UNIVERSIDAD PONTIFICIA COMILLAS

ESCUELA TÉCNICA SUPERIOR DE INGENIERÍA (ICAI)

OFFICIAL MASTER'S DEGREE IN THE ELECTRIC POWER INDUSTRY

Master’s Thesis

MODELING THE EFFICIENCY GAINS DERIVED FROM CROSS-BORDER EFFECTIVE PARTICIPATION OF FOREIGN AGENTS IN NATIONAL CAPACITY REMUNERATION MECHANISMS

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SUMMARY

Introduction

Generation adequacy refers to the degree to which a system can meet demand without having energy not served. Capacity mechanisms are policy instruments that improve the generation security of electricity supply in the medium and long term. This master's Thesis objective is to model the efficiency gains and benefits derived from the effective participation of foreign agents in national CRMs at a regional level.

Methodology

To assess the efficiency gains derived from the cross-border participation of foreign agents in national CRMs, three different settings have been modeled for a 2-area regional system.

- The first setting is the base-case setting where no capacity mechanism planning is carried out. This serves to analyze the adequacy of the systems without further additional investments, as well as to compute a baseline hourly flow for the interconnector.
- The second setting is the uncoordinated capacity mechanism planning in each area. Each area has its own reliability target (expressed through the EENS). In this setting, each area optimizes the mix and dispatch in two different subsettings, representing two different expansion strategies:
    - (i) Without considering the interconnection, which represents the most autarkic expansion strategy.
    - (ii) Considering the base-line flows through the interconnector obtained in the first setting.
- The third setting represents the effective participation of foreign agents in national CRMs at a regional level. This is modeled through a coordinated minimum cost expansion and dispatch, where each area holds an independent reliability target (the same target used in the second setting).

For each setting, a mathematical model was developed and programmed using GAMS.

Data, results, and discussion

The three settings mentioned above have been implemented in a stylized study case formed by two interconnected areas. To perform the comparison, the effect of implementing the capacity mechanism is evaluated on the planning, EENS, prices, technology benefits, and cost redistribution of each area. Also, the effects of the capacity mechanism on congestion rents have been assessed.

Conclusions

Through the evaluation of the results, it can be stated that the participation of foreign agents in national CRMs results in a less costly and more efficient expansion

investment for the overall system compared to the uncoordinated when the stylized study case is analyzed. The cost reduction is mainly due to the allocation of expansion units and power exchanges between the areas. Moreover, prices in both areas and congestion rents are very sensitive regarding the setting studied. In this context, it is critical for policymakers and planners to consider the cross-border participation of foreign agents when designing CRMs.

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Chapter 1: Introduction

In recent years there has been an increase in the participation of Renewable Energy Sources (RES) in the electricity market. This increase in RES participation is partly due to increasing concerns about climate change. While traditional coal and gas power plants emit considerable amounts of CO2 and greenhouse gases into the atmosphere, renewable energy sources are technologies with very low CO2 emissions. For instance, wind, solar, and hydropower saved 230 million tons of CO2 emissions in 2022 [1].

As is well-known, increasing RES penetration is changing how the market operates and its available power capacity structure. One of the core concepts and most important premises of the electricity sector is the supply and demand balance, which must be always met to have a well-functioning system. RES are intermittent and come with much more uncertainty than traditional technologies, thus can put at risk the supply-demand balance of a system and the generation adequacy of the system.

Generation adequacy refers to the degree to which a system can meet demand without having energy not served, and it is a key tool to know the level of security of supply of a region. In this context, capacity mechanisms are policy instruments that countries can implement, when necessary, to improve the generation security of electricity supply in the medium and the long term.

In this first chapter, an introduction of this Master's Thesis is developed. First, a justification of the work explaining the context and the focus taken is carried on. Then the motivation gives the main reasons why this work is current and relevant. Finally, the main objectives of the Thesis are enumerated in section 1.3.

1.1. Justification

While CRMs could help solve some problems regarding generation adequacy and security of supply, the participation of foreign agents in national CRMs at a regional level could improve the efficiency in multiarea electricity markets. The efficiency gain could be measured through the reduction of overall costs, considering operation, investment in expansion, and power not served costs. Other efficiency gains could be reflected in the change in benefits of the technologies in areas involved and in the price of electricity. Furthermore, the change in the congestion rents in the interconnection of the areas could also reflect efficiency gains for both areas.

This Master Thesis focuses on analyzing the efficiency gain that may result from planning a CRM with the effective participation of foreign agents in a multiarea electricity market. Specifically, volume-based CRMs with physical availability during all the study horizon for new wind and combined cycle gas turbine (CCGTs) units have been considered. Moreover, no penalties for the mechanism have been considered. In this way, the new investments and the market clearance of CRMs planning with effective participation of foreign agents and uncoordinated CRMs planning approaches are calculated through a stylized study case. It should be pointed out here that the targets of generation adequacy and security of supply are defined and accomplished by area, i.e., there is no regional obligation but local targets.

1.2. Motivation

Although various capacity mechanisms have been in place for a considerable period, the rise of renewable generation has brought renewed significance to this subject. In the Clean Energy Package, the European Union reflects its concern regarding capacity mechanisms and establishes an EU-wide adequacy assessment methodology covered in the EU Electricity Regulation (EU/2019/943) [2]. According to the regulation, ENTSO-E should carry out of this assessment and can be complemented by national medium to long-term assessments used to identify adequacy concerns and the need for capacity mechanisms.

ACER also published a Decision on the European Resource Adequacy Assessment in 2020 [3], where based on future supply-demand settings, they consider the availability of renewable capacity, demand side flexibility, and cross-border infrastructure.

As can be seen, capacity remuneration mechanisms are a hot topic nowadays which clearly concerns the European Union. CRMs will be key to the decarbonization targets of the EU and the energy transition as they promote security of supply during this time full of changes in the electricity markets and energy mix of all member states.

The main motivation of this Master Thesis is to shed some light on whether capacity remuneration mechanisms are more beneficial and efficient when applied to multiarea regions with the effective participation of foreign agents compared to the non-coordinated way, where each region has its own capacity remuneration mechanism completely independent from the other.

1.3. Objectives

The main objectives of this Master Thesis are:

1. To characterize the capacity remuneration mechanisms that are discussed today in the electricity sector, as well as the international experience there is of implementing them in the real world, especially in regional markets.

2. To build a stylized test system to simulate a multi-area electricity market, which will be used to simulate three different CRMs settings, including uncoordinated and allowing effective participation of foreign agents.

3. To compare through the study of different settings the efficiency gain of the planning of the national capacity mechanism with effective participation of foreign agents in interconnected areas, instead of doing it independently and in an uncoordinated way.

4. To draw relevant conclusions regarding the possibility of foreign agents' effective participation in the planning of CRMs against an uncoordinated capacity mechanism planning in the multiarea case setting.

Chapter 2: Capacity remuneration mechanisms

Energy-only markets are those in which electricity is traded exclusively based on energy value without a separate payment for capacity or availability. In these markets, the clearing price is equal to the marginal cost of the marginal producing technology for each hour. However, when there is more demand than generation available there is a situation of scarcity, and the market price rises above the marginal cost of the marginal technology. This scarcity pricing allows marginal technologies to recover their variable costs. In the short term this pricing system should in theory result in an efficient dispatch, leading to a socially optimal generation mix [6], and provide the optimal price signals both for short-term operation and long-term investments [5]. Nevertheless, the long-term efficiency of the generation mix in an energy only market relies on some assumptions that may be difficult to maintain in reality.

Moreover, the short-term market is not completely efficient mainly because the whole demand does not completely participate in the market. In addition, the regulator usually intervenes with price caps so that the prices don’t rise above a certain value and protect the consumers against risk. These price caps are market distortions that lead to prices not reaching high spikes that would otherwise promote investment in generation technologies. Here it is also important to remark that investors are risk averse and to invest in large generation plants they need some reassurance that they will recover their investment.

Furthermore, in the electricity markets there is the problem of market power and the potential of market power abuse, which also hinders the perfect market operation.

Although markets with long-term contracts could be a good solution to provide the long-term signals properly, these markets are not liquid enough and only have significant participation in the one-year ahead horizon.

For all these reasons it is not realistic to say that an energy-only market is sufficient to have a well-functioning market that assures generation adequacy and security of supply for short- and long-term operation and investments.

In this context, capacity remuneration mechanisms can give the investment and the market signals needed to attract investments and help achieve the levels of security of supply established by the regulator.

The most accepted classification of CRMs is the one shown in Figure 2.1.

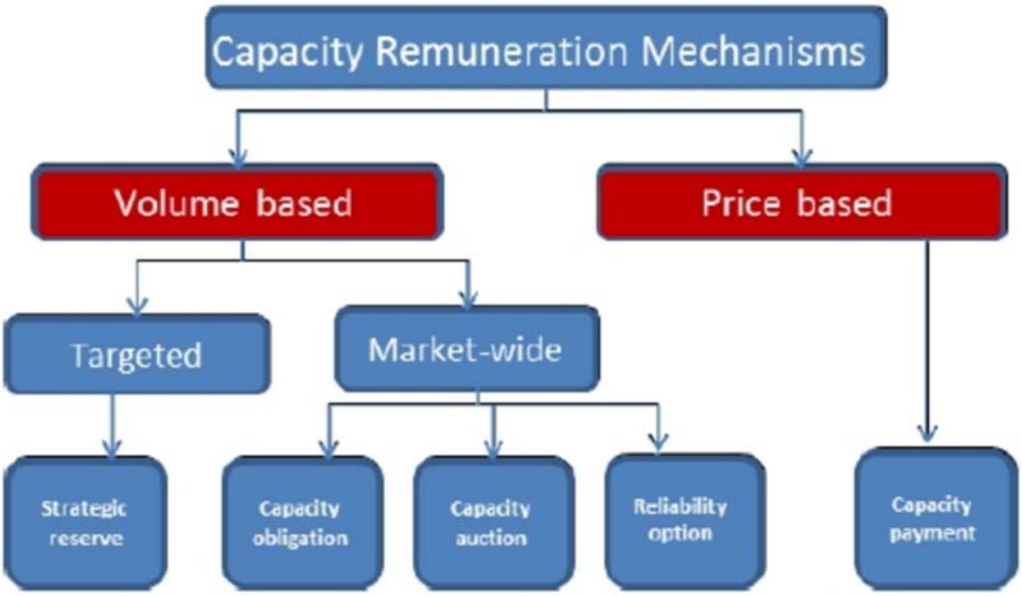


Figure 2.1. CRMs taxonomy [4]

The classification above differentiates between volume- and price-based mechanisms. Volume-based mechanisms are the most widely implemented today. In these mechanisms, the regulator sets the volume of reliability product needed for the capacity mechanisms and then the price is set through an auction or any other market-based price-clearing mechanism. Inside this category targeted mechanisms are focused only on one type of technology or technologies whereas market-wide mechanisms apply to all technologies which can provide the reliability product.

In contrast with the volume-based mechanisms, price-based mechanisms are those where the regulator sets the price to pay reliability providers and then the volume is set afterwards, this type of mechanism is losing presence and is not widely used.

This Master Thesis focuses on analyzing the efficiency gain that may result from planning a CRM with the effective participation of foreign agents when volume-based CRMs. In this context, the following section details the main characteristics of these kind of mechanisms.

2.1. Types of CRMs

From the classification mentioned in the previous section the main CRMs proposed and implemented in some regions today are [4]:

- Strategic reserve

The strategic reserve sets aside a volume of generation capacity that is not available in the wholesale market. This capacity at reserve is sold in times of scarcity when the capacity available cannot meet demand. The National Regulatory Authority normally sets the volume needed for the reserve and procures this capacity through an auction. This type of CRMs allows for plant selection.

The strategic reserve can be applied in different forms depending on how the reserve is procured, the price that triggers the activation of the reserve, the method to pay the generators and the time horizon of the mechanism.

In [5] authors argue that the strategic reserve seems to be more favorable than capacity markets as a temporal mechanism until demand-side flexibility and energy storage become more available, as the strategic reserve has a smaller scope and could be more easily abolished when no longer necessary.

- Capacity obligations

This capacity mechanism is volume-based and decentralized. It establishes an obligation to large electricity consumers and electricity suppliers to sign contracts to assure that they meet their self-assessed future consumption or supply, including a reserve margin.

These contracts are normally done through certificates, if agents do not contract all the capacity required, they are penalized.

- Capacity auction

In this type of CRM, the capacity needed in the long-term is centrally assessed some years in advance and procured through an auction, which sets the remuneration. There is new capacity built which participates in the electricity market and received a capacity payment for procuring the reliability product.

Capacity auctions may carry some risk as investors do not invest in technologies based on market price signals but on the volume set by the centralized auction.

- Capacity markets with reliability option

In this CRM the counterparties (capacity suppliers, large consumers, or transmission system operator) enter into an option contract. This contract gives the agent the option to procure electricity at a strike price. The reliability option will be exercised in situations of scarcity, when the price exceeds the strike price of the auction.

- Capacity payments:

This is a price-based mechanism where the payments for reliability product providers are set ex-ante by the regulator. The plant which receives these payments also keeps participating in the energy only market.

2.2. Design elements

When designing the capacity remuneration mechanism to be applied, there are some design issues to define, such as what technologies are going to be eligible, which demand is going to be covered, what the reliability product is going to be, among others.

- Eligible demand

First, it is important to determine the eligible demand for the capacity mechanism. There are two main types of demand: captive demand and free demand. Captive demand is driven by specific requirements, where consumers must purchase the product due to regulations or compatibility conditions, leaving them little freedom of choice and even obligating their participation in the capacity mechanism. On the other hand, free demand has no constraints or conditions, granting consumers the freedom to choose whether to pay for and receive, or not, the reliable product offered by suppliers. Additionally, the most common demand for capacity mechanisms is the whole-system demand, where the capacity mechanism considers the total demand of the system, taking overall consumption into account.

- Eligible technologies

After having decided which type of demand the capacity mechanism is going to have, the technologies who will be able to supply this demand have to be determined.

The eligible technologies can be of multiple types. First, technologies providing the reliability product can be already existing generation that are incentivized to be available during periods when there is insufficient generation to meet the firm capacity targets and achieve the desired level of security of supply.

Another category of eligible technologies for supplying the reliability product involves investment in new generation and expanding the regional generation system. These technologies require the recovery of their investment which can be facilitated through capacity payments in exchange for their availability. Furthermore, the expansion of generation system capacity facilitates meeting the growing demand and ensure the future reliability of supply of the system.

Recently the inclusion of RES, demand response and energy storage in capacity mechanisms is currently being discussed. These technologies are being considered as potential suppliers of reliability product considering their increased integration and presence in the system. For renewable resources capacity mechanisms can act as an incentive for them to be available during peak consumption hours which can be achieved also with their hybridization with energy storage, also providing flexibility to the system. Demand response mechanisms could adjust consumption decreasing it when the system most needs it. Furthermore, some technologies can be explicitly excluded or excluded by some restriction that doesn´t allow them to participate, such as CO2 emissions limitations.

In addition, it is currently being under discussion if foreign resources should be eligible to provide reliable capacity at a national level. In fact, with this Master’s Thesis is expected to shed some light on whether capacity remuneration mechanisms are more beneficial and efficient when the participation of foreign agents is allowed.

- Reliability product

Another critical issue to define when designing a capacity remuneration mechanism is what the reliability product is going to be. The product is the contribution of each resource to meet the reliability target. It can be capacity or energy or a combination and should be coherent with the reliability metric used to define the reliability target. This product can be procured either by a centralized or a decentralized mechanism.

- Level of procurement’s centralization

A centralized mechanism consists of a single auction, conducted by the system operator or by the regulator targeting the entire demand. These types of mechanisms are attractive for large projects as they put together more demand, also they need an accurate forecast of demand to set the volume of investment needed.

On the other hand, a decentralized mechanism consists of multiple auctions or bilateral agreements carried out by generating and consumption entities. In this context, the presence of vertical integrated utilities can hinder competition and prevent small players from entering into bilateral contracts because of their dominant position in the system.

In Figure 2.2 a graphic distinction between these two types of capacity mechanisms can be seen.

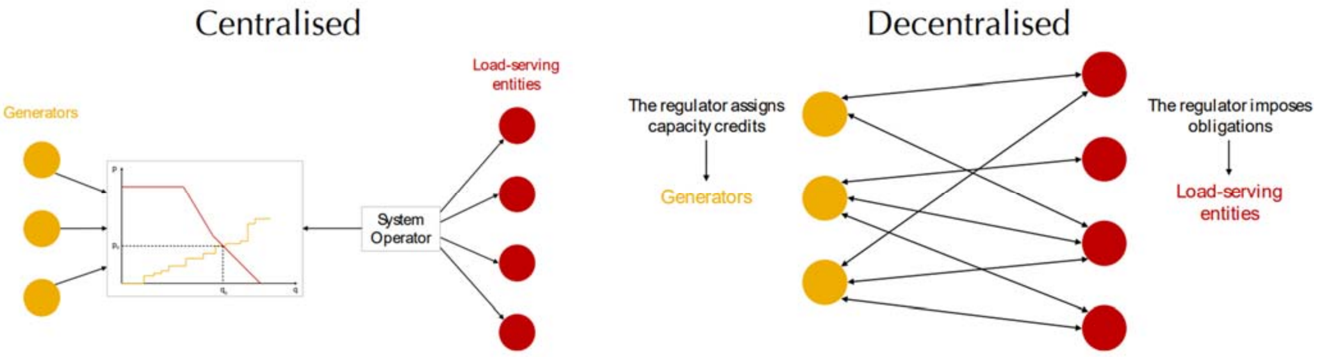


Figure 2.2. Distinction between a centralized and decentralized capacity mechanism design

- Contract characteristics

Once the generation, the demand, the reliability product, and the procurement process have been determined, the contract for the capacity remuneration mechanism has also have to be designed. Regarding the contract there are some important characteristics that may affect the outcome of the mechanism, these are: the lag period and the contract duration.

The lag period is the time between the procurement process and the time when the reliability product is delivered. When there is investment in new technologies this period allows for the construction and commissioning of the new capacity. Determining the lag period is crucial as it affects the timing for the capacity to be available if it is too long there could be a delay in the expansion of capacity but if it is too short there may noy be enough time for new capacity to be constructed and in operation.

The contract duration is the time in which the capacity mechanism contract is effective. On the one hand, the longer the contract's duration the more security it gives to the supplier as it ensures a revenue stream throughout this period. On the other hand, shorter contract durations can allow for more frequent reassessments and more flexible management of capacity mechanisms. It is important to find a balance between long-term stability for investors and enough flexibility and adaptability to market conditions.

- Penalties

If the reliability product suppliers do not meet their capacity contract obligations and fail to procure capacity when needed some penalties, which must be decided, ex-ante can be implemented. These penalties can take the form of financial penalties such as charges or fines, which can be applied for each unit of product not delivered or as a percentage of the capacity payment or an amount based on the severity of the shortage produced. There can also be replacement penalties where the supplier not able to procure capacity must pay for the costs associated with the shortage and the system operator having to use replacement capacity which may be more expensive. Whichever the type of penalty is, it should be clearly specified in the contract.

Finally, two critical issues regarding capacity mechanisms are to carry out an adequacy assessment through the selection of the most adequate reliability metric and determining the firm-capacity of each technology using the corresponding de-rating factors.

These concepts are explained in the next section.

2.3. Adequacy assessment and firm capacity

In this section two important concepts regarding security of supply and the reliability of an electricity system are going to be developed. First, the adequacy of the system and secondly the firm capacity of each technology of the system.

2.3.1. Adequacy assessment and reliability metrics

Before deciding to apply a capacity remuneration mechanism in an electricity market, there is a need to assess the long-term generation adequacy. This assessment allows to determine whether there is a resource adequacy problem or not. Regulators define a reliability metric to set the target the area wants to achieve in terms of generation adequacy, for instance not having more than a certain level of energy not supplied during the assessment horizon.

Usually, the selection and definition of these reliability metrics are based on a traditional generation mix, based on fossil fuels and with little renewable resources [6]. However, the current energy transition is leading to a completely new scheme and generation mix, dominated by the penetration of intermittent wind and solar technologies. For this reason, it is especially important to revise the different reliability metrics which are available for today’s energy mix.

The main reliability metrics used nowadays to set resource adequacy targets in the long-term are mentioned hereunder.

- Reserve margin

The reserve margin metric represents the difference between the system total installed capacity and its peak demand:

$$RM = \frac{Firm\ Capacity\ -\ Peak\ Demand}{Peak\ Demand} \cdot 100\ [\%]$$

This metric is mostly expressed as a percentage of demand. Because the reserve margin focuses on peak demand, this metric does not consider each generator's specific contribution to meeting demand during the periods of highest loss of load probability.

Targets are also based on the N-1 criterion so that the reserve margin should be larger than the installed capacity of the bigger unit of the system, so that in case it fails there is still enough generation to meet the peak demand.

- Loss of load probability (LOLP)/Loss of load expectation (LOLE)

These metrics reflect the probability of the system not being able to meet the demand at any time. This metric does not only focus on the peak demand moment, but also any other given instant.

LOLP is expressed as a probability (%) and LOLE is expressed as the total number of hours where scarcity events occur (h/year). The typical target of LOLE is limited to 1 day every 10 years.

The main problem with these metrics is that they do not show the gravity of the loss of load event. They do not consider the amount of energy not served of each scarcity event. With LOLP and LOLE metrics an event where 2 MW were unserved would be given the same importance as one where 2 GW went unmet [6].

Moreover, the degree to which one technology contributes to the scarcity event is also not covered by LOLP or LOLE. In a scarcity event of 150 MW for one hour a power plant covering 149 MW would not be considered, whereas a plant supplying 150 MW would cover the whole shortage reducing the LOLP/LOLE, even though the contribution of both power plants to the scarcity event was almost the same [6].

One case for LOLE is the 95th percentile of loss of load duration (LOLE95, LOLD95), which considers extreme settings.

- Expected energy not served (EENS)

This measure does consider the severity of the shortage event as it takes into account the expected amount of energy not served during the event. To compare the EENS of different regions it can be normalized by dividing the total EENS by the total demand in the assessment period.

- Energy supply in the least favorable hydrological setting

This metric is commonly used in hydro-dominated systems. Supply must be met in all hydrological settings, especially in the least favorable setting considering historical data of inflows in the region.

In Article 4 the Methodology for the European resource adequacy assessment by ACER [3] suggests that “resource adequacy shall be assessed using the following two probabilistic resource adequacy metrics: EENS and LOLE”.

In [6] another metric is proposed where market price could also reflect scarcity situation when it surpasses a certain threshold. In current systems where renewables are growing and flexibility is decreasing, market price increase can be a good indicator of scarcity. Moreover, the way settings are assessed should be increasingly focused on extreme settings, because of climate change. The conditional value at risk (CVaR) metric is also proposed as a statistical parameter to analyze these extreme settings that are gaining importance each year.

In this Master’s Thesis the EENS reliability metric has been selected to model the impact of foreign agents' participation in national CRMs. However, other reliability metrics are proposed to be investigated in future research.

2.3.2. Firm-capacity and de-rating factors

Another important parameter that will be discussed in this chapter is the concept and definition of firm supply. This is a de-rating factor applied to each technology's total installed capacity to define the actual capacity that each technology will be able to provide when a scarcity situation occurs. This parameter is very relevant to investors as the firm-capacity they can provide determines their final remuneration and level of participation in the capacity mechanism.

To define the firm-supply of each technology and their de-rating factor some criteria must be defined, regarding the aspects mentioned below.

First, whether to evaluate each technology separately or as part of the system. In [6] it is proposed as best practice to establish the firm supply of each technology as part of the system as the electricity system adequacy depends on the performance of all the resources.

It is also critical that the firm-capacity definition is based on the same reliability metric used to establish the adequacy target. As technologies are compensated to contribute to reach the adequacy target set by the regulator using that reliability metric, this retribution should be coherent with the target. This practice, however, is not commonly used by countries, where the firm-capacity is set using a different measure than the reliability metric [6]. For instance, in the UK the adequacy assessment uses the LOLE metric while the firm-capacity is calculated based on each technology contribution to decreasing the EENS.

Another important factor to consider is whether the de-rating factor for firm-supply calculation is shared by all generators of the same technology or a specific de-rating factor should be applied to each power plant even though they all use the same technology. In the case of technologies where all resources contribute similarly to the reliability target, irrespective of their geographical location, one de-rating factor for the technology may be a good approach. However, energy production of renewable resources such as wind or solar depends heavily on their location. In this case applying different de-rating factors among same technology generators is more efficient to calculate firm-supply [6].

2.4. International experiences

The European Union defines capacity mechanisms as: “temporary support measures that EU countries can introduce to remunerate power plants for medium and long-term security of electricity supply”.

A problem may arise when in the internal electricity market of the EU member states with energy-only-market coexist with member states that apply capacity mechanisms. This is the reason why the EU highlights that capacity mechanisms should only be applied when necessary and only in a temporary way. According to the EU Electricity Regulation 2019/943 [2] the capacity mechanisms should follow this premises:

- Be a last resort and temporary instrument.
- Not create unnecessary market distortions or limit inter-zonal trade.
- Not go beyond what is necessary to address the coverage problem.
- The capacity providers will be selected through a transparent, non-discriminatory, and competitive process.
- It will provide incentives for capacity providers to be available during those times when the national electrical system requires firmness.

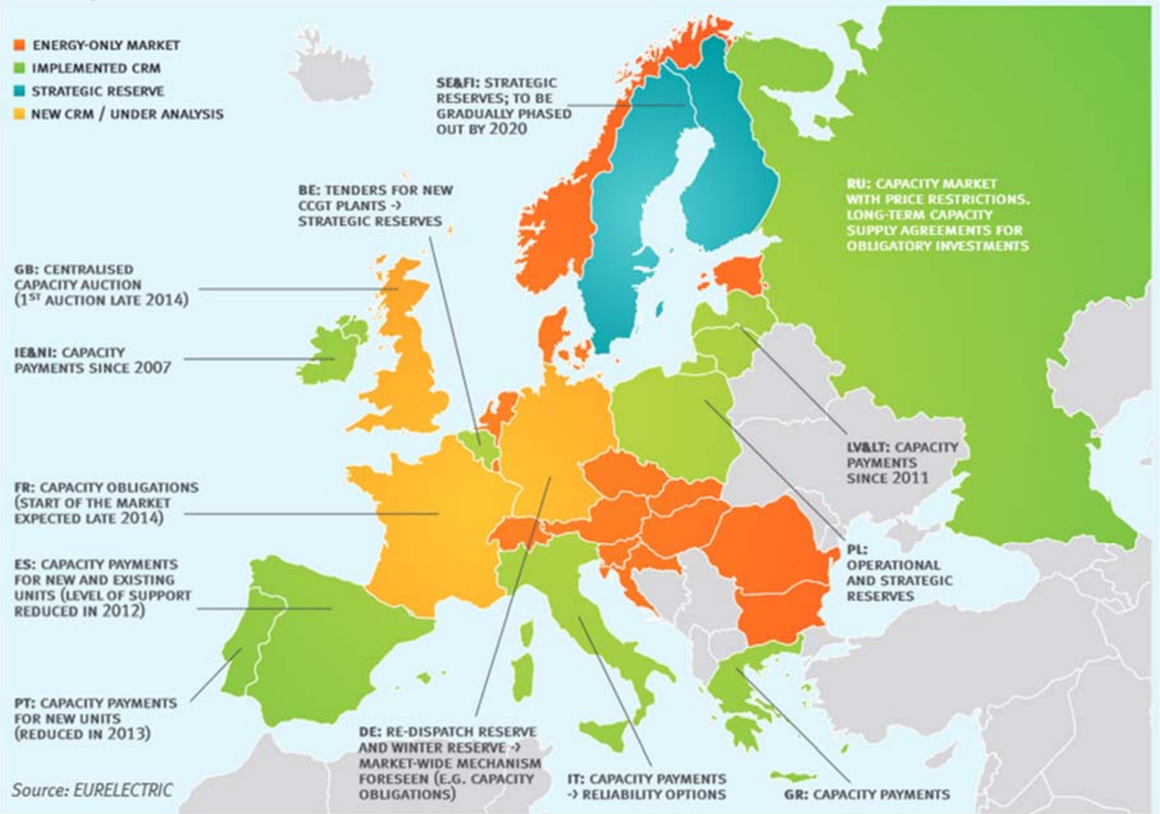
- The remuneration regime associated with the provision of the capacity service will be set through a competitive bidding process.
- The technical conditions for the participation of capacity providers will be established prior to the competitive bidding process.
- It will be technologically neutral.
- A sanctioning regime will be established to penalize capacity providers for unavailability during periods of high system demand.

The EU has also defined a Guidance for Member States on implementation plans [7] this national implementation plan should show that all other methods to resolve the adequacy problems are proven inefficient and so the capacity remuneration mechanism is needed.

In addition, before applying any capacity mechanism, seven specific groups of measures should be taken:

- Removing regulatory distortions.
- Eliminating wholesale price restrictions (“caps”).
- Making sure that the value of reserves in the system is appropriately reflected in prices, increasing interconnection and internal grid capacity.
- Enabling self-generation, storage, demand-side measures, and energy efficiency.
- Ensuring cost-efficient and market-based procurement of balancing and ancillary services.
- Removing regulated prices where required by Article 5 of Directive (EU) 2019/944.

If after these measures are taken, there is still an adequacy problem then a capacity mechanism may be applied in the affected member state.



Source: EURELECTRIC

Figure 2.3. Capacity remuneration mechanisms applied in Europe [8]

In the next section some international experiences are discussed by country regarding the implementation of the capacity mechanisms. In Figure 2.3 the different capacity remuneration mechanisms used nowadays in Europe are summarized.

2.4.1. Belgium

Elia is the system operator in Belgium and is the responsible of organizing, managing and when needed responsible for activating the Strategic Reserve mechanism to cope with structural outages of electricity in the country. The strategic reserve mechanism was introduced by the Law of 26th of March 2014 [9].

The strategic reserve needed for the year is calculated with a probabilistic Adequacy & Flexibility analysis carried out every 15 November. Each year a Volume Assessment is published on Elia's webpage. In this report Elia takes into account the situation and policies of neighboring countries.

For example, in its last report [10], Elia assesses the situation of its neighboring countries. The situation of France regarding nuclear plants availability, the situation of Germany regarding the closure of coal units; the situation of The Netherlands, and that of Great Britain, regarding the decoupling of the electricity market due to the Brexit. All of these situations could affect the availability of interconnections.

2.4.2. UK

In the UK the capacity mechanism used currently is the capacity market. It is in operation since 2014 [11] [12]. This mechanism was proposed and implemented by the Department for Business, Energy & Industrial Strategy (BEIS) and the UK regulator Ofgem. In Figure 2.4 of the capacity market design in the UK is summarized.

Department
of Energy &
Climate Change

Capacity Market – high-level design

Capacity to procure	Auction	Trading	Delivery	Payment
Forecast of peak demand made, and translated into a capacity requirement	Total amount of capacity contracted for from providers willing to provide it through a central auction Includes DSR, storage etc as well as generation	Capacity providers may trade between auction and delivery	Providers of capacity commit to be available when needed or face penalties in the delivery year	Costs of capacity shared between suppliers

Figure 2.4. Capacity market design in the UK [11]

First, by forecasting the peak demand of the country the volume of capacity needed to avoid having energy not served is determined. The volume of capacity needed is procured through a centralized auction. Until delivery, agents can trade the capacity in capacity markets. In the moment of delivery supplier must deliver the contracted capacity or otherwise will be penalized.

2.4.3. United States of America

In the United States there are Independent System Operators (ISO) that cover several states, for instance PJM or ISO New England, where capacity markets are used.

In March 2023 two commissioners of the Federal Energy Regulatory Commission (FERC) declared that there are important reliability and security of supply challenges across the United States [12]. They argue that there are fundamental problems in the capacity markets and especially in those where multiple states are involved.

This debate has arisen due to the extreme winter events that happened in the last years. During these events the capacity markets in these states have failed to secure reliability at an affordable price [13].

2.4.4. France

France uses the mechanisms of obligations of obligated parties called the de-central obligations [14]. This capacity mechanism obligates the parties to cover with production the peak demand periods. It is also based on the certification of generation and demand response, see Figure 2.5.

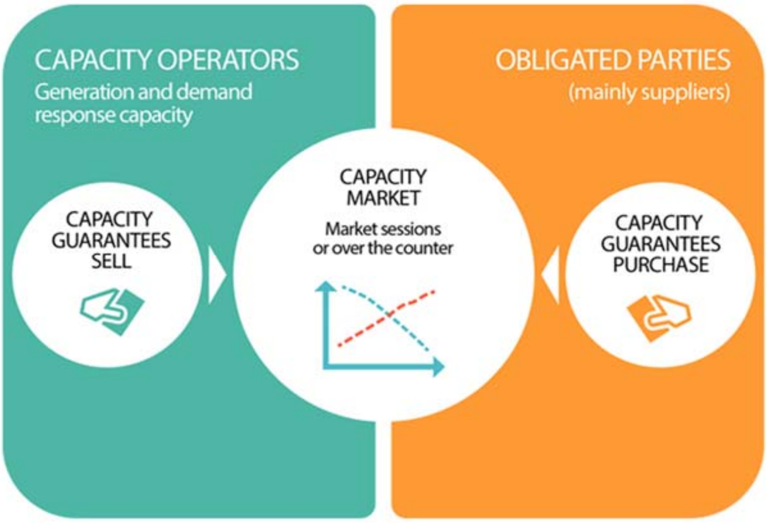


Figure 2.5. Capacity obligations scheme in France [14]

The capacity operators, which include generation and demand response, must establish a certification contract with RTE where an amount of MW is committed as available over a year. RTE issues capacity guarantees for the capacity operators. They can sell these guarantees, either bilaterally or in the market sessions, to the obligated parties.

The obligated parties are those agents which must be able to demonstrate that they are able to cover consumption even during peak winter hours. To meet this requirement, obligated parties buy capacity guarantees in the market or bilaterally from capacity operators.

2.4.5. Spain

The mechanism in Spain follows a price-based approach rather than a volume based one, it uses the capacity payments mechanism. This method sets the price to pay for the reliability product instead of the quantity. This can lead to the risk of having a high-priced volume that is not really needed. As Spain is an insular country in Europe with low interconnection capacity it decides its capacity remuneration mechanism taking little into account neighboring countries which can lead to inefficiencies [15].

2.5. Coordination between countries when applying CRMs

As has been discussed, European countries are implementing capacity remuneration mechanisms to comply with reliability and security of supply national objectives. However, countries' approach looks only at national energy level rather than at a regional coordination level. To achieve a long-term expansion and integration of the electricity European system is very important to achieve maximum efficiency and benefits, not only at a short-term horizon but also at a long-term adequacy horizon.

In the European Union comments have been raised regarding this issue. For instance, the European Commission said in 2012 that "if capacity mechanisms are introduced prematurely or without proper coordination at EU level, they risk being counterproductive" and that "poorly designed capacity mechanisms will tend to distort investment signals". Also, in the working document on energy adequacy the EC stated that "given the increasing integration of electricity markets and systems across borders it is now increasingly difficult to address the issue of generation adequacy on a purely national basis".

Likewise, ACER in 2013 observed that the "lack of coordination (on generation adequacy measures) has resulted in a patchwork of CRMs in the EU, which may be at the detriment of the market integration process".

Besides, the European Federation of energy Traders (EFET) highlighted in 2013 that CRMs should be "non-discriminatory, by taking into account the contribution of non-national generation through interconnection which may decrease local needs".

In [16] authors argue that two fundamental pillars are needed to achieve regional coordination in Europe for CRMs: a stronger coordination of TSOs and to introduce a particular type of firm cross-border nominations associated to CRMs commitments.

The authors in [16] also state that there are different degrees of harmonization at a regional level of CRMs where the highest level would be to implement a wide-EU capacity mechanism considering the whole EU demand. This scenario is not realistic and not necessary as each setting is that each country plans and implements their own capacity mechanism, in this setting the benefits of the common integrated market are still there to be exploited. To achieve this, countries should be open to generation in other member states to be able to support the national reliability target. Being the only limitation the commercially available transmission capacity between countries.

According to [16], in practice there are some barriers that prevent CRMs to allow for foreign participation. Some of them are:

- There is a lack of trust in article 4.3. of the Security of Supply Directive (2005/89/EC) that states that "Member States shall not discriminate between cross-border contracts and national contracts" [17]. This mistrust is promoted by the existence of national laws and network codes that say that in case of a domestic emergency exports to other countries would be interrupted.

- The transmission capacity is allocated through the short-term market clearing algorithm automatically, and the flows are determined by the generation and demand equilibrium. This could interfere with a foreign reliability provider being able to export to the country under a stress situation.

Possible solutions to these barriers proposed in [16] are, in the case of the first barrier to promote a stronger coordination between TSOs and modifying the national network codes. In the case of the second barrier, authors proposed that the problem could be solved with Physical Transmission Rights (PTRs), which has been considered effective for cross-border capacity trading. However, these auctions are to be eventually removed so other solutions must be studied. An alternative proposed in the paper are conditional nomination contracts with the reliability option capacity mechanism.

As it has been seen the participation of foreign agents in national CRMs poses some practical difficulties that must be assessed to promote efficiency and benefits both in the short-term and long-term adequacy horizon.

In the next chapters a mathematical a model will be developed to assess the efficiency gains and benefits derived from the effective participation of foreign agents in national CRMs at a regional level.

Chapter 3: Methodology

In this chapter the methodology used to develop this master thesis will be explained and developed. First, the different case studies and settings designed, and the mathematical models developed to assess the efficiency of a CRM planning which allow for foreign agents' effective participation will be explained. Next, the base case characteristics of each of the two areas involved in the CRM planning will be presented.

3.1. Case studies and proposed settings

The objective of the master thesis is to assess if, when implemented considering effective participation of foreign agents, capacity mechanisms can result in efficiency gains for both countries. In order to assess this, three different settings have been studied for two interconnected areas named area 1 and area 2. Each setting is hereunder explained.

3.1.1. Base-case setting: two areas without capacity mechanism

The base-case setting is the yearly dispatch of the two interconnected areas without considering any capacity mechanism planning or generation expansion.

This setting serves to analyze the adequacy of the systems without further additional investments, as well as to compute a baseline hourly flow for the interconnector. The capacity of the interconnection is of 5 GW.

Figure 3.1 shows a scheme of this setting.

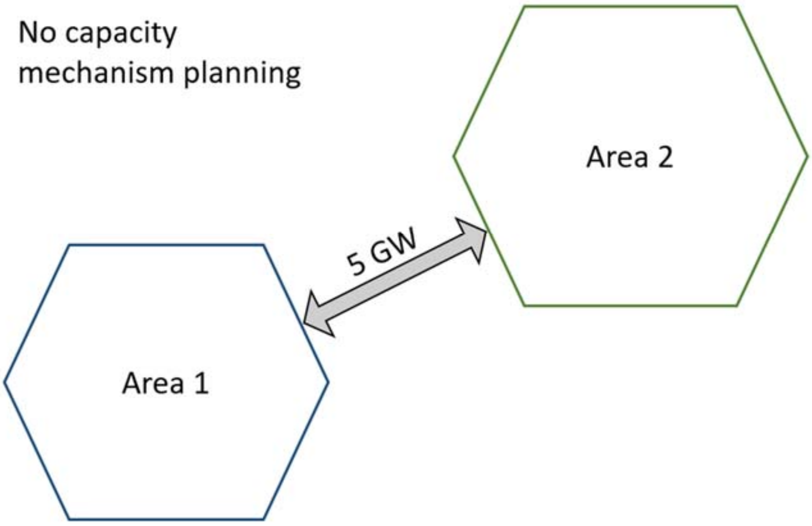


Figure 3.1. Scheme of base-case setting

3.1.2. Uncoordinated capacity mechanism planning

The second setting will consist of each area planning its capacity mechanism in an uncoordinated way. Uncoordinated meaning not considering that there are neighboring countries which may also be applying their own capacity mechanisms. Each area does not exchange information with the other.

In this setting expansion of eligible technologies is considered to determine the volume needed to participate in the capacity remuneration mechanism. Each area has its own EENS target. This target will be established as a 2% of the EENS of the base-case setting.

Inside this setting two subsettings are studied:

- The interconnection capacity is considered as exporting or importing a yearly amount based on historical data taken from the previous setting. Figure 3.2 shows a scheme of this setting.

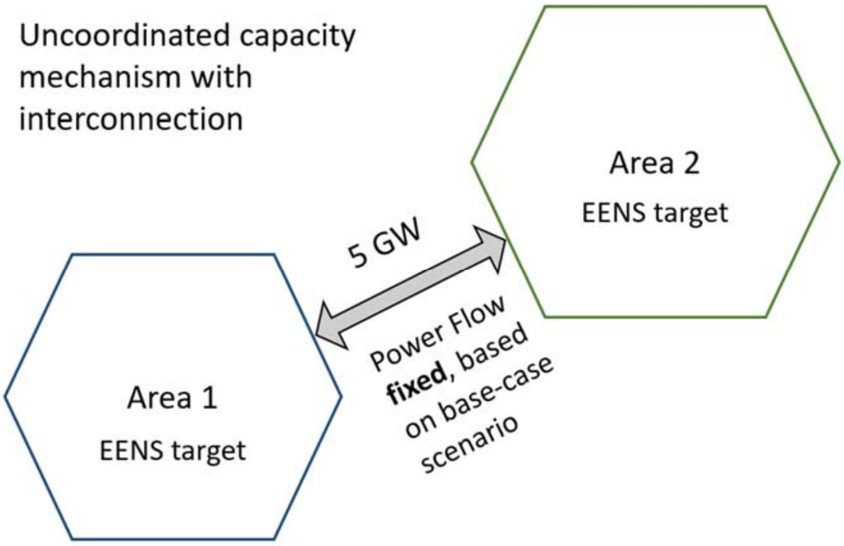


Figure 3.2. Scheme of uncoordinated CRM planning with interconnection

- The interconnection is completely disconnected and there is no possibility of exporting or importing any power between the areas, Figure 3.3 shows a scheme of this scenari0.

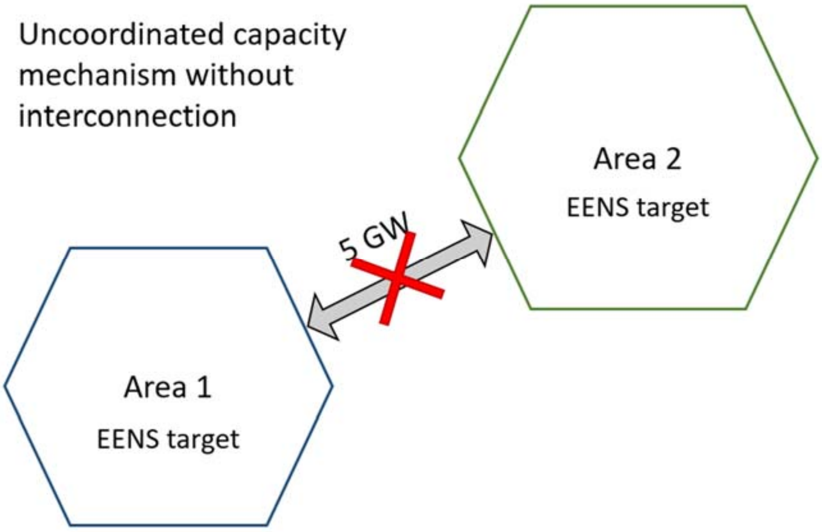


Figure 3.3. Scheme of uncoordinated CRM planning without interconnection

3.1.3. CRMs planning with effective participation of foreign agents

Finally, the third setting consists in both areas planning their own capacity mechanisms allowing for effective participation of agents from the other area. This is modeled through a coordinated minimum cost expansion and dispatch, where each area holds an independent reliability target (the same target used in the second setting). Both areas exchange information to plan the expansion volume needed for their capacity mechanisms.

Figure 3.4 shows a scheme of this setting.

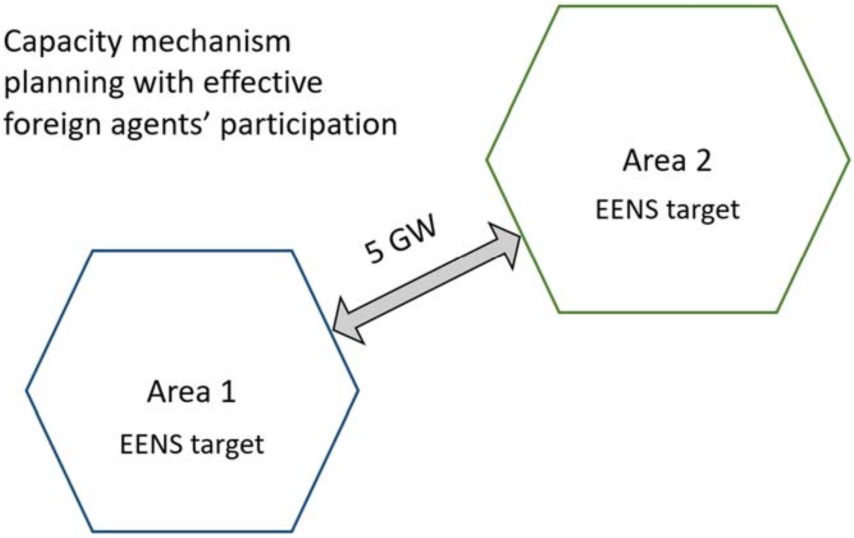


Figure 3.4. Scheme of CRM planning with effective foreign agents participation

3.1.4. Settings' assumptions and constraints

Each area wants to reach an individual security of supply targets expressed in EENS as well as a percentage of installed renewable energy, to comply with policy goals.

To comply with this security of supply target each area will have the possibility to invest in two technologies: wind and CCGT. Both technologies will be the ones targeted for the capacity remuneration mechanism.

- Cost of wind expansion: 136.100 €/unit
- Cost of CCGT expansion: 504.800€/unit
- Cost of energy not served: 180€

3.2. Mathematical model proposed

In this section the mathematical models used to model the settings and obtain the results is going to be explained.

The first model to be developed was the two interconnected areas without planning any capacity mechanism, therefore without expansion.

The second model was the uncoordinated planning of the capacity mechanism, this model consisted of one area's expansion planning without considering the other area. As explained above, the flow in the interconnection between the areas is set as fixed based on historical data which correspond to the power flow of the base-case setting.

The third model developed was an expansion planning model where both interconnected areas planned their expansion and capacity mechanisms considering the interconnection and allowing for participation of agents from the other area to reach their reliability target. The time horizon for all models is one year, covering 8760 hourly periods, divided into months.

The models were developed based on the MSEM weekly unit-commitment dispatch model and the network-constrained model for only one period used in the subject Decision Support Models in the Electric Power Industry of the master. Developed by Professor Javier García González. In this work both models were added together for the period of one year and adapted to allow for expansion investment in technologies and to achieve targets of EENS and RES installed capacity.

In the next section, the objective function and main constraints used for each of the settings are explained.

3.2.1. Two areas without capacity mechanism

First the base-case setting where there is no capacity mechanism planning and no expansion.

The objective function of this setting (1.0) consists of the reduction of costs for each area "a". These costs include the cost of energy not served, and the operation costs of the thermal technologies of each area. The operation costs include the fuel costs multiplied by the start-up, shut-down cost, and the operation and maintenance cost multiplied by the production of each technology, which is divided by efficiency.

Besides, the constraints of the model are shown in equations (1.1) to (1.7). Equation (1.1) is the balance equation by area. The constraints (1.2) and (1.3) refer to the maximum and minimum output of technologies, while constraints (1.4) and (1.5) are the constraints for the upwards and downwards ramps of the generation plants.

The constraint (1.6) stands for the unit-commitment variables, for the starting up and shutting down of plant logic.

Finally, the last constraint (1.7) is the water balance constraint which balances the available water in the system considering the water reservoir levels, the hydro production, the pumping, and the water inflows such as rain.

$$F_{obj} = \sum_{a=1}^{2}[\sum_{p=1}^{8760}[C_{pns} \cdot pns(p,a) + \sum_{t=1}^{11}[C_{fuel}(a,t) + C_{O\&M}(a,t)] \cdot \frac{q(p,a,t)}{k(a,t)}]] \tag{1.0}$$

s.t.

$$\sum_{a=1}^{2}\left[\sum_{t=1}^{11}[q(p,a,t)] + \sum_{h=1}^{3}[q(p,a,h) - b(p,a,h)] + q_{wind}(p,a) + q_{solar}(p,a) + pns(p,a) + \sum_{j=a} pwf(p,a,j) + \sum_{j=a} pwf(p,j,a)\right] = d(p,a) \quad \forall p,a \tag{1.1}$$

$$q(p,a,t) = u(p,a,t) \cdot q_{min}(a,t) \cdot k(a,t) + q_1(p,a,t) \quad \forall p,a,t \tag{1.2}$$

$$q_1(p,a,t) < \left(q_{max}(a,t) - q_{min}(a,t)\right) \cdot k(a,t) \cdot u(p,a,t) \ \ \forall p,a,t \tag{1.3}$$

$$q_1(p,a,t) - q_1(p-1,a,t) < ramp_{upw}(a,t) \quad \forall p,a,t \tag{1.4}$$

$$q_1(p-1,a,t) - q_1(p,a,t) < ramp_{dpw}(a,t) \quad \forall p,a,t \tag{1.5}$$

$$u(p,a,t) = \begin{cases} u(p-1,a,t) + y(p,a,t) - z(p,a,t) & p > pini \\ u_0(a,t) + y(p,a,t) - z(p,a,t) & p = pini \end{cases} \tag{1.6}$$

$$w(p,a,h) = \begin{cases} w(p-1,a,h) - [q(p,a,h) + s(p,a,h) - ef(a,h)\, b(p,a,h)] + i(p,a,h) & p > pini \\ w_0(a,h) - [q(p,a,h) + s(p,a,h) - ef(a,h)\, b(p,a,h)] + i(p,a,h) & p = pini \end{cases} \tag{1.7}$$

Where:

a	set of areas
b	variable for pumping output power
C_{fuel}	fuel cost parameter of thermal technologies
$C_{O\&M}$	operation cost parameter of thermal technologies
C_{pns}	power not served cost parameter
d	demand parameter
ef	pumping efficiency parameter
h	set of hydro technologies
i	water inflows parameter
k	efficiency of thermal technologies parameter
p	set for hourly periods, installed capacity variable
pns	power not served variable
pwf	interconnection power flow variable
q	variable for thermal and hydro units' production
q_1	power output above minimum output variable
q_{max}	maximum output power parameter
q_{min}	minimum output power parameter
q_{wind}	variable for wind units' production
q_{solar}	variable for solar units' production
$ramp_{dpw}$	upwards maximum ramp parameter
$ramp_{upw}$	downwards maximum ramp parameter
s	spillages parameter
sg	solar production parameter
t	set of thermal technologies
u	unit-commitment binary variable
u_0	initial state unit-commitment
y	start-up binary variable
z	start-up binary variable
w	variable for water available in a reservoir

w_0	initial amount of water available in a reservoir
wg	wind production parameter

3.2.2. Uncoordinated CRM model

In this setting there is the possibility of capacity expansion, this aspect is modelled through the creation of a new set named “e”, which groups the two technologies eligible for expansion: wind (‘EOL’) and CCGT (‘CONV’).

$$\begin{aligned} F_{obj} = \sum_{p=1}^{8760} [C_{pns} \cdot pns(p) + \sum_{t=1}^{11} [[C_{fuel}(t) + C_{O\&M}(t)] \cdot \frac{q(p,t)}{k(t)}] \\ + \sum_{e=1}^{2} [\left[Units_{exp}(p,e) - Units_{exp}(p-1,e)\right] \cdot C_{exp}(e)] \\ + [C_{fuel}('CONV') + C_{O\&M}('CONV)] \cdot \frac{q(p,'CONV')}{k('CONV')}] \end{aligned} \qquad (2.0)$$

s.t.

$$\begin{aligned} \sum_{t=1}^{11} [q(p,t)] + \sum_{h=1}^{3} [q(p,h) - b(p,h)] + q_{wind}(p) + q_{solar}(p) + pns(p) \\ + \sum_{e=1}^{2} q_{exp}(p,e) \\ = d(p,a) \quad \forall p \end{aligned} \qquad (2.1)$$

$$\sum_{p=1}^{8760} pns(p) < EENS_{target} \qquad (2.2)$$

$$q_{exp}(p,'EOL') < \frac{wind_{est}(p)}{p_{ini}('EOL')} \cdot Units_{exp}(p,'EOL') \cdot \ Cap_{unit}('EOL') \ \forall p \qquad (2.3)$$

$$q_{exp}(p,'CONV') < p_{exp}(p,'CONV') \ \ \forall p \qquad (2.4)$$

$$Units_{exp}(p,e) > Units_{exp}(p-1,e) \ \ \forall p,e \qquad (2.5)$$

$$p_{exp}(p,'EOL') = Cap_{unit}('EOL') \cdot Units_{exp}(p,'EOL') \ \forall p \tag{2.6}$$

$$\begin{aligned} &p_{exp}(p,'CONV') \\ &\quad = derat_{CONV} \, Cap_{unit}('CONV') \cdot Units_{exp}(p,'CONV') \ \forall p \end{aligned} \tag{2.7}$$

Where:

C_{exp}	unitary expansion cost of each technology parameter
Cap_{unit}	capacity of each unit of expansion technologies
$derat_{CONV}$	de-rating factor of CCGT parameter
e	expansion technologies
$EENS_{target}$	Expected Energy Not Served target
p_{ini}	initial installed renewable power parameter
p_{exp}	installed capacity of expansion units' variable
q_{exp}	production of expansion units' variable
$Units_{exp}$	expansion units installed variable

In this setting, the objective function (2.0) includes the costs of investing in expansion technologies. Besides, the balance constraint (2.1) considers the expansion units' production to meet the demand of the area and the variable of the demand includes the imports and exports fixed for the area.

The constraint 2.3 considers de de-rating factor of wind, as the production of the wind expansion units will depend on the wind resource of the area. This de-rating factor is the historical average wind production in the area for each period divided by the initial wind installed capacity.

Constraint 2.7 considers the de-rating factor of CCGTs expansion units which has a value of 0,9092.

3.2.3. CRM model with effective cross-border participation of foreign agents

In this setting there is expansion and both areas are interconnected through the transmission line of 5 GW, allowing for power to flow between the two areas. The demand balance equation (3.1) now accounts for both the expansion unit's production and the power flow through the interconnection to meet the demand of each area.

The constraints of this model are the same as the ones of the uncoordinated expansion model but accounting for both areas. The previous setting does not consider the interconnection, so the flows are either set at zero or fixed at historical values. The setting with cross-border participation considers the availability of the interconnection line and allocates the expansion units taking into account the possibility of exporting and importing power from the other area.

$$\begin{aligned} F_{obj} = \sum_{a=1}^{2}[\sum_{p=1}^{8760}[C_{pns}\cdot pns(p,a) + \sum_{t=1}^{11}\big[[C_{fuel}(t,a) + C_{O\&M}(t,a)\big]\cdot\frac{q(p,a,t)}{k(a,t)}] \\ + \sum_{e=1}^{2}[\big[Units_{exp}(p,a,e) - Units_{exp}(p-1,a,e)\big]\cdot C_{exp}(e)] \\ + [C_{fuel}('CONV',a) + C_{O\&M}('CONV',a)]\cdot\frac{q(p,a,'CONV')}{k('CONV',a)}]] \end{aligned} \quad (3.0)$$

s.t.

$$\begin{aligned} \sum_{a=1}^{2}\Bigg[\sum_{t=1}^{11}[q(p,a,t)] + \sum_{h=1}^{3}[q(p,a,h) - b(p,a,h)] + q_{wind}(p,a) + q_{solar}(p,a) \\ + pns(p,a) + \sum_{e=1}^{2} q_{exp}(p,a,e) + \sum_{j=a} pwf(p,a,j) + \sum_{j=a} pwf(p,j,a)\Bigg] \\ = d(p,a) \quad \forall p,a \end{aligned} \quad (3.1)$$

$$p_{exp}(p,a,'EOL') + p_{ini}(a,'EOL') + p_{ini_{solar}}(a) > RES_{target}(a) \;\; \forall p,a \quad (3.2)$$

$$\sum_{p=1}^{8760} pns(p,a) < EENS_{target}(a) \quad \forall a \quad (3.3)$$

$$\begin{aligned} q_{exp}(p,a,'EOL') \\ < \frac{wind_{est}(p,a)}{p_{ini}('EOL',a)}\cdot Units_{exp}(p,a,'EOL')\; Cap_{unit}('EOL') \;\forall p,a \end{aligned} \quad (3.4)$$

$$q_{exp}(p,a,'CONV') < p_{exp}(p,a,'CONV') \quad \forall p,a \quad (3.5)$$

$$Units_{exp}(p,a,e) > Units_{exp}(p-1,a,e) \quad \forall e,a \quad (3.6)$$

$$p_{exp}(p, a, 'EOL') = Cap_{unit}('EOL') \cdot Units_{exp}(p, a, 'EOL') \ \forall p, a \tag{3.7}$$

$$p_{exp}(p, a, 'CONV') = derat_{CONV} Cap_{unit}('CONV') Units_{exp}(p, a, 'CONV') \ \forall p, a \tag{3.8}$$

3.3. Metrics for comparison

To compare the setting that allows for foreign participation with the uncoordinated setting some comparison metrics are defined:

1. Effect of the effective participation of foreign agents in CRMs on the EENS of each zone.
2. Effect of the effective participation of foreign agents in CRMs on the price of each zone.
3. Effect on the benefits for the technologies in each area due to the effective participation of foreign agents in CRMs.
4. Effect on how costs are redistributed among areas due to the effective participation of foreign agents in CRMs.
5. The effect of the effective participation of foreign agents in CRMs on the congestion rents of the system.

3.4. Area 1 and area 2 characteristics

In this section the characteristics of the proposed two-areas stylized study case is shown. First, both areas are called area 1 and area 2.

Regarding the installed capacity in each area, Table 3.1 shows the maximum installed capacity per technology.

Table 3.1. Installed capacity [GW] of each area

	Area 1	**Area 2**
Nuclear	7,2 GW	60 GW
Lignite	2,1 GW	2 GW

Subbituminous	1,3 GW	0,5 GW
CCGT	26,25 GW	0,5 GW
Fueloil	0,008 GW	14,7 GW
Gas	1,15 GW	1 GW
Hydro reservoir	16,9 GW	12,95 GW
Hydro run-of-the-river	5,1 GW	25 GW
Hydro pumping	4,4 GW	5,1 GW
Wind	30 GW	9,2 GW
Solar	30,9 GW	20 GW
TOTAL	125,3 GW	150,95 GW

In Table 3.2 the minimum output power and the efficiency of each technology is shown.

Table 3.2. Minimum production and efficiency for each technology

	Minimum Production [GW]		**Efficiency**
	Area 1	Area 2	
Nuclear	7,2	60,00	1
Lignite	0,70	0,67	0,94
Subbituminous	0,43	0,17	0,95
Bituminous	0,00	0,17	0,93
Anthracite	0,00	0,00	0,96
CCGT	8,75	4,90	0,98
Fuel oil	0,00	0,33	0,94
Gas	0,38	4,32	0,94

Hydro reservoir	5,63	8,33	1
Hydro run-of-the-river	1,70	1,70	1
Hydro pumping	1,47	3,07	1

The pumping efficiency is 0,7. In Table 3.3 the costs for each technology are shown.

Table 3.3. Costs of operation for each thermal technology

	f [k€/MTh]	**alpha [MTh/GWh]**	**o [k€/GWh]**
Nuclear	3,5	1	1,2
Lignite	8	3	2,4
Subbituminous	8,5	2,6	1,8
Bituminous	8	2,3	1,2
Anthracite	7	2,2	1,2
CCGT	20	1,3	1,2
Fuel oil	23	2,1	1,2
Gas	20	2	2

The reservoir levels for both the hydro reservoir and the pumping reservoir are shown in Table 3.4.

Table 3.4. Hydro reservoir levels of each area [GWh]

	Area 1		**Area 2**	
	Hydro reservoir	**Hydro pumping**	**Hydro reservoir**	**Hydro pumping**
Maximum Reservoir Level	300.000	1.800	250.000	15.000
Minimum Reservoir Level	60.000	0	50.000	0
Initial Reservoir Level	180.000	900	150.000	750
Final Reservoir Level	119.000	600	59.500	300

The renewables resources present in each area are wind and solar. In Table 3.5 and Table 3.6 the main parameters for their distribution in each area are shown. Area 1 has better resource both in wind and solar than area 2.

Table 3.5. Wind production max, min and average values for each area

	Area 1	**Area 2**
Min [GW]	0,39	0,23
Max [GW]	8,53	5,12
Average [GW]	3,26	1,95

Table 3.6. Solar production max, min and average values for each area

	Area 1	**Area 2**
Min [GW]	0	0
Max [GW]	6,18	3,09
Average [GW]	1,50	0,75

To see more details about the evolution of renewable generation, both wind and solar, in each area please refer to the graphs in

Annex I: Figures of each area's characteristics.

The peak, minimum and average demand of each area is shown in Table 3.7.

Table 3.7. Peak demand in each area

	Area 1	**Area 2**
Peak demand	67,25GW	142,66 GW
Minimum demand	24,47	60,50
Average demand	49,87	105,92

To see more detail about the evolution of the demand in each area please refer to the graphs in

Annex I: Figures of each area's characteristics.

Chapter 4: Results and discussion

In this chapter the metrics for comparison are discussed. First, the results of each metric are shown, covering EENS, electricity prices, cost distribution among areas and congestion rents. Then the results obtained are discussed.

For each metric the results of the four main settings are discussed:

- Base-case setting: two interconnected areas without capacity mechanism.
- Uncoordinated capacity mechanism with interconnection flows based on historical data.
- Uncoordinated capacity mechanism without interconnection.
- Capacity mechanism planning with possibility of effective cross-border participation of foreign agents.

The first metric of comparison between settings is the Expected Energy Not Served (EENS) of each area. This is the reliability metric chosen to assess the adequacy target of the areas. Once the EENS in the base-case is determined, the reliability target is set at 2% of the original EENS in both areas.

In Table 4.1 the result for each setting is shown, as well as the target set. Likewise, regarding expansion units' investment in each area, Table 4.2 shows the results for each setting. Where it can be seen that, as the wind technology is cheaper than conventional CCGT both in investment and in operation, all expansion units invested are of wind.

From these tables it can be seen that in the uncoordinated without interconnection setting each area must invest in the expansion units needed to achieve their own EENS target without exchanging any power flow with its neighbor country. Once the units are installed, there can be enough wind resource to achieve even a lower EENS level than the target, as producing energy with wind is zero.

In the uncoordinated with interconnection setting the interconnection is considered available with fixed power flows based on historical data. This means a fixed export/import power amount for each area. The expansion units will be allocated considering that area 1 is mostly importing based on historical data, therefore more wind units will be installed in area 2. Although the wind resource in area 2 is worse than in area 1.

In the setting with effective cross-border participation of foreign agents, the interconnection can be used to optimize the expansion units' allocation because energy can be exchanged between the areas. In this case all the units are allocated in area 1. This is because area 1 has a better wind resource than area 2, and for each installed unit more energy will be obtained. Additionally, because of the interconnection capacity of 5 GW, the wind energy produced in area 1 can be exported to area 2.

Table 4.1. Expected Energy Not Served (EENS) results.

	Base-case [MW/year]	**EENS Target [MW/year]**	**Uncoordinated without interconnection [MW/year]**	**Uncoordinated with interconnection [MW/year]**	**Effective participation of foreign agents [MW/year]**
Area 1	7.272.336	145.446,72	125.367,00	145.307,41	119.356,00
Area 2	21.695.305	433.906,10	433.397,66	400.735,04	433.900,03

Table 4.2. Expansion units to install in each area

		Uncoordinated without interconnection	**Uncoordinated with interconnection**	**Effective participation of foreign agents**
Area 1	Wind	52	301	322
	CCGT	0	0	0
Area 2	Wind	575	268	0
	CCGT	0	0	0
TOTAL		627	569	322

As can be seen in Table 4.2 the overall invested units are almost half in the effective participation of foreign agents setting as compared to the other settings. This significantly lowers the expansion costs of the system which are shown in Table 4.3.

Table 4.3. Expansion costs for each area

	Uncoordinated without interconnection [k€]	Uncoordinated with interconnection [k€]	Effective participation of foreign agents [k€]
Area 1	7.077.200	40.966.100	43.824.200
Area 2	78.257.500	36.474.800	0

Even though area 1 sees its expansion costs increased, the overall cost of the system sees an important decrease.

In Table 4.4 the net exports from area 1 to area 2 are shown. In the setting with effective cross border participation of foreign agents, area 1 is on average exporting almost 3 GW to area 2. Whereas in the base-case and in the uncoordinated setting with interconnection area 1 is on average importing from area 2.

Table 4.4. Net export of power from area 1 to area 2

Base-case	Uncoordinated without interconnection	Uncoordinated with interconnection	Effective participation of foreign agents
-44 MW	0 MW	-44 MW	2637 MW

In Table 4.5 a sensibility analysis of the expansion unit’s allocation among areas to the capacity of the interconnection line is assessed. When the capacity of the interconnection line is reduced, units start to be installed in area 2 instead of area 1, as area 2 cannot benefit so much of the wind energy produced in the neighboring country. When the capacity is only 1 GW all units are installed in area 2, as this must cover its own energy not served, which is more demanding than in area 1. In this case is area 1 the one which imports power from area 2.

Table 4.5. Expansion units and EENS sensibility to interconnection capacity in effective participation setting

	A1 Wind Units	A2 Wind Units	EENS1 [MW/year]	EENS2 [MW/year]
5 GW	322	0	119.356	433.900
3 GW	212	125	143.861	433.899
1 GW	0	417	75.583	433.900

An important indicator of the system's efficiency is the overall costs in each area. The system costs include:

- Expansion costs corresponding to the costs needed to expand the generation of each area to assure the desired level of EENS or installed renewable capacity. Already shown in Table 4.3.
- Operation costs, which result from the operation of the generation plants in each area.
- Energy not served costs; it is the cost of the demand not met, which for this study has a value of 180 €/MWh.

Table 4.6 shows the overall cost for each setting. As can be seen, the most significant costs, and the ones who are more sensitive to the setting are the expansion costs. Operation costs stay almost the same for all settings and power not served costs see an important reduction when compared to the base-case setting as the EENS target is set at 2% of the initial amount.

The total cost for the base case is the lowest as no expansion is considered, however this setting is not acceptable as the amount of EENS in both areas is too high. The total cost from the last three settings is lowest for the CRM planning with effective cross-border participation of foreign agents setting, as the overall expansion costs are much lower.

Table 4.6. Overall costs results

		Base-case [k€]	**Uncoordinated without interconnection [k€]**	**Uncoordinated with interconnection [k€]**	**Effective participation of foreign agents [k€]**
Total cost (a1+a2)		24.756.000	103.658.100	96.355.662	63.484.097
Operation Costs	Area 1	7.704.085	7.782.931	6.982.480	7.722.473
	Area 2	11.838.217	10.439.891	11.833.995	11.837.838
Expansion Costs	Area 1	0	7.077.200	40.966.100	43.824.200
	Area 2	0	78.257.500	36.474.800	0
PNS cost	Area 1	1.309.020	22.566	26.155	21.484
	Area 2	3.905.155	78.011	72.132	78.102
Total Cost	Area 1	9.013.105	14.882.697	47.974.735	51.568.157
	Area 2	15.743.426	88.775.403	48.380.927	11.915.940

Another very important metric for comparison is the price in each area. This will affect how much the demand must pay for electricity, but it will also impact the benefits perceived by technologies.

Table 4.7 shows the results on average prices obtained in each setting. This table shows that the price of each area varies a lot with the setting.

Table 4.7. Average electricity prices in each area results

	Base-case [€/MWh]	**Uncoordinated without interconnection [€/MWh]**	**Uncoordinated with interconnection [€/MWh]**	**Effective participation of foreign agents [€/MWh]**
Area 1	169	192	31	166
Area 2	169	51	160	166

For the generation point of view their most relevant metric is the benefits each technology earns. This metric is closely related to the price in each area. As it can be seen, the prices of both areas are higher in the capacity mechanism planning with effective participation setting, this can attract investors in renewable energy technologies which can help achieve more ambitious EENS targets.

Another important metric to consider when evaluating the resulting efficiency of the settings is the congestion rents earned by the TSO, or by the TSOs, of the system.

Table 4.8. Congestion rents results

	Uncoordinated with interconnection [€]	**Effective participation [€]**
Congestion rents	8.370.000	3.078.000

As can be seen in Table 4.8 congestion rents are reduced by more than a half in the planning with effective participation of foreign agents setting with respect to the uncoordinated planning setting. This is mainly due to the reduction in price differences between areas, in the uncoordinated setting the difference in prices was 130-140€/MWh and in the effective participation setting it is 0€/MWh, as the prices in both areas are the same. In this study at least, the TSOs of each area would not benefit from a capacity mechanism planning with effective participation of foreign agents, as their benefits would be highly reduced.

4.1. Discussion on the results

Through the evaluation of the results, it can be stated that the planning of capacity remuneration mechanisms allowing for effective participation of foreign agents results in a less costly and more efficient allocation of expansion investment for the system.

The costs are significantly reduced from 103.658.100 k€ in the uncoordinated setting without considering the interconnection to 63.484.097 k€ in the setting of capacity mechanism planning with effective cross-border participation of foreign agents. This cost reduction is mainly due to the optimized allocation of expansion units and power exchanges between the areas.

When analyzing the investment in expansion technologies, wind in this case, there is a notable displacement of units allocated in area 2 to area 1 in the setting of effective cross-border participation. This shift is justified as wind is more efficient in area 1 than in area 2. Installing a wind unit in area 1 produces more power than installing one in area 2, resulting in improved overall system efficiency. If the interconnection capacity is high enough to transmit the energy generated in area 1 to area 2, the units will be installed in area 1. However, if the interconnection capacity is limited, units are displaced to area 2 to ensure it meets its more demanding EENS target, while area 1 can import enough energy from area 2 to meet its own EENS target.

Finally, regarding the congestion rents of the system, they are significantly reduced in more than a half in the CRM planning with effective cross-border participation setting. In this case, it may be beneficial for the overall system but not for the TSOs, as they will see their benefits reduced. However, this conclusion may not be applicable to all cases and may vary depending on the circumstances.

Chapter 5: Conclusions

This Master's Thesis has assessed the efficiency-gains and benefits derived from a national CRM planning with cross-border effective participation of foreign agents compared to an uncoordinated approach. The study focused on a two-area model over a one-year time horizon.

By evaluating the results, it can be concluded that the participation of foreign agents in national CRMs leads to a less costly and more efficient expansion investment for the overall system, compared to the uncoordinated approach when the stylized study case is analyzed. The cost reduction is mainly due to the allocation of expansion units and power exchanges between the areas.

It has been highlighted the critical role of the interconnection capacity in facilitating effective cross-border participation of foreign agents in CRMs. Ignoring this aspect when planning a CRMs could result in a costly and inefficient plan. Moreover, prices in both areas and congestion rents are highly sensitive to the setting studied.

In this context, it is critical for policymakers and planners to consider the cross-border participation of foreign agents when designing CRMs. A coordinated minimum-cost expansion and dispatch model enables the identification of optimal investment solutions that internalize the power flow behavior through the interconnection line between the areas.

In this master thesis the time horizon selected was one year for computational reasons. However, capacity remuneration mechanisms are typically planned for a period of around ten years. Future research could assess whether the benefits of cross-border effective participation of agents in CRMs planning are increased when considering larger time horizons.

Furthermore, it would be interesting to assess the model's sensibility to different demand peak positions in one area relative to the other. Addionally, for future research could be interesting to carry out the study of this Master's Thesis developing a more realistic and comprehensive test system that incorporates different reliability metrics such as reserve margin or LOLE.

Chapter 6: Bibliography

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Annex I: Figures of each area's characteristics

Wind

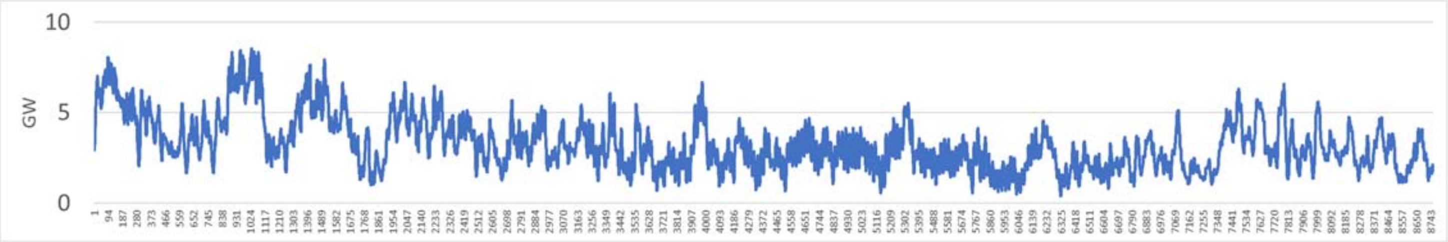

Figure I.1. Yearly wind resource distribution area 1

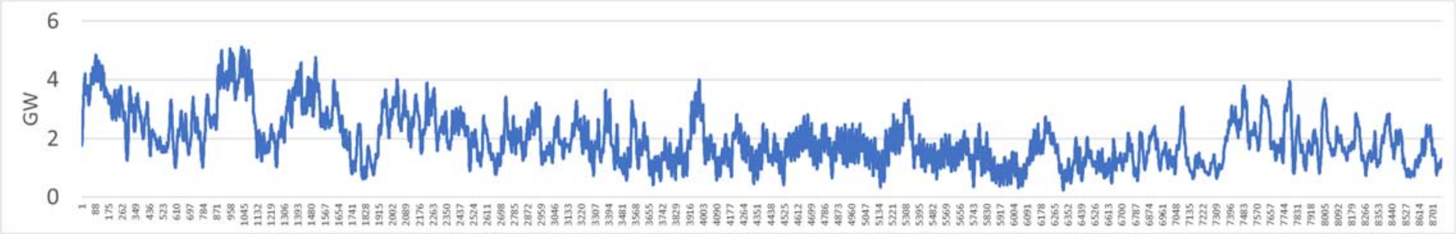

Figure I.2. Yearly wind resource distribution area 2

Solar

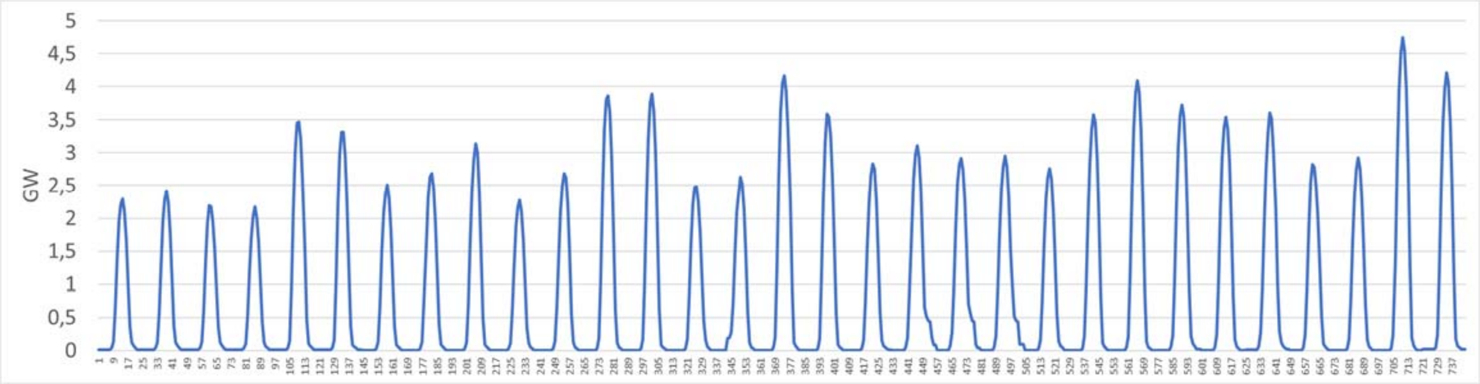

Figure I.1. Solar production January area 1

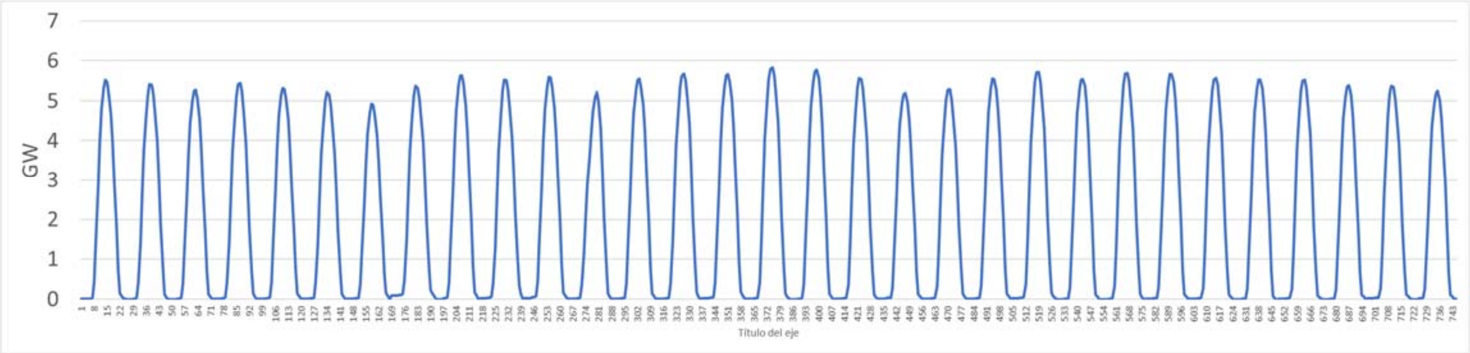

Figure I.3. Solar production July area 1

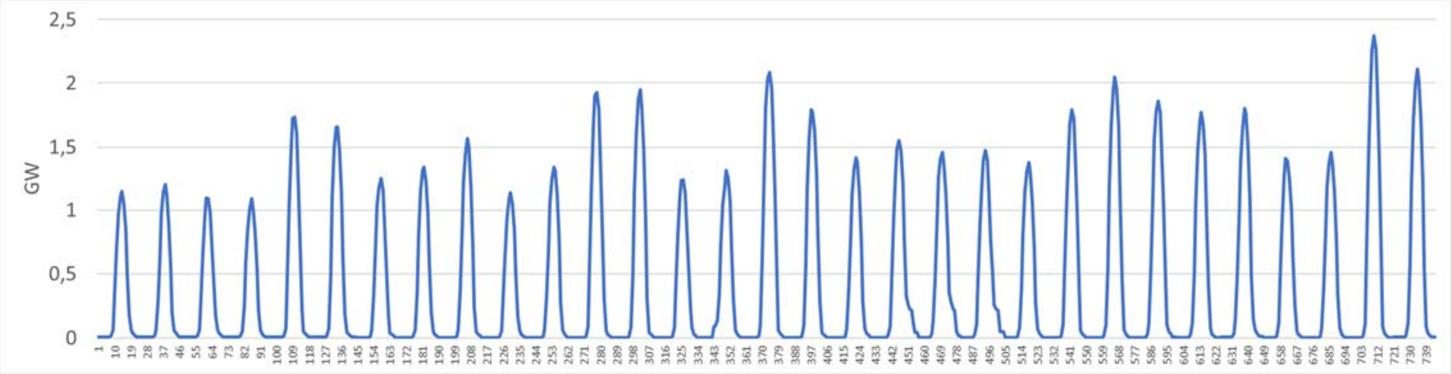

Figure I.2. Solar production January area 2

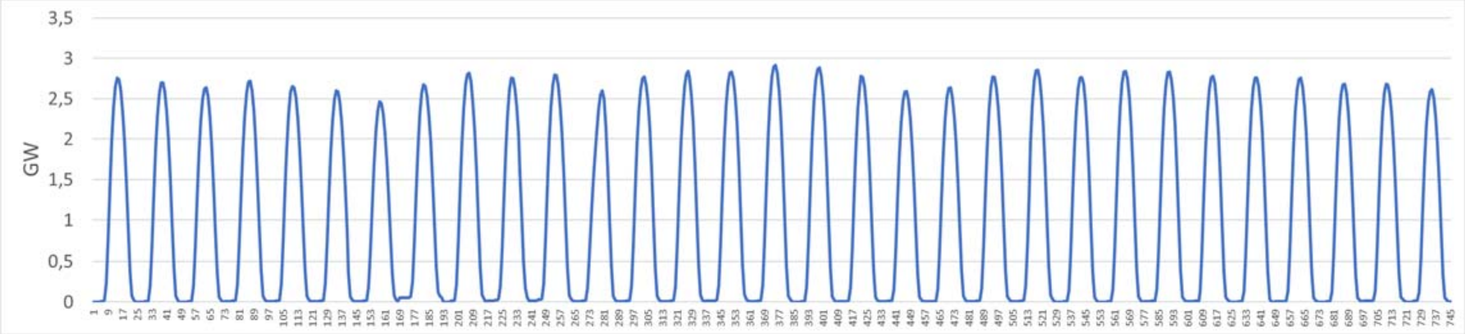

Figure I.4. Solar production July area 2

Demand

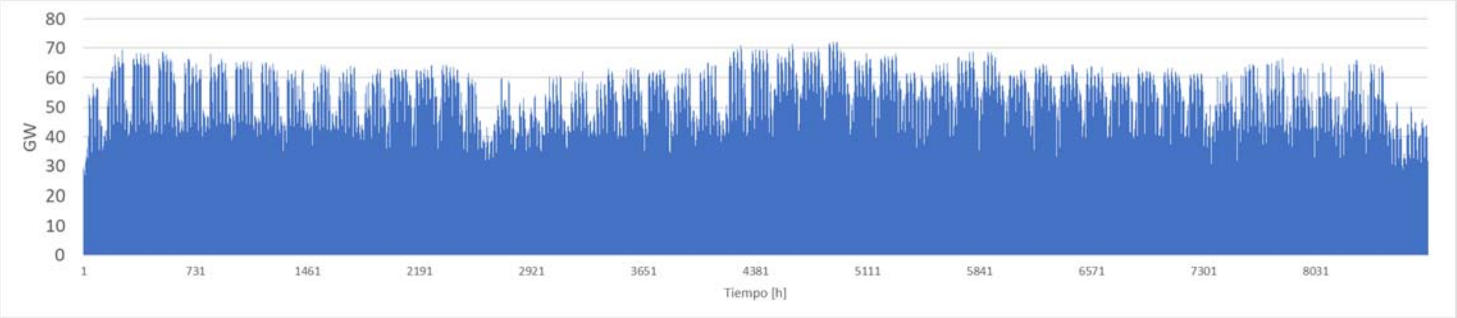

Figure I.5. Demand curve area 1

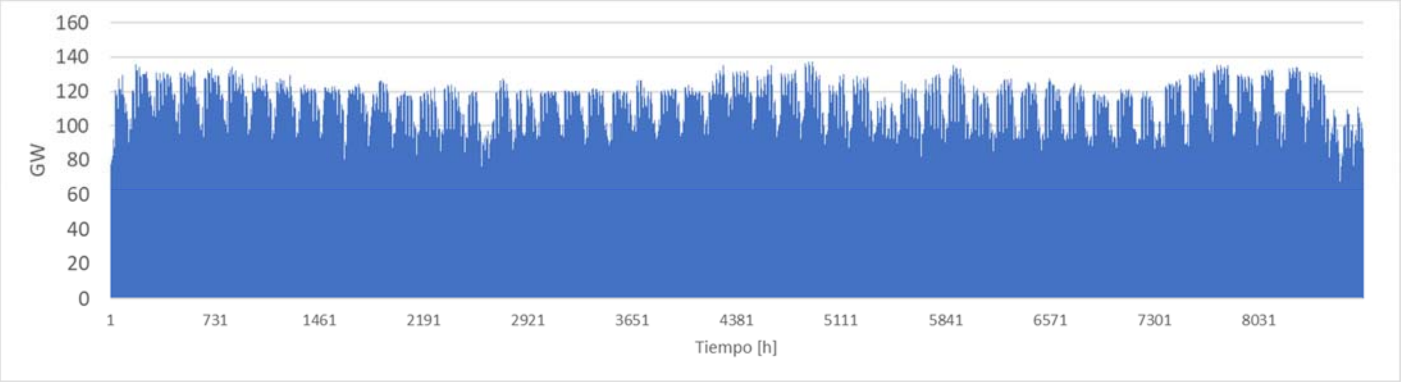

Figure I.6. Demand curve area 2