Cross-Border Participation in Capacity Mechanisms

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MASTER THESIS

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by

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Summary

To keep the generation adequacy of the power system up to standards, more and more countries in Europe are setting up capacity mechanisms. In a capacity mechanism power generation units receive payments for having their capacity available when this is needed (during moments of electrical supply shortage). These payments are received on top of payments that could be received from the energy markets or ancillary service markets [4]. This gives incentives to generation units to be available when needed and create a better investment climate in generation capacity. In this way, these capacity mechanisms can increase the security of supply. In the past, countries in Europe could implement such a capacity mechanisms locally, only local capacity providers (e.g. generation units) were allowed to participate. But the European Commission has developed new regulations which state that it is allowed for capacity providers to participate in cross-border capacity mechanisms. In this way capacity providers can receive additional payments from participating in foreign capacity mechanisms. But this raises questions, because the contribution (capacity value) of a capacity providers is thought to be dependent on its location.

This thesis analyzes what the effect of the new EU regulations regarding cross-border participation is on the payments resulting from capacity mechanisms. To answer this, the relevant EU wide regulations are analyzed and combined with the regulations of the capacity mechanism as implemented in Great Britain (at the time of writing), to find a likely implementation of a capacity mechanism in which cross-border participation is allowed.

A generation adequacy model was built and combined with the likely implementation of a capacity mechanism to analyze what the expected payments from the capacity mechanism will be to local and cross-border capacity providers. This was done to analyze how attractive it is for capacity providers to participate in two capacity mechanisms.

The generation adequacy model that is used consists of two areas, these areas represent Great Britain and France. For the model the same input data was used as in [38]. A Monte Carlo sampling method was used to analyze when payments are due.

It was found that with the implementation of the new regulations regarding cross-border participation in capacity mechanisms it is very attractive for capacity providers to be participating in two capacity mechanisms. But EU regulations set a limit on the amount of capacity that is allowed to participate in a cross-border capacity mechanism. Capacity providers have to compete with other capacity providers in a market based manner to be allocated to participate in a cross-border capacity mechanism. This will likely lead to a break even point where participating in two capacity mechanisms generates an equal income as participating in just a local capacity mechanism.

To analyze how much generation units contribute to the security of supply of a cross-border capacity mechanism, the two area adequacy model was used. An analytical method was used to calculate the capacity value of the generation units.

It was found that generation units can contribute to the security of supply of a cross-border area, although it does support the area it is located in more than the cross-border area. When the interconnection between the areas has a larger capacity, the effect of a generation unit to the cross-border area becomes larger.

It was concluded by implementing the new regulations in the model in this thesis, that the capacity mechanisms do not give financial incentives to invest in generation capacity for the security of supply of a cross-border area. This might lead to sub-optimal investments, because generation units can contribute to the security of supply of a cross-border area.

Preface

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1 Introduction

1.1. Background Information

The power system in many countries in Europe is becoming more dependent on renewable generation sources. The intermittent nature of these sources has raised concerns regarding the security of supply. To avoid supply shortages during periods with low wind power production and peak demand, a number of counties in Europe have set up local capacity mechanisms. A capacity mechanism is a financial system in which electricity generation units can receive payments for having their generation capacity available for the power system when this is needed. These payments are received on top of the income the generation units receive from the energy or ancillary service markets [4]. This gives incentives to generation units to be available when needed for the power system, increase the investment climate for new generation units and increases the security of supply. These capacity mechanisms are (at the time of writing) still implemented nationally: Generation units can participate in the national capacity mechanism of the country they are located in (if the country has a capacity mechanism). Power systems of individual countries in Europe are becoming more and more interconnected and the target of the European Union is to have at least a 15% import capacity over installed capacity by 2030 [13]. The increased security that is gained form deploying a capacity mechanism does affect the security of supply of neighboring countries and is expected to be distorting to market signals in surrounding markets [15]. The European Commission has decided to allow generation units to participate in cross-border capacity mechanisms, to reduce the distorting market signals to neighboring markets, such that generation units can trade their capacity product on cross-border capacity mechanisms. But this raises questions, because the value of a generation unit to the security of supply of a cross-border system is a complex matter, in the sense that it is dependent on many factors, such as the interconnection availability and the extent in which the capacity is utilized locally during shortage of supply [38]. Therefore it is expected that a generation unit delivers a different contribution to the security of supply of a system, whether it is installed locally or cross-border.

The trading of capacity is associated with large financial interest and because of its influence on the security of supply it is also associated with large social interest. The new regulations are expected to affect the financial flows of the capacity mechanisms. In certain capacity mechanism that were implemented in European countries, the interconnections between countries were allowed to participate in the capacity mechanism and receive revenue. This is expected to change, since in the new regulations foreign generators can directly participate in capacity mechanisms.

1.2. Problem statement & Research questions

As described in the section above the new regulations regarding cross-border participation in capacity mechanisms raise questions because of the complexity of the traded products. Also these changes in regulations are expected to change the money flows. This thesis is aimed to asses the effects and fairness of money flows resulting from the new regulations regarding cross-border participation.

The main research question of this thesis is:

What is the effect of the new EU regulations regarding cross-border participation on the payments resulting from capacity mechanisms?

To answer the main research question, the following sub-questions are formulated:

- What is a possible and likely way of implementing a capacity mechanism within these new regulations?
- What is a good model of a cross-border capacity mechanism, to analyze the financial and technical impacts? (it should be simple but not too simple)
- What will the resulting allocation of capacity payments be and how will this likely affect investments in generation capacity?

1.3. Report Outline

The structure of the report is as follows: Chapter 2 gives an overview of the shortcomings that energy only markets can have. It explains why capacity mechanisms are implemented and why new regulations regarding cross-border participation in capacity mechanisms were developed. In chapter 3 the new regulations regarding cross-border participation in capacity mechanisms are analyzed. First the general decisions made by the European parliament are analyzed and then the technical specifications by the European Union Agency for the Cooperation of Energy Regulators (ACER). At last the capacity mechanism regulations as implemented in Great Britain are analyzed. Then in chapter 4 the methods used in the thesis are described. At first relevant literature is presented, then the model is described that is used throughout the thesis. In chapter 5 it is explained how the models are used to find what the allocation of capacity is of generation units to local and cross-border areas. In chapter 6 it is analyzed what the resulting payments are from participating in cross-border capacity mechanisms and how attractive it is to be participating in multiple capacity mechanisms. In chapter 7 it is analyzed how suitable the method for calculating maximum entry capacity is as suggested by ACER. Chapter 8 draws the conclusion of the research and answers the main question and sub-questions.

2

Cross-Border Participation in Capacity Mechanisms

This chapter explains the functioning of energy markets, the functioning of capacity mechanisms, what the flaws can be for these markets and why cross-border participation in capacity mechanisms is required.

2.1. Generation Adequacy

For a power system it is important that all demand can be supplied by electricity producers at all times. But there is always a probability that not all loads can be supplied. This is due to the uncertainty of renewable production, demand and availability of conventional power plants. In systems with a significant portion of photo-voltaic and wind turbines installed a shortage of supply can occur during moments of low solar and wind production and high demand. But also conventional power plant do sometimes need maintenance, or they can have unexpected technical difficulties, because of this the power plants sometimes are able to produce only a portion of their rated power or no power at all.

If not all demand can be supplied with power without taking special measures, than there is a scarcity of supply. Periods during which not all demand can be supplied are called scarcity periods. During these periods the energy not served (ENS) is positive. The ENS can be measured or it can be estimated [35]. A scarcity period does not necessarily mean that there is a black out. In order to avoid a blackout, transmission system operators (TSOs) can reduce power to the demand by reducing the voltage up to a certain extent (brownout). For the loss of load and ENS there is no distinction between blackouts or brownouts. [1]

For the power system there is always the risk that a power producing unit suddenly fails. To cover this sudden lack of power and to keep the system stable, the system requires operating reserve. These consist of spinning and non-spinning reserve. The spinning reserve are generators that are connected to the power system, but do not produce the full power that they are capable of. The spinning reserve is required to be always at least the capacity of the largest generation unit that is producing. [44]. The operating reserve that is required for the system is not counted as available production capacity, since these have to remain assignable for when a generator fails, even when there is already a scarcity situation. This means the TSOs will start to disconnect customers before using the operating reserve to supply demand.

For the generation adequacy assessment the transmission systems ability to transport power is often not assessed, the system is seen as a copper plate in which power can move freely. But when multiple areas are analyzed which are electrical weakly interconnected, it might be necessary to model the interconnection with a finite transport capacity. [2].

2.2. Flaws in an energy only market.

For a high security of electricity supply it is important the generation adequacy is sufficient. For this it is required that enough generation or storage capacity is installed in the power system. But because in

Europe the electricity markets are liberalized [28], the amount of capacity that is installed in the system is left up to private investors. To keep the security of supply high it is important to have an attractive investment climate for investors.
The income for generation units was historically generated by an energy only market. On the electrical energy markets producers of electricity place bids for energy they sell and consumers place bids for energy they buy. In this way a market clearing price is established, for all bids lower than this clearing price energy is sold at the clearing price. The generation units that sold their energy receive revenue from the energy market. On peak moments when a lot of electricity is required, the price will become very high and almost all generators in the system will start producing. If this market operates well, the peak prices of electricity should rise to the value of lost load. The value of lost load is the price estimated that electricity consumers are willing to pay to prevent a power interruption [27]. This should generate enough revenue during these moments for generators to cover their fixed cost. And should give an incentive to keep enough generator capacity available to meet the security of supply standards [19].
There are several reasons why the energy only market might not always function well enough. First, due to stricter emission regulation conventional power plants are being closed and more renewable energy sources are being installed in recent years. Conventional power plants which burn coal, oil or gas can normally be controlled to produce power when this is required. Renewable energy sources like wind turbines and photo voltaic systems rely on the weather for their energy production and their production is in that way stochastic in nature. The consequence of this is that the energy generation becoming more stochastic in nature and thereby the electrical power system less controllable [16]. Renewable energy sources like solar and wind power have negligible marginal cost, because they do not require fuel to run. The effect of this is that these sources will always start producing for a positive market price. When many renewable sources are implemented in the power system, this will drive down market prices taking a way revenue from conventional sources. But these renewable sources are not controllable and therefore they do not contribute as much to the security of supply. The conventional generators will be replaced by renewable sources and this can decrease the security of supply [19] and [16].
Second, electrical energy markets can have a price cap on the market price. This is a maximum price for which the electrical energy can be sold on the market platforms. When this maximum price is set lower than the value of lost load, then the electricity price cannot reach the price that electricity consumers are willing to pay to be not interrupted from electricity supply. These price caps also reduce the revenue that electricity producers can earn from peaking energy prices. This also reduces the incentive for electricity producers to install capacity that is only required during moments with peaking energy prices [16].
Third, there is a risk involved in investing in peak units. Peak units are power plants built just to run for a few hours per year when energy prices are high. These power plants are for their income dependent on a few hours per year that energy prices spike. Even though the expected income might be sufficient to cover the cost for the unit, there is the probability that the plant does not generate sufficient income for years. This high volatility might drive away investors. [42]
Fourth, there is a delay for building new power plants. When the generation adequacy of the power system is low, this will increase peak prices on the energy market and the investment climate becomes more attractive for investors. But building a new power plant takes several years to realise. [7]. This delay for realizing power plants and uncertainty of demand growth can lead to investment cycles [43]. High electricity prices lead to more and more investments in generations capacity until many of these investments are realized and the electricity price plummets.

2.3. Capacity Mechanism

To give more financial security to investors in power generation units a capacity mechanism can be implemented [19]. In the European Union it is allowed for member states to implement a capacity mechanism on top of the energy market as a last resort to meet security of supply standards [6].

In a capacity mechanism generators can offer their capacity on a capacity market. They will receive a regular payment to keep their generator available for the electricity markets. This will create a more stable income than they would receive from the energy-only market. The payments from the capacity mechanism are received on top of the payments form the energy markets [19]. In this way a capacity mechanism will give an incentive to install more generator capacity and keep existing capacity available. The security of supply will become higher than in a system with an energy-only market. In [7] a comparison is made between the total cost of energy-only markets and an energy market combined with various types of capacity mechanisms. The total cost are the sum of the cost for electricity supply and the social cost which result from power outages. It is shown that all capacity mechanisms improved the stability of the market. This caused fewer outages and less volatile electricity prices.

There are different types of capacity mechanism. In [9] it is described that capacity mechanisms can be classified into different groups:

- **Strategic Reserve** This mechanism works alongside the energy-only market. A small portion of capacity providers is contracted by the operator to dispatch only when all other, market driven, capacity is already dispatched. In this way it does not disturb market signals. Most generators in the systems do not receive capacity payments. According to the article [7] this type of capacity mechanism was found to be equally effective at reducing outages as the capacity obligations. Although this did not reduce price volatility as much.

- **Capacity Obligation model** The volume of required capacity is determined by a central authority. The obligation to make sure this capacity is available is given to the retailers. The volume of capacity that each retailer has to buy is decided up on historic data of the load served by the retailer. According to the article [7] this type of capacity mechanism was found to have the strongest stabilizing effect on the electricity price and is equally effective at reducing outages as strategic reserve.

- **Capacity Auction** In this mechanism a central authority determines the required capacity to meet a certain security goal. The central authority organizes an auction where it buy the capacity form capacity providers. The demand set by the central authority can be elastic, by setting a sloped demand curve. this can be done to prevent large price swings when the already installed capacity is just above or below the demand goal. This type of mechanism gives a clear and transparent method to acquire system adequacy. The capacity auction type of capacity mechanism is installed in Great Britain at the time of writing, this capacity mechanism is further analyzed in chapter 3.3.

- **Reliability Options** The reliability options work similar to stock market options. It gives the consumer of electricity the option to buy electricity for a specified price. There is a central authority that sets an amount of capacity for which consumers must buy option from capacity providers. This gives a stable income for the capacity providers. The electricity market can operate like normal, but when the price of the electrical energy is higher than the strike price of the option, the option is exercised. The capacity provider has to deliver electrical energy for the strike price. The capacity providers is faced with the risk that it is unable to deliver and has to buy the energy for the spot price of the market or face a penalty for under-delivering.

- **Capacity Payment** In this mechanism each capacity provider that enters the market negotiates with the system operator for a fixed payment. Different methods of this capacity mechanism can be implemented: All capacity providers can be paid, only existing ones or only newly built capacity providers. According to [7] this type of capacity mechanisms does decrease the risk of power outages. But a disadvantage of this type of capacity mechanisms is that it is not possible to adjust payments when sufficient capacity is installed.

- **Capacity Subscription** In this model consumers can decide what amount of capacity they want to buy. They base their decision on their expected demand and the price for capacity. The consumers then buys the capacity on a capacity market. For this capacity mechanism it is required that all consumers install a load limiting device. This is essentially a controllable fuse that can be set to let a certain amount of power through at moments of supply shortage. The advantage of mechanisms is that individual consumers can indicate their preference of how much capacity they require and how much they are willing to pay for it. But this can also be a disadvantage as is requires a certain understanding from consumers.

2.4. Cross-Border Participation

Capacity mechanisms in Europe are implemented by multiple countries, including: Great Britain, France, Ireland, Spain to name a few according to [9]. At the moment of writing, these mechanisms are implemented locally: Local generation units get paid for their capacity by local consumers. But this might not necessarily be the best way to implement such a system. The power system between European member states are interconnected through interconnections. Through these, electrical power can flow from one country to another country. This is required for the coupled European energy market. But these interconnections also have a positive effect on the security of supply. For example, if one of the countries has shortage of supply (total demand is higher than the total available generation capacity). Then, if the power system of the neighboring country still has power available to share, this can be shared through the interconnection and prevent a loss of load. In this way an interconnection between power systems has a positive effect on the security of supply of both connected systems, according to [38].

In certain capacity mechanisms interconnections are allowed to participate, in others interconnections are included in the generation adequacy assessment but are not allowed to participate in the capacity mechanism [9].

The implementation of local capacity mechanisms can be distorting to the market operation of neighboring member state. This is because another effect of the interconnections between different member states is that, when one member state introduces a capacity mechanism, but its neighboring state does not, it will drive down revenue for generators during peak periods. But since the electricity network is coupled it will also drive down electricity prices in neighboring member states. The consumers of a neighboring member state will be free riding on the lower electricity price. But the generators in the neighboring member state will miss revenue from scarcity hours. This will have a negative effect on the investment climate for generators in the neighboring member states and it can make the power system more dependent on the member state which implemented the capacity mechanism [26]) and [22]. To prevent this dependency and because cross-border generators have a positive effect on the security of supply, it is suggested to allow cross-border participation on their capacity mechanism [6]. Generators from other member states are allowed to participate in a capacity mechanism, although subjected to a strict set of rules.

Another reasons for the implementation of cross-border capacity mechanisms is that the European Union has an ideology of free trade. It should be possible to trade goods and services between member states in the European Union and borders should not be limiting this trade [12].

In [25] and in [15] a financial analysis is given of a two area toy model with cross-border participation in capacity mechanisms. The model consists of auctions for both areas where capacity is sold, the capacity that is offered for a lower price than the clearing price is sold at the auction clearing price. For cross-border participation the rules are similar to the rules as proposed by the European council and ACER (as will be described later in chapter 3): There is a central entity that sets a maximum amount of capacity that can be traded through the interconnection (Maximum Entry Capacity), the capacity providers that participate in a cross-border capacity mechanism have to compete for the maximum entry capacity in a market based manner.

The model is used to analyze different scenarios:

- The two areas have both a capacity auction, but cross-border participation in capacity mechanisms is not allowed. In this scenario it is assumed that all capacity required for the system has to be bought from local capacity providers. This results in the highest cost for the consumers

- The auction of the two areas is coupled, the interconnection can be used to trade capacity from the area with the low price to the area with high price. The interconnection can change congestion rent for the price difference between the two auctions. This results in reduced cost for consumers.

The results show that the total cost for capacity for both areas becomes lower when cross-border trade is allowed.

But one rule makes this model very different from the proposed method by the EU. In this model capacity providers can only sell their capacity to one capacity mechanism at a time, whereas in the method by the EU, capacity providers could sell their capacity to multiple capacity mechanisms.

This analysis is an interesting approach, but it only uses a market model and not a probabilistic generation adequacy model for its analysis. Because of this, it cannot and does not take into account that capacity providers contribute to the security of supply in multiple areas or how much they contribute to each area. This can be seen from the first scenario, both areas have a capacity mechanism, but they are not allowed to buy capacity from the other area. Here it is assumed that if no capacity is bought from the neighboring area, it has to be bought locally, as if the interconnection does not provide any contribution when no capacity is bought from across-border. This is thought to be inaccurate, when the electric energy markets are coupled, then the interconnection is expected to be used to transfer energy form the area with the high price to the area with the low price and in this way prevent shortage of supply in both areas [38]. Because of this the amount of capacity that is required to be bought should be adjusted when the capacity markets are coupled.

3
The Regulations

To find out how a capacity mechanism can be implemented within these new EU regulations regarding cross-border participation, the applicable regulations are analyzed. At first the new EU wide regulations are analyzed and after this, the applicable regulations of the already existing capacity mechanisms of Great Britain are analyzed. Later for the model, these regulations will be combined and used to find out what the expected payments could be and how participating parties could be affected, if the capacity mechanism as in Great Britain is implemented in the areas.

The European Union wide regulation regarding cross-border participation in capacity mechanisms are developed by different regulatory organizations. This chapter describes the new regulations which are of concern for this thesis. The procedure of the EU to come to these new regulations was as follows: The EU parliament made a broad decision on how cross-border participation can be implemented and developed a set of basic rules. They then asked the European Network of Transmission System Operators for Electricity (ENTSO-E) [29] for their view on how these regulations should be specified further and how it should be technically implemented. Then the Agency for the Cooperation of Energy Regulators ACER [35] gave their view on it and made a final decision on the specifications and their technical implementation.

3.1. Regulation of the European parliament and of the council

The new decision made by the European parliament regarding cross-border participation in capacity mechanisms can be found under the official name "Regulation (EU) 2019,943 of the European Parliament and of the Council" [6]. Especially Article 26 is interesting for this thesis since it concerns the regulations regarding cross-border participation in capacity mechanisms. Here it is stated that capacity mechanisms must allow foreign capacity providers to participate on their mechanism.
Literally quoted from the [6] Article 26:

> 1. Capacity mechanisms other than strategic reserves and where technically feasible, strategic reserves shall be open to direct cross-border participation of capacity providers located in another Member State, subject to the conditions laid down in this Article.

Another important aspect is that the cross-border participation in capacity mechanisms can not influence the power flow in interconnections between member states directly. The power flow in the interconnection should reflect the outcome of the energy market. This means that if there happens to be a scarcity situation, then foreign providers which signed an agreement with the capacity mechanism have to be available for the energy market. If the scarcity situation is limited to just one member state it is expected to a have high energy price in these states. This should result in a power flow towards the member state, if the energy market functions well. What is more interesting is the power flow in the interconnection when a scarcity situation happens at multiple member states simultaneously, more on this can be found in chapter 4.2.4.

> 4. Cross-border participation in capacity mechanisms shall not change, alter or otherwise affect cross-zonal schedules or physical flows between Member States. Those schedules and

> flows shall be determined solely by the outcome of capacity allocation pursuant to Article 16.

The capacity providers are allowed to participate in multiple capacity mechanisms. This means that a capacity provider can participate in its local CM and at the same moment double sell this capacity to another CM. Although they have to make un-availability payments when they have made multiple commitments and cannot fulfill all of them. The capacity provider can for example sign a contract to a capacity mechanism that it will be available for the energy market when there happens to be a scarcity situation. It can do this for multiple capacity mechanisms. This means that if the capacity provider has double sold its capacity and now a scarcity situation happens to be in multiple areas, then it could be, that the capacity provider cannot fulfill all of these capacity commitments it has made. This results in the capacity provider having to make un-availability payments even though it can be fully available and not experience any technical difficulties.

> 5. Capacity providers shall be able to participate in more than one capacity mechanism.

> 6. Capacity providers shall be required to make non-availability payments where their capacity is not available.
>
> Where capacity providers participate in more than one capacity mechanism for the same delivery period, they shall be required to make multiple non-availability payments where they are unable to fulfill multiple commitments.

Capacity providers can participate into a foreign capacity mechanism up to a total capacity, this is the ”maximum entry capacity” which should be determined by the RCCs (regional coordination centers). The reason for this regulation is to limit the foreign capacity which can participate into the CM, for example it would not be logical if more foreign capacity is participating into the capacity mechanism than the maximum capacity of the interconnections to this member state.

> 7. For the purposes of providing a recommendation to transmission system operators, regional coordination centers established pursuant to Article 35 shall calculate on an annual basis the maximum entry capacity available for the participation of foreign capacity. That calculation shall take into account the expected availability of interconnection and the likely concurrence of system stress in the system where the mechanism is applied and the system in which the foreign capacity is located. Such a calculation shall be required for each bidding zone border.
>
> Transmission system operators shall set the maximum entry capacity available for the participation of foreign capacity based on the recommendation of the regional coordination centers on an annual basis.

There is a maximum entry capacity (MEC) which is the total foreign capacity which is allowed to participate into the CM. This MEC is determined for each electrical border of each capacity mechanism. The MEC limits the foreign capacity that is allowed to participate into the capacity mechanism. Because of this it could be possible that there is more foreign capacity which wants to participate into CM than is allowed by the ”maximum entry capacity”. According to paragraph 8 the allocation of the MEC should be done in a market-based manner. It is expected that if there would be more foreign capacity that wants to participate into a capacity mechanism than there is MEC available, then these capacity providers will have to compete for the interconnection capacity. It is expected that congestion rent is charged for these interconnections and that the capacity providers that are willing to pay the most for the MEC will be allowed to participate into the foreign capacity mechanism. This congestion rent is an income for the TSOs. This income must be shared with the two TSOs of the concerned border. But it could also be possible that no congestion rent is charged, but for example the capacity mechanisms use a different clearing process for local and cross-border capacity providers.

> 8. Member States shall ensure that the entry capacity referred to in paragraph 7 is allocated to eligible capacity providers in a transparent, non-discriminatory and market-based manner.

9. Where capacity mechanisms allow for cross-border participation in two neighboring Member States, any revenues arising through the allocation referred to in paragraph 8 shall accrue to the transmission system operators concerned and shall be shared between them in accordance with the methodology referred in point (b) of paragraph 11 of this Article or in accordance with a common methodology approved by both relevant regulatory authorities. If the neighboring Member State does not apply a capacity mechanism or applies a capacity mechanism which is not open to cross-border participation, the share of revenues shall be approved by the competent national authority of the Member State in which the capacity mechanism is implemented after having sought the opinion of the regulatory authorities of the neighboring Member States. Transmission system operators shall use such revenues for the purposes set out in Article 19(2).

3.2. ACER's decision on the implementation

3.2.1. Double selling of capacity and penalties

The the European Commission decided that double selling of capacity in multiple capacity mechanism is allowed. But the capacity provider that does this will have to make multiple non-availability payments when it cannot fulfill its commitments. The ACER has made a decision on how this should be implemented.

For the capacity providers participating in capacity mechanisms it is calculated what its "available volume" is for each time period and capacity mechanism they are committed to deliver to. The available volume is a value in MW and this is used to calculate how much the capacity provider is contributing to capacity mechanism and by that how much penalty it potentially has to pay.

To calculate the available volume to each capacity mechanism the capacity provider is participating in, it must be known what its "total available capacity" is and its commitments to each capacity mechanism for the considered time period. According to ACER, the total available capacity of the capacity provider is the capacity for which it is participating in the day-ahead and intra-day energy markets and balancing markets. The capacity provider does not necessarily have to be providing power to the system, but it should be available for the markets. It is important to note that in the situation that the capacity provider cannot participate in the market or deliver because of system operation requirements, as for example congestion management, then the capacity of the capacity provider is considered available. The total available capacity is a value with unit MW. The commitment to each capacity mechanism for the considered time period is also a value with unit MW. It is the amount of power the capacity provider has to deliver to the capacity mechanism at the considered time period according to its contract. It depends on the exact contract and implementation of the specific capacity mechanism, but when considering the Great Britain capacity mechanism as described in [18], [36] and section 3.3, this value is zero if there is no scarcity situation in Great Britain and it is the contracted capacity when there is a scarcity situation. Equation 3.1 shows the calculation for the available volume of the capacity provider to each capacity mechanism. When the capacity provider is deemed to deliver but the available volume does not meet its contracted capacity, it will have to make an un-availability payment to each capacity mechanism for which this applies. The amount of non-availability payment is dependent on the exact implementation of the capacity mechanism more information about this can be found in section 3.3.

$$avail.volume_{CM}(t) = total\ avail.capacity_{CM}(t) * \frac{avail.commitment_{CM}(t)}{\sum_{i \in CMs} avail.commitment_i(t)} \tag{3.1}$$

From equation 3.1 it can be seen that the available volume of a capacity provider is proportional to the commitment it made with the CM to the commitments it made in total.

An example of how these non-availability payments work for multiple commitments is as follows: An capacity provider signed a contract to two capacity mechanisms in two areas. In the contract the capacity provider is ordered to be available for its full capacity for the energy market in the area if there happens to be a scarcity situation. If the capacity provider cannot meet these agreements, it will have to make an un-availability payment to each area for which it cannot meet the agreement. Now the situation happens to be that both of the areas have a scarcity situation and the capacity provider is available for its full capacity. But because it now has multiple commitments it has to fulfill, its available capacity is divided and the capacity provider has to make non-availability payments even-though it is fully available for the energy market

3.2.2. Maximum Entry Capacity

The total maximum foreign capacity from each neighboring country that is allowed to participate in the capacity mechanism is called the maximum entry capacity. ACER decided on a method to calculate this maximum entry capacity.
According to ACER, the maximum entry capacity is calculated as the average expected contribution during scarcity periods. If this leads to a negative maximum entry capacity then it is set to zero.

> Calculate the maximum entry capacity as the average of the contributions to maximum entry capacity over all system stress MTUs. If the maximum entry capacity is negative, set it to zero.

This contribution must be calculated by the regional coordination centers (RCCs), these are provided with data from European resource adequacy assessment (ERAA). The RCCs performs a generation adequacy assessment on their system and neighboring systems based on Monte Carlo sampling. The results from this assessment are used estimate the scarcity periods (system stress MTUs) and the contribution to the considered area during these stress MTUs.

For the calculation of the maximum entry capacity it is required to know the contribution during all scarcity periods. The contribution is defined as the power flow from the neighboring areas to the considered area. For a two area system with one interconnection this definition is straightforward, since then the contribution is the power flow in the interconnection. But for systems with more areas and more interconnections it is not as straightforward. According to ACER the contribution is calculated bases on net position, a method for calculating power contributions in multi-area networks. It is not fully described how it works here because for this thesis the interconnection power flow gives enough information for the contribution, this is because the model has only two areas. The maximum entry capacity is calculated as the average contribution from the neighbour area during all scarcity hours, as in equation 3.2.

$$maximum\ entry\ capacity = \frac{1}{n}\sum P_{contribution}(t)\ [MW] \tag{3.2}$$

$t \in$ time unit for which the considered area has a production scarcity
n is the total number of time units for which the area has a production scarcity.

3.2.3. Interconnection revenue sharing

As described in section 3.1, the capacity providers should be allocated in a market based manner. If this generates an income than this income should be allocate be shared between the two TSOs of the considered border. The ACER did not decide on a method that must be followed to share the congestion income. It is left up to the regulatory authorities of the region to decide how the income is shared.

3.3. Capacity Mechanism as implemented in Great Britain

As seen in chapter 2.3 there are multiple ways in which a capacity mechanism can be implemented. Not all types of capacity mechanism are analyzed in this thesis. This thesis is limited to analyse the capacity auction with central buyer as in implemented in Great Britain. At the time of writing it is known that due to the UK leaving the EU, it is likely that Great Britain in not going to implement the regulations regarding cross-border participation in capacity mechanisms. But for this thesis the Great Britain rules are chosen as an example of how the ACER regulations can be implemented.

This section presents the relevant regulations of this capacity mechanisms which are of concern and in particular for the financial flows [18] and [36].

In Great Britain a capacity auction with central buyer is implemented. In this type of capacity mechanism there is a central entity that makes a generation adequacy analysis of their future system. This analysis yields a certain amount of expected capacity that is required to keep the system up to its reliability standard in the future. In the case of the Great Britain capacity mechanism the analysis is made for 4 years ahead. The central entity uses this capacity as goal to buy at the capacity auction. Figure

3.1 shows an example of such a demand curve. It must be noted that the demand curve is not an exact vertical line which would be expected for a fixed amount demand. This indicates that the demand is not exactly fixed for any price. A fixed amount of capacity demand could result in large price swings. When the supply is just short of meeting the required capacity goal a very high price for capacity would result. When there is an excess of generation capacity this would result in the price becoming virtually zero. To prevent large price swings, the demand curve has a slope. In [9] it is described how the demand curve is shaped. The reference price level is the cost of building a new capacity providing resource, called cost new entry. These cost are the annualized investment cost for building and having a capacity providing resource and not taking into account any income from energy markets. The negative sloping of the demand curve prevents price swings and also shows that there is added value by having additional generation capacity installed. Additional installed generation capacity that is more than the target, does increase the security of supply further. This is because there always exist a risk that not all demand can be supplied because many generation units are unavailable. This risk decreases by installing many generation units, but will never by zero. Because of this, the social cost of lost load decline further when adding additional generation units. This is also described in [47] and [30].

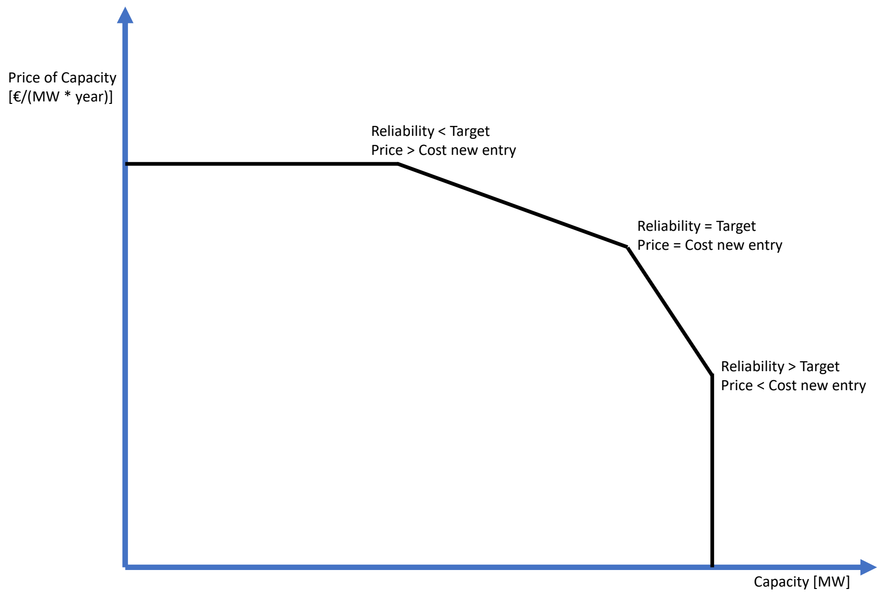

Figure 3.1: Example of a demand curve for capacity auction with a central buyer [9]

In Great Britain there are two auctions held to trade capacity for a delivery period, one for 4 years ahead and for the delivery period of 1 year ahead. This gives financially security for generation units that are new to be built. Capacity providers that are allowed to participate into these capacity mechanisms include thermal units of different fuel types, gas turbines, combined gas turbines, diesel generators, hydro power, storage units located in Great Britain and interconnection from other countries connected to the power system in Great Britain. But these regulations were expected to change with the introduction of the new regulations regarding cross-border participation in capacity mechanisms. It is assumed that also capacity providers from neighboring countries will be allowed to participate into the capacity mechanism and that the interconnection cannot participate anymore (Although we know this is likely not true because Great Britain is leaving the EU).

It is also important to note that wind turbines are not allowed to participate in the capacity mechanism. Installing additional wind turbines will likely have a very limited positive effect on the security of supply, because their production is highly correlated with other wind turbines. Wind turbines have other subsidy schemes in which they can participate.

3.3.1. De-rating

For the capacity mechanism it is important that the sold capacity is the expected average capacity that is delivered by the capacity provider. Providers have a certain unavailability because of planned outages and forced outages. If the whole installed capacity of a generation unit would be sold on the capacity mechanism, then this would overestimate the security of the system. Therefore the installed capacity of the capacity provider is multiplied with a de-rating factor. The de-rating factor is different for different types of generation technologies (coal, hydro power, etc.) and it resembles the expected availability of the generation unit. See equation 3.3

$$de\,rated\,capacity = installed\,capacity \times de\,rating\,factor \tag{3.3}$$

This calculation for the de-rated capacity can be used because it approximates the capacity value of the generation unit, this is explained in more detail in chapter 4.1.1. It must be noted that even by using this de-rated capacity there is still difference in the security that is gained form capacity that is provided from different capacity providers. For example, if all of the capacity in the system comes from just a few very large generation units. Then this would provide less security then when an equal amount of capacity would have been provided by many small generation units. This is because of difference in the resulting probability density function associate with it. But in a large system with many generators this effect is negligible and all of the de-rated capacity can be seen as equal [46].

3.3.2. Available during scarcity periods

When a capacity provider did sell its capacity in the auction for 4 years ahead, then it has 4 years to make its generation unit ready for delivering power. After this, the delivery period will start, during this period the capacity provider will have to be available for the energy market when there is a scarcity period. During a scarcity period the energy not served (ENS) is higher than 0MWh. This means that during this period not all consumers can be satisfied in their demand without taking special measures.

3.3.3. Revenue

The capacity provider receive revenue during the delivery period, the revenue is disbursed on a monthly basis. The revenue in [£] that each capacity provider receives is the product of the following three factors:

- The obligation capacity in $[MW]$, this is the capacity that the capacity provider is obligated to deliver during scarcity periods, this is at maximum its de-rated capacity.
- The auction clearing price in $[\frac{£}{MW}]$, this is the price for which the capacity was traded on the market.
- The last factor is the weighting factor, this is the portion of energy demand of the considered month form the yearly total energy demand. Because the total energy demand of the year is still unknown, historic data is used to determine the weighting factor. This is to make sure that the revenue for the capacity providers can be paid out after each month and the total yearly revenue sums up to the quantity agreed by the auction process.

$$Revenue_m = Obligation\,Capacity_y \times CM\,Clearing\,Price_y \times Weighting\,Factor_m \tag{3.4}$$

This revenue is not necessarily the payout for the considered month for the capacity provider. Additional over-delivery payouts or penalty charges could be added.

3.3.4. Penalties

When there is a scarcity period and the capacity provider is unable to be available for the markets for its contracted capacity, then it will have to make an unavailability payment. This penalty is meant as an incentive for capacity providers to be available when needed. The unavailability payment is calculated

for each scarcity period during which the capacity provider does not provide its contracted capacity. A capacity provider is providing capacity when it is delivering power to the power system, or it has unfulfilled bids on the energy markets or ancillary service market. If a capacity provider is unable to provide capacity because of congestion measures on the transmission system, then this is interpreted for the regulations as if the capacity provider is available and delivering capacity.
To check whether or not the capacity provider meets its contracted capacity, its contracted capacity in $[MW]$ is multiplied with the duration of the scarcity situation in $[h]$. This results in an energy value for which the capacity provider is expected to have been available to the markets during the period. The energy that the capacity provider has actually been delivering is subtracted from this.

$$E_{C_j} = \int_{Scarcity\ Period_j} Obligation\ Capacity_y dt \tag{3.5}$$

$$E_{D_j} = \int_{Scarcity\ Period_j} P_a(t) dt \tag{3.6}$$

$$Pen_j = max\left(0, \frac{CM\ Clearing\ Price_y \times (E_{C_j} - E_{D_j})}{24\ hours}\right) \tag{3.7}$$

The penalty during scarcity period j is calculated as in equation 3.5 to equation 3.7. The penalty is a value in [£]. In these equation E_{C_j} is the contracted energy during scarcity period j, $ObligationCapacity_y$ is the amount of capacity that the capacity provider has sold to the capacity mechanism and is obligated to deliver in year y. E_{D_i} is the energy that the capacity providers delivers to the system during scarcity period j. $P_a(t)$ is the power that the capacity provider is actually delivering to the system and the capacity for which it still has unsold bids in on the market. $CM\ Clearing\ Price_y$ is the price in $[\frac{£}{MW \times year}]$ for which the capacity provider has sold its capacity at the capacity mechanism for the considered year y.

From the equations it can be seen that when the capacity provider does not deliver any capacity during scarcity hours for for a total of 24 hours, it has to pay its full yearly revenue back as penalties.

It must be noted that when the capacity provider provides more than it contracted capacity, the penalty for that scarcity period is set to be zero. The penalty cannot be negative, if a capacity provider over-delivers during a scarcity period, it can however receive an over-delivery payment. There is also a penalty cap, the penalty that a capacity provider has to pay in a month cannot be higher than twice the revenue it receives from the capacity mechanism in that month.

3.3.5. Over Delivery Payment

It is also possible that the capacity provider receives an over delivery payment during a scarcity period. If there happens to be a scarcity period and the capacity provider is able to provide more capacity than it is obligated to, then it can receive an over delivery payment. Capacity providers can only participate up to their de-rated capacity and not up to their full capacity in a capacity mechanism, because of this a capacity provider can deliver more capacity than its obligated to when it is fully available.

The over delivery payment is calculated as in equation 3.8. This payment is a value in [£]. For the over delivery payment there is also a cap. The total amount of over delivery payments in a year to all capacity providers cannot be higher than the total amount of penalty payments to all capacity providers in that year.

$$ODel_j = max\left(0, \frac{CM\ Clearing\ Price_y \times (E_{D_j} - E_{C_j})}{24\ hours}\right) \tag{3.8}$$

3.3.6. Interconnection

At the moment of writing interconnections that connects the power system from other countries with the power system in Great Britain can participate in the capacity auction like any other capacity providers. Its de-rating is derived by a generation adequacy analysis of the system in Great Britain and continental Europe.

These models are used as follows: To the Great Britain model as much demand is added, such that the LOLE in Great Britain will be at least 3 hours per year, no matter what happens in continental

Europe. Then a detailed simulation is made of continental Europe and it is observed what the contribution of the interconnection is to prevent un-served demand in Great Britain [23].

The interconnection receives revenue for participating in the capacity mechanism. Its has to pay penalties for under delivering and it can receive over delivery payments for over delivering. The actual contribution of the interconnection is measured with power metering equipment. But with the introduction of the new regulations regarding cross-border participation in capacity mechanism this is expected to change. It is expected that the interconnection is not allowed to participate in the capacity mechanism directly anymore. This is because with the new regulations, foreign capacity providers can participate directly in a capacity mechanism.

4
Methods

The goal of this chapter is to setup a method for finding out what the allocation of capacity value and of capacity payments is for generators located in Europe which participate in local or cross-border capacity mechanisms. This can then be used to find out what the effect of the new regulations are on the willingness of generators to participate in cross-border capacity mechanisms, the effects on the income and thereby the investment climate for interconnections and the effects on the cost for the buyers of capacity in the capacity mechanisms. To achieve this goal, a two area model is built that has similar features as Great Britain, France and the interconnection between the areas. The simulations should answer what the capacity value of a generator is to local demand and to cross-border demand. Also the simulations should answer how the capacity payments as described in section 3.3 for revenue, penalties and over-delivery payments do relate for cross-border and local participation in capacity mechanisms.

4.1. Literature on generation adequacy models

At first a choice must be made at what type of simulation technique is required to achieve the goals. For finding the allocation of capacity value it is required to do a generation adequacy analysis. A generation adequacy analysis shows the probability of being not able to serve all demand due to a lack of generation capacity (see section 2.1 for more information regarding generation adequacy). The generation adequacy analysis can also be used to find the allocation of penalties payments and over-delivery payments that generators are expected to make, Since these depend on the system scarcity and the availability of the generator during scarcity, as described in chapter 2. Later in this chapter it is described in more detail how this is implemented.

4.1.1. Capacity value

The article [46] gives definitions that are useful for finding the capacity value of generators. The capacity value of a generator is its contribution to the system generation adequacy. To be able to define this, first a definition must be given for the generation adequacy. The generation adequacy is essentially the risk that not all demand can be supplied because not enough generation capacity is available to serve all load. This means the (energy not served) ENS is positive, as seen in chapter 2.1. The risk associated with the loss of load can be quantified by the loss of load probability (LOLP) and loss of load expectation (LOLE) in hours per year. This gives the probability that not all demand can be supplied and expected number of hours per year during which not all demand can be supplied respectively. The margin of the system is defined as the difference between available power production and demand. When the margin is positive there is more production available than demand, when it is negative there is more demand than production. This margin is considered as random variable in equation 4.1, where M is the margin. The random variable D described the total demand in the system. The random variable G describes the total available generation capacity, the generators in the system can either be fully available for the rated power fully unavailable. This means that the random variable G is distributed similar to $C_{max} - C_{out}$ of the capacity outage probability table (COPT) as described in [40]. Where the sum of individual independent generator random variables is calculated as the convolution of their probability mass function.

In [46] the random variable D, the demand is built from historic data. Metered data is used to construct a probability mass function of the demand.

$$M = G - D \tag{4.1}$$

If M is a random variable representing the system margin and F_M is the distribution function of the margin, the LOLP for the system can be calculated as in equation 4.2 [46].

$$LOLP = P(M \leq 0) = F_M(0) \tag{4.2}$$

This can be used to calculate a capacity value. The article gives two descriptions for the capacity value of a generator. One is the additional constant load that can be added to the system as result of the generator. The other is the additional constant power production that needs to be added to the system when the generator is removed to keep an equal system security.

If to this system additional generation capacity is added with random variable Y than the **effective load carrying capacity (ELCC)** v_Y^{ELCC} is the additional constant load that can be added to the system and keeping the same level of risk. The relation between Y and v_Y^{ELCC} can be found in equation 4.3.

$$P(M + Y - v_Y^{ELCC} \leq 0) = P(M \leq 0) = F_M(0) \tag{4.3}$$

The **equivalent firm capacity (EFC)** is the amount of additional constant power production that gives an equal risk reduction as adding an additional generator with random variable Y. This is shown in equation 4.4

$$P(M + Y \leq 0) = P(M + v_Y^{EFC} \leq 0) = F_M(-v_Y^{EFC}) \tag{4.4}$$

In [46] it is shown that when the variations in Y are small compared to the variations in M then the ELCC and EFC are practically equal. The ELCC and EFC of a generator that is modelled as a Bernoulli random variable and that is connected to a system where much more generation capacity is installed than the capacity of the considered generator, can be approximated as in equation 4.5. Here CI is the installed capacity of the generation unit and a is the availability of the generation unit. This is because the expected value of a Bernoulli random variable is equal to the probability that it is available a

$$ELCC \approx EFC \approx CI \times a \tag{4.5}$$

4.1.2. Generation adequacy of two area model

In [41] the technique for calculating the generation adequacy based on a probability function is used for a two area model with an interconnection of limited capacity in between. It is assumed that power can be shared through the interconnection when there a deficiency of local generation capacity and the neighboring area has a surplus of generation capacity. In this paper, probability functions are generated for each area that represent the total available capacity of all generators in the area given by G_{2d}. These can easily be constructed in to a joint probability function from the generation probability function of the two separate areas, by $f_{xy}(x,y) = f_x(x) \times f_y(y)$, because it is assumed that the generator random variables are independent. For the demand in the areas the joint probability function D_{2d} is generated that represents the probability of total demand in each area in relation to the probability of demand in the other area, for the calculation the demand is used as negative values. Demand and generator availability are assumed to be independent. The generation margin is defined as the excess of generation capacity minus the demand. $M_{2d} = G_{2d} - D_{2d}$ The probability function of this margin is calculated by adding the random variable of the generation to the negative random variable of the demand. This results in the probability function of the margins of both areas. The sum of probability function can be calculated by a convolution of probability density functions as described below, because generation capacity and demand are assumed to be independent. Because the areas are interconnected, the areas can interact with each other.

In [41] it is assumed that the areas will never export more power to the other system if this causes the area to have a negative or more negative margin. Figure 4.1 shows overview of the joint probability density function for the system margins. By integrating the function over the areas in which A has a negative margin. The probability is found of a loss of load in A, similar approach is taken for area B. From the figure it can be seen that when an area has a deficiency this can be solved by importing power from the neighboring area, when this does not cause the neighboring area to have a negative margin or exceed the interconnection capacity.

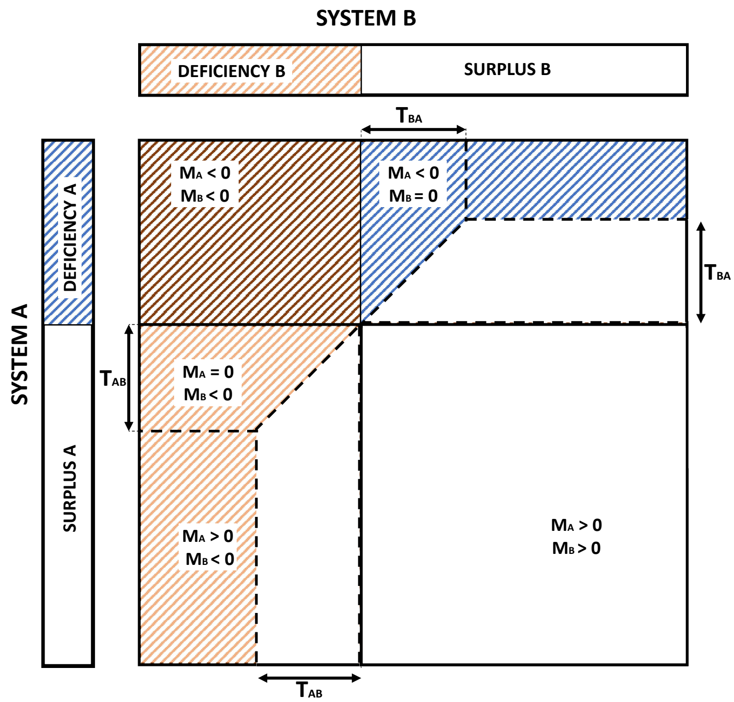

Figure 4.1: Capacity margin areas for two area system ”veto” policy [41]

4.1.3. Capacity value of two area model

In the article [38] a similar approach is used. Here it is extended further to take the wind generation into account for each area, with correlated wind generation between areas. if the areas are geographically close together, it is expected that when one area has much wind production, this can also be expected in the neighboring area. It also presents different interconnection policies for sharing deficiencies. These interconnection policies come into play when sharing power through the interconnection cannot prevent a loss of load in both areas.

- when the areas use the interconnection to only export power when this does not cause the area to have a negative margin. This is called the ”veto” policy and this is assumed in [41], the areas of the function to integrate for the LOLP of each area shown in figure 4.1.
- But it is also possible for the interconnection to share power between the areas such that the areas have a deficiency relative to the demand in the area. This is called the ”share” policy the areas to integrate for the LOLP in each area are shown in figure 4.2. Note the subtle difference when one area is assisting the other area, the assisting area can also have a negative margin when the ”share” policy is applied.

The method as described in [38] takes into account that the interconnection has a limited capacity, but also that the interconnection has a limited availability. The interconnection can be unavailable due to outages. The interconnection is modelled as separate independent channels. The availability of

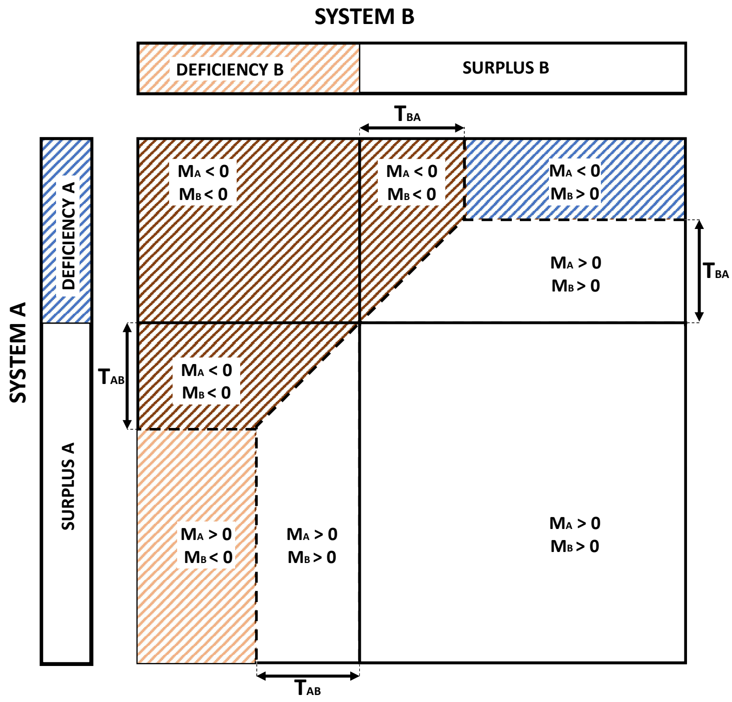

Figure 4.2: Capacity margin areas for two area system "share" policy [38]

the interconnection is taken into account by calculating the conditional probability of LOLP for having a certain number of interconnection channels available. This is multiplied with the probability of having the certain number of channels available. By the law of total probability, the sum gives the LOLP when the interconnection has different independent channels which can be unavailable. The model used in this article is a two area model based on Great Britain and France with its hinterland (this represents the other countries connected to France). Measured historic demand data of the areas is used, the wind data for Great Britain is gathered form a MERRA reanalysis and put into a wind turbine model, for France the same wind data is used but scaled according to the installed wind turbine capacity in France and its hinterland. The data and the models in used in this article are made available to use for this thesis.

4.1.4. Monte Carlo simulations for generation adequacy

In the book [2] two relevant methods are described for generation adequacy analyses. The methods in this book are based on the Monte Carlo method, as opposite to the methods above which are analytical. One is the state duration sampling method, this is a time sequential method, because the time advances. The generators are modelled to have a certain failure rate and repair rate. The generators can transfer from up to down state according and vice verca, according to these rates. The load is then also modelled as a time series. When the demand in the system is higher than the available generation capacity there is a loss of load. This is a useful method when the system is time dependent, for example when batteries are included in the model of which the state of charge depends on what has happened before or when the ramping of generation units is included.

The other method described is the state sampling method, this method is not time sequential. The model uses a Monte Carlo sampling method (explained in more detail below) to take random samples of the state in which the system could be found. The generators can for example be modelled as Bernoulli random variables: They are either on or off. The load can be modelled as a probabilistic function that represents the probability of having a certain amount of demand. To generate random samples from these probabilistic functions the book presents the inverse transform method. This method used the inverse of the distribution function of a random variable, when standard uniform distributed random samples u are put in the inverse distribution function, it generates random samples according to the distribution function x. See equation 4.6.

$$x = F^{-1}(u) \tag{4.6}$$

It also describes how correlated random variables can be generated, this is useful for multi area model. The correlation between demand of different areas and the correlation between wind production of different areas in a multi area model has a significant impact on the generation adequacy. The correlated random variables for example the wind production in each area can be generated by using the inverse transform method as in equation 4.6 with the distribution function for each area, but then using correlated standard uniform distributed random variables. These random variables can be generated by a Gaussian copula [32]. For multi area models it also gives a method for calculating the power flow in the interconnections between areas based on optimization function [2].

4.1.5. Definition of Monte Carlo simulation

A Monte Carlo simulation is a method that can be used for stochastic simulation. It is based on random sampling that is repeated for many iterations. It can be used to determine the expected value of certain system variables.

Is is a well known and often used technique for assessing reliability of power systems [20] and [40]. Also for generation adequacy assessments of power systems it is used as sampling technique [2], [39] and [17] to find the loss of load probability due to the uncertainty in generation and demand. An expected value can be calculated as in equation 4.7. In here C is the system variable that is calculated, Pr(s) the probability function, s are the states in the sample sample space Ω. But it can be challenging to calculate the expected value in this way, the probability function of all systems states can sometimes be hard or impossible to find. Therefore the Monte Carlo approach can be used to approach the expected value.

$$E[C] = \sum_{s\in\Omega} Pr(s)C(s) \tag{4.7}$$

If C is the system variables that is observed, than $r = E[C]$ is the expected value of the variable. Then when the n independent random states s_i area generated for the system. From this the simulated values $c_i = C(s_i)$ associated with the states are computed. These can be used to give an estimate of the expected value $\hat{r}$ in equation 4.8.

$$r = E[C] \approx \hat{r} = \frac{1}{n}\sum_{i=1}^{n} C(s_i) \tag{4.8}$$

[2] and [37]

By the law of large numbers as described in [8] as shown in equation 4.9, it can be expected that the larger n is (more iterations) the closer $\hat{r}$ goes to the expected value r as long as the probability distribution of the variable is finite.

$$\lim_{n\to\infty} = Pr(|\hat{r}_n - r| > \epsilon) = 0 \text{ for any } \epsilon > 0 \tag{4.9}$$

But because n will never be infinite, it should be expected that there is always an error. This error can be estimated, by relying on the central limit theorem [37] and [8]. For large n the results of the simulation are expected to converge to the normal distribution. The central limit theorem shows that the following relation exist $\hat{r}_n \sim N(E[C], \frac{\sigma_C^2}{n})$

Because of this the standard error can be calculated as in equation 4.10 in here σ_C is the estimated variance, calculated from the sampled set as in equation 4.11.

$$Standard\ error = \sqrt{\frac{\sigma_C^2}{n}} \tag{4.10}$$

$$\sigma_c = \sqrt{\frac{1}{n-1}\sum_{i=1}^{n}\left(C(s_i) - \frac{1}{n}\sum_{j=1}^{n}C(s_j)\right)^2} \tag{4.11}$$

4.1.6. Concluding

It was decided to use an analytical method for calculating the allocation of capacity value of a generator to local and cross-border capacity mechanisms. This is because it can provide exact answers and is computationally efficient. The method is similar to the method used in [38], the models and data used in this article have been made available to use for this thesis and can be used to build a two area model of Great Britain and France and its hinterlands. For finding the allocation of payments from capacity mechanism to generation units it was decided to use a Monte Carlo sampling method. This is because with this technique it is easy to add and additional generator and keep track of when it has to make payments. This technique could also be extended to a multi area model with more than two areas. For this sampling model the same data is used as for the analytical method it therefore also simulates the two area model of Great Britain and France.

4.2. Generation Adequacy model setup

This section describes the generation adequacy model used in this thesis. This model is used for the Monte Carlo sampling method that is used to find the number of hours during which the allocation of capacity payments from capacity mechanisms to generators and the same model is also used for the analytical method based on convolutions of probabilistic functions, this method is used to find the allocation of capacity value.

Because this research is done on the basis of the new EU regulations, it was decided to use a probabilistic model of a part of the European grid. The model should be relatively similar to the real grid. But the focus of the model is not on recreating the exact grid in detail, including precise power ratings for each producer and consumer and network losses. Power systems are constantly under development, new producers enter the market, producers leave and consumers can change their behaviour. Also, if these new regulations function well, they should function well in any grid configuration which is relatively similar to the real situation. For the model of the grid it was decided to make a two area model with an interconnection in between. One area has a similar setup as Great Britain [1], which is relatively small in the sense of generation capacity and consumption. The other area is France and part of its hinterlands, this is relatively large. The interconnection capacity between these two areas is limited and relatively small, it is expected that this will emphasis the difference between local and cross-border capacity value of generators. This setup is was adapted from the setup of [38].

The main output of this probabilistic model is the LOLE (loss of load expectation) this is the expected number of hours when demand is higher than available generation during the year after all system warnings and system operator balancing contracts have been exhausted, as it is described by the national grid [10]. In equation 4.12 the LOLE in hours per year is calculated, h is the number of hours in a year (8760) for a non leap year and here M is the random variable of generation margin defined as in equation 4.13. Because of the sampling method used, the results come with a certain error. The method for finding an estimate of the standard error is explained in section 4.3.5.

$$LOLE = h \times Pr(M < 0) \tag{4.12}$$

$$M = G + I + W - D \tag{4.13}$$

[1] At the start of the thesis the UK was still part of the EU and was expected to be following the regulations after exiting the EU, but during the research they have left the EU and do not necessarily follow EU regulations anymore. This is not a problem for the results or conclusions. substituting the countries in the model with any similar country in the EU should lead to similar results

M, G, I, W and D are random variables representing the margin, the generation by thermal power units, power from the interconnection, wind power and the demand respectively. In this way the LOLE is calculated for each area. In section 4.3 it is described how these random variables are created.

4.2.1. Generators

The generators in the system are modelled by their average availability and maximum capacity. The generators fall into capacity categories of 1200/600/300/150/80/20/10MW, groups of these units are constructed to represent the generation portfolio of the considered country. The Great Britain portfolio consists of 19 generator sets of 1200, 2x600, 2x300, 150, 80, 2x20, 3x10 in MW. The France portfolio consists of 45 generator sets of 2x1200, 600, 300, 150, 80, 2x20, 3x10 in MW. In France relatively many 1200MW units are installed because of its higher dependency on nuclear units, which result in larger fluctuations in available generation capacity.

4.2.2. Demand

The demand of the systems is modelled by using historic data of each area's demand for the year 2010 to 2014. The data shows the consumption of all consumers in the area for each hour. The power required for recharging storage was not included in the demand data and this is also not included in this model. The demand data used is the same as used in [38] and [45]. The demand for France is increased to 150% of the demand in the data, to simulate the neighboring countries of France (hinterlands). These neighboring countries are well interconnected, with large interconnection capacity. For the model it is assumed that power can flow freely through each of the two areas (Great Britain and France) and is only limited by the interconnection between the two areas. Each area has a constant load added to its demand, this is the offset. By adding this offset, the LOLE is increased. This can be used to adjust the LOLE precisely to specific value, in this case to LOLE of 3 hours per year for each area. For Great Britain this offset is 3015MW and for France 4466MW. A LOLE of 3 hours per year is a security goal of many countries in the European Union including Great Britain and France according to [31].

4.2.3. Wind Generation

To model the wind turbine power output in each of the systems a time series of the capacity factor for wind production is used. This time series was made by [33], which uses a MERRA reanalysis for generating wind speed time series. To generate the wind capacity factor it was assumed that the wind turbines have a spatially constant distribution over the area. The wind capacity data of Great Britain is used to generate random variables for both areas as described in 4.3.2. It is assumed that both areas have the same distribution for the capacity factor data. The data was generated for the period 2010 to 2014, the data is then scaled to get 13GW and 15GW installed wind generation capacity in Great Britain and France respectively. The correlation between the wind production in Great Britain and France is set to $\rho = 0.5376$, in section 4.3.2 it is described how this is used.

4.2.4. Interconnector

The interconnection between Great Britain and France is modelled as four independent channels with a combined capacity of 3GW and an availability for each channel of 0.95. Through this interconnection electrical power can be interchanged by the areas. If one of the areas has a negative generation margin, but the other area has generation capacity available, then this can be shared through the interconnection and prevent the loss of load. The interconnection in this model has 4 channels with each an availability of 0.95 and a total interconnection capacity of 3000MW.
But by introducing this interconnection the loss of load problem can result in multiple solutions in certain situations. For example, when one area has just a positive margin, but the other area has a serious negative margin. Then the interconnection can be used to share power from the area with the positive margin to the system with the negative margin, resulting is a negative margin in both areas. But it could also be possible to not share power, resulting in one area having a negative margin and one area a positive margin. To determine what the power flow in the interconnection should be in such a situation, the interconnection is set to work according to a certain policy. There are multiple policies thinkable for sharing the power when both areas experience stress event. These policies are described in [38], this thesis is limited to describing only the veto and share policy. In the veto policy, power is only exported when the areas have an excess op generation capacity. The effect of this is that interconnection can

never have a negative effect on the generation margin in the in area. According to [38] this policy would result in a lower LOLE for both areas, although it is currently not in accordance with EU regulation article 16 of [6]. This is because the power flow of the interconnection must be a result of the energy markets trades as described in [24] and [5]. The other policy is the share policy. If either of the areas has a negative margin, then power can be shared through the interconnection even when this results in a negative margin for both areas. In this policy, the power flow in the interconnection will be such that the volume of lost load in each area is proportional to the demand at that moment in that area. This policy seems to be in line with the expected power flow based on social welfare, since load shedding comes with social cost. The marginal costs of load shedding in the areas are assumed to be in proportion of the total demand in that area. We can think of this in the following way: If one area has a large volume of demand, then it also has a large volume of demand on which scarcity measures can be taken with little marginal social cost. For example, voltage reduction has lower marginal social cost than load shedding on residential consumers which has lower marginal cost than load shedding on water supply pumps, water treatment plants or other facilities where the impact of a black out is large for public health. As can be concluded from the Great Britain electrical supply emergency code [11].

A model to approximate marginal cost of load shedding is shown in [14]. This can be used to simulate the ”share policy”, in which ENs is shared according to demand in the areas. Equation 4.14 presents approximate marginal cost of load shedding. Here s_i is the volume of load shedding in area i and D_i is the volume of demand in area i. For positive α and β integrating this equation for ds_i results in the cost for load shedding in each area as in equation 4.15.

$$marginal\ cost = \alpha + \beta \frac{s_i}{D_i} \tag{4.14}$$

$$cost = \frac{\beta \Delta t}{2D_i} s_i^2 + (\alpha \Delta t) s_i \tag{4.15}$$

When this problem is minimized for cost, it results in a load shedding volume in each area proportional to the demand. This is used to calculate the power flow in the interconnection, but it has to be noted that the power flow in the interconnection can also be limited by the maximum capacity constraints of the available channels at that moment.

4.3. Monte Carlo Simulation

To find the LOLE of the two coupled systems, Monte Carlo simulation is used. The random variables of equation 4.13 are sampled and it is calculated whether or not each of the areas has a negative margin. The probability that the margin resulting from the calculating is negative is equal to the probability that the system has a loss of load. If the simulation results in a negative margin, this is counted as 8760 hours of lost of load and if the margin is positive this is counted as 0 hours lost load. This is repeated for many times (order of million repetitions) of which the average is taken, see equation 4.16, with M_i the margin random variable of area i, as defined by equation 4.13. Also the expected number of double scarcity hours per year is calculated by equation 4.17. By the law of large numbers this result should be close to the expected value, as is described by [8]. Another output of this simulation method is the number of double scarcity hours, this is the expected number of hours that there is a scarcity situation in Great Britain as well as in France.

For the calculation the random variables G, W, D in equation 4.13 are expected to be independent of each other. A quick check was done on the input data for the wind and demand for Great Britain, the correlation coefficient was found to be -0.0495, by pearman’s method. This means the wind and demand random variables should be weakly dependent (could be caused by distributed wind generation contributing as negative demand [46]). For this toy model it was accepted that these random variables are modelled as independent random variables. The wind random variable in Great Britain and wind random variable in France are modelled as correlated random variables and the demand random variable in Great Britain and the demand random variable in France are also modelled as correlated random variables. All Monte Carlo simulation in this thesis are run for 876M iterations

$$\hat{LOLE}_i = \frac{1}{n}\sum_{j=1}^{n} h \times \frac{-sgn(M_{ij}) + 1}{2} \tag{4.16}$$

$$\hat{LOLE}_d = \frac{1}{n}\sum_{j=1}^{n} h \times \frac{-sgn\left(max\left(M_{GB,j}, M_{FR,j}\right) + 1\right)}{2} \tag{4.17}$$

To analyze the financial flows to a generation unit that result from participating in capacity mechanisms, it is also important to know when a generation unit cannot deliver when there is a scarcity situation. When there is a scarcity situation and the generation unit cannot deliver at that moment, it will have to pay a penalty. When there is a scarcity situation and the generation unit can deliver more power then it is obligated to is can receive an over-delivery payment as seen in chapter 3.3. To analyze when these payments are due, an additional generation unit can be added to the model. When this generation unit is unavailable and there is a scarcity situation, then this is also counted in the simulation, to give an expected number of hours for when this happens. The additional generation unit is modelled as Bernoulli random variable. Its capacity can be changed and the effective load carrying capacity is calculated for the area it is located in and is added as constant load to the area. This is done to prevent the additional generation unit from changing the LOLE of the areas. The margin used for this model is given in equation 4.18, here RV_{SG} is the random variable of the separate generation unit, a is its availability and CI is its installed capacity of the separate generator, this last term is its EFCC calculated as the expected value of the Bernoulli random variable. The expected number of hours that there is a scarcity situation in an area and there the separate generation unit is unable to deliver is given by SG_i in equation 4.19, here S is the separate generation unit that is modelled as Bernoulli random variable. $\hat{SG}_i$ can be estimated by the Monte Carlo simulation as in equation 4.20.

$$M_i = G + I + W - D + RV_{SG} - a \times CI \tag{4.18}$$

$$SG_i = h \times Pr\left(M_i < 0 \cap S = 0\right) \tag{4.19}$$

$$\hat{SG}_i = \sum_{j=1}^{n} h \times \frac{-sign\left(max\left(M_{ij}, \left(S_j - \frac{1}{2}\right)\right) + 1\right)}{2} \tag{4.20}$$

4.3.1. Generation random variable

Generators are sampled as Bernoulli random variables, each generator in the system can either be on or off with a certain availability. In the on state, it is able to produce its full rated capacity and in the off state it not able to produce any power. All generators in each area are sampled as independent random variables. The sum of all of these generator random variables is the total generator capacity that is available in that area. To sample this, it would be possible to sample each individual generator separately and than sum their outputs. But for large systems with many generators, this would be relatively computational intense and not time efficient. Especially when this random variable is used for Monte Carlo sampling where this calculation has to be repeated. To make it more computational efficient some pre-calculations are performed. The Bernoulli random variables of the individual independent generators are convoluted to make a single probability mass function. This function describes all possible capacity outputs of all generators with this combination of generators in the system and assigns a probability to each outcome. From this probability mass function the cumulative distribution function is calculated. In the computer this cumulative distribution function is saved as an array, the items of the array are in increasing order and represent the probability of the the generation capacity being less or equal to the items index multiplied by a certain step size. This array can be used to look up what the probability is of the of having a generation capacity which is less or equal to the arrays index multiplied by a step size. But for generating a random variable which represents the total generation capacity it is more useful to use the inverse of this cumulative distribution function. This is done by letting the computer generate a uniform distributed random variable between 0 and 1 and then do a sorted lookup on the array to find the item which is closest to this value. Now the index of the array is multiplied with the step size to give the outcome of the total generation random variable. This is shown by equation 4.21, where F_{G1}^{-1} is the inverse cumulative distribution for area 1 (GB) and U(0,1) is the uniform distribution between 0 and 1. The sorted look up is computational relatively efficient and the pre-calculations require negligible time when a Monte Carlo simulation is performed for many interactions. The generation capacity in each of the two areas is assumed to be independent, therefore the random variables for both areas can be created independent from each other. This technique is called the inverse transform method and is described in [2].

$$Generation\ RV = F_{G1}^{-1}(U(0,1)) \tag{4.21}$$

4.3.2. Wind random variable

The wind random variable is a little harder to model in comparison to the generation random variable, this is because production of wind turbines in two areas is correlated when these areas are geographically close to each other. If there is a strong wind blowing in one area, it is more likely for the other area to have also a strong wind at the same time. Therefore these wind random variables of both areas should also be correlated with each other. To make these random variables historic wind data is used. This consists of the time series of wind data as described in section 4.2.3, which is run through a wind turbine model to give the power output. This data is then normalized to make 1 represent the highest possible wind turbine output and 0 no power at all. This time series is used as input for the wind probability in the model for both areas. By multiplying this data with the installed wind turbine capacity of each areas wind power time series of each area are made. From this a histogram is made for each area; the histogram describes the probability of a certain wind power output occurring. The bin width of the histogram is chosen to be 10MW, this is similar to the approach taken in [38]. This histogram describes how often a certain wind output power occurs in the 5-year time series data, by assuming these 5 years are representative for the wind profile, a probability mass function can be made of the histogram. The number of hours belonging to each wind power bin are divided by the total number of hour of the time series. This described the probability of each wind power output occurring for an arbitrary hour, this is shown in figure 4.3.

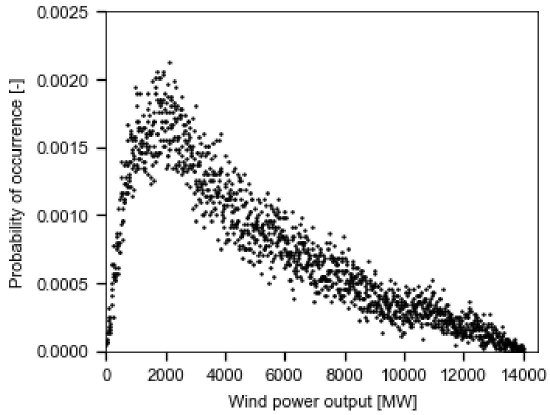

Figure 4.3: PMF for wind power output of arbitrary hour for France

The probability mass function is converted into a cumulative distribution function and by plugging in standard uniform distributed random variables in its inverse cumulative distribution function an output power for the wind can be found. This is similar to how it is done for the generator random variables in section 4.3.1, but as said before when a wind random variable has to be drawn for each area, it is important these random variables are correlated. To do this a Gaussian copula technique is used to generate standard uniform distributed random variables which are correlated with each other, as described in [3] and [38]. Two standard normal random variables are generated as in equation 4.22 and 4.23, then equation 4.24 is used to make a third standard normal random variable which has a correlation of ρ with X_1. The two correlated normal distributed random variables are converted to correlated uniform distributed random variables by using 4.25 and 4.26. The error function of SciPy library for Python is used to solve the integral efficiently. Now the wind power output of each area is found by plugging in the correlated uniform distributed random variables in the inverse cumulative functions for wind power output in a similar way as in section 4.3.1. These inverse cumulative function for wind power in area one and area two are noted by F_{W1}^{-1} and F_{W2}^{-1} respectively.

$$x_1 \leftarrow N(0,1) \tag{4.22}$$

$$x_2 \leftarrow N(0,1) \tag{4.23}$$

$$x_3 = x_1 + \sqrt{1-\rho^2}x_2 \tag{4.24}$$

$$u_1 = \frac{1}{2} + \frac{1}{\sqrt{\pi}}\int_0^{x_1} e^{-t^2}dt \tag{4.25}$$

$$u_2 = \frac{1}{2} + \frac{1}{\sqrt{\pi}}\int_0^{x_3} e^{-t^2}dt \tag{4.26}$$

$$Wind\ power\ area\ 1 = F_{W1}^{-1}(u_1) \tag{4.27}$$

$$Wind\ power\ area\ 2 = F_{W2}^{-1}(u_2) \tag{4.28}$$

4.3.3. Demand random variable

The demand random variables are generated by using historic data from the areas. The data is provided in long arrays where each items contains the power demand of an hour. The index of the item is the corresponding hour, starting from hour 0 to hour 43824 for 5 years of data. Now a random number is generated ranging from 0 to 43824 and the corresponding demand is looked up from the array for each area, care is taken for the time difference in areas. This results in two random variables being generated for the correlated demand of both areas.

4.3.4. Interconnection flow random variable

The interconnection power flow is a random variable and it is partly dependent on the generation, wind and demand random variables of both areas. The power flow in the interconnection is only calculated if any of the areas has a negative margin with an interconnection power flow of 0MW. If both areas have already a positive margin when without considering any power from the interconnection, then it is assumed that the interconnection does not cause any area to have a negative margin. But when any of the areas has a negative margin, then the interconnection power flow is specified further. This could be done by minimizing equation 4.15 for cost and then finding the load shedding in each area and from this calculating the required power flow in the interconnection. But to make the calculations more time efficient the non-linear optimization is circumvented by a linear calculation. Equation 4.29 show how the interconnection power flow is calculated in here: N_i is the margin of each area without the interconnection power flow, so $N_i = G_i + W_i - D_i$. The theory behind equation 4.29 is as follows, first it is calculated what portion the demand in France is of the total demand. Then this is multiplied with the total margin of both systems, this results in total margin in France which is expected when the margin in each area is proportional to the demand in each area. Then the margin N (without interconnection power) of France is extracted form it to get the power flow of the interconnection.

$$I_{GB\ to\ FR} = \frac{D_{FR}(N_{GB} + N_{FR})}{D_{GB} + D_{FR}} - N_{FR} \tag{4.29}$$

This shows the theoretical power flow in the interconnection, but the maximum interconnection power flow is limited. The power flow cannot exceed the total capacity of the available channels, if is calculated to be more, than it is set to the maximum power flow of the interconnection. To check what the maximum power flow is, each of the channels is modelled as an independent Bernoulli random variable. The capacity of all available channels is summed to get to the total available capacity. See equation 4.31, here n is the number of channels and $IC\ capacity$ is the total rated capacity of the interconnection. Here x_4 has a binomial distribution as shown in 4.30

$$x_4 \leftarrow Bin(n, channel\ availability) \quad (4.30)$$

$$Max\ interconnection\ power\ flow = \frac{IC\ capacity}{n} \times x_4 \quad (4.31)$$

4.3.5. Standard Error

The Monte Carlo simulation produces as result a loss of load expectancy for each area. The input states are randomly generated and used for calculated the LOLE. The result of the Monte Carlo simulation is the mean of the LOLE for many repetitions of the calculation. This result should be close to the real LOLE of the model, but because of the method used the result will never be exact. To give an indication of accuracy of the result the standard error is estimated. The standard error is the standard deviation of a sampled distribution, it gives an estimate of the range in which the correct result will be. Such that when r is the result of the Monte Carlo simulation and $\hat{R}$ is the true LOLE of the model, that there is a 64.2% probability that $\hat{R}$ is in the range [r-SE, r+SE] and 95% probability that $\hat{R}$ is in the range [r-1.96SE, r+1.96SE]. The estimate of the standard error is calculated by equation 4.32, in this equation SE is the standard error, σ^2 is the sampled variance and n is the number of repetitions of the calculation. Because the sampled variance is used for the calculation and not the true variance of the SE does not represent the real standard error, but for large n it is close to the standard error and gives a good indication of the range in which true value can be expected. [37] and [40]

$$SE \approx \sqrt{\frac{\sigma^2}{n}} \quad (4.32)$$

4.4. Convolution based method

The convolution based method is an analytical method based on adding random variables. It is used to find the contribution of generation units to the security of supply and in this way what the allocation of capacity value is to the areas of generation units. In convolution based method the random variables of equation 4.13 are added by convolving the probabilistic functions of the random variables. This results in the margin for each area. By analysing certain regions of the probabilistic function of the margin, as in figure 4.2, the loss of load expectation can be calculated precise. For this method the model and software tools of [38] were used. This model does not only return the LOLE of each area, but it gives the LOLE of each area as function of additional load that can be added to each area. When more constant load is added it results in a higher LOLE. Generation units with a certain capacity and availability can be added or removed from this model. This affects the LOLE as function of the additional load added to the areas. The convolution based method was compared with the Monte Carlo based method by calculating the LOLE of both areas of the model as described in section 4.2. The results where similar and resulted in a LOLE of 3 hours per year for each area.

5 Allocation of Capacity

In this chapter it is analyzed what the capacity value of generation units is to the local and to the cross-border area in a two area system. It is also analyzed what the effects of interconnection capacity between areas is to the capacity value of a generation unit.

5.1. Method

For the analysis the base case model as described in section 4.2 is used by the convolution based method described in section 4.4. In this model generators of various sizes can be added to either the Great Britain and France system. Because the model has as output the LOLE for each area as functions of the additional load added to each area, it is easy to see what the effective load carrying capacity (ELCC) of an additional generation unit is. The ELCC to each area is the additional constant load that can be added to each area due to the additional generation unit connected to the power system. This is found by comparing the system without the generation unit and with the generation unit. The resulting output of the convolution based method is the LOLE of each area as function of the additional constant load that is added to each area. Then two contour plots are made of this function where the border is the LOLE that is just acceptable for each area. An acceptable LOLE is set to 3 hours per year as also discussed in section 4.2.2. These contour plots for the base case model are shown in figure 5.1. From this figure it can be seen how much additional load can be added or removed before the system has an unacceptable LOLE in any of the areas. It is also easy to compare the local and cross-border effect of adding constant load.

The EFCC of an additional generation unit in a two area model is more complex than its EFCC of an one area model. The reason for this is that due to the generation unit, additional load can be added to both areas, but the amount of load added to each area affects the amount of additional constant load that can be added to the other area. There is not a single correct answer for the EFCC of an additional generation unit in a two area model, but it is possible to come up with likely scenarios for how much the generation unit can contribute to each area.

Besides the additional generation unit, also the interconnection capacity between the areas is increased to see how this affects the generation adequacy. In the base case model there was a 3GW interconnection of 4 independent channels with each an availability of 0.95, this was replaced with an interconnection of 5GW of 4 independent channels with each an availability of 0.95. It is analyzed how much additional load can be added to each area because of the larger interconnection capacity. Then this additional load is added as compensation, such that with the 5GW interconnection installed no additional load can be added anymore without exceeding the safety constrained of a LOLE 3 h/y. Then to this model also an additional generation unit of 1200MW is added to observe its effects.

- **Allocate to Great Britain** In this scenario as much additional load is added to Great Britain as possible due to the additional generation unit. No additional load is added to France even though it would be possible for France to add more load to their area without violating the acceptable LOLE in their area.

Scenario	Interconnection	Great Britain	France
1	3GW	150MW avail. 0.9	x
2	3GW	1200MW avail. 0.9	x
3	3GW	x	150MW avail. 0.9
4	3GW	x	1200MW avail. 0.9
5	3GW	150MW avail. 0.9	150MW avail. 0.9
6	5GW	x	x
7	5GW comp.	x	x
8	5GW comp.	1200MW avail. 0.9	x

Table 5.1: CV scenarios

- **Allocate to France** In this scenario as much additional load is added to France as possible due to the additional generation unit. No additional load is added to Great Britain even though it would be possible for Great Britain to add more load to their area without violating the acceptable LOLE in their area.
- **Maximize additional load** In this scenario as much additional load is added to each area as possible before the LOLE in each area is exceeded. This is the corner where both contour line of the border of LOLE in Great Britain and France cross.

To get an overview of the ELCC of different generation units that are added to each area, the eight scenarios as described in table 5.1 are analyzed. In scenario 6 the interconnection capacity is increased to 5GW which increases the ELCC of the interconnection. In scenario 7 and 8 the additional ELCC of the interconnection is compensated by adding additional load to each area. The results of the ELCC of the generation units as calculated by the convolution based method are verified by the Monte Carlo method. For the verification by the Monte Carlo based method the generation unit is added to the system and additional load is added to the model, as much as calculated by the convolution based method. This results in a LOLE for each area, the outcome is checked to see if it is reasonable compared to the convolution based method.

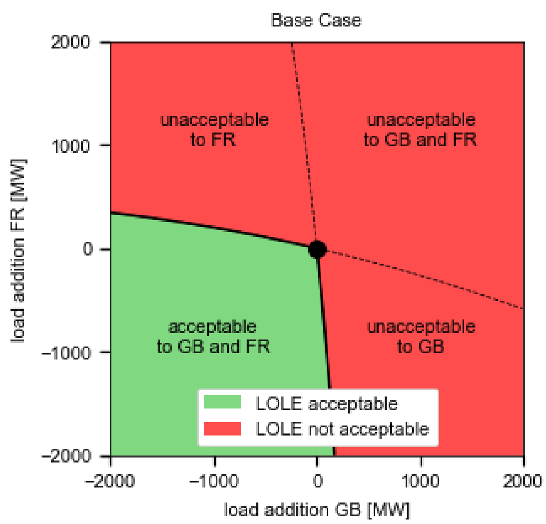

Figure 5.1: Shows the effect of adding additional constant load to either of the systems to LOLE. The green area is acceptable for both areas (LOLE < 3 h/y). Load additions in the red areas cause an unacceptable risk

5.2. Results

This section describes results of the analysis of the capacity value of additional generation units. It compares the capacity value of additional generation units to the local and to the cross-border areas.

In table 5.2 the results present the additional constant load that can be added to each area in the system when additional generation units are added. It presents the additional safety that is gained to each system by adding a generator by the decrease in LOLE. It shows the additional constant load that can be added, when this load is allocated to Great Britain, to France or the maximum possible load is added to both areas. The results are verified by a Monte Carlo simulation that shows the LOLE of the situation, these results are also presented in the table with their corresponding standard error [1]. The LOLE of the system is supposed to not exceed the base case LOLE of 3 hours per year.

Figure 5.2 to figure 5.7 give a graphical overview of the additional load that can be added to each area in the system because of additional generation units in the system. The amount of additional load that can be added to an area when all capacity is allocated to an area is found as follows: By moving from (0,0) only vertically or only horizontally to the edge where green and red meet. The maximum amount of additional load that can be added to the system due to an additional generation unit is found by moving from (0,0) to the corner where the line secreting unacceptable to GB and the line secreting unacceptable to FR meet.

It can be seen from the results that when an additional generation unit is added to the system then most load can be added to the area where it is located in. Less load can be added to the cross-border area in comparison to the additional load that can be added locally. Especially when as much load is added to each area that each area just meets in security goal of a LOLE of 3 hours per year. But is can be seen from the results that there are many other scenarios in which an additional generation unit does provide a capacity value to the cross-border area, although it is less than it does to the local area.

Increasing the interconnection capacity has as effect that the system has more load carrying capacity. By comparing figure 5.2 and figure 5.8, it can be seen that the effect of the larger interconnection is that to each are more load can be added without violating the security constraints of a LOLE smaller than 3 h/y.

The additional load carrying capacity of the larger interconnection is compensated for to be able to compare what the effect is of adding an additional generation unit to such a system. This can be seen in figures 5.9, in figure 5.10 an additional generation unit is added.

It can be seen that the ELCC of a generation unit to a cross-border area becomes larger with a larger interconnection capacity installed, by comparing figure 5.4 and figure 5.10.

[1] The LOLE and standard error are calculated as in 4.3. The result for LOLE in Great Britain with an additional generator of 150MW and no additional load added is 2.7603 hours per year with a standard error of 0.0053 hours per year. It is presented as 2.7603(53), this is in line with the notation as described in [34]

	No additional load LOLE GB	LOLE FR	Allocate load to GB LOLE GB	LOLE FR	Allocate load to FR LOLE GB	LOLE FR	Maximum load GB and FR LOLE GB	LOLE FR
Base Case	0MW add. lo. GB 2.9986(55) h/y	0MW add. lo. FR 3.0050(55) h/y	-		-		-	
GB add. gen. 150MW avail. 0.9	0MW add. lo. GB 2.7603(53) h/y	0MW add. lo. FR 2.9676(54) h/y	134MW add. lo. GB 3.0074(54) h/y	0MW add. lo. FR 3.0015(55) h/y	0MW add. lo. GB 2.7703(53) h/y	31MW add. lo.FR 2.9979(55) h/y	134MW add. lo. GB 2.9951(55) h/y	0MW add. lo. FR 3.0018(55) h/y
GB add. gen. 1200MW avail. 0.9	0MW add. lo. GB 1.5891(40) h/y	0MW add. lo. FR 2.8381(53) h/y	1041MW add. lo.GB 3.0052(55) h/y	0MW add. lo. FR 3.0014(55) h/y	0MW add. lo. GB 1.6092(40) h/y	210MW add. lo. FR 2.9965(55) h/y	1041MW add. lo. GB 3.0006(55) h/y	4MW add. lo. FR 3.0040(55) h/y
FR add. gen. 150MW avail. 0.9	0MW add. lo. GB 2.9781(55) h/y	0MW add. lo. FR 2.9040(54) h/y	14MW add. lo. GB 3.0050(55) h/y	0MW add. lo. FR 2.9004(54) h.y	0MW add. lo. GB 2.9930(54) h/y	135MW add. lo. FR 2.9942(55) h/y	0MW add. lo. GB 2.9947(55) h/y	135MW add. lo. FR 3.0029(55) h/y
FR add. gen. 1200MW avail. 0.9	0MW add. lo. GB 2.8325(53) h/y	0MW add. lo. FR 2.2688(48) h/y	98MW add. lo. GB 3.0017(55) h/y	0MW add. lo. FR 2.2789(48) h/y	0MW add. lo. GB 2.9967(55) h/y	1066MW add. lo. FR 2.9984(55) h/y	0MW add. lo. GB 2.9927(55) h/y	1066MW add. lo. FR 3.0055(55) h/y
FR & GB add. gen. 150MW avail. 0.9	0MW add. lo. GB 2.7496(52) h/y	0MW add. lo. FR 2.8738(54) h/y	148MW add. lo. GB 3.0027(55) h/y	0MW add. lo. FR 2.9082(54) h/y	0MW add. lo. GB 2.7699(53) h/y	165MW add. lo. FR 2.9994(55) h/y	134MW add. lo. GB 2.9967(55) h/y	135MW add. lo. FR 2.9918(54) h/y
Int. 5GW Compensated	0MW add. lo. GB 3.0063(55) h/y	0MW add. lo. FR 2.9988(55) h/y	-		-		-	
Int. 5GW add. gen. 1200MW avail. 0.9	0MW add. lo. GB 1.8532(43) h/y	0MW add. lo. FR 2.6196(51) h/y	-		-		1043MW add. lo. GB 2.9971(55) h/y	11MW add. lo. FR 2.9926(55)h/y

Table 5.2: Different generators added two the base case model, with different allocations of additional constant load. Results are verified with Monte Carlo simulation to see whether the system does not exceed the LOLE of 3 hour per year.

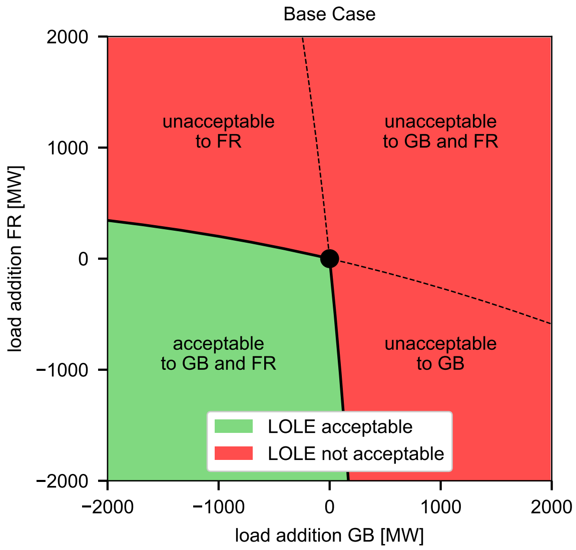

Figure 5.2: Base case system as described in chapter 4.2. It shows the effect of adding additional constant load to either of the systems to the LOLE of each area. The green area is acceptable for both areas (LOLE < 3 h/y)

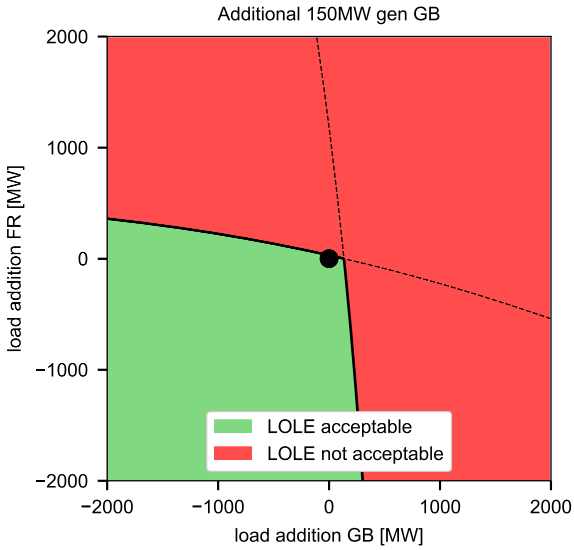

Figure 5.3: Shows the same system as in chapter 4.2, but with generator of 150MW and availability of 0.9 added to the Great Britain area

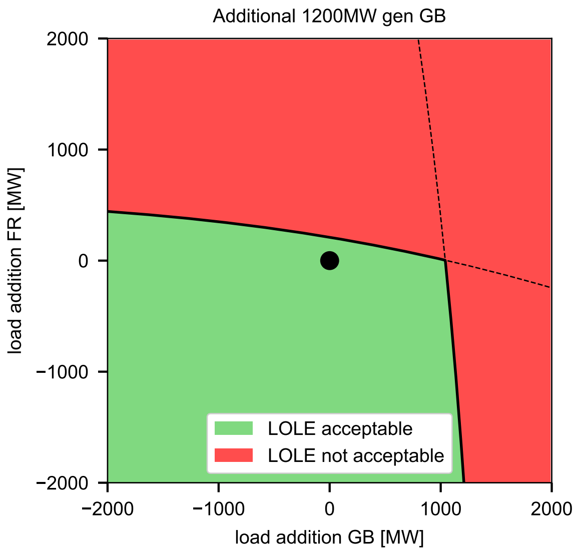

Figure 5.4: Shows the same system as in chapter 4.2, but with generator of 1200MW and availability of 0.9 added to the Great Britain area

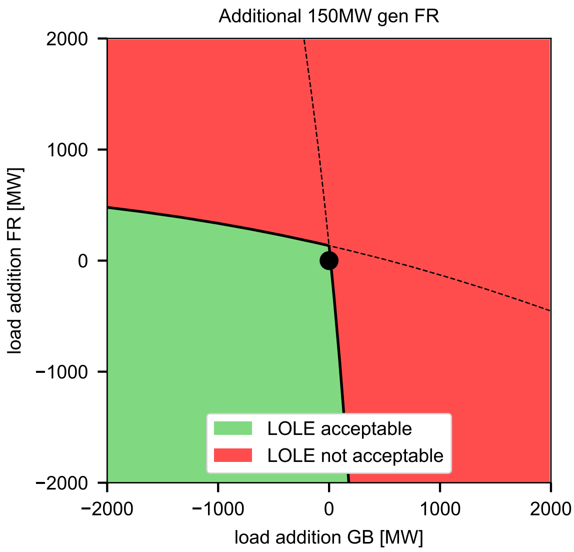

Figure 5.5: Shows the same system as in chapter 4.2, but with additional 150MW generator to the France area

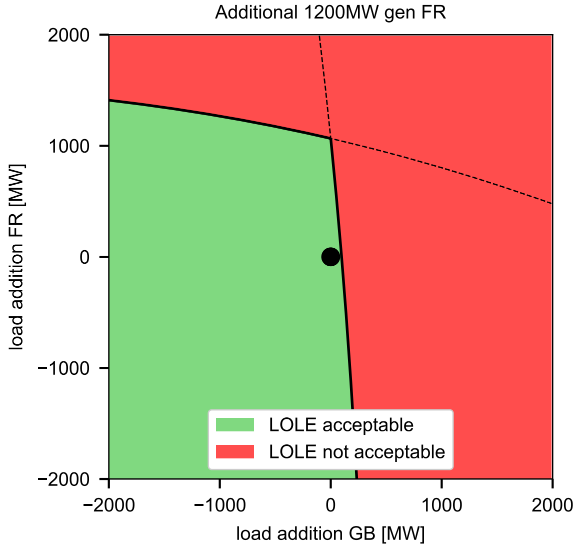

Figure 5.6: Shows the same system as in chapter 4.2, but with generator of 1200MW and availability of 0.9 added to the France area

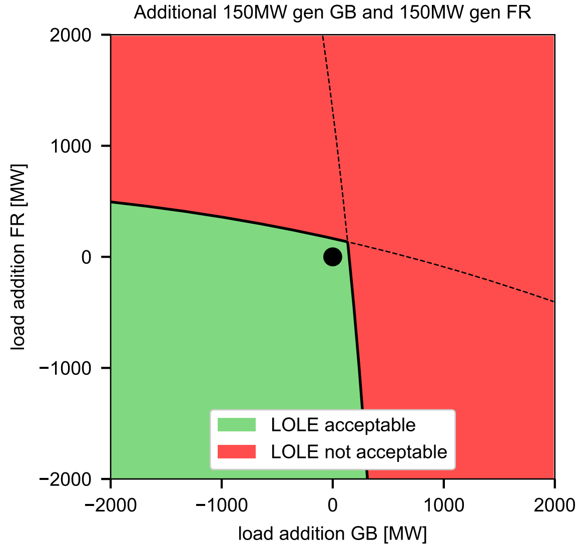

Figure 5.7: Shows the same system as in chapter 4.2, but with generator of 150MW and availability of 0.9 added to Great Britain area and a generator of 150MW and availability of 0.9 added to the France area.

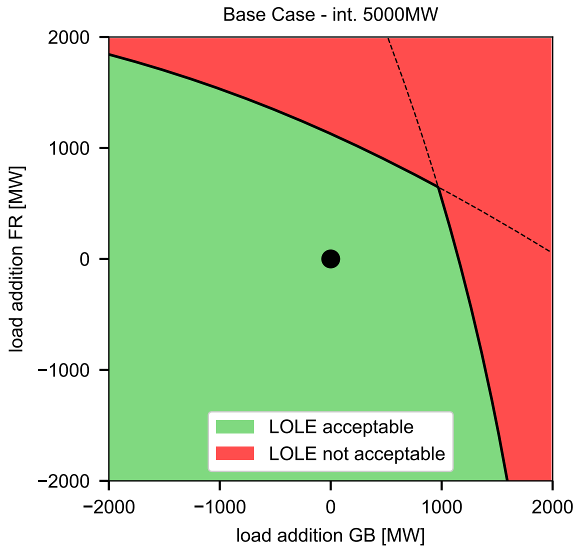

Figure 5.8: Shows the same system as in chapter 4.2, but the 3GW interconnection is replaced with a 5GW interconnection with 4 independent channels with an availability of 0.9.

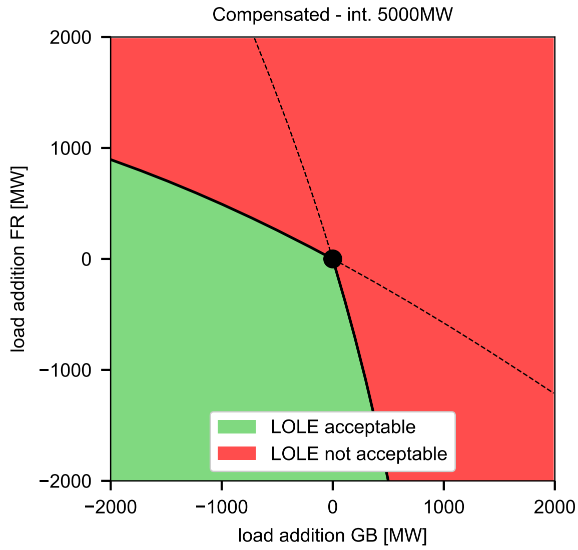

Figure 5.9: Shows the same system as in chapter 4.2, but with a 5GW interconnection and additional load added to compensate for the larger interconnection. This is as if the 5GW interconnection is the normal situation.

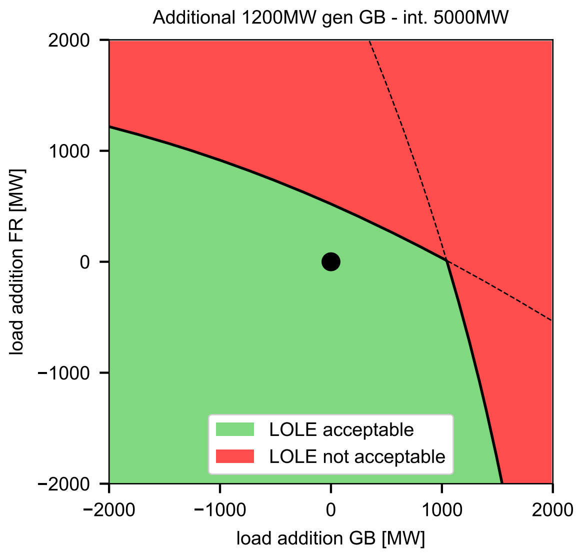

Figure 5.10: Shows the same system as in chapter 4.2, but with a 5GW interconnection, additional load added to compensate for the larger interconnection and an additional 1200MW generation unit with an availability of 0.9 added to Great Britain.

6 Allocation of Payments

In this chapter it is analyzed what the expected payments and penalties are which result from the participation in just local, or cross-border as well as local capacity mechanisms. This is used to analyze how attractive it is to be participating in a cross-border capacity mechanism.

6.1. Method

According to the new regulation generation units are allowed to participate in cross-border capacity mechanisms. But how much additional income will this give the generation units and how much incentive does this give generation units to participate in cross-border capacity mechanisms. A financial analysis is made to examine which of the participating parties in a cross-border capacity mechanism are likely to earn which portion of the revenues from the capacity mechanism and how likely they are to want to participate in a cross-border capacity mechanism. To do this the model of section 4.2 is used and in this model the regulations of chapter 3 are implemented.

Different scenarios are set up in which a generation unit is participating in local and cross-border capacity mechanisms. It is observed how much income it generates and which additional cost it is expected to have. This is used to determine how appealing it is for capacity providers to participate in a cross-border capacity mechanism.

It is assumed that the regulations that apply to the capacity mechanism in Great Britain at the time of writing and the new regulations regarding cross-border participation in capacity mechanisms, as described in chapter 3, apply to both the Great Britain as the France capacity mechanism. According to the regulations the capacity provider does receive revenue each month. This is calculated as in equation 3.4. The penalty that the capacity provider has to pay for each scarcity period during which it is unable to provide its contracted capacity is calculated as in equation 3.5 to 3.7. The over-delivery payment for scarcity periods during which the capacity provider delivers more than its contracted capacity is calculated as in equation 3.8. As presented in section 3.3

The input variables for the calculations are collected from a Monte Carlo simulation of the base case model similar to the model described in section 4.2. A slight change is made to this model, such that the model can be run for an arbitrary month of the year. In certain months of the year the demand will be higher than in other months of the year, this affects the revenue that capacity provider receives, the penalties it has to pay and the over delivery payments they receive during that month.

To make the Monte Carlo simulation calculate the results for a particular month, the input data of the Monte Carlo simulation is changed. As explained in section 4.2 and section 4.3 the wind random variables and the demand random variables are generated from historic input data of 5 years. This data consists of a time series of wind power output and power demand. The distribution of these powers is different in each month. Only the data for the particular month for which the simulation is run is selected as input to generate the random variables for wind and demand power. The data is separated into 12 consecutive parts[1]. The random variables that are generated from this input data have a distribution that is equal to the distribution of the power output of the data in the considered month. In section 4.3 it was assumed that the wind power data and the demand power data are independent of each other and therefore can be sampled as independent random variables. Although it is not entirely true that the data is independent, it is within reason and not a problem for this toy model especially since the security offset that does result from it is compensated for by adding additional load. But now when the input data is grouped into different months this correlation between demand and wind power does cause the model to result in a lower LOLE in each area than the original model. By separating the model in months with input data for demand and wind that is slightly correlated the probability is higher, that moments with high demand can be covered by moments of high wind output power. This results in a lower LOLE in each area when LOLE is calculated as the sum of the LOLE of each month, than when calculated with the original base case. To compensate for this an additional constant load is added to each area, to keep the LOLE in each area equal to 3 hours per year. To Great Britain 869MW is added and to France 848MW is added.

This Monte Carlo simulation is used to simulate separate months has the following output as described below. These outputs are used to calculate when a penalty payment or over-delivery payment is due for a generation unit. Different scenarios are made in which the separate generation unit participates in just the local capacity mechanism or it participates in the local as well as in the cross-border capacity mechanisms. These estimated financial flows can be used to predict how much income the generation unit will make in the different scenarios. The separate generation unit used to generate the outputs is modelled as described in section 4.2.

- $LOLE_{GB}$ number of hours per year that loss of load is expected in Great Britain
- $LOLE_{FR}$ number of hours per year that loss of load is expected in France
- $LOLE_{D}$ number of hours per year that loss of load is expected in Great Britain as well as in France at the same moment
- $S_{GB}U_{GB}$ number of hours per month that a generation unit located in Great Britain is expected to be unavailable and there is loss of load in Great Britain.
- $S_{GB}U_{FR}$ number of hours per month that a generation unit located in Great Britain is expected to be unavailable and there is a loss of load in France
- $S_{GB}U_{D}$ number of hours per month that a generation unit located in Great Britain is expected to be unavailable and there is a loss of load in Great Britain as well as in France

To analyze how financially attractive it is for an already existing generation unit to participate in a cross-border capacity mechanism the following two scenarios are made:

1. A 150MW generation unit located in Great Britain that is participating in the Great Britain capacity mechanism
2. A 150MW generation unit located in Great Britain that is participating in the Great Britain capacity mechanism as well as in the France capacity mechanism.

To be able to compare how attractive these scenarios are for a generation unit, the income and expenses for the different scenarios area summed. Table 6.1 shows the incomes and expenses for each scenario that are calculated.

[1] Care must be taken, since a month is not exactly $\frac{1}{12}$ of a year, because of this a month will also include incomplete days at the beginning and at the end of a month. However, effect of this simplification are expected to be minor and this simplification makes many of the subsequent calculations less complex.

Scenario Output	part. GB only GB	Cross-border part. GB	 FR
Revenue	T	T	T
Penalties	T	T	T
Over-delivery payments	T	T	T

Table 6.1: Output values for that have to be calculated for different scenarios

6.1.1. Modeling assumptions

To calculate how much the revenue, penalties and over-delivery payment for a capacity providers is, the capacity mechanism regulations as implemented in Great Britain at the time of writing are used. The regulations for this capacity mechanism are implemented in the Great Britain model as well as in the French model. Further it is assumed that the separate generator as described above is awarded with a de-rating factor of exactly its availability (because this results in a de-rated capacity close to its EFCC as described in section 4.1.1). This results in a de-rated capacity as in equation 6.1.

Another assumption that is made is that the capacity provider does participate in the capacity mechanism for its full de-rated capacity. This makes the obligation capacity for which the capacity provider is participating equal to its installed capacity multiplied with its availability. If this is implemented in equation 3.4, then the calculation for the revenue becomes as in equation 6.2. Here $Revenue_{mi}$ is the revenue for month m in area i, $Clearing\ price_{y,i}$ is the clearing price in year y in area i. The clearing price is also required to calculate the revenue, the penalties and the over-delivery payments. But to gain insight in this capacity mechanism works financially it is not necessarily required to input a realistic clearing price. The revenue, penalties and over-delivery payments are all linear dependent of the both the clearing price and the installed capacity. Also the clearing price and installed capacity are constant when only a single year is analyzed. When both the clearing price and the installed capacity are taken out of the equation, this results in a normalized revenue. The normalized revenue is such, that if the generator would be fully available $a = 1$, then the total revenue of all months in the year would sum up to 1. This is presented in equation 6.3. For the calculation of the penalties and the over-delivery payments the clearing price and the installed capacity are also taken out of the equations to normalize the values and to be able to compare the values easily.

The regulations are not entirely clear on how a cross-border capacity provider is allowed to participate onto a capacity mechanism. In chapter 3.1 section 8 it is described that the maximum entry capacity has to be allocated to capacity providers in a market based manner. It is not entirely clear how this part will be implemented in the regulations, as it is currently at the time of writing not taken into account in the regulations for capacity mechanisms in Great Britain. It would be possible that there is a different clearing price for local capacity providers and for cross-border capacity providers. But it could also be possible that there is just one clearing price and congestion rent is charged for the interconnection. For calculating the revenue, penalties and over-delivery payments it does not matter which option is chosen, because these are normalized in the calculations (such that the clearing price is taken out of the equation). Later when interpreting the results it is possible to add a factor for the different clearing price between local and cross-border capacity mechanism.

$$de\ rated\ capacity = installed\ capacity \times a \tag{6.1}$$

$$Revenue_{mi} = installed\ capacity \times a \times clearing\ price_{y,i} \times Weighting\ Factor_{mi} \tag{6.2}$$

$$Revenue_{m\ norm} = a \times Weighting\ Factor_{m} \tag{6.3}$$

6.1.2. Revenue

The yearly revenue for participating in each capacity mechanism is calculated as in 6.4, for Great Britain and France the weighting factor for each month is different since this depends on the amount of energy demand in the area in the particular month, although the sum of the revenue over the year will be equal to a.

$$yearly\ revenue_i = \sum_{m=1}^{12} Revenue_{m\ norm} = a \tag{6.4}$$

6.1.3. Penalty local participation

The penalty payment a capacity provider is expected to pay when it is located in Great Britain and is participating in the Great Britain capacity mechanism is calculated by equation 3.7. This equation is used to calculate the penalty that is due after each scarcity period. But $E_{C,m}$ and $E_{D,m}$ are substituted with the total contracted energy and total delivered energy during all scarcity situations in the considered month, then the resulting penalty is the total penalty in the considered month. Care must be taken when making this substitution since the penalty cannot be negative. When P_a is higher than the contracted capacity, then the penalty for that scarcity period is set to 0. The outcome of the Monte Carlo simulation are the number of hours per month that there are scarcity situation and the number of hours per month that there is a scarcity situation and the considered generator is available. In the Monte Carlo simulation the generator is modelled as a Bernoulli random variable: When it is available, it is fully available for its rated capacity. Because of this the generator is counted for its obligation capacity when it is available and counted for 0MW when it is unavailable. Therefore the total penalty that has to be paid in each month can be calculated as in equation 6.5. In this equation the $LOL_{GB,m}$ is the total number of scarcity hours in the considered month in Great Britain, $S_{GB}A_{GB,m}$ is the number of hours in the considered month that there is a scarcity situation and the considered generator is available.

$$Pen_m = \frac{Clearing\ Price_y \times (LOL_{GB,m} \times Obligation\ Capacity_y - S_{GB}A_{GB,m} \times Obligation\ Capacity_y)}{24hours} \tag{6.5}$$

This equation can also be normalized as the revenue by taking the clearing price and the installed capacity out of the equation, this results in equation 6.6. The Monte Carlo simulation gives the expected number of hours per month during which there is a scarcity situation and the generator is unavailable, therefore the equation used to calculate the penalty for each month is equation 6.7. In this equation the $S_{GB}U_{GB,m}$ is the number of hours per in month m that there happens to be a scarcity situation, but the capacity provider is unable to deliver power. This can be done, because the difference in the number of hours per month that there is scarcity and the number of hours per month that there is scarcity and the generation unit is available, is equal to the number of hours that there is scarcity and the generation unit is unavailable.

It must be noted that there is also a penalty cap, such that a capacity provider does not have to pay more than twice its monthly revenue as penalties in a month. This is not taken into account when calculating the expected penalty. Therefore the expected penalty as in equation 6.7 is an over estimate of the expected penalty that the generator has to pay in a month.

$$Pen_{m\ norm} = \frac{a \times (LOL_{GB,m} - S_{GB}A_{GB,m})}{24hours} \tag{6.6}$$

$$Pen_{m\ norm} = \frac{a \times (S_{GB}U_{GB,m})}{24hours} \tag{6.7}$$

6.1.4. Penalty cross-border participation

According to the regulation of ACER a capacity provider is allowed to participate in local capacity mechanism as well as in cross-border capacity mechanism for the same delivery period. The regulations of ACER are combined with the regulations of Great Britain capacity mechanism to find out how much penalty a capacity provider is expected to pay when it is participating in the Great Britain capacity mechanism as well as in the French capacity mechanism. This is done by using the same equations as for calculating the penalty when the capacity provider is participating only in the local capacity mechanism, equation 3.5 to 3.7. But according to ACER the P_a in this equation should be calculated as the $avail.volume_{CM}(t)$ form equation 3.1. The result of this is that the capacity provider not only has to pay a penalty when there is a scarcity situation and the capacity provider is unable to deliver, but it is also possible that it has to pay a penalty when there happens to be a double scarcity situation and the generator is fully available. By assuming the capacity provider is participating in the Great Britain and France capacity mechanism for its installed capacity multiplied with its availability, equation 3.1 becomes 6.8 for the hours that there is a double scarcity period and the capacity provider is available. This can be further reduced to equation 6.9, because P_a is equal to the installed capacity when the generator is available.

$$avail.volume_{Double\ scarcity\ gen.\ avail.} = (P_a) \times \frac{a \times installed\ capacity}{2 \times a \times installed\ capacity} \tag{6.8}$$

$$avail.volume_{Double\ scarcity\ gen.\ avail.} = \frac{installed\ capacity}{2} \tag{6.9}$$

The available volume as calculated in equation 6.9 can be used to calculate the expected penalty that has to be paid each month for the hours there is a double scarcity situation and the generator is available. This will later be combined with the equation to calculate the penalty for being unavailable. Equation 6.9 is used in equation 3.7 to calculate the delivered energy during double scarcity hours when the generators is available. This results in equation 6.10, it shows the penalty that has to be paid for each double scarcity period in which the generator is available. In the equation $S_{GB}A_{D,m}$ is the number of hours per month that there is a double scarcity period and the generator is available. By taking the the clearing price and installed capacity out of the equation, the equation can be normalized to equation 6.11. Because the Monte Carlo simulation gives the number of hours per month that the generator is unavailable during double scarcity hours, the equation is turned into equation 6.12. In this equation $S_{GB}U_{D,m}$ is the number of hours per month when there is a double scarcity situation and the generator is unavailable. Care must be taken when implementing this equation, because the penalty of equation 6.12 cannot be negative. When the generators availability is smaller than 0.5, the penalty for double scarcity hours when it is available will always be 0.

$$Pen_{D,m} = \frac{Clearing\ Price_y \times (S_{GB}A_{D,m} \times Obligation\ Capacity_y - (S_{GB}A_{D,m} \times \frac{installed\ capacity}{2})}{24hours} \tag{6.10}$$

$$Pen_{D,m\ norm} = \frac{(S_{GB}A_{D,m} \times (a - \frac{1}{2})}{24hours} \tag{6.11}$$

$$Pen_{D,m\ norm} = \frac{(LOL_{D,m} - S_{GB}U_{D,m}) \times (a - \frac{1}{2})}{24hours} \tag{6.12}$$

The penalty that a generator located in Great Britain has to pay when it is participating in the Great Britain capacity mechanism as well as in the French capacity mechanism is calculated as the sum of the penalty that it has to pay for being unavailable during scarcity hours in Great Britain and the penalty is has to pay when it is available, but cannot satisfy all of its commitments. The expected monthly penalty is given in equation 6.13. The sum over all monthly penalties in a year gives yearly total.

$$Pen_{D,m,GB\ tot.\ norm} = \frac{a \times S_{GB}U_{GB,m} + (LOL_{D,m} - S_{GB}U_{D,m}) \times (a - \frac{1}{2})}{24hours} \tag{6.13}$$

The penalty that a capacity provider has to pay to the French capacity mechanism when it is located in Great Britain and is participating in the Great Britain as well as in the French capacity mechanism, can be calculated by equation 6.13 by implementing for $S_{GB}U_{GB,m}$ the number of hour per month that there is a scarcity situation in France and the capacity provider is unavailable.

6.1.5. Over-delivery payment local participation

The over-delivery payment that the generator is expected to receive when it is located in Great Britain and participating in the Great Britain capacity mechanism only is calculated by equation 3.8. By defining $E_{C,m}$ and $E_{D,m}$ as the total contracted energy during all scarcity periods and the delivered energy during all scarcity periods in the considered month, these can substitute E_{C_j} and E_{D_j} in equation 3.8. The total contracted energy during all scarcity periods in the considered month, can be calculated by equation

6.14. The total delivered energy during all scarcity periods in the considered month, can be calculated by equation 6.15. Delivered energy in this sense is the energy for which the generation unit was available to the markets to deliver.

$$E_{C,m} = installed\ capacity \times a \times LOL_{GB,m} \tag{6.14}$$

$$E_{D,m} = installed\ capacity \times S_i A_{GB,m} \tag{6.15}$$

The $E_{C,m}$ and $E_{D,m}$ is filled in, in equation 3.8 and the clearing price and installed capacity are taken out of the equation. The over-delivery payment that a capacity provider can receive during a scarcity period can only be positive. Because of this, only the moments that there is a scarcity situation and the capacity provider is able to provide more capacity than contracted have to be taken into account. This results in equation 6.16.

$$ODel_{m\ norm\ 1} = \frac{(1-a) \times (LOL_{GB,m} - S_{GB} U_{GB,m})}{24 hours} \tag{6.16}$$

6.1.6. Over-delivery payment cross-border participation

The expected over-delivery payment that the generator receives from the Great Britain capacity mechanism when it is located in Great Britain and is participating in the Great Britain as well as in the French capacity mechanisms can also be calculated by equation 3.8. By following the same reasoning as for calculating the penalty for a generator participating in two capacity mechanism, the over-delivery for participating is two capacity mechanisms can be calculated as the sum of two parts.

The first part is the over-delivery payment that is received when there is only a local scarcity situation and the generator is available. This is calculated in equation 6.17.

$$Odel_L O, m, norm = \frac{(1-a) \times (LOL_{GB,m} - LOL_{D,m} - (S_{GB} U_{D,m})}{24 hours} \tag{6.17}$$

The second part is when there is a double scarcity situation and the generation unit is able to deliver more than it is contracted to. For this part to be non-zero, the generator would need have an availability and thereby a de-rated capacity that is smaller than $0.5 \times installed\ capacity$. If it has this and there would be a double scarcity situation, then the delivered capacity would be halved because it has double commitments according to equation 3.1. But because its de-rated capacity and thereby its contracted capacity is smaller than $0.5 \times installed\ capacity$, it is still able to meet the commitments and over-deliver. This normalized expected over-delivery payment when there is a double scarcity situation and the de-rated capacity of the generator is smaller than $0.5 \times installed\ capacity$ can be calculated by equation 6.18.

$$ODel_{D,m\ norm} = \frac{max(0, (\frac{1}{2} - a)) \times (LOL_{D,m} - S_{GB} U_{D,m})}{24 hours} \tag{6.18}$$

The equation 6.17, the over-delivery payment when there is only a local scarcity and equation 6.18, the over-delivery payment that could be received when there is a double scarcity situation are added. This gives equation 6.19, the total normalized over-delivery payment that is received from the Great Britain when a capacity provider is participating in Great Britain as well as in French capacity mechanism in month m.

To calculate the expected over-delivery from France for participating in Great Britain as well as in France, $LOL_{GB,m}$ and $S_{GB} U_{GB,m}$ are substituted with $LOL_{FR,m}$ and $S_{GB} U_{FR,m}$ respectively.

$$ODel_{D,m,GB\ tot.norm} = \frac{(1-a) \times ((LOL_{GB,m} - LOL_{D,m}) - (S_{GB} U_{GB,m} - S_{GB} U_{D,m}) + max(0, (\frac{1}{2} - a)) \times (LOL_{D,m} - S_{GB} U_{D,m})}{24 hours} \tag{6.19}$$

6.1.7. Break even point for cross-border participation

Participating in a cross-border capacity mechanism can give additional income but it can also generate additional cost because of penalties. This section describes the method used to find the break even point for which participating in the local capacity mechanisms only generates and equal income as participating in the local as well as in a cross-border capacity mechanism.

The participation in a foreign capacity mechanism comes with additional cost for penalties to the foreign capacity mechanism, but also local income can be reduced. This is because during moments of double scarcity the generation units available capacity is seen as shared between the areas, according to the regulations. This means that even though the generation unit might be fully available to generate power, it is counted as being only partly available to a capacity mechanisms, because it has to deliver to another capacity mechanisms at the same time.

When many capacity providers want to participate in a cross-border capacity mechanisms the interconnection gets congested for the capacity markets. Therefore there is a maximum entry capacity that limits the amount of cross-border capacity trade. The cross-border capacity trading capacity must be allocated to capacity providers in a market based manner. It is assumed that the allocation of capacity is a market based manner can be done in either of two ways.

A congestion rent is charged for using the interconnection. Capacity providers have to compete for the interconnection by paying for it. The maximum capacity which is allowed to use the interconnection is the maximum entry capacity.

The capacity mechanism uses a different clearing process for local and foreign capacity. The maximum amount of foreign capacity allowed to participate into the capacity mechanism is the maximum entry capacity. This gives the capacity mechanism an artificial low demand for foreign capacity, which results in a lower clearing price for foreign capacity.

It is assumed that capacity providers want to participate in a foreign capacity mechanism to make additional income. But because the foreign capacity allowed to participate is limited and allocated in a market based manner, the price for either congestion rent or the difference in clearing price, is expected to be such that participating only locally or cross-border as well as locally generates an equal income for capacity providers. This Break even point is calculated for both allocation methods.

- **Congestion rent** When congestion rent is charged, a part of the income from generation units participating in the foreign capacity mechanism has to be paid as congestion rent. The congestion rent is subtracted from the revenue from the foreign capacity mechanism. The resulting revenue from the foreign capacity mechanism is calculated as ratio of revenue from the foreign capacity mechanism over revenue from the local capacity mechanism.

  The generation units which are allocated to participate in the foreign capacity mechanism, receive in first instance the same revenue (although later part of this has to be paid as congestion rent), the same penalties and the same over-delivery payments as local capacity providers. This is because the capacity mechanism has an equal clearing price for local and foreign capacity providers. But the clearing price between the areas can be different. This is also taken into account when calculating the break even point.

- **Different clearing price for foreign capacity providers** When there is a different clearing price for local capacity providers and foreign capacity providers, then the revenue, penalties and over-delivery payments for local and foreign capacity providers in a capacity mechanism are different. The break even point is calculated as the rate of clearing price which capacity providers have cross-border over what they have locally, which leads to an equal income (participating locally generates equal income as participating cross-border as well as locally).

The break even point when congestion rent is charged for the interconnection is calculated as follows: It is the point where the congestion rent and rates between the capacity mechanisms clearing prices is such, that participating in only the local capacity mechanisms gives an equal profit as participating in a local as well as in a cross-border capacity mechanism. The calculation is shown in equations 6.20, which can be rewritten as equation 6.21. Here Rev_l is the revenue to Great Britain when participating only locally, Rev_{GB} is the revenue from Great Britain when participating locally as well as cross-border, these are equal since the generation unit is located in Great Britain. Here Rev_{FR} is the revenue from France when participating locally as well as cross-border.

z is the portion of revenue from the cross-border capacity mechanism that remains after congestion rent is subtracted, x is the ratio between the clearing price for all capacity providers participating in the French capacity mechanism over the clearing price for all capacity providers participating in the

Great Britain capacity mechanism. It is calculated for which combinations of x of and z the income for participating just locally is equal to the income for participating locally as well as cross-border.

$$Rev_l - (Pen_l - Odeli_l) = Rev_{GB} + z \times Rev_{FR} - (Pen_{GB} - Odeli_{GB}) - x \times (Pen_{FR} - Odeli_{FR}) \quad (6.20)$$

$$\frac{-(Pen_l - Odeli_l) + (Pen_{GB} - Odeli_{GB}) + x \times (Pen_{FR} - Odeli_{FR})}{Rev_{FR}} = z \quad (6.21)$$

The break even point when a different clearing price is used for foreign capacity providers is calculated as follows: It is the point where the ratio between the clearing price for foreign capacity providers into the French capacity mechanism and the clearing price in Great Britain is such that participating in only the Great Britain capacity mechanism gives an equal amount of profit as participating both in the French and Great Britain capacity mechanisms. Equation 6.22 which can be rewritten as equation 6.23 show the calculation for the break even point.

Here y is calculated, the ratio between the clearing price in France for foreign providers and the clearing price in Great Britain.

$$Rev_l - (Pen_l - Odeli_l) = Rev_{GB} + y \times Rev_{FR} - (Pen_{GB} - Odeli_{GB}) - y \times (Pen_{FR} - Odeli_{FR}) \quad (6.22)$$

$$\frac{-(Pen_l - Odeli_l) + (Pen_{GB} - Odeli_{GB})}{Rev_{FR} - (Pen_{FR} - Odeli_{FR})} = y \quad (6.23)$$

To conclude: When congestion rent is charged, the break even point is calculated as z, the portion of revenue from France which remains after congestion rent is subtracted. This is done for different ratios of clearing price between the capacity mechanism in Great Britain and France, x.

When a different clearing price is used for foreign capacity providers and local capacity providers, then the break even point is calculated as y, the ratio between the French clearing price for foreign capacity providers and clearing price in Great Britain. This ratio influences the French revenue, penalties and over-delivery payments.

6.1.8. Standard Error

The penalties and the over-delivery payments are calculated from inputs which come from a Monte Carlo simulation. This means that the results are not exact, to give an indication of the uncertainty that comes with the results, the standard error is calculated. The results of for example the penalty when participating in two capacity mechanism and the over-delivery payment when participating two capacity mechanisms, equation 6.19 and 6.13 are calculated from multiple uncertain results that come from the Monte Carlo simulation. This makes that calculating the standard error is not straight forward, the outputs depend on multiple inputs which are not independent.

To give an estimate of the standard error, the results of the Monte Carlo simulation are calculated in 20 batches. These batches are used to calculate the penalties and over-delivery payments, which result in 20 results for penalties and over-delivery payments. From these the variance is estimated which is used to calculate the standard error. This is a rough an estimate of the standard error because only 20 batches are used to calculate variance. Equation 6.24 shows the calculation for the standard error, here Y_b is the set of 20 final results, b is the number of batches.

$$S.E. = \sqrt{\frac{Var(Y_b)}{b}} \quad (6.24)$$

Using batched results of a Monte Carlo simulations to come to a standard error is presented in [21].

6.2. Results

An analysis was done to find what the expected allocation of payments are for cross-border participation in capacity mechanisms. This was used to find how financially attractive it is for a generation unit that is already existing to participate in a foreign capacity mechanism as well as in a local capacity mechanism. Two scenarios were made where a 150MW generation unit located in Great Britain is participating in just the Great Britain capacity mechanism or in the Great Britain as well as in the France capacity mechanisms. The revenue, penalties and over-delivery payments were simulated by a Monte Carlo method and are presented in table 6.2. The outputs are calculated for different generator availabilities and the outputs are normalized such that the clearing price and installed capacity are taken out of the equation as is described in chapter 6 The results are also shown in figure 6.4 to 6.6, the standard error margin is smaller than the thickness of the line, therefore the standard error is not displayed in the graphs.

6.2.1. Congestion rent

When it is assumed that congestion rent is charged, the break even point where the profit for participating in just the local capacity mechanism is equal to the expected profit for participating in a cross-border as well as in a local capacity mechanism. The results are presented in figure 6.1. A portion of the revenue from France has to be paid as congestion rent. Therefore the ratio between revenue from the French and Great Britain revenue indicated the portion of revenue that has to be paid as congestion rent. From the figure it can be seen that for various clearing price ratios between France and Great Britain only a small portion remains as revenue from France and the other part will have to be paid as congestion rent.

6.2.2. Different clearing prices

When it is assumed that there is a different clearing price for foreign generation units, then the break even point is presented in figure 6.2. Because it is expected to be very attractive to participate in a cross-border capacity mechanism, the clearing price for foreign providers is expected to be very low compared to the clearing price for local providers.

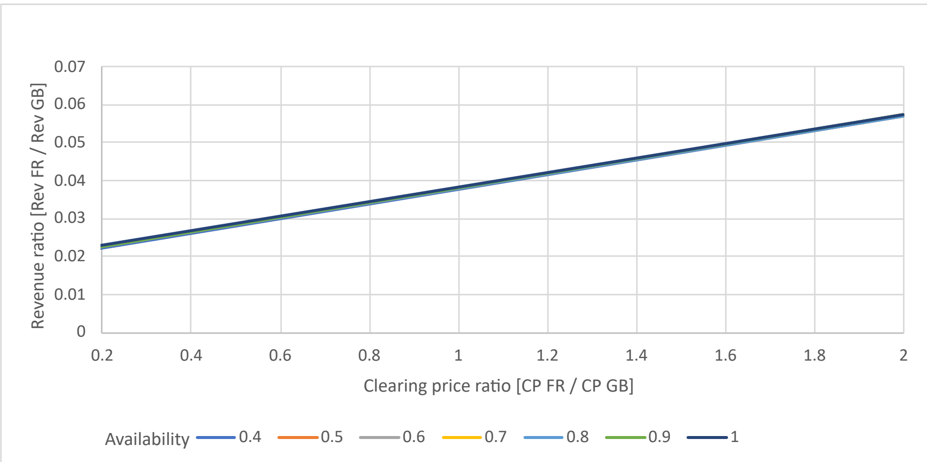

Figure 6.1: Break even lines where income from participating in Great Britain is equal to income from participating in Great Britain as well as in France when congestion rent is charged for participating cross-border. The lines are hard to distinguish because they are almost on top of each other.

6.2.3. Concluding

It can be seen from figure 6.3 to figure 6.6 that it is expected to be very attractive for capacity providers to be participating in a cross-border capacity mechanism. The additional revenue is expected to be larger than the expected penalties, especially when the expected over-delivery payments are subtracted from

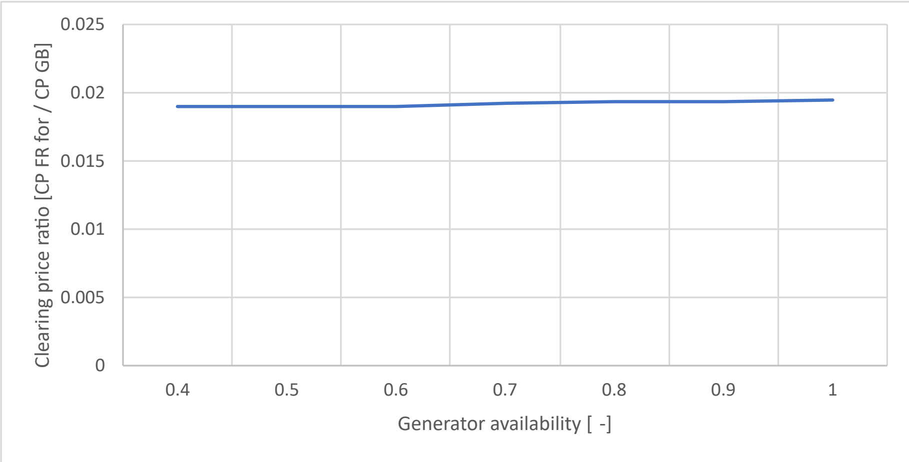

Figure 6.2: Break even line where income from participating in Great Britain is equal to income from participating in Great Britain as well as in France when the capacity mechanisms charges a different clearing price for local and foreign capacity providers

the penalties. But because it is so attractive and there is a limited capacity that is allowed to participate in the cross-border capacity mechanism (MEC), not every capacity provider can participate in the cross-border capacity mechanism. The MEC must be allocated to capacity providers in a market based manner. Two possible methods to do this were analyzed and it was calculated where the expected break even point is, where the income from participating in just the local capacity mechanism is expected to be equal to the income from participating in both local and cross-border. In one method to allocate the MEC, congestion rent is charged for the interconnection. The other method uses a different clearing price between Great Britain and France. It is expected that the market for foreign capacity will converge to this break even point. Therefore foreign capacity providers are expected not to earn additional income from participating in a cross-border capacity mechanism.

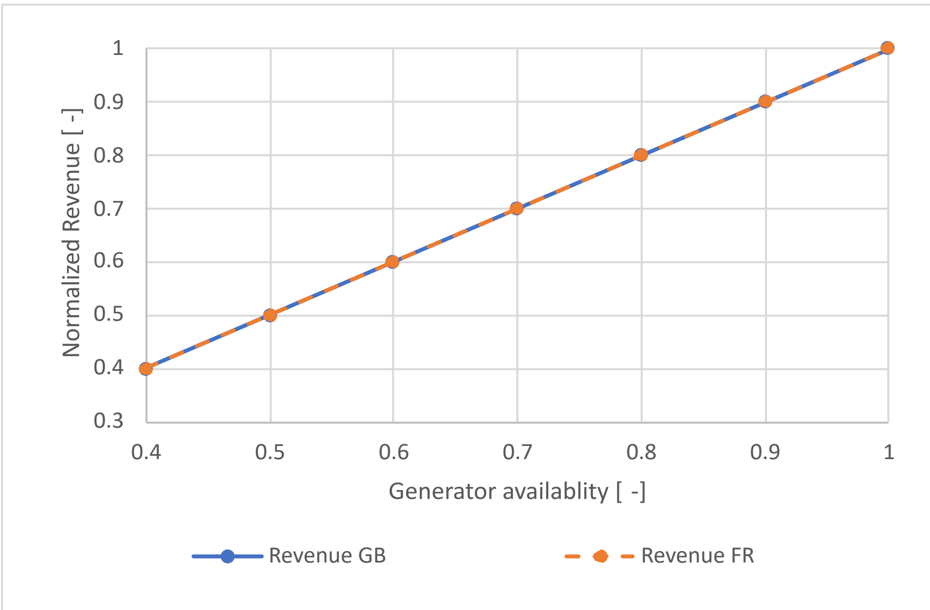

Figure 6.3: Capacity mechanism yearly revenue for various generator availability

Availability generator	1.0		0.9		0.8		0.7		0.6		0.5		0.4	
	Great Britain	France	Great Britain	France	Great Britain	France	Great Britain	France	Great Britain	France	Great Britain	France	Great Britain	France
LOLE	3.0006(27)h/y	2.9945(24) h/y	3.0016(23) h/y	2.9990(19) h/y	3.0027(22) h/y	3.0014(18) h/y	3.0105(21) h/y	3.0037(21) h/y	3.0057(22) h/y	2.9995(27) h/y	3.0088(19) h/y	3.0067(24) h/y	3.0076(23) h/y	3.0034(21) h/y
Double scarcity	0.9287(11) h/y		0.9188(11) h/y		0.91935(96) h/y		0.9224(10) h/y		0.9193(15) h/y		0.92232(98) h/y		0.9232(11) h/y	
Revenue	1.0	1.0	0.9	0.9	0.8	0.8	0.7	0.7	0.6	0.6	0.5	0.5	0.4	0.4
Penalty local (gen. located in GB)	0.000000(0)		0.012201(24)		0.021414(32)		0.027987(40)		0.031669(40)		0.032744(28)		0.031069(21)	
Penalty cross-border (gen. located in GB)	0.019139(24)	0.019139(24)	0.025904(32)	0.025015(26)	0.030512(32)	0.029199(32)	0.033279(43)	0.031739(26)	0.033912(40)	0.032455(46)	0.032744(28)	0.031430(32)	0.031069(21)	0.030124(24)
Over-delivery payment local (gen. located in GB)	0.000000(0)		0.011151(9)		0.019669(17)		0.025637(18)		0.028983(24)		0.029938(36)		0.028588(43)	
Over-delivery payment cross-border (gen. located in GB)	0.0000000(0)	0.000000(0)	0.007725(7)	0.007813(7)	0.013603(13)	0.013921(15)	0.017698(19)	0.018274(18)	0.020008(24)	0.020877(18)	0.020589(26)	0.021861(26)	0.021136(38)	0.022446(28)

Table 6.2: This table shows the LOLE for each area and the expected number of hour per year that there is a negative margin in both areas. It shows the normalized revenue, the penalties and over-delivery payments for a generator of 150MW with availability of 0.4 to 1.0. It is normalized such that the capacity mechanism clearing price and installed capacity are taken out of the equation.

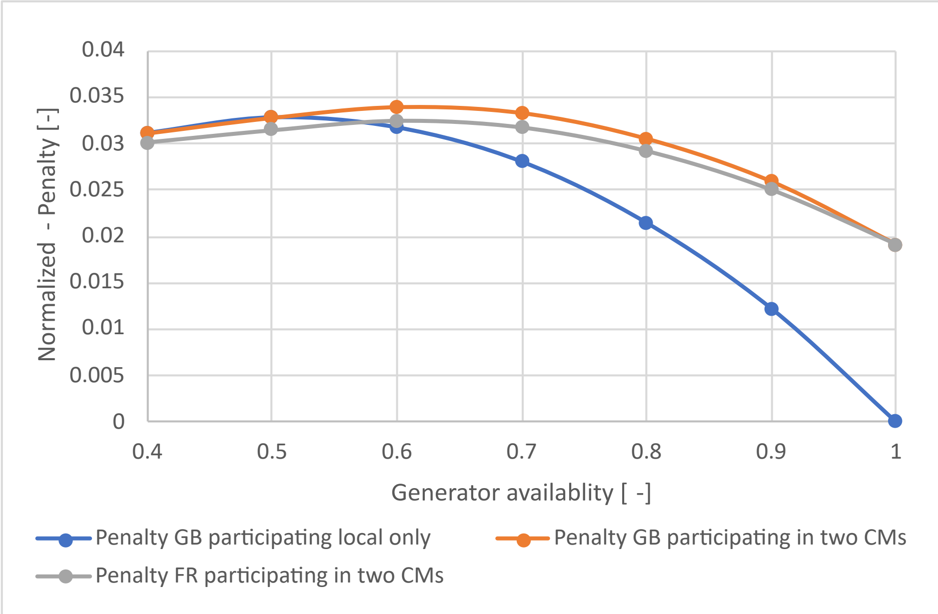

Figure 6.4: Capacity mechanism yearly expected penalties for 150MW generator located in Great Britain for various generator availability

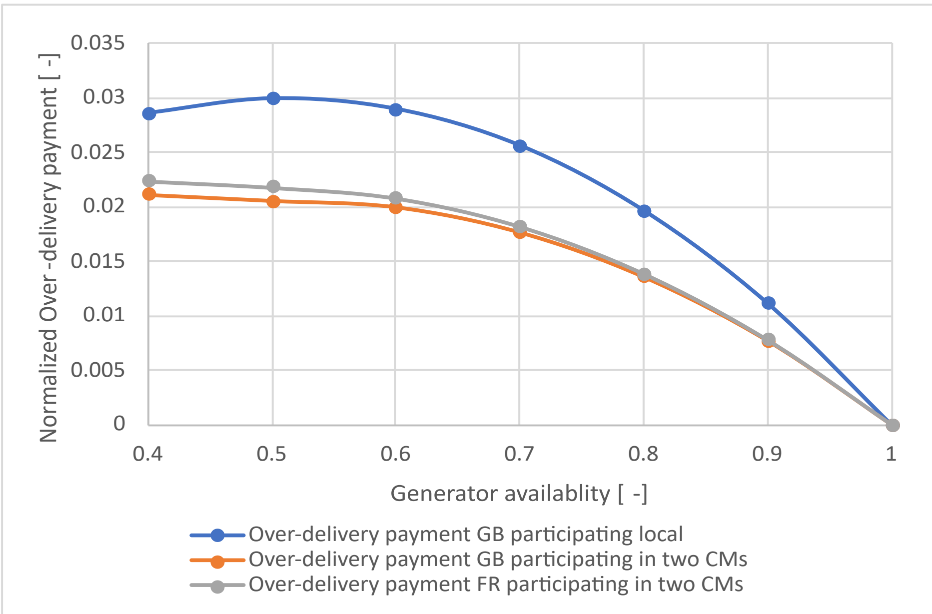

Figure 6.5: Capacity mechanism yearly expected over-delivery payments for various generator availability

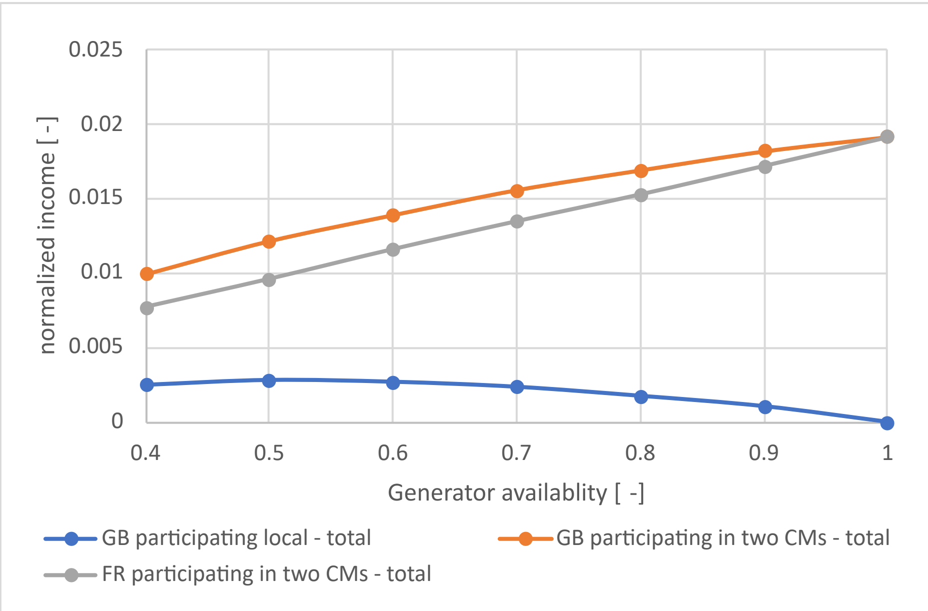

Figure 6.6: Capacity mechanism yearly expected penalties minus over-delivery payments for various generator availability

7

Maximum Entry Capacity

In this chapter it is analyzed how suitable the suggested method by ACER is for calculating the maximum entry capacity. The method as suggested by ACER as described in chapter 3.2.2, based on expected power contribution during scarcity situation, is compared to the calculation for capacity value based on the effective load carrying capacity as described in [38].

7.1. Method

The maximum entry capacity according to ACER is calculated as the average electrical power flow from one member state to the other during scarcity situations. This method is integrated in the Monte Carlo simulation method as described in section 4.3. The maximum entry capacity is calculated as the average contribution from one area to the other area during scarcity hours. In a two area model with one interconnection the contribution is defined as the power flow in the interconnection. Equation 7.1 and 7.2 show how the entry capacity is calculated for Great Britain and France respectively. In these equation $P_{Interconnection\,GB\,to\,FR}$ is the power flow in the interconnection during scarcity period (the margin M as defined in equation 4.13 is negative for the corresponding area). If the margin is negative, the area has a scarcity situation during that time period. n and m are the total number of periods during which there is a scarcity period in Great Britain and France respectively. The maximum entry capacity to the area is calculated as the average power flow in the interconnection during scarcity hours in that area.

The sample space used for the Monte Carlo simulation consist of the possible states in which the system can be. This includes whether or not there is a scarcity situation in Great Britain or in France, the generators that are operational, the power flow in the interconnection etc. For this experiment of simulating the maximum entry capacity, the scarcity situations of each area and the power flow in the interconnection are monitored.

$$Maximum\ Entry\ Capacity_{FR\ to\ GB} = \frac{1}{n} \sum_{t \in (M_{GB} < 0)} -P_{Interconnection-\ GB\ to\ FR}\ (t) \tag{7.1}$$

$$Maximum\ Entry\ Capacity_{GB\ to\ FR} = \frac{1}{m} \sum_{t \in (M_{FR} < 0)} P_{Interconnection\ GB\ to\ FR}\ (t) \tag{7.2}$$

To analyze whether the maximum entry capacity as described by ACER presents the capacity value that the interconnection delivers to each area, the following models are built and compared:

- **Base Case model:** Two area systems as described in section 4.2 with an interconnection. The maximum entry capacity of this model is calculated according to the method of ACER.
- **Model without interconnection:** The same two area system as described in section 4.2, but without the interconnection. The power flow in the interconnection is always 0MW, I in equation 4.13 is always 0MW.

- **Model without interconnection with additional generators with EFC of MEC:** The same two area system as described in section 4.2, but without the interconnection and to each area generators are added with a total capacity of the entry capacity. The additional generators added to each area are similar to the generators in the base case. They all have an availability of 0.9 and the EFC of the interconnection is distributed over the generator such that the new generation units have a similar distribution of capacity as the already existing generation units. The quantity of installed generation capacity that should be added in area i to meet the EFC of the interconnection is calculated as $\frac{MaximumEntryCapacity_i}{0.9}$. This can be used, because the expected value of the generator (that are modelled as Bernoulli random variables) is a reasonable well approximation of the EFC of the generation unit if the total capacity in the system is much larger than the capacity of the generation unit (as shown in section 4.1.1).

- **Model without interconnection with additional generators with EFC of interconnection CV:** The same two area system as described in section 4.2, but without the interconnection and to each area as much generators are added with a equivalent firm capacity equal to the effective load carrying capacity that the interconnection would have. The additional generators added to each area have a similar distribution of capacity as the generators in the base case. They all have an availability of 0.9 and their capacity is given in section 7.2.

  The effective load carrying capacity of the interconnection is calculated in the following way: First the base case model is made with an interconnection. Then a system is made similar to the base case but without an interconnection. This system should have a higher LOLE than the base case system. By using the convolution method it was calculated how much constant load should be added to each area.

7.2. Results

In this section the results are presented of how the maximum entry capacity as calculated by the method suggested by ACER compares to the capacity value to the interconnection as calculated in [38]. In table 7.1 the results of the simulations are shown. In the base case system with the interconnection each area has a LOLE of 3 hours per year. When the interconnection is removed, the LOLE increases in each area. In Great Britain the LOLE increases more than in France because the interconnection is contributing relatively more to Great Britain than to France. This is because the total installed capacity in Great Britain is smaller than the total installed capacity in France.

Then generators are added to the model without interconnection such that their total EFC is equal to the maximum entry capacity as calculated by the suggested method by ACER. The maximum entry capacity was calculated by the coupled base case model and found to be 1723.7(3.5)MW from France to Great Britain and 2207.3(2.6)MW from Great Britain to France.

To Great Britain the following generators were added:

- 1 ×generator 1200MW and availability 0.9
- 1 ×generator 600MW and availability 0.9
- 1 ×generator 80MW and availability 0.9
- 1 ×generator 20MW and availability 0.9
- 1 ×generator 10MW and availability 0.9
- 1 ×generator 5.2MW and availability of 0.9

$$1723.7MW = 0.9 \times (1200MW + 600MW + 80MW + 20MW + 10MW + 15.2MW)$$

To France the following generators were added:

- 1 ×generator 1200MW and availability of 0.9
- 2 ×generator 600MW and availability of 0.9
- 1 ×generator 20MW and availability of 0.9

- 2 ×generator 10MW and availability of 0.9
- 1 ×generator 12.6MW and availability of 0.9

$$2207.3MW = 0.9 \times (1200MW + 600MW + 600MW + 20MW + 10MW + 10MW + 12.6MW)$$

From table 7.1 and figure 7.1 it can be seen that these added generator with a EFC equal to the maximum entry capacity does not provide the same security as the interconnection would. Especially to the system of Great Britain which is the smaller system, the maximum entry capacity seems to under-estimate the capacity value of the interconnection.

Then to check whether the method as described in [38] is a suitable method for calculating the capacity value of the interconnection. Generators were added to the model without the interconnection with a total EFC of the capacity value calculated by the method of the article. The capacity value of the interconnection for Great Britain was found to be 2365.7MW the capacity value to France was found to be 2278.2MW

To the area of Great Britain the following generators were added:

- 1 ×generator 1200MW and availability 0.9
- 1 ×generator 600MW and availability 0.9
- 2 ×generator 300MW and availability 0.9
- 1 ×generator 150MW and availability 0.9
- 3 ×generator 20MW and availability 0.9
- 1 ×generator 10MW and availability 0.9
- 1 ×generator 9MW and availability of 0.9

$$2366MW = 0.9 \times (1200MW + 600MW + 2 \times 300MW + 150MW + 3 \times 80MW + 20MW + 10MW + 9MW)$$

To the area of France the following generators were added:

- 1 ×generator 1200MW and availability 0.9
- 1 ×generator 600MW and availability 0.9
- 1 ×generator 300MW and availability 0.9
- 2 ×generator 150MW and availability 0.9
- 1 ×generator 80MW and availability 0.9
- 2 ×generator 20MW and availability 0.9
- 1 ×generator 10MW and availability 0.9
- 1 ×generator 1MW and availability 0.9

$$2278MW = 0.9 \times (1200MW + 600MW + 300MW + 2 \times 150MW + 80MW + 2 \times 20MW + 10MW + 1MW)$$

For the area of France the maximum entry capacity seems to estimate the capacity value of the interconnection reasonable well. But for Great Britain the entry capacity seems to under-estimate the capacity value of the interconnection.

The reason that the method for calculating the maximum entry capacity does not always reflect the capacity value of the interconnection accurately is thought to be as follows: The method for calculating the maximum entry capacity, only takes the power flow in the interconnection into account when there is already a problem / scarcity situation. This is different from the contribution that the interconnection delivers that prevents scarcity situation from happening.

	LOLE GB	LOLE FR	Maximum entry capacity GB	FR
Base Case model	0MW add. gen. GB 2.9964(55) h/y	0MW add. gen. FR 2.9965(55) h/y	1723.7(3.5)	2207.3(2.6)MW
Model without interconnection	0MW add. gen. GB 12.009(11) h/y	0MW add. gen. FR 5.1984(72) h/y	-	
Model without interconnection with additional generator with total capacity equal to MEC of base case	1915MW total cap. avail. 0.9 of add. gen. to GB 4.593(78) h/y	2452.6MW total cap. avail. 0.9 of add. gen. to FR 3.0673(43) h/y	-	
Model without interconnection with additional generator with total capacity equal to interconnection capacity value	2629MW total cap. avail. 0.9 of add. gen. to GB 3.1136(56) h/y	2531MW total cap. avail. 0.9 of add. gen. to FR 3.0094(55) h/y	-	

Table 7.1: This table shows the LOLE for various model setups used to compare the effectiveness of the maximum entry capacity as calculation for the capacity value of the interconnection

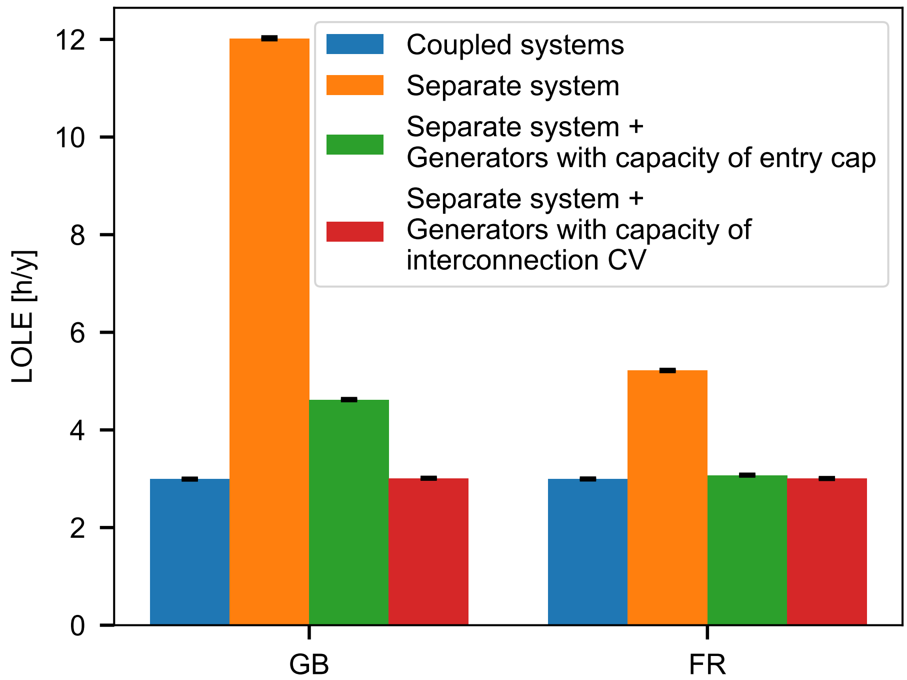

Figure 7.1: The effectiveness of the maximum entry capacity as method for calculating the contribution of the interconnection is compared with the method as presented in [38]. The interconnection is replaced with generators with an EFC of the MEC and with an EFC of the capacity value of the interconnection. The +- standard error range for each result is shown with a black vertical line. Be aware, this figure does not suggest that the method of calculating the contribution affects the contribution of the interconnection directly!

8

Conclusion and Discussion

In this chapter it is concluded what the effects of the new regulations regarding cross-border participation are expected to be. At first the logical steps are explained which lead to the expected outcome, then it is summarized for each of the involved parties what the expected effects are for these involved parties. A reflection is given on the effectiveness the new regulations are to achieve the supposed intended results. At last a suggestion is given for further work related to this thesis that would be interesting to analyze.

8.1. Conclusion

It was shown by simulating that generation units that are connected to a two area model have a positive effect to the security to supply to the area they are located in and also can have a positive effect to the security of supply of the cross-border area. In other words, they have a capacity value for the local area and for the cross-border area, although the capacity value for the cross-border area was found to be smaller than for local capacity mechanism in the model used.

Because the generation units can contribute to the security of supply of a cross-border area it would be logical that generation units can also earn income from cross-border participation in capacity mechanism. This should give them the correct incentives, such that generation units are being built and kept available in locations where it is most economic to have the generation units.

It was calculated how attractive it is for a generation unit to participate in a cross-border capacity mechanism. For generation units is seems very attractive to participate in a cross-border capacity mechanism, but there is a limited capacity that is allowed to participate, the maximum entry capacity. Because of this limited maximum entry capacity generation units will have to compete with other generation units when they want to be allocated to participate in cross-border capacity mechanism. According to the regulations the allocation of this maximum entry capacity should be done in a market based manner.

To analyze how these generation units will compete for the maximum entry capacity, two possible method of market based allocation of the maximum entry capacity were analyzed:

- Congestion rent can be charged for the capacity providers that use the interconnection for participating in capacity mechanisms.
- A different clearing price for foreign capacity providers in capacity mechanisms is charged.

It was calculated what the expected break even points are for both methods for which participating in just a local capacity mechanism generates an equal income, as participating in both a local as in a cross-border capacity mechanism.

It is likely that in a model as used in this thesis, the market for cross-border participating will stabilize at this break even point. This is because it was calculated to be very attractive to participate in a cross-border capacity mechanism and each area has already a lot of installed capacity that under the new regulations can just be double sold to the neighboring area to generator more income. When the market for cross-border participation stabilizes at this break even point, the income from participating in just the local capacity mechanism is equal to the total income that would be received when participating in the local as well as in the cross-border capacity mechanism.

When congestion rent is charged for using the interconnection, then the revenue from the cross-border capacity mechanism that remains after subtracting the congestion rent is expected to be about 4% of the revenue from the local revenue, when the clearing price is equal for both capacity mechanisms. This was found for a generation unit located in Great Britain that is participating both in Great Britain and the French capacity mechanism.

When a different clearing price is charged for local and cross-border providers, then the ratio between foreign and local clearing price was found to be about 2%. This was found for a generation unit located in Great Britain that is participating both in Great Britain and the French capacity mechanism.

The generation units do not seem to earn significant additional income from participating in a cross-border capacity mechanism under the new regulations, although they do seem to contribute to the security of supply of neighboring systems. The generation units do not receive an incentive to be built or kept operational for a foreign system. This could lead to sub-optimal investments, the effect of the capacity mechanisms is that they stimulate investments most in locations with highest payments, but not in locations where the total contribution to all areas is highest. A sub-optimal investment climate could lead to system wide higher prices for capacity buyers.

In the former situation (before the introduction of the regulations regarding cross-border participation in capacity mechanisms) generation units could not participate in a cross-border capacity mechanisms. With the introduction of the new regulations they can participate, but it is expected that it does not generate any additional income for the generation units.

Because of the new regulations, foreign capacity is expected to be offered to the capacity mechanisms. The generation units are expected to be willing to sell all of their capacity to the capacity mechanism for a very low price. In the former situation the interconnections were allowed to offer capacity as supply in certain capacity mechanisms, in others the interconnections were not allowed to participate. It is expected that the interconnection will not be allowed to participate anymore when the new regulations are implemented. This is because the offers of the foreign capacity providers will substitute the offers of capacity that would be made by the interconnections.

In the capacity mechanisms where the interconnections were not allowed to participate before, but after the introduction of the new regulations foreign capacity can be offered at the capacity mechanisms, it is expected that there will be a change in the demand goal of the capacity mechanism. The central entity which sets the demand goal, is expected to change its goal. This is done to make sure that the relatively cheap foreign capacity that is expected to be offered at the capacity mechanism does not prevent that more expensive local capacity is bought which is needed to meet the security goal.

The foreign capacity providers are not expected to be earning any significant additional income from participating in a cross-border capacity mechanism. The party that could be earning from the new regulations are the TSOs. When congestion rent is charged as method to allocate the maximum entry capacity to capacity providers in a market based manner, the congestion rent is awarded to the TSOs according to the regulations. It was seen that it is very attractive to be participating in a foreign capacity mechanism and it was shown that therefore capacity providers are expected to pay a significant portion of their revenue as congestion rent. It is expected that the capacity mechanisms are effectively paying significantly to the TSOs. Also it should be noted that it is possible that the congestion rent is charged for both directions of an interconnection. This is because a border between two countries with capacity mechanisms is awarded with a maximum entry capacity in both directions.

But it is also possible that a different clearing price is charged for foreign and local capacity providers as method to allocate the maximum entry capacity in a market based manner. The foreign capacity is expected to be sold at a very low clearing price, because it is very attractive for foreign capacity providers to participate in a capacity mechanism, but they are limited by the maximum entry capacity. This means that the buyer in the capacity mechanism are expected to pay little for the foreign capacity compared to the local capacity. In this scenario the TSOs do not earn from the congestion income.

The method as suggested by ACER as described in chapter 3.2.2, based on expected power contribution during scarcity situation,

The method as suggested by ACER as described in chapter 3.2.2, based on expected power contribution during scarcity situation, to calculate the maximum entry capacity, might in certain situations be an inaccurate estimation of the capacity value of the interconnections/contribution from foreign capacity providers. For the the foreign capacity providers this does not matter much, as they are not expected to earn from participating in a foreign capacity mechanism. For the buyers in the capacity mechanism it can matter how much the maximum entry capacity is. When the maximum entry capacity deviates without a change in contribution from the interconnections, then the demand goal should deviate too, to still meet the security of supply goal. This is because portion of foreign capacity which is allowed to participate in a capacity mechanism is expected not to change security of supply, but it does satisfy demand bids.

When congestion rent is charged as method to allocate the maximum entry capacity, then the buyers will have to pay the full clearing price to the foreign capacity providers (of which a significant portion goes to the TSO). Then it matters much for capacity buyers that the maximum entry capacity deviates.

When a different clearing price is used for foreign and local providers as method to allocate the maximum entry capacity, then buyers are expected to pay a very small price for the foreign capacity. This means that for the buyers it does not matter as much the maximum entry capacity deviates.

A summary of the conclusions is shown in table 8.1.

8.2. Reflection

8.2.1. Intended effects of the regulations

After analysing the effects of the new regulations regarding cross-border participation in capacity mechanisms, it is discussed whether or not these effects are as the were intended. If the intention of the regulations is that there is a European wide capacity mechanism in which capacity providers can earn income in cross-border capacity mechanisms, which leads to an optimal investment climate in which generation capacity that has the highest system wide contribution to security of supply is rewarded most, then these new regulations might not be very effective to achieve this goal.

The intention of the new regulations could be to increase the connectivity between countries in Europe. Then it would be logical to create an attractive investment climate for interconnections by using the method of charging congestion rent for capacity trade. If this is the intention, then it is expected to be very effective by this implementation of the regulations.

8.2.2. The models

The generation adequacy model used for this thesis is not a very exact representation of the power systems as implemented in Great Britain and France. But it is not meant as a generation adequacy analysis to find the security of supply in the areas. It has a similar distribution of generation units and wind production as can be expected in a real system. Additional load is added to the model to meet a certain security goal.

The model should be seen as something that is similar enough such that it can be used to analyze the expected effects of the regulations. Since these regulations are implemented EU-wide, it is interesting to analyze its effects on any model which could be a power system of part of the EU.

Party	Allocation method	Effects	Reason
Generation units		No significant additional income. No incentive to invest for the foreign security of supply.	Limited entry capacity and competition from other generation units. No significant additional income is expected from investments for cross-border capacity mechanisms.
Buyers	Congestion rent	Foreign capacity is relatively expensive	The clearing price for local and cross-border capacity is equally high.
	Different clearing prices	Foreign capacity is relatively cheap	The clearing price for foreign capacity is expected to be much lower than the clearing price for local capacity.
		Could lead to system wide higher prices for capacity	Due to a sub-optimal investment climate for capacity
TSO	Congestion rent	They are expected to earn a significant portion of income	The congestion rent which is charged to allocate the MEC to capacity providers in a market based manner is awarded to the TSOs
	Different clearing prices	They do not earn from the capacity mechanisms	When the foreign capacity providers can participate directly into a capacity mechanism, then the interconnections are expected not to be allowed to participate in a capacity mechanism.

Table 8.1: Summary of conclusions how various parties are affected

In the model to analyze the payments, a 150MW generation unit was chosen. It is expected that when this generation unit is larger, that its outages become more correlated with scarcity in the system. Therefore it is expected that larger generation units pay relatively more penalties than smaller units. This could influence the results slightly, but also for large units, it is thought to be attractive to be participating in foreign capacity mechanisms.

The model of the capacity mechanism is based on the capacity auction with central buyer as implemented in Great Britain. It is not analyzed what the outcome will be when a different type of capacity mechanism would be implemented. But when it is attractive to be participating in a foreign capacity mechanism and there is a limited maximum entry capacity, for which capacity providers have to compete, then it can be expected that foreign capacity providers do not earn much from participating in multiple capacity mechanisms.

8.3. Further work

An interesting scenario to analyze further would be the following:

In the model used for this thesis the maximum entry capacity is always the limiting factor for cross-border capacity trade. But it is interesting to analyze a situation in which not the maximum entry capacity is the limiting factor, but the installed generation capacity in an area. A possible scenario in which this might happen, in a three area system in which one relatively small area has two larger neighbours with much more installed capacity than the smaller area. Also the interconnection capacity is large. Then it might be possible that the small area is awarded with a higher maximum entry capacity than it has as installed generation capacity in its area. Then the maximum entry capacity might not be the limiting factor anymore. This might result in a very different outcome. In this situation the generation units in the small area could possibly be earning significantly from participating in multiple other areas.

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