaic distributed generation (PVDG) systems has taken place over the last few years. This trend is motivated by decreasing PV prices, increasing electricity tariffs, support policies and financing innovations (CAI ET AL. 2013; COSTELLO, 2015; DARGHOUTH ET AL., 2016). Over the next years the prices of electricity from the grid are expected to increase even more, as a result of investments in grid infrastructure upgrades and also capital replacements (CERES, 2012), while the PV industry development tends to force prices down still further. Combined, these trends may support a sustained growth of household PV adoption in the near future.

Despite distributed generation diffusion represents great opportunities to the electricity sector, it also characterizes a scenario that imposes great challenges to the financial sustainability of distribution companies. The impacts of the diffusion of distributed generation (DG) on distribution companies can be summarized in tow main issues: i. the growth of grid costs, related to the need of new investments on the grid to address technical challenges; ii. the risk of under-collecting revenues, as the increase of self-generation reduces electricity demanded from the grid, associated to volume driven distribution tariffs, challenges the capacity of distribution companies to recover fixed costs. The first kind of impact is related to the pressure that more embedded generation can put on the distribution networks, which were designed for demand. Mitigating these strains will require additional capital investments on the distribution grid to support two-way flows created by DG (COSTELLO, 2015). Investments on system upgrades, such as distribution automation and grid protection will also be necessary to accommodate high levels of DG penetration (i.e. increase the grid hosting capacity) (CEER, 2017). In this chapter, however, the focus is going to be the possible impacts on utilities revenues, also considering its impacts on cost allocation between consumers who adopt DG and those who do not, and exclusively rely on the network for their energy supply.

In this sense, this chapter aims to "contribute to the discussion about the impacts of rate design and net metering to the revenue and profitability impacts of DGPV on distribution utilities and non-photovoltaic consumers. The mitigation measures considered in the literature will also be analyzed. Finally, the discussion will be corroborated by the analysis of Italian and Californian cases.

2. The impacts of photovoltaic distributed generation on distribution companies and non-solar consumers - problem's description

The electricity sector traditional paradigm was marked by three main factors: electricity was generated in large-scale power plants, placed far from the load centers; power was transferred from large scale transmission networks, and consumers did not play an active role in providing flexibility to the system. Thus, historically, "distribution networks have been dominated by demand only consumers" (CEER, 2017). In this sense, the current network tariff structure was mostly designed to ensure cost recovery, cost reflectivity and fair allocation of costs based on this paradigm and, more specifically, on this network usage. As a result, utilities have typically recovered most of their total revenue requirement through volumetric rates (i.e., a price for each kilowatt-hour of electricity purchased from the grid) (BIRD ET AL., 2013).

However, the increasing participation of distributed generation, changing the use of distribution networks, and technological advances jeopardize this traditional regulatory framework. These changes not only create opportunities, but also challenge DSOs in the operation and development of their networks. New challenges faced by distribution companies (DISCOs) in this changing environment include (CCER, 2017):

a. Predictability problems due to changing consumption patterns and the integration of intermittent generation at the distribution level;
b. Reverse flow and quality control;
c. Increased risk of cross subsidies between network users (e.g. demand customers for paying costs driven by distributed generation); and
d. DISCOs revenue uncertainty if network tariff structures have a largely volumetric basis. Even if the revenue can be recovered with a time lag, this can cause DSO cash flow concerns.

Although the transition towards a more decentralized electricity system represents a great challenge, by its own, some support policies rise additional concerns about the effects of DPV rapid growth on non-solar consumers and on utilities' ability to recover costs and deliver attractive shareholder returns, as it is the case of net-metering (BARBOSE ET AL., 2016).

Net-metering is currently one of the most widespread support policies, being largely used in Europe and in the USA, where great results in terms of photovoltaic distributed generation capacity diffusion have been reached. Net-metering allows customers with DGPV to receive compensation for each unit of electricity generated by theirs systems at a price often equal to the full retail electricity rate, which includes transmission and distribution costs (BARBOSE ET AL., 2016). Under net metering, the output of self-generation not used on site is credited, usually at the retail rate, up to the consumers' total consumption. In most cases, monthly excess generation can be carried over future months, to compensate net consumption (BIRD ET AL., 2013). In some cases, consumers receive a financial compensation for expiring excess credits. It is also important to highlight that, in this kind of scheme, the distribution grid works as a battery for PVDG systems. Net metering tariffs are quite simple, giving a clear signal to households. On the other hand, this kind of tariff poorly reflect the costs and benefits of PV to the distribution grid, or even provide signals for consumers and utilities to reduce longer term whole-system costs (CEPA AND TNEI, 2017).

Combined with volumetric retail rates, net metering can lead to: i. DISCOs revenue erosion; and ii. cost-shifting from prosumers (consumers who produce electricity as well) to consumers who do not adopt DGPV (BARBOSE ET AL., 2016). These effects are better described bellow:

i. The revenue erosion: utilities grid costs are recovered through rates established in periodic rate cases. Usually, rates applied to residential consumers are primarily volumetric. This means that utilities' revenues recover vary according to their electricity sales. Thus, reductions in sales associated with DGPV reduce revenues in between rate cases, absent decoupling[1] or other analogous mechanisms of revenues protection against volume risk. As long as lost revenues exceed associated cost savings, they may negatively impact the return on equity (ROE[2]);
ii. Increased retail rates and cost-shifting: although there are utilities' avoided costs associated to DGPV (e.g. avoided fuel and power-purchase costs), revenue losses resulting from reduced utilities' sales exceed these cost savings. In order to ensure the recovery of distribution grid costs, average retail rate will tend to rise, shifting costs to non-solar consumers. Decoupling mechanisms can accelerate, or even

1 Decoupling is a regulatory mechanism designed to neutralize the incentive that utilities encounter in traditional regulation to increase sales and to resist policies that reduce electricity sales, as their revenue is affected by the sales level. This incentive is generally called the "throughput incentive". Although decoupling can be implemented in various ways, it generally has periodic reconciliations of the rate based on whether sales are exceeding or lagging a forecast, thus causing the utility to over- or under-recover its revenue requirements (BIRD ET AL., 2013).

2 ROE is the amount of net income returned as a percentage of shareholders equity. ROE measures a company's profitability, by reflecting how much profit a company generates with the money shareholders have invested. It is calculated as: ROE = Net Income/Shareholder's Equity (INVESTOPEDIA, 2017 http://www.investopedia.com/terms/r/returnonequity.asp).

aggravate, the cost-shifting, as lost revenues are passed on to tariffs in between general rate cases.

Thus, in short, the financial impacts of DGPV on utilities and ratepayers are strongly associated to the reduction in retail electricity sales (BARBOSE ET AL., 2016). In this process, the decoupling mechanism seems to play a key, but ambiguous role. By one side, by protecting utilities from the market risk, it can address the throughput incentive and the lost revenues attributable to distributed PV. On the other hand, it does so by shifting the revenues under-recovered to all customers through increased rates. But if all or most of the adjustments are passed through to volumetric rates, this will deepen concerns about cross subsidies (BIRD ET AL., 2013).

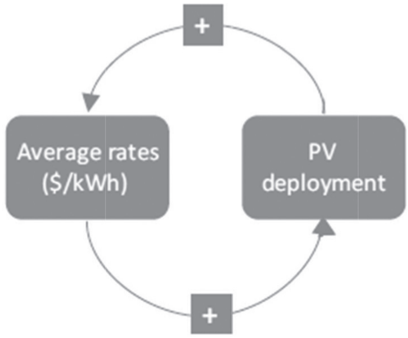
According to Schittekate et al. (2017), when network tariffs are mostly volumetric, by investing in DG, prosumers offset their contribution to grid costs. However, total costs to be recovered by the DSO through distribution tariffs remain almost the same, as major network costs are fixed, as they are not closely associated with the level of sales (BIRD ET AL., 2013). Therefore, just the allocation of these costs changes, as prosumers avoided contribution to grid costs is reallocated to non-solar consumers. In this sense, with the increasing adoption of DG, and the increase of costs being shifted to non-adopters, allocative inefficiency issues come into light.

Besides impacting the cost-shifting from prosumers to non-solar consumers, increased average retail rates, required to ensure network costs recovery, can also accelerate further distributed PV deployment. Darghouth et al. (2016) state that "the current design of retail electricity rates and the presence of net metering have elicited concerns that the possible under-recovery of fixed utility costs from PV system owners may lead to a feedback loop of increasing retail prices that accelerate PV adoption and further rate increases". This positive feedback between PV deployment and electricity rates is treated in the literature as the electric utilities' "death spiral", which is better described by Costello and Hemphill (2014) in the following excerpt:

> The death spiral occurs when an electric utility finds a price increase to be futile in raising sufficient revenues to cover its total costs. It starts with the utility having to raise prices. Lower sales follow. Hence, fewer units of electricity recover the utility's fixed costs and a further price increase becomes necessary. This higher price results in even greater sales declines, which requires yet another price increase. As the utility attempts to recover its fixed costs through higher prices, it actually makes less profit. A death spiral sets in. (COSTELLO AND HEMPHILL, 2014, p.7)

The death spiral is summarized through the conceptual scheme presented in Figure 1.

Figure 1: Conceptual schematic showing the feedback process between PV deployment and electricity average rates.



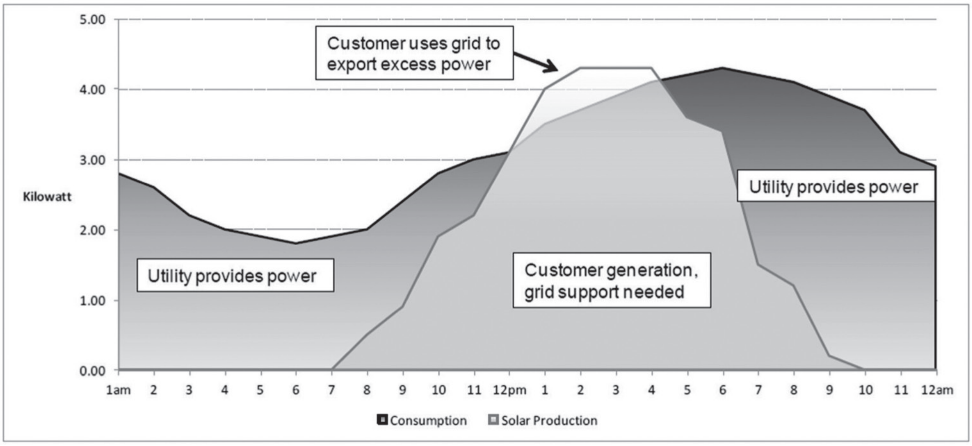
Source: Adapted from Darghough et al. (2016)

Another important issue to be considered is that, although net metering schemes, associated to volume driven tariffs, ultimately allow consumers to zero their electricity bills (if production equals consumption in a billing period) and avoid contributing to grid costs, it does not mean that prosumers do not use grid services. Rather, some authors argue that the value of the utility grid to DG consumers is even higher than to non-adopters, as the first group of consumers uses the grid both for injection and withdrawal of electricity, while the former just demand electricity (STANTON ET AL., 2013). Thus, in addition to the fact that most of the utilities fixed costs does not vary with consumption (what makes it unfair that DG consumers, by reducing their net consumption, avoid contributing to grid costs), in fact utilities continues to incur costs in serving DG consumers in many ways (COSTELLO, 2015). Some of the services provided by the DISCOs to prosumers are:

i. Voltage and frequency stability;
ii. Reverse power flow reactive power balance;
iii. Increasing re-dispatch transmission constraints;
iv. Protection;
v. Interconnection;
vi. Ancillary services.

Additionally, it is also important to reinforce that, as consumption and generation almost never exactly matches, most of the time prosumers are using the grid to offset the difference between electricity consumption and on-site production. Considering the production profile of a photovoltaic system, consumers will usually be taking electricity from the grid many hours of the day, as it can be seen in the Graph 1 bellow. So, it is clear that, considering a net-metering scheme, even if during a billing cycle consumption and self-production exactly equals, that consumer was not grid-independent during that period (WOOD AND BORLICK, 2013).

Graph 1: Small size photovoltaic system typical production and demand curves.



Source: Wood and Borlick (2013).

Therefore, in light of these considerations, the challenges faced by the utilities can be summarized as follow: as penetrations of distributed photovoltaic distributed generation grow, rates and regulatory policies must undergo fundamental changes in order to ensure that the utility can collect enough revenue to cover its revenue requirements and continue to safely and reliably provide vital services to all customers, while avoiding equity issues impacting non-photovoltaic consumer (BIRD ET AL., 2013).

3. A discussion of mitigation measures

With increasing levels of distributed photovoltaic generation, considering new rate structures and regulatory policies becomes imperative. One issue is to ensure that the utility collects sufficient revenue to cover its requirements and continue to safely and reliably provide vital services to all customers. Another key challenge to be addressed is guaranteeing equity across ratepayers and fairness for the utility and the distributed generator.

Many discussions about the most adequate response to these challenges can be found in the literature. The most relevant alternatives can be summarized in two groups: distribution tariff structure review and reforms specific to prosumers.

The former include measures such as minimum monthly bills and reduced compensation for electricity exported to the grid.

The proposal of adding a minimum monthly payment to an existing tariff structure aims to ensure at least partial recovery of the fixed costs of serving prosumers. Under this approach, the customer would pay the monthly minimum, contributing with some minimum amount to the utility's fixed costs (BIRD ET AL., 2013). Two features regarding this alternative must be highlighted: i. the volumetric network rate structure remains unaffected in this arrangement; ii. consumers can dimension their photovoltaic systems in a way that allows them to avoid triggering the minimum bill. Additionally, potential impacts of minimum bills on PVDG consumer-economics are quite low. The study developed by Cornfield and Kann (2014) confirms this statement, showing that, in the case of a Massachusetts household consumer, a minimum monthly bill of $10 would result in just a slight increase (3%) of the annual utility bill.

As previously discussed in this chapter, one of the most basic features of a net-metering scheme is that it allows excess generation fed into the grid to be credited at the retail rate, thus enabling a one-for-one compensation (BARBOSE ET AL., 2015). Reduced compensation for grid exports can be designed in many different ways, such as compensating generation exported to the grid at the wholesale electricity prices or at a utility's avoided-cost based rate. This kind of compensation scheme represents a great detachment in relation to the net-metering basic assumptions. Many studies have assessed the impact of alternative levels of compensation for exported generation on the consumer-economics of PVDG, in comparison to the one-for-one compensation provided by the net-metering. The main conclusion provided by these studies is that reducing the compensation for exported generation has quite a negative impact on bill savings achieved by photovoltaic consumer, which can be 10% to 44% lower than under the traditional net-metering rules (COOK AND CROSS, 1999; DARGHOUTH ET AL., 2010; DARGHOUTH ET AL., 2013; WISER ET AL., 2007; KANN, 2015). It is important to note that the results presented in each study are intrinsically related to the assumptions regarding the compensation model, the amount of electricity exported to the grid and also the rate structure considered.

Such considerations been made, is it possible to state that both minimum monthly bills and reduced compensation for electricity exported to the grid can be somewhat limited in addressing the challenges discussed in the previous section of this chapter. While the definition of monthly minimum bills seems to have a marginal impact on electricity bills payed by net-metered consumers, and even less on the cost-allocation issue, reducing the compensation for the electricity fed into the grid impacts bills saving by prosumers in such a negative way that PVDG diffusion rate would probably be substantially reduced. This effect, however, can diverge from the goals of environmental and energy policies, such as increasing the share of renewable sources in electricity generation and reducing carbon emissions associated to the power sector.

Although these two measures are just an example of many other possible reforms specific to prosumers, there is a kind of a consensus regarding the fact that rethinking the network tariff structure seems to be the most suitable and consistent way of addressing the impacts of FVDG on distribution utilities without limiting the diffusion nor increasing the amount of network costs which relies on non-solar consumers. Reaching these goals requires defining a fair and equitable allocation of grid costs, what is intrinsically associated to the tariff structure. Otherwise, this is also aligned to need of creating a resilient, "future-proof" tariff structure, which not only fits in the present, but also anticipate future changes (CEER, 2017).

> "Ideally, if utilities and regulators can establish tariffs for distributed PV that make sense regardless of the scale of deployment, they can avoid revising tariffs, avoid applying different tariffs circuit by circuit, and avoid applying different tariffs to customers depending on whether they installed distributed PV before or after grid stability issues arose. If it proves impossible to design tariffs that make sense at all penetration levels, regulators could anticipate the possibility of high penetration and plan for a transition in tariffs that is transparent and predictable for all stakeholders." (BIRD ET AL., 2013).

In this sense, this section will focus on the first group of mitigation measures, i.e. distribution tariff structure reforms, as the creation of resilient tariffs is considered a consistent answer not only to the challenges faced by utilities and regulation authorities (considering the need of promoting allocation efficiency) due to PVDG diffusion, but also to future challenges associated to a wider process of transformation of the electricity sector, linked to the advent of DERs.

Finally, it is believed that addressing the impacts of FVDG on distribution utilities and on cost allocation between consumers requires rethinking the allocation of fixed costs within the network charging framework. However, DG adoption by low voltage consumers is sensitive to network tariffs design (SCHITTEKATE, ET AL., 2017). Whereas the impacts of the rate design on the economics of PVDG cannot be neglected, some considerations will be made about the implications of each tariff structure for prosumer. In this sense, an expected contribution of this section is presenting some of the alternatives which stand out in the current debate about cost-recovery charges structure, also discussing some pros and cons, in the light of models and simulation results available in the literature.

3.1. Alternative tariff structures

The Council of European Energy Regulators (CEER) reinforces the thesis just presented and states that the change in technological paradigm, which transforms how distribution networks are used, exposes the need of redesigning network tariffs structure, ensuring a tariff structure appropriated to this new context and its intrinsic challenges (CEER, 2017).

Tariff structures alternative to traditional, predominantly volumetric, charges are under review or have already started to be implemented in many countries. Basically, these new rate designs aim to ensure that DG consumers pay their fair share of grid costs. As stated by Bird et al. (2013), the network tariff structure goal can be to avoid systematic unfairness in the way tariffs assess grid costs to different consumers' classes. Returning to the fact that traditional volumetric rates to recover fixed and variable costs becomes unsuitable in the case of FVDG, thus the redesign of network tariffs to better reflect cost-causation principles, is an important step in enabling a fairly apportion of the costs and benefits for a typical FVDG system (BIRD ET AL., 2016; COSTELLO, 2015).

As identified by the CEER (2017), the overall objectives of network tariffs is to recover costs of building, operating and maintaining networks while incentivizing efficient use and development. Historically, regulators have relied upon three key principles, which should be reflected in network tariffs (BIRD ET AL., 2013):

i. Ensure the utility viability by yielding the total revenue requirement;
ii. Fairly apportion the utility's cost among consumers;
iii. Relatively stable rates without unduly discriminating against any customer or group of customers.

Considering the new paradigm, however, some additional assumptions must be considered when defining distribution charges' structure, such as (CEER, 2017):

i. Network tariffs should, as far as possible, be future-proof;
ii. Tariff structures should be sensitive to the different costs of network provision;
iii. Net metering on self-generation that prevents the fair contribution of self-generation towards network costs should be avoided;

iv. All tariff structures reflect multiple objectives which need to be balanced;
v. Regulators should have sufficient expertise.

In this sense, an increasing number of authors have been discussing the distribution tariff structure most suitable to this new scenario, characterized by the growing participation of photovoltaic distributed generation in the grid. Some alternatives considered are (HLEIDIK AND GREENSTEIN, 2016; SIMSHAUSER, 2016; BROWN ET AL., 2015; BORESTEIN, 2016; BARBOSE ET AL., 2015; COSTELLO, 2015):

i. Capacity-based charges;
ii. Fixed charges;
iii. Hybrid approaches, combining fixed charges and time-varying volumetric charges, for example.

Each of these alternatives, and also their advantages and disadvantages, are going to be discussed below.

3.1.1. Fixed charges

Fixed charges are pointed out as simple stable and predictable both to distribution companies and consumers (CEER, 2017). The rationale behind the adoption of this kind of tariff structure is that most of the distribution costs are fixed in the short run. Typically, an increase in a fixed charge for all household consumers is accompanied by a corresponding reduction in the energy charge, such that total utility revenues maintain revenue neutrality (BIRD ET AL., 2015). Although higher fixed charges are a straightforward and guaranteed mechanism to recover utility fixed costs (Kennerly 2014), they are quite controversial because of their possible negative impacts on low-income customers and on energy efficiency and self-generation adoption (BIRD ET AL., 2015).

Currently, in many countries and US states household consumers pay a fixed charge on their electric bill. In most cases, however, these charges are not oriented toward recovering grid costs, effectively. In the US states, for example, this monthly consumer charge is usually used to recover customer and facilities charges, such as call center and billing, despite of distribution infrastructure costs. Considering the costs they are supposed to cover, these charges are usually low, varying from $10 to $20, average (URBD, 2015).

Thus, the proposal of stablishing fixed tariffs for the recovery of grid costs represents quite a great difference in relation to what have been made until now, as it requires completely, or partially, moving these fixed costs from the volumetric rates to the fixed charge.

The negative factors associated to fixed distribution tariffs are the possible increase of bills for lower energy consumers and the fact that they do not give signals in relation to long term costs, nor encourage energy efficiency and system flexibility (CEER, 2017). This kind of disincentive to energy efficiency associated to a shift to higher fixed charges and lower volumetric charges is due to the fact that consumers' ability to reduce costs by increasing their efficiency would be reduced (BIRD ET AL., 2013).

Brown et al. (2015) reviews the electric industry practice and the relevant price literature and identify that recovering significant costs in a fixed charge is perceived to be unfair of inequitable. This perception is related to the fact that consumers who do not have a high consumption level will have higher bills under such a system, and customers who consume a lot of electricity will have lower bills than under an alternative arrangement where residual costs are recovered through volumetric charges. However, the authors point out that the increasing participation of PVDG, while exposing the inefficiencies associated with recovering residual costs in kWh charges, "may also weaken the argument about the "fairness" of charging high, albeit cost-based, fixed charges" (BROWN ET AL., 2015, P. 141). This happens because the increasing viability of installing rooftop PV systems is changing electricity price elasticity in a way that an increase in the volumetric charge that is sufficient to induce additional customers to install solar PV results in a large drop in those customers' consumption of electricity supplied by the distribution network, may mean that the inefficiencies associated with volumetric tariff structures are greater now than they have been in the past.

Brown et al. (2015) states that the option for recovering sunk costs through fixed charges, besides being considered unfair in comparison to current tariffs, is aligned with the strategy of prioritizing the principle of efficient prices.

Another relevant point to be considered is that, if all consumers (including photovoltaic ones) are billed entirely or primarily through monthly fixed charges, then the cross-subsidization issues will not be eliminated, despite of changing in comparison to other rate structure options. As with the current volumetric rates, homogeneous fixed tariffs would not consider, nor reflect, how prosumers impose different kind of costs to the utilities (regarding the different kind of services they demand from the grid) and/or offer benefits to the utility system. In this regard, the effects of raising fixed charges are ambiguous and, in the worst case, it would change who is subsidizing whom (BIRD ET AL., 2013).

Studies developed recently claims to measure the impact of fixed monthly charges on PVDG customer-economics. The results found in each of them are closely related to the assumptions regarding the size of the fixed charge and whether the charge is associated to a corresponding reduction in volumetric charges. An analysis of a recent $7 increase to monthly fixed charges in Wisconsin found that the corresponding reduction in volumetric rates would lead to a roughly 15% reduction in the bill savings from prosumers (KANN, 2015). Another analysis about the possible impacts of adopting fixed charges in Massachusetts found that a hypothetical $10 increase in fixed customer charges would increase the total bill for a representative residential solar customer by approximately 9% (Cornfeld and Kann 2014,).

3.1.2. Capacity based/demand tariffs

Demand charges have been considered a possible solution to the utilities lost revenues and cross-subsidy issues which emerge with DGPV diffusion. In the case of net-metered prosumers, an electricity bill based on the peak demand, for example, could reflect the costs the distribution companies incur in providing grid services to those consumers (BIRD ET AL., 2013).

The basic assumption behind the definition of capacity based tariffs is that the investments on grid infrastructure are dimensioned based on the projected peak load. In this sense, this kind of charge allow the utility to better allocate the non-energy costs of serving individual consumers, as the grid is designed, and the utilities' capital investment decisions are taken, to meet consumers' peak demand (BIRD ET AL., 2013).

Although capacity-based tariffs are treated as a single, uniform tariff structure, there are many possible designs (HLEIDIK, 2014; HLEIDIK AND GREENSTEIN, 2016; SCHITTEKATTE ET AL., 2017). Two parameters are especially relevant when determining the design of a capacity based network charge, as they have a huge influence on the level of accuracy of the charge in forecasting the peak demand. The first one is the billing cycle of the charge – i.e. "is the peak demand determined on a daily, monthly, seasonally or annual basis to calculate the network charges" (SCHITTEKATTE ET AL., 2017). The second parameter is the duration over which the peak demand is measured, i.e. instantaneously, based on an average over fifteen minutes, average of one or more hours, etc. Broadly speaking, the accuracy level of the tariff is influenced the following way: the longer the billing cycle and the shorter the shorter the period over which the peak measurement is averaged, the more inaccurate a tariff is in forecasting the peak demand (SCHITTEKATTE ET AL., 2017). Thus, capacity-based tariffs can be designed in many different ways, and each of them has different effects, such as (CEER, 2017):

i. Tariff based on the highest capacity used in a year: this kind of design is close to a subscribed capacity tariff. As it does not differentiate between capacity used at peak time and capacity used off-peak, it is only partially cost-reflective;
ii. Tariff based on the highest capacity used in a shorter timeframe, for instance the highest each month: although it is considered more cost-reflective, it requires smart metering, what can restrict its applicability;
iii. Tariff based on the highest capacity used in a very short timeframe (for instance day, or even hour): on the one hand it the most cost-reflexive design; on the other hand, it is extremely complex and less predictable for many consumer groups, what can make it less acceptable to consumers.

One of the positive aspects of demand charges is the inherent incentive for consumers to adopt energy efficiency measures and to flatten their load shape, in order to lower their peak demand and so reduce their electricity bills. This change in consumers' pattern of consumption would also reduce the utilities overall costs of service, as a reduced peak level would require utilities to acquire less resources (BIRD ET AL., 2013).

Hleidik and Greenstein (2016) and Simshauher (2016) consider capacity-based charges an attractive option to deal with the challenges discussed earlier. They argue that capacity-based charges would avoid inequitable bill increases and, at the same time, allow for better cost reflection.

One of the limits of this kind of charge are related to the fact there are some fixed costs that do not fluctuate with peak demand (BIRD ET AL., 2013).

Regarding the impacts of demand charges on net-metered consumers, on the one hand, the corresponding reduction in volumetric tariffs components would reduce bill saving achieved through net metering. On the other hand, this reduction could be partially compensated by consumers load shift (associated to changes in consumption patterns), reducing demand charges (BARBOSE ET AL., 2016).

Schittekatte et al. (2017) also analyze possible impacts of adopting capacity-based tariffs. The authors consider a capacity-based network charge based on the observed peak demand during one hour. Their results show that, with this kind of capacity-based tariff in place, investments in batteries and PV was over incentivized in some scenarios, leading to an increased capacity of DER per consumer and subsequent equity issues. The authors recognize, however, some limitations of the presented results, regarding not only the restrictions considered in the model, but also the design of the capacity tariff. They state that, for example, a "capacity based charges based on the peak demand during 15-minutes with a seasonal or annual ratchet would perform better than the results shown in this analysis" (SCHITTEKATTE ET AL., 2017). Another issue is that, by considering grid costs to be sunk, the authors focused on the limitations of capacity-based charges. Although they recognized that this assumption may not be valid for countries where the distribution grid is being expanded, and thus sunk costs are lower and many investments are driven by future demand forecasts. In this case, the total costs to be recovered by the DSO would be a function of network usage.

When comparing fixed and capacity-based network tariffs, some authors consider the latter fairer than imposing the same fixed charge for all consumers within the same consumption class (COSTELLO, 2015). Costello (2015) argues that, due to the apparent correlation between demand and energy consumption, it would be unfair to charge both low-usage and high-usage consumers the same fixed costs. In this sense, a demand charge would better reflect cost causation (COSTELLO, 2015).

3.1.3. Hybrid approaches

Although much has been discussed about the best rate structure alternative, as it was just presented, there are also many authors who recognize that there is not an only, one-fits-all approach. In general, they propose that hybrid tariff structures are highly recommended.

Borenstein (2016) is one of these authors. The main assumption behind his thesis is that "challenges arise as a significant part of the network costs are sunk costs", and no clear recommendation can be found in economic theory about the better way of allocating such costs, as the cost causation is not clear. Thus, he argues that possibly a combination of higher fixed charges and time-varying volumetric charges would be the least bad option.

Time-varying tariffs aims to provide a more efficient price signal to consumers, as tariffs are supposed to reflect the variation of the cost to provide power and grid services throughout the day. Besides of incentivizing a more rational and optimal use of the electricity and the grid, time-varying pricing can play an important role in providing system flexibility for integration of renewable, intermittent generation, and for managing DER and distribution systems (CAPPERS ET AL., 2011; LAZAR, 2014). One of the most common kinds of time-based charge are Time-of-Use (ToU) rates, which "charge different prices during the day, typically falling within two or three predetermined prices and time periods (BIRD ET AL., 2013).

Brown et al. (2015) do not identify any single option either. However, they argue that setting a multi-part tariff for households – potentially including a fixed charge, a demand charge and a volumetric charge - is closer to being efficient, because the three parts of the tariff have different impacts on consumer behavior.

An important issue when analyzing hybrid tariff structures is the proportion of revenues recovered through each of the tariff components. Brown et al. (2015) illustrate the importance of taking a further look in the weight of the components through the analysis of the Italian case. They show that, while in most countries there are no demand charges for household customers, in Italy the tariffs structure includes a demand component. the demand charge is small. The weight of the Italian demand charge, however, is small, as the charge recovers around 20% of the total revenue. So, even though the network incurs most costs to supply demand (kW) and almost no costs to supply energy (kWh), a large proportion of revenue is recovered through kWh charges.

Reinforcing the thesis that a hybrid tariff structure would be preferable, "both the European literature review and the answers to the EC public consultation on Energy Market Design indicate a general support for a move towards (…) a hybrid or capacity and consumption based charging to incentivize a change in consumer behavior" (CEER, 2017, P. 21).

4. Case studies

4.1. The Italian case

4.1.1. Electricity distribution sector general information.

Italian distribution tariff regulation regime consists on a hybrid approach with an incentive-based scheme (price cap) applied to OPEX and a cost-of-service scheme for tariff components related to CAPEX (Oglieti and Delpero, 2016). DSOs allowed revenues are based on the number of connected customers, in order to decouple revenues from energy volumes (REF-E et al., 2015). Additionally, allowed revenues are guaranteed by an ex-post equalization mechanism, thus the DSOs are not exposed to energy volumes (ENEL, 2016). Currently, there are 151 DSOs operating in the country, to around 27 million customers (REF-E et al., 2015).

Electricity distribution tariff paid for residential customers consist of three components (REF-E ET AL., 2015):

- A fixed component (€/point of delivery);
- A capacity component (€/kW); and
- A progressive volumetric component (€/kWh).

Despite the presence of three components, the most of the costs were recovered though the volumetric charge (CEPA AND TNEI, 2017). In 2013, approximately 66% of the distribution tariff payed by a household consumer[3] was associated to the energy component (REF-E ET AL., 2015).

An interesting feature about the structure of distribution network tariffs in Italy is that there is an "ideal", cost-reflective, tariff for households (the D_1 tariff) towards which tariffs are supposed to converge. Yet this tariff is not effectively applied in the country. In the ideal tariff the fixed component is supposed to cover the costs of metering and some other consumer related costs. The capacity and the energy charges, in turn, are supposed to cover the cost of the network.

Additionally, there are two more tariffs defined:

- D_2 tariff: for households in their place of residence, with no more than 3.3 kW of contracted power. About 80% of Italian residential consumers fit into this category;
- D_3 tariff: applied both for households in their spare homes and for households in their place of residence with contractual capacity over 3.3. kW.

The variable component of both D_2 and D_3 tariffs is progressive (i.e. the kWh unit cost grows for higher consumption blocks). The tariff structure implies that, on one hand, low consumption households pay distribution tariffs below the cost reflective level (i.e. bellow D_1 rates). Residential consumers with highest consumption, on the other hand, pay tariffs higher than the cost reflective level (CEPA AND TNEI, 2017; BROWN AND FARUQUI, 2014).

When analyzing Italian residential rate structure and its recent evolution, it is important to consider the context in which it was firstly adopted. The increasing consumption inclining block was implemented in the early 70s, when Italy was facing the consequences of the oil crisis, and was though to discourage excessive consumption by domestic consumers. At that time, the boundaries of consumption blocks were defined based on the following data, gathered from statistical surveys over a sample of Italian households: half of them used less than 2 kW of contracted capacity and 1000 kWh/year,

3 Considering a consumer with an annual consumption of 3.500 kWh, connected to the low voltage grid and 6 kW of contracted capacity

and the average electricity consumption was around 1.350 kWh/year (CEER, 2017). Based on this data, three blocks were defined:

- Up to 900 kWh/year for the application of subsided prices;
- 901 to 1.800 kWh/year for the average price, which should be a proxy of the cost-reflective prices;
- Over 1.800 kWh for the highest price.

Since the implementation of this tariff structure, the consumption blocks increased from three to six. The boundaries definition, however, did not change much, despite of the clear change in the Italian households consumption profile: in 2013 only 2% of the consumers used less than 2 kW, and the electricity consumption averaged 2.200 kWh/year (against 1.350 kWh/year in 1972-1973) (CEER, 2017).

The Italian household network tariff structure is better illustrated in the Tables 1 and 2 bellow. Table 1 shows the elements of D_1, D_2 and D_3 tariffs for a low-use consumers, while Table 2 shows the flat variable charges structures for the ideal tariff (D_1), and the inclining block structure for tariffs for low usage (D_2) and for households in their spare homes or with high consumption (D_3).

Table 1: $D_{1,}$ D_2 and D_3 tariffs for Low Use Consumers (<1.800 kWh/year)

	Fixed Charge (€)	Demand Charge (€/kW)	Variable Charge (€/kWh)
D1	20.7	15.6	0.016
D2	6.1	5.7	0.005
D3	20.7	15.6	0.025

Source: Brown and Faruqui (2014)

Table 2: Variable Charge (€/kWh)

Annual Consumption	D1	D2	D3
0 to 900 kWh	0.016	0.005	0.025
901 to 1,800 kWh	0.016	0.005	0.025
1,801 to 2,640 kWh	0.016	0.042	0.042
2,641 to 3,540 kWh	0.016	0.082	0.082
3,541 to 4,440 kWh	0.016	0.082	0.082
4,441 kWh and up	0.016	0.124	0.124

Source: Brown and Faruqui (2014)

It is also worth highlighting that initially the increasing block were applied to all components of the household's electricity bill. However, since July 2007, when the retail market was completely opened to competition, this progressive structure has been limited to the regulated components of the bill (i.e. network tariff and general system charges[4]) (CEER, 2017).

4.1.2. Support policies

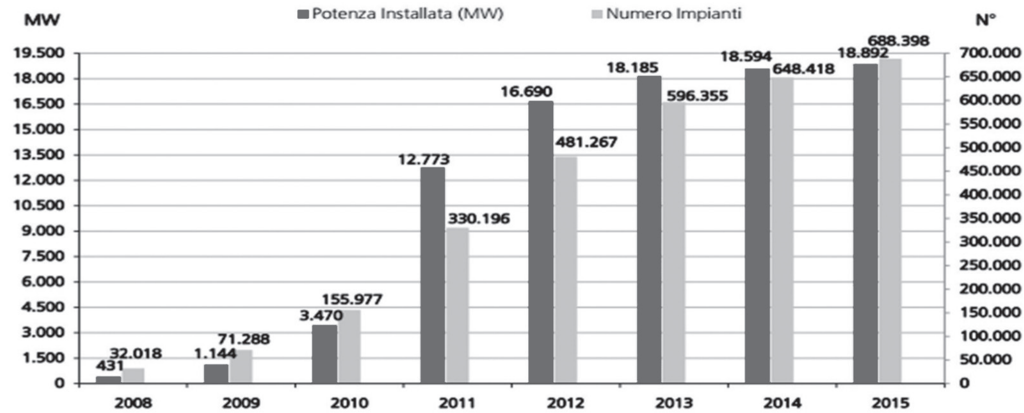
FiTs for photovoltaic installations were first stablished in 2004, through the introduction of the "*Conto Energia*" (Di Dio, 2013). From 2005 to 2012 the mechanism was revised five times (Campoccia, 2014; Orioli et al., 2016). In its last version (*Quinto Conto Energia*), a support system composed by two terms (an all inclusive FiT for the share of electricity injected into the grid and a premium for self-consumption) was granted for a 20 year period (Campoccia, 2014; Samuele, 2016; Dusonchet and Telaretti, 2015). Additionally, PV installations bellow 200 kW could choose between FiT or net-metering (in the previous versions of the policy, FiT and net-metering could be accumulated) (Campoccia, 2014; Di Dio, 2013). The FiT scheme ceased to have effect on 2013, July, after reaching a cumulative cost of € 6.7 billion per year (IEA, 2015; Samuele, 2016).

Currently, most PV plants with self-consumption are supported by a net billing scheme called "Scambio Sul Posto", a kind of net metering scheme, valid for systems with capacity of up to 500 kW, where different rates are used to value the excess energy fed into the grid and energy received from the grid (GSE, 2017). The credits generated by exporting electricity to the grid are valid for a three years period.

Reflecting the support policies implemented in the country, by the end of 2015, Italy had 18.9 GW of installed photovoltaic capacity, which was responsible for generating 22,942 GWh, corresponding to approximately 9% of the total consumption in the country (GSE, 2016). The evolution of photovoltaic installed capacity and of the number of photovoltaic systems between 2006 and 2015 can be found in Graph 2 bellow.

4 The network tariff covers the costs related to all the activities of electric energy transmission, distribution and metering across the network. The general system charges cover the costs sustained for all the services which present a public usefulness, such as renewable sources support policies (BOVERA, 2016).

Graph 2: Evolution of Photovoltaic Installed Capacity and number of photovoltaic system in Italy (2008 – 2015).



Source: GSE (2016)

4.1.3. Impacts identified and recent reforms

Italian distribution companies have experienced a revenue under-recovery. Yet, these deficits have been "eliminated by feeding the under-recovery into tariffs in subsequent years" (CEPA AND TNEI, 2017). Addressing this and other distortions, such as the negative signals and incentives provided by the progressive structure of volumetric charges, the Italian Regulatory Authority for Electricity, Gas and Water (AEEGSI) has been working on gradual reform to network tariff structures for households, as the previous one "has been considered outdated and no longer capable of fulfilling its original goals of promoting sustainable use of electricity by households" (CEER, 2017). In this sense, in the fifth electricity transmission and distribution price control review, which took place in December 2015, the AEEGSI final proposal on redesigning the tariff system introduced crucial changes regarding distribution tariffs regulation. One of the most important was de decision of eliminating historical progressivity with electricity consumption that was introduced in the 1970s as a first energy efficiency measure (REF-E ET AL., 2015; CEER, 2017).

In general, the reform is seen as a move "towards a large share of distribution costs being attributed to fixed and capacity component tariff components" (CEPA AND TNEI, 2017). In this regard, the capacity component of the tariff tripled and the fixed component for households increased by 66% (CEPA AND TNEI, 2017).

According to the new regulatory approach the progressive tariff is going to be progressively eliminated during the current regulatory period (i.e.2016-20123). By doing so, it is expected that, by 2018, the network tariffs (i.e. the tariff component which covers the distribution costs) for households will become linear, cost reflective (largely capacity-based) and homogenous for all low voltage users (households and business customers), providing the right incentives for energy efficiency and self-consumption (CEER, 2017). In other words, the network tariffs will be the same for all consumption levels, as well as largely related to the capacity contracted (CEPA AND TINEI, 2017).

In terms of impacts of the new tariff structure on the viability of PVDG, there are two expected effects (CEER, 2017):

i. The decrease of economic value of electricity that could be saved investing in a photovoltaic rooftop system, associated to consumers with the highest consumption levels (> 2.700 kWh/year), so affected by the higher prices. This decrease, however, impacts quite a small portion of households (15% of approximately 29 million);
ii. The increase in the economic value of savings related to the tariff reform affects around 43% of Italian residential consumers (those consuming no more than 1.800 kWh/year).

Another import change recently introduced in Italy was the creation of fixed annual charges specific to self-consumption projects, which are gradually being called to contribute to the grid costs (European Commission, 2015). The value of the charge depends on the system capacity. While micro-generation projects are fully exempted, systems with a capacity equal or above 20 kWp, connected to the low voltage grid, pay approximately €36/year. Finally, systems with an installed capacity of 200 kWp or above (connected to the medium voltage) will pay about €237/year (European Commission, 2015).

The Table 3 below provides a summary of Italian case study, presenting the main problems identified, the changes to network charging arrangements and the possible impacts.

Table 3: Summary of changes to network charging arrangements and their impacts.

Country	Original Charging arrangement	Problem identified	Change introduced	Impacts	Conclusions
Italy	All households faced: • Capacity based charging elements, set through their smart meters (roll-out complete); • A flat component; and • A progressive volumetric component.	Italy has faced a tariff revenue deficit. This has been resolved by passing any under-recovery through to allowances in subsequent years.	The Italian regulator is gradually eliminating the progressive structure of the distribution network tariffs. By 2018, the network and system charge tariffs will be the same for all consumption levels.	The changes are currently in progress or yet to be introduced. Hence it is too early to evaluate impacts.	As the reduction of importance of the progressive volumetric element is likely to result in regressive distributional impacts, the re-distribution of charges may become a contentious issue. The reforms can also lower incentives to reduce consumption from the grid.

Source: Adapted from CEPA and TNEI (2017)

4.2. The Californian case

4.2.1. Electricity distribution sector general information.

California electricity sector is dominated by vertically integrated monopolies, with emphasis on the three main investor owned utilities (IOUs): Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E) (Joskow, 2000). A revenue cap regulatory approach is used to define distribution tariffs. The General Rate Case, the process of tariff revision, takes place every three years (CPUC, 2016). Another important aspect of the regulation is the application of a revenue decoupling mechanism, which protect the utilities from market fluctuations (Center for Climate and Energy Solutions, 2016).

Regarding electricity tariffs, a tiered rate structure, based on a single, progressive volumetric component, is applied to residential customers (RMI, 2012). Four tiers are considered in this approach. In general, the range of baseline consumption is defined as between 50% and 60% of the average residential consumption in a given region. Tier two, in turn, equals the consumption range between and 100% and 130% of the baseline. The tiers three and four consist respectively of consumption levels between 130% and 200%, and above 200% of tier one consumption. The central objective of this tariff structure is to stimulate energy efficiency.

In 2001, in response to the Californian energy crisis, some changes were made regarding the tiers system. Considering that one of the effects of the 2001 crisis was the high volatility of the electricity tariff, in order to protect consumers from the erratic trajectory of market prices, the regulator set a ceiling for residential tariffs, whose practical result was the freezing of the value of the first two tiers (RMI, 2012). One result of this freeze was that during the following years all tariff increases were applied to higher tiers, further penalizing consumers with higher demand.

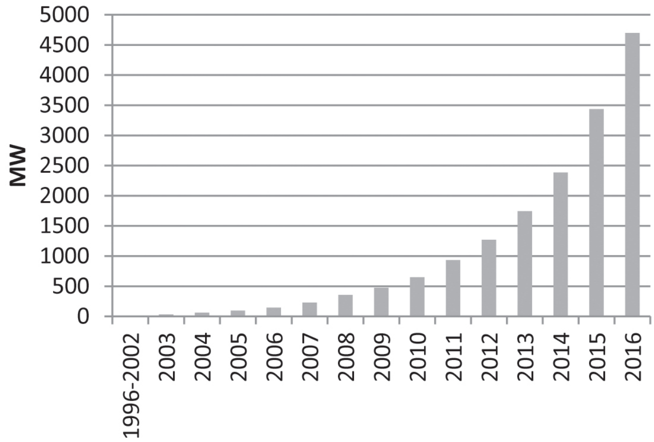
In 2010 it was approved a measure revoking the freezing of the tariffs of the first two tiers, which could then suffer annual adjustments between 3% and 5%. Although this partially alleviated the pressure on the upper tiers, the freezing effects were not eliminated. By way of example, in 2015 a tier four consumer paid four times as much kWh as a Tier 1 consumer (CPUC, 2016).

4.2.2. Support policies

One of the main photovoltaic distributed generation supporting policies in effect in California is the Net Energy Metering (NEM), which was adopted in 1995 (Alquist, 1995). According to NEM, additionally to the self-consumption, when exporting electricity to the grid, prosumers receive energy credits, valued by the full electricity retail rate, which are deducted from monthly gross consumption, so the prosumer is just charged for its net consumption. (Go Solar California, 2016). Since 1995, the NEM was subject of many revisions. In 2009, an important bill was approved (AB 920), defining that, if at the end of a 12 month billing period, the consumer had exported more electricity to the grid, than the amount demanded from the grid, thus the one could opt to roll the credits to next billing period, or to receive the net surplus compensation (NSC), based on a 12 months electricity retail rate moving average (Huffman, 2009; CPUC, 2010). The payment was proportional to the net excess generation. This financial compensation is still valid, and currently, the NSC can vary from US$ 0.04 to US$ 0.05 per kWh, according to the utility (CPUC, 2016a).

In 2016 more than 90% of the photovoltaic capacity connected to the grid, in the operation area of the three main IOUs, was registered in the NEM (CPUC, 2016a). This capacity corresponds to a total of 594,685 systems (residential and non-residential), what is equivalent to a capacity of approximately 4.7 GW, as of December, 2016 (California Distributed Generation Statistics, 2017). Graph 3 shows the evolution of cumulative installed capacity under NEM scheme, between 1996 and 2016.

Graph 3: NEM cumulative installed capacity (MW) – (1996 – 2016)



Source: California Distributed Generation Statistics (2017)

4.2.3. Current reforms

Given the rapid growth of DGPV in California, in response to the aggressive support policies implemented in the state, and the resulting reduce in utilities sales, have lead many utilities and regulatory authority to analyze the rate impacts and cost-shifting associated with DGPV under NEM rules and retail rate structure (BARBOSE ET AL., 2016). In 2013, a study commissioned by the California Public Utilities Commission (CPUC), included a COS analysis for the states' three main IOUs: PG&E, SCE and SDG&E. The results were that, on average, NEM residential consumers contributed between 54% (in the case of SDG&E) and 84% (PG&E) with their correspondent grid costs share (BARBOSE ET AL., 2016).

There are also relevant data regarding absolute values being shifted from DG to non-DG consumers. According to estimates presented by San Diego Gas & Electric, December, 2015, costs that would be shifted to non-DG consumers sum up $160 million, what would mean an average increase of $100 in those consumers annual electricity bill (FRANZ, 2016). PG&G also found alarming results. The company preliminary estimates indicate that, in 2015, between 25% and 30% of their residential consumers' electricity was related to cost-shifting. Additionally, it was also estimated that, if NEM rules were maintained the same, cross-subsidies would have a huge impact on residential consumers bills: circa $45/month/per family in 2025 (DSIRE, 2017; NC Clean Energy Technology Center, 2016b).

Another discussion that calls ones attention is the issue of by whom the gains of solar projects are being appropriated. Considering that 75% of rooftop solar installed in California is leased, most of the benefits go to the leasing company rather the householder (THE EDISON FOUNDATION, 2014).

Addressing these challenges, the most recent revision of the program took place in June 2016, in order to align the costs of NEM 2.0 customers to those of customers who don't have photovoltaic systems, as the cost shifting is one of the main challenges to be addressed in the state (PG&G, 2017). The following adjustments were implemented (CPUC, 2016b; CPETA E TNEI., 2017):

- One-off interconnection fee (around $75-$150), based on the historical interconnection costs;
- Definition of a minimum monthly bill of $10 per month ($5 in the case of low income consumers) to be payed by prosumers even if the consumption is zero;
- Non-bypassable charges of approximately $0.03, per kWh consumed from the grid. This charge will be used to finance energy efficiency programs, cover costs such as for nuclear decommissioning, and to subsidize low-income consumers;
- Time-of-use tariffs compulsory for new photovoltaic consumers from 2017.

In addition, a "super-user energy surcharge" rate (for consumers requiring a high volume of electricity) will be implemented from 2017 (CPUC, 2016). It is estimated that this rate will affect less than 10% of residential consumers (CEPA and TNEI, 2017).

Even in face of the pressure from the distribution companies' lobby to reduce the compensation for electricity fed into the grid, the California Public Utilities Commission (CPUC) decision was to maintain net metering based on the valuation of surplus electricity exported to the grid by the retail electricity tariff. Another proposal rejected by the regulator was the implementation of capacity based charges and fixed charges for solar consumers. The proposals presented by the IOUs were as follow (NC CLEAN ENERGY, 2015):

- PG&E: $3 per kW, based on the maximum 60-minute demand during the billing cycle;
- SCE: $3 per KW of installed PV;
- SDG&E: $9.19 per kW, based on the maximum 60-minute demand during the billing cycle, and a $20.54 fixed monthly customer charge

Another key measure adopted in the State was the reform of the residential tariffs, in January 2016. The CPUC determined the gradual move to two-tier rate, rather than four-tier system. It was also created a super-user surcharge, which is going to affect less than 10% of the residential consumers. It was also stablished that the gap between the two tiers should be 25%, maximum (BARBOSE ET AL., 2016).

The four tiers scheme worked as a strong incentive to the installation of GDFV systems. Data indicate that in 2012 the levelized cost of a photovoltaic system for a residential consumer was between $ 0.25 and $ 0.29 per kWh, while the network tariff applied to tier four consumers was $ 0.33 per kWh (RMI, 2012). This reflects that, in the previous four-tiered rate structure, the above-cost, higher tired rates was inducing customers to adopt solar PV systems in large numbers, impacting low-usage consumers in two ways: the utilities loses revenues from solar PV adopters who were subsidizing other consumers (as they were billed in the upper tiers), and are also lost revenues resulting from a net-metering rate higher than the avoided costs (COSTELLO, 2015). In this sense, the high usage consumers who previously subsidized lower-usage, and, on average, lower-income consumers, after installing photovoltaic systems began to be subsidized by other consumers, including low-income households. "The result is gross economic inefficiency and a redistribution of wealth that favors higher-income consumers" (COSTELLO, 2015).

The Table 4 below provides a summary of Californian case study, presenting the main problems identified, the changes to network charging arrangements and the possible impacts.

Table 4: Summary of changes to network charging arrangements and their impacts.

State	Original Charging arrangement	Problem identified	Change introduced	Impacts	Conclusions
California	Net energy metering - customers can net off generation and demand effectively being paid retail rate for energy generated. Tiered volumetric tariffs so consumers of more net energy pay higher $/kWh.	Estimates of significantly higher gains to solar companies than utilities' avoided costs. Predictions of significant shift of charges from DG to non-DG customers by 2020.	The regulator's reforms included: • gradual move to two-tier rather than four-tier system; • move towards mandatory ToU tariffs for DG by 2019; • minimum $10 monthly charge, even without consumption; • "non-bypassable" charges; and • utilities can charge a one-off connection fee, estimated between $75 and $150.	The changes have proved controversial but are considered a better balance between the interests of solar companies and utilities than similar reforms introduced in other States. Changes to the ToU component are proving challenging. Historically, peak demand was during summer afternoons, but now a "duck curve" effect is starting to occur.	Consumer acceptance of tariffs depends on perception of fairness between energy users. Important to strike balance between reflective charging and simplicity. ToU tariffs must be flexible enough to adapt to changing trends in demand and generation.

Source: Adapted from CEPA and TNEI (2017)

5. Conclusions

As discussed in this chapter, volumetric network charges associated to net metering support policies create severe equity issues and inefficiencies. It happens because, as consumers install DG systems and fed excess generation into the grid, the electricity consumption from the grid is significantly lowered (SCHITTAKATTE ET AL., 2017). Due to this decrease, network charges must increase to allow cost recovery. Consequently, network charges paid by non-adopter consumers increase substantially, thus creating significant equity issues for non-PV owners (EID ET AL., 2014). Consequently, simple netted out volumetric network charges to recover grid costs cannot be considered an adequate network tariff design anymore.

Regarding the potential economic and financial impacts on electric power distributors, the analysis of the cases of Italy and California, carried out in chapter 3, showed that the potential loss of revenue coupled with the market downturn, although verified in both cases , it is only confirmed in the short term, in the period between the application of decoupling, that it is a regulatory mechanism capable of shielding distributors against market risk. This factor, however, does not mean that there are no impacts linked to the greater insertion of GDFV. At this point, it is necessary to return to the discussion of cost-shifting, which is not only pointed out as one of the central problems in both cases, but is also aggravated by the application of decoupling, since revenue losses are transformed into annual tariff increases. Thus, although it is a mechanism capable of addressing the possible impacts associated with the market risk faced by the distributors, the decoupling tends to accentuate, and even accelerate, the cost-shifting problem.

It is therefore necessary to consider that deeper reforms are necessary in order to ensure that PVDG diffusion does not result in a scenario where prosumers no longer bear the costs they effectively impose on distribution companies. Tariff structures need to be reassessed to ensure that they are still efficiently and fairly recovering the costs of network provision whilst also sending appropriate signals to network users (CEER, 2017). Thus, creating resilient tariffs has a key role in this discussion.

Although many arguments can be found in the literature showing the merits of some tariff structure in detriment of others, there is not a consensus over the best, a hundred percent resilient and future-proof network tariff design (SCHITTEKATTE ET AL., 2017).

In this context the reforms of the network tariff structure emerges as a possible response. The application of a tariff structure that is composed of elements that reflect the capacity demanded, and not only the volume of energy consumed, is widely discussed in the literature, and is especially relevant in the cases of Italy and California. Both cases, although having substantially different tariff structures, had two common characteristics: the predominance of the volumetric component in the distribution tariff (corresponding to a share of about 80% in the case of Italy and 100% in the case of California), and progressivity of the volumetric component. In both cases, this structure resulted, for different reasons, in the generation of cross subsidies. In the case of Italy, the kWh value applied to lower consumption blocks was set at a lower level than the actual kWh generation cost, resulting in a subsidized tariff. In the case of California, the freezing of the kWh price in the first two consumption blocks after the 2001 electricity crisis resulted in a context in which consumers with higher demand paid four times more for kWh consumed.

Thus both reforms in Italy and in California are underway to reduce the distortions generated by the application of progressive volumetric tariffs and to implement tariffs that are in line with the cost-reflectivity assumption. The reforms adopted in each case, however, differ in several respects. While in Italy the regulator has proposed both to completely eliminate the progressive nature of the volumetric tariff, when increasing the share of fixed and power components, in California the residential tariff is still compounded by the volumetric component, which continues to be progressive, despite the fact that reducing the number of consumption blocks from four to two and limiting the maximum difference between the tariffs applied in each block to 25%.

Changes in the tariff structure in order to mitigate cost shifting, therefore, are imperative in the face of the need to make prosumers with the costs that they impose on the network.

"Italy provides yet another example of a European country that has moved towards a greater reliance on capacity charges as the basis for network cost recovery. The tariff structure appears to be broadly in line with efficient charging principles – i.e. recovering (most) fixed costs through fixed and capacity charges. The tariff structure has been supported by the widespread availability of smart meters in Italy." (CEPA AND TNEI, 2017).

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Assessing the effect of the diffusion of solar PV in the Colombian and Brazilian residential sector

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Abstract

As the electricity industry is changing worldwide with the advent of Distributed Generation (DG), rapid expansion of DG has sparked the possibility of the 'utility death spiral'. This is a reinforcing cycle between solar Photovoltaic (PV) deployment and increases in electricity rates that speed the learning curve of the new technology, which results in demand reductions for the utility, with consequential revenue losses for utilities. These effects are matters of major concern to utilities as these challenge the traditional business model. In this context, and given multiple uncertainties, this paper examines the effect of the diffusion of PV technology on the revenues of a utility in the Brazilian electricity market, which offers favourable conditions for solar PV deployment such as: high radiation quality, high electricity tariffs, low solar PV costs and net metering.

The paper proposes a system dynamics (SD) model to investigate the effect of death spiral on the revenues of utilities, PV diffusion process is analysed for residential, commercial and industrial sector. It is concluded that for the Brazilian and Colombia cases, utilities could be higher affected for solar PV development, especially those over contracted. Much of the focus of previous research has been on the PV adoption in residential sector rather than the PV adoption in other sectors such as small commercial and industrial customers and their feedback effect on rates and utility cost recovery, this paper contributes to filling this gap.

Keywords solar PV diffusion, net metering, death spiral, simulation modelling

1. Introduction

As governments are increasingly committed to greenhouse policies, there has been greater investment in renewables. In this context, developed and emerging economies are swiftly establishing renewable targets, from 43 countries in 2005 to 164 in 2015 (IRENA, 2015) (See also Erro! Fonte de referência não encontrada.); and consequently power markets are incorporating large amounts non-fossil technologies.

Figure 1. Global map of national renewable energy targets of all types, 2005 vs 2015. Source: Irena (2015).

In 2015, 61% of new renewable energy capacity was added globally (Irena, 2017), increasing the participation of renewable power by 9.3% with respect to 2014. Most capacity additions have been in wind and solar photovoltaic (PV) facilities, which together account for 77% of all additions (147GW) (Ren21, 2016).

Learning effects make renewable power technologies more attractive and this is expected to be the case in the years to come: while the average Levelized Cost of Electricity (LCOE) from solar PV is expected to fall by as much as 59% by 2025, onshore and offshore wind are expected to drop by 26% and 35%, respectively (Taylor et al., 2016). In addition, these technologies have already reached grid parity in a great number of regions across the world (Breyer & Gerlach, 2013).

The cost reduction of renewable power technologies has incentivized distributed generation (DG)(Deloitte, 2015), and promotes to simultaneously produce and consume electricity on the same site, making this agents what are denoted "prosumers" (Bonbright et al., 1961).

European countries lead DG activities worldwide. While Denmark, Finland and Netherlands are prominent cases in Europe (Gischler & Janson, 2011), Mexico and Chile stand out in Latin America (Gischler & Janson, 2011). The development of

DG poses opportunities, yet also challenges for policy makers. Some of the challenges include increasing uncertainty in distribution grid flows and increasing volatility of net demand, as well as on local over-voltage.

Additionally, DG technology, particularly when based on solar photovoltaic, may be inconvenient to traditional business models of utilities, as costs have been showing swift reductions in recent years (Costello & Hemphill, 2014; Bronski et al., 2014); and these have also pressed further losses to utilities in terms of customers, sales and profits (EPRI, 2014; Satchwell et al., 2015a).

The growth of DG based on solar PV is tied to the concept of utility death spiral. This may occur as a reduction in the cost of solar PV sparks the adoption of solar PV panels by households (Castaneda et al., 2016); this, combined with the learning-curve effects, reduces the costs of solar PVs, incentivizing PV adoption. Note that the cost of electricity from the grid – transmission and distribution – is largely fixed and is recovered through charges allocated to customers; they are calculated as the fixed cost divided by the electricity demand (Hledik, 2014).

The utility death spiral has motivated reforms in the electricity markets; for example, changing the cost structures of Distributor Network Operators and redesign network charges (Pérez-Arriaga et al., 2013). However, under the right regulation and market design, DG can be exploited to establish a more efficient and cleaner electricity market (Pérez-Arriaga et al., 2013). The transformation process towards a green and decentralized power systems may be attained through the energy-political triad: clean, secure and competitive energy supply (Röpke, 2013).

Some countries are moving faster than others to a cleaner and decentralized power systems, but undoubtedly most of them will reach this technology transformation in the years to come. Regulator and electricity utilities face a variety of uncertainties in predicting the effect of renewable energies development, which hinders their long-term planning. This raises the following research questions:

- What are the potential impact of residential solar rooftop on distribution businesses?
- What are the market conditions that may lead to a death spiral for utilities?
- What can the regulator and utilities do to avert a death spiral achieving social welfare?

This research addresses these questions, adding insights to the analysis of the long-term effects of renewable energies on stakeholders in the context of Brazil and Colombia as both are developing nations with a high share of hydropower and confront challenges with the penetration of renewable energies. The chapter applies a System Dynamic (SD) modelling approach as this has been widely used in the field of energy policy.

2. Simulation model

Figure 2 shows the electricity market dynamics with a specific focus on the diffusion of solar PV systems. The Levelised Cost of Electricity (LCOE) refers to the generation cost of PV-owners. The electricity tariff, paid by consumers, incorporates the following components: electricity generation price, transmission charge, distribution charge, retail charge and other charges. Households compare LCOE alternatives with the electricity tariff to decide on their choice of electricity supply. Learning effects lead to solar PV cost reduction as the number of adopters of PV systems increases (See feedback loop B4). Electricity demand decreases when PV adopters increase, and consequently tariff charges increase to guarantee the economic sustainability of the network (See feedback loops R1 and R2). These reinforcing cycles increasingly reduce the number non-PV adopters.

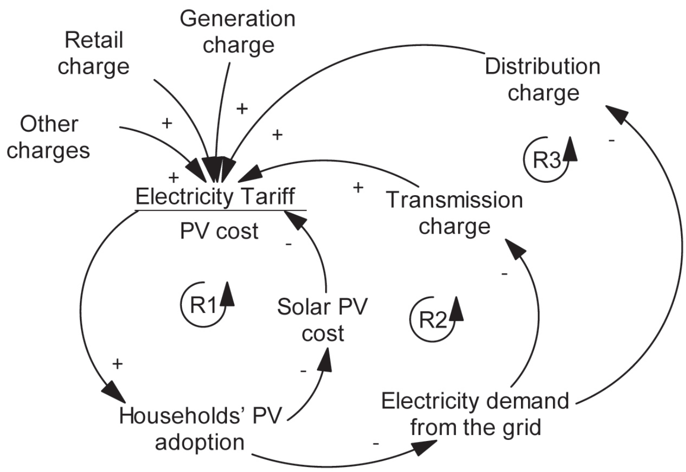


Figure 2. Utility death spiral.

The electricity tariff *EC* paid by consumers (Eq. (1)) incorporates the following components: generation charge *G* (also called electricity price), transmission charge *T*, distribution charge *D*, retail charge *R*, and other charges that incentivise renewable energies and security of supply (CREG, 1997).

$$EC = G + T + D + R + Other \tag{1}$$

PV diffusion follows the Bass model ("Bass (1969) New product growth.pdf," n.d.) that considers how information disseminated through potential households translates into PV-adoption. Eq. (2) establishes that the adoption rate, $n(t)$, depends on the potential number of adopters, m, the cumulative number of adopters at time t, $N(t)$, and coefficients of innovation and imitation, which correspond to p and q, respectively (Mahajan, Muller, & Bass, 1990):

$$n(t) = \frac{dN(t)}{dt} = p[m - N(t)] + \frac{q}{m}N(t)[m - N(t)] \tag{2}$$

The dynamics of the PV adoption, PV learning curve and rate-setting are depicted in **Figure 2,** that describes the main model components using stock and flow diagrams. "Households" is the unit of analysis used to measure populations of potential adopters and adopters, since a solar PV system usually owns to one family. In fact, total households, TH is calculated taken the population, P, and divide it by the average size of persons in a household, q (Eq. 3).

$$TH = P / q \tag{3}$$

PV adoption is considered by household customers that live in houses with exclusive rights to the roof. Potential PV adopters increase according to the population growth and new dwellings in place with no PV installations. Households willing to adopt, WHA, augment by the fraction willing to adopt, FWA, and population growth, that is calculated as the total households, TH, minus potential household adopters, M, and adopters, N (Eq. 4).

$$HWA = FWA \cdot (TH - M - N) \tag{4}$$

Fraction willing to adopt is a function that compares electricity *PV Cost* and electricity *Tariff* to represent the attractiveness to install PV (Sterman, 2000).

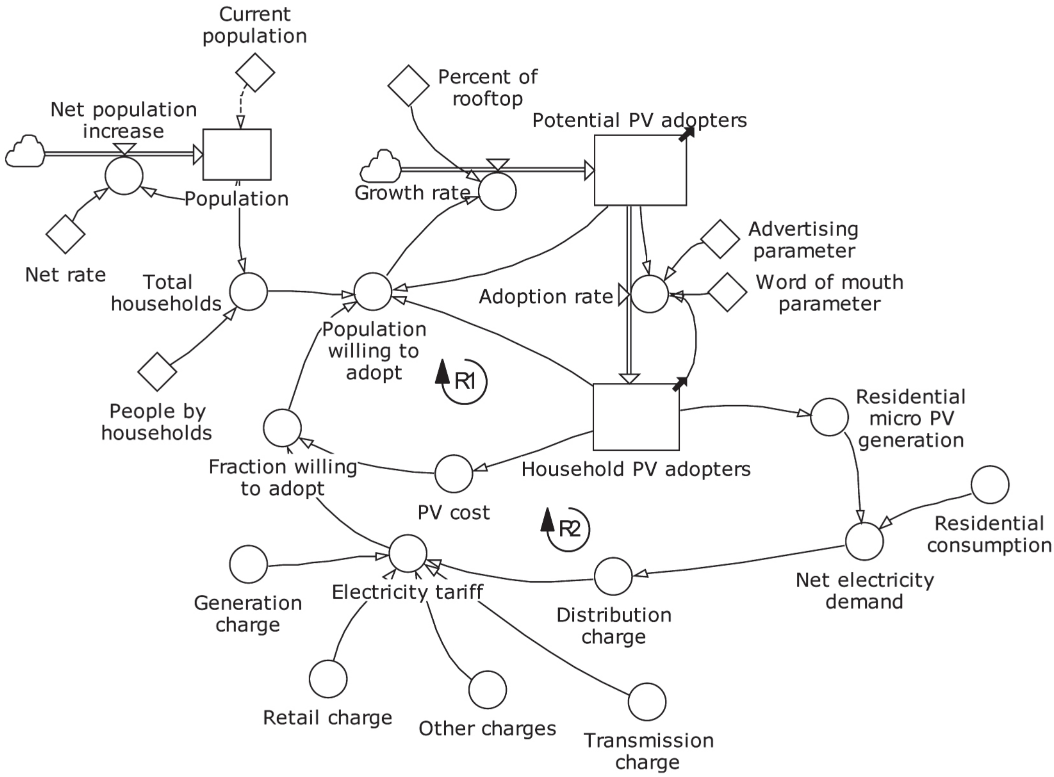


Figure 2. Stocks and flows of the utility death spiral residential sector.

In this research, distribution charge is model endogenously. Distribution charge is mostly volumetric, i.e., fixed costs are spread on the households' energy use or Net electricity demand. The model calculates the distribution charge based on the principle that the utility must fully recover the fixed costs, achieving the total revenue requirement. Eq. 5 to 9 show how distribution charge is model endogenously.

$$D_t = \frac{DNC}{E_{vt}} \tag{5}$$

$$E_{vt} = EM + EN \tag{6}$$

$$EM = M \cdot (Z - S) \tag{7}$$

$$EN = (TH - M) \cdot Z \tag{8}$$

$$Utility\, income = D_t \quad E_{vt} \tag{9}$$

Where D_t is the distribution charge, DNC are the distribution network costs, E_{vt} is the electricity demand by voltage level, EM is electricity demand from PV adopters, EN is the electricity demand from non-PV adopters, Z is the average energy consumption by household, and S is the microgeneration by household.

3. Application cases

This section presents the application cases: Colombian and Brazilian electricity markets. Though, both electricity markets present regulatory differences. Both countries have similar hydropower capacity and high potential of solar energy.

3.1 Colombia

Colombia is located in the equatorial zone of South America, with a high sunshine availability and an average solar radiation of 4.5 kWh/m^2/day, which is favorable to photovoltaic deployment (UPME & IDEAM, 2005). Despite its solar potential, the implementation of solar-based resources has been only about 9 and 11 MWp (UPME, 2015b), while its generation is greatly hydroelectric (around 70%) (UPME, 2015a). This article considers the penetration of rooftop solar panels in the residential sector only, though attractive given its great potential – about 40% of the total electricity demand (SUI, 2015) – which leaves out the industrial, commercial and institutional sectors – clearly underestimating the overall effect that PV diffusion may perpetrate on the system.

Furthermore, PV diffusion is not only favored by Law 1715 (Congreso de la República de Colombia, 2014) but also because the technology has reached grid-parity in a great number of urban areas of the country (Jiménez et al., 2014; SUI, 2016). While the effects of Law are still uncertain, there are nevertheless challenges in the electricity generation and distribution business as discussed in Jiménez et al., (2016) and Castaneda et al., (2016).

The Colombian electricity market adopted in 1994 the pool-based British design: unbundling the generation, transmission, distribution and trading businesses, and creating competition in generation and trading, according to the liberalization trend that dominated the industry at the time (Larsen, Dyner, Bedoya V, & Franco, 2004). Regarding technology, Colombia has a high share of hydropower (about 70% of the total installed capacity) and a high potential for non-conventional sources of energy. The average solar radiation is 4.5 kWh/m^2/day and the wind power potential in the northern region is 21 GW (exceeding its current installed capacity, which amounts to 16 GW) (Pérez & Osorio, 2002; UPME, 2005; "XM," 2015). Additionally, the government has taken an important step to support the development of renewable energies, through Law 1715 (Congreso de la República de Colombia, 2014).

This involves risk, considering that: i) sustained growth in electricity demand could lead to power shortages due to droughts caused by El Niño phenomena (Larsen et al., 2004);

ii) disregarding grid imperfection, during an average rainy season hydroelectricity is capable of meeting 100% of demand; iii) as electricity dispatch operates according to merit-order rules, there are no market incentives to *firm* energy – the capability of delivering energy during dry periods – different from the capacity mechanism in place; and iv) as Colombia faces natural gas shortages, some thermal generation operates with imported liquid fuels at a price as high as 25USD/MWh, which, given the logistical expenses, makes it unsustainable as the system price peak is not much higher than 15USD/MWh. In the short- to medium-term, imported gas is not a solution as infrastructure is inadequate.

In summary, Colombia was chosen for analysis because of the propitious conditions for solar PV development such as high solar radiation, the new Law for renewables and the availability of quality data. Thus, it is necessary to study the transitional actions to help utilities adapt to the changes that could be on the horizon. This research attempts to fulfill this need.

3.2 Brazil

Several features make the Brazilian power system an interesting application. Brazil is the largest power market in the Latin American region, its installed capacity reaches 116 GW and hydroelectric power accounts 70% of the energy produced (MME & EPE, 2015). The regulatory model in Brazil is based on long-term contracts, seeking to secure reliable electricity supply to consumers at least-cost expansion (Maurer & Barroso, 2011). From 2004 onwards, electricity is negotiated in two energy-trading environments: The Regulated Contracting Environment (RCE) and the Free Contracting Environment (FCE). In the RCE, distribution companies buy energy from generators through energy auctions of long-term contracts, to meet the electricity demand of captive (regulated) consumers; in the FCE, free consumers can negotiate bilateral contracts with generators (Rego, 2013). Furthermore, distribution companies are required to cover 100% of their expected demand by energy contracts.

Brazil's renewable energy target calls for 70% of its energy coming from renewable sources by 2020 (Ministry of Economic Affairs, 2015). This target attaches great importance to solar PV development in Brazil, with favorable conditions for solar PV as electricity tariffs are high, PV system costs are low and as solar radiation reaches between 6.5 and 7.0 kW kWh/m2/day (Bueno et al., 2006). The feasibility of solar PV systems is analyzed in Brazil, particularly in Minas Gerais, the country's second largest state for rooftop solar PV potential in the residential level – 3675MW (EPE, 2014).

Although, PV adoption of the residential, industrial and commercial low voltage consumers is the focus of this study.

In 2012, Brazil introduced a net-metering scheme for small-scale distributed generation systems by regulation 482. Brazilian net-metering program enables energy producers to receive credits for providing surplus energy into the grid, which can then be used to lower next month’s electricity bill or as virtual net-metering to abate consumption costs on other locations associated to the same customer and distribution area. This scheme allows customers that do not own roof space to take advantage of solar energy-saving opportunities (Aneel, 2012). The credits are valid for up to five years; additional, electricity drawn from the grid is paid at prevailing electricity tariff (Aneel, 2015).

The Brazilian Government's effort to harness the true potential of distributed solar is evidenced through other legislations such as ICMS, PIS and COFINS tax exemption for net metered solar PV systems (EPE, 2012).

Several papers have addressed the effects of solar PV household-diffusion on rates, utilities profit and the load curve (Januzzi & Melo, 2013; Cai et al., 2013; Darghouth et al., 2016; Jiménez, Franco, & Dyner, 2016). Nevertheless, important aspects on this topic remain unanswered; particularly, it remains unknown the effect that PV diffusion within the residential has on hydroelectric countries, in comparative basis. This chapter fills the aforementioned gap using a system dynamic approach.

4. Results

This research applies the simulation model that has been built to Colombia and to the state of Minas Gerais in Brazil. Next, this section discusses simulation results that address the posed questions.

- What are the potential impact of residential solar rooftop on distribution businesses?

By 2036, the percentage of PV adoption respect to the total number customers is 30% and 25% for the Brazilian and Colombian residential sector, respectively. Particularly, the total PV installed capacity from Colombia for the residential sector by 2036 is 7.2GW, considering an average panel size of 1.7kW. For the Brazilian case, Minas Gerais, the residential solar PV capacity accounts for around 276MW, considering an average panel size of 1.2kW. (See **Figure 3**)

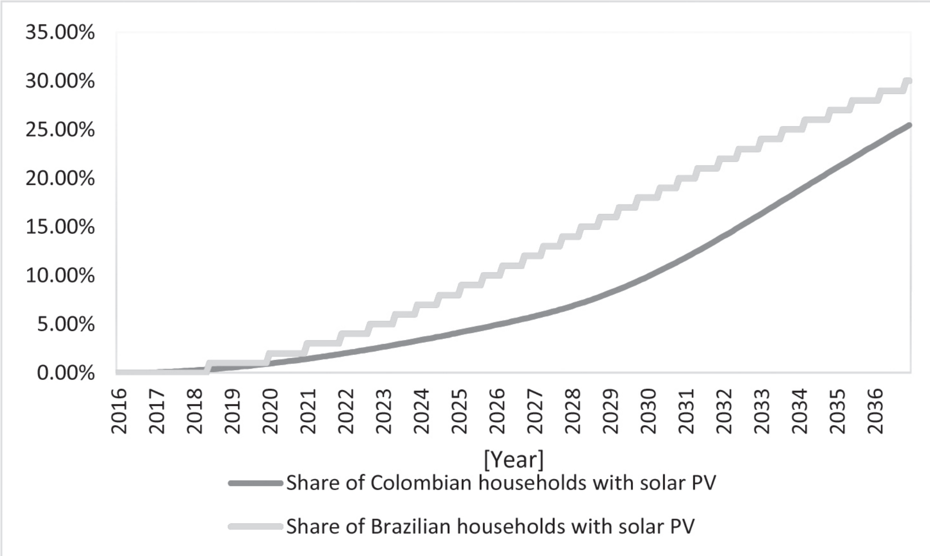


Figure 3. Share of households with solar PV

From 2016 to 2036, residential energy demand decreases at rate of 0.5% per year for Brazilian region, Minas Gerais. While in Colombia, residential energy demand decreases at rate of 2% per year.

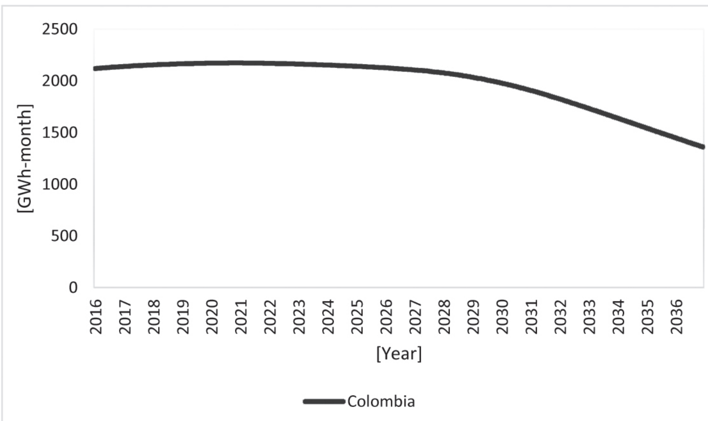


Figure 4. Colombian energy consumption from the residential sector

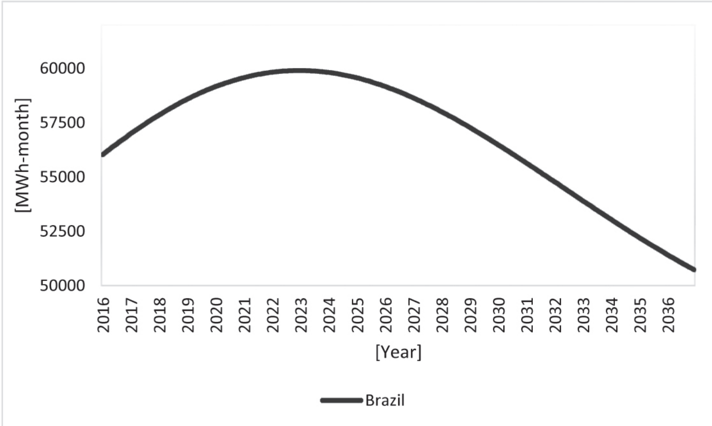
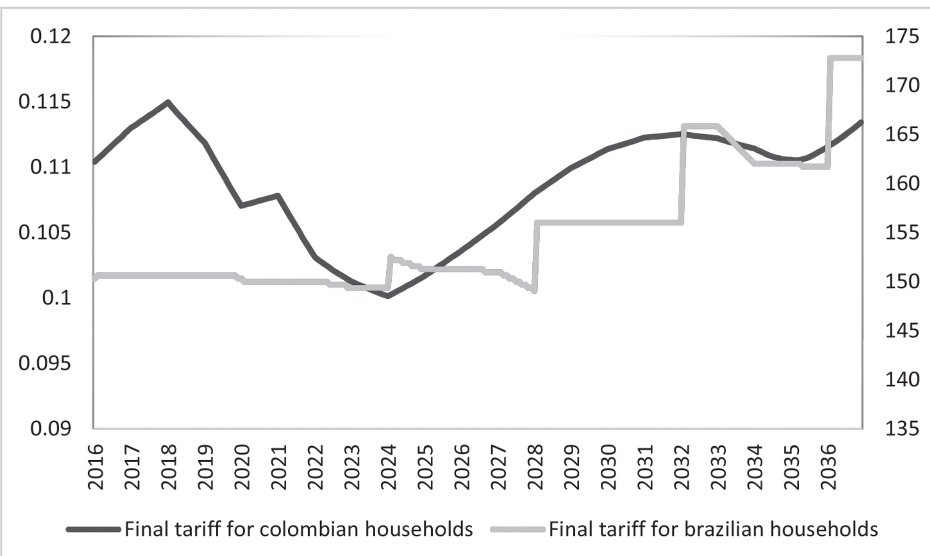


Figure 5. Brazilian energy consumption, Minas Gerais, from the residential sector

Between 2016 to 2036, distribution tariff for residential sector in Brazil increases by 55%. Similar behavior is experienced for the distribution tariff of residential customer in Colombia, where distribution tariff grows 56%. In Brazil, tariff revision is more notable because the distribution tariff is calculated yearly, with a four years delay, and remains constant during each period until the new tariff review, which explains the step pattern.

In the Brazilian region of Minas Gerais, the energy cost for the distribution company, i.e., the cost of buying electricity to generators through contracts declines by 11% due to solar PV penetration and contract expiration. In Colombia, the solar PV penetration causes oscillation in the energy cost which is modelled endogenously. The behavior of these tariff components is depicted in **Figure 6**.



- What are the market conditions that may lead to a death spiral for utilities?

In Colombia if households are over installed with 3kW panels the system collapses in 2035. The large-scale diffusion of solar PV provokes the highest residential tariff because network costs are spread over a shrinking energy consumption by 2035 – since the total solar PV production minus the total energy consumption falls dramatically in the residential sector for this hypothetical case (Castaneda et al., 2017).

In Brazil, the compensation scheme –Net Metering– is clear to PV adopters. In this place, surplus of solar PV is not compensated with cash, and credits are accumulated for the next period. These credits have expiration date. Therefore, it seems that there is not an incentive to PV adopters have over sized PV systems. However, there could be an incentive if PV adopters with several properties decide to take advantage of virtual net metering. However, this could also be motivated if Brazilian government creates the environment to flourish new business models such as community solar based on crowdfunding (Funkhouser et al., 2015).

- What can the regulator and utilities do to avert a death spiral achieving social welfare?

The challenge for the policy-maker is to integrate the PV systems ensuring system sustainability, i.e., affordability to customers. Alternative systemic market interventions that can be implemented to address death spiral problem, including: (i) reducing the ratio between the electricity tariff and the cost of solar PV, by internalizing the transmission/distribution costs involved in back-up-support to household, which in turn will increase the transition costs of solar PV systems; (ii) modifying the methods of compensating prosumers (e.g. Net Metering) to reduce the incentives to install oversized PV arrays; (iii) tariff changes to distribution tariff. Additionally, utilities can take different stands in order to protect their business models from the death spiral taking actions such as: (iv) proactively changing their business model; and (v) strategically costing their services (Costello & Hemphill, 2014; Poisson-de Haro & Bitektine, 2015).

5. Conclusions

This chapter explores the solar PV effects on distribution utilities in Brazil and Colombia. Long-term consequences of the solar PV deployment are sales reductions resulting from greater PV adoption, and greater revenue losses for utilities.

Results indicate that death spiral for utilities is possible when some vicious cycles take place, where the electricity PV cost, the electricity tariff and the PV adoption rate for customers are critical variables. Distribution tariff review exacerbates death spiral effect, making distribution tariffs higher as a consequence of PV adoption and therefore lower energy consumption. Mid- to long-term consequences of the death spiral include sales depression as the result of greater PV adoption, and greater revenue losses for utilities.

Regarding these concerns, different strategies to deal death spiral were analyzed. Strategies aim at helping the transition process of utilities towards different business models, mainly taking care for the social damages of not taking preventive measures, not favoring utility businesses over societal benefits, and only providing alternatives to avert the death spiral as a possible threat to system sustainability and the social welfare.

As distribution company has energy contracts with a very long duration, energy cost is not very sensitive to high PV adoption, therefore energy cost reduction does not compensate distribution tariff increases leading to the rise of electricity tariff.

For the Brazilian, as the distribution company has energy contracts with very long terms, energy tariffs are not very sensitive to high PV adoption in the short-term, and tariff increases take place with a lag. For the Colombian case, electricity tariff increases instantaneously overtime and on average tend to be higher than in the case of Brazil.

Mid- to long-term consequences of the death spiral to the incumbent electricity distribution business include sales decreases as the result of greater PV adoption and greater revenue losses for utilities. Specifically, public goods affected by a death spiral include grid reliability: if large numbers of customers become prosumers, the network reliability is destroyed, and everyone loses because households remain connected to the grid and electricity distribution becomes unsustainable. This situation suggests that efforts to protect the system from a death spiral's negative effects would be desirable for a smooth technology transition of the power supply system.

Although there are market design differences between the Colombian and Brazilian cases, the mid- to long-term effects are similar, and findings, recommendation as well as lessons do not differ significantly.

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Net Energy Metering in Nevada: A Case Study[1]

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Abstract

The Net Energy Metering (NEM) rate structure was first implemented in the US in 1983 to encourage renewable generation. Under the NEM rate structure, the utility must purchase customer-generated power even if less expensive power is available from other suppliers, and the customer does not have a contractual obligation to sell power. In the US, 44 states implemented NEM rate structures, and most of these states capped the NEM capacity. As states approached and hit these caps, regulators and policy-makers faced a pair of related questions: a) Should the state increase the cap and continue to offer the NEM rate structure to customers with rooftop solar panels? b) If not, how should the state transition to a new rate structure for those customers?

Regulators and policy-makers facing these issues have commissioned analyses and implemented changes in 27 states. Recent events in one state, Nevada, highlighted the potential political implications of terminating NEM rates given the current level of concern about long-term impacts of climate change. These events demonstrate the importance of public perceptions and understanding of NEM regulatory issues, and the challenge of conveying clear information through media channels.

This chapter fills a gap between the in-depth analyses provided in technical reports and the more accessible descriptions of specific events provided by media sources. It provides a non-technical summary of the advantages and disadvantages of rooftop solar generation, and it describes the sequence of events in Nevada as regulators and policy-makers addressed the issues posed by the NEM rate structure. We conclude that the emerging smart grid technology may provide solutions to these issues. Smart grid technology can potentially obviate some of the grid-management challenges posed by mandatory purchase of power generated by rooftop solar panels. In addition, this technology will generate new types of micro data that will support the detailed cost studies needed to resolve questions about the extent to which non-NEM customers cross-subsidize NEM customers.

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1. Introduction

Net energy metering (NEM) is a rate structure for utility customers with on-site generation capability. Typically, these customers own or rent rooftop solar panels; however, net metering can be applied to electricity generated from a range of energy sources such as wind, geothermal or biomass energy. Under a NEM rate structure, the customer consumes electricity generated on-site as well as electricity generated, transmitted and distributed by the utility[2]. Generating electricity in such decentralized manner with relatively small scale equipment is called distributed generation (DG). Distributed generation could potentially occur under a range of rate structures, including a NEM structure.

During time periods when the customer-generated electricity exceeds the customer's consumption of electricity, the excess customer-generated electricity is delivered to the distribution and transmission grid. The customer pays the retail rate for net electricity consumed during a specified time period. Net electricity consumption is typically computed, in U.S. states, on a monthly basis. However, most states permit carry-over of unused credits to the following month, and California computes net consumption over a 12-month period. NEM is usually justified as a means to incentivize private investments in renewable energy and diversify the energy sources while helping the local economy and the environment.

Under this rate structure, utilities essentially purchase customer-generated power at the retail rate. In addition, these purchases are not optional: the utility cannot refuse to buy customer-generated power when prices offered by other power producers are lower than the mandated retail rate. Most states, therefore, legislated caps on the installed capacity for customer-generated power that would qualify for NEM rates.

The first net metering law in the U.S. was enacted in Minnesota in 1983 (Wan and Green (1998)). At the time, the share of renewable sources in US electricity generation was negligible. NEM emerged as an innovative way to attract private investments into renewable generation. For utility companies, allowing such environmental friendly endeavors while letting the customers save money was an opportunity to build good reputation at little extra cost.[3] As of January 2011, total NEM installations amounted to 2,024 megawatts, less than 0.2% of the total generation capacity.[4]

2 Transmission refers to transferring the high voltage electricity from the power plant to the transformers where it is "transformed" into lower voltages. Distribution, on the other hand, is for the lower voltage electricity taken from the transformers and carried to our homes.
3 Mostly in the form of foregone revenues.
4 Source: http://www.eia.gov/electricity/data/eia826/. Accessed August 2016

Recently, the consensus on anthropogenic reasons being behind the increases in the earth's surface temperature has strengthened among scientists (Stenhouse, Maibach, Cobb, Ban, Bleistein, Croft, Bierly, Seitter, Rasmussen, and Leiserowitz (2014), Cook, Nuccitelli, Green, Richardson, Winkler, Painting, Way, Jacobs, and Skuce (2013)). In response to concerns about climate change and environmental quality, federal and state governments in the U.S. support increased reliance on renewable energy sources by offering subsidies as well as passing regulations in favor of NEM. At the same time, technological advances have reduced the cost of solar PV panels dramatically (Barbose and Darghouth (2016)). These trends made residential solar rooftop generation technology accessible and desirable to middle or upper-middle income households in the U.S., and installed NEM capacity nearly doubled from 2013 to 2016 (see Figure 1).

As of October 2016, 44 states plus the District of Columbia implemented mandatory NEM policies with varying rules.[5] In addition, two states (Idaho and Texas) permitted utilities to voluntarily implement NEM rate structures, and three states (Nevada, Mississippi, and Georgia) implemented non-NEM rate structures for customer-generated power. Nevada's non-NEM status was short-lived, however, as this policy was reversed in the subsequent legislative session.

Many states are currently going through revisions of their net metering policies. Due to scheduled reductions in energy-related federal tax credits and increasing recognition of challenges posed by the NEM rate structure, the sustainability of NEM without some major changes is questionable at best (Price, Ming, Ong, and Grant (2016). In response, regulators of 27 NEM states recently made some changes or conducted further studies on NEM policies (Inskeep, Case, Daniel, Lips, Proudlove, and Shresta (2015)). These state level policies are expected to play a key role in defining the future of distributed generation due to the fact that U.S. utilities are typically regulated by state regulatory commissions.

Information sources around this issue are confined to highly technical reports and media coverage which tend to be limited to reporting of the specific events and/or one sided arguments. The purpose of this paper is to fill this gap by providing a comprehensive, unbiased, and relatively accessible account of this rather complicated topic. In this chapter, we discuss the advantages and disadvantages of NEM policies from a conceptual perspective, and then we describe the events in Nevada that provide a concrete illustration of the political implications of these issues and role of data and analysis in the policy debates. We conclude by discussing the potential for improved cost estimation

5 Source: http://www.ncsl.org. Accessed July 2016

techniques, supported by data from smart grid technology, to support policies to utilize customer-generated electricity while reducing the disadvantages of the NEM strategy.

2. Advantages and Disadvantages of the NEM Rate Structure

While NEM rate structures facilitate several policy goals, they also pose significant challenges. Effective policy making requires unbiased and impartial evaluation of all the aspects to the extent possible. Since most of the technicalities regarding the electricity sector are highly location specific, rigorous local engineering analyses may be required for some of the items, instead of relying on studies done at other states.

A. Benefits offered by NEM

The distributed generation facilitated by NEM rate structures offers several benefits. First, when generation occurs onsite, the electricity used by these consumers is not carried through the transmission lines. This reduces the losses that occur during the transmission and distribution, which are directly proportional to the amount of energy transmitted at any point in time. In addition, reduction in transmission may reduce the rate of depreciation of components of the grid. Note, however, that the losses avoided this way will be limited if the majority of the distributed generation is exported into the grid.

Second, distributed generation could potentially reduce the need for investment to increase generation and transmission capacities. In exchange for the monopoly status, the regulated utility has to meet reliability standards. This implies that the utility must maintain sufficient generation, transmission, and distribution capacity to deliver electricity demanded during peak load hours. Therefore, the extent to which the existence of decentralized generation capacity obviates the utility's need to invest in new capacity depends on the degree to which distributed generation coincides with peak loads. This relationship between the time-of-day and time-of-year peak demands and the time-of-day and time-of-year of peak onsite generation is location-specific.

Third, distributed generation diversifies the location “portfolio”, which provides protection against potential natural and manmade physical hazards. Perez and Collins (2004) suggested that the 2003 blackout, that impacted both the U.S. and Canada, could have been prevented with strategically located PV generation units. Another benefit of having more geographically diversified generation capacity is the reduced fluctuations in overall generation quantity. Ho and Perez (2010a) and Ho and Perez (2010b) show that short-term intermittency of a fleet of PV generators decreases in the inverse of the square root of their number if the fluctuations in the generations of each system are uncorrelated. According to Perez, Kivalov, Schlemmer, Hemker, and Ho (2012) correlations among these fluctuations decrease in distance.

Fourth, rooftop solar PV installations reduce solar gain, reducing the need for air conditioning and potentially increasing the need for heating. Using data collected in San Diego, Dominguez, Kleissl, and Luvall (2011) estimated a cooling load reduction of 38% with no significant impact on the heating load. In contrast, Kapsalis and Karamanis (2015) found that the heating load increased by 6.7% while the cooling load decreased by 17.8%, using data collected in western Greece.

Fifth, distributed solar installations may function as substitutes for large-scale solar plants. Large-scale solar maintains a cost advantage over distributed solar installations; however, this cost advantage may be offset by adverse environmental impacts of large-scale solar installations or by incentives built into Renewable Portfolio Standards. Trade-offs between distributed solar installations and large-scale solar plants are also location-specific (Turney and Fthenakis (2011)).

Finally, distributed solar installations may reduce carbon emissions, to the extent that this power generation substitutes for fossil fuel generation.

B. Challenges posed by NEM

First, large-scale solar facilities generate electricity at substantially lower cost than distributed-generation installations. Using data from U.S. solar installations, Barbose and Darghouth (2016) report that the 2015 median installed price for residential systems was $4.1/Watt of installed capacity, while the price for nonresidential systems larger than 500 kW capacity was $2.7/Watt. In addition, large scale solar facilities typically yield more electricity per Watt of installed capacity. This cost differential implies that residential solar generation is not economical for utility customers who do not participate in a NEM rate.

Second, the utility cannot curtail electricity exported into the grid by the NEM customer, while the utility can specify the terms on which it will purchase power from other producers. In this situation, NEM rate structures prevent the utility from ensuring that it purchases power from low-cost producers.

Third, NEM customers essentially sell generated power at the retail rate. In contrast, other power producers sell generated electricity at a lower wholesale rate[6], with the difference between the retail and wholesale rates covering the costs to transmit and

6 The retail rate is about 12c/kWh in Nevada, for example, while the wholesale rate can be as low as 2c/kWh.

distribute the power. To the extent that the timing of NEM customer generation does not fully coincide with the timing of electricity utilization, NEM customers utilize exports (and imports) to (and from) the grid without paying for those grid services. This implies a cross-subsidy from non-NEM customers to NEM customers.

Fourth, NEM customers can utilize free grid services to address discrepancies in the timing of their electricity production and consumption of electricity. The availability of these services minimizes incentives for NEM customers to adjust the timing of electricity consumption or to invest in storage battery capacity.

Fifth, the structure of distributed generation exacerbates the problem posed by the intermittent nature of solar and wind power generation. Imagine a hypothetical situation in which a large cloud casts a shade over all solar panels in a city. Solar panels in this city will not generate power until the cloud moves away. A house with rooftop solar PV panels will not only stop exporting electricity to the grid; it will also instantaneously start drawing electricity from the grid. These sudden changes will exacerbate volatility in the overall system, potentially increase the amount of spinning reserves necessary to address the volatility issue, and increase reliance on the imbalance market to insure the resilience of the overall grid.

Finally, the regulated utility is required to provide universal, reliable service. The utility files detailed rate cases in which information about costs incurred by the utility is substantiated in open PUCN hearings before they are allowed to increase the rates. In addition, the electric utility business is inherently highly capital intensive where large investments in generation, transmission, and distribution capacity are necessary before the electricity is sold and bills are collected. Under current regulatory policies, regulators typically mandate that utilities recover these investments over the physical lives of the power plants; hence cost recovery may extend over 40 years. When a NEM customer starts utilizing less electricity the utility saves money on fuel to serve this customer, however the portion of the fixed cost that was incurred to serve that customer does not go down. If the regulator does not increase rates (for all customers) to enable the utility to fully recover that cost, the utility would face "stranded costs". "Stranded costs" occur only in regulated industries. Regulated utilities build capacity to meet customer service requirements mandated by the regulator, after that regulator approves the construction plan. The regulator subsequently sets the price customers will pay for electricity, in compliance with the legal requirement that prices must be set to permit the utility to earn a reasonable return on its investment. Thus, the utility has a duty to build sufficient capacity to serve its customers, and the regulator (who represents the customers) has a responsibility to allow the utility to recover the invested funds.

Subsequent installation of rooftop solar units by some of those customers does not negate that responsibility. (Utilities do not bear the same market risk as unregulated firms, because they are not permitted to charge market-clearing prices.) If the regulator raises rates charged to non-NEM customers, then these non-NEM customers would cross-subsidize the NEM customers. If the regulator does not raise rates enough to allow the utility to recover its invested funds, then the unrecovered costs are denoted as “stranded costs”.

3. Case Study: Controversy and Policy in Nevada

Nevada created a NEM rate structure in 1997, for customers installing onsite generation capacity that did not exceed that customer’s annual electricity consumption (with a maximum allowable installed capacity of 1 MW). In addition, the state mandated that statewide NEM capacity would not exceed 3% of the statewide peak capacity. Installations using solar, wind, geothermal, hydropower and biomass energy were eligible; however solar power dominates this market and the political controversy focused on rooftop solar generation.

The state also strengthened the Renewable Portfolio Standard (RPS), which specifies the percentage of electricity generation that must utilize renewable sources of energy. By 2025, 25% of electricity generation must utilize renewable energy sources. NEM customers receive rebates from the utility for their investments in renewable capacity, and – in return - the electricity generated from these installations is included in the renewable generation required to meet the RPS requirements. The 1997 law capped spending for these rebates at $255 million.

To encourage development of the solar industry, the state mandated that each kilowatt-hour generated by from utility scale solar plants and distributed solar panels “counted” as 2.45 kWh and 2.4 kWh of renewable generation, respectively. Thus, each kWh of generation from these sources had a higher value to the utility company relative to other avenues for compliance. Under this policy, the residential rooftop solar systems in Nevada actually increased the carbon footprint because they reduce the overall capacity needed to meet the standard. By law, this policy was terminated at the end of 2015, so that each kilowatt-hour of electricity generated from solar power is now “counted” as one kilowatt-hour.

The state also granted $614 millions of tax credits to new capital investment in renewable energy generation under its Renewable Energy Tax Abatement Program .[7]

7 Approximately 90% of the generation capacity built within this program in 2015 is solar. Source: State of Nevada Status of Energy Report (2015)

Additionally, loans were offered to businesses financing construction of renewable energy systems, as a part of the 2009 American Recovery and Reinvestment Act effort to stimulate recovery from the Great Recession. Coincident with the state's policies to encourage development of renewable energy generation, the federal government offered a tax credit for residential renewable energy systems that are installed by the 2019.[8]

The trajectory of the solar industry in Nevada was further accelerated by the State's ambitious economic diversification efforts in addition to the environmental goals. In 2013 Solar City (a residential rooftop solar PV company) was offered a 1.2 million dollar incentive to move their operations to the state.[9] Solar City began accepting applications for rooftop solar installations in May 2014, while the installed capacity started inching towards the 3% cap (225 MW).

This package of policies fostered rapid growth of installed rooftop solar generation capacity in Nevada (see Figure 2). In turn, this growth raised questions about the economics of NEM. Initially, these questions focused on the price paid for electricity exported to the grid, and the magnitude of potential cross subsidies from non-NEM customers to NEM customers.

In June 2013 the state governor approved Assembly Bill 428 requiring the Public Utility Commission of Nevada (PUCN, which regulates utilities in the state, to open an investigatory docket to examine the comprehensive costs and benefits of net metering".[10] During the process PUCN publicly solicited comments on the appropriate approaches for answering the question. Eventually, Energy and Environmental Economics, Inc., a private consulting company, was commissioned to conduct the study (E3 hereafter) and first results are published in 2014 (Price, Pickrell, Kahn-Lang, Ming, and Chait (2014)). It is estimated that there would be about a \$36 million benefit to non-metering customers.

One of the key assumptions under which E3 came up with this number is that the cost of utility scale solar would be \$100 per MWh. This study was published in 2014 so the assumptions regarding the cost of utility scale solar were based on the data available at the time. However, since then, the cost of utility scale came further down. According to a recent study by Lawrence Berkeley National Laboratory, \$50 per MWh was achievable as of 2015 (Bolinger, Weaver, and Zuboy (2015)). These figures inevitably affect the economics of NEM. The E3 study also estimated that the median income of all residential NEM customers were about \$67K while the Nevada median income

8 Source: http://energy.gov/savings/residential-renewable-energy-tax-credit
9 Source: http://diversifynevada.com. Accessed July 2016
10 https://www.leg.state.nv.us/ Session/77th2013/Minutes/Senate/CL/Final/1371

at the time was $53K. This implies that the cross-subsidy from non-NEM to NEM customers is regressive.

The 2015 session of the Nevada Legislature addressed two issues. First, the rapid filling of the 3% quota by increasing the cap on installed capacity to 235 MW (SB 374). Second, the PUCN was directed to examine the rates applicable to net metering customers and identify and eliminate any unreasonable shifts in costs from net metering customers to other customers" (SB 374). Additionally, the state's electric utility was required to file a proposed tariff, or rules and rates and the PUCN had until the end of the year to review it and approve a new tariff. The utility proposed a new tariff structure that eliminated cross subsidies by separating the rate payers into classes. The tariff included three components: a basic service charge, which is a fixed charge that the NEM customer pays regardless of the consumption level; a volumetric charge that increases with the kilowatt hours consumed; and the compensation rate paid by the utility to the NEM customer for the exported electricity.

The rates under this rate schedule are provided in Table 1. The basic service charge is scheduled to triple within the next 12 years, while the amount by which the excess generation will be credited will gradually drop from 11 cents/kWh to less than 3 cents/kWh. Also, the NEM customers will pay slightly less for volumetric charges.[11] This rate redesign strategy is not unique to Nevada. As states increase the fixed charge and reduce the volumetric rate, they reduce the salience of the fact that NEM requires utilities to purchase power at the retail volumetric rate.

Following a series of hearings and economic investigations, the PUCN announced decisions in December 2015 that effectively rendered NEM uneconomical for both new and existing customers. These decisions terminated the NEM rates for both new and existing NEM customers. These decisions sparked vigorous opposition from rooftop solar vendors, renewable energy advocacy groups, consumer protection agencies, politicians, and Hollywood stars (Fehrenbacher (2016)). According to an online survey conducted by Las Vegas Review Journal, large portion of the respondents said they are not happy with the new rates. The primary concern articulated by survey respondents was that the PUCN was “going back on its word” by not grandfathering existing NEM customers into an ongoing NEM rate.[12]

11 Initially these changes were scheduled to take place within 4 year, but later on in February 2016 the transition period was increased to 12 years.

12 Source:http://www.reviewjournal.com/business/energy/utility-regulators-ok-phased-rate-hikes-rooftop-solar-customers. Accessed September 2019.

The future for distributed generation under NEM was also clouded by the fact that the rebate program reached it's spending limit of $255 million. As a result, the future NEM systems are not expected to be eligible (Price, Ming, Ong, and Grant (2016)) for this financial support. In theory, those customers who did not receive any state incentives for their renewable systems could potentially earn credit for the electricity they generate. However, in practice the power utility is already over-complying the RPS.[13] Therefore, at the moment there is not really any mechanism for the renewable energy system owners to be rewarded for reductions in carbon emissions.

Eventually, the PUCN approved in September 2016 to grandfather the existing NEM customers back to the original rates.[14] Although this decision significantly reduced the tension, it was not quite sufficient for certain stakeholders and there were further pressure for bringing back the favorable NEM rates for the new customers as well. An attempt to place this proposal on the November 2016 ballot as a voter-initiated ballot measure was rejected by Nevada Supreme Court in August 2016.[15]

Nevadans did, however, vote on a second voter-initiated ballot measure, to open the retail electricity market to competition in the November 2016 election. This measure passed. To become law, it must appear on the ballot again in 2018, and pass a second time.

The Nevada legislature convened in January of 2017 and passed three pieces of renewable energy legislations, two of which was vetoed by Governor Sandoval. The Governor signed the third bill, AB 405, which essentially restored the NET metering. Under this legislation, the net excess credit will be set at 95% of the retail rate in 2017. For every 80 megawatts of additional solar deployed, this credit will decline by 7% until is reaches the floor of 75% of the retail rate.

AB 206, which was vetoed, would have increased the state's renewable portfolio standard to 40 % by 2030, from the current target of 25% in 2025. The veto is generally attributed to opposition from the casino industry, which is a major electricity customer in the states. NEM and RPS policies intertwine because the utility earns RPS credits when customers install renewable generation capacity. Increasing the RPS makes rooftop solar installation more valuable to the utility.

The third energy bill passed by the legislature, SB 392, would have established a 200-megawatt community solar program by 2023. Sandoval explained the logic underlying his veto: "Although I am confident that the system set up by AB 405 will be

13 In person communication with Mr. Jesse Murray, Renewable Energy Programs Director of NV Energy
14 http://www.rgj.com/story/money/business/2016/09/13/nv-energy-solarcity-deal-grandfather-residential-rooftop-solar-customers/90306788/
15 http://www.greentechmedia.com/articles/read/nevada-supreme-court-blocks-rooftop-solar-referendum

beneficial to Nevada and its solar energy economy, it is unclear whether these bills are compatible or conflicting."[16] He also cited the uncertainty posed by the second vote on the "Energy Choice Initiative" which is expected to occur in 2018. If that ballot measure passes, substantial restructuring will occur in Nevada's electricity industry, that would likely impact any community solar program.

A. GAPS IN AVAILABLE ANALYTICAL RESULTS

The study commissioned by PUCN, to estimate costs and benefits of the NEM rate structure, provided estimates of the some of the issues discussed in section 2 of this chapter. This study considered the avoided transmission losses based on data provided in the general rate cases led by the utility company (Price, Pickrell, Kahn-Lang, Ming, and Chait (2014)). It also provided some discussion of potential savings from avoided expansion of transmission and distribution capacity were provided on an average system-wide $/kWh basis per each utility. However, it is not quite clear whether the degree of correlation between the NEM generation hours and the peak load hours was incorporated into this analysis.

The study did not provide estimates for other benefits and challenges. First, benefits of location portfolio specification were not quantified. Data requirements for analysis of this issue would be substantial. For example, analysts could identify vulnerable spots on the infrastructure and use computerized grid models to simulate the hypothetical energy output in case of a system failure at these points with and without the existence of the rooftop solar installations. Also, looking at the correlation of the solar generation at different locations to evaluate the reduction in intermittency due to diversification should be relatively more straight forward using the past generation data. Second, the potential impact of rooftop solar panels in reducing air-conditioning usage was not accounted for, despite the fact that Nevada's major city Las Vegas is located in an area with significant air-conditioning requirements. To produce reliable estimates, it would be necessary to use data on the timing of the associated energy savings, since they may occur during high-demand times.

Third, ecosystem impacts of large-scale solar facilities and associated economic value losses are not well-understood.

Dividing the Nevada utility customers into classes based on NEM status was a step in the right direction to prevent cross subsidies. However, there are additional steps that are needed to be taken to make this fair for all the participants. All costs and

16 Source: https://www.greentechmedia.com/articles/read/nevada-bill-to-restore-net-metering-for-rooftop-solar-passes-in-the-senate

benefits need to be studied locally using engineering techniques and statistical analysis using actual hourly generation, load, and emissions data. The cost and benefit amounts vary by consumption quantity, time, and location. For example, avoided transmission losses due to a KWh of NEM generation will depend on how congested the transmission lines at that point in time as well as how much of the generation was used onsite vs. injected into the grid.

Furthermore, the carbon-reduction benefit of any renewable system should be determined by identifying which generation source it displaced at each point in time throughout the day. Instead of giving each kWh of renewable generation one credit, the value of the renewable portfolio compliance credits should be determined by how much carbon is displaced by each particular generation Instead of using the averages from past data, costs and benefits could more accurately be determined by simulating multiple scenarios using computerized grid models to disentangle the time, location, and customer specific nature of this problem. Modern computational capabilities allow such detailed analyses. As a result, instead of trying to establish fairness with a universal rate, the billing can be made granular at customer level. Each NEM customer could be charged for each cost item and compensated for each benefit item separately.

4. Conclusion

Controversies surrounding effort to modify and rationalize policies for compensating owners of distributed generation capacity have been salient in Nevada in recent years, but elements of Nevada's experience are shared by regulators and policy-makers in most states in the US. As of 2016, utility customers with distributed generation capacity were compensated via net energy metering (NEM) rate schedules in most of the states. Regulators and policy-makers have initiated discussions and processes to modify or transition away-from NEM rate structures in several states.

The potential benefits and costs of NEM policies are complex, and the magnitudes of these impacts are sensitive to an array of location-specific factors such as weather and utility industry structure. Analysts have not quantified these benefits and costs using methodologies that can be readily applied to specific locations.

Growing adoption of time-of-use meters and the anticipated adoption of smart-grid technology will generate rich databases to support the detailed analyses that are needed to fully understand the impacts of distributed generation on utility costs, carbon emissions, water use, sensitive ecosystems and other environmental characteristics.

5. Tables and Figures

Table 1: New Net Metering Rates Approved by the PUCN in December 2015

Nevada Power Company (Northern Nevada)

Step	Date	Basic Service Charge	Vol. Charge/KWH	Excess En. Cr./KWH
	Prior to Jan. 1, 2016	$12.75	$0.11	$0.11
1	Jan. 1, 2016	$17.90	$0.11	$0.09
2	Jan. 1, 2019	$23.05	$0.11	$0.07
3	Jan. 1, 2022	$28.21	$0.11	$0.06
4	Jan. 1, 2025	$33.36	$0.10	$0.04
5	Jan. 1, 2028	$38.51	$0.10	$0.03

Sierra Pacific Power Company (Southern Nevada)

Step	Date	Basic Service Charge	Vol. Charge/KWH	Excess En. Cr./KWH
	Prior to Jan. 1, 2016	$15.25	$0.09	$0.09
1	Jan. 1, 2016	$21.09	$0.08	$0.08
2	Jan. 1, 2019	$26.92	$0.08	$0.06
3	Jan. 1, 2022	$32.76	$0.07	$0.05
4	Jan. 1, 2025	$38.59	$0.07	$0.04
5	Jan. 1, 2028	$44.43	$0.06	$0.03

6. Tables and Figures

Figure 1: Installed NEM Capacity in US in MWH.[17]

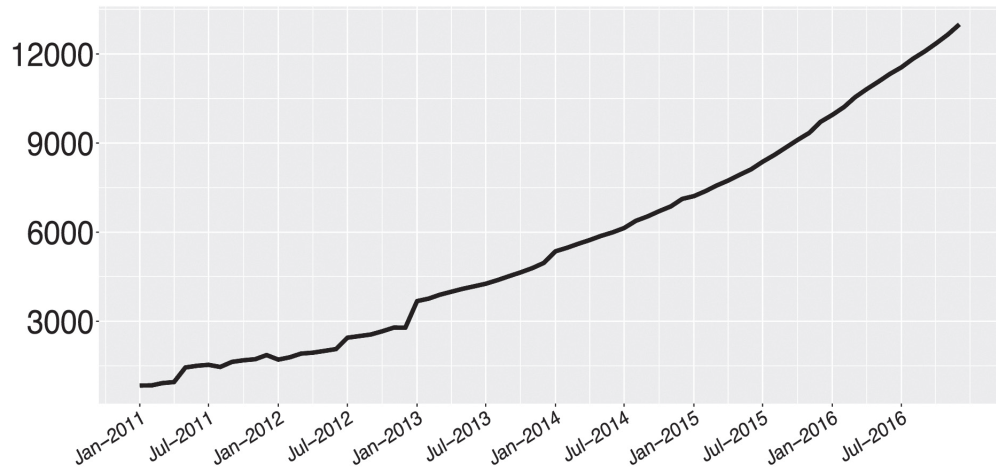
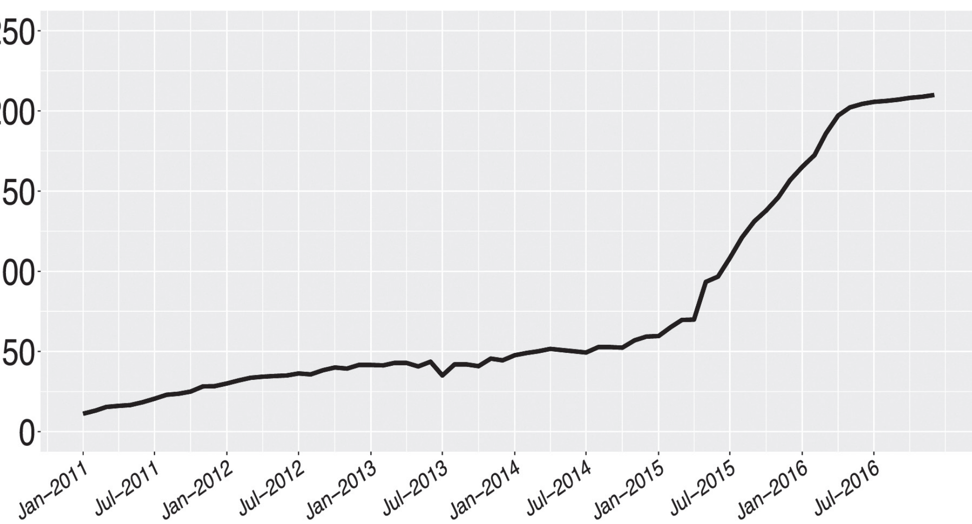


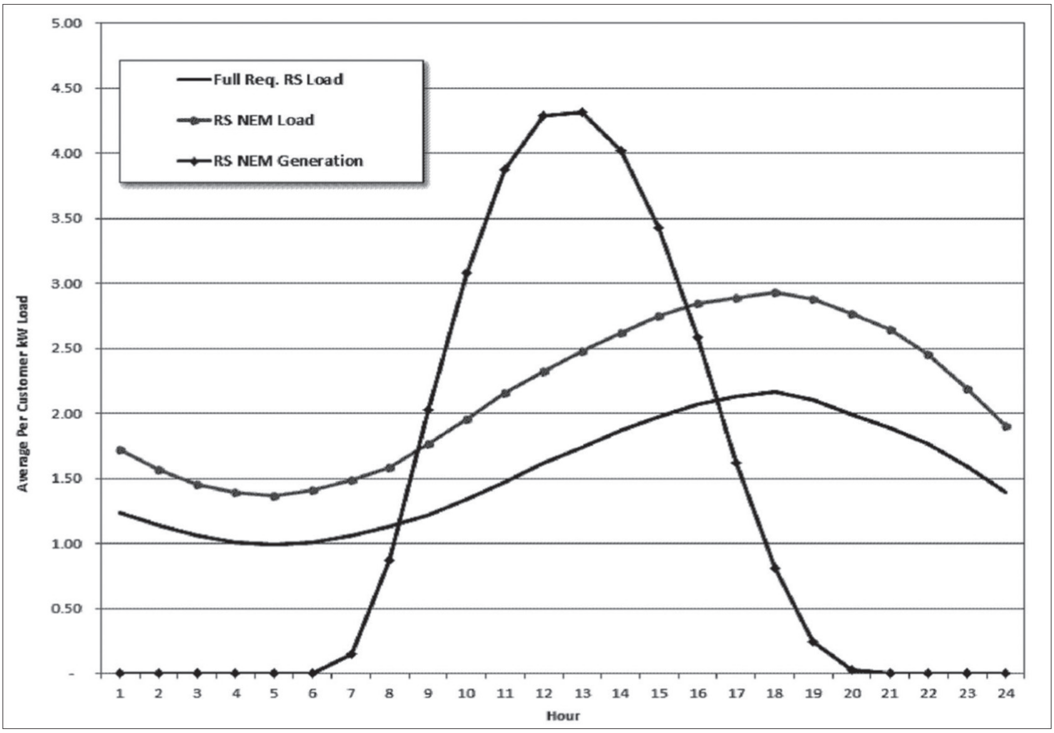
Figure 2: Installed NEM Capacity in Nevada in MWH[18]



17 This figure shows how the total installed NEM capacity in the US changed over time between 2013 and mid 2016. The data to prepare this figure was taken form US Energy Information Ad- ministration website. URL: http://www.eia.gov/electricity/data/eia826/xls/f826netmetering

18 This figure shows how the total installed NEM capacity in Nevada changed over time between 2013 and mid 2016. We see that the trend was somewhat flat until the end of 2014 after which it started to rapidly increase. Solar City, one of the largest residential solar PV producers had been offered generous incentives to move its operations to Nevada soon after that it started to take applications from the local customers in May 2015. The data to prepare this figure was taken form US Energy Information Administration website. URL: http://www.eia.gov/electricity/data/eia826/xls/f826netmetering

Figure 3: Hourly Comparison of NEM Generation and the System Load.[19]



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19 In this figure we see how the solar NEM generation and the system load vary in different hours of the day. The bell shaped curve represents the solar generation which peaks around noon. The other curves represent the system loads of NEM and non-NEM customers, which peak between 6 and 7 pm. This demonstrates that there is not a perfect overlap between NEM solar power availability and the system demand. We also see that, on average, NEM customers tend to use more electricity which may explain why they wanted to invest in rooftop solar panel which they expected to save money with. This figure is an excerpt from the page 31 of the original filing of state's regulated power utility for Public Utility Commission Docket 15-07041. URL:http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS 2015 THRU PRESENT/2015- 7/4401.pdf

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New Business Models with Diffusion of Distributed Generation

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Abstract

In recent years, the technological innovation has brought a deep transformation of the power sector. As a result, we are now witnessing a transition towards a more sustainable electricity sector, in which distributed generation, smart energy management, digitization and consumer engagement play a crucial role. In this paper, we examine how the emergent pathways for the transition towards a new electricity paradigm are reshaping the business ecosystem in electricity markets, opening the door to new (heterogeneous) players and to innovative business models, creating serious regulatory challenges. To this end, we provide an extensive review of emergent business models in the era of distributed generation. We also examine to which extent distributed generation technologies constitute a threat or an opportunity for incumbent utilities, highlighting how the answer to this question depends on the specific regulatory and institutional environment. In this respect, we put special emphasis on the need for regulatory innovation regarding the tariff structure design and the existence of market-based mechanisms to invest in DG. At the end of the paper, we use the Brazilian case-study to illustrate that regulatory mechanisms have a very important in promoting the adoption of distributed generation technologies. We also use the Brazilian case to shed some light on how the pathways towards a smarter and more sustainable electricity sector is deeply affected by the interplay between distributed generation, business model innovation and the regulatory framework.

1. Introduction

Electricity markets used to be dominated by vertically integrated structures (utilities), which controlled the entire value chain from production to retail. In recent years, the sector has been reinventing itself resulting in the transition of a linear value chain to a less centralized structure taking the form of a (smart) grid.

A key dimension of the ongoing transformation in the electricity sector is the emergence of innovative solutions and new business models within a complex web of economic interactions envisaging the transition towards a low-carbon economy. e-Lab (2013) sums up this new reality as follows: *"At the customer level, advances in communications and controls, distributed generation and storage, electric vehicle charging, and other technologies are opening new avenues for investment and value creation. Third-party providers are stepping in to provide innovative energy services ranging from solar leasing to emergency power systems. Microgrids are being developed to help integrate and manage distributed resources at the local level. New approaches to delivering energy efficiency are yielding deeper savings and, coupled with distributed supply options, are opening the door to achievement of net zero energy buildings and campuses."*

One of the most important drivers of this transition is the expansion of Distributed Generation (DG) technologies and applications, which are acting both at the demand-side and the supply-side to promote a smarter and more sustainable energy system. In DG is also entailing positive (macro and micro) economic effects. On the macroeconomic grounds, DG expansion stimulates innovation and investment dynamics; it allows for the diversification of energy sources, reducing the countries' dependence on non-renewable (often exogenous) resources and it increases the system overall energy efficiency. In addition, it reduces the expected costs with network congestion and power line losses and it creates new (highly qualified) job opportunities. At a microeconomic level, DG may potentially reduce consumers' exposition to price variation (supposing self-consumption is allowed) and it opens the door to new business opportunities and new market players.

However, DG also brings an unprecedented number of technological, economical, policy and institutional challenges, affecting all the business ecosystem actors: the system is becoming increasingly digital, there is an increasing penetration of intermittent renewable energy sources (RES); production is decentralized; the relationships among the economic agents in the system are no longer linear and uni-directional (e.g. consumers are now involved in electricity generation, becoming *prosumers*); there is a strong focus on demand-side management and storage; many new heterogeneous players (often smaller and highly specialized) are entering in the market offering new (smart) value propositions; …

Hence, as the power sector reinvents itself, the actors in this sector (consumers, firms, regulators and policy makers) must think about the best strategy to absorb the economic benefits entailed by DG (and minimize possible costs). In particular, utilities need to revise their business model (BM) in order to guarantee their own financial stability and get ready to the grid management challenges brought by DG (likewise, new entrants must shape their business strategies to achieve competitive market success). Consumers need to rethink their consumption patterns (managing consumption more effectively and, eventually becoming *prosumers).* Finally, regulators and policy makers need to reflect on the ideal features of future electricity systems and take the appropriate measures to assure that the pathway to the future electricity paradigm is smooth.

As mentioned earlier, one of the most visible outcomes of the reinvention in energy powers is the emergence of new business model configurations, whose dynamics obviously depend on agents' initiative but is also highly shaped by the institutional and regulatory environment. Indeed, as referred by Burger and Luke (2017) technological innovation is an important driver business model innovation (both in the case of conventional utilities and new players) but the larger driver of the new business model structure is probably the regulatory and policy environment. Provance *et al.* (2011) and Huijben *et al.* (2013) also argue that firms and BM should be analyzed within their contextual factors, namely in terms of policy context.

In this paper, we enrich the literature on business model innovation in the electricity sector, by investigating how the increasing weight of DG is enabling the appearance of new BM configurations and new players in the sector. We provide an extensive review of existing BM, contributing to a better understanding of current business dynamics in the sector, which is a necessary condition to investigate the current and future economic overall impacts of DG. We also examine to which extent DG constitutes a threat or an opportunity for incumbent utilities, highlighting how the answer to this question depends on the specific regulatory and institutional environment. In this respect, we put special emphasis on the need for regulatory innovation regarding the tariff structure design and the existence of market-based mechanisms to invest in DG.

Finally, we re-examine the previous theoretical questions in light of the specific developments of DG in Brazil. This is an interesting case study since DG is remains at a relatively early stage in this country but it has a huge growth potential (especially given the good natural conditions to exploit PV solar, which is the distributed RES by excellence) if the regulatory and institutional framework is not adverse. Therefore, it is especially important to identify the current challenges in the sector and understand how BM innovation may successfully contribute to the prosecution of the country's goals, namely in terms of market-enabling, sustainability, efficiency, flexibility, resilience and reliability of the Brazilian electricity system.

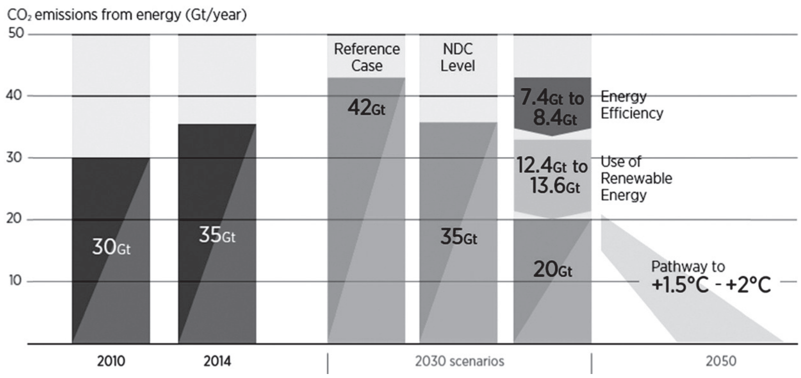
The rest of the paper is organized as follows. Section 2 presents a brief overview of the recent perspectives on the DG paradigm, at a global scale. Section 3 examines the BM innovations enabled by DG technologies and applications. Section 4 analyzes the threats and benefits encountered by incumbent utilities in the era of DG, highlighting how regulatory innovation may mitigate some of the negative impacts of DG on utilities' conventional BM. Section 5 presents the case of Brazil and, finally, Section 6 concludes.

2. Distributed electricity generation: an overview of recent developments and trends

We are currently living an era of transition in electricity systems worldwide. The previous linear electricity value chain is being transformed into a complex interconnected web of relationships among very heterogeneous agents interacting within a decentralized and digital system (this complexity is illustrated in the DSO model proposed by Poudineh and Jamasb (2014), who emphasize the increasingly complex activities of distributed system operators in the era of decentralized energy systems).

Along the same lines Gangale *et al.* (2017), who overview smart grid projects in the European Union, identify a wide range of domains currently affecting power system operators, who are in charge of managing an increasingly complex system. More precisely, Gangale *et al.* (2017) cluster the ongoing smart grid projects in the European Union in several domains, comprising issues such as: (i) Integration of large scale RES, (ii) Integration of DG and storage, (iii) Demand side management, (iv) Smart network management, (v) E-Mobility and (vi) other projects. Gangale *et al.* (2017) find that the dimensions related to DG are actually the ones attracting more (private and public) investment: Investment in projects related to Smart Network Management reach 1.600 million Euros (with almost 1.000 million Euros representing private investment); Demand-Side Management projects represent total investments of more than 1.200 million Euros, whereas total investment in the DG and Storage is over 1.000 million Euros). Total investment in e-Mobility projects reach 600 million Euros and the integration of large scale RES only mobilizes total investments representing less than 200 million Euros. These huge European investments in several DG domains are the reflex of an overall institutional framework favoring the transition to a low carbon energy sector, in which DG plays a key role given its greater environmental sustainability both at the demand-side and the supply-side level. The following figure illustrates how both energy efficiency (demand side) and the use of renewable energy (supply side) are expected to contribute significantly to an effective reduction of CO 2 emissions from energy (Gt/year).

Figure 1. Expected pathways to reduction in CO2 emissions from energy



Source: IRENA (2017)

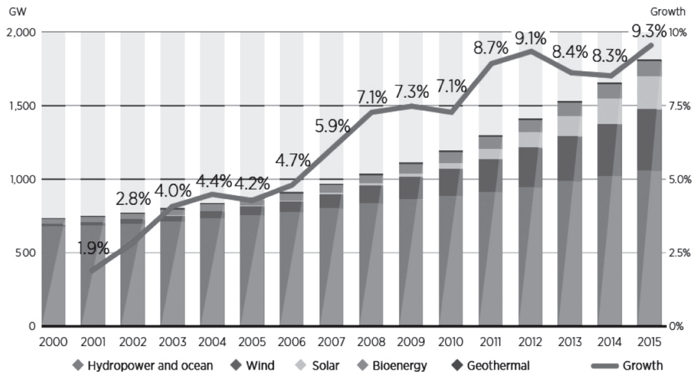
On the demand side, smart grids allow for a much more effective demand-response, increasing the energy efficiency performance of the overall system. The developments on metering, controlling and digital communication allow consumers to monitor much closer their energy consumption, allow firms to implement dynamic pricing schemes and allow consumers to respond to such price signals much faster (even in real-time), making them more effective.[1] According to Accenture (2016), *"demand response tools … will become a key tool for electricity distributors to manage peak load and maintain reliability of supply. Accenture modeling indicates that demand-response solutions could provide meaningful changes to peak demand through programs that incentivize action on very few hours per month"* For example, a response program covering 2 hours a month may lead to a variation in the peak load of 1,5%, approximately. If the program covers 6 hours a month or more, the relative change in the peak load may reach values around 4% (or more).

On the supply side, DG facilitates the electrification of the energy systems and promotes the decarbonization of the electricity sector, through a greater participation

1 Eurelectric (2015) estimates that *"accelerated innovation in power supply technologies and business models for energy efficiency could be worth €70 billion to the EU economy by 2030. Additional benefits are also expected in terms of energy security, lowering of system costs, and enhancing consumer satisfaction."*

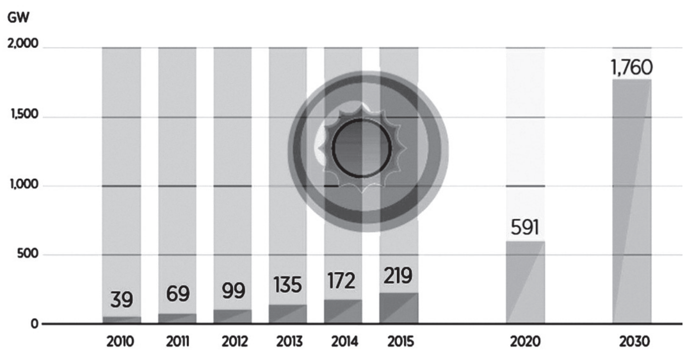
of RES on the generation electricity-mix, in line with the sustainable energy transition pathways established by 2015 UNFCCC Paris Agreement (UNFCCC, 2015). Figures 2 and 3 below illustrate this trend, showing that RES are growing at a fast rate (worldwide) and PV Solar capacity is the one growing the most in recent years.

Figure 2. Renewable power capacity and annual growth rate



Source: IRENA (2017)

Figure 3. PV Solar global installed capacity and projections



Source: IRENA (2017)

REN21 (2016) estimates that by mid-2015, around 44 million off-grid pico-solar products were sold worldwide (corresponding to an annual market of 300 million of USD). The increase in PV solar in recent years echoes the expansion of distributed energy production worldwide, both in industrialized countries (such as USA, Japan, Germany, Italy or China) and developing countries, where distributed energy projects are key to provide energy services to people living without electricity.[2]

2 According to REN21 (2016) around 1.2 billion people live without electricity. An increasing number of of small-scale distributed energy production projects are being implemented in order to reduce this impressive figure.

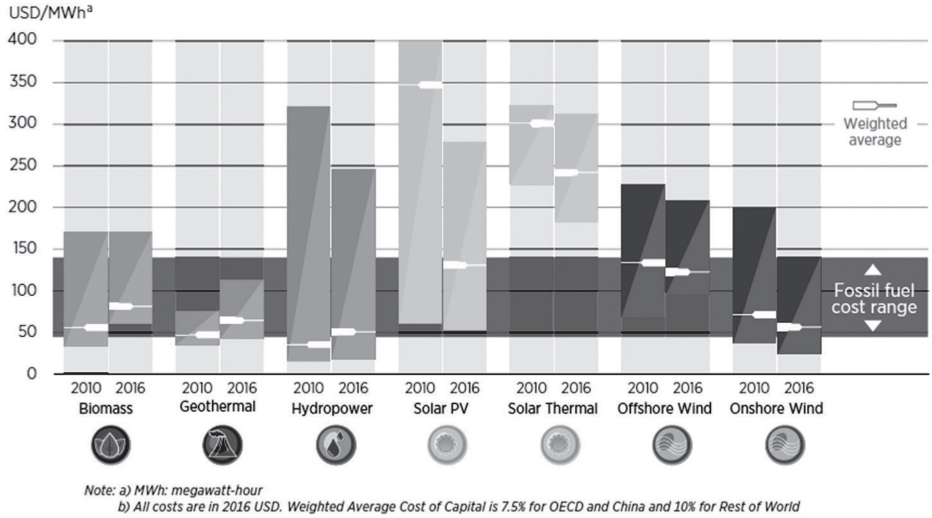
Figure 4. Cumulative installed PV Solar capacity by country, 2015

Source: IRENA (2017)

Looking at the worldwide cumulative installed PV Solar capacity, its asymmetric distribution is quite evident. Figure 4 shows that some countries are very active in this field (namely China, USA, Japan, Germany and Italy), whereas other countries still have very limited installed PV Solar capacity, including countries with a great production potential (e.g. Brazil). In this respect, it is important to note that, at a country-level, the increase in PV Solar capacity may have not only very important environmental impacts but also significant economic ones. Grijó and Soares (2016) find that PV Solar installed capacity have a positive impact on GDP. Using a fixed effects model with panel data for 18 European countries, the authors found that "1*% increase in PV Solar installed capacity and in electricity production from renewable sources has a positive impact on GDP of 0,0248 and 0,0061 %, respectively.*" When they account for differences across countries, they find that Germany, France, Italy and the UK are the countries in which PV Solar has the largest economic impact.

It is also interesting to note that this increase in RES capacity has been accompanied by a significant reduction in the levelised cost of electricity (LCOE) from RES. This fact is illustrated in the figure below that represents the LCOE for utility-scale power (range and averages).

Figure 5. Levelised cost of electricity for utility-scale power (ranges and averages).

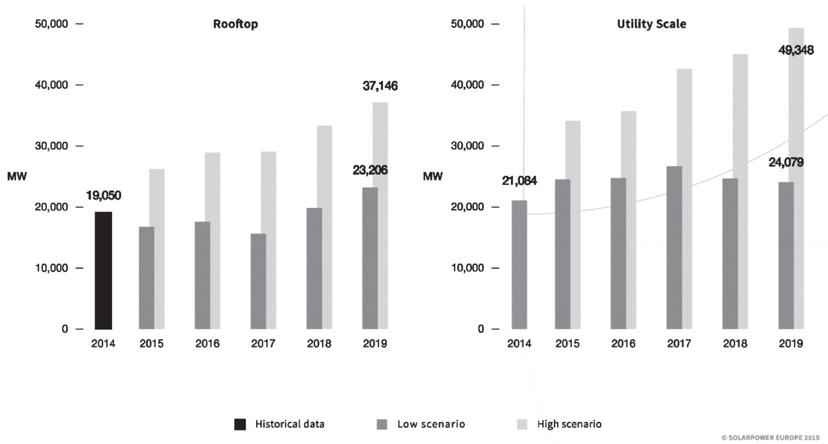


Source: IRENA (2017)

The figure illustrates a remarkable reduction in the LCOE of RES. In addition, it also shows that onshore wind LCOE is now within the fossil fuel cost range (becoming more and more competitive). Finally it also points out the increasing competitiveness of PV Solar, which is the energy source registering the greatest reduction in the LCOE. This trend is expected to continue in the future: as more and more PV Solar capacity is exploited (both at the end-user scale and the utility scale), further cost reductions are expected to occur due to scale and learning economies.

At the present moment, solar production plants remain quite heterogeneous, with end-user micro projects coexisting side-by side with very large utility-scale power plants. This is illustrated in Figure 6 that shows the proximity of global rooftop capacity and utility scale solar capacity. It also shows that both generation modes are likely to growth further in the near future. Hence, some players will probably continue to exploit more conventional BM (e.g. large-scale PV solar plants, whose production can be brought to the market), whereas other projects (e.g. community-based small PV solutions or new services bundling PV solar production with storage and aggregation) are opening the door to new players and pushing utilities to create new lines of business.

Figure 6. Scenarios for PV Solar rooftop and utility scale segments development until 2019



Source: Solar Power Europe (2015)

The transition towards a low-carbon decentralized power system in which many heterogeneous agents interact raise important challenges, including:

(i) **technical issues** related to the intermittency[3] and the integration of DG resources in the grid;

(ii) **economic issues**, related to: the significant investment amounts needed to build a smart interconnected grid; the economic and financial sustainability of the distribution operators, which now have to manage a much more complex system but are deprived of an important revenue bulk if the current volumetric tariff system remains unchanged; the design of appropriate market-based mechanisms to provide economic agents with appropriate investment, storage and consumption incentives;

(iii) **regulatory issues** related to the appropriate regulation framework and market design in the context of an interconnected grid, with many heterogeneous stakeholders.

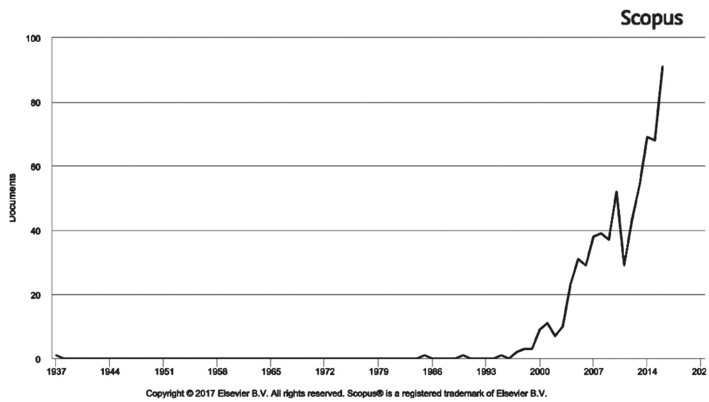
Given the stirring developments arising in electricity markets, there has been a growing interest in understanding how countries may fully benefit of the DG (environmental and economic) potential, overcoming the challenges mentioned before. In

3 For example, as referred by Alves et al. (2017), in California, as a consequence of the increasing weight of RES there has already been an increase in the slope of the "duck curve" reflecting ramping problems, which may affect the reliability of energy systems during certain periods of the game. In order to avoid the collapse of the system during the demand peak periods, it is crucial to ensure an effective coordination among the agents in the system. This may not be easy to achieve both in the short-run (where effective price signals may result in too complex dynamic pricing schedules) and in the long-run (where the incentives to invest in back-up capacity may be almost inexistent).

this context, scholars have been trying to understand the technical, economic, environmental and social dimensions behind DG deployment. BM innovation has been a particularly fruitful are of research since understanding the business dynamics is a necessary condition to identify the economic impacts of DG and then understand how the challenges DG raises can be overcome.

Consequently, the number of articles published in the field of BM in electricity markets have increased exponentially in the recent years. This is illustrated in the figure below, which shows the yearly production of scientific articles (indexed in the Scopus bibliographic database) that combine the terms "business model" AND "distributed generation" in their title, abstract or keywords.

Figure 7. Number of yearly publications simultaneously covering the areas of BM and DG



Source: Scopus

The recent interest of energy economists on business model innovation is not surprising considering that the policy shifts and the drastic innovations taking place in electricity markets are leading to a decentralized business ecosystem, which calls for novel market design and innovative business strategies. In the following section we provide an integrated overview of the wide business model constellation currently emerging in power systems.

3. New business model configurations in the era of distributed energy

At the present moment, there are many changes shaping the transition towards DG in electricity systems, resulting in new value propositions, new goods and services, new players, new competitive dynamics and new economic relationships within a dense and intricate value network. As a result of all these changes, power systems have been witnessing (and will continue to do so) a BM innovation boom (e.g. Provance *et al.* (2011); Richter (2012, 2013); Hellstrom *et al.* (2015), Behrangrad (2015); Strupeit and Palm (2016); Hall and Roelich (2016); Burger and Luke (2017), just to mention a few).

A particularly interesting feature of the BM innovation phenomena occurring in electricity systems refers to the shift from a pure homogeneous good system (offered by a vertically integrated utility) to a product-service system (e.g. Vine (2005) or Hamwi and Lizarralde (2017)), in which digitization and dematerialization transition have allowed "*the switch from owing to delivering functionality"* (Hellstrom *et al.* (2015) and Ceshchin (2013)). In this new system heterogeneous players provide differentiated products, combining energy provision services with other differentiated services, such as energy efficiency, storage, ancillary or even financial services. This new reality results in a deep change in the market structure of electricity markets. In particular, electricity markets are expected to shift from highly concentrated markets to less concentrated ones, in which many players are active and product differentiation is a key competitive dimension.

PwC (2013) provides an holistic approach to the future business model ecosystem in electricity markets, organizing it along four dimensions: *(i)* Energy suppliers, who are asset-focused, in order to guarantee that *"assets are optimized in market to match price signals"; (ii)* Integrators, who are system focused in order to facilitate grid interconnection; *(iii) Enablers*, who are value-focused aiming at expanding the grid value to all the stakeholders (namely distributors and end-users); and *(iv)* Optimizers, who are insight-focused, developing innovative solutions and allowing consumers to better *"leverage behind the meter technology".*

Considering these new four dimensions arising within the electricity value network, PwC (2013) identify eight new BM, which are expected to co-exist (sometimes in competition, other in cooperation) with the utilities' traditional utilities business model: *(i)* gentailer*; (ii)* pure play merchant; *(iii)* grid developer; *(iv)* network manager; *(v)* product innovator; *(vi)* partner of partners; *(vii)* value-added enabler; *(viii)* virtual utility.

The asset-based models (*i)-(iv)* already exist in the context of traditional deregulated markets but in the traditional linear model, they emerge in a much more simplistic way. The pure play merchant model includes firms whose business alignment is mostly focused on electricity generation, whereas the gentailer model refers to business lines based on the combination of generation and retail. In the new electricity paradigm, the asset-based models comprise not only conventional pure play merchants and gentailers but also consumer centric prosumers, community based generation models, third-party DG systems and so on.

Similarly, the grid developer and the network manager already exist in the context of the conventional value chains. However, their functions are much more complex within the new decentralized and interconnected system since they must assure the integration of DG resources, facing the risks derived from uncertainty, production intermittency and mis-coordination.

In addition to the reformulation of already existing BM, PwC (2013) also predicts the consolidation of a set of completely new business configurations allowed by technological, institutional and regulatory innovation. These new lines of business may be driven by:

- the appearance of new products and services ("product innovator model");
- the development of virtual utility plants, taking advantage of new generation and storage technologies and applications;
- the offer of service bundles relying on strategic partnerships ("partners of partners);
- "value-added enabler" solutions designed to *"leverage technology to enhance system performance and customer engagement".*

The broad business model categorization proposed by PwC (2013) is in line with recent studies examining the new perspectives on the future business model constellation in electricity markets. For example, Burger and Luke (2017) have analyzed the value proposition of 144 distributed energy BM, covering a vast number of technologies and applications. The authors analyze the constituting blocks of the *Business Model Canvas* framework proposed by Osterwalder and Pigneur (2010), comparing existing models in terms of value proposition, customer segments, channels and customer relationships, key activities, resources and partnerships, as well as the cost-revenue streams. As a result, the authors propose a three-category classification to group all the 144 BM: *(i)* demand response and energy management systems (EMS); *(ii)* storage; and *(iii)* PV Solar.

The previous classification focus on the features of the product-service offers now available in electricity markets and, to a certain extent, it mimics some of the domains of the EU smart projects related to DG identified by Gangale *et al.* (2017), namely: smart network management, demand response; the integration of DG and storage. When we analyze the classification proposed by Burger and Luke (2017), we conclude that it is more specifically focused on BM within DG areas. It highlights weather BM are demand or supply oriented (with demand response and energy EMG being demand-side models, whereas storage and PV Solar are more supply-oriented models). In the case of supply side models, the authors distinguish between BM focused on storage and the ones focused on decentralized generation (in which PV Solar can be considered a dominant resource), covering two important pillars of the future electricity paradigm.

It is important to note that the BM analyzed by Burger and Luke (2017) not only include a vast number of differentiated products and services but also reflect very different approaches regarding the firms' cost-revenue model. While some players keep on having a stream of revenues based on commodity sale and access fees (even if those sales may cover a wide range of electricity services, like capacity or operating reserves), other players are relying on an innovative revenue structure based on asset sales, brokerage fees or financial operations such as leasing/ renting/ lending.

The following table sums up the new business model configurations within the typology suggested by Burger and Luke (2017).

Table 1. New business model configurations within the future electricity paradigm:

Demand Response and EMS (I)	Storage (II)	PV Solar (III)
EMS Providers	End-user optimization	Technology manufacturing
Utility-based capacity and Reserve DR	End-user and system co-optimization	Solar-plus-storage ("virtual power plant)" end-user optimization
Market-based Capacity and Reserve DR	Network services	Solar-plus-storage ("virtual power plant)" end-user and system co-optimization
	Pure-play software and technology developers	Utility scale PV financiers and integrators
		Distributed PV financiers and integrators

Source: Own elaboration based on Burger and Luke (2016, 2017)

Table 1 clearly illustrates the business model heterogeneity within the future electricity paradigm. In category (I) Burger and Luke (2017) include the wide range of technologies and services envisaged to enable or facilitate the adjustment of energy loads in response to price signals or other possible drivers (reflecting the state of the power system). Hence, all the recent BM hinging upon monitoring and controlling devices as well as the services designed to improve the frequency control and the mitigation of network constraints are included in this category. The later also includes a set of innovative solutions developed by actors outside the electricity sector. In particular, the Information and Communication Technologies (ICT) players are becoming increasingly important players (especially regarding EMS provision), given their know-how and expertise in digital technology and communication.

Category II includes a wide range of services related to electrical and thermal storage like end-user optimization services (both at the level of residential and industrial consumers), system optimization and network services. These services share a common goal related to the avoidance of wasteful production, the reduction in consumers' energy costs and the improvement of energy systems functioning (e.g. by easing network constraints, providing additional capacity availability or aggregating consumers' storage resources).

As in the case of category I, also in this case, the new business opportunities emerging in this area are opening the door to the entry of new diversified players (both in terms of their dimension and in terms of their core business). On the top of innovative energy solutions, some of the players are also offering non-electricity services (mostly related to ICT-based optimization and other control services) to both system operators and final consumers. It is also important to stress the increasingly important involvement of car manufacturers and infrastructure developers in storage BM. This is a natural consequence of the new electric mobility paradigm (Madina *et al.* 2016), whose implementation may give very important competitive advantages in the storage business to car industry players (the vehicle to grid system allows Electric Vehicle (EV)'s batteries to store energy and then inject it to the grid), allowing them to offer as well competitive offers in other areas (e.g. bundles consisting of EV solutions+storage+solar energy are expected to become quite important in the future, considering that the EV is now said to have reached the critical mass of users to become the dominant paradigm[4] in the automotive industry).

The third category suggested by Burger and Luke (2017) clusters new BM developed related to PV solar. Despite the close relationship between PV solar and the other categories, the boom in PV solar production (and the new business opportunities it is creating for the technology manufacturers, electricity services and financial services) justifies the creation of an independent category and, as referred by Schleicher-Tappeser (2012) PV solar is a DG source by nature, allowing for new market dynamics and business model innovation. Burger and Luke (2017) indeed include a multiplicity of players in this category, namely technology manufacturers, virtual power plants, utility

4 Fickling (2017) argues that a tipping point has been reached in the car worldwide industry since *"China, one-third of the world's car market, is working on a timetable to end sales of fossil-fuel-based vehicles"*.

scale and distributed PV integrators as well as financial services firms offering specialized products designed to facilitate the equipment acquisition in the case of direct ownership - or renting solutions– in case of third-party ownership.

The last aspect is a particularly relevant aspect within the new BM' archetypes. Hamwi and Lizarralde (2017) review the extant literature on emergent BM growing with the diffusion of generated distribution[5] grouping them in three different categories: *(i)* Customer-owned product centered; *(ii)* Third-party service centered and *(iii)* Energy community models. These three business categories have also been stressed by other authors, like for instance Huijben *et al.* (2013).

This clustering criteria makes it explicit the fact that in the context of distributed and interconnected electrical systems, similar value propositions may have very different approaches to the assets' ownership, resulting in different BM configurations. In case *(i)* the customer owns the electricity (frequently on-site) generation/ management technology. This model has been particularly frequent in countries with favorable Feed-in-Tariff (FIT) systems for DG sources, as in the case of Germany. On the contrary, in case *(ii)* the DG technologies are owned by a third-party who provides electricity services to consumers. This model has been quite frequent in the USA context. Finally, in the last case, resources are pooled and shared within a community of users.[6] The last models are becoming increasingly successfully and they are expecting to growth exponentially in the coming years, according to Augustine and McGavisk (2016).

Community-based models have the advantage of alleviating technical installation constraints (since installation does not necessarily take place on-site). They also allow consumers to share the up-front and maintenance investment and share the performance risks among a large community of users. [7]

5 According to Hamwi and Lizarralde (2017) *"bibliographic databases have been used to identify all the articles related to our topic between 2000 and 2016 : EBSCO Business Source Complete and EcoLit, IEEE Xplore, and Direct Science. Our research comprises few key keywords "Energy, power, electricity, renewable and ." and "Business model" in the title. The research process resulted in 80 articles."*

6 According to Burger and Luke (2016) *"Many residences or businesses are not proper sites for distributed PV installations because of shading, building ownership challenges, and other factors. "Community solar providers" have emerged to capitalize on economies of unit scale or to enable consumers located in unsuitable areas to procure PV Solar. Community solar involves installing large PV Solar plants located away from the customer site. Customers can purchase the rights to a portion of the output of the solar plant, or can purchase an equity stake or share in revenues from a portion of the plant outright ."*

7 Coughlin *et al.* (2012), cfr. Vilela and Silva (2017) identifies three BM which have supported the development of shared solar solutions: the utility-based model, the non-profit model and the special purpose vehicle (SPV) model (which isolates the project's risk on the SPV to benefit from better financing conditions).

It is important to notice that, analogously to other BM in the power sector, the risks and return rates of community-based models depend significantly on the specific features of the energy policies and regulatory options. Herbes *et al.* (2016) illustrates this point by studying how changes in the regulatory framework have affected the Renewable Energy Cooperatives (RECs) in Germany. According to the authors, the favorable FIT system in Germany has sustained a considerable growth of RECs, with "*their number having risen to nearly a thousand since 2004.*" However, the profitability of the previous REC's BM have been undermined when the specific incentives to REC were reduced.

The following table sums up the business model configuration proposed by Hamwi and Lizarralde (2017), identifying some illustrative examples of each business model configuration.

Table 2. Business Model archetypes (according to the value proposition and asset's ownership)

Customer-owned product centered	**Third-party service centered**	**Energy community models**
Customer-owned **Renewable Energy technologies** (Supply side) *BM examples:* Plug and Play; Customer-owned PV VM; Host-owned model	Third-party **Renewable Energy technologies** (Supply side) *BM examples:* Thid-party ownership; Company-driven BM; Cross-selling BM; Partner of Partner; Local white label BM	**Utility-sponsored** energy community models
Customer-owned **demand side management** (Demand side) *BM examples*: Energy Efficiency Services, Value-Added Enabler Model	Third- party for **demand response** (Demand side) *BM Examples:* Third-party local aggregator, E-balance BM; Timing-based BM: Balacing Service Platforms; Peer to Peer BM	**Non-for profit** community models *BM Examples:* REC; virtual online platforms (e.g. "Glassroot P2P model); Citizen Participation Initiatives
	Third-party for energy efficiency *BM Examples:* Sharing savings and Guaranteed Savings Models; ESCO; Useful Energy BM; Energy Performance Contracting (EPC)	**Market-based** (profit oriented) community models

Source: Own elaboration based on Hamwi and Lizarralde (2017)

Table 2 shows that the classification proposed by Hamwi and Lizarralde (2017) clusters firms along two dimensions: *(i)* the value proposition and the features of the product-based services (e.g. energy generation, demand-side management or energy efficiency services[8]); as well as *(ii)* the asset's ownership structure. This is an important consideration since the shift in firms' cost-revenue model is actually constituting an important driver for BM innovation in the electricity sector. For example, Richter (2012) points out an important dichotomy in the features of new BM: consumer-centric models versus utility-based BM, whereas Huijben e Verbong (2012) add to the picture the third-party models.

Another interesting aspect of the classification proposed by Hamwi and Lizarralde (2017) refers to the insertion of new energy services as an independent sub-category of third-party service centered BM. For example, Qin *et al.* (2017) study different business approaches adopted by Chinese energy service companies (specifically focused on EPC). The authors identify four different types of BM: *(i)* the Shared Savings Model, *(ii)* the Guaranteed Sabings Model, *(iii)* the Energy-cost Trust Model and the *(iv)* Finance Lease Model.[9] The four models differ in several dimensions such as the allocation of performance and financial risk among economic agents (see Table 1 in Qin *et al.* (2017) for a detailed description of each model regarding asset ownership during (and after) the project, the allocation of saving benefits among ESCO and users, …). The authors also examine how to select among these four models, proposing a multi-criteria approach that takes into consideration aspects such as: energy saving potential of the project, consumers' energy-saving requirements, financial conditions and services, credibility, technical experience and ability of the ESCO, policy context.

Gabriel and Kirkwood (2016) highlight as well the new role of pure service-oriented firms in the power sector, specifically focusing on the case of developing countries. They have interviewed 43 entrepreneurs, covering 28 developing countries. Their sample is clustered in three different categories: consulting businesses, distributors and integrators, with the first one representing lighter corporate structures (mostly human-capital intensive) and the last one referring to the services with a greater complexity degree. Not surprisingly, authors find that the integrators model is more frequent in

8 Differently from Burger and Luke (2017) the authors do not explicitly account PV solar as an independent cathegory, which might be a little restrictive given the huge dynamism (regarding technological innovation and BM innovation) we have been witnessing in this field.

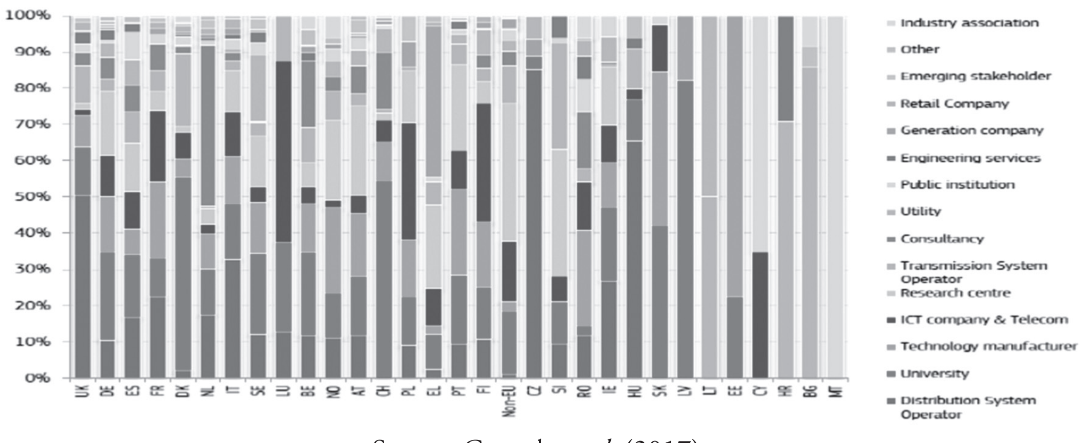
9 According to Qin *et al.* (2017) from 1998-2003, *"283 EPC projects were implemented. A total of 600 million CNY was invested in these projects. Initial reports showed that 730 thousand tces (ton of standard coal equivalents) of energy were saved per year and annual CO2 emissions were reduced by 480 thousand tons." Since 2003, there has been an increasing interest in ESCO services so that…. from 2010-2013, a total 3242 of ESCO companies have been announced"*

countries with a larger number of active renewable energy policies, whereas the consultants model (which is much lighter) is more frequent in the contexts characterized by low policy intervention (in the field of renewable energy) and the existence of more significant barriers for doing business. The distributors model (which is more complex than the purely service-based consultants model but less complex than the integrators model) arises in contexts where doing business is relatively easy but the governments' interest in Renewable Energies is rather limited.

A particularly interesting aspect of the new competitive dynamics in the power sector refers to the entry of new players who are substantially different from the traditional utilities, with whom they may interact in very different ways (sometimes competing, others cooperating and others *coopeting*, meaning that they cooperate in some dimensions but compete along others). In this respect, Hellstrom *et al.* (2015) highlight the importance of collaboration among different firms in the electricity value network as a key factor for successful business model innovation.

This new collaborative environment is quite evident when we analyze, for example, the stakeholders involved in the context of EU smart grid research and development projects (see Figure 8 below).

Figure 8. % distribution of investment in smart network management across different stakeholders



Source: Gangale *et al.* (2017)

The figure shows that the involvement of Distribution System Operators in the ongoing EU smart grid projects in the domain of Smart Network Management is very different from country to country. In some countries like UK or Italy, they are assuring a high fraction of the investment in the smart grid projects. However, in most of the countries their enrollment is rather small, especially if we take into consideration the remarkable challenges these players are expected to face in the coming years. The relatively low weight of DSO's on the investments in EU smart grid projects is also a product of the rise of other relevant players, who are shaping future electricity systems, namely: *(i)* Universities and research centers - which are actively contributing to the intense technical innovation in the sector; *(ii)* Technology manufacturers (especially car industry players) – who are looking for new business opportunities arising with the mass diffusion of new DG, storage and metering technologies; *(iii)* ICT companies – who are starting to have an increasingly important role in light of the current system digitization and dematerialization trends.

It is important to note that the relative involvement of new stakeholders may substantially depend on the type of smart grid projects. For example, the weight of ICT players' investment is higher in the field of demand management, where indeed ICT technologies are key to develop an appropriate online metering system, facilitate digital communication and ensure fast (sometimes real-time) demand responsiveness. Differently, the relative weight of technology manufactures is more relevant on the case of projects related to the integration of DG and storage which indeed will entail great equipment needs when DG +storage become a dominant paradigm; and especially e-mobility, where car manufacturers (and their suppliers) are especially active at the present moment.

The complexity of the relationships emerging in new business ecosystems within the power sector is well illustrated by the density of the collaboration links between different organization types. Successful BM in the DG era seem to require the involvement of multidisciplinary (highly qualified) resources working together to foster smart products and services that allow them to differentiate themselves from existing solutions and foster market competition.

As the number of services, players and business practices within the electricity network grows (being expected to grow even further in the future) and competitive/cooperation dynamics shift in an unprecedented way, the utilities' business model starts to be challenged, affecting the financial-economic sustainability of the old incumbent corporations. Given their key role as grid managers (who assure the reliability of micro and mini generators systems), it has become imperative to shift the regulatory paradigm and (re) design appropriate policy measures in order to ease the current transition to low-carbon energy markets.

The next section specifically focuses on the market and regulatory challenges related to the financial-economic sustainability of utilities. We choose to concentrate on this particular aspect taking into consideration that the short-run and long-run survival of traditional utilities has been one of the most debated DG challenges among scholars and practitioners. Moreover, it is an urgent issue since utilities are already starting to feel (at least in countries with high DG penetration, such as USA, Germany or China), unprecedented revenue losses (as a result of the demand shifting effect), financial problems related to the delay in tariff revisions to reflect such losses and increasing grid management challenges.

4. Utilities: financial-economic sustainability in the era of DG

4.1 The DG threat to the utilities' conventional BM

DG is creating unprecedented challenges to utilities. On the one hand, DG technologies allow consumers to produce their own energy (Schleicher-Tappeser, 2012), considerably reducing (or even eliminating, at least in some periods of the day/ periods of the year) the demand faced by traditional utilities. This translates into a strong negative effect on the distributors' revenue model (which up to now has mostly been based on a volumetric criteria according to regulated tariffs), inevitably leading to (i) an increase in the energy prices (especially for those consumers who are still exclusively consuming from the grid) and (ii) financial deficits for conventional generators, transmission system operators and distribution system operators (see Castro et al. (2016) for a more detailed discussion of these issues).

On the other hand, DG is increasing substantially the complexity level of grid management activities (e.g. Poudineh and Jamasb (2014) illustrate the increasingly complex tasks attributed to Distribution System Operators within the new DG paradigm). Indeed, the system operators (often old utilities) will now have to:

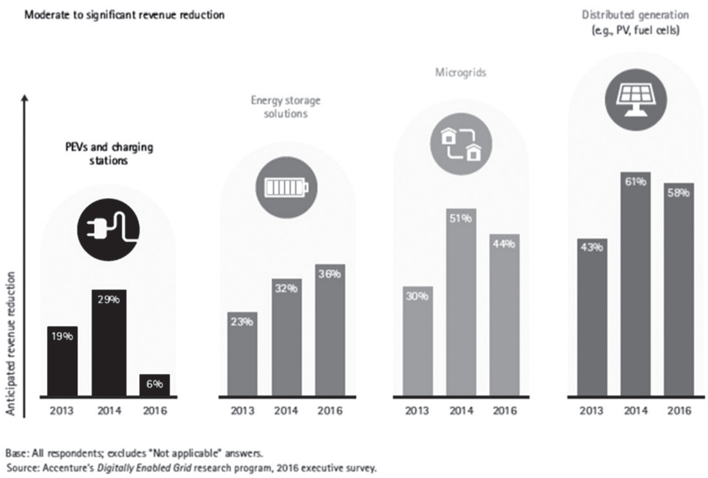
(i) enable the technical integration of DG production in the grid (|for example, Vilela (2014) refers to the technical difficulties in this task since the grid has not been designed to allow for bi-directional electricity flows and therefore must be re-structured in order to integrate DG, calling for considerable investments);
(ii) facilitate coordination among many new heterogeneous players (e.g. prosumers, integrators, EV) within a power system characterized by uncertain decentralized production[10] and storage,
(iii) assure the grid's reliability under an increasing presence of (intermittent) RES,
(iv) assure the (sizeable) investments required to successfully achieve the previous goals.

10 For example, Castro et al (2016) refer that the lack of generalized adoption of online meters impedes the visibility of DG production and storage, enhancing the system operators' difficulties in managing the grid under an uncertain environment.

Moreover, the network management difficulties referred above may be further exacerbated if current market design fails to provide agents' with appropriate investment incentives,[11] leading to distortions in capacity investment choices.

In order to understand how utilities' managers are facing the DG threats, Accenture (2016) has recently conducted surveys and interviews among more than 100 utility executives (in 23 countries) involved in the decision-making process for smart-grid related issues within their firms.

Figure 9. Impact of network assets on utilities by 2030



Source: Accenture (2016)

The figure above shows that utility managers seem to be relatively less concerned with market developments related to storage and EV generalized adoption. This behavior might be explained by the somewhat incipient stage of these technologies (at the time of the survey) or by the fact that utilities' managers actually see EV massive adoption as a new business opportunity. On the contrary, the utilities' managers are increasingly concerned with the loss revenue pertained by the transition to the new electricity paradigm (namely micro-grids and GD like PV Solar).

Several authors have referred to the drastic challenges encountered by distributors (as GD steadily grows) using the term *"death spiral"* effect to coin the threats of GD to utilities (e.g. Dyner *et al.,* 2016, Castro *et al.,* 2016, Castaneda *et al.,* 2017).

11 This problem is expected to become more and more relevant since, as referred by e-Lab (2013) the diffusion of DG projects also implies that "*more capacity investment is made outside of the utility's control and more energy is supplied at the distribution level.*"

The rationale behind the death spiral is the following: the increase in DG (e.g. PV Solar end-users production+storage solutions) leads to a significant reduction in the utilities' demand, resulting in an increase in the utilities' tariffs in order to assure its financial-economic viability (the tariff increase may be further magnified due to the increase in the complexity of smart grids management). However, as the utilities' tariffs increase, end-users' incentives to invest in decentralized generation solutions become larger (since the "*grid parity*" becomes easier to achieve), shrinking the utilities' demand even further and aggravating their financial-economic stability.

This vicious cycle constitutes a major problem at the heart of DG generalization since an appropriate management of the smart grid system its crucial to assure its sustainability and reliability. Indeed, even the micro and mini-generation systems (which are among the main drivers behind the utilities' demand shift) often need to be connected to the grid (which may end up working as a cheap battery for those systems, namely in the case of *net-metering* systems).

Thus the survival of old utilities (who became the system operators) is fundamental. To overcome the death spiral problem, not only utilities need to embrace new business opportunities created by GD, but also a shift in the regulatory paradigm must take place.

Castaneda *et al.* (2017) provides an interesting view on this problem. The authors refer that *"Although theoretically feasible, others argue that the utility death spiral is unlikely as this implies an unreasonable inertia from utilities and regulators (Eid et al., 2014; Costello and Hemphill, 2014); nonetheless, it is a threat to the incumbent distribution utility and to societal welfare (Clift, 2007; Hirschberg et al., 2004). The move towards a decentralized power industry requires appropriate transitional attention"*.

In particular, on the regulatory side, in the short-run, it looks essential to change the regulated tariffs' current structure to a cost-reflective system that sends agents appropriate signals about the costs they impose on the network and avoids unnecessary inefficiencies due to cross-subsidization issues (cost-shifting problem)[12]. These aspects will be analyzed in more detail in Section 4.3.

Before moving towards the regulatory considerations, in section 4.2 we briefly analyze how utilities on their own have been shaping their BM in order to overcome the death spiral and guarantee their own future financial-economic viability.

12 Burger and Luke (2016) describes the cross-subsidization problem as follows: the recent DG trend allows *"systems to enable the system host to significantly reduce or eliminate their total consumption of energy from the bulk power system, thereby reducing network congestion and deferring investments in network reinforcements (but also commonly resulting in a shift of sunk network costs from the system hosts to other network users)"*.

4.2 New business opportunities for *utilities*

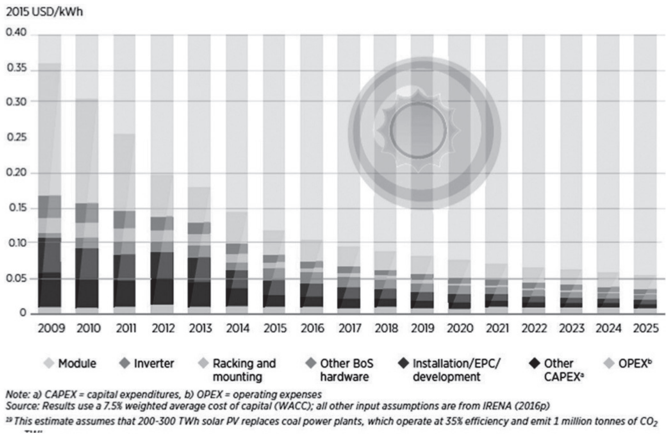
According to Burger and Luke (2016) ,"*the changes driven by DERs will be highly disruptive to the electricity sector, and without adaptation, incumbent utilities risk falling into a "death spiral" that threatens their financial viability"*. Despite DG challenges encountered by utilities, the recent market dynamics may also result in an immense avenue for future business opportunities, which require "*transformative, rather than incremental changes in utility BM"* (eLab (2013)). Utilities need need to take advantage of easy access to new technologies and applications to enlarge their business focus and create competitive advantages *vis-à-vis* new comers in the market (namely learning and scale economies, brand and reputation effects, technology acquaintance).

According to Hamwi and Lizarralde (2017), there is still a considerable inertia in the transformation of the utilities' business model. The situation is highly diversified from country to country, with utilities being more lethargic in countries with lower DG penetration. On the contrary, in countries where DG start gaining momentum (and in which the regulatory, institutional and policy environment is more favorable to DG), at least some utilities seem to be actively working in strategically switching to new business models. This is for instance the case of Germany (E.ON) or NRG Energy (USA): *"E.ON, Germany's largest utility, and NRG Energy, one of the U.S.'s largest power producers, each announced major structural changes to their BM, selling off billions of dollars in assets, and developing new undertakings in distributed resources and renewable energy"* (Burger and Luke, 2017). Moreover, utilities are also starting to get acquainted (and actually in some cases they are deeply involved) in the creation and the deployment of innovative DG technologies and solutions.

On the one hand, they attempt to exploit (at a utility scale) the same resources that constitute the base of many micro and mini DG systems (e.g. PV Solar), enjoying a competitive advantage due to considerable scale economies.[13] Figure 15 indeed shows that there has been a considerable cost reduction in the Global weighted average utility-scale PV Solar LCOE, especially in the module and other hardware components (in which scale economies are quite likely).

13 For example, Burger and Luke (2016) refer *"The community solar provider approach has been particularly popular among regulated utilities that see it as an option to leverage their strengths and provide a value-added solar service"*.

Figure 10. Global weighted average utility-scale PV Solar LCOE: actual and predicted



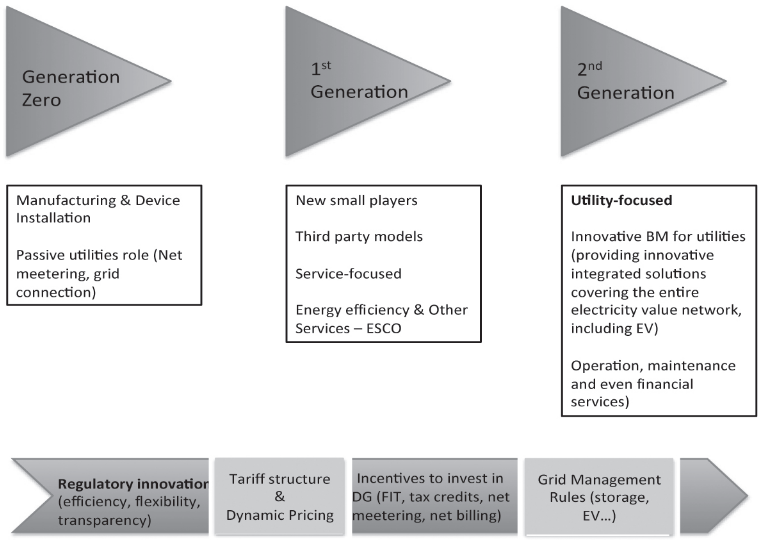
Souce: IRENA (2017)

On the other hand, utilities themselves are also starting to exploit the wide range of energy and ancillary services arising in the era of DG. For example, in the Brazilian case, CEMIG, which is an important distributor with a vertically integrated activity has been sponsoring spin-offs and creating new firms, specifically focused on innovative energy and ancillary services (e.g. *Efficientia* is an ESCO within the universe of CEMIG corporation, being specialized in the offer of energy efficiency services). Likewise, in the Portuguese case, EDP, the previous incumbent utility is already developing energy and ancillary services (e.g. *Serivço Funciona*[14], heating specialized solutions[15] or smart-housing controlling solutions[16]).

In this respect, Vilela and Silva (2017) present an interesting view on the timeline of DG developments (mostly focused on PV Solar), highlighting how the utilities may actually end up being central players in the context of the new DG paradigm. This time frame is illustrated in the figure below, where we also highlight how the regulatory environment may affect the transition across DG generations *through (i)* the appropriate choice of tariff structures and DG remuneration schemes in order to balance the DG investment incentives and utilities' financial stability; *(ii)* the licensing and quality of service conditions imposed on utilities *vis-à-vis* new players in the sector; *(iii)* the rules for technical and economic integration of new players in the power system; *(iv)* the metering systems; or *(v)* the rules of information control and exchange within power networks.

14 https://energia.edp.pt/particulares/energia/gas-eletricidade-funciona/
15 https://energia.edp.pt/particulares/poupar-energia/
16 https://energia.edp.pt/particulares/servicos/redy/

Figure 11. DG diffusion Generations



Source: Own elaboration

From the previous figure, it becomes clear that the evolution from Generation zero to the 3rd Generation wave depends essentially on two (often inter-related) factors, besides technological developments: the strategic behavior[17] of utilities and features of the regulatory framework. The first aspect has been addressed in this sub-section. The next one will focus on regulatory issues.

4.3 Regulatory innovation envisaging utilities' financial-economic stability

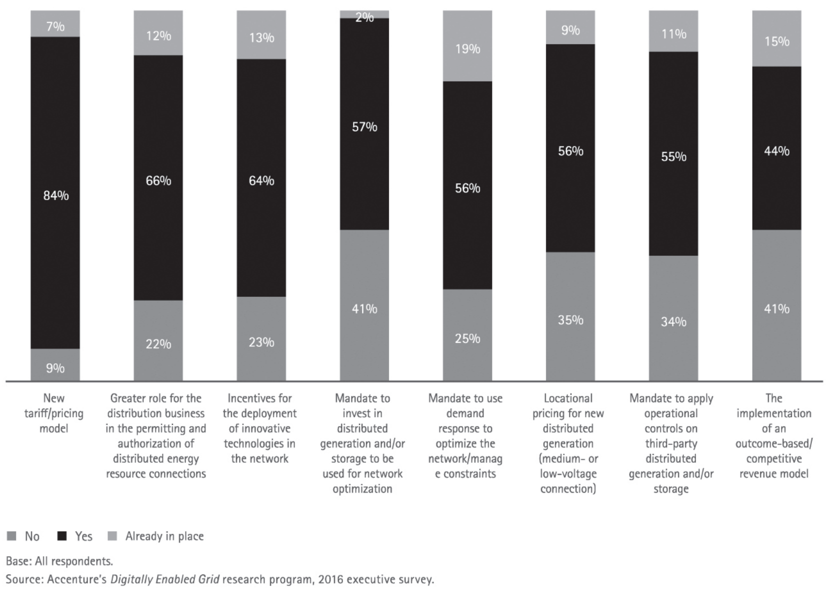
The utilities' financial-economic sustainability constitutes a key aspect in the debate of about regulatory DG challenges. Several countries have already put in place explicit mechanisms to alleviate the impacts of DG on utilities (for example,: in California and Hawai, there is a decoupling mechanism designed to protect utilities from the financial risks deriving from the reduction in utilities' demand. In Nevada, there is a Lost Revenue Adjustment Mechanism)[18].

Accenture (2016) has examined the most important regulatory changes (to be introduced in the next 10 years), according to a sample of 100 utilities' managers in 23 different countries. The results are summarized in the figure below, which clearly

17 For example Vilela and Silva (2017) refer that Brazil is already approaching the 1st Generation BM but, in most cases, utilities are still behaving within the Zero generation set-up.
18 See Alves et al. (2017) for an interesting review on some utilities' protection mechanisms, which are now being implemented in some states of the USA.

shows that the new pricing/ tariff scheme currently is the biggest regulatory concern of utilities' managers in the short-medium time horizon. Managers are also worried (to a slightly less extent) with the regulatory specification of the utilities' role regarding the permission and authorization of distributed energy, the deployment of innovative technologies in the network and the use of demand response to optimize the network/ manage constraints (regarding the last point, it is worth noting that 19% of the managers actually consider that this issue is already being tackled). Other concerns expressed by the utility managers include: the need for mandates to invest in generated distribution and storage (although 41% of the interviewed sample considers this is not a relevant issue for regulatory changes in the next 10 years); locational pricing for new DG; the application of operational controls on third-party distributed energy and storage; and the implementation of an outcome-based / competitive revenue model (again 41% of the interviewed managers does not see room for regulatory change in this point, at least in the coming years).

Figure 12. Necessary regulatory challenges in the next 10 years according to utilities' managers



Source: Accenture (2016)

As already mentioned the most striking result of Accenture (2016) is the utilities' managers concerns with the regulatory changes needed on the grounds of new tariff/ pricing models. In this respect, (at least) two very important dimensions need to be considered: the tariff structure (which directly affects the utilities' revenues) and the DG pricing incentives (which affect the grid parity and the relative profitability of

DG investments, which are shifting demand from traditional utilities to the mini and micro-generation projects). We will now turn our attention to the analysis of each of these dimensions.

Tariff structure

As referred in Section 4.1, the current tariff structure is in the center of the death spiral problem since the existing volumetric system (which charges users according to their consumption levels) does not reflect the (possibly differentiated) structure of costs incurred with different profiles of users in the grid. *Prosumers,* in particular, end up being favored by the current system (at the expenses of other consumers and utilities' financial stability[19]): they are able to satisfy almost all their electricity consumptions needs through mini and micro-generation technologies but they impose costs on the system operators since they need to be connected to grid and even consume from it (especially during some periods of the day, like night periods, in which the network ends up being quite congested due to the correlation in the production conditions of different users' profiles relying on PV Solar).

In this context, both scholars and practitioners have pointed out the need to revise the current (mostly) linear tariff system, replacing linear pricing schedules by a non-linear system that puts more weight on the fixed tariff component in order to reflect the changes in the utilities' BM. [20]

Another widely discussed point in the tariff structure debate is the use of dynamic pricing schemes (such as *critical peak pricing, critical peak rebate, real time pricing*) or even *time-of-use* simpler pricing schemes. In this scenario, prices are more cost-reflective (especially in the case of real-time pricing) and therefore, at least from a theoretical viewpoint, they constitute more effective price signals (e.g. prosumers who only get electricity from the grid when it is highly congested, like early night periods, would be penalized by paying much higher prices). However, the implementation of these systems represents an increasing level of complexity both in the definition of tariffs (for regulators) and their comprehension (for consumers, who need to be increasingly so-

19 Even if the recovery of such costs ends up being possible (at the expense of other consumers), the delay in the tariff revision to recover such costs exposes utilities (namely distributors) to serious financial distress.

20 In some countries (e.g. Portugal), the current regulatory scheme is already based on a two-part tariff. However, even in those cases important changes in the tariff structure are needed to guarantee the utilities' viability. In particular, as DG becomes more important, it is necessary to change the weights of the variable and the fixed components, with the former having a much higher weight (in contrast to the current situation).

phisticated and tech-savvy). Moreover, as referred by Castro *et al.* (2016), time-specific and locational tariffs may also have undesirable results on a social perspective, since they may put lower-income consumers in an especially fragile position.

Despite the difficulties in finding the appropriate tariff mechanism that aligns the incentives of all relevant stakeholders, it is worth noting that regulatory innovations are already being introduced in order to reflect the idea of *"cost to serve"* instead of the "consumption amount" prevalent philosophy. For example, e-Lab (2013) refers the San Diego Gas & Electric's Network Use Charge Proposal, in which consumers are charged "*for the costs associated with network use based on measured demand for distribution service, regardless of whether that service is required for importing or exporting power*".

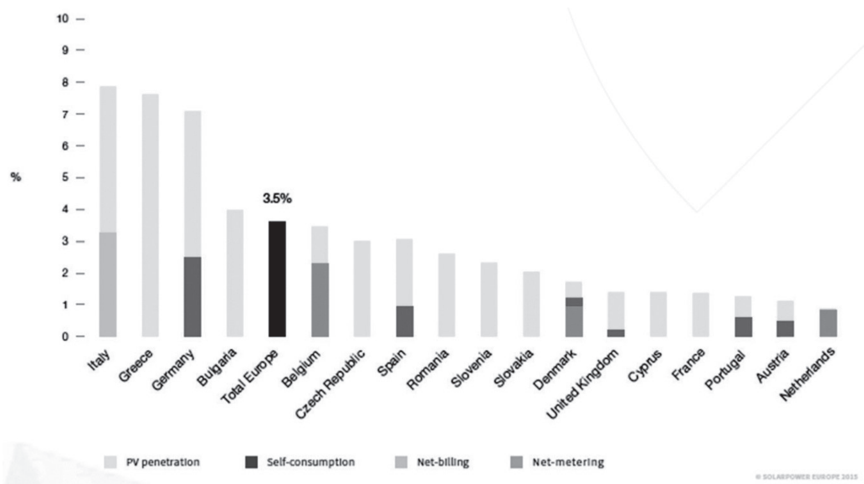
Monetary incentives to invest in DG: billing arrangements and others

In recent years, many incentive schemes have been designed to promote the diffusion in DG technologies and applications, founded on *(i)* their greater environmental performance as well as on *(ii)* the fact that most of these embryonic technologies might need specific support at the early-stages of their life cycle in order to reach a critical user mass and then become mature technologies.

The regulatory framework around the monetary incentives to invest in DG considerably shapes the benefits and costs of DG systems, affecting the attractiveness of such investments (namely the grid parity) and therefore determining the extend to which extent utilities are exposed to demand cuts (resulting from shifts in consumption from the grid to micro or mini grid systems.

Evidently, the regulatory and institutional incentives to invest in DG are very important both from the investor's and the user's perspective. The extant incentives are very diversified. The most frequently used incentive mechanisms are based on FIT, tax benefits, favorable net meetering or net billing systems. The following figure illustrates the diversity of available monetary incentives to invest in DG, focusing on the specific case of the EU.

Figure 13. European PV Solar production and self-consumption in 2015



Source: Solar Power Europe (2015)

The feed-in tariff system has been particularly common in Germany (and other European countries, like the UK[21]). In this system, users are paid for the electricity they generate at a favorable administratively defined rate. If the former is sufficiently high, this system becomes quite favorable to the deployment of DG technologies (e.g. Herbes *et al.* (2016) argues that the shift of FIT to auction tendering systems consisting of an open market bidding system for REC will create price risks and enhance the investors' uncertainty regarding community solar projects). Despite FIT effectiveness in the deployment of DG technologies, this remuneration mechanism is not market-based and therefore agents will lack economic signals to make appropriate investment decisions.

The tax benefit system consists in giving DG's users some kind of tax benefit (e.g. lump sum tax credit, lump sum subsidy, reduction in the tax rate,…). This system has been widely used in the US (at a federal level). However, according to Burger and Luke (2016) this has not been the major motivation for users to invest in DG technologies, actually opening room for new BM that try to exploit and monetize the Investment Tax Credit (e.g in the US system).

The Net Metering System is based on a "credit system" assuring that prosumers who transmit the electricity surplus into the grid get a credit for the surplus they generate (being able to recover the corresponding electricity consumption afterwards). From the consumers' perspective the philosophy behind this system may be quite favorable (e.g.

21 http://www.energysavingtrust.org.uk/renewable-energy/electricity/solar-panels/feed-tariffs

it allows them to use at night the PV Solar generated during the day, without much costs). However, in practice, the net benefits entailed by net-metering policies for DG users depend on *(i)* weather regulation allows a 1:1 credit or has a more restricted scope, with the credit covering only some tariff components like electricity purchase, network access or taxes; *(ii)* the tax treatment of delayed consumption (which has been a controversial issue in the Brazilian case, where the energy regulator ANEEL has been highlighting the unfavorable tax treatment of electricity credits, claiming the need to change the current system); *(iii)* the billing period in which consumers can recover the consumption credit.

The net metering system has been vastly adopted in the USA (E.g California or Nevada), often having a positive effect on agents' willingness to invest in DG technologies. This system is also presently used in Brazil, whose specific features will be descried in Section 5 with more detail. The model has also been used in some European countries (like Belgium, Denmark or Netherlands).

The great advantage of the net metering system lies on the possibility of allowing consumers to displace consumers across periods. This is quite important, especially in the case of non-dispatchable sources like solar or wind. However, without further restrictions the net-metering schemes do not give consumers the appropriate signals about the grid congestion at each point in time. Hence, prosumers are essentially using the grid to store their electricity surpluses (sometimes at zero or very low cost) neglecting the fact that both the network congestion and electricity prices change over time, reflecting the electricity's relative scarcity at each moment of time.

Part of the electricity consumption is not responding to market signs at all, negatively affecting the utilities' profit and the overall efficiency of the electricity system. For this reason, there have been several attempts (see Davies and Carley (2016) for a detailed study of the Nevada case) to revise net metering systems in the USA[22] and mitigate their negative effect in the utilities' financial-economic stability and create stronger demand-response incentives for users. The drawback of such revisions lies on their negative impact on the return of DG projects, diluting investment incentives.

In the context of net-billing schemes, the electricity surpluses that are transmitted to the grid are sold at a given value. The latter could either be a wholesale or retail market place (endowing agents with market-based incentives) or it could be an "avoided cost" price, which tries to reflect the amount of costs that are saved when the energy

22 In Nevada, the regulator has been trying to remove NEM supporting schemes. California and New York are also redesigning their regulatory framework, albeit following a more gradual approach than Nevada (which previously had a very favorable set-up).

surplus is transmitted to grid. For example, e-Lab (2013) refers to the Austin Energy's Value of Solar Tariff, which aims at incorporating *"the net value of distributed solar power to the grid, including net impacts on line losses, energy, generation capacity, transmission and distribution, capacity, environmental benefits, risk mitigation, or other factors"*.

Despite the theoretical insight of the saved cost approach, its practical implementation is very complex due to the difficulties in evaluating, at each point in time, what are the saved costs of transmitting additional distributed electricity to the grid.

Castro et *al.* (2016) refer to the importance of establishing market-based incentives, in the context of which agents' actions may be guided by appropriate market signals. They refer to an interesting solution consisting of the creation of a generated distribution market, in which retailers (buying the electricity from coalitions of mini and micro-generators) would act as coordination devices (aggregators) that would then sell this electricity in the retail market (where price reflects supply and demand interaction). This proposal has the advantage of granting agents in the DG activity with market-based incentives, facilitate the coordination among micro and mini-generators and favor the technical quality of the distribution networks. [23]

5. Case Study - Brazil

The photovoltaic generation in Brazil has a great potential, due to its high natural characteristics (namely high level and low variability of solar irradiation). Although the production potential is not the same throughout the whole country (the areas with greater potential for solar generation in the summer period in Brazil, from January to March, are in the South and Southeast), it is interesting to note that the country's zones with the worst PV solar production characteristics can generate more electricity than the sunniest areas (with largest production capacity) in Germany, a country with significant PV solar capacity. Moreover, according to the National System Operator (ONS), the areas with greater production potential are juxtaposed with the areas with the largest demand, showing the great potential of DG (namely PV solar) in the future to reducing network congestion (namely the demand spikes causing technical distress to the transmission).

According to Castro *et al.* (2016), the greater environmental sustainability of PV Solar does not seem to be an investment-inducing element as it is the case in other countries in which non-RES have a great weight on the electricity-mix, raising serious

23 See Castro *et al.* (2016) for further information on the practical implementation of this Market-based system which aims at balancing the trade-off between the creation and maintenance of DG investment incentives and the utilities' financial stability.

environmental concerns towards the promotion of a low carbon electricity sector (in the Brazilian case, the electricity-mix already counts with a great weight of RES, namely hydro). According to Castro *et al.* (2016), in Brazil, the following major investment determinants in PV solar are the following:

(i) Current transition to a hydrothermal paradigm, in which there is a trend towards tariff increase (given the more frequent activation of thermal plants);
(ii) The need for large investments in the transmission network with the obvious economic effects (and also environmental impacts caused by large scale construction works). This is a key issue in Brazil, where the country's large dimension results in large distances between generation plants (like the hydroelectric plants and wind farms) and the consumption spots, which lead to considerable technical losses in the network (resulting in higher tariffs=
(iii) Electricity universal provision;
(iv) Severe non-technical energy losses (due to energy theft) that also result in upwards price pressures (Shayani, 2010).

The barriers to the diffusion of GD to the consumer in the country are of a financial, regulatory and commercial nature, according to Martins (2015). For distributors, it includes: the question of connecting the UG to the network; the complexity of the procedures, maintenance, security and planning of the system; the networks load reduction and the resulting tariff increase and death spiral effects (generating tariff and financial deficits to generators, distributors and transmission system operators).

The centralized PV solar generation comprises the larger plants, which have been located in the regions with better conditions for PV solar in order to maximize physical production and financial returns (these projects have been located in Northeastern, Midwestern and Southeastern). This are mostly utility-scale projects under the responsibility of larger national and foreign companies in the Brazilian electricity sector are (e.g. ENEL, Green Power, Cobra, EDF, ENGIE, Canadian Solar, Renova, among others). Aneel has already carried out four reserve PV solar auctions since 2013, with a total of 3.2 GWp of photovoltaic projects. In this universe, 55 solar photovoltaic power stations are in operation with 236.248KW. This is quite far from the country's full potential since it only represents 0,15% of the Brazilian electricity capacity. Nonetheless, 37 projects are already under construction (resulting in a capacity expansion of approximately 1GW) and another 65 projects with uninitiated construction, totaling the remainder. (Aneel - Generation Information Data).

Distributed PV solar generation also exists in Brazil. It is more prevalent in urban areas (where PV solar panels are integrated in buildings' roofs). From an individual investors' point of view, the decision to adopt or not of this energy system essentially depends on: (i) the grid parity (which is determined by grid tariff imposed on the consumers, the specific investment benefits within the Brazilian net-metering system and, of course, the radiation index of his/her region, which will affect the investment's value and return; and (ii) the investors' financial.

According to Aneel (2017) the initiative to invest or not on DG technologies and applications should be centered on consumers, who need to balance DG's costs and benefits accounting for several variables, such as the equipment cost, the type of energy source (solar panels, wind turbines, generators biomass, etc.), technology of the equipment, consumer and generation plant size, location (rural or urban), consumers' current tariff regime, payment conditions and consumers' liquidity, consumers' coordination ability (E.g. coordination of up-front capital investments through community based PV solar projects; or design compensation system to manage consumers' energy credits within the Brazilian net-metering system).

Regulation in Brazil

In light of the huge Brazil potential in what comes to DG capacity (namely in terms of solar PV), there have been some recent attempts to change the regulatory framework in order to launch DG business (with positive synergies to other economy sectors). Through Normative Resolution 482/2012, Brazil adopted a net-metering energy compensation mechanism, in which PV solar generation technologies (e.g. solar roof) can be connected to the public electricity grid through the Consumer Unit (UC) and inject the surplus in the electric grid as if it were a battery of infinite capacity, accumulating credits to be compensated in kWh. The power limit contemplated by REN 482/2012 was 1.000 kWp in 2012 and in 2016, this limit was increased by REN 687/2015 to 5.000 kWp per UC (equivalent to the average consumption of more than one thousand middle-class residences in the Brazil). The energy credits injected into the grid are valid for compensation during a 60 month-period. As mentioned earlier (section 4.3) thus system has the advantage of creating a more favorable investment environment. However, it does not provide individuals with price incentives to assimilate electricity's relative scarcity at each point in time. Moreover, by not allowing the commercialization of energy surplus, the system does not create any incentives for the deployment of DG technologies (possibly benefiting from favorable locations) with capacity above the expected level of the investor's consumption.

As of March 1, 2016, Aneel revised the regulation framework, introducing some innovations (RN 687/2015). The first innovation referred to the regulatory limits defining micro and mini generation. According to the new rules, the use of any RES connected in the grid through consumer unit installations, in addition to the qualified cogeneration, is allowed, being denominated distributed micro generation (in the case of generating power plants with installed power up to 75 kilowatts (KW)) and distributed mini generation (when the installed power is above 75 kW and less than or equal to 5 MW).

The new rules have also slighted review the Brazilian net-metering system, expanding the credit recovery period. According to the new rules, the term of validity of the credits went from 36 to 60 months. Moreover, the new rules do not require a full correspondence between the production and the consumption set allowing energy credit holders to reduce the consumption bills of his/ her consumer units located in another place, provided that the later is located in the service area of the same distributor. This type of energy credit system was labeled of *"remote self-consumption"*.

Finally, another important innovation in DG rules introduced by RN 687/2015 concerns the possibility of installation of DG in condominiums (multi-consumer units), extending the coverage of solar roofs to the concepts of condominium, consortium, cooperative and also remote self-consumption. In this configuration, the energy generated can be divided among the condominiums in percentages defined by the consumers themselves. So, those consumers who do not have a roof with good conditions to *"solarize"*, may generate electricity somewhere and use the corresponding energy credits to compensate for the consumption elsewhere (e.g. their residence), within the distributor's concession area. End-users may also constitute a condominium, cooperative or consortium and install a community generator in a location that is not necessarily coincident with the location of any of the members of the condominium, cooperative or consortium. This regulatory revision enlarges the flexibility of the Brazilian DG system (namely in terms of PV solar) so that Aneel estimates that by 2024, in Brazil, more than 1,2 million solar generators will have been installed with a power maximum capacity of 5MWp.

As the regulatory framework starts getting gradually more favorable to DG deployment (PV solar in particular), economic agents seem to start responding to the greater investment incentives (despite the strongly unfavorable macroeconomic conjecture). After 2012, the installation of PV solar started to steadily grow, reaching, in May of 2017, 11.780 connections and 10.561 consumers with credit allowances within the Brazilian net-metering system.

The relevance of the PV solar in Brazil is quite evident when we account for the fact that it represents 99% of the total number of installations in GD. In terms of installed power (114,7 KW), the solar source accounts for 70%, followed by wind power with 9%. As far as concerns consumers, the residential segment is the dominant one in GD, reaching a market share of 79,5%, followed by commercials (with 15% share). The reminders are other industrial and rural customers. In terms of the geographical distribution, we have that more than 40% of the GD capacity is concentrated in the states of Minas Gerais and São Paulo State, followed by Rio Grande do Sul and Rio de Janeiro state, with a clear predominance of the south-southeast of the country. As far as concerns the features of DG projects, in Brazil 93,2% of the DG connections are individual ones (serving only one consumer unit), reflecting the large market share of the residential the residential and commercial facilities (in the context of the Brazilian consumption segmentation). Up to now, only few units are benefiting of the shared generation mode, enabled by RN 687/2015. (ANEEL, 2017)

Although the PV solar sector is far from its maturity within the Brazilian context, the previous figures show that the sector is expanding but a great growing potential remains unexploited. The institutional and regulatory framework will of course be critical variables to promote the sector's sustainable expansion. The table below summarizes the PV generation incentives that exist in Brazil, distinguishing among centralized projects, DG segments or both.

Table 3. Photovoltaic Solar Generation Incentives in Brazil

Incentives targeted to DG segments	**Incentives targeted to centralized projects**	**Incentives targeted to both DG and centralized projects**
Agreement 16/2015 - ICMS exemption on compensated energy	REIDI	CONFAZ agreement on exemption of ICMS on equipment (C.101 / 97)
Law 13,169 / 2015 - exemption from PIS / COFINS	Discounts on TUSD and TUST	PADIS - federal taxes
	Infrastructure Debentures (Law No. 12,431 / 2011)	Sudene, Sudam and Sudeco - IR exemption and accelerated depreciation

As referred in section 4.3, one of the most important pre-requisites to promote the deployment of centralized and distributed solar generation is the investors' financial capital. In the financial markets, the funding modalities most commonly adopted for the case of centralized generation, present certain requirements as collateral, which may act as an investment barrier. Moreover, there are other financial and institutional barriers such as difficulties in credit access and high financial costs; local content requirements; and bureaucracy issues. For small and medium-sized enterprises, which are part of the value chain of this sector, there are special lines in the state development agencies (AgeRio, Bandes, Desenvolve SP, etc.) especially devoted to PV solar projects, and for individuals, associates of SICREDI the financing for solar energy, bonuses for installation of systems in homes (Celesc), among others. More precisely, PV solar specific support is being implemented through BNDES sponsoring, use of regional funds such as *Banco do Nordeste* or *Banco da Amazônia,* multilateral banking system (e.g. CAF, IDB, IFC, NDB), commercial banking system (e.g. Banco do Brasil, Bradesco, CEF, Santander, Itaú), Export Credit Agencies as well as specific Energy Funds. Moreover, energy companies also start proposing (often partnershiping with strategic allies) innovative funding solutions. In particular, large energy companies, integrators and PV system installers are beginning to offer financial funds mechanisms, through which a client can request the installation of a solar roof in his residence and pay the cost of this installation with the energy saving amounts.

New Business Models in Brazil

Since the implementation of Resolution 687/2015 of Aneel, new business models with significant growth potential have already been established, namely Condos and Consortium or Cooperative. This is expected to have a significant impact on the Brazilian economy, both directly, through the positive effects on the energy sector itself and indirectly, through potential synergies with other economy sectors. Indeed, the value chain of the PV solar generation sector comprises many actors and activities, from the raw material (metallurgical silicon), materials (solar grade silicon, steel, glass, acrylic, etc.), parts (photovoltaic cell of crystalline silicon, ingot and silicon wafer, films and frames, etc.) and equipment such as module, inverter, meter, monitoring and storage system, etc.

Sebrae/BID/ OEI (2017) has mapped the Brazilian value chain, concluding that about ten links in the production chain are not being produced internally. These products comprise material links and components, which are imported. Regarding services (which include very diversified activities such as project developer and integrator, EPCs, equipment distributor, energy producer, operation and maintenance) Sebrae/BID/ OEI (2017) refers that they are provided, in their totality, in the national territory.

The dynamism of the PV solar industry is illustrated in the number of firms participating in the sector nowadays (despite the economic crisis in Brazil). Around 400 companies are estimated to be producing goods within the PV solar value chain, whereas more than 1.000 companies are estimated to be involved in different points of the distribution service chain throughout Brazil. Some of the large companies involved in this sector include WEG, GE, ABB, BYD, Enel Solutions, among others. Averages and small firms are also active in the market, as well as national and foreign firms. It is also worth noting the important role that start-ups, accelerators and incubators are playing in the sector. They are bringing additional dynamism to the market by focusing their efforts on the development of new technologies, searching for new materials and new production processes, designing new final products and investing in innovative smaller generation plants. Start-ups often develop new business models, stimulating remote self-consumption, solar condominiums, shared generation, subscription services and adaptation of imported components and equipment. Some large companies and institutions in the Brazilian electric sector support start-ups, with specific incentive programs for their development and subsequent acquisition.

The technological development at PV Solar has advanced a lot worldwide and in Brazil it still needs improvements aimed at benefiting from scale and learning economies, reducing the cost of the PV system, developing new semiconductor materials and developing new applications, such as storage and batteries, increasing overall efficiency both in a static and in a dynamic perspective.

An ongoing research project in Federal University of Santa Catarina (UFSC) (www.fotovoltaica.ufsc.br) has identified situations where PV solar modules used as coating material for office buildings can be economically viable due to a reduction in opportunity costs (namelythe avoided cost of replacing coating materials of facades such as glass, granite or ACM (aluminum composite material).

To sum up, it is possible to conclude that Brazil is far from reaching its full potential regarding DG. However, the sector starts to register some dynamism. In the future, new business opportunities are expected to arrive, opening the door to more sophisticated BM (e.g remote self-consumption and shared generation), mergers and acquisition operations (attenuating the current trend towards decentralized market structures), increasing demand for highly qualified resources, increasing collaboration among different types of stakeholders (being quite important to follow how EV producers will position themselves within the solar PV sector), stronger focus on Quality of Service and standardization.

Impacts on Distributors

Aneel (2017) has estimated the number of residential and commercial consumers that will install or receive credits in the period 2017-24, according to its own methodology. Although in May 2017 the number of connections is only 11.780; the projected number of residential and commercial consumers for 2024 reaches the figure of 886.700, with an installed capacity of 3.208 MW. These projections also include the tariff impact, which was calculated for each distributor, based on the readjustments occurred in 2016. These are quite impressive figures, which will probably put current distributors into financial distress.

The results of the simulations carried out show that some distributors would have a tariff increase due to GD ranging from 2,4% to Ampla and 2.6% for Cemig, and the cumulative average impact in the country would be 1,1% in the period 2017/24.

Therefore, we may conclude that the Brazilian electric sector is undergoing a transformation marked by the inflow of the mini and the distributed micro generation. At the present moment, current infrastructures, as well as the operational characteristics, are not yet adapted to this imminent transformation. Consumers, investors and regulators need to find a coordination device in order to assure that the physical network is adapted (being replaced by a smart grid) and technical issues are overcome. The regulatory framework should also follow the technical developments (and sometimes even anticipate them), changing the tariff structure and encouraging of the use of technologies with a greater systemic synergy impact in order to balance the need to create good investment conditions for PV solar and the need to assure good conditions for the economic viability of distributors (most of them still working within a traditional utility BM).

6. Conclusions and Future Research

The business paradigm in electricity systems has been experiencing a global-scale disruptive shift in recent years. The dominant BM consisting of vertically integrated utilities is being replaced by a decentralized and digitalized complex system sustained by an increasingly complex value low-carbon system. This complex process obviously raises many interesting questions, in very different domains, such as environmental performance, technological innovation, communication models, business model innovation, market design, regulation, public policy design, just to mention a few.

The main objectives of this paper were the following: First, we aimed at reviewing the state-of-the-art literature on BM innovation in the electricity sector, in order to gain a more systematic view on current business dynamics. Second, we aimed at understanding how utilities are coping with BM innovation in the era of DG, highlighting the threats but also the opportunities they may be encountering. Third, we intended to illustrate how the analysis of the previous issue depends on the specifics of countries' regulatory options, underlining how the interplay between regulation and BM innovation may shape the transition path towards low-carbon electricity markets. Finally, we intended to illustrate all these matters in the specific case of the Brazilian power system, where DG is still at a relatively early stage but the growth potential is enormous, accounting to the countries' natural conditions for PV Solar.

Our analysis revealed that the new electricity paradigm has not yet been achieved but the system is already quite complex, with many heterogeneous agents co-existing side-by-side within a "coopetition" framework. This new reality is resulting in the entry of many new players (with the concomitant reduction on market concentration indexes) and the shift of key competitive variables (e.g. in the downstream market, strategic interaction is shifting from a price competition environment _ in de-regulated retail markets _ to a product differentiation set-up, where multi-product/ service firms actively invest in offering innovative differentiated solutions).

The emergent business dynamics around DG are threatening the utilities' traditional BM, possibly causing a death spiral phenomenon. However, they are also opening new business opportunities. In particular, eLab (2013) points out that the activity of utilities needs to be rethought in order to accommodate their new roled as "*1) distribution system operations coordinator, 2) provider of reliability/standby and power quality services for customers that do not self-provide these services, and/or 3) integrator of large-scale supply resources, distributed energy resources, and storage, all under circumstances in which regulation creates a level playing field for the utility to combine these resources for least cost overall.*"

The extent to which utilities may or not benefit from those opportunities is highly related to the regulatory framework. We found that regulatory innovation is needed to better balance the need to provide DG investment incentives and the financial stability of distributors. In the short-run, two of the most important elements within this regulatory innovation process are: the revision of the current tariff system (whose linear (or almost linear) structure is exposing utilities to financial distress and penalizing consumers who are only getting electricity from the grid); and the definition of market-based remuneration mechanisms for DG surpluses that are transmitted to the grid in order to balance the trade-off between the utilities' financial stability and the GD investment incentives.

In this respect, both scholars and practitioners agree on the need for a regulatory gradual shift in order to accommodate the paradigm shift in the electric system without hindering the system's stability and agents' trust in the regulatory set-up (which would create considerable regulatory risks, with an obvious negative impact on agents' investment decisions.

Moreover, the regulatory shift towards the new electricity paradigm is not always easy since on the one hand different stakeholders may favor conflicting regulatory changes; and, on the other hand, there are still many uncertainty layers regarding the future of electricity markets. Accordingly, regulators and policymakers should reflect on the ideal characteristics of the future electricity system and proactively contribute to their emergence.

In this context, eLab (2013) identifies some important attributes that regulators and policy makers must take into consideration when revising the regulatory and institutional set-up: *(i)* promote network efficiency, resilience, and reliability by developing arrangements that facilitate the communication among system operators, like the transport and the distribution system operator; *(ii)* foster product and process innovation, encouraging competition whenever it is possible; *(iii)* ensure cost effectiveness; *(iv)* assure a level playing field for competition; *(v)* guarantee the transparency and simplicity of the overall system; *(vi)* act as a facilitator in the transition towards a new business paradigm, supporting "*the harmonization of business models of regulated and non-regulated service providers*").

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Systemic Impacts of Distributed Generation

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Abstract

A large increase in the solar distributed generation is expected in Brazil in the coming years, driven by the fall in prices of photovoltaic systems, regulatory changes and growing societal concerns about greenhouse gas emission. Even though there are potential benefits to the electricity system, there are also potential costs, in which many of them are not explicit. In addition, it is necessary to consider how these costs and benefits, as well as the risks involved in the process, are allocated among the different stakeholders. Based on a wide bibliographical review, we seek to identify metrics for the evaluation of this energy source and its impacts, considering also the specific challenges of its application in the Brazilian Electric Sector.

1. Introduction

With the decrease in prices of photovoltaic panels, regulatory advances - such as Aneel's Normative Resolution No. 482/2012 (ANEEL, 2012) - and society's growing concerns about greenhouse gas emissions, it is expected to increase sharply the electricity production in a decentralized way in Brazil in the coming years. Commonly, the diffusion of the distributed solar photovoltaic generation is considered as beneficial for the electric power system. In fact, this process has potential benefits to the system. However, it should be noted that there are also costs, many of which are not explicit. In addition, it is necessary to consider how these costs and benefits, as well as the risks involved in the process, are allocated among the different stakeholders.

In this context, it is noticeable the need to examine the impacts of the diffusion of micro and mini solar photovoltaic generation on the Brazilian system in different perspectives. This document presents a description of the potential impacts to be observed by Brazil due to the large-scale entry of distributed photovoltaic generation. These impacts came from several aspects, such as economic, environmental, electricity, among others.

It should be noted that these are potential impacts. Its effective verification depends on the level of diffusion of distributed photovoltaic generation and the characteristics of each electric power system. For example, the postponement of investments in the network is usually seen as a benefit of the diffusion of distributed generation. But we must consider that this postponement is only verified when there is a temporal coincidence between the peak demand of the system and solar photovoltaic generation.

The methodology for preparing this report was based on a wide literature review and contacts with specialists[1] with a view to understanding how these issues are occurring in electric power systems in which the diffusion of distributed solar photovoltaic generation is already a reality. In this international analysis, metrics were identified for the dimensioning of these impacts. At the same time, we highlight the analysis of the characteristics of the Brazilian electricity sector for a better understanding of how these impacts can occur in Brazil.

2. Characterization of the electricity sector

The problem of the operation of the electricity sector is to meet the demand at the lowest costs, ensuring a low probability of interruption in supply. Traditionally, the

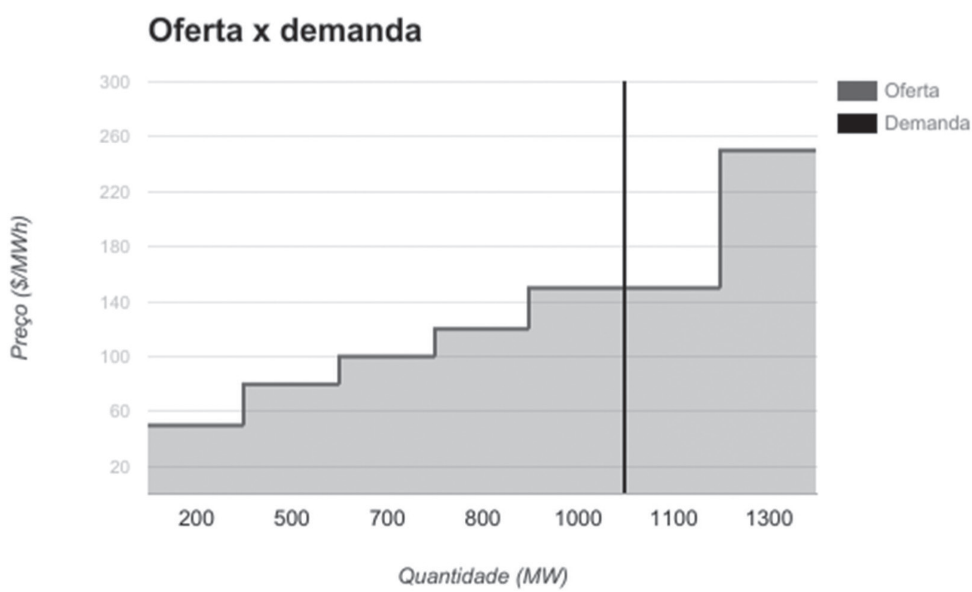
1 This contact resulted from a technical visit to the United States, in which we spoke with several institutions, such as distribution system operators, regulators, among others.

power plants have variable costs to generate electricity. Thus, in order to operate the system at the lowest possible cost, priority is given to those with lower variable costs. If demand is not fully met, more expensive power plants will start operating.

Thus, disregarding inflexibility constraints, the plants are organized in increasing order of variable costs. Thus, wind, photovoltaic and hydroelectric power plants are a priority because their variable cost is close to zero. Then there are those with low variable costs like nuclear thermoelectric and coal. Among the most expensive, in general, are those driven by fuel oil or diesel oil.

Figure 1 illustrates a hypothetical example of a system consisting of plants with variable costs of 50, 80, 100, 120, 150 and 250 monetary units per megawatt-hour ($/MWh). It is observed that the demand of 1,000 MW[2] can be met by dispatching all the power plants, except the most expensive, of 250 $/MWh. A small increase in demand could be met at the additional cost of 150 $/MWh. Therefore, it is said that the marginal operating cost of the system is 150 $/MWh. If demand increases to more than 1100 MW, the most expensive plant would start operating and the marginal cost would increase to 250 $/MWh.

Figure 1 - Hypothetical Example of Supply and Demand in the Electricity Sector



Source: In-house preparation

2 Considered completely inelastic in this example.

In industry jargon, this ordering of the dispatched power plants is called the "order of merit." Renewable plants like wind and photovoltaic have very low variable cost. In this way they shift the supply curve to the right, which can reduce the marginal cost of operation.

In electricity sectors where the sale of electricity is liberalized, there are usually spot markets, which form the price of electricity due to demand and short-term supply. Roughly speaking, the generating agents indicate how much energy they are willing to produce and at what price. The offer is "stacked up" to meet demand. In many cases, the price of electric energy is defined as equal to the marginal cost of operation. Thus, even if its variable cost is lower, all power plants that generate receive the marginal cost. This gain of the plants above their variable cost can be used to lower their fixed costs. This encourages efficiency and investment in capacity expansion. This is a mechanism that works well in systems with plants with variable costs above average costs[3]. However, entering a large number of sources with low variable costs can cause prices in the long run to remain below average costs. This discourages new investments, because in this case companies cannot recover the amount invested (Castro *et al.*, 2010).

Hydroelectric power plants, as well as other renewable ones, have variable cost of reduced generation, since they do not consume fossil fuel. On the other hand, they have the capacity to store water in the reservoirs. If one chooses to generate energy now, there will be less available water in the future. In this way, it is observed that there is an opportunity cost in relation to the production of energy. The value of this opportunity cost is called the "water value."

Therefore, in Brazil, the operation is done centrally. There are no spot markets to meet short-term demand. The dispatch decision is made by the National System Operator (ONS), which operates to achieve system security (i.e., low probability of deficit) and also lower operating costs. In general terms, the dispatch is supported by computational models, which, based on the current conditions of the system - such as storage levels in the reservoirs and installed capacity - and the expected expansion of the generator park, defines the optimal strategy to meet the demanded load. In this process, the inflows are modeled in synthetic scenarios and from analyzes of water use on the future cost of generation, the optimal dispatch is calculated (Castro *et al.*, 2009).

It is noticeable that electric power systems with the predominance of sources characterized by a high proportion of fixed costs over the total costs lead to the neces-

3 The average cost is given by the ratio between total costs (given by the sum of variable costs and fixed costs) in relation to the quantity produced (in this case, energy units).

sity of adaptation of the markets in view of electricity[4]. In these markets, the establishment of long-term contracts is important. Therefore, in Brazil, it was decided to carry out the expansion through auctions of new enterprises, the so-called New Energy Auctions (LEN, Leilões de Energia Nova). In these auctions, long-term contracts[5] between power generators and power distributors. Thus, there is a certain guarantee in the financial return of the investment[6].

According to d'Araujo (2009), for producing most of its electricity[7] through hydroelectric generation, the system is highly interconnected in order to take advantage of the complementarity and synergy between the operation of different hydroelectric power plants located in different geographic regions. This integrated system is called the National Interconnected System (SIN, Sistema Interligado Nacional). It covers much of the Brazilian territory and serves the majority of its population, and currently only one capital, Boa Vista, is not part of it. This large interconnection is a characteristic feature of the Brazilian system, not being common in other locations. For example, in the United States - a country with similar dimensions to Brazil, but with much greater demand - there are several electric power systems isolated from each other or with small interconnection capacity.

The large integration of SIN can be an advantage for the expansion of non-controllable renewable power plants, such as wind and photovoltaic. The fact of interconnecting regions with different climatic characteristics causes risks and variability to decrease.

The Brazilian electricity sector is undergoing a process of transformation of its operational paradigm. The capacity to regularize the reservoirs of electric power, which historically contributed to the stability of hydroelectric generation in the country, has been reducing in recent decades. According to Dantas *et al.* (2015), the security of supply depends on the ability to regularize the supply of energy over the years through the storage of water in large reservoirs with thermoelectric plants complementation in situa-

4 In a competitive market, the price must converge to the marginal cost. Thus, electric power systems with predominant sources with low variable costs present low marginal costs. This is the case of photovoltaic and nuclear systems. Therefore, the low price in the energy market can generate economic disincentives to certain generation plants, in the absence of other mechanisms such as power market. More recently, this dynamic has been verified in Europe, due to the diffusion of wind and solar sources.

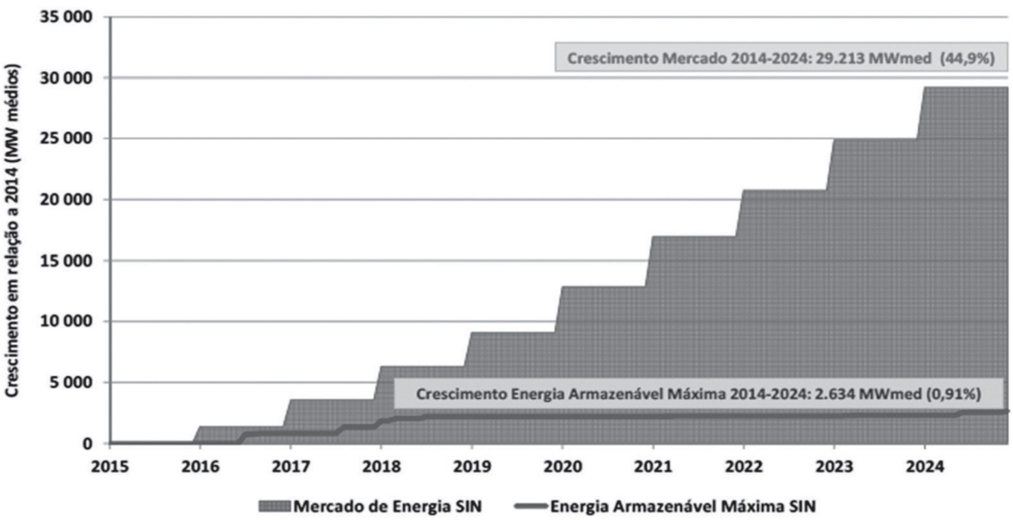
5 Minimum of 15 years.

6 In the case of thermoelectric plants, the contract is made by availability, depending on the water risk. They receive a fixed annual amount to be available for generation. By the time they actually go live, their variable costs are reimbursed by consumers. In this way, it sells the availability to generate electricity at a certain cost, thus resembling a call option.

7 Considering the period between 1971 and 2015, the average share of the hydroelectric power plant is 87.74%.

tions of unfavorable hydrology. Accumulation reservoirs allow for the regularization of affluence over long periods (months or years). However, this capacity for regularization has been declining in recent times, partly because of the growth in demand, partly because the best storage potential has already been explored and partly because of the greater resistance of society to the environmental impacts of large reservoirs. Figure 2 below shows the expected expansion of storage capacity compared to the projected demand increase over the same period.

Figure 2: Projection of Brazilian regularization capacity



Source: EPE, 2015

According to EPE (2015), demand in 2024 is expected to increase by 29,213 MWaver[8] (256.1 TWh) compared to 2015 levels, while the increase in storage capacity will be only 2,634 MWaver (23.1 TWh), even with the predicted increase in the installed capacity of hydroelectric power plants of 28,349 MW in the same period.

Most of the remaining potential of hydroelectric power plants corresponds to those whose reservoirs are insufficient to store excess water from the wet period for months. These power plants are called run-of-the-river power plant. This represents a major change in the Brazilian electric power system, which should change its operating paradigms, historically based on reservoir hydropower, with multi-year storage capacity.

8 MWaver is the energy corresponding to the generation of 1 MW during a certain period of time. In the case in question, the period is one year. Then, 1 MWaver = 1 MWyear = 1 MW x 8766 hours (average duration of one year) = 8766 MWh.

It should be noted that the dispatch models used for planning the operation in Brazil do not capture the characteristics and uncertainties of non-controllable renewable sources in the energy matrix, which show a tendency to grow, especially the wind power source. 2015 was the first year in which the electricity generated by wind power surpassed that from nuclear origin[9]. While the energy coming from the winds was 21.6 TWh in the year, the nuclear energy generated 14.7 TWh. In terms of installed capacity, wind energy closed 2015 with 7.6 GW and nuclear energy with 1.9 GW.

In this context of falling, the reservoir regularization capacity, increasing uncertainties due to climate change and generation expansion through intermittent and non-dispatchable sources, it becomes more challenging to operate the SIN and also the work to quantify the potential benefits of photovoltaic generation distributed to the Brazilian electric power system. In addition, there is a need to adapt the regulatory model of the electricity sector to guarantee sustainability in the evolution of the national energy matrix, in order to preserve security of supply and modest costs.

3. Impacts of photovoltaic diffusion on the Brazilian electricity sector

3.1. Avoided generation costs

From the systemic point of view, distributed photovoltaic generation is equivalent to a load reduction because it is consumed at the place where it is produced. Thus, generation of a source that would be dispatched to meet the load was avoided if there was no such source (Denholm *et al.*, 2014). The power plant that will stop generating due to the diffusion of the distributed photovoltaic will be that which is marginal at that moment, that is to say, the one with greater variable cost being dispatched.

Thus, for the calculation of the economy resulting from the displacement of the generation, it is necessary to correlate the photovoltaic production with the generation of the system to estimate which power plant would stop producing. There are more simplified ways (e.g., consider that the marginal power plant is always a specific thermoelectric plant) and other more complex ways to define what the marginal power plant would be. In the case of the Brazilian electric power system, there is an even greater complexity in this calculation, because often the marginal power plant is a hydroelectric power plant. The fact that it fails to generate due to the expansion of the installed photovoltaic capacity is beneficial to the system, because although the water

9 It is worth remembering that the generation of the nuclear source is basic, constant over time, while the wind varies according to the wind regime. This causes these sources to contribute in different ways to the system.

does not have a direct cost, as would the fuel of a thermoelectric power plant, keeping it stored makes more water available in the future. That is, there is an opportunity cost of using the water that is in the reservoir. However, in order to quantify the value of this stored water, it is necessary to use the more complex tools, such as optimization models of the operation.

Denholm *et al.* (2014) identify the main ways of quantifying the costs avoided due to generation displaced by photovoltaic production. The first one is called a "simple avoided generator", in which it is assumed that the marginal plant whose production would be avoided at the moment of photovoltaic generation is always the same. In the case of the United States, in general, it is considered a combined cycle natural gas plant. Thus, the calculation is made by the product between the specific consumption of the plant and the cost of fuel. This method has the advantage of its great simplicity of calculation. Thus, this method serves as a first estimate to verify the order of magnitude of avoided costs. On the other hand, this simplicity prevents us from observing the specific characteristics of each system, as well as the fact that different plants may be marginal at different times.

A development of this method would be the "weighted avoided generator" (Denholm *et al*, 2014). The idea is that in periods of peak load, photovoltaic production displaces less efficient plants, while more efficient plants are displaced in the off-peak period. This assumption stems from the idea that to attend to the tip of the system, more plants are dispatched and the more efficient ones are expected to enter the system before the least efficient ones. Thus, the same account is made of the simple avoided generator method, but weighted by the proportion of photovoltaic production at peak and off-peak times. This methodology adds a bit of precision to the calculation, compared to the previous methodology, but also a little more complexity, since it is necessary to estimate the proportion of photovoltaic generation that occurs in the peak and off-peak periods.

The first two methods treated have the advantage of being simpler and requiring relatively less data than the other methodologies that will be exposed. However, they consider that distributed photovoltaic generation will replace only one or a few typical thermoelectric power plants. In practice, in large electric power systems, there are several types of power plants with different characteristics that may be marginal. Although they present their limitations, these approaches may be useful to provide a first approximation of the operational cost benefits avoided by distributed photovoltaic diffusion to the studied electric power system.

Thus, there is a third method, called the historical price method, which consists in correlating the historical data of short-term prices, i.e., the marginal costs of operation of the analyzed system or region, with the expected photovoltaic generation. With this, we can verify the monetary value of the production displaced by the distributed photovoltaic. Therefore, the estimated photovoltaic production for the analyzed period is multiplied by the energy price at the same time to obtain the total value of generation avoided from that period. This value can be aggregated to calculate the total annual value or the average value per unit of energy (for example, R$/MWh) over a certain period (Denholm *et al*., 2014).

The application of this methodology has the advantage that the analyst does not need to define, which plant is the marginal one at any time, since this was already defined at the time of dispatch and recorded in the price history. On the other hand, the disadvantage is based on past prices, which will not necessarily be reflected in the future, especially when considering the changes that must occur in the consumption and production of electricity. Changes such as: increased inflow of non-controllable renewable sources, demand-side consumption management, smart grids, electric cars, energy efficiency, start-up of large hydroelectric power plants in the Amazon region.

An improvement of this methodology was suggested by Morais (2015) to verify the monetary contribution of the start-up of wind and solar power sources to the electric power system. Historical prices, the penetration of these sources and the need to expand the system, measured by the historical trajectory of the Settlement Price of Differences (PLD, *Preço de Liquidação de Diferenças*), were used to calculate the value of these sources.

In the case of Brazil, the greater discretization that exists for short-term prices is weekly and *ex-ante,* given by the PLD. This characteristic is a disadvantage, since short-term prices are not given hourly, but in three weekly levels linked to pre-defined periods of time (heavy, medium and light load levels). In this case, the method would provide a recipe calculated from weekly prices and would not capture the variability of solar power production, which is captured in systems with spot markets with defined prices in smaller time intervals.

Another disadvantage of the application of historical prices to the Brazilian case is that the current price setting system does not necessarily reflect the plants being dispatched and would be displaced with the entry of distributed photovoltaic generation. In many cases, ONS dispatches thermoelectric plants to meet peak demand and this generation is not reflected in short-term prices and is paid through charges. In addition, price is defined by subsystem and not by electric bus. Thus, any dispatches to meet local electrical restrictions do not enter into the calculation of price formation and are paid through charges. Finally, the published PLD values do not always reflect the marginal cost of operation calculated for the operating week. This is because there are limits of maximum and minimum values[10] of PLD. For these reasons, estimating costs avoided from historical prices would tend to find values below the real ones.

Finally, the most complete way of estimating avoided generation costs is through the simulation of the electric power system, considering the characteristics of its power plants in an ideal dispatch model. This simulation allows us to more accurately estimate the costs avoided, although it is the more complex methodology, both in terms of computational effort and data requirements. This type of program is widely used by the electricity sector agents to analyze and anticipate future service conditions. There are several commercial options available, such as Plexos (Energy Exemplary, 2016), GE MAPS (GE Energy Consulting, 2017)[11].

One disadvantage of using this type of tool is the so-called "black box" effect, in which the user does not have access to the internal workings of the program, nor can verify the source code (Denholm *et al.* 2014). In general, these programs are made available through the sale of the license, with relatively high values. These characteristics limit the transparency and reproducibility of results. Another problem with using this methodology is the large amount of data needed to adequately represent a given electric power system.

In Brazil, the most used models for simulation of the operation are Newave (Cepel, 2015) and Decomp (Cepel, 2015b), developed by Eletrobras Cepel. The horizon of the Newave simulation is medium term and some simplifications are made in the formulation of the problem, such as equivalent reservoirs and the monthly discretization. The Newave results serve as input data for Decomp, which has weekly discretization at three load levels (heavy, medium and light).

ONS uses these two programs in its official simulations of the monthly operation planning. Similarly, the PLD is calculated by the Electric Energy Trading Chamber (CCEE, Câmara de Comercialização de Energia Elétrica) using the same tools. Empresa de Pesquisa Energética (EPE) also uses Newave in some of its activities, such as the preparation of the Ten Year Expansion Plan (PDE, Plano Decenal de Expansão) and the definition of the physical guarantee of the power plants. Because these models are used by the Operator and for price formation, electricity generation and trading companies tend to use them in their internal analysis. The input data for SIN simula-

10 The following were the limits in 2017: PLDmin = R$ 33.68/MWh, PLDmax = R$ 533.82/MWh.
11 A listing and analytical description of some of these software can be found in Foley *et al.* (2010).

tion are publicly available. Thus, the use of these tools, in principle, would be the most appropriate for the analysis of the avoided costs of solar photovoltaic generation.

However, while these models are capable of presenting optimal demand-side configurations at minimum costs, they do not reproduce the operation in hourly discretization, so this makes it difficult to adequately represent distributed photovoltaic generation, which varies throughout the day. Consequently, with the use of these tools, identification of the impacts of large-scale entry of this source is impaired. This problem was pointed out by Gemignani *et al.* (2014) in a study that analyzes the impacts of large-scale solar source insertion on the SIN using Newave. Thus, more precise analyzes should be made with tools that allow more discrete simulations, such as those used in international studies (Jorgenson *et al.*, 2014, Denholm *et al.*, 2013, and Xcel Energy Services Inc., 2013) and national studies (Castro, 2015).

Different penetrations of the photovoltaic technology in the electric power system bring different impacts. Unlike the previous methods, which always consider a marginal contribution of the source, this methodology allows to carry out cost analysis avoided considering the effects of bigger penetrations of the photovoltaic technology in the system.

3.2. Postponement of investment in new power plants

Distributed photovoltaic generation can delay the investment in another power plant to meet the maximum demand of the system. The metric used to quantify this benefit is the capacity value (Denholm *et al.*, 2014). When a new power plant is added to a generator park, it increases the reliability of the system because it reduces the chance that it will not be able to meet all the demand at any given time. In general, it is not possible to obtain 100% service reliability, since even in a system composed only of flexible thermoelectric power plants, there is a risk of forced unavailability in the generators. Thus, planning is done to ensure an acceptable level of reliability, the lowest possible costs and following certain operational constraints.

In the context of distributed photovoltaic generation, this is an extra resource for the system. In this way the reliability of the system[12] is greater than or equal to the situation without this feature. In the more specific case of Brazil, its contribution is likely to be significant, since the time of the year with the highest consumption of electricity is during summer (ONS, 2017), when the highest daily demands usually occur in the

12 Considering the risks in terms of reliability indexes, such as LOLP (Loss of Load Probability) and LOLE (Loss of Load Expectation).

afternoon, due to the large amount of air conditioning and refrigeration appliances in use[13]. This moment coincides with the generation of photovoltaic power stations.

In order to estimate this contribution to the system's ability to meet demand, there is a specific metric, called capacity credit. With this, it is possible to know the collaboration of the power plant to supply the capacity of the system. In general, capacity credit is reported as a percentage of installed capacity, but can also be given in absolute terms. So if the rated power of a power plant is 100 MW, if you say its capacity credit is 30%, it is equivalent to say that it is 30 MW[14] (Madaeni *et al.*, 2012).

After defining the capacity credit of a power plant, it is possible to quantify this benefit in monetary terms. This is called capacity value or capacity payment. This value is determined by what is required to encourage the installation of a generating unit capable of meeting the power requirements, and can be given by the capacity market of a region, if any. Another way of estimating it is by the cost of implementing a plant with end-user characteristics, for example a natural gas plant with a single cycle and a quick start.

There are several methodologies for estimating capacity credit, which vary considerably in terms of complexity, computational effort and data need (Madaeni *et al.* 2011)[15]. The most robust methodologies are those based on reliability analyzes such as ELCC (Effective Load Carrying Capability), ECP (Equivalent Conventional Power) and EFC (Equivalent Firm Capacity), all discussed in Madaeni *et al.* (2012). In order to calculate the ELCC, it is verified the increase of load in the system that - after the addition of the analyzed power plant - it maintains the same risk of non-compliance that there was initially[16]. This increase in load is the capacity credit of the power plant.

The disadvantage of this methodology and others that use reliability analysis is that large amounts of data and computational effort are required. Data of capacity and

13 By the end of January 2017, the maximum demand recorded in the National Interconnected System (SIN) occurred on 2/5/2014 at 3:41 pm with the value of 85,708 MW (ONS 2014).

14 Results from studies conducted in other countries show a capacity credit for photovoltaic power plants of approximately 40% in Toronto Canada (Pelland and Abboud, 2008) and 52% to 70% in different locations in the western United States (Madaeni *et al.*, 2012). It is observed that, in these cases, the capacity credit is greater than the capacity factor of the power plant, which in the case of photovoltaics, typically varies from 15 to 25%.

15 A summary of the main methodologies applied to photovoltaic generation can be found in Perez et al. (2008). Another good description and comparison of the different methodologies applied to the photovoltaic technology can be found in Madaeni *et al.* (2012).

16 The EFC (Equivalent Firm Capacity) is defined as the capacity of a power plant with a zero failure rate that would replace the power plant under analysis with the same level of reliability. On the other hand, the ECP (Equivalent Conventional Power) is the capacity of a power plant with a typical failure rate that would replace the power plant analyzed with the same level of reliability.

forced unavailability rate (TEIF) of all power generators of the analyzed system are required. In addition, the LOLE calculation must be performed iteratively until the expected result is achieved. Thus, many authors prefer to use other methodologies for this calculation. These results are similar to those of the ELCC methodology.

Reviews made by Madaeni *et al.* (2012) for photovoltaic generation located in the western interconnection of the United States (WECC, Western Electricity Coordinating Council) show that the approach method with the closest results of the ELCC is what considers the factor of capacity of the power plant at the most critical hours for the system. The definition of what these periods would be varies, and may be the hours of maximum demand[17], with higher short-term prices or greater risk of non-compliance. The number of hours considered as the most critical hours also varies. This methodology is simpler to calculate and requires less data than the ELCC.

Studies show (Pelland and Abboud, 2008) that the capacity credit of a group of photovoltaic solar generators is greater than that of an individual installation. On the other hand, a greater penetration of photovoltaics in the system tends to decrease the capacity credit of these plants (Perez *et al.*, 2006). This is due to a saturation effect, an effect explained more fully in Section 3.9 of this TDSE, which deals with the "duck curve".

Considering the application of the concept of capacity credit for the Brazilian case, a problem found for its implementation is the scarce reliable solar irradiation data for the country. As pointed out by Morais (2015), the solar data measurement stations of the National Institute of Meteorology (INMET, Instituto Nacional de Meteorologia) present a large number of unavailable observations (gaps), which restricts their use in solar generation analyzes. This impairs the quality of results, as Madaeni *et al.* (2012) show a bias related to the influence of the year used on the results obtained so the ideal would be the use of data of several years to enable the calculation of the average value of capacity credit.

3.3. Postponement of investments in transmission and distribution

Transmission investments are driven by the increased demand for electricity in a given region. In this context, distributed photovoltaic generation can contribute, if there is a coincidence between generation and peak demand, to postpone the need for investments in this network.

17 In this case, already discounting the generation of other non-dispatchable power plants, such as wind power.

According to Denholm *et al.* (2014), in terms of benefits for transmission, distributed photovoltaic generation can influence both the congestion relief of the lines[18] and the reliability of the transmission system. Just as panels avoid the need for power generation, they also alleviate the need to transmit power because the generation is close to the load, so that the need to add transmission capacity is reduced. Since the transmission line is sized to meet the peak demand, it is necessary that there is a coincidence between distributed photovoltaic generation and consumption within the area served by the considered transmission network so that any benefits can be verified.

This feature of postponing investments in transmission can be a positive factor not only in terms of cost reduction but also environmental impacts. The Brazilian generator park is usually built far from the cargo centers, and there are plans to build new hydroelectric plants in the Amazon region. Thus, it is necessary to construct transmission lines that can extend through areas being little anthropized, with large areas of preserved natural forest and relevant ecosystems, or in proximity to indigenous lands, quilombola communities and conservation units. It is inferred, therefore, that distributed photovoltaic generation can have a positive influence in postponing the need for these investments.

There are several approaches used to estimate the impact of distributed photovoltaic generation on the value of the transmission capacity. Among these approaches, we highlight the analysis that this generation would have on the differences in the marginal costs of operation of the bars in which expansion could occur, called, Congestion Cost Relief. It can also be called the marginal benefit of transmission[19]. These could be a proxy of the value of eliminating restrictions on transmission, and may reduce the load in regions where these prices were high. For example, in locality A, the marginal cost is 50 $/MWh, while in locality B the marginal cost is 300 $/MWh. Thus, the marginal benefit is 250 $/MWh. Photovoltaic generation of 1 MWh in B would reduce by 1 MWh, the import of energy from A with a value of 250 $. It is observed that this is a method that considers only the marginal impact of photovoltaic generation.

A second methodology to estimate the value of the postponement of transmission investments is with the use of dispatch optimization models, as discussed in Section 3.1. It compares the expected operation with and without photovoltaic generation and observes the changes in network congestion costs. This methodology allows to evalu-

18 The occurrence of congestion in the network is an indication of the need for new investments in transmission, since it shows that the line is operating at its maximum capacity.

19 The marginal cost difference between two buses (or subsystems) indicates how much would be saved if there was more than 1 MWh/h transmission capacity. Therefore, it is the marginal benefit of expanding transmission capacity.

ate this benefit even in case of higher penetration levels, which change the dispatch decision and the expected power flows (Denholm *et al.*, 2014). It is worth mentioning that the simulation methodology requires a high volume of data and a large number of simulations, depending on the number of scenarios considered, which tends to generate computational complexity.

In the case of distribution, the expansion of distributed generation has dubious effects on the need to increase network capacity. Under certain circumstances, this generation could reduce or avoid the need for investments by providing power locally and reducing the required electricity flow in the network. However, accommodating large distributed photovoltaic diffusion can be challenging and require improvements in wires, transformers, and voltage regulation equipment. The benefits of this generation are greater in systems where there is greater operational flexibility on the part of the distribution system operator (e.g., management according to the demand, electric vehicles and storage).

In this way, it is possible to consider that the distribution system installed will not be impacted in situations of low penetration of distributed photovoltaic generation. In this case the value of the distribution capacity is simply considered zero. In this case, the potential gains or costs linked to the peak demand reduction are not considered.

Another methodology is to estimate the average cost of investment in expansion of distribution capacity and to verify how distributed photovoltaic generation decreases peak demand. It is necessary to check how much of the photovoltaic generation coincides with the peak period of local demand. It is also necessary to consider the possibility that the maximum energy requirement of the network occurs at another time when there is no photovoltaic generation. A reliability analysis, similar to ELCC, could be made to estimate the reduction of peak demand. However, Denholm *et al.* (2014) emphasize that there is no formal and widely accepted methodology for this estimate.

Thus, it is clear that the benefit that photovoltaic energy can generate for the transmission and distribution networks depends on the characteristics of these networks and on the photovoltaic generation patterns and the load curve of the electric power systems considered, mainly from the existence of the coincidence between this generation and the demand. Therefore, a more accurate cost-benefit assessment of this diffusion for transmission and distribution systems depends on a detailed analysis that considers the characteristics of each of these systems.

3.4. Need for investments in distribution networks

With the expansion of distributed photovoltaic installed capacity there may be a need for new investments in the distribution network. As presented in Denholm *et al.* (2014), the diffusion of the distributed generation photovoltaic can lead to problems in maintaining the voltage in the distribution network. Electricity must reach the final consumer within a permitted range. Voltage fluctuations above permitted levels[20] may damage electronic equipment.

Traditionally, the voltage across a feeder decreases as the distance from the substation increases. In the case of local generation, the tension tends to increase. Thus, the introduction of distributed photovoltaic generation causes the voltage, at the locality where this energy is generated, to increase. This increase is not constant, because there are variations in the energy generated due to the passage of clouds, for example. Thus, there may be an increase in the activation of voltage control mechanisms in the distribution system. This can deplete and reduce the useful life of equipment, especially mechanical devices such as taps of the transformers and the keys of the capacitor banks. It may also be necessary to install voltage regulation equipment on the network. For the correct quantification of the potential impact on the network voltage and possible investment needs, it is necessary to know the characteristics of the feeder, the locality of the photovoltaic generation and the pattern of the load curve.

On the other hand, more modern inverters are capable of supplying or absorbing reactive power, helping to maintain voltage within the desired range. These inverters can even help in cases of over generation in the system, failing to provide power when the frequency increases[21].

In the distribution network security issue, distributed photovoltaic generation systems have lower impacts than other distributed generation sources in the protection systems, since there is little energy stored in the inverters and there are integrated mechanisms that allow rapid disconnection of the network in case of failure, as highlighted by Denholm *et al.* (2014). Even so, high levels of diffusion of distributed photovoltaic generation may present risks. Protective equipment generally operates by detecting overcurrent in the network. A distributed generation source is connected after the protective equipment, so it ends up reducing the current that passes over them. This phenomenon can cause these devices to function inadequately and not act when they should.

20 In the case of Brazil, 5% of the nominal voltage up or down.

21 Increasing the frequency of the system indicates that there is more energy being generated than demanded. Likewise, the decrease in frequency indicates the need for more generation.

In addition, the equipment must have anti-islanding devices, i.e., be disabled in case of blackout in the system. Failure to do so may result in electric shock hazards to the equipment responsible for maintaining the distributor's network. Therefore, systems with greater diffusion of the distributed generation photovoltaic can generate costs also in the coordination of the network protection.

3.5. Cross-subsidies, cost shift and commercial losses

According to Taylor *et al.* (2015), the public policy makers have an interest in ensuring that the electricity generating unit receives payment for its services and that cross-subsidization between adopters and non-adopters is minimized. This type of allowance can be defined as the payment by a consumer of a value greater or less than the costs generated for the provision of a particular service.

In the case of a regulatory framework in which the net energy metering (NEM), the classes that do not participate in this compensation system can afford proportionately more with the costs of the network. For example, if there is a large expansion of photovoltaic generation distributed in a given district of the concession area and the distributor needs to make timely reinforcements in that network, the costs of these procedures will be charged in the tariff and will be passed on to a greater or lesser extent to other consumers which are not part of the NEM system.

An example of this phenomenon was observed in the USA and highlighted in the California Public Utilities Commission (CPUC) study carried out by E3 (2013). This study showed that residential NEM from San Diego Gas and Electric (SDG&E) contributed with 54%, on average, of their costs. Another study carried out by the Arizona Public Service (APS, 2015) showed that NEM residential consumers contributed with 36%, on average, in the costs associated with their consumption. In other words, NON residential consumers in these states were paying less than the cost of the service provided.

An interesting aspect is that, if there is an increase in the tariff for consumers who did not adhere to the NEM system, the attractiveness of the installation of photovoltaic modules increases. In addition, economies of scale are encouraged with increased sales of modules. The coexistence of cross-subsidies and economies of scale can lead to a phenomenon known as the Death Spiral, which tends to generate allocative and distributive problems. In the case of Brazil, this issue becomes relevant, since the low purchasing power of the average consumer of electricity does not allow it to acquire a photovoltaic system and contributes to the existence of a perverse subsidy of the poorer consumers (non-adopters) to the richer ones (adopters).

According to Araújo (2006), theft of electricity, also called non-technical or commercial losses, can be explained by several socioeconomic factors, among them the tariff level. Thus, if the problem of cross-subsidization between adopters and non-adopters is not fixed, the increase in tariffs may lead to increased clandestine connections to steal energy. Consequently, the finances of the power distributors may be affected, since they are only compensated by these losses.

Even without considering the possible increase of non-technical losses in absolute terms of energy quantity, the diffusion of the distributed photovoltaic generation can cause the relative index of non-technical losses of a given power distributor to increase in relation to a scenario in which this diffusion is not observed. This is because less energy will be demanded from the power distributor by customers with their own generation. Thus, the ratio of non-technical losses to total load increases because the total load decreases.

3.6. Impacts on energy trading contracts

The expansion of sources with low variable costs can affect the formation of electricity prices. Castro *et al.* (2010) indicate that spot markets may fail to promote efficiency in such cases. These markets can function properly only if thermocouple generators often determine prices. From the moment in which fixed costs start to prevail, the market will no longer be economically efficient. Thus, they show certain characteristics, such as: (i) low prices - which are independent of production costs; (ii) not to ensure that the break even of existing firms occurs; (iii) lack of adequate incentives for signaling new investments; (iv) tendency to concentration with large players within markets and frequent regulatory interventions to correct distortions in the economic signals emitted by market prices.

In this way, electricity generating companies are affected by the entry of photovoltaic technology. In some states of the United States, for example, they experience revenue losses and some generation assets become inoperative as the generation from larger power plants is shifted. Power generators with cost structures based on marginal costs (e.g., fossil fuel-fired thermoelectric plants) may also encounter problems in selling their energy.

In the Brazilian case, the rules for the commercialization of electric energy are dictated by Law No. 10.848 of 2004 (Brazil, 2004). It is inserted in the context of the new electricity sector model implemented with the 2004 reform. It defined the free and regulated contracting environments and determined rules for the entry of each agent into each of these environments. One of its most striking features, in the regulated market, is the compulsory contracting by consumers (power distributors) of energy certificates in a volume equivalent to 100% of consumption, with a risk of payment of penalties for non-compliance with this projected consumption.

In this context, the distributors declare to the Ministry of Mines and Energy (MME), in a secretive manner, their estimated needs for the coming years. This demand must be met by the New Energy Auctions. Existing Energy Auctions are performed so that generators with non-contracted energy can use it for the supply of distributors in the following year, considering the termination of existing energy contracts and market oscillations.

Considering an increase in the share of distributed photovoltaic generation, the remaining load to be met by the power distributor may decrease considerably to the point of exceeding the limit of 5% established by Law No. 10.848, generating an over contracting bias. Once the power distributor incurs penalties if this occurs, there is a possibility that photovoltaic diffusion will have a negative effect on their financial health.

In addition, the large-scale entry of distributed photovoltaic generation brings the possibility of the distributor being over contracted even if it matches its forecast of demand, because the marketing contracts in the regulated environment between power distributors and power generators are established for the period from 15 to 35 years (Brazil, 2004). Historically, the contracting model has been based on a perspective of consumption growth over the years. Therefore, it does not contemplate situations in which energy consumption has a downward trajectory. Therefore, the addition of distributed photovoltaic generation can cause the demand perceived by the distributor to decrease and, in this way, may lead to over contracting risks of the power distributors.

3.7. Environmental impacts of distributed photovoltaic diffusion

Several environmental benefits can be highlighted in a context of diffusion of distributed photovoltaic generation. The main one is the fact that this type of electricity generation does not emit greenhouse gases (GHG) during its operation phase. As discussed in Section 3.1, the electric power generated from the solar source replaces the generation from another source. This replaced generation can be from some plant that emits greenhouse gases. If this is the case, a certain amount of CO_{2eq} is no longer emitted.

In section 3.1, we discussed the methodologies of avoided generation estimation, which could be useful for this analysis with some exceptions. Using these methodologies, it would be sufficient to check, in the results, which plants no longer generate due to photovoltaics and, based on the emissions of these specific power plants, calculate the emissions avoided in CO_{2eq}/ MWh.

In addition to the reduction of greenhouse gas emissions, the lower need for electricity generation by traditional plants, especially in countries with thermoelectric power plants, has the positive impact of preserving air quality by reducing the emission of pollutants with local impact[22]. In other words, when compared to a power plant that burns fossil fuels, distributed photovoltaic generation prevents the emission of pollutants such as nitrous oxides (NO_x), sulfur oxides (SO_2) and particulate materials. The preservation of air quality due to these factors contributes to a reduction in the risks of respiratory diseases in society in general.

Another benefit of distributed photovoltaic generation is the fact that this technology uses less natural resources when compared to traditional systems. For example, regarding the area requirement, NCAT (2010) states that it would take 60,000 km² of photovoltaic cells to meet the full demand of the United States. This represents 20% of the area of the state of Arizona. Akorede *et al.* (2010) state that distributed photovoltaic systems require less area to produce one MWh of electricity than coal-fired power stations considering the area required for coal mining and that unoccupied area could be used for other purposes. In the case of distributed photovoltaic generation, the benefits of decreasing occupied area are even greater, since they are generally installed at the top of the buildings. In this way, there is no competition of the use of the ground for generation of electric power with other uses.

3.8. Diversification of the Brazilian energy matrix

One advantage of the large-scale expansion of distributed photovoltaic generation is the diversification of the energy matrix. One way in which it is reflected is the increase in electricity generation in the country, making the system less vulnerable to problems that may impact the generation and cost of a given source, such as a generalized drought or an increase in international natural gas. Another form is the spatial diversification derived from decentralized generation. Diversification should also be highlighted as a means to promote energy security.

With regard to electricity generation, according to EPE (2016), there are in Brazil eight main primary sources, shown in Table 1 below. This table also reflects the evolution of the participation of these sources in the country's electricity generation.

22 It is worth remembering that reducing the emission of local pollutants through the promotion of renewables eliminates the traditional *trade off* in which mechanisms to reduce local pollutants end up increasing the emission of greenhouse gases in function of the parasitic consumption that reduces plant efficiencies.

Table 1: Evolution of the Brazilian energy matrix

Source	2000	2005	2010	2013	2015
Hydraulics	88.68%	85.17%	79.61%	70.57%	64.01%
Natural Gas	1.03%	4.25%	6.61%	11.29%	12.90%
Biomass	2.00%	3.07%	5.72%	6.62%	7.96%
Oil Derivatives	3.88%	2.65%	2.92%	4.26%	4.70%
Coal and derivatives	2.87%	2.60%	2.12%	3.65%	4.52%
Wind	0.00%	0.02%	0.39%	1.08%	3.51%
Nuclear	1.54%	2.23%	2.63%	2.53%	2.39%
Solar	0.00%	0.00%	0.00%	0.00%	0.01%

Source: EPE (2016)

Despite the decrease in recent years, it is possible to observe that the hydraulic source is predominant in the Brazilian energy matrix, which makes the system very vulnerable to periods with low flow to the reservoirs. This is even one of the causes of the increase in the share of oil and natural gas derivatives in the energy matrix, which raised electricity costs in this period.

Thus, the diversification of energy sources can reduce the risk of non-service or high costs similar to the modern portfolio theory of Markowitz (1952). Applying this theory to the problem of expansion of the electric energy supply, it is possible to consider the generating plants as the active candidates to form the optimum portfolio and the electric power system, the portfolio to be optimized. Therefore, a system with a larger number of plants from different sources tends to reduce the systemic risks of deficit and high costs.

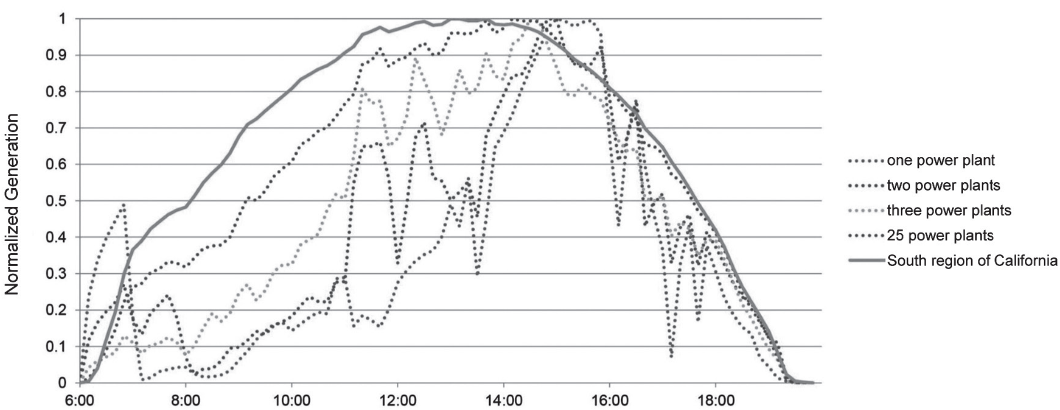
Schmidt *et al.* (2016) show that the monthly averages of hydroelectric production are complementary to the averages of wind production in the four Brazilian states with more wind farms. Generally speaking, in the first half of the year, hydroelectric production is higher than its annual average and tends to decrease as it approaches the middle of the year, while wind production is lower than its annual average, but tends to increase. From the sixth month of the year the curves intersect, so that the wind energy generation happens to be higher than its annual average.

That said, it is possible to perceive that the production profile of photovoltaic solar generation is more stable (seasonality less accentuated) than the production profiles of hydroelectric and wind sources, that is, the average monthly values are closer to the annual average. According to Schmidt *et al.* (2016), the variance of the annual hydroelectric production is significantly higher than the variance of the other renewable sources. In other words, deviations in generation from their mean tend to be larger. Solar photovoltaic presents the smallest variance among all sources analyzed in the study (wind, hydroelectric and photovoltaic solar). In terms of the probability distribution of the annual production, the values of P75 and P90 are closer to the average for the photovoltaic source, that is, the probability of production in annual terms being significantly lower than expected is lower.

Still on the profile of solar production, the Schmidt analysis *et al.* (2016) found that the monthly solar production of the 24 analyzed localities presents a variation between 14% below the average and 35% above the average. This means that the locality that presented the lowest production in a given month generated 14% below the average of that locality. Similarly, the same interpretation can be applied to the upper limit of the variation. As a comparison, wind generation values are between 50% below the mean value and 50% above the mean and the hydroelectric production values vary between 20% of the average value and twice the average. Thus, the solar photovoltaic source has a less intense seasonal characteristic than the water and wind sources.

Another form of diversification of the distributed photovoltaic generation is related to the fact that it allows the decentralization of the electricity production. This helps to mitigate one of the problems of photovoltaic generation, which is the sudden variation in generation due to the passage of clouds. When installing panels in different locations, the system makes better use of the available resources and reduces the risks of not operating the source as a whole, because a site may have a momentary interruption while panels in another location may be generating. In this sense, although it is perceived locally, instantaneous intermittency may not be observed by the system as a whole. Figure 7 shows that variations related to cloud passage are large at the plant level, but not significant considering the impact on the system as a whole (Lew *et al.* 2013).

Figure 7 - Normalized generation for different solar photovoltaic aggregations in Southern California on a partly cloudy day



Source: Adapted from Lew et al. 2013

Another important feature is that it is a generation whose primary source is freely available in the environment. Thus, the exposure of the costs of the electricity sector to the international prices of fossil fuels is reduced[23]. In this way, it can be seen that international fuel prices influence the costs of electricity generation, even if the country is not an importer. In the specific case of Brazil, the fuel costs of thermoelectric plants[24] are indexed by the international quotation of oil or natural gas.

In summary, the larger scale entry of photovoltaic solar power presents diversification as a new source to be explored by the Brazilian electric power system and as a possibility to increase the locations of electricity generation. With one more source and a greater number of electricity generation points, it is possible to affirm that the system tends to increase its reliability in order to generate a greater security of supply for the population.

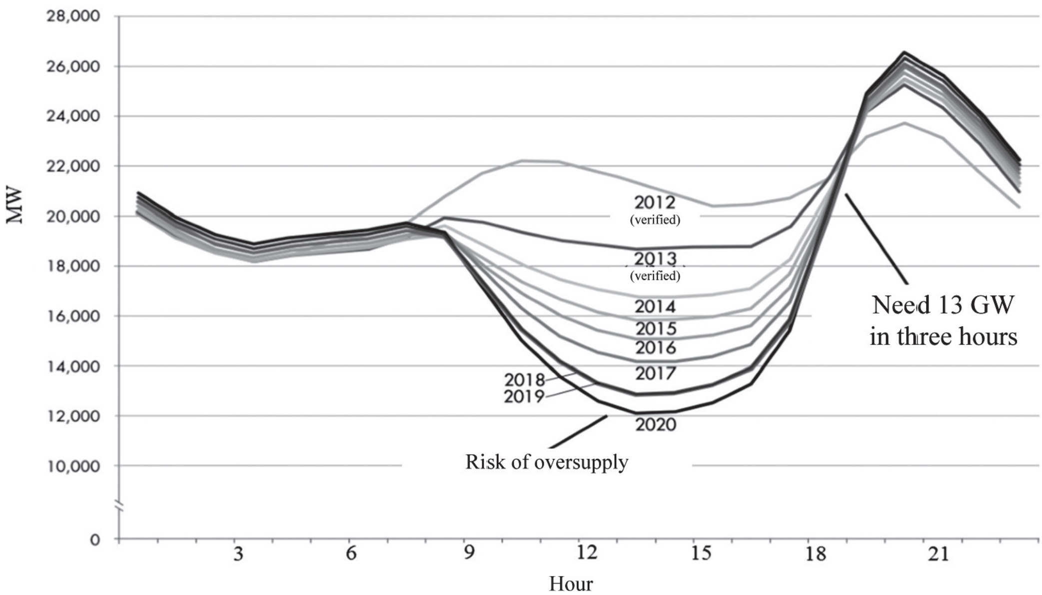
3.9. Duck curve and system flexibility

In an electric power system with high participation of photovoltaic panels, the variations in the daily load curve can be perceived with greater amplitude. In this context, the phenomenon is known as the duck curve. This is the sharp fall in net load (ramp down) that can occur around the middle of the day, the maximum production time of the solar panels. In other words, the duck curve refers to the possibility that a large portion of the load will be supplied by the distributed generation in the middle of the day, which would be reflected in a drop in the load observed by the electric power system, which would be resumed in the subsequent hours (ramp up). The net load curve, derived from the difference between the load and the hourly photovoltaic generation, would have the shape of a duck. This phenomenon was identified by the California Independent System Operator (CAISO) in 2013. Figure 8 shows the duck curve (CAISO, 2016).

23 In the case of countries that depend on imports of fossil fuels, another benefit is the reduction of external dependence. External dependence is defined as the balance of payments situation.

24 This rule applies to power plants participating in a new energy auction, except in the case of power plants that use fuels produced in Brazil, such as national coal and biomass.

Figure 8: Duck curve designed for the California system on March 31 in different years



Source: Adapted from CAISO (2016)

According to CAISO, in California, the duck curve accentuates year by year, reaching critical values in 2020, with a load ramp up of 11 GW in just three hours. However, authors, such as Fowlie (2016), identified, as early as 2016, the behavior that was only expected for 2020.

Fowlie (2016) highlights two challenges arising from the phenomenon of the duck curve. The first is the reduced net load in the middle of the day, also called over generation risk. The possible problem is that the net load is reduced to such an amount that the system operator needs to shut down power plants with low operating flexibility. In other words, the generation reaches a very high value to the point that it is necessary to shut down power plants designed to have few interruptions in the operation.

For example, a nuclear power plant[25] is characterized by the longer time to start and stop operation due to the time the boilers take to warm and cool respectively. In addition to failing to provide power for several hours, the outage brings costs to the power plant, such as equipment wear. Therefore, it is interesting that these plants operate with the smallest possible number of interruptions and therefore, the reduction of load during the day provided by distributed photovoltaic generation can bring some problems in the operation of systems with large amount of base generation.

25 Other types of power plants that tend to operate inflexibly are those that use coal as fuel. Natural gas plants are also inflexible but, in many cases, because of contractual issues of gas supply (take-or-pay).

Another challenge that the duck curve brings is the rapid need for resumption of load as solar production decreases and the load peak is approaching. This happens, usually between 5 pm and 8 pm. This resumption requires flexible power plants that can start generating electricity quickly and storage sources that allow the stored energy to be used while more power plants are in operation. The California operator indicates that the system has already experienced a recovery of approximately 10.89 GW in a 3-hour period on February 1, 2016 (CAISO, 2016).

Below is a list of measures that the California operator notes as necessary to maintain the high share of photovoltaic generation and ensure energy security for its population.

- Encourage the generation of energy by more flexible technologies, which are prepared to turn on or off machines quickly, so as to allow fast load handling and rapid entry of renewable sources;
- Investments in energy storage technologies, including reversible hydroelectric plants (pumped storage)[26];
- Increase in CAISO's commercialization area, increasing the number of merchants, facilitating both the purchase and sale of electricity;
- Implementation of more sophisticated forms of charging such as time-of-use[27].

In addition, measures that encourage self-consumption at the time of generation for people who have distributed photovoltaic generation can help mitigate the effects of the duck curve.

3.10. Ancillary services

Ancillary services are services that help system operators maintain network reliability with sufficient power quality. Examples are reserves operations (of regulation, contingency and flexibility) and tension control.

Each electric power system defines in a different way the contingency reserve required in the system. In the event that the reservation is based on a single large contingency[28], the impact of the expansion of distributed photovoltaic generation on contingency reserves is nil. In case reserves are defined as a proportion of the load, the

26 The technology of pumping water from a river at times of low load (at dawn, for example) to supply the reservoir of a hydroelectric power plant and generate energy at the time the load is higher.
27 It is the charging that applies different prices for electricity in different parts of the day. Thus, electric power is more expensive at the tip and cheaper off the tip. The idea is similar to the white tariff that will be applied to the Brazilian electricity sector.
28 Like the loss of the largest machine in the system.

expansion of this generation could contribute to the reduction of reserve requirements. In the case of the impact on regulation reserves, as the greater photovoltaic diffusion increases the short-term variation in the network, this leads to higher reserve requirements.

The calculation of the costs and benefits of the expansion of distributed photovoltaic generation over ancillary services can take different forms. The first one is to assume that this diffusion does not impact the supply of ancillary services. This is explained by the fact that, at a low level of diffusion, photovoltaic distributed generation does not provide significant ancillary services to the grid and also does not imply relevant negative impacts.

Another, simplified approach is to check the total costs with reserves in previous years and their proportion to the total costs with the generation of energy. When estimating the avoided costs of generation of the photovoltaic source, it is considered that the avoided costs of future ancillary services will be in the same proportion (E3, 2013).

4. Conclusions

It is possible to observe that there are several potential impacts resulting from the diffusion of distributed photovoltaic generation. Some of these impacts are more significant and direct, while others occur more indirectly and with less intensity. In this chapter, we sought to identify and explain them, considering the particularities of the Brazilian electric power system.

The main methodologies used to quantify these benefits were presented. They are quite varied in form and complexity. The choice of the ideal methodology varies on a case-by-case basis and depends on several factors, but in general, it can be summarized as follows: the degree of precision of the expected result, the availability of system data and the available computational resources. Since this work did not have the objective to measure these impacts, future studies can be developed with the intention of implementing the suggested methodologies in Brazil.

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The Politics of Distributed Generation: The Case of Germany

By Max Staib Ramalho

Abstract

Since the beginning of the 21st century, Germany has witnessed an unprecedented expansion of renewable energy systems (RES).This process is commonly associated with a greater transition known as the Energiewende (energy transition) encompassing a multitude of policy efforts aimed at transforming the German energy system.A central part of this process, has been the dissemination of RES and with it, the decentralization of electricity generation.

The following chapter will investigate the political contestation surrounding the implementation and reform of the *Renewable Energy Sources Act* (Germanys main RES incentive policy), in order to shed light on the political dispute about the manner in which the electricity sector should be transformed. In this sense an attempt will be made to illustrate the political dimension of DG.

In this sense the reform process of the EEG and the potential of *Bürgerenergie* initiatives illustrate the dispute among different interest groups and their attempts to shape and influence the policy arena in their favour. While this might seem straightforward, particularly the potential for new governance models offered by DG is an aspect often neglected in the debate about effective and suitable renewable energy policies. Thus, the transition to a renewable energy system is not merely a technical obstacle to be overcome, but it represents the need for a political and economic reorganisation of the sector, in order for this transition to be sustainable and most beneficial to society.

Keywords: Renewable Energy, Energiewende, DistributedGeneration, Bürgerenergie

Since the beginning of the 21st century, Germany has witnessed an unprecedented expansion of renewable energy systems (RES). The increasing role played by these RES in the countries electricity sector is part of a greater effort to transition to a more sustainable and 'greener' economy. This transition process is commonly referred to as the Energiewende (energy transition) encompassing a multitude of policy efforts aimed at transforming the German energy system. Today the country has set itself the goal of generating at least 40 to 45 percent of its power from renewables by 2025, and at least 80 percent of its power from renewables by 2050.

A central part of this process, has been the dissemination of RES and with it, the decentralization of electricity generation. In this sense, wind and in specifically photovoltaic energy systems offer themselves particularly well for the deployment in the form of distributed generation (DG). In Germany DG has grown hand in hand with the increased renewable energy capacity and it represents a paradigm shift with the traditional organization and structure of the electricity sector. Thus, DG offers unique opportunities and challenges to the ongoing transformational process of the sector. The German case offer a particular insight, into the opportunities of this decentralized form of generation to contribute to greater political acceptance and popular participation in energy politics and the energy transition specifically. In other words, DG (and the dissemination of RES) has allowed for greater citizen participation in the electricity sector, which has consequently contributed to a stronger political mobilization in favour of renewable energy policies.

The following chapter will investigate the political contestation surrounding the implementation and reform of the *Renewable Energy Sources Act* (Germanys main RES incentive policy), in order to shed light on the political dispute about the manner in which the electricity sector should be transformed. In this sense an attempt will be made to illustrate the political dimension of DG. This includes the possibilities offered by DG to 'democratize' and reshape the governance structure of the sector through greater citizen and regional participation. To this end, the role of *Bürgerenergie* (citizen's energy) in advancing the dissemination of RES will be explored, its contributions, its enabling conditions and its organizational forms. Finally, this will enable the reader to better evaluate the political debate and the conflicts of interest informing and shaping the reform of policy support for renewable energy in Germany.

The Renewable Energy Sources Act (EEG)

In order to comprehend the successful diffusion of RES and simultaneously an important enabling factor for greater citizen participation in this process, one needs to understand the countries incentive/support mechanisms for renewable energy. In the case of Germany, the principal policy tool utilized to progress the dissemination of renewable energy technologies was the feed-in tariff (FiT), or more specifically, the Renewable Energy Sources Act (*Erneuerbare-Energien-Gesetz*, short: EEG). An initial version of this incentive mechanism was introduced in the early 1990s as the *Stromeinspeisungsgesetz* (StromEinspG)[1]. Yet, it was the 2000 reform which implemented the now famous EEG and ushered in a new dynamism in renewable energy diffusion.

In a nutshell, the policy implements a remuneration for electricity generated by renewable energy systems (i.e. a feed-in tariff). The remuneration rate is differentiated between renewable sources and system sizes, revised on a regular basis and with the law undergoing a review and amendment process every 3-4 years. In addition, renewable energy sources are guaranteed access to the grid, grid operators are required by law to purchase renewable power, and the remuneration levels for approved systems are guaranteed for 20 years.

The rationale behind determining the feed-in tariffs is quite straightforward: the cost of a system per kilowatts-hours is determined by taking the cost of a particular system and dividing that by the number of kilowatt-hours the system can reasonably be expected to generate over its service life (generally 20 years). To that is added a return on investment (ROI), which in the case of Germany is usually targeted at around five to seven percent (MORRIS AND PEHNT, 2016). The fact that the ROI target is the same for every technology, helps explain why the remuneration rate is different for each technology, being about three times the retail rate for photovoltaics in 2004.

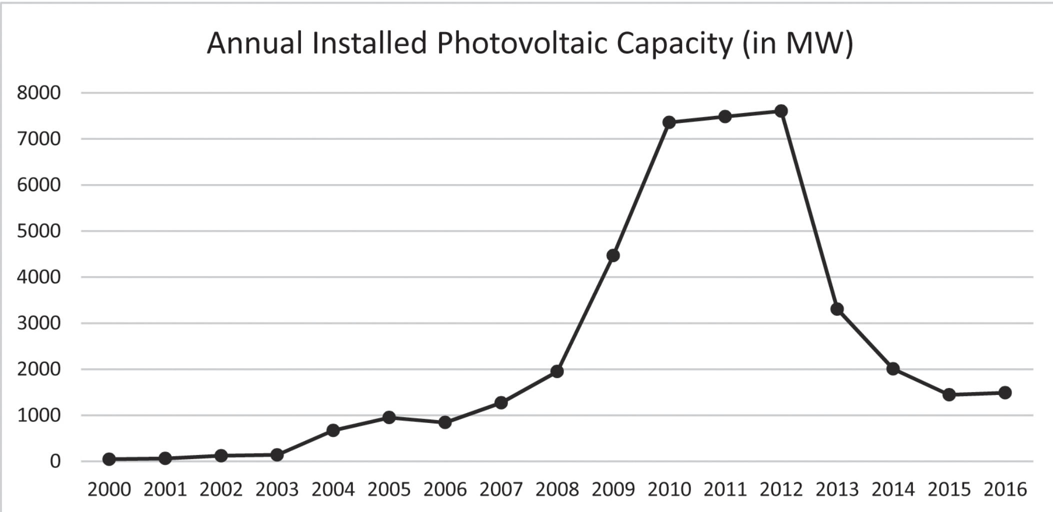
On the other hand, the costs of paying for the feed-in tariffs is passed on to electricity consumers. This is done through a surcharge on electricity consumed which, in 2016, amounted to 6.4 cents per kilowatt-hour, or nearly a quarter of the retail power price (MORRIS AND PEHNT, 2016).

As a consequence, while the years following 2008 witnessed an unprecedented increase in annual capacity growth for photovoltaics, after 2012 this was followed by a rapid deceleration (see Graph I). Between 2010 and 2012, average annual growth was approximately 7,5 GW. This momentum was reversed resulting in a growth rate between 2014 and 2016 of less than 2 GW, falling short of the government's own growth goals. Massive cost reductions of renewable energy technologies (RETs), particularly photovoltaics, coupled with high remuneration levels in part explain the rapid expansion until 2012. On the other hand, the reforms in response to this accelerated diffusion, sub-

1 The StromEinspG can be considered the predecessor of the EEG. It introduced an early version of the feed-in tariff for RETs and formalized grid access rights for these systems.

sequently provoked a collapse of renewable energy (RE) expansion. The notable drop in photovoltaic capacity growth in 2013 was criticized by many stakeholders.

Graph I: Accumulated Photovoltaic Capacity installed and Annual Photovoltaic Capacity growth.



Source: BMWi, 2017

In its 17 years since implementation, the EEG has contributed tremendously to the diffusion of renewable energy in general, and photovoltaic in particular. This becomes evident, when considering that photovoltaic capacity in 2000 was 114 MW and a decade and a half later had skyrocketed to 41,275 MW (BMWi, 2017). Yet this progress in photovoltaic (and RES as a whole) expansion was greatly enabled through the efforts and investments of citizens and citizens initiatives.

Distributed Generation and the Role of Citizen Initiatives

As Morris and Jungjohann (2016) frame it, if one understands the German effort to progress the Energiewende (energy transition) as a grassroots movement, rather than a "governmental master plan", one recognizes the need to better understand the struggle within the political arena between these grassroots movements and the incumbent energy industries. The authors (ibid., p. 9) illustrate this by writing: "How do you get utilities to close power plants that are working just fine in order to make space for renewable electricity? The challenge is financial, not technical, and the solution can only be political."

In many ways, RES are compatible with the traditional model of centralized electricity generation, administered by established big energy providers or big investors. Nonetheless, the possibilities of a decentralized organization of energy generation offered by RES has spurred the interest of actors, traditionally excluded of participating in this sector. In this sense, the important role of distributed and decentralized generation is increasingly being recognized not only as a contributing factor to the expansion or RETs but also as niche in which important technical and institutional innovations for energy transitions can and are being developed, tested and brought to application on regional and local levels. As a consequence, the call for more decentralization involves electricity production as much as governance/organization. Thus, this is also driven by a growing demand by many actors on the local level of establishing control of local energy policy. Fuchs and Hinderer (2016, p. 6) identifies this as “transformation of a field”.

On the other hand, decentralized generation projects are financially unattractive for large energy companies, since their return on investment rates of regularly 4-6%, are far below what they are accustomed to. This is exacerbated by the negative competitive impact that distributed generation projects have on the economic existing fossil peak plants owned by nationwide operating energy suppliers. As a consequence, while utilities are indeed building giant wind and solar parks everywhere, this largely takes place in competitor territory, not their own. In this sense, community projects and distributed generation as a whole is often perceived as a threat, since they compete with their existing conventional energy assets[2].

Empirical investigations of ownership structures of existing wind (on-shore) and photovoltaic energy capacities have highlighted the central role played by citizen participation models (also referred to as *Bürgerenergie* (citizens' energy)). These citizen participation schemes in a narrower sense account for 34.4%, while in the broader sense[3] account for approximately 47% of the installed capacity in Germany in 2012 (while the traditional energy suppliers owned only 12.5%) (LEUPHANA UNIVERSITÄT LÜNEBURG UND NESTLE, 2014). In the specific case of photovoltaic, this number is even higher at 48% of the installed capacity is owned by citizens, just behind institutional and strategic investors with a share of 48.5% (leaving traditional energy

2 The Big Four utilities only accounted for 0.2 percent of photovoltaics arrays in Germany in 2010.

3 Citizen participation models (*Bürgerenergie*) in the narrower sense are defined as projects in which citizens or local business invest equity in renewable energy systems, and these actors hold at least 50% of the voting rights. The broader definition is used when less than 50% of the voting rights are held by local stakeholders and the participants originate from different regions (LEUPHANA UNIVERSITÄT LÜNEBURG UND NESTLE, 2014).

suppliers with 3,5%) (LEUPHANA UNIVERSITÄT LÜNEBURG UND NESTLE, 2014). In terms of total investment in renewable electricity, citizens accounted for a share of 30,6% (or approximately 5 Billion Euro) in 2012 (LEUPHANA UNIVERSITÄT LÜNEBURG UND NESTLE, 2014).

The activities of energy cooperatives are often categorized according to their mains business field within the energy sectors' value chain: production, distribution or consumption. With this in mind, energy cooperatives are predominantly involved in energy production (including commercialization), representing 86% of cooperatives. Nonetheless, a growing debate over the remunicipalization and engagement of cooperatives in the distribution sector (yet currently only 1% of cooperatives are active in this segment) (DGRV, 2016).

A manifestation of this boom in *Bürgerenergie* can be observed by looking at the growth of the number of energy cooperatives. While in 2006, the number of new energy cooperatives set up under the *Deutschen Genossenschafts- und Raiffeisenverbands (DGRV)* (an umbrella organisation for the German cooperatives)[4] were only 8, this number had grown to 43 two years later and 167 in 2011 (DGRV 2014). In this period, since 2006, the DGRV has united about 130,000 members, 92% of which are private citizens.[5]

A reform in 2006 facilitated the set up of cooperatives by reducing the minimum number of so founding members, and by allowing investing members (i.e. not using the electricity for example) to participate, improving access to capital. Two other important conditions enabled this growth in citizen participation;

i) a legal framework which defined and facilities the emergence of business models for financial citizen participation within the renewable energy sector
ii) the implementation of the FiT-system, which offered a stable regulatory framework for investors and guaranteed revenues for energy produced.[6]

Yet, the rise of energy cooperatives is more than just a form of financial participation. As Yildiz (2014) argues, they should also be appreciated as an alternative model for advancing investments in distributed energy infrastructures and governance and

4 The DGRV is also involved in auditing potential new cooperatives, thereby providing a level of legitimacy/gate keeping.
5 Farmers, churches, businesses and (cooperative) banks as well as municipalities and municipal entities account for the remaining parties.
6 Aside from the FiT, the German government has offered loans at low interest rates (for example through the '100,000 Solar Roofs Initiative') for citizens for renewable energy projects or other loan programs by the state-owned German development bank (Kreditanstalt für Wiederaufbau - KfW)

participation in local energy policies. A particular characteristic of these types of business/investment models is their concern with public/community welfare, displacing financial returns as the principal motivation (YILDIZ, 2014). Thus these investments combine security, albeit moderate returns, with non-financial factors such as climate protection and community development (BEERMANN, 2009).

In addition, the low financial contributions necessary in order to participate in these cooperatives[7], together with their governance structure[8], allow for a reduction in barrier to participate. In addition, personal liability of members is usually limited to the capital invested, eliminating the risk for further financial costs. In fact, the legal form of cooperatives has been identified as least likely to become insolvent (SOZIAL-INVESTIEREN, 2013). In addition, as Yildiz (2014) points out, some RETs, such as photovoltaics, are favourable to citizen participation due to their technical characteristics of modularity, simplicity, high reliability, low maintenance requirements and short lead times.

As a consequence, the greater participation of citizens in the investment in photovoltaics (and RETs in general) was facilitated on the hand by a tradition/historical legacy of grass roots movements and activism in energy policy ad environmental protection. On the other hand, a fundamental facilitator for this trend, was the design and the effectiveness of the feed-in tariff scheme adopted in 2000. Thus, tracing the reform process of this support policy and its accompanying societal/political debate, permits for a better understanding of the changing role and importance of distributed generation in driving the greater energy transition.

Therefore, the following section will present the reform process of the EEG, with a particular focus on photovoltaic energy, due to its particular compatibility with DG and its controversial history in Germany.

Political and Institutional Contention

During the period since its implementation, the EEG has come under reforms by four different government coalitions, over 5 legislative periods. The responsibility for renewables has changes ministries three times, and the evolution of the EEG was closely accompanied by political debate, which saw a shift in party lines and increased relevance of regional politics. The following section will offer an overview of some of

7 The financial barrier to participate in energy cooperatives are typically low, ranging from 50 to 5,000 Euro per (cooperative) share (YILDIZ, 2014).
8 Every member of an energy cooperative has an equal vote, independent of financial contribution. This translates into members having an active role within the entrepreneurial decision-making processes.

the political developments and debates during the past 17 years, maintaining its focus on photovoltaics, over the future of the EEG. In particular, this section will illustrate the political struggle of determining how and if to maintain and/or adapt the support policies.

Initially, it needs to be emphasized that the origins of support policies for renewables in Germany predated the implementation of the EEG, and that the foundation for the countries successful renewable energy expansion was created during the late 1980s and 1990s (what Fuchs and Hinderer (2016) categorized as 'phase one').

Implementing the EEG (1998–2008)

The 1998 elections in Germany represented a hallmark for renewable energy policy in the country. The elections saw the Social Democrats (SPD) and the Greens securing enough votes to form a coalition government. It was the first time, that the Green Party participated in federal government, and this coalition would come to initiate some of the major policy advances in favour or renewable and solar energy promotion.

The government dedicated special attention to introducing a paradigm shift in energy policy, which focused on the support for renewable energy technologies and culminated in the adoption of EEG. The Act came into force on April 1st, 2000, effectively replacing the 1991 Electricity Feed-in Act[9].

The feed-in tariff systems developed and implemented on communal levels, also contributed to the design and formulation of that similar system on a national level. This caused Gründiger (2017, p.279) to observe: "Policy heritage therefore created new path dependence with positive feedback effects."

The state of Thuringia which was home to many solar cell factories, early on recognized that solar promotion was of economic interest for the state. Consequently, environmental politicians and local industries effectively lobbied the government to support the EEG.

The coalition of advocacy groups and sympathizers with photovoltaic energy came to include the traditional renewables branch associations (such as the BEE) and envi-

9 As a reaction to the 1986 nuclear disaster and growing mounting political pressure, the German government passed a Grid Feed-In Law in 1991 (in short StromEinspG). It stipulated a remuneration at a level of 90% - the average customer purchasing price for the energy generated by renewable technology systems, around 0.17 DM (JACOBSSON AND LAUBER, 2006). While this feed-in tariff had some positive effects on investment in wind energy, the law had no measurable effect on the use of photovoltaic power. The technology was still much too cost inefficient to be an attractive investment, given the financial incentives offered by the StromEinspG.

ronmental organizations, but also the metal worker's union (IG Metall), the Farmers Association, and solar citizens' initiatives and churches. Most remarkably, with the German Engineering Association (VDMA), also an important conventional industry sector was among those on board.

With the re-elections in 2002, Wolfgang Clement (SPD) assumed the head of the economics ministry, while Juergen Trittin (Greens) remained the environmental minister. In addition, as an acknowledgement to the electoral gains the Greens had made during the 2002 elections, the responsibility for renewables policy was shifted from the economics ministry to the environmental ministry (held by the Greens). This was an important victory for the pro-renewables alliance and would greatly impact the formulation and negotiations over the 2004 EEG reform.

> "[W]hen authority over the renewable energy sector switched from the BMWi [i.e. the economics ministry] to the BMU [i.e. the environmental ministry] in the early 2000s, the Green-led BMU rapidly expanded its expertise with the help of renewable energy advocates and it has since then dominated the periodic revisions of the EEG. The BMU also forced its way into the energy summits that are irregularly convened by the Chancellery and brought with it representatives of the renewable energy sector. It thereby opened the last bastion of the traditional energy sector" (STEFES, 2013, p.15-16).

As had become apparent earlier, the ideological conflict between the economics ministry and the environmental ministry greatly influenced the EEG reform. Among other things, the economics ministry pushed for greater exemptions for industry. The economics ministry dedicated special effort to push for the enlargement of industry exemptions (HIRSCHL, 2008) and sought to influence further aspects.

Yet the great popularity of the EEG among both government parliamentary groups, resulted in the economics minister Wolfgang Clement being strongly criticised for his anti-EEG stance, ultimately resulting in him being isolated within his SPD party (LAUBER AND MEZ, 2004). This example is striking because it demonstrated an interparty support for the EEG and renewables, which superimposed itself on inner party loyalties and consistency. The SPD parliamentary group collaborated with the Green environmental minister against their own SPD economics minister. This would come to be one of many examples of important role which the parliament played as a basis for the pro-renewables coalition.

As already being part of the agreement of the EEG in 2000, the law was reformed in 2004, taking into consideration the challenges and limitations it had encountered during the past four years. This reform was particularly important for photovoltaics since it represented the first point at which the FiT for photovoltaics was strong enough by itself. Recognizing a necessity for greater remuneration levels for photovoltaic systems, due to a discontinuation of low interest loans, the tariff for rooftop-mounted PV systems was increased relative to the systems size (57.4ct below 30 kW, 54.6ct below 100 kW, 54.0ct above 100 kW)[10].

The EEG remained highly contested, particularly among parts of the industry and the big energy corporations. Boasting with strong economic power and financial resources, these groups utilized their ties to policymakers stemming from the corporatist tradition of interest intermediation in order to influence and direct the development of energy policies in their favour.

Curiously enough, Angela Merkel, the then parliamentary chairwoman of the CDU/CSU[11] group expressed similar concerns after the ratification of the new EEG, stating:" It is hardly realistic to raise the share of renewables in electricity consumption to 20%. I believe that it is unrealistic to expect that renewable energies can close a gap that would be opened by the early shutdown of nuclear power" (MERKEL, 2005). In her defence, there was much confusion at the time about the future development of the renewables market and the EEG. The Federal Association for Renewable Energies (BEE), an advocacy group for renewables, completely underestimated the cost development forecasting costs to reach 4.4 billion euros in 2010 and 7.0 billion euros in 2020 (BEE, 2004). In contrast, these numbers had reached 8.2 billion euros in 2010 and 20.4 billion euros in 2013 (BMU, 2013).

During that time, the renewables industry, which was initially characterized by fragmentation, weak organizational structures and financial 'light weight', began to deliberately professionalize its lobbying efforts and consolidate its strength. Of course a positive contributing factor, was the sectors growing economic and financial strength which went hand in hand with the growth of renewables. A materialization of these efforts could be seen in the increasingly coordinated statements and direct political lobbying by the DFS, UVS, and BSE associations.

One of the forerunners of this movement could be seen in the solar industry lobby. In 2003, in order to increase its effectiveness, the DFS and BSE merged, establishing the German Solar Industry Association (*BundesverbandSolarindustrie*, BSi). In addition, the BSi moved its headquarters to the countries capital, Berlin, setting up its of-

10 An additional bonus of 5.0ct for integrated facade systems.

11 The Christian Democratic Union/Christian Social Union are the main conservative parties in Germany.

fices in the same building as the UVS. The two associations (BSi and UVS) increasingly coordinated their activities through the "ARGE Solarwirtschaft" working group and ultimately merged in 2006.

In parallel, efforts were also made to strengthen the collaboration within the 'Environmental Coalition'. This cumulated in the creation of the "Alliance Renewable Energies" (*Aktionsbündnis Erneuerbare Energien*) on 1 September 2003, which encompassed a broad group of stakeholders from business, unions and environmental movements, including BEE, Eurosolar, the Farmers Association, the German Association of Small and Medium-Sized Businesses (*Bundesverband Mittelständische Wirtschaft*, BVMW) and the unions Ver.di, IG Metall and IG BAU. By presenting renewables as a motor for growth and jobs, they hoped to mobilize small investors and homeowners in favour of these new technologies, not from a purely idealistic belief but through a private economic objective. They understood, that these groups needed the opportunity to partake in these profits and invest, in order to firmly cement the cause of renewable energies in the midst of society (BSW, 2012).

Notably, the incumbent parliamentary groups pursued the strategy of securing a cross-party consensus with the CDU/CSU, to maintain the tradition of renewables policies being a cross-party project as was the case of the previous Electricity Feed-in Act in 1990/91. At the same time, the CDU/CSU opposition had already begun to lighten up on its opposition against the EEG and to look to approximate itself with the pro-renewables coalition (REICHE, 2004, p.142).

Differently to the Bundestag, the Bundesrat (chamber of states) was ruled by a CDU/CSU-led majority. In May of 2004, they called for a mediation committee in order to discuss the reform proposal of the EEG, in effect delaying its initial implementation of 1 June 2004. This delay and potential political uncertainty, threatened the investment security for renewables. The Bundesrat sided with the large energy suppliers, who also owned large parts of the grid, and wanted to avoid increasing shares of wind power. In addition, concerns were expressed, particularly by the states of Bavaria and Baden-Württemberg, over the negative impacts of Wind farms on the natural scenery. While the Bundestag had the right to overrule the appeal, pushing through their original version of the reform, the SPD/Greens were willing to seek a consensus in order to strengthen cross-party support for the EEG.

One interesting outcome of these negotiations, was the heterogeneity in positions and preferences towards the EEG and individual technologies, among CDU/CSU-led state governments and the state associations of the parties. Certain patterns became clears, such as a preference and stronger support for bio-energy in agriculturally strong states, a consensus among Northern coastal states in favour of wind power, and priority in photovoltaic energy in the sunnier southern states of Bavaria and Baden-Württemberg.

The latter was a result of solar energy coming to be recognized by farmers as a promising economic investment, resulting in stronger political pressure in favour of those technologies, in state such as Baden-Württemberg and Bavaria, traditionally strongholds of CDU/CSU (who were predominantly against solar subsidies) (DAGGER, 2009; EVERT, 2005).

As had become clear during the Bundestag debates over the EEG reform, proponents of the law had created their own constituencies, strengthening the overall conflict capacity of the environmental coalition. This was partly due to the fact that the pro-renewables lobby could demonstrate impressive employment figures and regional economic relevance, on top of the traditionally held high trust level among the public.

Thus, substantial parts of the CDU/CSU group began supporting the EEG, in parts due to the historic role the party has played in the implementation of the EEGs predecessor, "…a success story that they did not want to sacrifice to the political opponents…" (GRÜNDIGER, 2017, p. 303), but also as a reaction to shifting pressure and interest in their electorate. This development, brought Gründiger (2017, p. 303) to asses that "Self-reinforcing path dependence effects tracing back to the political heritage of earlier, seemingly minor reforms can be clearly observed." The federal government pursued a consensus based solution, making concessions to their original formulations, in order to secure the collaboration and support of states in the implementation of the law and future amendments.

The outcome of the Federal election in 2005 resulted in a change in government. The CDU/CSU formed a grand coalition with the SPD, with Angela Merkel as Chancellor. In the coalition agreement, both parties assured their commitment to "the environmentally and economically sound expansion of renewable energies" as an "important element" of energy policy (DAGGER, 2009, p. 101-103; HIRSCHL, 2008, p. 168-171).

The new Chancellor convened three energy summits on the 3 April 2006, 9 October 2006 and 3 July 2007 (DAGGER, 2009; HIRSCHL, 2008) in order to involve a greater number of stakeholders in the preparation of the new energy strategy. The central issues that were discussed during the first summit were related to security of supply, competitive energy prices, research, energy efficiency and renewables.

This was part of an effort to regain political ground within the renewables energy/climate protection debate. In the parties' view, the CDU/CSU with Angela Merkel as their leader, had managed to portray herself as champion of renewables and the "Climate Chancellor". Thus, in order to strengthen their stance as the 'leading environmental force' in government, environmental minister Gabriel (SPD) and environmental politicians in the parliament pressed ahead with a clear profiling in energy and climate policy (DAGGER, 2009).

Rising policy costs (2008–2012)

Yet during the same period, some have observed that the renewables branch began defending its subsidies in the same manner as traditional industries (such as the coal industry) has done, thus positioning it as a "normal" industry that has lost its idealistic drive (SCHRÖDER, 2013).

By 2008, it had become undeniable that photovoltaic energy was the costliest renewable energy. Its high tariffs accounted for 24.6% of total EEG remuneration payments, while only supplying 6.2% of renewable electricity in that same year (RWI, 2009). This helps explain why many considered the subsidization 'inefficient' i.e. too much money for too little return. Aggravating this, was the fact that enormous demands coupled with undersupply in solar panel production, meant that the industry was making huge profits. Of course this growing demand could directly be traced back to the generous tariffs.

Another turn of events, was the withdrawal of support by the VZBV (the consumer organization). While they had been in support of the EEG and were naturally distrustful of the conventional big electricity companies, they were critical towards the rising promotion costs which the EEG represented for private households and the excessive windfall profits for the solar industry. This was seen to have been achieved at the cost of consumers, and thus the VBZV lobbied for stronger tariff cuts and degression rates.

The political establishment recognized the importance of creating a political framework which would foster a stable environment for investment. In addition, the positive contributions of the solar industry were quite apparent, industry jobs and the branches promising potential were apparent to most. On the other hand, politicians also recognized the need to tackle increases in electricity prices and the growing costs associated to the promotion of the industry. A compromise which had been found, meant that small PV systems (which represented the majority of the market) would be spared substantial cutbacks, while larger systems would take the brunt of the cuts. In addition, the idea of a flexible cap was adopted, an idea originally elaborated by Green politicians (GRÜNDIGER, 2017).

The conflict between the economics ministry and the environmental ministry continued. Growing confidence by the environmental ministry meant that its advocacy for renewables and the political competition which resulted from it, strengthened the environmental party wings and pro-renewables interest groups. This went as far as the economics ministry being openly criticised, by State secretary Michael Müller (SPD), for wasting taxpayer's money for superfluous studies in fields outside its tasks (BMU, 2008).

At the same time the increasing complexity of the EEG meant that the ministerial expertise became invaluable as support for policy makers and parliamentarians who were struggling to cope with heavy workload. Consequently, the ministries ability to influence and advice the reform processes grew.

Again, in an effort to create consensus among policy makers, during the formulation of the EEG reform state government were invited to contribute. This was done in order to evade any further delays to the implementation of the reform through appeals in the Bundesrat. During this process it became clear again, how the growth of the solar industry had affected the different regional governments. All five of the former East-German state governments had expressed their dismissal of sever photovoltaic cuts. In all of these regions, the industry had gained significant economic importance and there were considerable concerns with the economic repercussions of major promotion cuts.

The difficulties in predicting cost developments of photovoltaics were partly caused by uncertain market developments, supply and demand issues, technological progress and advances in manufacturing. Thus, while the period between 2004 and 2006 was marked by a stagnation and even partial increase of PV market prices, mainly due to high demand caused by shortages in production, the following years saw an accelerated decrease in PV system prices, mainly driven by cheap imports from China. In 2009 alone, prices dropped by approximately 30% (GRÜNDIGER, 2017).

Yet growing competition from outside markets (especially from Asia), later accompanied by the previously mentioned decline in capacity growth, threw the industry into existential crises. The country's solar PV industry fared poorly, suffering a 38% decline in sales in 2014. Employment decreased by 32%, reaching 38,300 jobs (down from a peak of 113,900 jobs in 2012) at the end of the year. In the meantime, the German PV sector was marked by insolvencies and companies exiting the market

(O'SULLIVAN ET AL., 2015). As a result, 2009 witnessed the bankruptcy of one of the leading manufacturers of large solar power plants, Solar City.

The growth of photovoltaic capacity continued to be difficult to predict. The environmental ministry's 2008 Lead Study forecasted a growth of 1,300 MW for the following year, while in actual fact 2009 saw a capacity growth of 3,800MW (nearly three times as much). This had also occurred in 2008, when capacity growth was 1,933MW while estimations had predicted it as 1,250MW (BMU, 2008; BNetzA, 2012).

In 2010, the new government presented its 'National Energy Concept' (*Energiekonzept*). While it gave continuation to the ambitious goals for renewables of 35% until 2020, 50% until 2030, 65% until 2040 and 80% until 2050 (BMWi, 2010), it put a strong emphasis on the need to design this expansion to be more cost-effective.

At the time, the dominant feeling was that tariffs need to be adjusted, yet market uncertainties made it difficult to determine how far-reaching these reductions could and should be. This hesitation from policy makers paved the way for lobbies to influence the decision making.

Gründiger (2017, p.335) observes that: "This intense cost debate reinforced the public image of PV as expensive form of electricity production, although prices had already dropped." Nonetheless, a survey by Forsa (a polling firm) at the beginning of 2010 showed, that public opinion remained supportive of the EEG and the solar industry. In the survey, 71% of respondents stated that they were willing to bear an increase of the EEG levy from 3% at the time to 5% in their electricity bill within the next five years (FORSA, 2010).

Building on a consensus that tariffs needed to be reduced, the principal debate concentrated on determining the extend of these cuts. The environmental minister Norbert Röttgen presented his plans in early 2010, proposing a cut of 15% for roof systems. In opposition, the economics minister Rainer Brüderle (FDP) argued for more severe cuts by 17% for roof systems (DER SPIEGEL, 2010).

A discrepancy became clear, as the federal government identified the need to control increases of the EEG levy, while state governments in the German Parliament were focused on protecting their regional industries. Thus the Bundestag proved to be an important veto power, as their demand for lower cuts (only 10%), resulted in compromise under which a cut of 13% was established from 1 June with an addition 3% coming into effect from 1 October onwards.[12]

12 This was the case for roof systems. In the case of freestanding systems in open space, the cuts were 15%.

Policy decision making was informed by high uncertainties in regards to the current market situation and future market development. As a consequence, policy makers had to cope under conditions of time pressure – react to the fact-paced market changes and cost increases – and limited access to information about the very volatile and dynamic market environment.

As a consequence, mounting pressure to reduce these costs culminated in the PV Act 2010, which introduced drastic tariff cuts, ranging from 8-13% depending on the system type. An additional cut by 3% was done in a second step which came into effect during the second half of that same year. With this also came a tighter growth-dependent degression rate of 1-12%, in addition to the basic regression by 9%. Should capacity growth fall below the growth corridor, the ordinary degression would be relaxed in accordance.[13]

Despite strong tariff cuts, as a response to pressure on improving cost reduction, photovoltaic expansion continued to accelerate (7,400 MW new capacity has been installed in 2010 (BMU, 2011)). With this, the EEG levy increased culminating in photovoltaics, in 2011, being responsible for a share of 56% of total remuneration costs, while representing only a 20% share of renewable electricity production[14](BMWi/BMU, 2012, p. 36).

The FDP economics minister Rösler called for a fundamental reform of the EEG, pushing for restrictive growth corridors and substantial solar tariff cuts. In particular, he lobbied for a growth target reduction from 3,000 MW to 1,000 MW, as a way of effectively curbing the promotion costs (RÖSLER, 2012).

On the other hand, the states demanded less severe cuts, lighter degression rates among others. It sends out a strong signal, that "… state governments have turned into political protectors of the energy transformation, independent from party composition, and use the Bundesrat to give thrust to their demands and preserve the status quo against regress" (GRÜNDIGER, 2017, p.379).

Reinventing the EEG (2012 – to present)

The years of 2012 and 2013 marked the first time the existence of the EEG were seriously questioned. This was exemplified by the environmental minister Peter Altmaier (CDU) (a ministry traditionally in support of the EEG) expressing in interview his con-

13 The 2012 PV Act continued this trend and introduced major tariff cut of up to 30%.

14 In comparison, onshore wind constituted a share of 14% of remuneration costs while contributing 44% of renewable electricity production (BMWi/BMU, 2012, p. 36).

cerns over the costs of the support for renewables. It caused him to controversially claim that the programme would run up costs of 1 trillion euros by 2040[15]. While the debate over the costs of the EEG had been debated for years, political pressures were rising.

The coalition government of SPD and CDU/CSU which came into power in 2013, identified as one of their priorities, an impactful reform of the EEG. Already in march of 2014, the policy proposal, known as EEG 2.0, was passed by the Bundestag, ultimately going into effect in august. One of the principal elements introduced by the policy, was a pilot project for photovoltaics which would test auctioning mechanisms for the determination of remuneration eligibility for future projects. This represented a first step in the major overhaul of the feed-in system, which was predicted to take place 2 years later.

The EEG 2.0 was condemned by a majority of environmental groups for failing to continue to provide a strong incentive framework for renewables. The continuation of growth corridors for photovoltaics (and other RET) was seen by many as counterproductive to the governments energy transition goals.

Overall, the pro-renewables coalition articulated their concerns over the one sided cost debate associated with the EEG. The Renewable Energy Sources Act was seen as reduced to a one-sided cost debate, depicting the costs for the development of renewables as a burden, instead of an investment in the future. This was echoed by suggestions for new ways of addressing the costs associated with the EEG.[16]

On the other hand, representing the traditional industry, energy companies welcomed the changes implementation by the reform, as an important step for stronger market integration, the introduction of more competitiveness and more security for the grid infrastructure.

As a continuation of the efforts of the 2014 reform, the 2017 EEG introduced a tendering system for photovoltaic installation with a capacity that exceeds 750kW. The design of the auction model had previous been tested through a pilot program which was initiated in 2015. In essence, it meant that eligibility for receiving a floating[17]feed-in premium (for the duration of 20 years) is determined by a tendering process under

15 After harsh critique from the opposition (particularly the Greens), pointing out the lack of evidence for this figure, the ministry distanced itself from these claims.

16 The VZBV for example suggested a new approach to covering the costs for the support for renewables, by introducing a state fund to cover some of the costs, thereby lowering the EEG surcharge. The Öko-institute suggested that an overhaul of the EEG-surcharge exemptions for industries, could decrease the surcharge by 20% (ÖKO-INSTITUT, 2014).

17 A floating premium unlike a fixed premium, is adjusted in relation to the fluctuation of the electricity price.

which only the most competitive projects were chosen. Systems with a capacity inferior to 750kW continue to be eligible to for the traditional remuneration model (feed-in or premium).

The reform can be considered one of the most controversial in recent years, not alone for its abandonment of feed-in tariffs for the majority of system sizes and types.[18] While some saw the changes as step in the right direction (IW, 2016), many within the pro-renewables coalition and the political opposition argued that it jeopardised the future of renewable energy development, and the *Energiewende* as a whole. This provoked the President of the *Bundesverband Erneuerbare Energien* to asses:" …until now, the EEG was an engine for the development of clean energies, but with today's reform, it serves mainly to preserve fossil energies, and to significantly slow the speed of the *Energiewende* (BEE, 2016)."

Many of these critiques were more concerned with the different mechanisms introduced to control and curb renewable expansion, than with particular cuts in remuneration levels. Particularly the auction system was seen as adding to the expansion cap. Experts argued, that the deceleration of expansion could be exacerbated by the fact that annual expansion caps did not take into consideration if projects were actually implemented (BWE, 2015) and did not take into account decommissioning of older systems. As a result a study argued that by 2023, the entire planned expansion volume will be used for replacing phased-out installations,"[19], ultimately resulting in net-decreases in capacity (BWE, 2015).

The concerns over the negative effects of RE expansion due to the EEG 2017 reform also overlapped with discussions about the feasibility of the Energiewende goals. Experts pointed out the future need for greater renewable electricity, in order to support the growing electrification of the transport and heating sector. At the same time, the increased industry exemptions were counterproductive as long as they were not coupled with energy efficiency demands.

Conclusion

As illustrated previously, the EEG has undergone a substantial transformation since its implementation at the beginning of the century. In particular, the recent reform processes have emphasized concerns over the growing costs related to renewable

18 Se section "EEG Reform", in chapter 3, for more details.
19 The study focused on the case of on-shore wind. Yet the critique of gross and net value increases of capacity continues to be relevant for photovoltaics as well, particularly once the first 20-year feed-in contracts end.

energy remuneration, and controlling the general rate of renewable expansion. Consequently, the eligibility for receiving the traditional FiT has been considerably reduced, practically only available for systems with a capacity below than 100kW or through the new tendering system.

These changes have raised concerns about the ramifications of these revision for the future of *Bürgerenergie* initiatives. As discussed earlier, the original design/accessibility of FiT enabled a level of investment security which allowed for and even incentivized citizen participation. In other words, RETs represented an attractive investment opportunity for Germans. Thus, critics are quick to point out that the recent trajectory of renewable energy support in Germany has been detrimental to citizens' initiatives/involvement, in favour of 'big business'. The introduction of tenders, has been criticized for increasing the financial obstacles for broader participation, through greater financial and transaction costs. On the other hand, the change towards feed-in premiums is seen to increase the risk for generators, including energy cooperatives. In the words of Morris and Jungjohann (2016, p. 417): "… the government's renewable energy policy increasingly seems designed to shut out the very citizen and community groups that have sustained the energy transition for at least the past 25 years. "

A recent emphasis on off-shore wind energy is also seen as problematic, since these projects are exclusively run by large corporations[20]. In addition, the emphasis on policy cost reductions is incompatible with the high remuneration levels for this type of RET. As a study by Agora Energiewende (2015) points out, off-shore support will almost exclusively be responsible for the increase in the cost of the feed-in remuneration in the coming years.

In addition, these expressed concern with cost reduction seem incompatible with the governments tendency to increasingly exempt certain electricity-intensive industries from paying for renewable energy remuneration[21]. Over the period of 2012 to 2014 alone, the number of companies exempt from paying the full costs of the EEG surcharge increased from initially 734 to 2098. In terms of monetary exemptions, this increased from 2,7 billion euros in 2011 to 5,1 billion euros in 2014 (MAYER AND BURGER, 2014).[22]

20 In part due to the elevated investment costs.

21 Critiques point out, that this is particularly concerning due to the decrease in retail electricity prices, driven renewable energy expansion.

22 A recent study by the Öko-Institut argued, that a reform of the industry exemptions set out by the EEG could decrease the surcharge costs for consumers by 20%, just by adopting the European Union's categorization of energy intensive industries which are exposed to international competition (thus drastically reducing the number of industries exempt) (ÖKO-INSTITUT, 2014).

As illustrated earlier, recent years has seen a substantial deceleration of renewable energy expansion, particularly for onshore wind and photovoltaics (two technologies in which citizen involvement played an important role). At the same time, this has naturally challenged the wider adoption of a distributed generation[23] model. Yet as discussed earlier, the value of distributed generation goes beyond its mere contribution to renewable energy expansion. The gateway GD represents for greater citizens' participation has implications for the organization, legitimization and ultimately governance of the energy transition as a whole. Engerer (2014) emphasizes that these initiatives contribute on a local level, to the acceptance of the greater energy transition, but also through greater awareness of the technologies and energy issues. This is also done through its role in reducing the costs of participating in these technologies and offering consulting services.

The reform trajectory of the EEG is also interesting, as it demonstrates the growth of political weight of pro-renewable coalitions. Overall, the German political landscape has been transformed by the expansion of renewable energy, and the industries growing political clout through lobbying, *Bürgerenergie* and institutional/organisational professionalization. The countries political tradition of consensus building and regional and ministerial competition have also been fundamental in defending and enabling policy continuity. As Morris and Jungjohann (2016, p. 229 and 240) express it:

> "Germany's energy transition took place within the German political system, and that has made a difference…The German system focuses on long-term consensus across party lines, political levels (federal and state), and geographical regions, giving a large number of political actors a way of tweaking legislation to their taste without blocking it outright."

Thus, as this chapter has attempted to illustrate, the trajectory of renewable energy policies, the policy approach and the technological application need to be understood in the context of political debate. The reform process of the EEG and the potential of *Bürgerenergie* initiatives illustrates the dispute among different interest groups and their attempts to shape and influence the policy arena in their favour. While this might seem straightforward, particularly the potential for new governance models offered by DG is an aspect often neglected in the debate about effective and suitable renewable energy policies. The German case clearly demonstrates that the overall energy transition benefits from greater public participation, not only through theoretical debate but practical involvement.

23 Growing debates over grid stability and the necessity for grid expansion have tried to legitimize the critique towards distributed generation.

At the same time, a greater appreciation is needed for the limitations of confiding in a traditional, 'big business' approach to renewable energy expansion. The transition to a renewable energy system is not merely a technical obstacle to be overcome, but it represents the need for a political and economic reorganisation of the sector, in order for this transition to be sustainable and most beneficial to society.

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