National Design and Multinational Integration of Balancing Services Markets

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Alireza Abbasy,

Amsterdam, August 2012

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1. Overview of Balancing Markets

1.1. The electricity sector and ancillary services

Since power systems are aimed to deliver a very essential good to the society (electricity), traditionally, states used to own and have control over everything from generating the electricity, to transmitting, and distributing it. Traditionally, on the one side, there were consumers of electricity, and on the other side, a huge state-owned entity who did everything to make sure that the consumer will receive its electricity. After privatization of almost all parts of the electricity sector, unbundling of the three basic components of power systems (generation, transmission and distribution), and introduction of *markets*, everything changed in the electricity industry. The process was justly called *restructuring* of the sector.

Now, electricity (electric energy) is being traded in various markets. *Long-term bilateral contracts* are widely used and make for a very significant share of the entire power trades, because these contracts bring stability to both the generator and the consumer; they can be protected from price volatilities in other markets. *Day-Ahead* auctions are short-term auctions for trading of electricity on a day-ahead basis, and can make up for a considerable share of all power trades in a system. Additionally, *Intra-Day auctions* are hourly auctions that run during the operating day. Through these auctions, energy can still be traded up to a short time (usually one hour) before the real-time, and thus these markets are used for fairly small adjustments.

These markets and their interrelations build the structure of the liberalized electricity sector today. Next to these markets, which are all meant to create a platform for wholesale trades of (electric) energy, in order for the system to work in a *secure* way, further actions need to be taken. *Security* refers to the short-term resilience of the system to respond to standard short run disturbances [1-3]. The need to satisfy system security has led many countries to define certain services, generally known as *Ancillary Services* (simply because they are complementary for the energy product) [4]. These services include voltage support (reactive power control), black start capability, and all the services related to balancing generation and consumption in the system. Since the balance between generation and consumption is directly related to system frequency, this category of ancillary services is also known as *Frequency control*. Frequency control maintains load and generation in balance in real time and is most of the time divided into several other services of different qualities [1]. These services, which are generally known as *balancing services* (representative of their purpose), are the main focus of this dissertation.

In the following of the first chapter, the definition and objective of these services are discussed and the structure of the markets used for procurement of these services is presented. More importantly, we describe how these services (and their markets) fit in a more comprehensive mechanism usually known as Balance Management Mechanism.

1.2. Definition of 'balancing' in electricity grids

According to the non-storable nature of electricity (a main difference between electricity and other conventional commodities), the amount of electric power produced must equal the amount of power consumed in a power system at every moment [5, 6]. The balance between electricity supply and demand has a close relationship with the frequency of the entire system. Imbalances can occur due to a wide variety of reasons: load forecast errors, generation outages, intentional deviations from energy plans, etc. Any imbalance between production and consumption will lead to frequency deviations from the synchronous frequency of the system, which in turn can result in serious system stability problems and equipment damage. Therefore, balancing production and consumption in a power system plays a critical role in ensuring the security of the entire electric grid.

In the new liberalized power systems introduced in the early 90's, the task of operating the system in a secure and reliable way is the responsibility of the Transmission System Operator (TSO). In order to fulfill its responsibility of balancing the system, the TSO needs to have access to power resources able to change their generation/consumption in real time on a short notice, to regulate the system up/down and to restore the system balance. The TSO also needs slower-response resources in order to replace the faster ones and to free up their capacity so that they can be used again. These services offered mainly by generators with free capacity (and also large consumers in some cases), are called "balancing services", which are the means of balancing the system used by the system operator [5, 7, 8].

In order to procure these services, the system operator has a wide range of options, from purely mandatory approaches (in which the provision of the service by generators is obligatory) to free market-based approaches in which service providers are free to decide on the capacity they offer and the price they ask for their service. This entire mechanism, which includes the system operator on the one hand and generators on the other hand is called Balance Management Mechanism, which may include "markets" as well.

1.3. Definition of balancing services

As described above, the final objective of the balance management mechanism is to maintain system's frequency at its nominal value. Therefore, in many countries, the balance management mechanism is also known as the Frequency Control Service. Categorization of balancing services varies widely in different countries. Balancing services can be divided into different types based on various criteria such as their activation time (response speed), the method of activation (manual/automatic), the minimum deployment time, and the state of the service compared to the system (synchronous/non-synchronous). Therefore, there is no general consensus on categorization of balancing services. Definitions are different in different countries because of the differences in the dominant generation portfolio, technologies used in the control systems, regulators' policies, history, etc. However, regardless of the differences in terminologies used in different systems, based on the objectives of activation of the services and the general response speeds, three main types of services that are used to maintain the balance between load and generation can be identified in all power systems according to [9, 10]. We use the general UCTE (Union for the Coordination of Transmission of Electricity) terminologies here [11]:

- **Primary Control Service**

Primary control is a local automatic control that adjusts the active power generation of generating units to quickly restore the balance between generation and consumption within the synchronous area, using turbine speed or turbine governors. In particular this control is designed to stabilize frequency after large generation or load outages, and therefore it is indispensable for the stability of the system. The activation time of this service is in the time frame of several seconds, less than **30 seconds**. The primary control capacity that is used must be replaced (freed up) by other resources in order to ensure that there is enough primary control capacity available to respond to frequency deviations in the future. Primary control is performed on generators based on the automatic frequency response defined by the droop setting on each generating set.

- **Secondary Control Service**

Secondary control restores the balancing area's frequency and interchanges with other areas to their target values following an imbalance, without impairing the primary control that is operated in the synchronous system in parallel but by a margin of seconds. While primary control limits frequency deviations and stops them from growing, secondary control brings the frequency back to its nominal value. Secondary control makes use of a centralized generation control, modifying the active power set points/adjustments of the generation sets in the time frame of seconds to typically around **15 minutes**. In other words, secondary control is required to change the output (set point) of the balancing resources so that the total production (or consumption) can be achieved within 15 minutes [11, 12]. In North America and continental Europe (the UCTE system), Automatic Generation Control (AGC) is used as the central control for secondary control resources. The marketplace that the system operator employs to procure this type of balancing service from the providers is typically called "regulating power market" [13-16]. As the name of the market implies, the service that is traded in this market is regulating power which is used to regulate system's generation up- or down-ward (up/down-ward regulation) in case of an imbalance.

- **Tertiary Control Service**

Tertiary control refers to manual changes in dispatch and commitment of generating units. This service is procured by the system operators in order to free up activated secondary and primary reserves, and also to relieve congestions in the transmission network. Tertiary control resources may directly be used to restore the balance between generation and consumption when secondary control is unable to maintain the balance (sufficient secondary reserve is not available in case of large contingencies). The activation time of the tertiary control service varies from several minutes to **hours**.

As mentioned above, there is no general consensus on the definition of balancing services. Here, we present the definitions used in North European countries which are actually the main case study of this research.

In the Nordic system, the following definitions are used [12, 17]:

• *Frequency controlled normal operating reserves (FCNOR)* are automatically activated reserves used for handling small frequency deviations that occur during the operational hour.

• *Frequency controlled disturbance reserves (FCDR)* are reserves automatically activated by sudden frequency fall caused by grid or production failure.

• *Fast active disturbance reserves (FADR)* are the manual reserve available within 15 minutes in the event of the loss of an individual principal component (production unit, line, transformer, bus bar, etc.) and restores the FCDR.

In the Netherlands, the following definitions of balancing services are used [12, 18, 19]:

• *Regulating power* is continuously controllable and is used for controlling the instantaneous system balance. It is procured by the TSO on contract with certain producers, who through the contracts are obliged to offer this capacity. Other parties may also offer regulating bids. "Regulating power" in the Netherlands perfectly fits the UCTE definition of secondary control.

• *Reserve power* can be used for restoring the control area balance. Reserve power is primarily used to alleviate transmission constraints. It may sometimes be used to free some regulation capacity for frequency regulation. Being manually activated with low response speeds, "reserve power" fits into the UCTE definition of tertiary control.

• *Emergency power* is used to re-establish the system balance when there is insufficient regulating or reserve power. It is procured through contracts with certain producers or consumers as load shedding capability. Emergency power can be seen as the last resort, and by UCTE standards it is slow tertiary control.

In Germany, the same definitions as in UCTE are used for balancing services, only the Tertiary Control service is called Minutes Reserves [12, 20, 21]. Table 1. 1 summarizes the differences in definition of balancing services in Northern Europe. The definitions in PJM Interconnection are also added for the sake of comparison [15, 16]. The services in one column have the same technical characteristics (response speed), but their method of activation can be different (manual or automatic). For example, FADR in the Nordic system, in terms of the response speed fits the UCTE definition of secondary control but the method of activation is manual; there is no automatic generation control (AGC) in the Nordic system.

Table 1. 1. Comparison of the definitions of balancing services in different countries

<table>
<tr><th>UCTE</th><th colspan="2">Primary Control</th><th>Secondary Control</th><th colspan="3">Tertiary Control</th></tr>
<tr><td>Netherlands</td><td colspan="2">Primary Reaction</td><td>Regulating and Reserve Power</td><td colspan="3">Reserve Power
Emergency Power</td></tr>
<tr><td>Nordic System</td><td>FCNOR</td><td>FCDR</td><td>FADR</td><td colspan="3">-</td></tr>
<tr><td>Germany</td><td colspan="2">Primary Control</td><td>Secondary Control</td><td colspan="3">Minutes Reserves</td></tr>
<tr><td>PJM [22]</td><td colspan="2">Frequency Response</td><td>Regulation</td><td>Primary Reserves</td><td>Secondary Reserves</td><td>Reserve Beyond 30 min</td></tr>
</table>

1.4. Components of balancing markets

The mechanism that system operators employ to procure balancing services may range from a purely obligatory approach without any compensation for the services to a voluntary approach based on free markets. The term "balancing market" has been widely used in literature usually without a clear definition of its elements. In this dissertation, a "balancing market" is defined as the "market-based balance management mechanism". Therefore, a balancing market is more than solely a single market, and it consists of different marketplaces for the trade of different products (balancing services) used to balance the system, the system operator being the single buyer in each of these markets. Based on this definition, a balancing market also includes the procedure of allocating the costs of balancing the system (costs of procuring the required balancing services) to the system users. In other words, a balancing market includes purchasing of the required services by the system operator and also allocating the resulting procurement costs to the parties who use the grid and benefit from system security. In order to clarify the structure of a balancing market, its key components are described in details in the following sections:

1.4.1. Balancing service procurement

The TSO procures the required amount of each balancing service from the corresponding marketplace in order to resolve system imbalances. For each type of balancing services, there can be two types of markets:

- ***Reserve capacity markets*** are rather long-term option markets for "reserves". In these markets, the TSO buys the reserves required for secure operation of the system. The service providers (generators, and in some cases large consumers) offer their capacity in these markets and if selected they have to leave that capacity free for the corresponding time period and they will be compensated for "availability" of their service ("availability" or "capacity" payment). In other words, they leave their capacity free so that if the system operator needs it in real time it can be activated. Regardless of whether or not the capacity will be actually activated, the reserve providers are compensated for making this capacity available (the basic definition of "reserves"). The "demand" in this market is the "reserve requirement" of the system, which is calculated based on technical characteristics of the system and shows the minimum amount of reserves required for secure operation of the system.

- ***Balancing energy markets*** are real-time markets through which the TSO procures the required amount of (balancing) power that will compensate for the power imbalance (production-consumption mismatch) in the system. Thus, in these markets, service providers are compensated for the actual delivery of energy ("utilization" or "energy" payment). The "demand" in this market is the real-time imbalance of the system.

As mentioned above, for each type of balancing services (primary, secondary, tertiary control), a reserve capacity and/or a balancing energy market may exist in order to, respectively, procure the required amount of reserve capacity to insure system security, and to procure balancing energy to resolve imbalances in real-time. The need for establishment of these markets for each type of balancing services highly depends on the characteristics of the corresponding service and is a "design variable" of balancing services markets which will be discussed in depth in the third chapter. The combination of all these different markets constitutes the first component of a balancing market, "balancing service procurement".

1.4.2. Balance responsibility

The system operator needs accurate generation, consumption, and trade "schedules" of market parties beforehand in order to be able to ensure that operational constraints of the system will be met and the system will work securely in real-time. The schedule of a party shows the planned generation/consumption/trade of that party for the specified time period (usually one hour). Needless to say, there can always be a mismatch or "imbalance" (as a result of forecast errors, an outage, etc.) between the scheduled (planned) portfolios and the actual amount of generation, consumption or trade in real-time. These individual imbalances constitute the "system imbalance" that will be resolved by activation of balancing energy in the balancing energy markets. Balance Responsible Parties (BRPs) are market parties who take over the responsibility of preparation and submission of schedules to the system operator for all the parties under their control. A BRP can include generators, consumers, and traders and submits one schedule for the entire portfolio under its control. A balance responsible party is responsible for keeping the balance between its submitted schedule and actual portfolio in real-time, and faces liability consequences (in the form of an "imbalance charge") if there is a mismatch. In other words, if a BRP has an imbalance (there is a mismatch between its planned and actual portfolio), it will be charged with an imbalance price. Construction of this imbalance price involves the third component of balancing markets described in the next section.

1.4.3. Balance settlement

Balance settlement is the procedure of allocating the costs of balancing the system, incurred by activation of balancing energy bids, to the balance responsible parties with an imbalance (deviation from their submitted schedules). Therefore, the balance settlement procedure determines the imbalance price with which the parties with an imbalance will be charged. This imbalance for each BRP is the difference between its scheduled/planned energy volume and its metered energy volume, and it can be either positive or negative. The imbalance price is based on the balancing costs that are determined by the activated bids in the balancing energy markets. In other words, the individual imbalances of BRPs form the system imbalance, and the TSO buys balancing energy (in the balancing energy markets) by activating bids of the service providers to resolve this system imbalance. Then based on the price the TSO pays the service providers in the balancing energy market, the imbalance price is calculated with which the BRPs who created the system imbalance are charged. Calculation of the imbalance price involves many details and can be performed in a highly complex way. Since it is not the focus of this research, we refer the interested reader to the current literature on the different aspects of designing the "balance settlement" procedure [23-29].

It should be noted that balance settlement concerns allocation of TSO's expenses in the "balancing energy markets". Costs of procuring reserve capacity, which are the TSO's expenses in the "reserve capacity markets" are usually socialized so that every system user pays its share. This originates from the nature of the reserve capacity service: Reserves are needed for insuring security of the system (that benefits all) regardless of the real-time imbalances.

The three components of balancing markets are illustrated in Figure 1. 1.

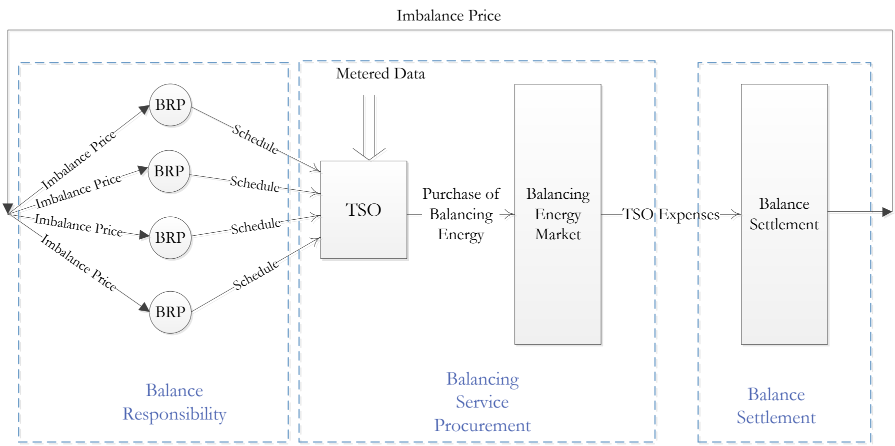


Figure 1. 1. three components of balancing markets

1.5. Balancing services markets

The focus of this research is on the first element of balancing markets described above: balancing service procurement. Therefore, "balancing services markets" are at the heart of this research, and so, we describe these markets in more details in this section. As mentioned earlier, there are three main balancing services namely primary, secondary and tertiary control. For each of these services there can be a capacity (reserve capacity) and an energy (balancing energy) market depending on the balancing market design which differs in different countries/regions. We call all these different markets "balancing services markets". Figure 1.

2 illustrates the reserve capacity and balancing energy markets for one type of balancing services. The TSO is the single buyer and balancing service providers (BSPs) are the sellers in both markets.

Balancing energy markets are real-time markets through which the TSO procures the power that will compensate for the real-time power surplus/shortage in the system. BSPs offer part of their capacity that is still available after the closure of all the other electricity markets in balancing energy markets. Each bid consists of a volume in MW and a price in €/MWh. BSPs can offer upward or downward bids. If there is a power shortage in the system, the TSO will activate upward regulation bids so that more power is generated in the system and the shortage is resolved. In case of a power surplus in the system, the TSO will activate downward regulation bids so that less power is generated in the system and the surplus is resolved. Therefore, for each time period, two bid ladders are formed; one for upward and one for downward regulation. The TSO looks at the system imbalance and activates the required amount of bids (in the direction needed) to remove that imbalance, the cheapest bids activated first. Depending on the pricing mechanism used, the selected BSPs will be compensated either by their own bid price or by the market price (price of the marginal bid). Balancing energy markets are cleared once for each Program Time Unit (PTU), the basic time unit used in the balancing market. PTU is the time unit for which the system imbalance needs to be resolved, which can be as short as 10 minutes (e.g. in PJM Interconnection) or as long as one hour (e.g. Nordic system) [12, 28, 30]. In other words, PTU is the time unit for which the schedules are made by balance responsible parties, balancing energy bids are submitted by balancing service providers, and imbalances are resolved and settled.

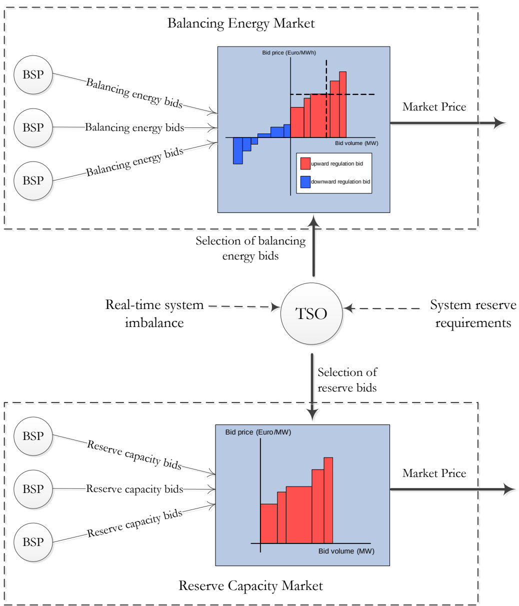


Figure 1. 2- Schematic view of balancing services markets: balancing energy and reserve capacity markets

As shown in Figure 1. 2, balancing services markets also include reserve capacity markets. BSPs can offer their free capacity in the reserve capacity market, each bid consisting of a volume in MW and a price in €/MW. The demand in the reserve capacity market is the "reserve requirement" of the system which is calculated based on technical characteristics of the system and shows the minimum amount of reserves that needs to be available at all times to insure system security. Thus, the TSO buys the required amount of reserves in the reserve capacity market by selecting the cheapest bids offered by BSPs in the market. Depending on the pricing mechanism used, the selected BSPs will be compensated either by their own bid price or by the market price (price of the marginal bid). Reserve capacity markets by nature are not real-time markets, and depending on the design they might be yearly, monthly, weekly, daily or even hourly markets. Design of these markets will be discussed in details in chapters 3 and 4.

1.6. Balancing market integration (EU context)

During recent years, there have been many discussions at the international level regarding facilitation of cross-border balancing exchanges and creation of integrated multinational balancing markets in order to use balancing resources in a more regionally efficient way. European Regulators Group for Electricity and Gas (ERGEG) provides guidelines of good practice for electricity balancing markets integration which consists of general policy-related recommendations on design of integrated balancing markets with special emphasis on improvement of operational security of the system, efficient allocation of cross-border capacities, market efficiency and competition, transparency, and development of standards for data and information exchange [31, 32]. Union of the Electricity Industry-EURELECTRIC advocates a sequential approach in order to achieve integration of intra-day and balancing markets across borders [33]. The report mentions the need for establishment of national and cross-border "intra-day" markets, and in parallel, introduction of market-based procurement mechanisms for reserve and balancing power with sufficient harmonization of the key issues of these markets in order to allow, as a further step, the cross-border optimization of balancing markets.

European Transmission System Operators (ETSO) focus on facilitation of cross-border tertiary control service and analyzes the consequences of the steps in integration of the corresponding markets considering four different models (related to different levels of cooperation/integration) [34]. Although the report mentions that it is extremely difficult, if not impossible, to quantify these effects ex ante or even assign them to regulatory differences ex post, it recognizes main challenges in markets integration to be product incompatibility, differences in price structure, and differences in procurement mechanisms of system operators of different systems, and emphasizes the harmonization needed in market design issues and calculation of imbalance prices.

In another report, ETSO envisages an evolving regional harmonization and integration process enabled by a cooperation agreement between the TSOs in the region and supported by changes in existing legal, regulatory and inter-TSO arrangements as far as necessary [35].

The report emphasizes that in order to achieve full benefits all issues defining the characteristics and costs of the balancing services, including reserve definitions, technical requirements and procurement principles, and also issues defining characteristics and price of the balancing services, including gate closure time, balance responsibility, imbalance definition, settlement period, determination of imbalances and imbalance pricing principles, need to be harmonized. Based on previous reports, Union of the Electricity Industry (EURELECTRIC) analyzes the balancing markets integration problem in more depth and focuses on the design of markets for procurement of balancing services and proposes a design model for the capacity and energy markets without any distinction between different services with different characteristics [36, 37].

Beside the literature briefly reviewed above, which concerns high level policy-related guidelines and recommendations on balancing markets integration as a single problem, comprehensive studies addressing various technical, institutional and economic challenges of integration of national balancing markets are missing. In addition, although as mentioned in several reports, full harmonization of all components of balancing markets would lead to the highest "benefits", considering the fundamental differences in the market design of different countries, a realistic assessment of the current situation and "feasible" changes that can enable cross-border balancing exchange is of critical importance. In other words, although a fully integrated balancing market can be considered as the ideal case (in terms of yielding the highest benefits), the fundamental market design differences, resistance against change by market parties and system operators, and legal and regulatory complications make feasibility of "full harmonization/integration" of balancing markets debatable. Therefore, in this research, one main goal is to find a "feasible" way of enabling cross-border balancing exchanges, with minimum structural changes imposed on the individual markets.

Since, in contrast to wholesale electricity markets, e.g. day-ahead markets, a balancing market is not a single market with one single product to be traded in the market, the process of integration is much more complex and every element of balancing markets needs to be studied in more detail. This dissertation is focused on exchange of balancing services, and thus, the two other components of balancing markets, namely balance responsibility and balance settlement, are not directly addressed. We study the design of balancing services markets first from a national perspective, studying the effect of different design variables on the performance of the entire market. And then, using our findings in the first part, we study the market design from a multinational perspective addressing challenges in realization of an integrated balancing market for Northern Europe. We provide recommendations on the basic changes essential for enabling cross-border exchange of balancing services, and then we argue for some further changes that although not fundamentally essential for exchange of balancing services but can improve the performance of the resulting integrated market rather significantly.

2. RESEARCH FRAMEWORK

2.1. The "Balance Management in Multinational Power Markets" project

According to the Union of the Electricity Industry-Eurelectric, although significant progress has been made in the development of efficient national and multinational day-ahead and forward markets, liquidity is still limited in intra-day markets – where these markets do exist – and in real-time balancing markets [33]. Achieving open liquid intra-day and balancing markets is crucial to allow further progress in developing efficient wholesale electricity markets move towards the goal of a pan-European market [33]. In addition, due to the continuously increasing share of Renewable Energy Sources (RES) with less predictable outputs in power generation, the need for balancing services increases and the challenge of balancing the system in an effective and efficient way becomes more prominent.

On this basis, the project titled "balance management in multinational power markets" was defined and initiated in 2007 by the Norwegian Research Council [38, 39]. The main objective is: "To design the scientific foundation for a framework for efficient, market-based balancing of power systems that can be implemented in multinational ('regional' in the wording of the European Commission) power markets." The focus of the project is on integrating separate balancing markets of the Nordic system, the Netherlands, Germany (and probably Poland) [38]. The possibility to trade balancing services between Nordel on one hand, and Germany and the Netherlands on the other hand is of particular interest because of three main reasons [39]:

· Hydro generation has ideal characteristics for providing balancing services compared to thermal plants.

· Increasing integration of the Nordic system with UCTE, specifically through the recent Nor-Ned cable.

· Norway will be a net importer of electrical energy in the coming years, which leaves more room for exporting balancing services.

According to the project proposal, cross-border trading of balancing services will lead to more flexible and efficient use of balancing services, irrespective of the control area, which in turn will result in reduced total balancing costs of the multinational balancing market. The project consists of the following work packages [39]:

1. *Identification and analysis of existing balancing mechanisms:*

As a necessary prerequisite for further analysis, a thorough overview of the existing balancing mechanisms and how they are applied is presented in this work package. As a preparation for the subsequent activities, this work package will include analysis of the institutional and regulatory differences between the countries as well as potential institutional and technical barriers for integration.

2. *Documentation and analysis of present costs:*

The main objective of the project is to reduce the balancing costs in the North European power markets. As a further preparation for the main activities in the project, it is necessary to know the present costs of balancing. In this work package an attempt will be made to estimate the real balancing costs of existing thermal plants in the relevant countries, and compare these with the TSOs' actual balancing costs.

3. *Alternative market designs:*

Based on outputs of the first two work packages the existing institutional and regulatory environments in the respective countries will be analyzed, as well as any supranational guidelines (European Commission, ETSO, Nordel, UCTE). This work package analyzes the relation between technical characteristics, the market and the institutional design of the existing balancing markets.

4. *Balancing costs in integrated balancing markets:*

The objective of this activity is to obtain accurate estimates of the balancing costs under various assumptions with respect to the integration of balancing markets. To this end, models are developed for simulating the operation of integrated multinational power systems, with a specific focus on balancing markets.

5. *Institutional design and harmonization:*

In this part of the project the focus is on the institutional arrangements in the participating countries, the necessary degree of harmonization, identification of barriers and a systematic approach to overcoming these barriers. Output of this work package will be policy advice with respect to how to integrate national balancing markets.

This dissertation addresses the aspects related to institutional and economic design of integrated multinational balancing markets, which is part of work packages 3 and 5. It should be emphasized that, although the above-mentioned distinction between different main research activities (work packages) helps structure the research within a systematic framework, the work packages are not independent. Work package 3 is related to finding the most promising designs while work package 5 is focused on the implementation of the selected design. Obviously, they are highly interrelated because the decision on the best design cannot be made without deliberation on the implementation process.

2.2. Focus of the research

Although the task of balancing generation and consumption in a power grid is technical by nature, any balance management mechanism is a complex institutional arrangement that, among other things, includes various markets and thus, integration of separate national balancing markets cannot be achieved without taking highly interwoven economic and institutional aspects into consideration. As mentioned in the first chapter, this research focuses on markets for procurement of balancing services. The market design will be the main concern in this dissertation. We investigate how different designs for balancing services market can possibly change the market performance.

As mentioned earlier, balancing services are markets with the system operator as the single buyer on one side, and the balancing service providers (BSPs) as sellers on the other side. The TSO is the entity responsible for security of the system; it buys the balancing services needed for secure operation of the system and then allocates the costs to system users. So the system operator is an entity that ideally does not have a financial stake in the outcomes of the markets; as long as system security is ensured, the system operator has done its responsibility. However, system operators are not necessarily totally objective or impartial entities; in practice, system operators have their own sets of priorities and in particular cases, may behave in ways that are in contradiction with their ideally intended neutrality in the market.

On the other hand, the BSPs are profit-driven parties and their behavior can be significantly influenced by the design chosen for the market. In our search for the possible effects of different market designs on market performance, we study the behavior and possible reactions of BSPs to market design (actor perspective), and then look at the aggregate effect of behavioral changes of BSPs on the system performance (system perspective).

In order to understand the dynamics of balancing services markets, we start our analysis from a national perspective; we identify the variables that play an important role in design of these markets and study the variables which have been partially overlooked in the current literature on design of "ancillary services markets" (a more generic term that includes balancing markets, as well as other markets needed for secure system operation, e.g. reactive power control market). This first part of our analysis (design from a national perspective) will lead to recommendations on how to improve the performance of the national balancing services markets. These recommended changes will also facilitate integration of the separate national markets; these reforms in the national markets would take us closer to the point where integration of balancing services markets is feasible. In the second part of our research, market design from a multinational perspective is studied. We investigate how alternative arrangements for cross-border exchange of balancing services can influence the behavior of balancing service providers and consequently the performance of the market as a whole.

2.3. Research questions

The main research question addressed in this dissertation is as follows:

- Given the fundamental design differences in balancing services markets of different countries (mainly in Europe), what changes need to be made, both at the national and at the multinational level, in order to improve economic performance of the national markets and to achieve a regionally integrated market for balancing services?

As the main research question implies, this research is divided into two major parts. The first part dealing with balancing services markets design from a **national** perspective addresses the following sub-questions:

1. What are the decision variables in design of each type of balancing services (identification of the design space)?

2. What are the relevant criteria in assessing the performance of balancing services markets design (identification of the performance criteria)?

3. How can alternative decisions for each design variable influence the incentives and behavior of market parties and consequently performance of the entire market?

4. What recommendations can be drawn regarding design of national markets in order to improve market performance and also to facilitate market integration?

The second part of this research dealing with balancing services markets design from a **multinational** perspective addresses the following sub-questions:

1. What is the design space for integration of separate national balancing services markets?

2. How should the current infrastructure (interconnection lines) be managed in order to use the transfer capacity in the most efficient way, concerning both day-ahead and real-time balancing trades?

3. How should the basic design variables be harmonized in order to enable cross-border exchange of balancing services with minimal structural changes on the national markets?

4. As the next step, what other variables can be harmonized in order to improve the performance of the multinational market and achieve a fully integrated market?

2.4. Phase one – national design

According to the wide differences in balancing services markets designs used in different countries/regions, lack of scientific literature on the generic subject of balance management, and high level of complexity in real-time electricity markets compared to wholesale electricity markets, a comprehensive study of the existing balancing services markets used in different power systems is the unavoidable first step. A combination of various designs employed in different countries in Europe and designs used in the North American systems can be a suitable set of case study. The markets in the Netherlands, the Nordic system, Germany, PJM Interconnection and California ISO have been studied in this research. Although our focus in this dissertation is Northern Europe, studying other designs next to the European designs can broaden our perspective and help us understand the various alternatives in market design.

After studying the different mechanisms used for procurement of balancing services in each of the case studies, the different variables in design of the markets for balancing services can be identified. In addition to identifying the design space, we identify the performance criteria, which are the factors one should look at in order to assess the market performance. So as the second research step, by identifying the design variables and performance criteria, we create a tool that can help "measure" the performance of different designs that are to be analyzed in this research.

The next step is dedicated to investigating the effect of the design variables on the performance of balancing services markets using the identified performance criteria. We do not study all the variables identified in the previous step, given the considerable literature on the effect and role of some of the design variables (which will be reviewed in detail in chapter 3), we focus on the most critical and overlooked design variables. We will use market simulation, agent based modeling and case studies as the methodologies of this step.

The last research step of the first phase, draws conclusions about reform on the national markets that can improve market performance and also get the current national markets closer to the point where market integration is achievable and realistic. This last step will lead to two major outcomes:

- General conclusions on appropriate designs for each balancing service market from a national perspective.
- Case-specific recommendations for required reform in design of balancing services markets at the national level (case of Northern Europe).

2.5. Phase two - multinational design

Phase two of this research is focused on design of regional markets for balancing services from a multinational perspective. In order to identify the main alternative designs, the results of the first phase and the current literature on market integration in Europe is taken into consideration. In order to investigate the effects of different designs, agent-based models are developed and the markets are analyzed from a market party perspective and then the aggregate effect of change of behavior of market parties on the system is studied. The case of Northern Europe is particularly modeled in this step.

Fundamental differences in design of balancing services markets at the national level lead to serious institutional and technical barriers in integration of markets, which in turn will make the process of harmonization and integration extremely complex. Therefore, considering the practical challenges in integration of national balancing services markets, the integration problem is not solely about finding the best design for the resulting multinational market: implementation of the desirable design is a crucial aspect of the integration problem as well. The transition from separate individual national markets to a fully integrated market for balancing services cannot be achieved in a single step. Therefore, the second step of phase 2 focuses on facilitation of cross-border balancing services trades with minimal changes imposed on the local (national) arrangements. In this step, which is an intermediary step to achieve fully integrated balancing services markets, two main research activities are performed. Firstly, the fundamental design variables that need to be harmonized in order to enable cross-border balancing services trades are identified and the proper way of harmonizing them (with minimal changes) is discussed. Secondly, the issue of interconnection capacity allocation is addressed. Interconnection capacities (between countries) can be used for wholesale electricity exchanges or for near real-time balancing services. Therefore, in order to enable balancing services exchange, the most efficient interconnection capacity allocation method needs to be found. This research step has two main outcomes:

- General and case-specific recommendations on integration of national balancing services markets

- Recommendations on efficient interconnection capacity management

3. Exploring the Design Space of Balancing Services Markets

3.1. Introduction

Identifying all the design variables is the prerequisite for finding possible market designs for balancing services and eventually evaluating those different alternative designs. For each design variable, there may be different possible states, therefore, based on the identified design variables and different possible decisions for each variable, the entire design space for each balancing service market can be identified. Additionally, in order to analyze the effect of different decisions on the performance of the whole market, the relations between design variables and the performance criteria should be understood. Identifying the relevant performance criteria actually enables us to develop a tool to assess the performance of alternative market designs.

3.2. Design variables

Figure 3. 1 which is based on the theoretical framework developed and presented in [5], shows the main design variables for balancing services markets and illustrates the interrelations between different variables. Since the priority and the relative importance of different design variables play a key role in understanding the design space and interrelation of various variables, in this figure the variables are divided into three levels. The decisions made on variables at a higher level directly or indirectly influence the "possible" decisions on variables at the lower levels. Therefore, the variables at top represent the fundamental decisions that need to be made before any other decision in design of balancing services markets. All these main design variables are described and their interrelations discussed in the following sub-sections.

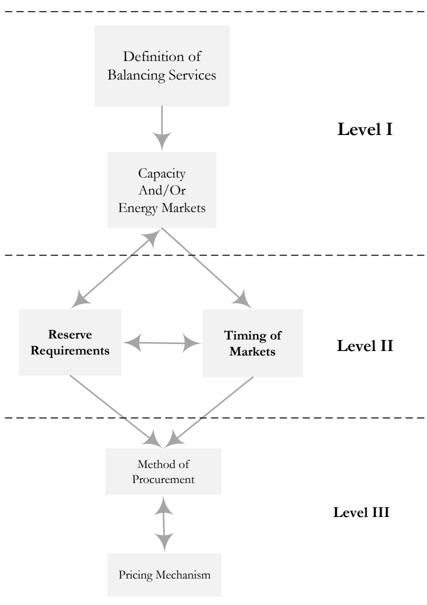


Figure 3. 1. The design variables (divided into three main levels) and their interrelations

3.2.1. Definition of balancing services

The very fundamental variable in design of balancing services markets is the definition and categorization of services. As mentioned in the previous chapters, in order to maintain the balance between generation and consumption in a power system, the system operator needs different types of services with different technical characteristics, e.g. the activation times (response speed), the method of activation (manual/automatic), the minimum deployment time, and their state (synchronous/non-synchronous). Definition of balancing services is made based on technical characteristics of the system such as the share of different technologies in the generation portfolio (thermal, nuclear, hydro, etc.), and the technologies used in the control systems, for example use of Automatic Generation Control (AGC), and the method of activation of services (automatic signals, manual over the phone, etc.). The general criterion, based on which balancing services are defined, is 'effective' operation of the entire balancing market. It should be noted that definition of balancing services is not really a decision made when the markets are being designed. Even before the liberalization of the electricity sector, in the vertically integrated systems that preceded the current systems, balancing services were being used to balance the grid, the only difference was that these services were not procured through a market-based mechanism. Therefore, the current definitions for balancing services used in different countries are the result of a path taken through the history of the electricity sector in that country.

However, this does not necessarily mean that the definitions cannot be changed. Especially in Europe, with the omnipresent discussions on creating regional electricity markets (and finally one single European market), some changes in how balancing services are defined in different countries may seem likely, simply because if the balancing market are to be integrated, the services traded in these markets should be more or less the same in different countries across Europe so that they can be exchanged across borders more easily. As an example, in the Nordic system where balancing services are manually activated (the requests are sent using phone conversations), introduction of AGC is being seriously discussed, so that the Nordic system can exchange balancing services with the UCTE system (in continental Europe, where AGC is in use) [23].

3.2.2. Capacity and/or energy markets

As discussed in the first chapter, for each type of balancing services, a (reserve) capacity and/or a (balancing) energy market may exist in order to, respectively, procure the required amount of reserve capacity to ensure system security, and to procure balancing energy to resolve imbalances in real-time. The need for establishment of these markets for each type of balancing services highly depends on the characteristics of the corresponding service.

There may be no market at all: for example, provision of the primary control service in the Netherlands and PJM interconnection is the prerequisite for generators to be connected to the grid (because of the high interrelation of this service with system security), so service provision is compulsory and there is no compensation for service providers [18, 19, 40].

There may be only a capacity market and no energy market, e.g. primary control service in Germany is procured via a capacity market and there is no compensation for the actual delivered energy (no utilization/energy payment). Since the primary control service has a high response speed (15 seconds) and it is quickly replaced by other slower balancing services, the amount of actual energy delivered in real-time by primary control resources is marginal and therefore, no utilization compensation is considered for this service in Germany (no energy market) [20].

Another possibility is the use of both a capacity and an energy market, e.g. regulating power (corresponding to secondary control service in UCTE terms) in the Netherlands and Norway. In this case, capacity bids selected in the capacity market receive the availability payment and the energy bids selected in the energy market for real-time energy delivery receive a utilization payment.

There may also be one single market that functions both as the capacity and the energy market. For example, in PJM Interconnection, the regulation market (corresponding to secondary control) is actually a capacity market with which the PJM system operator procures the regulation reserve requirement of the system. But there is no other separate energy market and the system operator uses the same bids for activation of regulating power in real-time based on the actual imbalance of the system. So the regulation bids are in $/MWh, and the service providers take their production costs (which is only applicable to energy bids and not capacity bids) into account in their bids for the regulation market. Therefore once selected, irrespective of whether or not their capacity is actually activated in real time, regulation service providers will be compensated for both availability and utilization of their service [15, 16]. In case they are actually activated in real-time, they may receive another payment from the system operator which will compensate them for their lost opportunity costs.

This design variable (the need for capacity and energy markets for each type of balancing services), as Figure 3. 1 illustrates, is influenced by the definition of balancing services, which is a higher level design variable itself.

3.2.3. Reserve Requirements

The reserve requirement is considered a design variable because, on the one hand, it is the key to secure operation of the system, and on the other hand, plays a crucial role in determining the procurement costs of 'reserves' which is part of the costs of system security. As noted in chapter 1, the reserve requirement for each type of balancing services is the minimum amount of reserve (for that balancing service; primary, secondary, tertiary) that must be available in order to ensure that the system will work in a secure and reliable way. Thus, the reserve requirement for each type of balancing services determines the 'demand' in the reserve capacity market for that balancing service; and therefore, it significantly influences the total reserve procurement costs of the system. These requirements are determined based on the **system security criteria** which are different for different types of balancing services and for different countries, and determine the minimum amount of reserves for each type of balancing services. However, the security criterion is not the only factor affecting reserve requirements; **Frequency of calculation of reserve requirements** plays a crucial role as well. Requirements can be calculated for different time horizons; annual, monthly, weekly, daily, and even hourly. Once calculated, the minimum reserve requirements are fixed for that time span. This design variable will be discussed in more detail in the next chapter.

3.2.4. Timing of markets

The variable that is called 'timing of markets' in this dissertation is a complex variable with critical importance regarding market performance. This variable has two main aspects: *timing of the bidding procedure* and *timing of the markets clearance*, which are discussed in the following subsections.

3.2.4.1. Timing of the bidding procedure

Different time horizons for the 'bidding procedure' can be used for different types of balancing services, both reserve capacity and balancing energy markets. As an example, in Germany, the bidding procedure of the capacity market for primary and secondary control service is monthly, so capacity providers submit their monthly bids that are fixed for the entire coming month. However, the capacity market for tertiary control (minute reserves in Germany) is a daily market and capacity providers submit their bids on a day-ahead basis [20, 41]. The time horizon of the bidding procedure for different markets (which can also be seen as 'frequency of bidding') highly depends on the characteristics of the service (primary, secondary, tertiary) and the type of the market (capacity and energy). Table 3. 1 summarizes the time horizon of the bidding procedure (frequency of bidding) of the reserve capacity markets for different types of balancing services in different systems/countries. Since the terminologies widely differ, the particular name, by which each balancing service is called in the corresponding country (in case a different name is used), is also mentioned in parentheses.

Table 3. 1. Time horizon of the bidding procedure of the reserve capacity markets for different types of balancing services- different systems

	Primary Control	Secondary Control	Tertiary Control
Netherlands	-	Yearly (Regulating and Reserve Power)	Yearly (Emergency Power)
Germany	Monthly	Monthly	Daily (Minutes Reserves)
Norway	-	Weekly (FADR)	-
PJM	-	Daily (Regulation)	Daily (Synchronized Reserves & Day-ahead Scheduling Reserves)

After making the decision on frequency of bidding (possible from annual to PTU-basis), the gate opening and closure times of the markets need to be decided upon. Since generators have the possibility to offer their free capacity in wholesale electricity markets (such as day-ahead and intra-day markets) or in capacity and energy markets for various types of balancing services, the gate opening and closure times for the bidding procedure in balancing services markets (both capacity and energy) need to be carefully coordinated with those of other markets such as day-ahead market. This timing coordination aspect significantly influences the interrelations between different markets and has a critical influence on the efficiency and liquidity of balancing services markets (especially because of the very small size of these markets compared to day-ahead markets).

3.2.4.2. Timing of the markets clearance

Similar to 'timing of the bidding procedure', 'timing of the markets clearance' for balancing services has two main elements: frequency of balancing services markets clearance and coordination of markets clearance with other electricity markets. Generally speaking, frequency of bidding (related to the time horizon of the bidding procedure discussed in the paragraph above), can be different from the frequency of the clearance of the market.

As an example, the balancing energy market for secondary control in Germany is monthly and generators submit one bid (a price and a volume) for the entire coming month (frequency of bidding is once per month), while the balancing energy market is 'cleared' once for each Program Time Unit (PTU), which is 15 minutes in Germany and thus the frequency of market clearance is once per quarter of an hour [5, 7].

The second aspect of 'timing of the markets clearance' is the coordination of balancing services markets clearance with those of other electricity markets, specifically day-ahead (DA) and intra-day (ID) markets. Since balancing energy markets are real-time markets and are cleared when all other markets are closed and cleared, there is no coordination needed between clearance of balancing energy markets and other markets. On the contrary, clearance of the reserve capacity markets may need to be coordinated with clearance of day-ahead or intra-day markets (depending on the frequency of market clearance of the capacity market). In case of a day-ahead capacity market (e.g. tertiary control service in Germany, and day-ahead scheduling reserves in PJM), there are two main possibilities in terms of coordination of the capacity market clearance with the day-ahead market: sequential and simultaneous clearance.

Another example is coordination of capacity markets clearance with each other (and not with the day-ahead or intra-day markets). The Californian ISO (CAISO) uses four capacity markets for four different balancing services (regulation service, spinning reserve, non-spinning reserve, and replacement reserves) [13, 14, 42, 43]. CAISO used to clear these markets sequentially (from higher quality services to lower quality ones) and has recently changed it to simultaneous clearance of all the four capacity markets, because of efficiency and liquidity considerations [42, 43]

In short, 'timing of markets' as a design variable can significantly influence the interrelations of balancing services markets with each other and with other electricity markets, and thus, the decisions that need to be made on this design variable demand meticulous studies of the effect of this variable on the performance of balancing services markets as well as day-ahead and intra-day markets.

3.2.5. Method of procurement

Different methods can be used in procurement of balancing services: compulsory provision, bilateral contracts, long- and short-term auctions (tendering), and a combination of bilateral contracts and auctions. For example, the primary control capacity is procured on a compulsory basis in PJM and the Netherlands [5, 12]. Bilateral contracts are used for secondary control capacity procurement in the Netherlands, Sweden and Finland [12]. Long-term auctions are used for secondary control energy in Germany, and short-term auctions in the Netherlands, and the Nordic system [4, 40]. In Australia and New Zealand, both bilateral contracts and auctions are used to procure primary control capacity [9, 10].

Each of these procurement methods has its advantages and disadvantages that need to be studied, taking into account different characteristics of different balancing services. Table 3. 2 summarizes the methods of reserve capacity procurement for different types of balancing services used in different countries/systems. In case of balancing energy markets, auctions are typically used.

Table 3. 2. Methods of reserve capacity procurement for different types of balancing services used in different systems

	Compulsory provision	Bilateral contracts	Long-term auctions	Short-term auctions
Primary Control	NL, PJM	-	DE	-
Secondary Control	-	NL	-	DE, NO, PJM, CA
Tertiary Control	PJM	NL	-	DE, PJM, CA

Because of this design variable's influence on balancing service providers' incentives, it affects the offered capacities in different balancing service markets, available resources in each market, bid prices of service providers, and transaction costs of market parties. This variable also plays an important role in the transparency of balancing service markets, e.g. use of confidential bilateral contracts for secondary control capacity procurement in the Netherlands has led to a non-transparent situation in which no data from the market is available to the public.

3.2.6. Pricing mechanism

The last design variable is the pricing mechanism of various balancing services markets. Balancing services can either be non-remunerated, or paid for, using any of the following types of pricing mechanisms: a regulated price, a pay-as-bid price, or a uniform clearing price (marginal pricing). Although a non-remunerated mechanism may be very convenient for the system operator, it will logically result in the costs of the balancing service providers being reflected in the price of other products. A regulated price is set by the regulator or the system operator and is usually the same for all service providers. In a pay as bid system, the supplier receives the price of its accepted offer. This type of remuneration method is suitable when the quality of the ancillary services offered is highly differentiated and those offers are thus not easily comparable [44]. In a uniform-price system, all the successful providers are paid the price of the most expensive accepted offer (and in some designs, the least expensive rejected offer).

3.3. Performance criteria

In order to evaluate the effect of different design variables on the performance of a balancing market, and eventually to evaluate different alternative market designs, a set of performance criteria need to be identified. By studying and measuring the effect of different decisions in market design on the performance criteria, impact of those decisions on the performance of the entire balancing market can be studied. Figure 3. 2 demonstrates the performance criteria related to design of balancing markets. The diagram starts with the most generic abstract criteria and divides each criterion into several other lower-level more concrete criteria that can be measured and studied.

As can be seen from the figure, the two main criteria in evaluating performance of balancing markets are operational security and incentive compatibility. These two criteria representing the technical and economic performance of the market respectively, can be divided into other detailed performance criteria. The definition of each of the proposed criteria is presented in the next section.

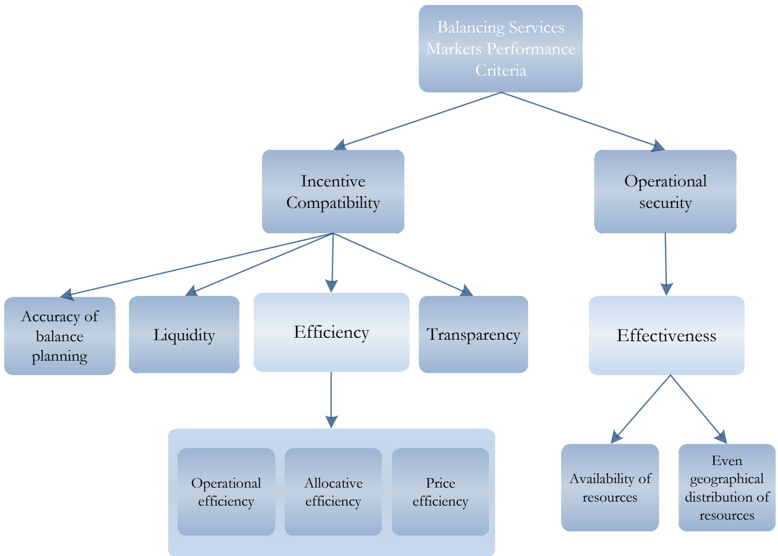


Figure 3. 2. Performance criteria in design of balancing services markets

3.3.1. Operational security

As mentioned before, the foremost objective of balancing markets is to balance supply (generation) and demand (load) in the grid by means of a market-based mechanism. The operational security criterion refers to the technical performance of balancing markets and therefore to the 'effective' operation of the balancing mechanism in achieving its main goal. Thus it is directly connected to 'effectiveness' of the balancing mechanism, and consequently effectiveness of the reserve capacity market and balancing energy markets. Availability of resources (in these two types of markets) and even (geographical) distribution of resources are the two criteria determining effectiveness of these markets. The latter plays an important role in reserve capacity markets, especially for the primary control service. Purchasing reserves from resources that are evenly distributed throughout the network reduces the likelihood of not being able to activate the purchased reserves in real-time simply because of transmission congestion.

3.3.2. Incentive compatibility

Incentive compatibility is the generic characteristic of the market design that addresses incentivizing market parties to behave in such a way that best serves the general goal of maximizing societal benefit. An incentive compatible rule is one that makes the people who have to obey it do so voluntarily because it is in their own interest to do so [45]. According to their self-interestedness, market parties will pursue the means available to them to maximize their own profit in an open environment. This could lead to undesirable situations and sub-optimal solutions that are more preferable to some parties and not acceptable to others. Therefore, incentivizing market parties to behave in such a way that ensures the fairness/optimality of the final solution plays a critical role in the design process. Incentive compatibility is the key to defining proper rules [45].

Incentive compatibility in balancing markets design includes all the highly interrelated institutional and economic aspects of balancing markets and it stands as the second main criterion next to operational security. In order to be able to understand and study this high-level abstract criterion, it needs to be divided into more concrete criteria.

3.3.2.1. Transparency

Information availability, information symmetry (equal access to information) and clarity of the rules of balancing markets lead to market transparency which is a prerequisite of a competitive market. High level of transparency regarding balancing market rules (balance responsibility, balancing services markets and balance settlement), determination of imbalance prices, and imbalance volumes will improve the functioning of the market by enabling market parties to make informed decisions and eventually to encourage new entry and increase competition in the market.

3.3.2.2. Efficiency

This performance criterion refers to the economic efficiency of both reserve capacity and balancing energy markets. Because of the ambiguity of the concept, market efficiency, as one of the primary objectives in design of electricity markets in general, needs to be carefully defined and divided into more tangible performance criteria:

- ***Operational efficiency*** is the aspect of market efficiency that addresses transaction costs of market parties in the market. Therefore, operational efficiency is related to carrying out the market operations with as low a cost as possible. There are various variables in the design of balancing markets that influence this aspect of market efficiency, e.g. method of procurement of reserve capacities (compulsory, bilateral contracts and auctions), the time horizon of reserve capacity and balancing energy markets (frequency of bidding), etc.

- ***Allocative efficiency*** (from a system perspective) is the aspect of market efficiency relating to optimal use of limited available resources. In case of balancing services markets, this performance criterion aims at meeting system's reserve requirements (through reserve capacity markets) and resolving system's real-time imbalances (through balancing energy markets), with use of the optimal set of available balancing resources. Since this criterion addresses the "optimal selection" of "available resources", the two factors influencing this criterion are: Firstly, the system operator's use of the cheapest balancing resources offered in the markets (optimal selection), and secondly, incentives of balancing resource owners to offer their capacity as balancing services (available resources). The second factor can play an important role because in case of reserve capacity markets, service providers can offer their capacity in other wholesale electricity markets instead of reserve capacity markets, and in case of balancing energy markets, service providers may keep their resources in order to regulate internally (self-regulation). So giving them the incentive to offer their free capacity in balancing services markets is of great importance.

- ***Price efficiency*** relates to cost-reflectivity of prices in both reserve capacity and balancing energy markets. The price efficiency criterion deals with opportunity for service providers to behave strategically, and therefore it addresses the issue of market power and competitiveness in balancing services markets. It is also interrelated with markets liquidity (while it is not the same as market liquidity).

3.3.2.3. Liquidity

Market liquidity characterizes the market's ability to quickly match any bid to buy with an offer to sell without changing the market price. The liquidity incorporates four features: the tightness (i.e., the capability to avoid a large spread between the highest demand price and the lowest supply price); the depth (i.e., the capability to absorb large trade volumes without significant price changes); the immediacy (i.e., the capability to quickly meet the demand to sell or buy); and the resilience (i.e., the capability to recover after a price change) [46]. A market is liquid if there are many buyers and sellers who can access each other easily and have access to information about the market prices. A defining feature of a liquid market is that it can generally absorb the addition or loss of a buyer or seller without a noticeable change in the market price. Liquidity of balancing services markets criterion is related to both reserve capacity and balancing energy markets for each type of balancing services. Since balancing services markets are single buyer markets with system operator as the only buyer, liquidity of these markets relates to the number of balancing services providers and their willingness to offer services in these markets (instead of other electricity markets).

3.3.2.4. Accuracy of balance planning

The accuracy of planning deals with the accuracy of the energy schedules (energy programs) that are submitted by the balance responsible parties to the TSO that show their planned energy production/consumption/trade for specific hours. The accuracy of these programs determines the size of the imbalances that occur in real-time (since these imbalances are the deviations from the schedules). The balancing market should be designed in a way that incentivizes balance responsible parties to minimize their own imbalance, or in other words maximize the accuracy of their energy schedules.

3.4. Current literature on analysis of the design variables

The two design variables at the first level of Figure 3. 1 ('definition of balancing services' and 'capacity and energy markets') represent the basic decisions regarding design of balancing services markets. However, the definition of balancing services currently in use in different countries/regions, as noted before, is the result of a complex path taken throughout the history of the electricity sector in that country. In addition, definition of balancing services highly depends on the technologies used in the power system (especially in generation and in the control systems), which implies that different countries with different technical characteristics would need somehow different definitions.

In case of the second design variable, 'capacity/energy markets', the specific system characteristics play a decisive role. As an example, in Norway, for FADR which is manual secondary control, during summer there is no reserve capacity market. There is no need for reserving capacity in summer because the load level is low, the excess of generation capacity in Norway is high, and almost all the generating units are hydro that can provide FADR (they meet the technical requirements). Therefore, the system operator does not need to reserve capacity to ensure that enough resources will be available in real-time. However during winter, weekly reserve capacity markets are employed by the system operator because the higher load level in winter makes availability of sufficient resources in real-time less certain, so the system operator buys sufficient reserves in the RKOM market.

Therefore, although the variables at the first level of Figure 3. 1 are fundamental to market design, they are influenced by historical and technical issues to such an extent that the decision on these variables is not essentially market design related.

The two variables at the second level, 'reserve requirements' and 'timing of markets' are discussed in detail in this dissertation. The next chapter addresses reserve requirements and timing of markets, and then, the fifth chapter discusses coordination of timing of balancing services markets with other wholesale electricity markets.

The design variables at the third level of Figure 3. 1 (method of procurement and pricing mechanism) have attracted significant attention in the research on ancillary services markets design, and a considerable volume of literature exists addressing these two main variables. Thus, in the following paragraphs, we give an overview of the studies performed on these two variables and will not directly discuss them any further in the following chapters.

Authors in [4] give an overview of the advantages and disadvantages of various procurement methods for balancing services; compulsory provision, bilateral contracts, long- and short-term auctions. In compulsory provision, a certain category of service providers (mainly large generators) are obliged to provide upon request from the TSO up to a certain amount of a given balancing service. Although it is effective (will lead to insured system security because of both availability of resources and even geographical distribution of resources), and can be transparent and simple as well, compulsory provision would not be efficient. If the service providers are not compensated for their service, the costs of service provision will be reflected in other electricity products. And if they are compensated for their service with a common regulated price, the mechanism would not be fair because the high-cost resources are treated the same as low-cost ones [4].

When the TSO procures reserve capacity using bilateral contracts, it negotiates with some providers on the quantity, quality, price and delivery conditions of the service to be provided. Bilateral contracts will result in effective procurement of balancing services, they can solve the two above-mentioned problems with compulsory provision (fairness and unnecessary over-supply), and they enable service providers to hedge against risks [4]. However, they have disadvantages as well. Firstly, they lack transparency since they are confidential contracts between the system operator and specific service providers. Secondly, negotiations can be complex, time consuming and therefore costly; high transaction costs and low operational efficiency. Thirdly, since bilateral contracts are long-term contracts, the prices may be higher because of real or perceived opportunity costs for the service providers; lower price efficiency. And lastly, bilateral contracts make competition for small resources and new entries to the balancing services markets difficult (especially because contracts are long term, the uncertainty is high and small resources do not have the flexibility of their large counterparts); low allocative efficiency and liquidity.

Auctions enhance transparency and competition; higher price efficiency. In addition, in short-term auctions, the demand in the market can be updated more frequently leading to avoidance of unnecessary resource procurement; higher allocative efficiency. Short-term auctions also make new entries and competition for small parties easier; higher allocative efficiency and liquidity. However, installment of new auctions is costly and they can have a high operating cost [40]. In addition, according to the authors in [40], in case of short-term auctions, service providers get feedback from the market more frequently and can more easily learn to behave strategically.

Authors in [4] present a table that summarizes for each procurement method some of the perceived (by the authors) advantages and disadvantages. The authors mention that their analysis of different procurement methods is subjective. Table 3. 1 compares the effect of different procurement methods on the identified performance criteria in a qualitative way.

Table 3. 3. Qualitative comparison of different procurement methods using the identified performance criteria

	Compulsory provision	Bilateral contracts	Long-term auctions	Short-term auctions
Effectiveness	++	++	++	+
Transparency	++	- -	++	++
Liquidity	++	- -	+/-	++
Operational efficiency	++	-	+/-	+/-
Allocative efficiency	- -	-	+	++
Price efficiency	- -	- -	-	+
Accuracy of balance planning	+/-	+/-	+/-	+/-

As can be seen, no general statement can be made regarding superiority of a specific method. Furthermore, the importance of each parameter varies across jurisdictions (e.g., a market designer may give more importance to a procurement method that facilitates entrance of new participants, whereas another designer may prioritize market transparency) [4]. As various methods are complementary, market designers are likely to choose a mix of methods.

Regarding the other design variable, pricing mechanism, as noted earlier balancing services can be either non-remunerated, or paid according to one of the three types of pricing mechanisms. While a non-remunerated system is very convenient for the system operator (and transparent), it is unlikely to be economically optimal because the costs that the providers incur end up bundled in the price of other products such as electrical energy [40]. A regulated price is set by the regulator or the system operator and can be either nodal or zonal. Although using a regulated price might be justified to some extent when dominance of some participants is an issue, a regulated price does not properly reflect the actual cost of providing a balancing service, especially because the costs change with time and circumstances (it would lead to very low price efficiency).

Discriminatory auction prices (pay-as-bid pricing) can be justified when the quality of the balancing services offered is different, and so the offers are not easily comparable. However, since basically there are separate markets for different types of balancing services, non-comparability is not an issue. In addition, a discriminatory auction price does not give providers an incentive to offer their marginal cost, except when market concentration is low [47]. Authors in [48] argue that discriminatory auctions generally perform poorly in electric power markets. Nevertheless, many systems have actually adopted discriminatory auction prices, for example, all the balancing energy and reserve capacity markets (for primary, secondary and tertiary control) in Germany use pay-as-bid pricing.

Uniform pricing, defended for example in [42, 49, 50] for balancing services, is deemed to give suppliers a real incentive to offer their marginal cost. Uniform pricing can be used in either a Zonal or a Nodal context. Some system operators, such as in Texas, argue that nodal payment of reserve capacity gives an incentive for relieving congestion similar to energy [43]. In [42], the authors argue that it gives stronger signals to compute the marginal value of security in a nodal fashion than in a zonal manner. Nevertheless, nodal pricing is expensive to implement, increases the complexity of the system and may increase the market power of some participants in the short run. Although it's seen as a simple given fact that North American systems use nodal and the European markets use zonal pricing, and there is no sign of a willingness to change in this regard, discussions on the relative advantages of nodal and zonal pricing are still ongoing in many countries [51].

Generally speaking, there is no consensus on the superiority of either discriminatory/pay-as-bid (PAB) or uniform/marginal (MP) auctions for balancing services. In [52, 53], authors conclude that although MP and PAB yield identical expected generator profits and consumer payments, the risk of not meeting these values is greater under MP than under PAB. In [44], the author using a qualitative argument concludes that since electricity markets are non-homogeneous, the nature of the product and market incompleteness necessitate a high degree of product fragmentation, in which case a pay-as-bid settlement approach with optimized assignment based on requirements and multi-attribute of the tender, may be promising. Analyzing the case of the UK, the authors in [54], conclude that a move from uniform to discriminatory pricing under monopoly conditions has a negative impact on profits and ambiguous implications for prices and welfare.

There are reasonable arguments on both sides. There seems to be simply no consensus.

3.5. Conclusions

In this chapter, we have identified the design variables dividing them into three levels. At the top level are the variables that are influenced by historical and technical factors to such an extent that the decision on these variables actually falls out of the 'market design' domain. The variables at the lowest level have attracted significant attention and a literature review was presented showing the main findings regarding these variables. Nevertheless, the variables at the intermediate level, namely reserve requirements (the market-related aspect of it and not its technical dimension) and timing of markets, have been partially overlooked in literature. Thus, these two variables will be discussed in detail in the next two chapters. In addition, in this chapter the main performance criteria were identified which will be used in order to assess balancing services markets performance. In short, this chapter serves as the foundation for the analysis presented in the rest of this dissertation.

4. RESERVE REQUIREMENTS AND TIMING OF MARKETS

4.1. Introduction

The objective of this chapter is to study two fundamental variables in design of balancing services markets: reserve requirements and timing of markets. 'Reserve requirements' relates to reserve capacity markets only, while 'timing of markets' applies to both reserve capacity and balancing energy markets. The two case studies used in this chapter are the markets in Germany and the Netherlands. The structure of the chapter is as follows: the market design characteristics of the two case studies are introduced, the variable 'reserve requirements' is studied, 'timing of markets' for reserve capacity as well as balancing energy markets is analyzed in details, and finally conclusions (case-specific recommendations for changes in the market design from a national perspective) are drawn based on the findings.

4.2. Case studies

In this chapter, we use the case of Germany as the main case study because of two basic reasons:

- The transparency in the balancing services markets of Germany: All the 'bids' (volumes and prices) are published after market clearance in all the markets (reserve capacity and balancing energy) in Germany. Thus, in addition to the outputs of the markets, all the inputs are accessible.
- Specific design characteristics of the German balancing services markets: The designs of different balancing services markets are not only different from the designs used in other countries/areas, but also differ from each other, i.e. different designs are used for different types of balancing services in Germany.

In addition, the case of the Netherlands is also used for comparison. Since the design of the wholesale markets (day-ahead and intraday) is similar in the Netherlands and Germany, but the design of balancing services markets are fundamentally different, using the case of the Netherlands can lead to meaningful insight into the effect of different market designs in the two countries. Different 'indicators' are used in order to measure the effect of different design variables on the performance criteria. The indicators include the selected bid prices in each market, excess supply ratios, and number of pivotal suppliers.

4.2.1. Germany

Since 2001, the German TSOs have been procuring their required primary, secondary and tertiary control services on an open market. They cover their need for these reserves via a common tendering procedure in accordance with the requirements stipulated in the Energy Act ("EnWG" in German) and the associated Electricity Grid Access Regulation (StromNZV) [41]. In case of primary control, *monthly* auctions are used for procuring the required reserves (monthly reserve capacity markets). There is no balancing energy market for primary control in Germany, so the service providers are compensated only for the availability of their capacity and not for actual energy delivery. In addition, there is no distinction between upward (positive) and downward (negative) capacities, therefore when a service provider bids a certain capacity in the market, it implies that it can provide the capacity in both directions. Thus, for primary control, there is one single auction for each month.

In case of secondary control, *monthly* auctions are used as reserve capacity markets. However, there is a real-time balancing energy market for secondary control as well. Service providers submit their capacity (in €/MW) and energy (in €/MWh) bid prices simultaneously during the preceding month. Bids are selected based on their capacity price until the reserve requirement for secondary control is met. The selected bidders are obliged to keep their capacity free for the entire coming month. During the month, for each PTU, depending on the imbalance of the system in real-time, bids will be activated based on their energy prices which were submitted (together with the capacity bid price) in the preceding month. These energy bid prices are fixed for the whole month. Thus, in case of the reserve capacity market for secondary control, the frequency of bidding and the frequency of market clearance are once per month, while in case of the balancing energy market for secondary control, the frequency of bidding is once per month and the frequency of market clearance is one per PTU (15 minutes). There is a distinction between positive and negative capacities for secondary control and two separate auctions are used. In addition, there are separate auctions for peak and off peak hours. Thus, in each month, there are four separate auctions in which service providers offer their capacities as secondary control reserves: negative capacity for off-peak hours, negative capacity for peak hours, positive capacity for off-peak hours and positive capacity for peak hours.

In case of tertiary control, *daily* auctions are used as reserve capacity markets. Similar to secondary control, there is also a balancing energy market for tertiary control. Service providers submit their capacity and energy bid prices at the same time on a day-ahead basis, bids are selected based on their capacity price, and in real-time, in order to resolve system imbalance, bids are actually activated for energy delivery based on their energy bid price. Each day is divided into 6 periods, 4 hours each, and for each period two separate auctions are used, one for positive and one for negative capacity. Thus, there are 12 separate auctions in each day for procurement of tertiary control. In case of the reserve capacity markets for tertiary control, the frequency of bidding and frequency of market clearance are once per day, while in case of the balancing energy market, the frequency of bidding is once per day and the frequency of market clearance once per PTU. Table 4. 1 summarizes the characteristics of balancing services markets in Germany.

Table 4. 1. Summary of the characteristics of balancing services markets in Germany

	Reserve Capacity Market			Balancing Energy Market			Number of auctions per bidding period
	Bidding horizon	Market clearance	Distinction Up-Down-ward capacity	Bidding horizon	Market clearance	Distinction Up-Down-ward capacity	
Primary Control	Monthly	Monthly	No	-	-	No	1
Secondary Control	Monthly	Monthly	Yes	Monthly	Quarter hourly	Yes	4
Tertiary Control	Daily	Daily	Yes	Daily	Quarter hourly	Yes	12

4.2.2. The Netherlands

In the Netherlands, no market-based mechanism is used for the procurement of primary control. Providing the primary control service is mandatory and the generators providing the service are not compensated. “Regulating power” in the Netherlands is defined as “the capacity which can be controlled by means of load frequency control (LFC) with a regulating speed of at least 7% per minute” [18, 19]. Thus, regulating power is the exact equivalent of secondary control in UCTE terms: resources that can be fully activated within 15 minutes (speed of 7% per minute) and are controlled by automatic generation control (load frequency control in TenneT’s words). The reserve capacity market for regulating power in the Netherlands is yearly; TenneT procures the required reserves for regulating power (secondary control) through yearly bilateral contracts with generators.

The balancing energy market for secondary control is quarter hourly with quarter hourly bidding. The bids can be different for different PTUs (15 minutes), and the bid for each PTU can be changed up to one hour before the PTU of operation. Therefore, in case of the balancing energy market for secondary control, the frequency of bidding and frequency of market clearance are once per PTU, 15 minutes. This is the major difference between the market designs in Germany and the Netherlands, see Table 4. 1.

“Reserve power” in the Netherlands is defined as the reserves offered to the TSO that do not fit the definition of regulating power. So they are not connected to the LFC system, and can have response speeds of lower than 7% per minute. So it can be considered as the equivalent of tertiary control in UCTE terms. There is no reserve capacity market for this service in the Netherlands; only a balancing energy market is used which is a quarter hourly market with quarter hourly bidding. Thus, in case of the balancing energy market for tertiary control, the frequency of bidding and frequency of market clearance are once per PTU, 15 minutes.

In the Netherlands, in case of the reserve capacity markets, there is no distinction between upward (positive) and downward (negative) capacity. However, separate auctions are used for up and downward balancing energy in real-time.

Table 4. 2. Summary of the characteristics of balancing services markets in the Netherlands

	Reserve Capacity Market			Balancing Energy Market		
	Bidding horizon	Market clearance	Distinction Up-Down-ward capacity	Bidding horizon	Market clearance	Distinction Up-Down-ward capacity
Primary Control	-	-	-	-	-	-
Secondary Control	Yearly	Yearly	No	Quarter hourly	Quarter hourly	Yes
Tertiary Control	-	-	-	Quarter hourly	Quarter hourly	Yes

4.3. Reserve requirements

As mentioned in the previous chapter, 'reserve requirement' determines the minimum amount of reserves (for each type of balancing services) needed for secure operation of the system. The reserve requirements are determined by the *system security criterion*, which differs across countries and is different for different types of balancing services.

That is the technical aspect of 'reserve requirements', which has been extensively discussed in the power systems engineering literature, [55-60] to mention a few. This literature introduces the concepts of system reliability, adequacy and security. The basic role of this very essential power systems literature is to translate our vague idea of reliability into indices that can be measured. They tell us what exactly needs to be done in order to achieve a certain level of system reliability. This technical literature on reserve requirements essentially determines the minimum reserve requirements of the system by making a balance between system reliability and costs, using various methods; cost-benefit analysis [56], reliability cost/reliability worth method [59], and using risk indices [55, 58, 60], to mention a few.

In the context of the UCTE system, reserve requirements for primary, secondary and tertiary control are discussed in the UCTE operation handbook [11]. The minimum amount of primary control reserves is set at 3,000 MW which hedges against the simultaneous trip of two generating units each 1500 MW (n-2 criterion) [11, 12]. This total amount will then be allocated to all the control areas in UCTE proportional to their annual production volume.

In case of secondary control, UCTE uses the following square root formula as an empiric sizing approach for the recommended minimal amount of secondary control reserves of a control area [11]:

$$R_{sec} = \sqrt{a.L_{max} + b^2} - b \qquad (4.1)$$

L_{max} being the maximum anticipated consumer load for the control area over the period considered and the parameters a and b being established empirically with the following values: $a=10\ MW$ and $b=150\ MW$ [11]. It should be noted that although it is obligatory for UCTE members to meet the reserve requirement for primary control calculated by UCTE, in case of secondary control, the above-mentioned formula only shows the 'recommended' reserve requirement by UCTE, and the members are free to use other values based on their local needs.

The Netherlands complies with the UCTE reserve requirements both for primary and secondary control. In 2009, the Netherlands represented a share of 3.6% of the total production in UCTE and consequently its minimum primary reserve requirement was 3.6% of 3000 MW or 110 MW. The secondary control reserve requirement for the Netherlands according to equation (4.1) is approximately 300 MW, based on a maximum anticipated load of 18 GW [19].

Germany represented a share of 22.4% of the total production in UCTE (in 2009) and consequently the minimum primary control reserve requirement was 22.4% of 3000 MW or 673 MW [12]. According to [20], by means of a mathematical approach, the German TSOs determine the required volume of secondary control and tertiary control for their control areas in such a way that the defined residual risk probability of a power surplus or deficit that cannot be balanced is not exceeded. We could not access the details of the method that is used in Germany but according to [12] and [20], the amount of secondary control reserve procured by the German TSOs is two to four times higher than the recommended UCTE values, because of the use of a different method for calculation of the reserve requirements.

These discussions are all related to the basic technical aspect of 'reserve requirements', which is about how to determine the minimum amount of reserves that needs to be purchased. However, there is a market-related aspect to this design variable that has been partially overlooked in literature. *Frequency of calculation of reserve requirements* plays a crucial role in determining how much reserves are purchased in different periods, and eventually determining the reserve procurement costs. Requirements can be calculated for different time horizons (using the exact same formula/approach): annual, monthly, weekly, daily, and even hourly.

We use the case of UCTE as an example. In UCTE according to equation (4.1), the reserve requirement of secondary control for a specific time span is related to the forecast *peak* load in the corresponding time span. The UCTE handbook does not tell control areas what time span this formula should be applied to; the formula gives the minimum reserve for a *certain period of time* that can be one year (calculation of reserves once a year), or one day (daily calculation of reserves).

If the reserve requirement is calculated on a monthly basis (since the load changes with a seasonal pattern and the peak load is different for different months), then the reserve requirement will be different from one month to the other, while if the requirement is calculated on an annual basis, then it will be fixed throughout the year and will be related to the peak load of the entire year meaning that the yearly reserve requirement will be equal to the largest of all the monthly requirements. In the first case, the reserve requirement can follow the monthly change of load while in the second case it will be fixed throughout the year and in several months the amount of reserves procured will be more than necessary.

Thus, without changing the system security criterion (without compromising system security) and only by changing the frequency of calculation of the reserve requirement, unnecessary reserve procurement can be avoided, and the demand in the reserve capacity market and consequently reserve procurement costs can be reduced.

In order to appreciate the size of this effect, the reserve capacity market for secondary control in the Netherlands is studied here. In the Netherlands, TenneT, the Dutch TSO, buys the required reserves, calculated based on equation (4.1), through annual bilateral contracts from reserve providers. Figure 4. 1 shows the reserve requirements for the Netherlands (using the load data of 2009) and compares the yearly reserve requirement with monthly requirements (in case they had been calculated on a monthly basis instead of yearly) [61].

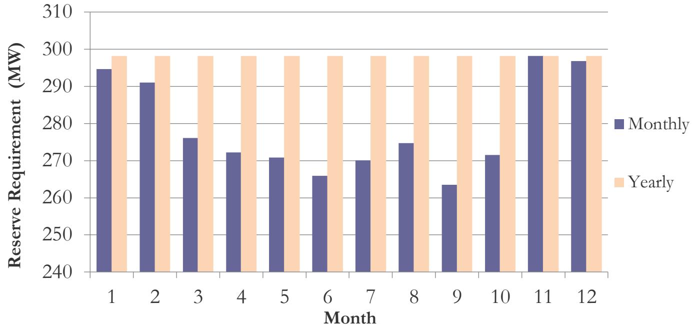


Figure 4. 1. Yearly and monthly reserve requirements for secondary control in the Netherlands based on the system load in 2009

As can be seen from the figure, if calculated on a monthly basis, the reserve requirement can follow the monthly load patterns and in several months during spring and summer, the needed reserve requirement is considerably lower than the yearly requirement simply because of the lower load levels in those seasons. Figure 4. 2 shows the reserve requirements for secondary control in the Netherlands in case they were calculated on a daily basis. In several days, the reserve requirement goes down to 200 MW which means more than 30% reduction in secondary reserves that need to be purchased by the TSO in those days.

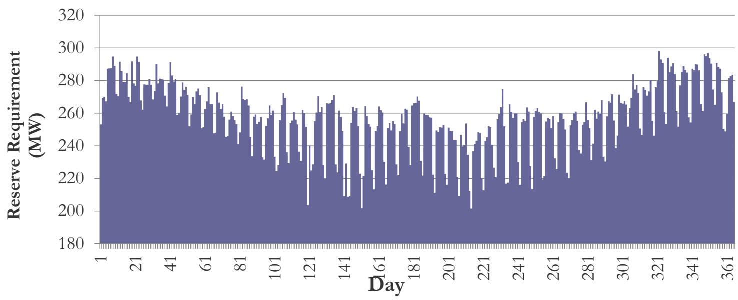


Figure 4. 2. Daily reserve requirements for secondary control in the Netherlands based on the system load in 2009

Calculating the reserve requirement on a daily basis would lead to an average reduction in the required reserves of 41 MW, or a 14% reduction in the reserves needed to be purchased. Unfortunately, since in the Netherlands, the reserve capacity prices (with which the TSO purchases reserves from service providers) are not public information (because of the confidential nature of the yearly bilateral contracts between the TSO and service providers), an estimation of the possible reduction in the 'costs' of procuring reserves cannot be made.

This issue can be taken even one step further: reserve requirements can be different for peak and off-peak hours in each day (as is the case in PJM [16]), in which case an average reduction of 20% in the amount of reserves required to be purchased can be achieved in the Netherlands, using the data of year 2009. Figure 4. 3 shows the reserve requirements for the Netherlands in case they are calculated separately for off-peak (from 00 to 07 hour) and peak hours (from 07 to 24 hour) for each day. Because of the difference in load levels in these two periods, the corresponding reserve requirements are noticeably different.

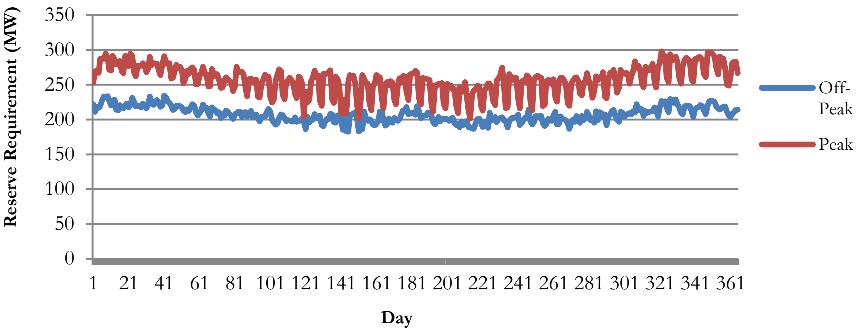


Figure 4. 3. Peak and off-peak reserve requirements for secondary control in the Netherlands based on the system load in 2009

Therefore, using the exact same security criterion, and only by changing the frequency of calculation, a considerable reduction in the amount of required reserves can be achieved, which in turn will lead to lower reserve procurement costs. Needless to say, the frequency of calculation of reserve requirements is closely related to the 'timing' of the reserve capacity markets, which will be discussed in the next section.

It should be emphasized that the purpose in this section was to demonstrate that *regardless* of the method we use for calculation of the reserve requirements (which is the technical aspect of procuring reserves and discussed extensively in literature), the market design decisions still play a decisive role in determining how much reserves needs to be purchased, and eventually in determining reserve procurement costs. In other words, even if we assume that the security criterion (the method to determine reserve requirements) is given, considerable costs can be avoided by just calculating the reserve requirements on a more frequent basis.

4.4. Timing of reserve capacity markets

The two aspects of timing of markets are timing of the bidding procedure and timing of the markets clearance. Timing of the bidding procedure addresses frequency of bidding (which determines the time horizon of the market) and gate opening/closure times for bidding, which need to be carefully coordinated with those of other electricity markets, especially day-ahead (DA) market. 'Timing of the market clearance' addresses frequency of markets clearance and their coordination with clearance of other markets. In this chapter, we do not analyze the coordination aspect of balancing services and DA markets. We focus on the frequency of bidding and frequency of market clearance of the balancing services markets, without directly addressing the coordination that may be needed with other markets, which is the subject of the following chapter of the dissertation.

In this section, we focus on timing of the reserve capacity markets and study the German case. As noted before, various possibilities exist regarding the time horizon of the reserve capacity markets; from yearly markets (such as regulating capacity market in NL) to daily markets with hourly bidding (e.g. regulation market in PJM, and tertiary reserve capacity market in Germany). At one extreme of the spectrum are long-term markets with bilateral contracts (between the TSO and the reserve provider) as the procurement mechanism, and at the other extreme are short-term auctions with daily or hourly bidding.

4.4.1. Bid prices

As shown in the previous section, in case of using a short-term auction, reserve requirements can be calculated on a more frequent basis leading to avoidance of unnecessary capacity reservation in many time periods. In addition to this factor, changing the time horizon of the market has a direct impact on the possibilities for defining services in a more specific way leading to prices that are more reflective of the real costs of providing the service. In order to clarify the issue, the market prices of the reserve capacity markets for primary, secondary and tertiary control in Germany are studied.

Figure 4. 4 shows the average selected bid prices in the reserve capacity market for primary control in different months throughout 2009 [41]. As mentioned earlier, there is no distinction between peak and off-peak hours or between up- and down-ward capacities. Thus, as one can see from the figure, there is one market price per month for reservation of primary control capacity. There is no significant variation in the average market prices; the prices are not volatile. When bidding in the market, reserve providers calculate their lost opportunity costs for offering their capacity in the primary control reserve market, other than offering it in other markets including DA and ID markets. As the figure shows the prices are high, and there is no price difference between up and down capacity or peak and off-peak hours.

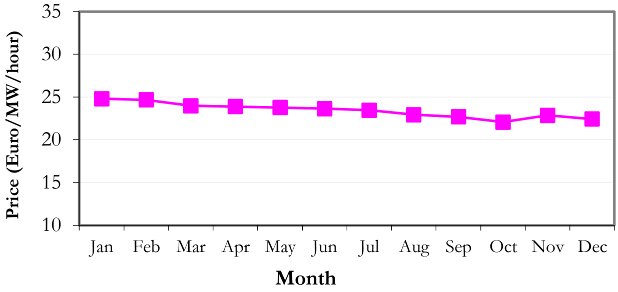


Figure 4. 4. Average selected capacity bid prices for primary control, Germany 2009

Figure 4. 5 shows the average selected bid prices in the reserve capacity market for secondary control in different months throughout 2009. The improvement in the design of the market for secondary control (compared to the primary control market) is a distinction between peak and off-peak hours, and between up- and down-ward capacities. As can be seen, these distinctions between services make the bid prices more reflective of the real value of the corresponding service. During peak hours, many production units are running and can decrease their outputs on TSO's notice, therefore, in peak hours negative reserves cannot be expensive because of the large number of units that can provide this service, so as can be seen in Figure 4. 5, the average price for negative capacity in peak hours is the lowest; as low as 1 €/MW/hour. However, during off-peak hours, when many gas and oil plants that can provide secondary control reserve are not running, providing downward capacity will be expensive because of the very limited number of the providers of this service, therefore as the figure shows, the average price for negative capacity in peak hours is the highest, ranging from 7 to 10 €/MW/hour. Regarding the positive capacity, the price in peak hours is higher than in off-peak hours because of the limited availability of the resources able to regulate upward (increase their output) during peak hours compared to off-peak hours.

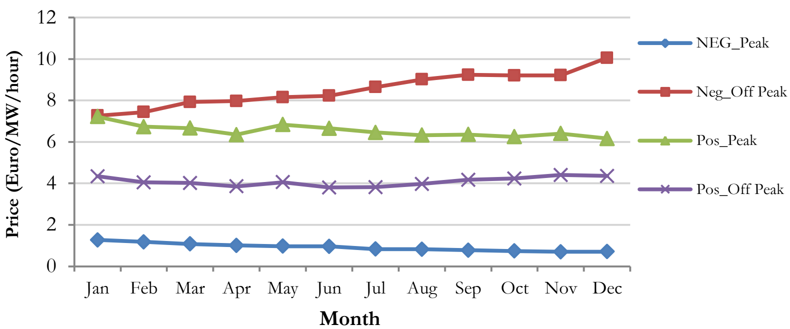


Figure 4. 5. Average selected capacity bid prices of the fours monthly auctions for secondary control, Germany 2009

Therefore, making these distinctions and defining services in a more specific way will lead to prices that are more reflective of the value of the service and the price differences that appear will result in a reduction of the costs of capacity reservation in general.

By reducing the time horizon of the market even more, the services can be defined in a much more specific way, as is the case for the tertiary control reserve capacity market in Germany, which is a daily market and the prices can be different in different days. Figure 4. 6 shows the average selected bid prices in the reserve capacity market for tertiary control in the 6 daily auctions, for the first day of September 2009, which is a Tuesday (a work day). The x-axis shows different auctions, for instance, 00-04 shows the first auction of the day (from 00h to 04 h), auctions are for 4 hours each. The first prominent point in the figure is the variations of the prices. Prices dramatically vary for different hours during the day; the phenomenon that was missing in the monthly markets for primary and secondary control, see Figure 4. 4 and Figure 4. 5. The prices are more reflective of the real costs of providing the service (higher price efficiency), with prices going down to almost zero in some hours: negative reserves for peak hours (the last four auctions of the day). This cannot be the case in markets with longer time horizons: prices in a monthly market cannot be different for different hours or even different days.

In addition, using daily markets can lead to lower prices because it would lead to lower opportunity costs (as a result of elimination of many uncertainties about the markets which do exist when bidding one month or one year in advance), and also because of higher competition since more players can participate in a daily market (small players with low flexibility cannot participate in long-term markets).

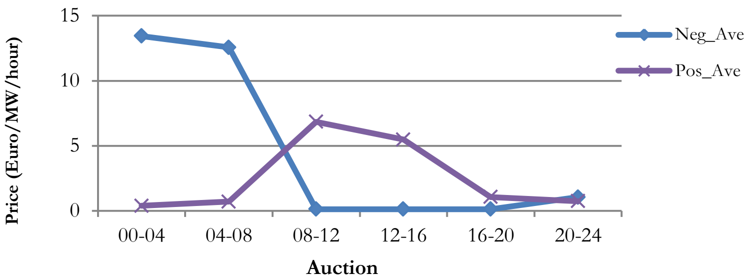


Figure 4. 6. Average selected capacity bid prices of the 12 daily auctions for tertiary control, Germany, 01-09-2009, Tuesday

Figure 4. 7 shows the average selected bid prices in the reserve capacity market for tertiary control in the 6 daily auctions, for the 6th day of September 2009, which is a Sunday (a holiday). The figure is presented for the sake of comparison. As can be seen the price for positive reserves is consistently low, simply because of the fact that on a holiday with a low demand, there is a lot of free capacity that can be offered as reserves. The price for negative reserves is higher than in Figure 4. 6 because of the exact same reason.

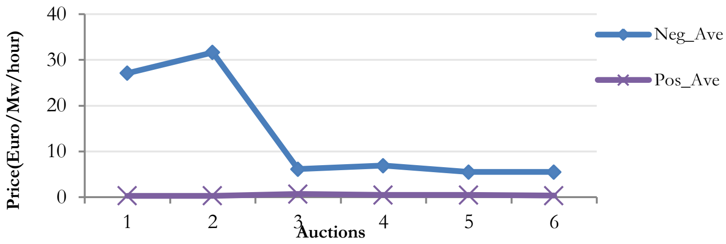


Figure 4. 7. Average selected capacity bid prices of the 12 daily auctions for tertiary control, Germany, 06-09-2009, Sunday

4.4.2. Excess supply ratios

A critical issue regarding increasing the time horizon of markets is its influence on 'competition'. As the time horizon of the market increases, the number of service providers participating in the market decreases because of the lack of flexibility of small units, and also the uncertainties regarding forecasting the outcomes of other electricity markets: the capacity that will be sold in other electricity markets and the corresponding prices. It simply originates from interrelations of different electricity markets; generators have the opportunity to offer their capacity in different electricity markets as different services, therefore these markets compete with each other to attract capacity from suppliers. Thus, changing the design of one market (e.g. changing the time horizon of one market) can lead to changes in the offered capacities and bid prices in the corresponding market, simply because of its interrelations with other electricity markets. Table 4. 3 shows the excess supply ratio, defined as the excess of supply (not selected bid volumes) divided by demand (selected bid volumes), for the four auctions of secondary control in Germany for different months of 2009. This indicator compares the offered capacity in the market with the demand.

Table 4. 3. Excess supply ratios (in percentage) of the four auctions for secondary control- Germany 2009

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average
Negative Off-Peak	16.7	17.4	19.5	0	0	0.4	0	0	0	1.8	9.1	2.7	5.6
Negative Peak	11	8.3	1.1	0	10.1	4.6	0	17.5	14	11.6	12.9	3.2	7.8
Positive Off-Peak	6.7	7.8	1.9	2.2	2.2	9	5.1	0	3.1	8.9	7.9	9.9	5.4
Positive Peak	15.2	9	0	0	0	8.1	16.3	16.7	24.2	17.2	15.6	19.6	11.8

One can see in the table that in 18 auctions (out of 48) the excess supply ratio is less than 3% and in 11 auctions, the ratio is zero which indicates that absolutely all the bids are needed to meet the demand (in order to meet the reserve requirement for secondary control). This shows that because of the limited number of service providers and consequently the limited amount of capacity offered in these markets, considerable market power exists in the markets for secondary control in Germany.

Figure 4.8 shows the excess supply ratios in the German auctions for positive secondary control reserves (*peak* as well as *off-peak* hours), for 16 months in a row, starting January 2010. As can be seen, very low excess supply ratios is not a phenomenon limited to 2009 only. During 2010 and 2011 (the first six months), the excess of supply in the market (for positive reserves) can hardly reach 10% of demand ever. In most months, the excess of supply is negligible compared to demand, and in several months the indicator is negative, indicating that the capacity offered in the market was not enough to meet the market demand. In all those months, a secondary auction was held in which the TSOs procured the remaining of their reserve requirement that they were not able to purchase in the first market, due to extremely low supply.

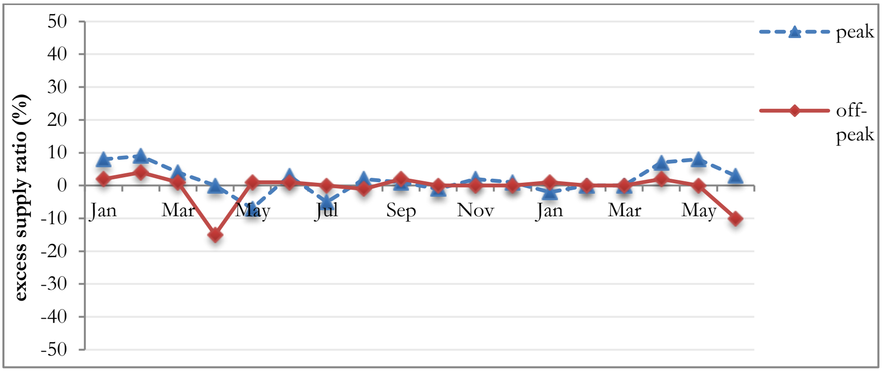


Figure 4. 8. Excess supply ratios in the German auctions for *Positive* secondary control reserves (peak ad well as off-peak), beginning from January 2010

Figure 4.9 is the counterpart of Figure 4.8 for negative reserves, thus it shows the excess supply ratios for *negative* secondary control reserves (*peak* as well as *off-peak* hours), starting from January 2010. The indicators show no improvement compared to positive reserves. Actually in a few months in 2010, there was significantly low supply to the extent that the TSOs had to repeat the auction two times more, to be able to meet their reserve requirement for secondary control. Lack of participation in the reserve market, to such an extent, creates serious opportunities for abuse of market power in the market.

Since we had access to detailed data for year 2009, we applied the pivotal supplier tests to the 4 separate German auctions in 2009 (there were 4 separate control areas and thus 4 separate auctions).

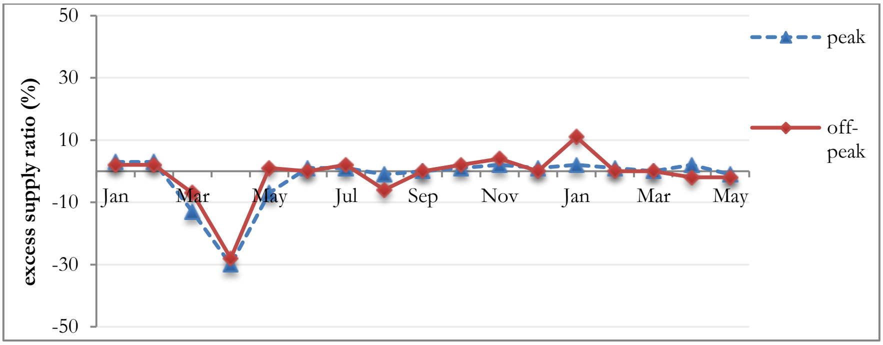


Figure 4. 9. Excess supply ratios in the German auctions for *Negative* secondary control reserves (peak ad well as off-peak), beginning from January 2010

Table 4. 4 shows the number of pivotal suppliers (for each of the four German control areas) in the auction for positive secondary control in "off-peak" hours for all the months of 2009. The table confirms the existence of market power in the markets for secondary control in Germany. As can be seen, in March, April, May and August 2009, absolutely all the bidders are pivotal which illustrates serious market power, not even for the suppliers with large market shares but also for all the small suppliers of secondary control reserve (for off-peak hours) in these 4 months. In addition, in more than 60% of the time, more than one supplier is pivotal in the auction for positive secondary control during off-peak hours.

Table 4. 4. Number of pivotal suppliers in the auction for positive secondary control in off-peak hours-Germany 2009

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
ENbW	0	3	10 (All)	6 (All)	8 (All)	0	3	18 (All)	5	0	1	1
Transpower	0	0	11 (All)	8 (All)	10 (All)	0	3	18 (All)	5	0	1	1
Amprion	3	4	11 (All)	9 (All)	10 (All)	3	9 (All)	8 (All)	4	4	4	4
50 Hertz	1	3	9 (All)	6 (All)	7 (All)	0	3	18 (All)	5	0	1	1

Table 4. 5 shows the number of pivotal suppliers (for each German area) in the auction for positive secondary control in "peak" hours for all the months of 2009. Compared to Table 4. 4, the number of pivotal suppliers is more promising for peak hours, which is expectable because, in off-peak hours, the units that are synchronous to the grid and can deliver power compatible with secondary control characteristics are very limited. However, according to Table 4. 5, still during 3 months of 2009, all the units in all the four German areas are pivotal meaning that all suppliers are needed to meet the demand. And this creates serious market power concerns.

Table 4. 5. Number of pivotal suppliers in the auction for positive secondary control in peak hours- Germany 2009

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
ENbW	0	0	10 (All)	6 (All)	8 (All)	0	0	0	0	0	0	0
Transpower	0	0	11 (All)	8 (All)	12 (All)	0	0	0	0	0	0	0
Amprion	0	3	11 (All)	10 (All)	12 (All)	3	10 (All)	1	0	6	0	2
50 Hertz	1	1	9 (All)	7 (All)	9 (All)	0	0	0	0	0	0	0

The pivotal supplier tests have been applied to the positive secondary control auctions for peak hours and Table 4. 6 shows the percentage of the time in which the auction passes each test in each German area separately. As one can see, in Amprion, in only 25% of the time, the auction passes the one-pivotal supplier test and always fails the two- and three-pivotal supplier tests. The other three areas can pass the two-supplier test in less than 50% of the time and they pass the three-supplier test in only 25% of the time. These tables show that serious attention is needed to solve the noticeably high market power concerns in the markets for secondary control in Germany.

Table 4. 6. Percentage of the time in which the market passes the pivotal supplier tests- Positive secondary control for peak hours, Germany 2009

	One-Pivotal Supplier Test	TWO-Pivotal Supplier Test	THREE-Pivotal Supplier Test
ENbW	75%	50%	25%
Transpower	75%	50%	25%
Amprion	25%	0	0
50 Hertz	58%	42%	25%

It should be noted that since the published bid data in Germany is anonymous, these results are based on the implicit assumption that each bid is from a different supplier. However, obviously a supplier might offer different parts of its capacity with different prices, leading to different bids from the same supplier. Thus, the results of this analysis, showing serious market power issues, could be much worse if the identity of every bidder was known. In other words, the results presented above are *optimistic*.

As a comparison, Table 4. 7 shows the excess supply ratios in percentages for the 12 auctions of *tertiary control* in Germany for 1st of September, corresponding to Figure 4. 6. As can be seen, the offered positive and negative capacities in all the auctions are at about 40% more than the required capacity (the market demand). This phenomenon compared to the excess supply ratios for the secondary control market, which according to Table 4. 3, for different auctions differ from 5 to 11% on average, illustrates a noticeable difference between these two markets (secondary and tertiary control). One reason is the difference in time horizon of these two markets: monthly market for secondary and daily markets for tertiary control. The frequency of bidding in the secondary control market is twice per month (positive or negative), while the frequency of bidding in the tertiary control market is 12 times per day. Serious uncertainties for bidding in a monthly market, considering the fact that when the bid is selected the supplier has to make that capacity available (keep it free) for all the PTUs of the coming month, significantly limits the service providers who can and have the incentives to offer their capacity in the monthly secondary control market. While on a daily basis, the suppliers have much more accurate forecasts about the state of different electricity markets and therefore the risks and uncertainties are much more limited. In addition, they offer their capacities for periods of 4 hours and not an entire month.

Table 4. 7. Excess supply ratios (in percentages) of the 12 auctions of tertiary control in Germany- 01-09-2009

	Neg. 00-04	Neg. 04-08	Neg. 08-12	Neg. 12-16	Neg. 16-20	Neg. 20-24	Pos. 00-04	Pos. 04-08	Pos. 08-12	Pos. 12-16	Pos. 16-20	Pos. 20-24
Excess Supply Ratio (%)	40.7	40.3	39.7	39.3	39.6	39.8	46.3	43.6	41.3	41.7	41.5	43.3

4.4.3. Conclusions

Based on the results, we identify five main reasons to move towards auctions with shorter-time horizons for reserve capacity markets:

1. **Lower demand**: As discussed in detail in the third section of this chapter, reducing the time horizon of the reserve capacity market will provide the possibility for the system operator to calculate the reserve requirements on a more frequent basis, which in turn will reduce the demand for reserve capacity in many time periods by avoiding unnecessary reservation of capacity. In fact, using the same security criterion and only by calculating the reserve requirement on a daily basis, rather than yearly, a 14% reduction in the required reserves to be purchased (14% reduction in market demand) in the Netherlands can be achieved. And by calculating separate requirements for peak and off-peak hours (having two separate auctions) the reduction in the amount of required reserves (demand in the reserve capacity market) would increase up to 20%.
2. **Easier new entries**: Small players (small generating plants capable of offering reserves) cannot enter long-term markets, especially because of their lack of flexibility which will in turn increase their minimum profitable price at which they are willing to sell their reserve. In addition, small players lack the negotiating power in arranging bilateral contracts with the system operator, and very high transaction cost is a deterrent as well. Therefore, moving towards auctions with shorter time horizons (preferably daily markets) for reserve capacity will enable small players to enter the market and compete with larger players. The key point that makes the importance of enabling small players to participate even more prominent in case of reserve capacity markets is the small size of these markets. As an example, the average load in the Netherlands is in the order of 14,000 MW, while the capacity that is reserved

for secondary control in the Netherlands is 300 MW. This is the total amount of secondary control reserves that would be sufficient for the entire Dutch system. Therefore, enabling the entrance of a small player with a very modest size of 30 MW into the reserve capacity market would compensate for 10% of the entire market demand. Thus, because of the mere small size of reserve capacity markets, small players do matter and facilitating their entrance to the market is of critical importance.

3. **Higher competition and market liquidity**: As a result of higher number of market players being able to participate in the market, the excess of supply would increase, less suppliers would have a dominant position (would be pivotal) and consequently competition would improve and market liquidity increase.

4. **Lower lost opportunity costs**: The prices can be lower because of various reasons: more parties can participate in the market (especially smaller and less flexible units), the level of competition will increase, and more importantly, the opportunity costs will be much lower. Opportunity costs are based on the predictions of a market party about how much of its capacity it can possibly sell in other markets and with what price, so that it can calculate the profit it could make by offering its capacity in other markets (other than reserve capacity markets). Thus, the lower the time horizon of the market, the lower the opportunity costs because of availability of more information (it is closer to real-time), and the more accurate predictions on the prices of other markets. These predictions obviously will be more accurate on a daily basis rather than on a yearly basis where everything is extremely uncertain. In addition, in case of an auction with short time horizon, bidding is less risky in the sense that in case of a yearly market, once a party bids in the market the bid will be fixed for the whole year and cannot be changed, so a mistake in predicting possible future profits (underestimating the possible profits) can lead to higher losses compared to the case where a daily market is used and if the party makes a mistake (or underestimates possible profits) in its bidding, it can change its bid for the next day. So on the one hand, having more accurate information makes it possible to make a more accurate estimation of the real opportunity costs, and on the other hand, since the level of uncertainty is lower, the tendency to intentionally overestimate the opportunity costs (in order to control the risks) becomes lower. Thus, both 'real' and 'perceived' opportunity costs can be much lower. It is this second reason that will improve 'price efficiency' of the market, meaning the bid prices will be more reflective of the real costs of providing the service.

5. **More proper TSO incentives**: The incentives of the TSO, being the single buyer in reserve capacity markets, play an important role in the efficiency of these markets, specifically the allocative efficiency. On the one hand, the TSO

is the independent entity above the market that ensures system security implying that it cannot have any financial incentive in the market outcomes, and on the other hand, the TSO is the sole entity deciding on which resource to purchase the reserves from. Therefore, by definition, the TSO lacks incentives to truly try and minimize the costs of purchasing reserves. In this situation, the only sensible action one can take is to limit the room the TSO has to behave in a way that does not necessarily minimize costs but merely ensures its convenience in fulfilling its responsibility of buying the required reserves. Long-term bilateral contracts leave everything to 'confidential negotiations' between the TSO and reserve providers. Information cannot be disclosed because of confidentiality concerns and the TSO, after having purchased the required amount of reserves from the most convenient resources (and not necessarily from the cheapest available) claims the incurred costs and gets reimbursed by the regulator. Lack of transparency as well as proper incentives make low allocative efficiency unavoidable. Having a short-term auction in which the reserve providers offer their reserves and the cheapest bids are selected automatically can restrict the freedom the TSO has to overlook efficiency concerns.

4.4.4. Arguments against short-term markets

Although the disadvantages of long-term reserve capacity markets were analyzed in the previous section, one should be aware that there are arguments in literature against moving towards short-term auctions. We discuss the main arguments mentioned in literature in this section. The author in [40] mentions the following as a disadvantage of using markets with shorter time horizons (higher frequency of market bidding/clearance) for ancillary services:

A high frequency market clearing helps players understand the behavior of the market, and therefore to game it, as happened in California, where some capacities were withheld in order to raise prices [62]. Therefore, a low frequency market clearing has the advantage of reducing somewhat the influence of dominant players.

Although at the first glance, it sounds true, looking deeper into the issue may prove otherwise. The lower the frequency of market clearance, the higher the time horizon of the market and the lower the number of players, simply because small players that are less flexible (compared to large players with a flexible portfolio) cannot enter and compete in a yearly market, as an example. Thus lowering the frequency of clearance in a sense actually makes the dominant players even more dominant. In addition, small players are very important in reserve capacity markets because the size of these markets is small and so small players do matter. In this sense, small market parties can play a much more decisive role in balancing services markets than in wholesale electricity markets, such as day-ahead market in which the role of small players is not critical because of the large size of the market.

In addition, generally speaking, players being able to understand the behavior of the market is only a good thing. They should be able to understand the market behavior, but the regulator should be able to understand it better, so that it can design the rules and regulations in a way that prevents players from gaming the market.

The author in [63] points out the vital issue of investment:

In the short term, a wholesale electricity system that is not a monopoly is feasible, as has been demonstrated by the NordPool, which covers Norway, Sweden, Finland and Denmark, and by Britain. However, in California and Brazil, serious under-investment in new capacity led to a near collapse of their electricity systems, raising doubts about the sustainability of markets. It will do no service to consumers if liberalization creates a market that is competitive in the short term, but is too risky to justify investment in new generating capacity being undertaken.

Although the author does not mention this issue directly about ancillary services markets (he addresses electricity markets in general), the investment argument can be used as a valid argument against introduction of markets with short time horizons for balancing services, especially reserve capacity: if they are real short-term markets with volatile and unpredictable prices, then the investment would be risky which is the main concern regarding sustainability of electricity markets. Although the argument is quite infallible considering electricity markets in general, this investment issue is somehow different in case of reserve capacity markets. The key is the very small size of the reserve capacity markets compared to wholesale electricity markets, especially the day-ahead market (e.g. in the Netherlands the size of the reserve capacity market for secondary control is only 2% of the system load). Therefore, although one is right to say that moving towards markets with shorter time horizons would increase the investment risks in general, the reserve capacity market, merely because of its small size, does not seem to send a direct investment signal to market players. In other words, in case of investment, the main worrying factor is the volatility and unpredictability of the wholesale electricity market prices (especially the DA market) and not the reserve capacity market prices.

Later on, the author in [63] rightly raises the issue of costs of arranging short-term auctions:

The newly redesigned wholesale market (NETA) is rumored to have cost in excess of 600 million Pounds. Running costs are also high, the Balancing Market element of NETA alone costs 80 million Pounds per year to run [64].

The argument concerns the running costs of short-term auctions. However, the number mentioned in the paper, 80 million Pounds per year just to run the balancing mechanism in Great Britain, is slightly misleading because, according to the source, 80 million is *the annual cost of running balancing market operator Elexon*, which is the company responsible for operating the balancing mechanism [64]. Thus, this cost does not only reflect the running costs of short-term auctions for balancing, but *all* the costs associated with the single company responsible for performing the task of balancing the national grid.

Needless to say, introduction of new auctions incurs investment costs (development of rules and regulations, development of software and data management tools, etc.), and incurs running costs as well. And so, obviously a cost-benefit analysis needs to be performed on a case-specific basis. However, it should be noted that the benefits from this change because of increased competition, market efficiency and flexibility will be felt for a long time, while the initial investment is an expenditure made once and for all.

4.5. Timing of balancing energy markets

In Germany, in the markets for procurement of secondary control, there is a clear distinction between upward (positive) and downward (negative) regulation and they are traded in two different sets of markets. In addition, separate auctions are used for off-peak and peak hours. Thus, in each month, there are four separate auctions in which service providers offer their capacities as secondary control reserve. The service providers bid once per month for both reserve capacity and balancing energy markets. However, the reserve capacity market is cleared once per month and the balancing energy market is cleared for every quarter of an hour, using the same set of bids for all the PTUs (the energy bids are fixed throughout the month). Therefore, in case of the balancing energy markets for secondary control, while the frequency of bidding is once per month (time horizon of one month), the frequency of market clearance is once per 15 minutes.

In the following paragraphs, using various indicators, we study the characteristics of the German market and compare them with those of the Dutch market.

Figure 4. 10 shows the average selected upward energy bid prices (in €/MWh) for secondary control (SC) in Germany for 2009, for peak as well as off-peak hours. These are the energy prices of the bids selected in the reserve capacity market and they constitute the bid ladder that will be used for real-time balancing of the system. The figure compares these prices with the monthly average intra-day (ID) prices in Germany for 2009, [41, 65]. As mentioned earlier, the frequency of market clearance is a lot higher than the frequency of bidding in case of balancing energy markets in Germany. According to the figure, while the average ID price in Germany (for 2009) is 39 €/MWh, the average selected positive SC energy bid price is 128 €/MWh and 178 €/MWh for off-peak and peak hours, respectively. The intra-day market is the closest energy market to the real time.

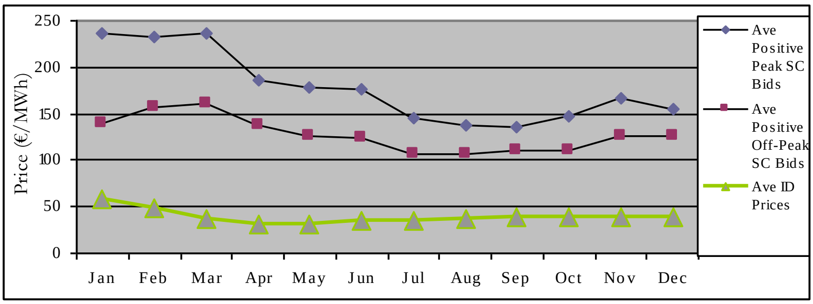


Figure 4. 10. Average selected positive secondary control energy bid prices (peak and off-peak hours) compared to the monthly average intraday prices for Germany in 2009

Figure 4. 11 illustrates the average selected positive SC energy bid prices divided by the average intra-day price for the different months of 2009 in Germany. As can be seen, the average SC energy bid prices (which are actually the real-time energy bids) are considerably higher than the intra-day energy prices; from two to almost seven times higher.

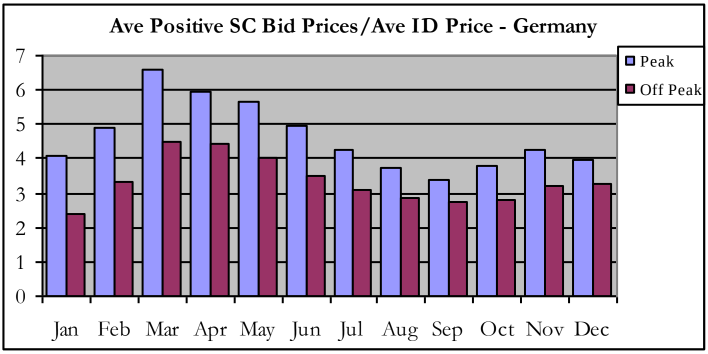


Figure 4. 11- Average selected positive secondary control energy bid prices (peak and off-peak hours) divided by the monthly average intraday price for Germany in 2009

In order to have a closer look at the situation, we compare these balancing energy bid prices of Germany with those of the Netherlands. Before making the comparison on the balancing markets of the two countries, we should make a short comparison of the wholesale electricity prices of the two countries. Figure 4. 12 shows the average hourly day-ahead market prices in Germany and the Netherlands for 2009. As one can notice, the average day-ahead prices of the two countries almost match; no considerable difference in the average day-ahead prices can be seen.

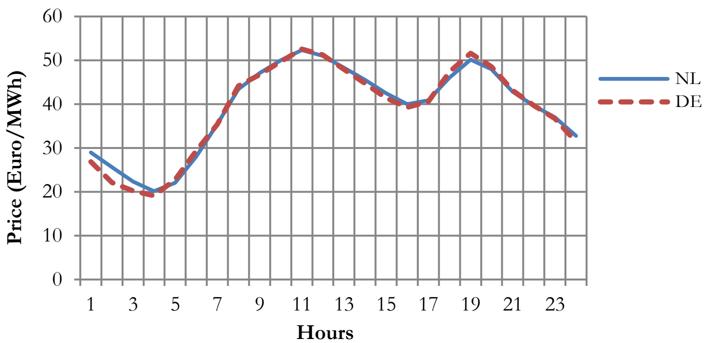


Figure 4. 12. The average hourly intra-day market prices in Germany and the Netherlands for 2009

While the wholesale electricity market designs in Germany and the Netherlands are basically the same, and there is no considerable difference in the average market prices, the designs of the balancing services markets (specifically the secondary control service studied in this section) are very different. While the service providers bid once per month and the balancing energy market for secondary control is cleared once per 15 minutes in Germany, the service providers in the Netherlands can bid separately for each 15 minutes (they can change their bids up to one hour before real-time) and so the frequency of market clearance is the same as the frequency of bidding.

Figure 4. 13 compares the last selected positive secondary control (SC) energy bid prices of Germany with those of the Netherlands. It shows the maximum selected positive SC energy bid price (corresponding to the last selected bid in the reserve capacity market) divided by the average intra-day price. In case of the Netherlands, the entire bid ladder is not published publicly, but TenneT publishes four prices corresponding to four different points on the bid ladder, including the bid price for 300 MW [61]. Since TenneT reserves 300MW for regulating power (equivalent of secondary control) in the Netherlands (by annual contracts), we used the price corresponding to this volume in Figure 4. 13. As the figure illustrates, although the maximum bid in the Netherlands does not go higher than three times the average DA price, the maximum SC bid of off-peak hours in Germany varies from four to nine times the average DA price, and for peak hours it changes from five to even twenty times the average DA price.

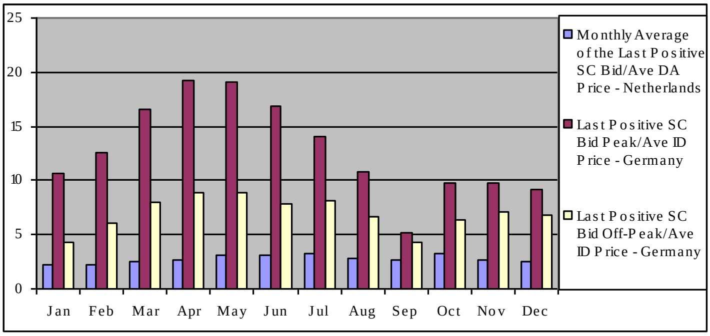


Figure 4. 13- Comparison of the monthly average of the last energy bid price for positive secondary control in the Netherlands and Germany (peak and off-peak)- 2009

In the German market, pay-as-bid pricing is used which, according to the existing extensive literature, does not provide the incentives for service providers to bid at their marginal costs, compared to marginal pricing that is used in the Netherlands. Nevertheless, the difference in bid prices is too high to be explained only by use of pay-as-bid pricing. Other market design issues, specifically timing of markets, play an important role. First of all, the difference in the time horizon of these two markets is critical: monthly market in Germany and quarter-hourly market in the Netherlands. The uncertainties in bidding in the German market are a lot higher than in the Dutch market (because of all the uncertainties in forecasting the wholesale electricity market demand and prices one month in advance) which will push the bid prices higher in Germany. Secondly, the difference between the frequency of bidding (once per month) and frequency of market clearance (once per quarter an hour) in the German market is of crucial importance. The consequence of this design is that since each bidder has to submit one single bid price for the entire coming month (all the 15-minutes of the next month), its secondary control (SC) bid price cannot follow the electricity price changes in the day-ahead (DA) market, throughout the coming month. Therefore, if for example, the bidder offers its SC energy at the expected monthly average DA price, it means that it will lose some profit in half of the PTUs of the month (on average) because its SC bid price will be lower than the DA price half the time, and it could have offered its energy in the DA market other than the SC energy market. This phenomenon leads to an indirect and unintentional introduction of a Lost Opportunity Cost (LOC) in the bids for SC energy market, even though this service, in its nature, creates no LOC for the provider, simply because this is a real-time market and it will be cleared after the closure of all the other markets (in contrast to the capacity reservation service which creates LOCs for the provider by nature, because the reserve capacity market is a longer term market). This large LOC will push the bid prices even higher; the effect that could be seen in Figure 4. 13.

Figure 4. 14 illustrates the last energy bid price for positive secondary control in Germany (for peak hours) and the Netherlands, in December 2009. As expected, the last selected energy bid price in Germany is a fixed value for all the PTUs of the month. The figure also illustrates the volatility of the energy bid price in the Netherlands which originates from the fact that the frequency of bidding in the Netherlands for the energy market for secondary control is once per PTU. Thus, the service providers, in the Netherlands, can submit different bids for different PTUs so they have the opportunity to take into account the changes of electricity prices in other electricity markets (day-ahead specifically) in their energy bids for secondary control (which represent the real-time bid prices for electricity). The secondary control service providers can follow the electricity price changes in different hours of different days by their energy bids for secondary control. The figure also shows the monthly maximum and average of the last bid in the Netherlands. It illustrates what was described as introduction of lost opportunity costs by having different frequencies for bidding and clearance. As one can see in the figure, the monthly average of the last bid in the Netherlands is 99 €/MWh, while the monthly maximum of the last bid (in the Netherlands) is 246 €/MWh. In case of a monthly bidding in the Netherlands (one single bid for the entire coming month), it would be likely that the bidders would go for the expected monthly maximum price in order to make sure that in all PTUs, their bid price is high enough so that they would not lose any profit in other electricity markets. Therefore, in Figure 4. 14, for each PTU, the difference between the last bid and the monthly maximum of the last bid can be seen as the opportunity cost that would have been added in case monthly bidding had been used in the Netherlands. As can be seen, the last bid (for peak hours) in Germany is even higher than the monthly maximum of the last bid in the Netherlands which can be attributed to the uncertainties in forecasting the electricity prices one month in advance, and the use of pay-as-bid pricing in Germany.

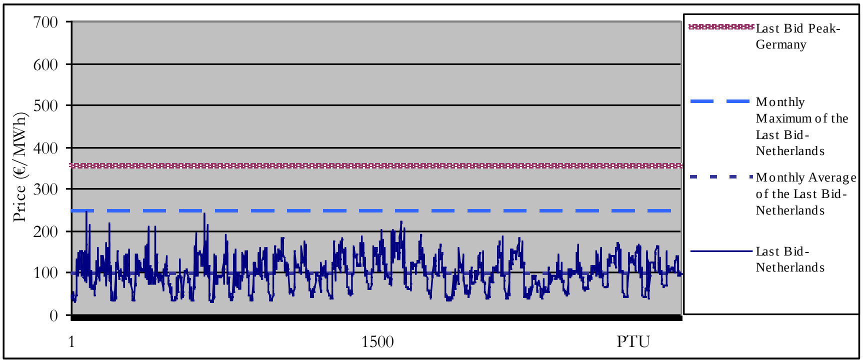


Figure 4. 14. The last energy bid price for positive secondary control in Germany (Peak hours) and the last bid price in the Netherlands- December 2009

In order to summarize, in addition to the reasons mentioned for moving towards daily markets for reserve capacity, using long-term auctions for balancing energy has two more disadvantages:

1. **Introduction of a 'lost opportunity cost' element to bid prices**: As illustrated in the figures presented above, using a long time-horizon for balancing energy markets means that the frequency of bidding will not be the same as the frequency of market clearance. Balancing energy markets are by definition cleared on a PTU basis because activation of balancing energy bids aims to resolve system imbalance that is different in different PTUs. Thus, using for example a monthly market for balancing energy means that the bidding will happen once per month while the market will be cleared on a PTU basis. Having to submit one bid for all the PTUs of the coming month will push the bid prices high simply because of the added lost opportunity cost (LOC): the one single bid submitted for the entire month needs to be sufficiently high for the bidder to ensure that no profit is lost in other markets, for each of the market clearing periods (each PTU). So the bid price cannot follow the change in electricity price throughout the month, and this will indirectly add the above mentioned LOC component into the bid prices, a component that can be considerably large because of the volatility of the electricity prices throughout the month. This unnecessary LOC component can be eliminated if the bidders are allowed to submit different bid for different PTUs: using a market with a time horizon equal to the PTU length.

2. **Limited players**: Since the market is monthly, as soon as the market is closed no new bids can be accepted, so there cannot be any bidding throughout the month. Close to real-time, many generating units may have free capacity that can be offered as balancing energy in the real-time market, but because they were not selected in the auction cleared in the preceding month, they cannot participate in the market. This will significantly influence the allocative

efficiency of the market: available resources are not used in an efficient way, a large part of potential bids are left out because no new bidding is allowed throughout the month. That is the implicit consequence of using different frequencies for bidding and market clearance; in the Netherlands the players who did not participate in the yearly reserve capacity market can still participate in the real time energy market because in the energy market, bidding and market clearance are both on a PTU basis, while in Germany the players who did not participate in the monthly reserve market cannot participate in the real time energy market because although the energy market is cleared on a PTU basis, bidding in the market happens on a monthly basis.

4.6. Conclusions

In case of reserve capacity markets, short-term auctions (preferably daily) can avoid several undesirable effects in performance of the market. Demand would be lower (because of higher frequency of calculation of reserve requirements), new entries would be easier (small plants can participate in the market that can have a significant effect on market price because of the small size of the market), competition would be higher (because of more players and higher excess supply ratios), opportunity costs would be lower (both the real and perceived opportunity costs, because of lower uncertainties), and the TSO would have less room to deviate from optimal procurement of resources. These factors would in turn lead to higher liquidity, allocative and price efficiency, and transparency, in other words a more incentive compatible design. Nevertheless, the costs of implementing this new design need to be taken into consideration in an objective way. In case of a daily reserve capacity market, the next question would be 'should the daily reserve capacity market be closed and cleared before the day-ahead market, or the other way around, or should they be simultaneous?'. This question is the topic of the next chapter.

In case of balancing energy markets, two more arguments exist for moving towards markets with very short time horizons (bidding separately for every PTU). First, because the balancing energy market is cleared on a PTU basis, having a bidding horizon longer than one PTU will lead to introduction of an extra opportunity cost to the bid prices. And second, for example in a monthly market, new bidders cannot participate in the market throughout the month, because they were not selected in the market cleared in the preceding month. Thus, for balancing energy markets, having a long time horizon (for bidding) will significantly impact the liquidity, allocative and price efficiency of the market.

5. Coordination of Timing of Reserve Capacity and Day-ahead Markets

5.1. Introduction

As discussed in the previous chapter, using markets with short time horizons for procurement of reserve capacity would lead to various improvements in the market performance. As a result of short term auctions, the number of reserve providers who can participate in the market increases leading to higher liquidity and higher competition, the reserve requirements can be calculated more frequently and more accurately resulting in a reduction of the "demand" in the reserve capacity markets, the room for the TSO to deviate from optimal procurement of reserves would be limited resulting in higher allocative efficiency, the transparency of the market would improve, and the prices would be more reflective of the real value of the service. As a conclusion in the last chapter, use of daily auctions (preferably with hourly bidding) was recommended. However, in case of daily reserve capacity markets, the critical question would be: how should the reserve capacity and the wholesale day-ahead market be coordinated?

The complicating factor in design of reserve capacity markets is that generators have the opportunity to offer their free capacity in day-ahead market *or* the reserve capacity market. In other words, these markets compete with each other for attracting bids. Thus, design of reserve capacity markets cannot be done in isolation from design of other electricity markets especially the day-ahead market. This chapter focuses on coordination of timing of the reserve capacity (RC) market and the day-ahead (DA) market. The effect of alternative clearance sequences of the DA and RC markets are studied in this chapter. Using an intuitive argument, the authors in [20] mention that in order to avoid low liquidity and higher prices, the RC market must be closed before the DA market. Authors in [37] confirm this recommendation arguing that in order to ensure that the system operator has the required amount of reserves to maintain system security, the RC market should be the first one. However, the issue of the sequence of these two markets is still an open question and there are examples in various systems in which the RC market is cleared after the closure of the DA market, e.g. the regulation market in PJM is closed one hour before the hour of operation while the DA market is obviously cleared on a day-ahead basis [15, 16]. Since the order of clearance of these two markets has a direct impact on possibilities for integration of reserve capacity markets across borders, this entire chapter is devoted to study this issue and the outcomes will be used in the next chapter that explicitly discusses challenges of integration of reserve capacity markets.

In this chapter, the objective is to develop a model that can help us understand the consequences of changing the sequences of these two markets. The objective of this study is to see how these different possible designs can influence the behaviour of bidders in the two markets, using market clearing prices and volumes of the offered capacity in each market as the main indicators. A simulation model is developed in MATLAB, which focuses on behaviour of the generators as "sellers" in both the DA and RC market. Each generating unit decides on its offered capacities in the two markets (bid capacities) and the corresponding bid prices in each round of the simulation.

5.2. Agent-based modeling, motivation

The electricity sector, and economies in general are characterized by difficult real-world aspects, such as asymmetric information, imperfect competition, strategic interaction, collective learning, and the possibility of multiple equilibriums [66]. Analytical approaches usually have to put strong and constraining assumptions on the agents that make up the economic system under study, in order to set up elegant formal models [67]. Equilibrium models either do not consider strategic bidding behavior or assume that players have all relevant information about the other players' characteristics and behavior; they also disregard the consequences of learning effects from daily repeated interactions [68]. Game theoretical analysis is usually limited to stylized trading situations among few actors, and places rigid – oftentimes unrealistic – assumptions on the players' behavior [67].

Introduction of the concept of *complexity* made some economists take a different approach to market modeling. A system is typically defined to be complex if it exhibits the following two properties [69]:

- The system is composed of interacting units.
- The system exhibits emergent properties, that is, properties arising from the interactions of the units that are not properties of the individual units themselves.

As the concept of *complexity* and *complex adaptive* systems gained popularity, more economics research was performed focusing on heterogeneity and adaptivity rather than rational behavior and equilibrium. At the same time, the tremendous availability of computational resources made it possible to set up large-scale and detailed computational models that allow a high degree of design flexibility [67]. Agent-based models offered the possibility of not only describing relationships in complex systems, but growing them in an artificial environment [70]. Agent-based simulation is, thus, a third way between fully flexible linguistic models and more transparent and precise but highly simplified analytical modeling [71]; the resulting models are dynamic and executable, so that their evolving behavior can be observed step by step [72].

5.3. Agent-based modeling, concepts and procedure

Agent based modeling essentially researches the two-way feedback between regularities on the macro level and interaction of economic actors on the micro level. The actors are modeled as computational agents. Each agent is an encapsulated piece of software that includes data together with behavioral methods that act on these data [66]. Some of these data and methods are designated as publicly accessible to all other agents, and some are designated as private and so, not accessible by any other agents. Agents can communicate with each other through their public and protected methods. The modeler specifies the initial state of an economic system by specifying each agent's initial data and behavioral methods and the degree of accessibility of these data and methods to other agents [66].

The concept of (computational or software) "agents" comes from the fields of Distributed Artificial Intelligence (DAI) and Multi-Agent Systems (MAS). Common definitions of the term characterize them as autonomous, reactive, goal-oriented, or socially able, just to cite a few [67]. However, as the authors in [73] correctly annotate, these features do not all translate into computational properties in agent-based simulations. Most AB models do not require agents to exhibit all the characteristics of the software agents from the DAI or MAS world; instead, the most important features of agents in AB models is that they are goal-oriented and adaptive [67].

All agents are assigned a value, like e.g. payoff, fitness, or utility, the amount of which is dependent on their actions in the environment they are placed in. Agents are goal-oriented meaning that they seek to maximize this value, and they are adaptive, meaning they have the ability to learn which actions to take in order to increase this value over time, and so to reach the goal.

The modeling procedure can be described as follows [66]: After having (i) defined the research questions to resolve, the modeler (ii) constructs an economy comprising an initial population of agents and subsequently (iii) specifies the initial state of the economy by defining the agents' attributes (e.g. type characteristics, learning behavior, knowledge about itself and other agents) and the structural and institutional framework of the electricity market within which the agents operate; the modeler then (iv) lets the economy evolve over time without further intervention—all events that subsequently occur must arise from the historical time-line of agent-agent interactions, without extraneous coordination; this procedure is followed by (v) a careful analysis of simulation results and an evaluation of the regularities observed in the data.

Our aim is to develop a model that can help us understand what the possible consequences are when the sequence of the day-ahead and the reserve capacity market is changed. At the heart of such model is the behavior of market parties. Different designs would lead to different outcomes partly because they are perceived and reacted to differently by market parties, even though there might not be a fundamental difference between the designs. Thus, what we would like to study is the mutual effect of the environment and the actors: the environment changes, which would influence the behavior of the actors, and the change in behavior will result in different outcomes at the system level. Therefore, the behavior of market parties plays a decisive role, the behavior that is of course focused on profit maximization and whose effect would be even more prominent considering the oligopolistic structure of the electricity markets.

5.4. Agent-based modeling, various methods

Genetic algorithms have been applied to electricity markets in order to study the bidding behavior of market parties [74-77]. Although genetic algorithms have been widely and rather successfully applied to various optimization problems within power systems engineering, use of these algorithms for determining the bidding behavior of individual bidders in an electricity market seems to be contradictory to some fundamental issues in electricity markets (and anonymous markets in general). In GAs, during each generation of the evolutionary process, creatures are randomly selected for reproduction with some bias towards higher fitness. After parents are selected for reproduction, they produce children via the processes of *crossover* and *mutation* [77]. The parents are required to be in pairs for reproduction, and the result is two children. Children are created by copying the contents of parent 1 into child 1 and of parent 2 into child 2 until a randomly selected crossover location is reached [76]. At this point, bits are copied from parent 1 into child 2, and from parent 2 into child 1.

So it is the sharing of information between agents that enables them to learn. In other words, genetic algorithms are designed as systems in which agents cooperate and share information and it's the entire *population* that is *learning* something, and not individual agents learning separately (using market outcomes). That's in contradiction with the basics of markets in which bidders are independent and do not share information. Thus, although genetic algorithms can be quite successful in solving optimization problems (in which case it is the entire *population* trying to reach an optimal result, and not independent agents), seeing the bidders in a real market as agents within a genetic algorithm seems to be in contradiction with the basics of the market.

Based on psychological findings on human learning, Erev and Roth developed a three-parameter reinforcement-learning algorithm [78]. This learning model has gained much attention by agent-based modelers in many fields, including electricity market studies [79-82]. This algorithm assumes a certain limited number of actions for each agent, or in other words, the algorithm assumes discreet decision variables. Each action of the agent has a certain weight, which determines the likelihood of the agent taking the corresponding action in each round. These weights are updated at the end of each round using the market outcomes (the agent's profit).

The rules are simple, agents explore (the decision space) a lot and the final results are very path-dependent, especially as the number of variables increases. Effective applicability of this algorithm seems to be very dependent on the number of decision variables and the complexity of the problem that is being analyzed. If there is only one variable (e.g. only bid price) and very limited number of agents, these models manage to give us meaningful insight about the dynamics of the market. However, as the problem gets more complex, and the number of decision variables increases, this very simple algorithm does not seem to be able to handle the complexity in an effective way. Adding a decision variable means adding another dimension to the decision space, which means a large increase in the number of possible *actions* for each agent.

Q-Learning is yet another popular algorithm that has been used to simulate electricity markets [83-85]. Although the details of Q-learning and Roth-Erev are different (the way the weights are updated in each round are different in the two algorithms), both algorithms use the same basic assumptions and have the same structure. In this chapter, we are trying to simulate two markets (and their interrelations), and we have bid capacities in addition to bid prices in each market.

We applied Q-learning and Roth-Erev to this problem, which has 3 decision variables (the capacity in the second market is a dependent variable), using the case of Germany, which will be explained in detail later in this chapter, with 62 bidding agents. Different runs of the simulation led to wildly different results, the standard deviation of the market prices (compared to the mean) was too high to enable us make any meaningful conclusion. If one looks closely at the results reported in the extensive and insightful working paper of Iowa State University [86] which uses a modified Roth-Erev algorithm, the same issue can be noticed.

For each day (one set of inputs), the algorithm is run for 20 times and the outcomes are reported. As can be seen in the tables of the Appendix (particularly table 9), the price of the same node, varies so much in those 20 runs that the standard deviation of the price is sometimes more than 50% of the mean. These variations do not challenge the validity of the conclusions of the report, because the report compares the no-learning case (bidding at operating costs) with the learning case (where agents use the proposed algorithm) and aims to show that using the learning algorithm would enable the agents to learn how to behave strategically and take advantage of the opportunities in the market, and thus bidding at a price higher than their operating costs.

However, those high variations (in different runs) would limit the applicability of this algorithm if two or more particular designs are to be compared. In addition, it should be emphasized that these high variations occur while the problem (studied in the report) is highly simplified: there are only five generators and they each have two decision variables, one with 5 possible states and the other only 3. So the number of players is limited, and the decision variables are highly discretized, and yet the numerical results vary wildly in different runs.

The method we use in this chapter falls under the last category of agent-based models as categorized in [67]: *model based adaptation algorithms*, which are usually tailored for the specific design of the simulated market(s). They do not explicitly rely on findings from psychological research about learning or on developments from the DAI or MAS fields of agent learning. The most prominent work in this field has been conducted at the London Business School [87-89]. Other approaches, such as those by Visudhiphan and Ilić, have also attracted interest by researchers. Bower and Bunn in [87] present an agent based simulation model of the England and Wales electricity market. The simulation is designed to compare different market mechanisms, i.e. daily versus hourly bidding and uniform versus discriminatory pricing. Generator agents use a simple reinforcement-learning algorithm, which is driven by the goal to simultaneously maximize profits and reach a target utilization rate of their own power plant portfolio. The agents adjust their bidding strategies according to their last round's success: they either lower, raise, or repeat their last bid price, depending on whether their utilization and profit targets have been met in the last round, or not. It is an extremely simple mechanism used to simulate bidding, and yet manages to lead to new insights regarding different market designs.

The following section will explain the basic logic of the model used in this chapter, and the mathematical formulation can be found in Appendix A.

5.5. The basic logic of the model

The system we are trying to sturdy comprises of two basic elements: the environment and the agents. The environment is determined by the rules of the market design, and the actors are the generators who would bid in the market and if selected would be able to sell their offered capacity.

Regarding the environment, there are two markets in which the actors can bid into: the day-ahead (DA) market and the reserve capacity (RC) market. The question we try to answer is what would happen if the sequence of these two markets is changed. Thus, three cases are defined: two cases in which markets are cleared sequentially (first DA then RC, and the other way around), and one case in which the markets are simultaneously cleared. Each of these cases has its own characteristics. In case of sequential clearance, the bids in the first market would have a lost opportunity cost component simply because from the seller's perspective, the product that is offered in the first market needs to have a price that is high enough for the seller to make sure that by offering that product in the first market he is not losing a possible profit in the second market. Another important characteristic of sequential clearance is that when the outcomes of the first market are known, the seller can adjust its bid in the second market. In other words, if the seller has some capacity that was not selected in the first market, he still can offer that capacity in the second market, while in simultaneous clearance, the bidder has to divide up its capacity between the two markets and cannot offer the same capacity in both markets.

The second element of the model is the agents (generators/sellers in the market). In each round, agents bid in the two markets, and based on the market outcomes they would change their bids for the next round. Agents do not have information about the bids of the other agents: they can only see the market outcomes. The decision variables that the agents have are their bid price and the bid volume. There are two markets and therefore, in each round, every agent decides on two bid prices and two bid volumes. The objective of an agent is maximizing its total profit. They do not necessarily bid at their marginal cost. The marginal cost only determines their minimum bid price. Depending on the market conditions, their market power and other agents' bids, an agent can bid at a price much higher than its marginal cost (there would be a price cap in the market though).

In order to be able to model the opportunistic behavior of the agents, we define a basic characteristic for the agents which models their attitude towards risk. On one hand, we have risk-averse agents who do not behave opportunistically: when they bid in the market and their bid is selected they will not try to increase their bid price in order to increase the market price and gain more profit. These agents do not try to take risks, they bid at their marginal cost plus a margin and if they are selected in the market they would simply keep their bid price for the next rounds. On the other hand, we have risk-prone agents who do not necessarily keep their current bid price (for the next round) if they are selected, but they will try to influence (increase) the market clearing price by increasing their bid price. So they take the risk of not being selected (in the next round) in order to increase the market clearing price. These agents try to abuse their market power and take advantage of all the opportunities in the market to gain more profit.

In addition to the bid price, the agents need to decide on their bid volumes in every round as well (based on the market outcomes). The agents use a simple logic to change their offered volume in the two markets. They calculate their average profit per MW of their capacity (in €/MW/hour) in the two markets and withdraw some of their capacity from the less profitable market and add it to their offered capacity in the other market. The size of this volume change in each round depends on the difference between the two profit values (in the two markets). The lower the difference, the smaller the size of the volume change in that round. We use a simple linear relationship for shifting of volumes.

The mathematical formulation of all these rules and the model as a whole can be found in Appendix A.

5.6. Inputs and parameters setting

The data list of the generating units in Germany is used in this model: 262 units (different types) with different operating costs [90]. The list includes oil, gas, coal, nuclear and hydro power plants. It is assumed that each generator bids separately. In the following results, the demand of the DA market is 74,000 MW (rough estimation of the current peak load in Germany) and the demand in the RC market is 6,000 MW which is the sum of the demand for secondary and tertiary control in Germany (the average value in 2009) [41]. The total generation capacity is 108,855 MW. It should be emphasized that the goal of this study is not to "simulate the German market", but to use the available real data in order to be able to have a realistic picture (to avoid making conclusions based on a non-real test system).

Distinguishing between risk-averse and risk-prone units is also a critical input to the simulation. The desirability of taking a risk-prone approach highly depends on the level of the operating costs of a unit; Low-cost units can add a decent profit margin to their operating costs and expect to be selected in the market with a high probability, simply because of their low level of operating costs. Thus, when marginal pricing is used, trying to increase the market clearing price (taking a risk-prone approach) for low-cost units endangers their otherwise-secure and continuous profit. Therefore, we define the risk attitude of units based on their operating costs: units with costs lower than a certain level are considered risk-averse and the ones with higher costs are considered risk-prone. The setting of this "critical cost level" has profound impact on the simulation results. Figure 5. 1 shows the cumulative distribution of the operating costs of the units used in this study (power plants list in Germany). As can be seen, 50% of the total available capacity comes from units with an operating cost of less than 41.07 €/MWh. Using this value as the critical cost level means that half of the capacity will belong to risk-averse units and the other half to risk-prone units.

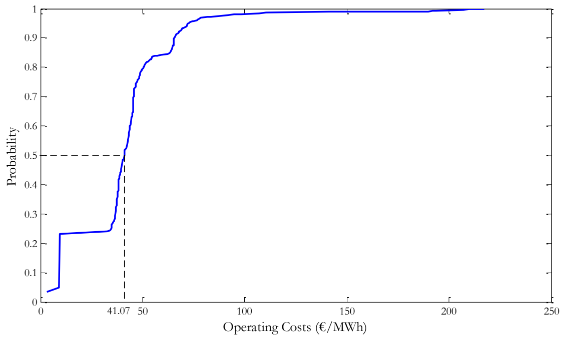


Figure 5. 1. Cumulative distribution of the units' operating costs

Figure 5. 2 illustrates how the DA market clearing price in case A depends on the critical cost level used for distinguishing between risk-averse and risk-prone agents. As the critical cost level increases, the number of risk-prone units decreases which results in reduction of the market clearing price. Risk-prone units have to compete with others in order to be selected in the market and by reduction of the number of risk-prone units, their impact on the market clearing price would be more and more limited. However, it should be noted that the objective in this study is to *compare* the three cases so the key factor is to apply the same critical cost level to all the cases.

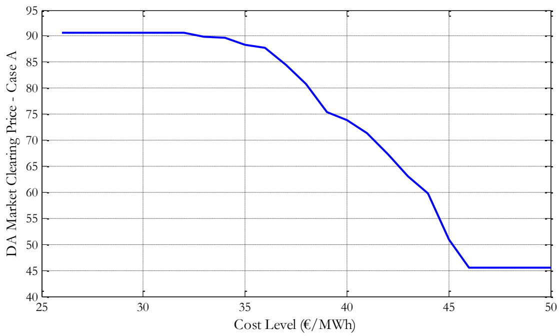


Figure 5. 2. Final market clearing price of the DA market for Case A, as a function of the critical cost level used for distinguishing between risk-averse and risk-prone units

Various values for the critical cost level were used and the simulation results (for case A, which is the current design in Germany) were compared with the real market price data in Germany. Figure 5.3 shows the real day-ahead (DA) market prices in Germany for different load levels in 2009, and the solid line shows the trendline estimating the trend of the data. Using a critical cost level of 40 €/MWh in the model would result in the market prices shown on the graph. As can be seen, the simulation results closely follow the trendline of the real market data, having a correlation coefficient of 0.98. Thus, we have used a critical cost level of 40 €/MWh for the simulation results presented in the rest of this chapter. The exact same parameter setting is applied to all the three cases.

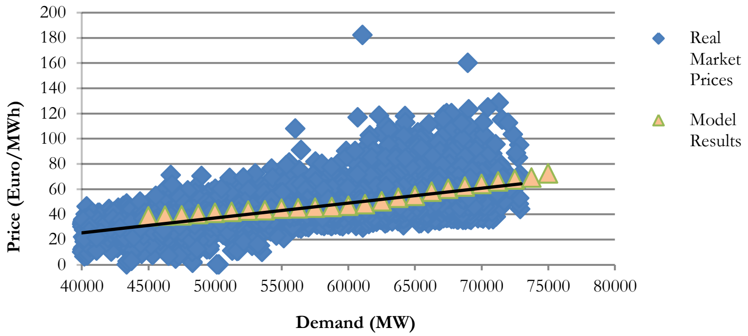
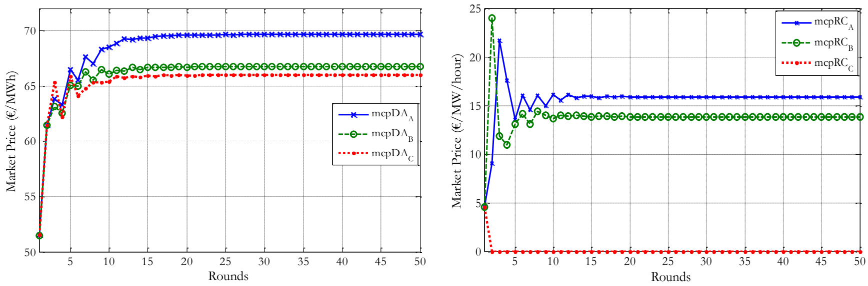


Figure 5. 3. Real and simulated day-ahead market prices in Germany 2009

5.7. Model results

Figure 5. 4 shows the market clearing prices (for each round) of the DA market and the RC market for the three cases, assuming the critical cost level of 40 €/MWh. As can be seen, regarding the DA market, case A results in the highest market price, 70 €/MWh, which originates from the lack of the possibility of capacity substitution between the two markets in case A, meaning non-selected bids in one market cannot be bid into the other market so the corresponding non-selected capacity is lost (not used). Case B and case C result in almost the same DA market prices, 67 €/MWh and 66 €/MWh, respectively. Regarding these two cases, it seems that, although capacity substitution can be performed by units in these two cases which leads to lower bid prices and consequently lower DA market clearing prices, because of the significant difference in the size of the DA and RC markets (the DA market is 12 times larger than the RC market) the sequence of market clearances has an insignificant effect on the DA market prices. Thus, even though in case C, a lost opportunity cost component is added to the bid prices in the DA market (the first market in case C), this case leads to the lowest DA market clearing price. The difference in size of the markets originates from the nature and objective of the two markets: the DA market aims to meet the electricity demand of the system, but the RC market aims to procure the required reserve capacity to compensate for deviations in real time.



(a) (b)

Figure 5. 4. Market clearing prices (MCPs) of (a) the DA market and (b) the RC market for the three cases-assuming a critical cost level of 40 €/MWh

Nevertheless, regarding the RC market, both case A and case B result in high market prices, 16 €/MW/hour and 14 €/MW/hour, respectively. In case B, a considerable lost opportunity cost component is added to the bid prices of generators in the RC market because of the sequence of markets clearances; the capacity offered in the first market (RC in case B) comes with a price high enough for the bidder to ensure that no possible profit is missed in the second market (by offering that capacity in the first market). Another interesting outcome is that in case C the RC market price goes down to zero. In case C, the RC market is the second so there is no opportunity cost component in the bids of generators and in the RC market there is no operating cost either (in contrast to the DA market). Presence of a sufficiently high level of competition will push the bid prices down to zero (actually to the level of fixed costs which have been neglected in this study). This is the reason why, even in case of an opportunity component in the DA bid prices for case C, the DA market price is the lowest: the LOC component depends on the RC market price which becomes zero after the few first rounds.

In order to clarify the activities inside the two markets, the individual bid prices and bid volumes of a specific unit are shown in the next two figures. Figure 5. 5 illustrates the DA and RC bid prices of an individual unit in case A. The 43rd unit is a combined cycle gas-fired plant with an operating cost of 64.26 €/MWh and a net capacity of 162 MW [90]. Figure 5. 6 shows the DA and RC bid volumes of the same unit in case A. Comparing the unit's operating costs to the DA market clearing price in Figure 5. 4, it can be seen that after the first few rounds the DA market price is higher than the unit's operating costs, meaning that the unit can make profit by bidding in the DA market, however, according to Figure 5. 6, the unit constantly reduces its offered capacity in the DA market and shifts it to the RC market. The key is comparing the unit's profits in the two markets. As noted earlier, since the fixed costs of the units are neglected in this study, the average-per-MW profit of the unit in the DA market is the difference between the market price and the unit's operating costs, which is 5.34 €/MW/hour, while the unit's profit in the RC market is the RC market clearing price, which is 16 €/MW/hour, see Figure 5. 4. Thus, although there is profit to be made in the DA market, simply because of the unit's profit in the RC market being higher, in order to maximize its total profit, the unit constantly shifts its capacity from the DA to the RC market until all of its 162 MW of capacity is offered in the RC market and it has no capacity offered in the DA market, see Figure 5. 6.

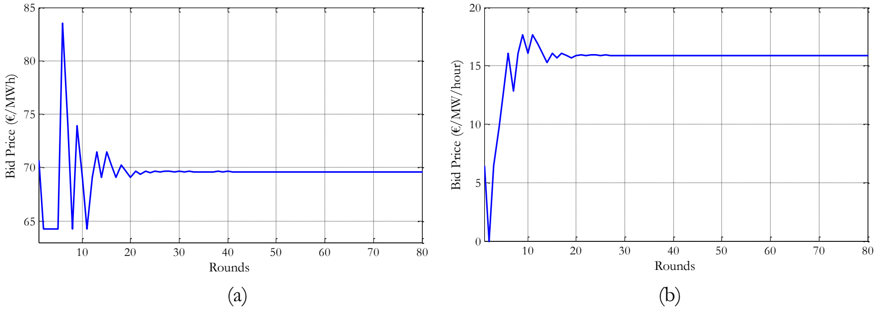


Figure 5. 5. Individual bid prices of unit #43 in Case A- (a) DA bid price (b) RC bid price

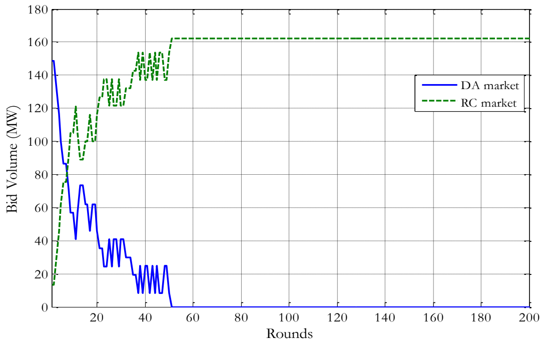


Figure 5. 6. Individual bid volumes of unit #43 in Case A

Table 5. 1 shows the total volumes (in MW) offered in the RC and DA markets for the three cases. It should be noted that the sum of the offered volumes in the two markets for cases B and C is higher than the total available capacity in the system (108,855 MW) which is because of the fact that in those two cases, capacity substitution between the two markets is possible, so non-selected capacity of a unit in the first market can be offered in the second market (offering of the same capacity in two markets, but not at the same time). However, in case A, a unit has to divide up its total available capacity between the two markets because bidding is simultaneous and the same capacity cannot be offered in both markets.

Table 5. 1. Total offered volumes (in MW) in the DA and RC markets for the three cases- For a critical cost level of 40 €/MWh

	Case A	Case B	Case C
Day Ahead Market (DA)	91,697	102,855	108,046
Reserve Capacity Market (RC)	17,158	16,373	34,855

Regarding the RC market, the lowest volume is offered in case B and the highest volume is offered in case C in which the units learn to offer all of their capacity that is not selected in the DA market (the first market in case C) in the RC market, resulting in a final offered volume of 34,855 MW in the RC market (the difference between the total available capacity and the demand in the DA market). In case B, because of the uncertainties in whether or not offering the capacity in the RC market (first market) will lead to loss of profit in the DA market (second market), the offered volume in the RC market is limited. One might expect the same phenomenon to happen in case C for the DA market (the first market in case C). However, the offered volume in the DA market for case C is the highest. The main difference is that there is basically no minimum bid price in the RC market while in the DA market, the bid price of a unit cannot go below the operating costs of the unit. Therefore, while in case B the DA market price cannot go down to zero, in case C, the RC market price reaches zero after a few rounds, which in turn leads to elimination of uncertainties for bidding in the first market (DA in case C). Thus, although the uncertainties in offering capacity in the first market lead to the lowest offered volume in the RC market for case B, these uncertainties cannot limit the offered volume in the DA market for case C.

Comparing these market results with the *perfect* market situation may be useful in clarifying the effect of strategic behavior. The fixed costs in providing reserves have been neglected in this study, and therefore, at the perfect model situation, bidders would bid at their marginal costs in the day-ahead market and at zero in the reserve market. If there were no learning, the day-ahead market price would have been 47.2 €/MWh and the reserve price would have been zero.

However, one cannot conclude that in any of the three cases, the difference between the day-ahead market price and 47.2 €/MWh is the effect of opportunistic behavior of the agents. The final cost of providing a service includes both the physical costs and the opportunity costs, and these opportunity costs very much depend on the market design. In terms of day-ahead market, cases A and C both incur opportunity costs for the day-ahead market. Only in case B where the day-ahead market is second, there is no opportunity costs in the day-ahead market. Same argument holds for the reserve capacity market.

In order to demonstrate the effect of the critical cost level (used for distinguishing between the risk-averse and risk-prone units), Figure 5. 7 shows the DA and RC market clearing prices for the three cases using a critical cost level of 44 €/MWh, instead of 40 €/MWh as used in the previous graphs. As the figure suggests, all the market prices decrease compared to Figure 5. 4, for which a critical cost level of 40 €/MWh was used. Nonetheless, comparing the three different cases, case A still leads to the highest market prices, followed by case B, and the differences in market prices in case A and case B are even more distinct. Case C, again, results in the lowest market prices, with a zero RC market price, in particular.

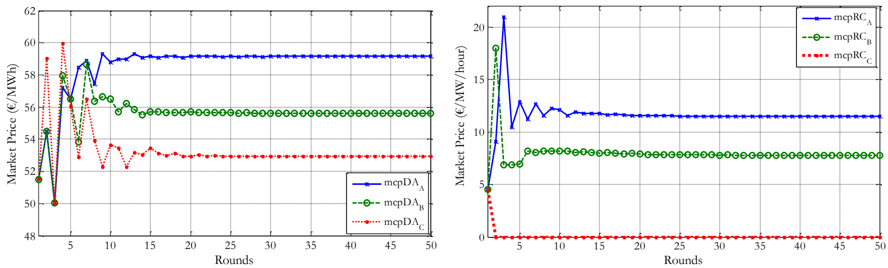


Figure 5. 7. Market clearing prices (MCPs) of the DA market (left) and the RC market (right) for the three cases- assuming the critical cost level to be 44 €/MWh (instead of 40 €/MWh)

The results of this study so far, show that having the DA market closed first and then closing and clearing the RC market (case C) will lead to the highest offered volumes in both markets and lowest market clearing prices. The objective of the reserve capacity market is to ensure that enough reserves will be available in real-time to compensate for deviations in power generation and consumption. Thus, the entire RC market is aimed at guaranteeing system security.

The results of this study suggest that making such a guarantee before closure of the day-ahead market is much more expensive (case B) than making the guarantee after the closure of the DA market (case C).

5.8. Shortage of reserves

The critical controversial issue, in case the reserve market is closed after the closure of the day-ahead market, is the availability of capacity from *proper resources* in the reserve capacity market. In other words, having the reserve market closed *after* the day-ahead market might result in insufficient reserves in the reserve capacity market.

This would be crucial in case of secondary control reserves. To utilize the output of a generator for secondary control, its response speed must meet specific requirements. The offered capacity in the reserve market for secondary control must be capable of being fully activated within 15 minutes; a minimum response speed (rate of change) of 7% of the nominal output per minute. However the bids for tertiary control can take hours to be fully activated.

Therefore, the question is: if the reserve market is closed and cleared *after* the closure of the DA market (as in case C), will sufficient capacity from the proper resources, capable of providing secondary control reserves, still be available in the reserve market? In order to answer this question, we make a distinction between secondary and tertiary control reserves in the RC market (in the simulation). The demand for secondary control is assumed to be

2800 MW (the average of the secondary control demand in Germany over 2009) and the demand for tertiary control is 3200 MW (the average of the tertiary control demand in Germany over 2009), summing up to 6000 MW demand in the RC market. According to [12, 20], the rate of change for oil- or gas- fired units is around 8% per minute. Reservoir power stations, such as pumped storage plants, have rates between 1.5 and 2.5% per second (more than 90% per minute) whereas for hard coal- and lignite-fired plants, rates from 2 to 4% per minute and 1 to 2% per minute, respectively, are typical. The maximum rate of change for nuclear plants is approximately 1 to 5% per minute. Therefore, we assume that only the gas, oil and hydro units are capable of providing the secondary reserve. The simulation is run again, assuming that in clearance of the RC market, the demand for secondary control reserves has to be met only using bids from the gas, oil and hydro units, whose net capacity sums up to 33,655 MW (30% of the total available capacity in the system). All units can provide tertiary reserves.

Figure 5. 8 shows the market clearing prices of the day-ahead (DA) and reserve capacity (RC) markets, for the three different cases (using the same critical cost level as in Figure 5. 4 to Figure 5. 6), making the aforementioned distinction between secondary and tertiary reserves. An increase in the DA market prices for all the three cases (as compared to Figure 5. 4) can be observed. The RC market prices suffer a larger change for cases B and C (an increase of almost 5 €/MW/hour), while the RC market price in case C remains at zero.

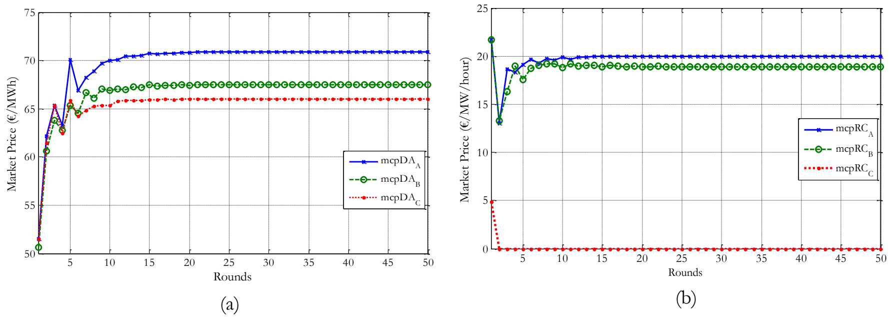


Figure 5. 8. Market clearing prices of (a) the DA market and (b) the RC market for the three cases (Critical cost level of 40 €/MWh)- Distinction made between SC and TC reserves

Therefore, even in case C, where the reserve market is the second market, still sufficient capacity from eligible secondary control reserve resources is available. Clearing the reserve market after the DA market does not lead to lack of enough secondary control capacity in the reserve market.

This simulation so far shows that under *normal* operating conditions, availability of reserves does not seem to be a serious concern if the reserve market is closed after the closure of the day-ahead market. Nonetheless, since system security is concerned, extreme cases need to be analyzed as well. The critical factors defining these extreme scenarios are the demands in the two markets AND the availability of the generating units. The demand in the reserve market is the reserve requirement of the system, and the demand in the day-ahead market can very much depend on system load. Availability of the generating units depends on the characteristics of the system (diversity of generation technology, the generation portfolio, maintenance frequencies, extreme weather conditions, etc.).

In order to see the effect of demand (load level) on the results, we run the simulation for cases B and C, with different demand values in the day-ahead market, assuming that all generating units are available. For both cases (separately), demand in the day-ahead market is increased until, in either markets, there is not sufficient capacity to meet the market demand. The reserve capacity market in Case C (in which the reserve market is closed *after* the day-ahead market) is suspected of not being able to attract sufficient bids as the load level and consequently demand increases. Simply put, since the reserve market is second in case C, it might end up with insufficient supply.

Based on our results, in both cases, it is indeed the reserve capacity market (and not the day-ahead market) that collapses first. So, although it is the demand in the day-ahead market that is increasing, because of the interrelations of the two markets, regardless of whether or not the reserve market is first, it is indeed the reserve market that collapses (insufficient supply to meet demand). Figure 5.9 illustrates the offered volume in the reserve capacity market for cases B and C, as the day-ahead market demand increases. These two supply curves intersect with demand (system's reserve requirement) at almost the same point, which is the point where the market collapses. As the figure shows, the offered volume in the reserve market for case B (reserve market first) is consistently lower than the offered volume in case C (reserve market second).

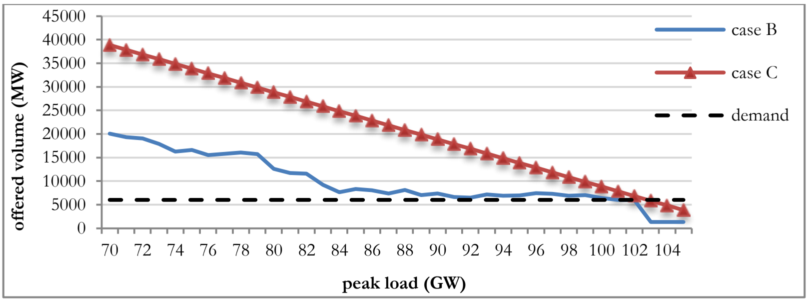


Figure 5. 9. Offered volumes in the reserve capacity market for cases B and C, as the demand in the day-ahead market increases

It might sound counter-intuitive at first sight but it essentially means that when there are two markets, the players in the two markets are the same, and the products traded in the two markets are to a great extent substitutable, if the markets are closed and cleared sequentially, players' *expectations* of the second market can highly influence the offered volume in the first market. In case B (reserve market first), service providers do not bid some of their available capacity in the reserve market simply because of what they expect to earn in the second market, especially when the demand in the second market (day-ahead) is very high (the cases studied here), and therefore high market prices in the day-ahead market are expected. While in case C (reserve market second), the agents learn to offer what is remained after the closure of the day-ahead market in the reserve market which is still enough to meet the market demand in the reserve market.

One should not forget that the size of the day-ahead market is much larger than the reserve capacity market. In addition, the reserve capacity market is much less volatile in terms of demand values and prices (and therefore profits), compared to the day-ahead market, which has to take the burden of high peak load values and whose market price can be very high at times. So, when the day-ahead market is second, it can have a large influence on the small reserve market, which is cleared before. When the reserve market is first, it can be, to a great extent, under the heavy shadow of a large, volatile and profitable market that is going to be cleared afterwards, and this can significantly reduce the offered volume in the reserve market.

5.9. Discussion

The author in [40] mentions the following, regarding coordination of timing of the day-ahead and reserve capacity markets, or ancillary services (AS) in general:

Sequential auctions (also called cascading clearing) have been defended in the early designs of market for frequency control AS [91] and [92]. With this method of coordination, AS are provided in a prioritized manner. Once an AS is bought, the capacity of the successful provider of this service for the following AS auction is reduced. However, this approach suffers from some flaws, in particular price reversals, illustrated by the infamous failure of the Californian AS market at the end of the 1990s, [62, 93]. Since then, it has been recognized that simultaneous auctions have to be in place for AS and energy-only markets (e.g., [94], [95, 96]).

The paragraph seems to be in clear contradiction with the findings of this chapter. However, there are implicit assumptions that need to be pointed out and clarified. In this chapter, the fundamental design in Europe is used in which "central dispatching" does not exist. In these markets, the system operator does not intervene in clearing the day-ahead market. If the entities that clear the day-ahead market and the reserve market are not the same, these two markets cannot be "co-optimized". In the European design, the day-ahead market is cleared separately and the system operator who is the single buyer in the reserve capacity market clears that market. Therefore, simultaneous clearance of these two markets in this chapter does not imply co-optimization. The main difference is since under the European design, there is no central dispatch, capacity cannot be substituted between the two markets. Thus, if the bidding is simultaneous, a bidder has to split up its capacity between the two markets, while if capacity substitution is possible (in presence of a central dispatch system), one bidder can bid (part) of its capacity in both markets (with two different prices) and the central dispatcher who co-optimizes the two markets, selects the bid in the way that minimizes the total costs.

Therefore, if there is a central dispatch system, bidders do not have to divide up their capacity between the two markets AND the two markets can be co-optimized in which case simultaneous clearance is absolutely superior to sequential clearance, as mentioned by the author in [40]. Nevertheless under the European design, there is no co-optimization of reserve and energy, and the bidder cannot bid the same capacity in both markets and therefore the answer to the question 'which one is superior' is less straightforward. Assume that simultaneous clearance is used and a bidder has 100MW available capacity and offers 50MW in DA and 50 MW in the RC market. In this case if its bid gets selected in the DA market but its bid price is too high to be selected in the RC market, the bidder does not have the opportunity to offer the non-selected 50MW in the DA market again: that capacity is simply lost. However if sequential clearance is used, there is always the possibility to offer the non-selected capacity (in the first market) into the second market.

To summarize, under the European design, when there is no co-optimization of reserve and energy AND capacity substitution is not possible, simultaneous clearance is not 'necessarily' the superior option as suggested in [40], and backed by references in literature. The implicit assumption in those references is that the basics of the American design is in place. This chapter investigated which design leads to better performance given that the fundamental European design is used. And the findings show that case C in which sequential clearance is used and the reserve capacity market is cleared after the closure of the day-ahead market leads to lower market prices and higher offered volumes.

5.10. Conclusions

The dominant design in Europe, as mentioned and supported by [12, 20] involves closing and clearance of the reserve capacity market before the day-ahead market. However, the sequence of these two markets is still an open question and other designs are also possible. This chapter tried to answer this question using a model that studies the change in behavior of generators as a result of changing the market design. The results show that clearing the reserve capacity market after the closure of the day-ahead market can lead to higher efficiency and liquidity particularly in case of the reserve capacity market.

Nonetheless, the question of whether or not sufficient capacity from eligible *secondary control* resources will be available in the reserve capacity market in case the market is cleared after the clearance of the day-ahead market needs to be answered on a case-specific basis. Our case study shows that if the reserve market is cleared first, the offered capacity in the reserve market would be lower than in the case when the reserve market is second. Therefore, our case study suggests that closing the reserve market after the closure of the day-ahead market does not necessarily lead to lower offered reserves and therefore system security issues. On the contrary, it can increase the offered volumes in the reserve market, as this market would not be under the shadow of the much larger (and mostly more profitable) day-ahead market anymore.

However, because of the very high stakes regarding security, this chapter does not directly recommend clearing the reserve capacity market for *secondary control* after the day-ahead market. More studies on a case-specific basis are required in order to evaluate the security issues, studies that, particularly, take into account availability of the generation side into consideration.

Nonetheless, since the requirements on *tertiary control* reserves are much looser and a very high percentage of units can provide this type of reserve, based on the results of this study, it is recommended that the market for tertiary control reserves be cleared after the closure of the day-ahead market, which will lead to higher offered volumes in the market, lower prices, and higher liquidity.

It should be emphasized that the objective in this chapter was not to make generic conclusions about the sequence of clearance of the reserve capacity and day-ahead markets, but primarily to raise the question and discuss the possibilities other than the ones that seem obvious because of historical reasons.

6. INTEGRATION OF RESERVE CAPACITY MARKETS

6.1. Introduction

This chapter is the first of two complementary chapters addressing integration of balancing services markets. This chapter is dedicated to the essential discussions on integration of 'reserve capacity' markets. Integration of 'balancing energy' markets will be discussed in the forthcoming chapter.

In the documents and reports which study integration of balancing markets in Europe, a significant amount of effort has been made in introducing generic integration models which define how service providers and system operators interact in a multinational context [31-37, 97-99]. Although these models (known as "multinational arrangements") are a valid concern and can influence the performance of the resulting multinational market, there are fundamental challenges that have to be faced, probably even before the 'integration models' are discussed. Challenges that stem from the design of the individual (national) markets in the countries/regions involved. In addition, handling of interconnection capacity is an influential factor in integration of reserve capacity markets.

In this chapter, first, using the case of Northern Europe as the main focus, we review the already-proposed integration models, discuss the issue of interconnection capacity and look into its interrelations with the designs of the national reserve capacity markets involved in market integration. Then, we will discuss whether or not integration of reserve capacity markets in Northern Europe in economically beneficial, and what factors its economic justification depends on. In the last section, using the findings and discussions in the previous sections, we discuss how reforms at the national level (proposed in chapter 4) can influence the outcome of market integration at the international level. The basic question raised in the last section is: what is the goal of integrating the reserve capacity markets in Europe?

6.2. Is the 'multinational arrangement' the main concern?

A large part of the current literature on integration of balancing services markets focuses on formulating various models whose main goal is to define the arrangements (at the international level) that can be used for exchange of balancing services across borders. These multinational arrangements define how the service providers (sellers) and the system operators (buyers) in different countries interact with each other in a multinational context.

In [97], written by ETSO, two alternative cross-border models are outlined: the BSP-TSO trading model and the TSO-TSO trading model. In the first model, balancing service providers (BSP) can directly offer their reserves to the neighboring system operators, whereas in the second model, TSOs trade with each other. In [34], by ETSO, two basic models (in addition to the 'no trading model') are proposed that "represent different levels of technical cooperation/integration". The first model is called 'cross-border reserve pooling' which creates a common market in which the TSOs can voluntarily share 0-100% of their bids with other TSOs. The second model of 'cross-border reserve trading' allows for procurement of part of the reserve capacity from another control area (separate markets, inter-TSO trading).

Later on, in [35], by ETSO, in addition to the models described in [97], a new model called 'from area control to regional control' is proposed. The model is described as the next integration step, which will include both 'reserve pooling' and 'reserve capacity sharing', as well as the leveling of surpluses and shortages in different areas.

Three generic models for the linking of balancing arrangements of neighboring control areas are described and discussed in [100] (by Frontier Economics): 'System Operator to System Operator trading', 'integrated balancing arrangements', and 'participant offers to multiple mechanisms'. Although different in wording, these models, in essence, are the equivalents of, respectively, reserve pooling of [97], regional control of [35], and BSP-TSO trading of [97].

Then, a report by EURELECTRIC, [37], has described principles and preferred design choices for balancing market integration. In this report, the creation of a merit order is advocated for exchange of reserves. This common merit order list is that last conceivable phase of market integration in which one single merit order list (made of all the bids in all the involved countries) is created and procurement of services is optimized at a regional level.

Furthermore, the European Commission has commissioned a report dedicated to balancing market integration, which gives an overview of the proposals on cross-border balancing models [98]. Three models are shortly described: 'TSO-BSP trading', 'TSO-TSO trading', and 'one regional control area'.

Subsequently, a report on guidelines for balancing market integration by ERGEG, [101], mentions three cross-border balancing models, namely a BSP-TSO model, a TSO-TSO model without common merit order, and a TSO-TSO model with common merit order.

Finally, the author in [99] describes and evaluates five cross-border balancing proposals. 'System imbalance netting' (concerning the netting of opposed control area imbalances), 'TSO-BSP trading', 'TSO-TSO trading' and 'Cross-border imbalance settlement' (concerning the cross-border trade of BRP imbalances). 'One regional control area' is the last model which proposes the merging of control areas.

These models/arrangements mainly deal with how the system operators and service providers should interact in a multinational context. These models can be applied to both reserve capacity and balancing energy exchanges but because of the focus of this chapter we only focus on exchange of reserve capacity. There is no doubt that the multinational arrangement used for exchange of reserves (discussed extensively in literature, as shown above) is a valid concern and that different arrangements (especially regarding the role of the system operators) could have different consequences. However, before that, there is a need to address some fundamental challenges regarding enabling cross-border exchange of reserves: Challenges that originate mainly from the design of the reserve capacity markets in the corresponding countries as well as the issue of interconnection capacity.

If we would like to come to conclusions that can be practically and effectively used, we need to address 'market integration' on a case-specific basis. If studies are focused on market integration in a specific region, with limited number of markets involved, then the market design of the individual countries can be analyzed and the challenges that originate from these national designs (and their differences) can be noticed and then addressed. Otherwise, if the focus is, for example, on entire Europe (with all its diversity in market design), the resulting analyses inevitably will stay at a conceptual level discussing the basics of how the service providers and the system operators can work together in a multinational context.

Thus, we limit our focus to the case of Northern Europe (Norway, the Netherlands and Germany) in this chapter. As discussed in details in the previous chapters, the reserve capacity markets in Northern Europe are long-term markets. Reserves are purchased by system operators in advance (on a long-term basis, yearly/monthly/weekly) in order to be activated in real-time. This is where the issue of 'interconnection capacity reservation' comes into the picture, in a multinational context. If a system operator purchases 50 MW of reserves from a foreign service provider for a specific time period, the same amount of interconnection capacity (50 MW) *must* be reserved in order to make sure that if needed in real-time, the system operator can activate that 50 MW from the foreign resource. In other words, exchange of reserves across borders implies reservation of interconnection capacity. And this reservation period is long because of the long time horizon of the reserve capacity markets in Northern Europe.

When a certain amount of interconnection capacity is reserved for a certain period, it cannot be used for trades in other markets, mainly the day-ahead market. Thus, purchasing 50 MW of reserves from a foreign resource for a period of one year implies 50 MW less room available for day-ahead trades throughout the entire year. In other words, exchange of reserves across borders incurs opportunity costs. This lost opportunity cost depends on the period of interconnection reservation and consequently on the time horizon of the reserve capacity markets involved. In case of Northern Europe with monthly and yearly markets, this opportunity cost can be a critical factor in determining the desirability of market integration. The next section looks more into how reservation of interconnection capacity relates to timing of the reserve capacity markets (an important design variable that was discussed in the previous chapters merely from a 'national' perspective).

6.3. Lost opportunity as a result of interconnection capacity reservation

Generally speaking, when integration of two separate markets is being discussed, the very first issue that comes to mind is: (from a system perspective) how much money can be saved (costs avoided) by integrating the two markets? Reserve capacity markets are not an exception in that respect. This cost-saving question, in turn, leads to the basic issue of 'price difference' between the two markets. One could simply look at the two market prices and consider the difference as the value of integrating the two markets, or in other words 'the money that could be saved'. This number can be tempting and yet deceiving. The price difference is usually the igniter for 'market integration' discussions. However, the designs of the two markets involved can impose significant limitations on what can be achieved economically.

Exchange of reserve capacity implies reservation of interconnection capacity for quite long periods of time, and that consequently means loss of trade in other electricity markets, especially the day-ahead market. In several cases in Western Europe cross-border exchanges in the day-ahead markets are at quite an advanced phase: as long as there is a difference in the day-ahead prices on the two sides of the line, the line capacity is used to the fullest for cross-border day-ahead exchanges, good examples are the Nor-Ned cable, or the trilateral market coupling among the Netherlands, Belgium and France, with implicit interconnection capacity auction. Thus, reservation of interconnection capacity for reserve capacity exchanges would come at the cost of those trades. In other words, exchange of reserve capacity across borders incurs opportunity cost and thus, to evaluate the economic viability of these exchanges, one should look at the price difference in the reserve markets as well as the opportunity costs incurred by trade losses in the day-ahead markets.

The day-ahead prices obviously play a critical role in determining this lost opportunity cost, and since the day-ahead prices in Norway vary significantly depending on the reservoir levels, we study the data of two consecutive years: 2009 during which there was no particular shortage of hydro power, and 2010 which was a dry year and thus, the day-ahead prices in Norway were significantly higher.

6.3.1. Year 2009

First let us study the case of the reserve capacity markets (for secondary control) for Norway and Germany. The RKOM market, the Norwegian reserve capacity market, is a weekly market that functions only in winter. The whole market is divided into three areas (area A in the south, area B in the middle and area C in the north of Norway) and three separate auctions are run for procurement of reserve capacity. **Error! Reference source not found.** illustrates the prices in the RKOM market for the three areas during 2009 (weekly prices). As mentioned above, the market did not operate in summer.

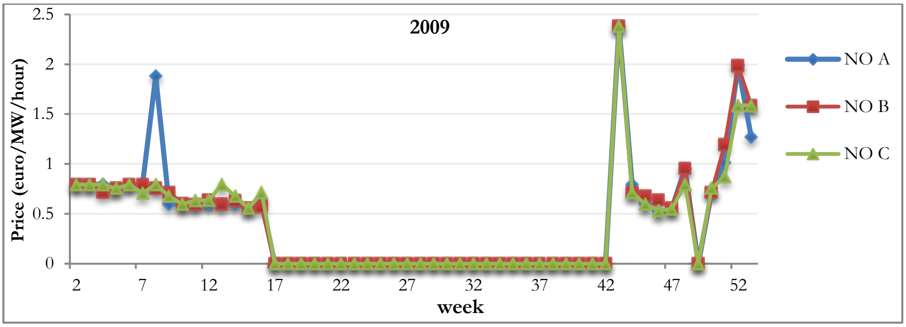


Figure 6. 1. Prices in the RKOM market (reserve capacity market in Norway) for the three Norwegian areas, 2009

As one can see, the prices are quite similar. We use the prices in the Southern Norway area (NO A) since if the reserves are in that area, then no interconnection capacity reservation (within Norway) would be needed in order to exchange reserve with continental

Europe. If the weighted average of the weekly prices in NO A is calculated, it would lead to an average reserve capacity price of 1 €/MW/hour, for 2009. The reserve capacity price in Norway is, on average, considerably low.

In case of Germany, the monthly reserve capacity prices were shown earlier in Figure 4.5, but for reader's convenience, the figure for upward reserves (peak and off-peak hours) is shown in Figure 6. 2.

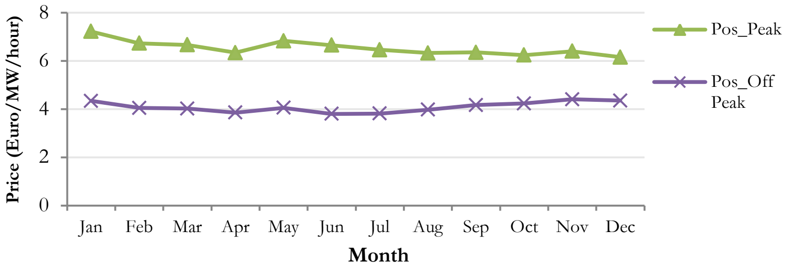


Figure 6. 2. Monthly reserve capacity prices (upward) for peak and off-peak hours in Germany, 2009

Figure 6.3 shows the difference in reserve capacity prices between Norway and Germany (peak as well as off-peak hours), for different months in 2009. As can be seen, in several months, there is a price difference as high as 5 €/MW/hour, meaning that enabling cross-border exchange of reserves between the two countries could lead to a cost reduction of 5 €/MW/hour, on average, during those months.

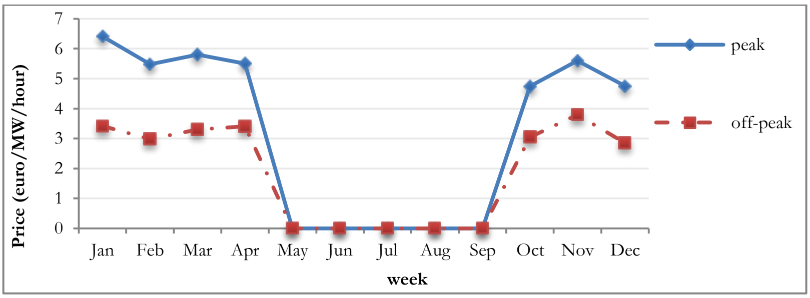


Figure 6. 3. Difference in reserve capacity prices between Norway and Germany, peak and off-peak hours, 2009

Nonetheless, exchange of reserves implies reservation of interconnection capacity and consequent loss of trades. In order to determine the size of this loss in case of Norway and Germany, the level of the day-ahead prices in the two countries has to be compared. The day-ahead prices vary in different hours of different days. Figure 6. 4 shows the day-ahead prices in Norway and Germany for January 2009 (as an example).

If interconnection capacity was reserved for exchange of reserves from Norway to Germany meaning that the interconnection capacity would not be available to day-ahead trades, in all the hours when the German price is higher than the Norwegian price, a potential profit is lost. The difference between the German and the Norwegian price determines this opportunity cost. In the hours when the German price is lower than the Norwegian price, reservation of interconnection capacity incurs no opportunity costs.

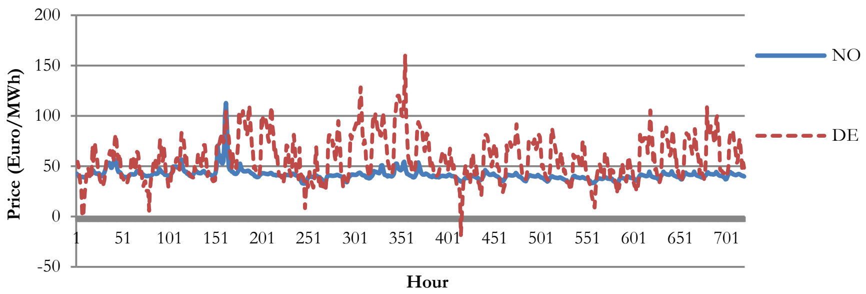


Figure 6. 4. Day-ahead prices in Norway and Germany, January 2009

Figure 6. 5 illustrates this lost opportunity cost as a result of reservation of interconnection capacity from Norway to Germany, on a monthly basis. Two separate figures for peak and off-peak hours are presented. As one can see from the figure, the opportunity cost differs wildly in different months (as a result of the volatility of the day-ahead prices) and is significantly high in many months. This opportunity cost needs to be subtracted from the reserve capacity price differences between the two countries when calculating the ultimate potential profit that can be achieved through reserve markets integration (enabling cross-border exchange of reserves).

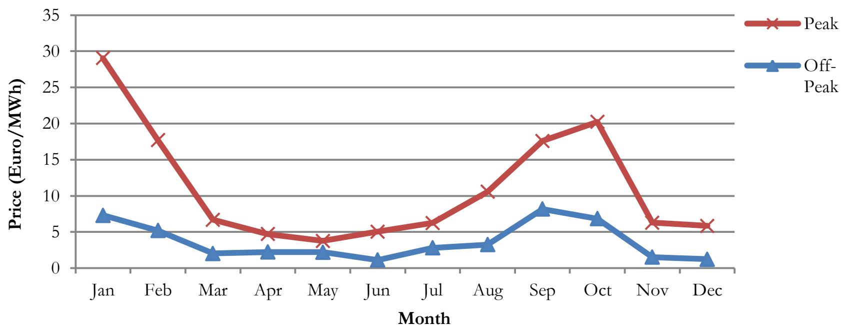


Figure 6. 5. Lost opportunity cost (in the day-ahead market) as a result of reservation of interconnection capacity (from Norway to Germany) on a monthly basis, for peak and off-peak hours

Both for peak and off-peak hours, exchange of reserves between the two countries would have been sound, economically, only in months where the opportunity cost shown in Figure 6.5 is lower than the difference in reserve capacity prices shown in Figure 6.3, which had a maximum of 6.4 €/MW/hour (for peak hours in January 2009). In case of peak hours, during no month in 2009, the price difference in the reserve markets is higher than the lost opportunity cost incurred by trade losses in the day-ahead markets.

In case of off-peak hours, in March, November and December, the lost opportunity cost was lower than the reserve price differences, and so market integration in those months passes the basic economic test. However, even in those months, the lost opportunity costs leave only a tiny profit margin (less than 2 €/MWh). In other words, even in those months, after the opportunity cost is subtracted from the price difference, the remaining price difference is not really significant enough to justify going through the complex costly process of integrating the markets.

Therefore, according to the data of 2009, integrating the reserve capacity markets of Norway and Germany does not introduce considerable economic benefit. Only comparing the reserve capacity prices (after subtracting the opportunity costs) shows that the potential for cost reduction is marginal. This fact, next to the inevitable costs of implementing an integrated market (costs of making the institutional changes), challenges the idea of integrating the reserve capacity markets between Norway and Germany as a means to reduce costs at a regional level (or achieve higher allocative efficiency).

The case of Norway-Netherlands is less straightforward though. TenneT, the Dutch system operator, purchases reserves on a yearly basis through bilateral contracts with reserve providers. Because of the confidential nature of these contracts, no official figure of the prices exists today. Therefore, comparing the reserve capacity prices of Norway and the Netherlands is not possible. However, the opportunity cost as a result of the lost day-ahead trades (in case the reserve markets were integrated) can be calculated.

If reserves can be exchanged across borders between these two countries, the Netherlands can benefit from the cheap reserves of Norway. Since the Dutch market is yearly, the Netherlands would be purchasing reserves from Norway on a yearly basis, and thus some interconnection capacity needs to be reserved (from Norway to the Netherlands) for the entire year, leading to lost trades in the day-ahead markets for an entire year.

If the day-ahead market price differences (between Norway and the Netherlands) are averaged over one year, the data of 2009 would lead to a price difference of 6.8 €/MW/h. This indicates the potential profit in the day-ahead market that would have been lost if the yearly interconnection capacity reservation had happened in 2009. Therefore, exchange of reserves in 2009 would have been economically meaningful only if the price difference in the reserve capacity markets was higher than 6.8 €/MWh, meaning a minimum reserve capacity price of 9 €/MW/h in the Netherlands.

Despite the conclusions made for 2009, a dry year (e.g. 2010) can potentially draw a completely different picture.

6.3.2. Year 2010

Figure 6.6 shows the RKOM prices for Southern Norway (NO A) in 2010. As it was a dry year, there was a jump in the reserve prices (compared to 2009): the average price in NO A was 3.5 €/MW/h in 2010 (compared to 1 €/MW/h in 2009).

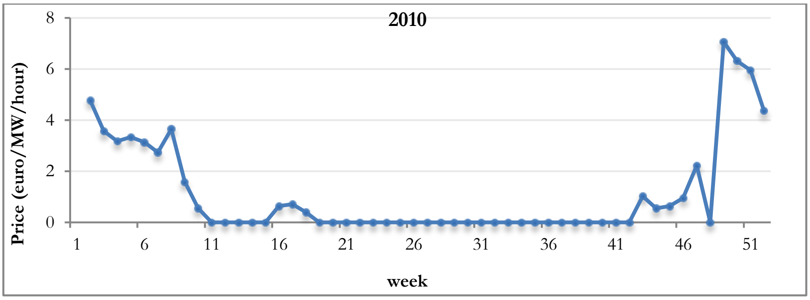


Figure 6. 6. Prices in the RKOM market (reserve capacity market in Norway) for the southern Norway (NO A), 2010

Figure 6.7 shows the monthly reserve capacity prices (for upward regulation) in Germany, for peak as well as off-peak hours in 2010.

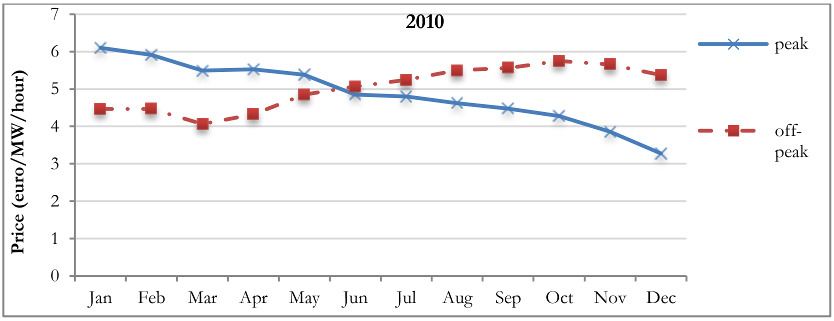


Figure 6. 7. Monthly reserve capacity prices in Germany, for peak and off-peak hours, 2010

The prices are generally above 3.5 €/MW/hour, but still the price difference is less significant than in 2009 where the reserve prices in Norway were lower. However, what changes the entire picture is the lost opportunity costs in the day-ahead market. Low reservoir levels in a dry year such as 2010, not only increase the reserve prices but also the day-ahead prices. The Norwegian day-ahead market price in 2010 was significantly higher than in 2009. Actually, the vast majority of the time the prices in Norway were *higher* than the prices in Germany. In two months, the prices were more than 25 €/MWh higher in Norway than in Germany, on average.

Figure 6.8 shows the opportunity costs that would have been incurred in case interconnection capacity (from Norway to Germany) was reserved for exchange of reserve capacity (rather than used for day-ahead trades). As can be seen, since the Norwegian day-ahead price is higher, the opportunity cost is negative. In other words, exchange of reserves from Norway to Germany in 2010 would have not resulted in any opportunity costs, simply because of the high Norwegian day-ahead prices in a dry year.

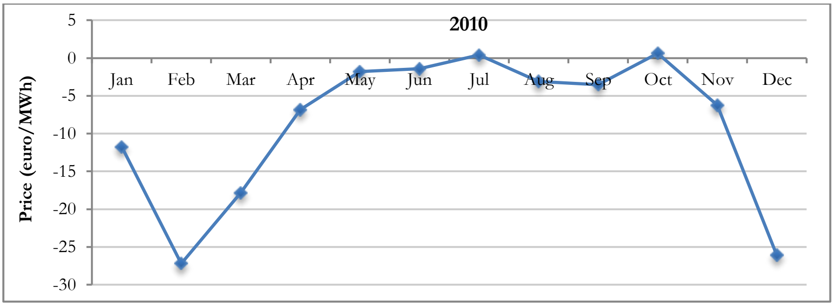


Figure 6. 8. Lost opportunity cost (in the day-ahead market) as a result of reservation of interconnection capacity (from Norway to Germany) on a monthly basis, 2010

Therefore, in 2010, hydro power scarcity results in significantly high day-ahead prices in Norway which would in turn mean that reservation of interconnection capacity for exchange of reserves would incur almost no opportunity costs, and so the difference in the reserve prices can be fully taken advantage of by cross-border exchange of reserves.

However, as mentioned earlier, the reserve prices are also higher in Norway in a dry year. Figure 6.9 shows the monthly price difference in the reserve capacity markets of Norway and Germany for peak as well as off-peak hours in 2010. As can be seen the price difference is typically lower than 2 €/MW/h. So although in a dry year, there may be absolutely no opportunity costs for reservation of interconnection capacity, since the reserve prices in Norway are also higher in a dry year, the price difference between the two areas would shrink. Nonetheless, exchange of reserves in 2010 (as a representation of a dry year) passes the basic economic criterion: the reserve price difference is positive after subtracting the opportunity costs.

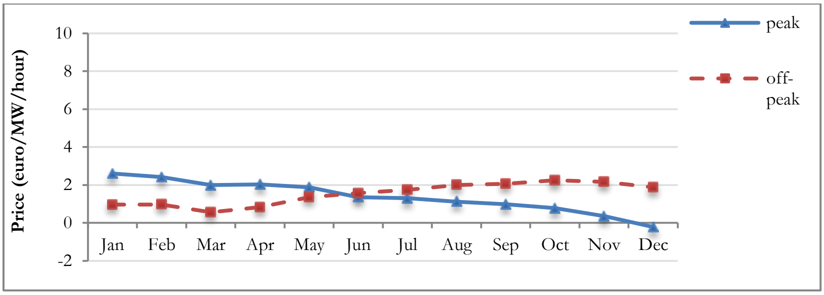


Figure 6. 9. Monthly price differences in the reserve capacity markets between Norway and Germany (peak and off-peak hours), 2010

To summarize, in case of Norway and Germany, in a normal year such as 2009 (with no particular shortage of hydro power in Norway) the reserve price difference between the two areas would probably be offset by the opportunity costs incurred by loss of day-ahead trades as a result of interconnection capacity reservation. In case of a dry year, significantly higher day-ahead prices in Norway would result in almost no opportunity costs as a result of cross-border exchange of reserves, however in that case, the reserve price difference between the two areas seems to be rather small to justify the costs and efforts of integrating the two markets in order to enable cross-border exchange of reserves.

Nonetheless, in case of Norway and the Netherlands, the price difference is believed to be considerably higher than the opportunity costs incurred by loss of day-ahead trades, even in a normal year where there is significant price difference in the day-ahead markets.

6.4. Is interconnection capacity reservation generally wrong?

Regarding the justification of reservation of interconnection capacity for balancing exchanges, there are arguments on both sides, [102] [103]. As discussed above, although the difference in the reserve capacity prices might be significant, the opportunity cost originating from the lost day-ahead trades can as well be significant, limiting the potential cost reduction as a result of reserve capacity markets integration. So we are back to the question whether or not interconnection capacity should be reserved for balancing services.

The key in answering this question is the opportunity costs incurred by reservation of interconnection capacity. As was discussed above, in a dry year, reservation of interconnection capacity from Norway to Germany implies almost no opportunity costs, and so interconnection reservation makes perfect economic sense. However, in 2009, where there was no particular shortage of hydropower, interconnection reservation would have incurred rather significant opportunity costs, to the extent that integrating the two reserve markets loses its economic justification.

The question is: are there ways to control this opportunity cost. Reservation of interconnection capacity can be done in an *indiscriminate* way (reserving interconnection for all the hours of the coming year) but it can also be done in a more flexible and intelligent way. For example, in the Netherlands, if reserves are going to be purchased by TenneT from a foreign resource, interconnection needs to be reserved for the entire year. And that means the opportunity costs will be averaged out all over the year. Nonetheless, obviously there are periods in which the opportunity cost is very high and there are periods in which interconnection reservation incurs no costs at all. If TenneT could be more flexible, it could reap the benefit from the difference in reserve prices during those periods where there is little or no opportunity cost, and not purchase reserves from a foreign resource in the periods when the opportunity cost is significant.

As noted above, if interconnection capacity (from Norway to the Netherlands) was reserved indiscriminately for all the hours in one year, it would have led to an opportunity cost of 6.8 €/MWh, according to the day-ahead prices of 2009. However, if the reservation of interconnection capacity is done separately for peak and off-peak hours, the picture would be completely different. In this case, the opportunity cost will be 11 €/MWh for peak hours, and 2.4 €/MWh for off peak hours (2009).

In other words, when reserving the interconnection capacity, the behavior of the day-ahead prices are taken into consideration, unnecessary opportunity costs can be avoided. Interconnection capacity can be reserved only for those periods that do not incur too high an opportunity cost. In this case, reservation of interconnection capacity from Norway to the Netherlands for off-peak hours incurs an opportunity cost of 2.4 €/MWh, and so TenneT can purchase reserves from Norway only for these hours and not for the peak hours which incur a significant opportunity cost of 11 €/MWh. This way, opportunity costs (as a result of interconnection reservation) can be controlled.

Despite the above-mentioned discussion, the single yearly reserve market that is being used in the Netherlands does not leave much room for flexibility. We have shown that purchasing reserves from Norway for peak and off-peak hours (separately) limits the unwanted opportunity costs. However, this cannot be achieved without some reform in the Dutch market. Assume that TenneT buys 100 MW of reserves (one third of its demand) from Norway, for off-peak hours only. That implies that in off-peak hours TenneT would need to buy only 200 MW from internal resources, while for peak hours it buys 300 MW from internal resources (no exchange with Norway in peak hours). This, in turn, would imply that TenneT is using separate markets for peak and off-peak periods in the Netherlands. So unless the market design currently in use in the Netherlands is changed, there is not much room for handling the interconnection capacity reservation in a more flexible way.

One of the changes in the Dutch market proposed in chapter 4 was to use separate auctions for peak and off-peak hours. This is where the reforms at the national level, recommended in chapter 4, connect to the performance of the multinational market. Although the reasons for recommending the reforms in chapter 4 came from concerns purely at the national level (the only goal being improvement of the performance of the domestic market), those reforms do improve the performance of the future multinational market as well. Holding separate auctions for peak and off-peak hours in the Netherlands improves the performance of the domestic market (by defining services in a more specific way leading to more cost-reflective prices) as well as the future multinational market in the region (by enabling more flexible and intelligent use of interconnection capacity).

In addition, shorter time horizons for reserve capacity markets (the other major recommendation of chapter 4) play an important role in a multinational context as well. Firstly, the closer to the real-time, the better the estimation of the behavior of the day-ahead prices, which consequently means more informed decisions about reservation of interconnection capacity for exchange of reserves (more accurate calculation of the opportunity costs). Secondly, if exchange of reserves could be done on a monthly or (even daily) basis rather than yearly, it would enable us to reserve interconnection capacity in a less 'indiscriminate' way. Day-ahead prices follow seasonal patterns; there are months in which the significant difference in day-ahead prices imposes too high an opportunity cost for exchange of reserves. Figure 6. 10 shows the average day-ahead prices for different months of 2009, in Norway and the Netherlands. As can be seen, the prices vary significantly in different months meaning that the opportunity costs would be different as well, which illustrates the need for handling reservation of interconnection capacity for reserve exchanges on a shorter time horizon than yearly. If done on a monthly basis, the general monthly patterns of the day-ahead prices can be taken into consideration while the decision on reservation of interconnection capacity is being made.

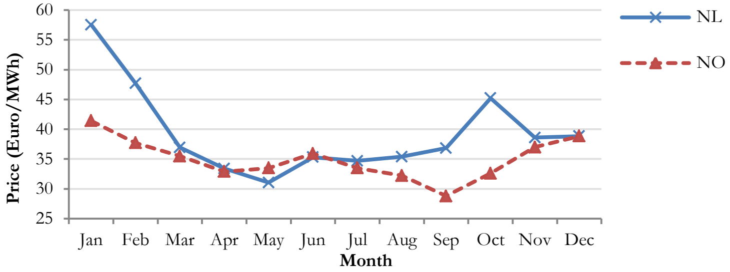


Figure 6. 10. Monthly average day-ahead prices for Norway and the Netherlands, 2009

If separate auctions are held for peak and off-peak hours in each month, even higher flexibility regarding reservation of interconnection capacity can be achieved. Figure 6. 11 shows the lost opportunity costs (for the case of Norway-Netherlands) on a monthly basis for peak and off-peak hours using the day-ahead prices in 2009. The opportunity cost is consistently low for off-peak hours. In case of peak-hours, during spring and summer, the opportunity costs are reasonably low, around 5 €/MWh. However in most winter months, the difference in day-ahead prices leads to very large opportunity costs. Thus, if separate monthly peak and off-peak auctions are held, TenneT can purchase reserves from Norway only for the periods in which the opportunity cost is sufficiently low.

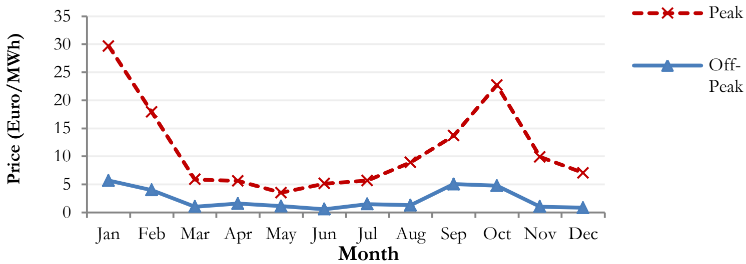


Figure 6. 11. The lost opportunity cost (in the day-ahead market) as a result of reservation of interconnection capacity (from Norway to the Netherlands) on a monthly basis, for peak and off-peak hours, 2009.

The same argument can be used for moving towards daily markets instead of monthly. Other than being able to reserve interconnection capacity only for those days and hours in which the opportunity cost is sufficiently low, on a day-ahead basis, much more accurate estimation of the day-ahead prices are available which results in much more informed decisions regarding reservation of interconnection for exchange of reserves.

To summarize, if reservation of interconnection capacity is done in a flexible way, if the services are defined in a specific way (there is a distinction between peak and off-peak hours), and if the time horizon of the markets is relatively short, reservation of interconnection capacity can be quite beneficial even in a normal year like 2009 where there were significant opportunity costs. The two above-mentioned factors (specific definition of services and the time horizon of the market) are basic market design variables (discussed in the previous chapters of this dissertation). Thus, in short, desirability of reservation of interconnection capacity (and therefore, desirability of integrating reserve capacity markets) depends on the design of the markets involved.

6.5. Are we arguing for more complexity?

Although using markets with shorter time horizons, especially daily markets, would lead to more informed decisions and more intelligent handling of the interconnection capacity, it does add complexity to the system. Exchanging reserves on a daily basis means handling daily bids and daily calculation of the opportunity costs (as a result of reserving interconnection capacity). Avoiding complexity is one of the reasons why some design aspects used in other parts of the world (the nodal pricing as the most well-known example) are dismissed by decision makers in Europe. Although their concern is very much understandable, we need to admit that the complex nature of electricity markets (and especially their interrelations with each other) in general, demands to-some-extent complex market design. As an example, using one yearly market (with no distinction between peak and off-peak, or between upward and downward capacity) for reserves underestimates the complexity of the system.

Needless to say, whether the reserves are purchased through yearly bilateral contracts or daily auctions, as long as the required amount of reserves is procured, the objective is met. In other words, from a technical perspective, as long as enough reserves are purchased, the system will work properly (effective design). Although effective, a very simple design raises efficiency concerns. Yearly confidential bilateral contracts raise the five issues discussed in chapter 4 (from a national perspective), as well as the two issues discussed in this chapter (from a multinational perspective). Thus, the difficult decision is to make a tradeoff between efficiency and simplicity of design.

6.6. Market integration, reform on a national level

Integration of separate reserve capacity markets with different time horizons could lead to yet another complication. The case of the Netherlands and Norway can be used as an example. The Netherlands uses a yearly market while Norway has a weekly reserve capacity market. If cross-border exchange of reserves is to be enabled without any change in the Dutch market, TenneT would need to ask for yearly bids from the Norwegian reserve providers. And that would imply different bid prices. The Norwegian service provider offering a certain capacity for the entire coming year will probably ask for a different price than the price it would ask for offering the same capacity not for the entire year but for a specific week in summer. Uncertainties in estimating the potential profits that the reserve provider could have made in other markets would be logically higher if the estimations are done for a period of one year rather than one week. And higher uncertainties would probably mean higher bid prices. So, if TenneT asks for yearly bids from Norway, the bids would be likely to come with a price higher than the current weekly prices in Norway illustrated in Figure 6. 1.

In other words, generally speaking, part of the initial price difference (for reserves) can be artificial, in the sense that the price difference is not necessarily due to the difference in technology, or the available capacity, or other physical/technical factors. Part of the price difference is due to the difference in market design: the difference in the time horizon of the markets and the method of procurement (bilateral contracts vs. auctions). Part of why the reserve prices in the Netherlands are believed to be significantly high (compared to Germany and Norway) is because of the (confidential) yearly contracts used in the Netherlands, and if the Norwegian bidders are going to bid in that yearly market they probably would ask for a higher price as well.

At the same time, reform in the Dutch market would have an effect on the potential benefits of integrating the markets. If the Dutch market is changed from confidential bilateral agreements (between TenneT and the large suppliers) into an auction running on a monthly basis, with a distinction between peak and off-peak hours, the prices would probably change. This reform, discussed in chapter 4, would enable participation of more suppliers and also lead to more specific definition of the services (and in more cost-reflective prices). Thus, this way the current price difference between the Netherlands and Norway (for example) would probably shrink; the price difference that determines the benefit achievable by integrating the markets. Thus, market integration would have less attraction, from an economic perspective.

The fundamental question that needs to be answered is 'what exactly do we seek'? Do we seek improvement in performance of the reserve capacity markets (and market integration is a promising option) or do we see market integration as something of intrinsic value that should be desired anyway?

If we assume the market design in the Netherlands is partly responsible for the high Dutch market prices, what needs to be done in order to reduce costs and improve efficiency is some reform in the Dutch market and not necessarily integrating the Dutch market (as it is today) with the market in Norway. If the design in the Netherlands is kept as it is, according to the analysis in this chapter, reservation of interconnection capacity will impose high opportunity costs because of the lost day-ahead trades. Additionally, since the Netherlands has to ask for yearly Norwegian bids (instead of the current weekly bids in Norway), the reserve capacity from Norway will probably come with a higher price. And this will limit the potential benefit of market integration even further.

Nonetheless, exchange of reserves (integrating the markets) can still be economically beneficial for Norway and the Netherlands. It depends on the current Dutch prices (that are not public) and the size of the increase in the Norwegian bid prices (when they are asked for yearly bids instead of weekly). Although we believe it can still be beneficial, market integration is not the primary solution for the high prices in the Netherlands. We first need to address issues related to the Dutch market: lack of transparency, limited players, low competition and liquidity, high opportunity costs and the system operator's lack of proper incentives (all discussed in chapter 4). If we define services in a more specific way and move towards shorter term auctions, not only will these issues be addressed but interconnection capacity reservation can also be handled in a more efficient way (as discussed in this chapter), paving the way for integrating the reserve capacity markets in the future.

6.7. Wind and future

Despite all the discussions above, one factor that has significant impact on the picture we have of reserve capacity markets is the issue of large-scale wind power integration. Introduction of large-scale wind power generation raises lots of discussions regarding the support schemes and market designs adjustments that are needed to promote investment in wind generation and to achieve a high penetration of wind power in the system. Additionally, wind power raises discussions regarding reserve capacity markets, and the minimum reserve requirements of the system.

Authors in [104] using scenarios from [105] estimate that the minimum reserve requirements in Northern Europe (the Nordic system, Germany and the Netherlands) will increase by 19% in 2015 and by 50% in 2020 (compared to 2010). According to the authors, the reserve capacity procurement costs will more than double in the course of 10 years. This can potentially have a decisive influence on the future of the reserve markets, and particularly it can change the picture that was presented in this chapter. The effects of large-scale wind power integration would depend on many different variables, including the size and distribution of the new wind generation capacity, and also the designs of the various electricity markets in the region. As an example, effective and efficient integration of intra-day markets (which at the moment suffer from lack of liquidity, especially in a multi-national context) is mentioned repeatedly as an effective tool to prevent high imbalances in real-time and therefore higher needs for reserves [106]. In short, large-scale introduction of wind generation can potentially have a decisive role on the future of the reserve capacity markets, particularly in Northern Europe.

6.8. Conclusions

Because reserve capacity markets are long-term markets, cross-border exchange of reserves implies reservation of interconnection capacity for relatively large periods of time, and that consequently implies loss of day-ahead trades for the entire period of reservation. Thus, exchange of reserves implies lost opportunity cost in the day-ahead markets. Economic benefits of integration of reserve capacity markets depend on the size of this opportunity cost. If reservation is done indiscriminately for an entire year, the opportunity costs can be significant. By defining reserves in a more specific way (a distinction between peak and off-peak hours) and using shorter time horizons for reserve capacity markets, those opportunity costs can be controlled. In other words, interconnection capacity will be handled in a more efficient way, and the benefits of reserve capacity market integration will be higher. Thus, desirability of integration of reserve capacity markets depends on our way of handling the interconnection capacity, and that in turn depends on the design of the reserve capacity markets involved.

According to our case studies, in case of Norway and Germany, when there is no particular shortage of hydro power (e.g. 2009), the opportunity costs incurred by day-ahead trade losses are so high that integrating the two markets loses its basic economic justification. However, in a dry year such as 2010, high day-ahead prices in Norway would lead to almost no opportunity costs and so exchange of reserves from Norway to Germany would be economically desirable. Nonetheless, the price difference in the reserve capacity markets (in a dry year) seems to be rather too small to justify the costs and efforts of market integration.

In case of Norway and the Netherlands, although in a normal year (e.g. 2009) the opportunity costs are significant but the Dutch prices are believed to be sufficiently high to make market integration a very logical decision. In a dry year, there are almost no opportunity costs and therefor, exchange of reserves would be even more beneficial and would lead to even higher cost savings.

7. INTEGRATION OF BALANCING ENERGY MARKETS

7.1. Introduction

This chapter is the second of two complementary chapters addressing integration of balancing services markets. This chapter is dedicated to the essential discussions on integration of 'balancing energy' markets. Firstly, we discuss ACE netting as the most basic arrangement that can lead to significant reductions in the amount of activated balancing energy (and thus in balancing costs). Then we compare two cross-border arrangements, namely BSP-TSO trading and TSO-TSO trading, using a model that studies the change in behavior of market parties as a result of implementing these arrangements. Discussing advantages and disadvantages of each arrangement, we propose using an in-between arrangement that can make a better trade-off between what is gained and what is lost by implementing each arrangement. Having analyzed the arrangements from a market perspective, in the last section we discuss some practical complications that can challenge the efficiency of enabling cross-border exchanges to a great extent.

7.2. Basic ACE netting

The Area Control Error (ACE) signal determines the demand for secondary control in each program time unit. According to [11], within each control area/block, the individual Area Control Error (ACE) needs to be controlled to zero on a continuous basis. In continental Europe (the UCTE system), automatic generation control is used which functions according to the ACE signal. Each area has its ACE, which is calculated based on the deviations in system frequency and in the planned interchanges with the neighboring areas:

$$ACE = \Delta P + k \times \Delta f$$

where ΔP is the total power deviation of the area which is the difference between the total activa power flow (actual measurements) and the control program (sum of all related exchange schedules). Δf is system frequency deviation and k is the control area's power system frequency characteristic (for detailed descriptions see [11], appendix A).

The most basic cross-border arrangement that can lead to significant reductions in balancing costs is what is known as *ACE netting* or *imbalance netting*, meaning that imbalances (ACEs) in two areas, when in opposite directions, can cancel each other out. As an example, when there is an imbalance of +50 MW in the Netherlands and -50 MW in Germany, they can offset each other without a need for activation of balancing energy bids in either of the areas. So when there is frequency deviation in the system and/or power interchanges with other areas are different from the planned values, then balancing energy needs to be activated to bring the ACE signal back to zero. Therefore, this arrangement is called ACE netting, because, in UCTE, it is the ACE that defines the area's imbalance. Generally speaking though, it is actually the demands for secondary control that offset each other in this arrangement, so even for systems which do not use automatic generation control (e.g. Nordic system), and therefore do not have an ACE signal, this arrangement can still be applied, in which case, it would be the imbalances that offset each other. Thus, we call this arrangement *imbalance netting* rather than *ACE netting* to show its general applicability to systems that do not use ACE.

It should be emphasized that there is a fundamental difference between imbalance netting within a synchronous system and between two systems that are connected with HVDC lines and so, are not synchronous. Exchange between Scandinavia and continental Europe is an example of the second case. In case of non-synchronous systems, when there are imbalances in opposite directions, and imbalance netting is being used, then the power needs to be physically transferred between the two areas. As an example, if there is a power surplus of 50 MW in Norway and a power shortage of the same size in the Netherlands, the excess of power in Norway needs to be physically delivered to the Netherlands, because otherwise the frequency in the Netherlands (and the entire UCTE) will deviate. Therefore, in case of non-synchronous systems, for activating imbalance netting, enough interconnection capacity needs to be available in the right direction so that the power surplus can be physically delivered to the area with a shortage.

Nonetheless, in case of imbalance netting within a synchronous system, the power does not need to be physically transferred. Take the case of UCTE, assuming there is an imbalance of +50 MW in the Netherlands and -50 MW in Germany, and there is no imbalances in the other UCTE areas. In this case, whether or not imbalance netting is used, since the total imbalance of the (UCTE) synchronous system is zero, the system frequency will not deviate. Thus, in this case if imbalance netting is used, the power surplus (+50 MW) in the Netherlands does not need to be physically transferred to Germany in order to avoid frequency deviations. In other words, imbalance netting within a synchronous system, is all about adjusting the signals and thus, availability of interconnection capacity plays no role in imbalance netting. What needs to be done is developing an automatic control system, like the one already implemented in Germany [107, 108], which automatically adjusts the imbalances to avoid unnecessary activation of balancing energy (in case imbalances can offset each other).

In short, while imbalance netting between two non-synchronous systems needs physical transfer of power (and therefore, availability of interconnection capacity), in case of imbalance netting within a synchronous system, it is all about adjusting the signals without a need for any change in the power flows. Imbalance netting can yield considerable reductions in the amount of activated balancing energy.

7.3. Main aspects of balancing energy markets integration

One fundamental difference between balancing energy and reserve capacity markets (discussed in the last chapter) is that balancing energy markets are real-time markets while reserve capacity markets are markets with long time horizons that are cleared way before the real-time. Since balancing energy markets are real-time markets, they are cleared after the closure of all the other electricity markets and that implies that for exchange of balancing energy across borders, reservation of interconnection capacity is not a prerequisite, in contrast to reserve capacity exchanges. For balancing energy, the interconnection capacity that is remained after the closure of the day-ahead and intra-day markets can be used for cross-border exchanges.

In the previous chapter (on integration of reserve capacity markets), we did not discuss the details of different 'multinational arrangements' for exchange of reserve capacity because the more basic issue that needed to be addressed was the issue of interconnection capacity reservation. However, in this chapter (in case of balancing energy markets), since the interconnection capacity does not necessarily need to be reserved, we pay special attention to the effect of different multinational arrangements for exchange of balancing energy across borders.

An extensive literature review of various arrangements was given in the previous chapter. If all the various arrangements, proposed in different reports/documents/theses are summarized, three main arrangement can be distinguished:

- *BSP-TSO trading*, in which the balancing service providers (sellers) in one control area can directly bid in the market of the other area. The TSO of the other area (importing TSO) selects the cheapest from its domestic and foreign bids. Thus, this arrangement connects the sellers (BSPs) in one area to the buyer in the other area (TSO).
- *TSO-TSO trading*, in which it is the two TSOs who interact. The exporting TSO collects the bids in its area and shares some of them with the other TSO. Alternatively, the exporting TSO itself (before having collected its bids) can bid in the other market a certain capacity with a certain price based on its forecast of the bid prices in its area. In both cases, the exporting TSO functions as an intermediary between the BSPs in its area and the (importing) TSO of the other area.
- *Common merit order list*, which is the most advanced arrangement in which the two TSOs share everything in a common market and choose the cheapest bids together on a regional basis. Obviously, this arrangement needs significant changes and cooperation on a regional level between the TSOs.

The last arrangement is the one that has been discussed extensively in literature. Authors in [6], [99] and [109] have studied the common merit order list arrangement using different assumptions regarding modeling the markets. These studies are aimed at estimating the potential balancing cost reduction as a result of integrating the markets. Therefore, they compare the most advanced arrangement (common merit order list) with the case of no balancing exchanges across borders, and consider the difference as the potential cost reduction. Nonetheless, the underlying assumption is smooth transition from no-exchange to full-exchange. Having a common merit order list means full harmonization of the markets involved. From a market perspective, the timing of markets (frequency of bidding and market clearance) needs to be fully harmonized, and the same pricing mechanism needs to be used. In addition, since in this arrangement, the bids are activated in a way that minimizes the total regional balancing costs, each TSO cannot decide on which bids to activate independently. The TSOs need to be cooperating very closely and develop a common bid activation mechanism that takes into account all the bids throughout the region, imbalances in all the areas, and transmission restrictions. Therefore, although a common merit order list can lead to an efficient market and low balancing costs (on a regional basis), it does need a great deal of dedication and willingness to make fundamental changes in the market design.

Since transition from separate markets (with no exchanges) to a fully integrated market with a common merit order list cannot be done in one single step, the intermediary stages are of critical importance. In this chapter, we look into the details of the first two arrangements, BSP-TSO and TSO-TSO trading, as the less ambitious arrangements that enable cross-border exchange of balancing services while do not need fundamental changes in the national markets. In other words, instead of focusing on what can be achieved if markets are fully integrated (the last conceivable stage), this chapter focuses on how we can get to that final stage where the markets are fully integrated.

7.4. BSP-TSO trading

In BSP-TSO trading, suppliers have the freedom to choose which market they like to offer their bids in. As a clarifying example, consider the case of BSP-TSO trading between two areas, area 1 with cheap resources and area 2 with more expensive ones. Since in this arrangement, the TSOs are not directly involved in selection of the bids that will go to the other market, the foremost concern is that too many bids go to area 2 in search of higher profits, which may leave the cheaper area with not sufficient resources to resolve its own area imbalances. This impact, from a system security perspective, is not acceptable at all. Even if after the shifting of bids to area 2, area 1 still has sufficient resources for domestic use, the market price in area 1 may increase dramatically because less bids are available, the excess of supply in area 1 decreases, and therefore there is more opportunity for abuse of market power by suppliers in area 1.

We investigate the validity of this concern for cases of Norway-Netherlands and Norway-Germany using an agent-based model. The model uses the basics of the model presented in chapter 5, with the difference that the 'reserve capacity' and 'day-ahead' markets are replaced by the two national balancing energy markets of the two countries involved in market integration. The service provides in both countries can bid either in their own market or the foreign market, and using the bidding logics of the model presented in chapter 5, they change their bid prices and shift their offered capacities between the two markets based on their per-MW profit in the two markets. Another difference is that the available interconnection capacity is an extra variable that determines the maximum balancing energy exchange possible between the two areas.

7.4.1. Norway-Netherlands

We have used the power plant list of the Netherlands in [90], in which the names of the owners are presented as well. Each owner with its portfolio (the group of its generating plants) is considered to be one BSP. The market for secondary control (or the regulation market) is the focus of the simulation. A plant in order to be eligible to bid in this market has to have a minimum response speed of 7% per minute; it needs to be able to fully activate its offered capacity in 15 minutes. The power plants which can meet this requirement are oil, gas and hydro units [40]. According to [90], there are 21 oil and gas units in the Netherlands which we consider as the units which can bid in the regulation market. In case of Norway, due to lack of public data, we do not have a complete list of the generating plants. Therefore, we use the approach used in [110] which models each of the five areas in Norway by one aggregate generating plant, each representing generation in the corresponding area.

One critical input to the model is the day-ahead (DA) market prices in the two countries because these prices influence the minimum/maximum bid prices in the upward/downward regulation markets. Take upward regulation as an example. In Norway it is not allowed to bid at a price lower than the DA price in the corresponding hour. In the Netherlands, there is not an explicit rule addressing this issue. However, the regulation market is the last market the generators can sell their capacities in. Therefore, the capacity sold in the regulation market is the capacity that is still available after the closure of all the other electricity markets (including DA), so it is the capacity that was not selected in the other markets. Thus, the upward regulation price has to be higher than the day-ahead market prices under normal operating conditions. In this simulation, in case of upward regulation bids, the minimum bid price for Norway is considered to be the Norwegian DA price, and for the Netherlands it is assumed to be the maximum of the DA price (in the Netherlands) and the marginal operating costs of each unit, because the bid price has to be higher than both the DA price and the marginal cost of the unit.

In case of downward regulation bids, the maximum bid price for Norway is assumed to be the DA price in Norway, and for the Netherlands it is assumed to be the minimum of the DA price and the marginal operating costs of each unit, because the downward regulation bid price has to be lower than both the DA price and the marginal cost of the unit. Figure 7. 1 shows the average DA prices for Norway and the Netherlands in 2009.

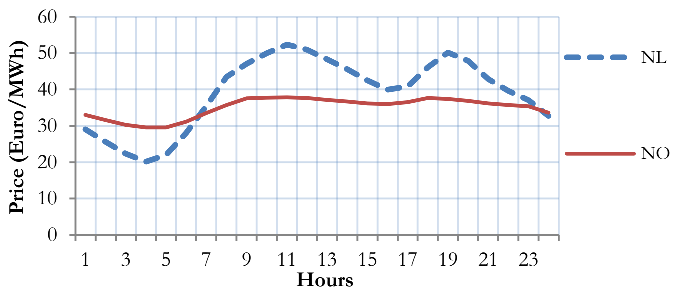


Figure 7. 1. Average day-ahead prices for Norway and the Netherlands, 2009.

Based on the graph, and considering the crucial effect of the DA prices on the simulation outcomes, we define two periods: Off-peak hours (from hour 00 to 07), in which the DA price in Norway is higher than the price in the Netherlands, and Peak hours (from hour 08 to 24), in which the DA price in Norway is lower than the price in the Netherlands. We simulate these two periods separately, using two different sets of DA prices as inputs.

Therefore, for upward regulation we will have two sets of outcomes, one for peak and one for off-peak hours. The same applies to downward regulation. Another important input is system imbalances in the two countries. These real-time imbalances have to be resolved by activation of regulating power. Therefore, these imbalances determine the 'market demand' in the regulation market. Studying the real data regarding activated regulating power in Norway for 2009 [111], it can be seen that the imbalances fit a normal distribution function with a mean of -30 MW and a standard deviation of 370 MW. Same trend can be seen for the activated regulating power in the Netherlands in 2009; a normal distribution function with a mean of -12 MW and a standard deviation of 102 MW. For each direction (upward and downward), and for each period (peak and off-peak), we take 200 samples of these two distribution functions (representing the demand in the two markets) and run the model once for each pair of demand values.

Before presenting the results, one basic issue should be clarified about how the results of the simulation should be seen. The results of every run of the model (for every set of inputs) show the final outcomes after the model has run for enough iterations so that the agents have 'learned' how to bid, and the market outcomes do not change anymore with more iterations. Therefore, the results of every run show the market outcomes after the market has reached a steady state and there is no more learning happening.

Therefore, every time, the model is fed with a set of inputs (demands in the two markets and available interconnection capacity), and agents learn how to bid for that set of inputs in particular. In other words, agents do not learn how to bid for different demand values in one run of the simulation. So every run simulates learning of bidders for a *certain* demand value *over time*. The implicit concept is that the agent learns separately for separate situations (demand values) over time. Therefore, the model simulates the real world situation as follows:

Every time the market is cleared (every PTU), bidders decide on their bid price and volumes for the particular demand values in that PTU, and so they *learn* (as much as one iteration) for that demand. If the demand in the market changes in the next PTU, they will be learning (as much as one iteration) for the new demand value. The next time the market has the same demand, agents would, again, learn as much as one more step for that particular demand.

Thus, in order to have an overview of how the players will bid in the market, different runs with different demand values and available interconnection capacities are required. In the following graphs presenting the results, the model is run for various values of Norwegian and Dutch demand, as well as various amounts of available interconnection capacity.

Figure 7. 2 shows the upward regulation market prices in the Netherlands during off-peak hours. The market is cleared for three available interconnection capacities; 0 MW, 100MW, and 300MW. The first curve with zero interconnection capacity available between the two countries represents no market integration, because there is no room for cross-border exchange of balancing services, and therefore, the two markets are cleared separately and no capacity is offered by BSPs in the foreign markets. The other two curves show the market price in the Netherlands as a result of market integration (enabling foreign bidding between the two markets). In all the following figures, we use this set of interconnection capacities. The horizontal axis shows the demand in the Dutch market; 200 samples were drawn from the distribution functions mentioned above.

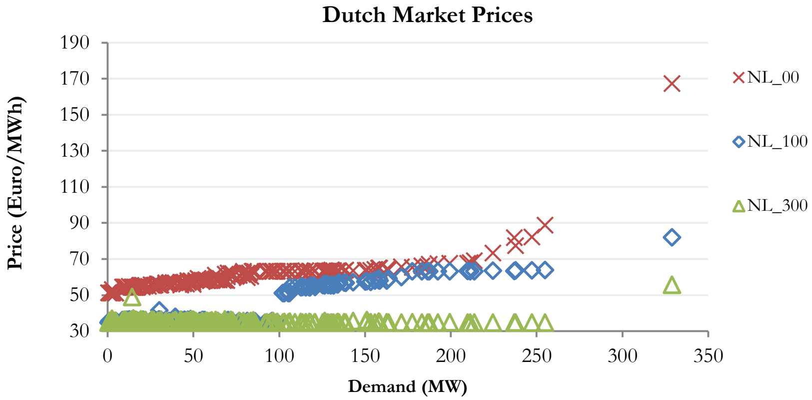


Figure 7. 2. Upward regulation prices in the Netherlands for three available interconnection capacity values- Off-Peak hours

As can be seen, with no market integration, the price in the Netherlands is the highest; it starts from 50 €/MWh, and increases up to 170 €/MWh as the demand increases to 340 MW. When 100MW interconnection capacity is available from Norway to the Netherlands, Norwegian BSPs start bidding in the Dutch market, which would consequently bring the Dutch market price down. If the demand is lower than 100MW, the entire Dutch demand can be met by the Norwegian bids so the market price would go down to the level of the Norwegian market price. For demand values higher than 100MW, although the market price would still decrease (because 100MW of the demand is met by the Norwegian bids), the remaining demand has to be met by Dutch bids. Therefore, one can see a jump in the Dutch price at a demand value of 100MW. In the third case, 300MW interconnection capacity is available; therefore demands up to 300MW can be fully met by bids from Norway. So the Dutch market price goes down to the Norwegian market price, for demand values lower than 300MW.

Figure 7. 3 shows the upward regulation prices in Norway during off-peak hours for the three available interconnection capacities. Thus Figure 7. 3 is the counterpart of Figure 7. 2 for Norway. As one can see from the figure, there is no noticeable change in the

Norwegian market price as a result of market integration. The three curves lie on top of one another.

Therefore, the main potential disadvantage of BSP-TSO arrangement, which is shifting of too much capacity from the cheap market (Norway) to the expensive market (Netherlands) to the extent that the market price in the cheaper market increases, does not seem to be a valid concern in case of Norway and the Netherlands. One important reason is the huge excess of supply in the Norwegian market. During off-peak hours, the offered capacity in the regulation market in Norway was 9,320MW on average in 2010, while the activated upward regulation in Norway was less than 290MW on average. This means a market with a supply 30 times higher than demand on average! Such an extremely high excess of supply limits the extent to which BSPs can behave strategically and increase the market price by abusing their market power. In addition, demand in the Netherlands is low, therefore shifting of some capacity to the Netherlands that can meet the whole Dutch demand does not have a noticeable effect on the competitiveness in the Norwegian market, and consequently on the Norwegian market price.

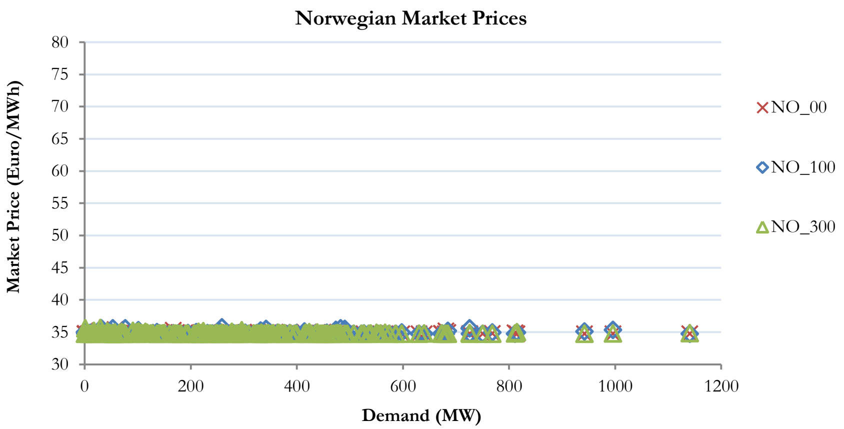


Figure 7. 3. Upward regulation prices in Norway for three available interconnection capacity values- Off-peak hours

The same trends were seen in case of upward regulation during *peak hours* as well, and therefore we skip presenting the graphs illustrating market prices for *peak* hours.

In case of downward regulation, the situation can be different. In contrast to upward regulation, bids are sorted in the decreasing order on the bid ladder for downward regulation; a higher bid price is to be activated first. The reason is simply the sign convention for downward regulation; a positive downward bid price is the price the BSP is willing to 'pay' the system operator in order to decrease its power output. The BSP has already sold the power in other markets, so if it reduces its output, it will be saving operating costs. Therefore if it bids at zero for downward regulation, it is actually making an extra profit equal to its operating costs in the regulation market. Thus if it pays the system operator any price lower than its operating costs, it will still make a profit. The downward regulation price can become negative too, in which case the BSP would be asking the system operator to pay him for lowering its output. As mentioned earlier, we use the minimum of the unit's marginal cost and the day-ahead price, as the maximum downward regulation bid price of a generating unit.

Marginal cost of the units eligible for bidding in the regulation market in the Netherlands are higher than those in Norway, simply because of the generation technology: oil and gas plants in the Netherlands and hydro in Norway. Therefore, if in a certain hour, the DA price in the Netherlands is higher than Norway, then the maximum bid price for downward regulation would be higher as well in the Netherlands, which means the bid prices can potentially be higher in the Netherlands, meaning for downward regulation the bids in the Netherlands can be more attractive. According to Figure 7. 1, during peak hours, the Dutch day-ahead price is higher on average which implies that the Dutch bids for downward regulation can be more attractive than the Norwegian ones, and therefore the Netherlands can be exporting downward regulation to Norway.

Figure 7. 4 shows the downward regulation prices in the Netherlands during peak hours for the three values of available interconnection capacity.

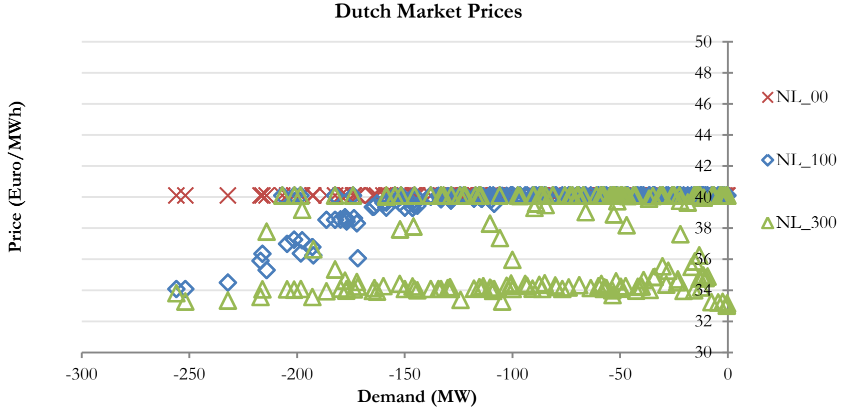


Figure 7. 4. Downward regulation prices in the Netherlands for three available interconnection capacity values- Peak hours

As can be seen, when 100 MW interconnection capacity is available and so the Netherlands can export up to 100 MW of downward regulation to Norway, for high demand values (higher than almost 150 MW), the market price decreases (corresponding to an 'increase' of the market price for upward regulation; an increase of balancing costs) in the Netherlands as a result of the export to Norway. This shows that the basic concern for BSP-TSO trading (change of the market price of the exporting country because too much capacity is shifted to the foreign market) is valid in case of downward regulation for the Netherlands. That means what did not happen in case of upward regulation for Norway (see Figure 7. 3) does happen in case of downward regulation for the Netherlands. The main reason is lower excess of supply in the Netherlands; on average, the offered volume in the Dutch market for downward regulation during peak hours is about 600 MW. Thus, if 100 MW is exported to another market (and the demand in the Netherlands is sufficiently high), it can easily have a noticeable effect on the market price because it increases the opportunities of the BSPs to behave strategically and change the market price to their advantage. As shown before, this did not happen in case of Norway (for upward regulation) because of the huge excess of supply in Norway. According to the figure, if 300 MW interconnection capacity is available, then the Dutch market price decreases even for very small demand values in the Netherlands, as a result of exporting downward regulation bids to Norway.

Figure 7. 5 shows the downward regulation prices in Norway for peak hours (corresponding to Figure 7. 4 for the Netherlands). The price without cross-border exchanges is 34 €/MWh, and when the exchange is enabled (the other two cases), the market price for low demand values increases (corresponding to a price 'decrease' for upward regulation; a reduction of balancing costs). For higher demand values in Norway, since the whole demand cannot be met with the bids from Dutch BSPs, the Norwegian bids need to be activated as well, and therefore the price decreases again.

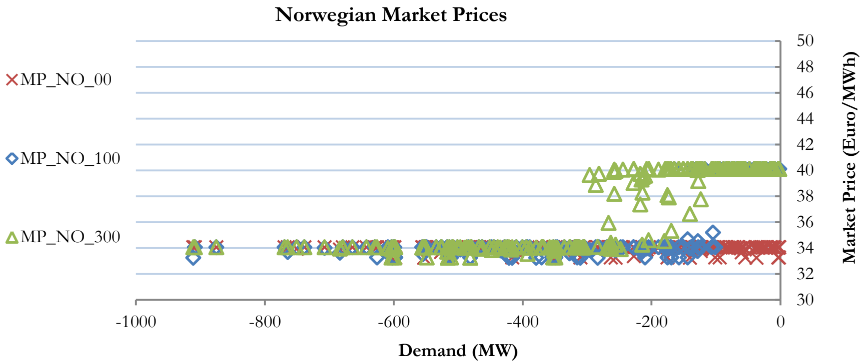


Figure 7. 5. Downward regulation prices in Norway for three available interconnection capacity values-Peak hours

As mentioned before, the main concern in BSP-TSO trading is whether or not enabling this arrangement would lead to shifting of too much capacity from the cheap market to the expensive one to the extent that the market price in the cheap market considerably increases. Having studied the case of Norway and the Netherlands, the first finding is that this question has to be answered on a 'case-specific' basis, simply because there are numerous factors that influence the answer to the question, such as the level of day-ahead prices, supply size, demand size, generation portfolios, typical marginal costs, and the number of market players. Thus, there is no 'general' answer to the question whether or not BSP-TSO trading has a negative or positive effect on the market prices. In this specific case of Norway and the Netherlands, according to our results, the market price in Norway (when it is the exporting country) does not change noticeably (no undesirable effect on the market price in Norway), because of the huge excess of supply and the flat bid ladder (almost fully hydro system) in Norway. However, when the Netherlands is the exporting country (downward regulation during peak hours), this cross-border exchange has an undesirable effect on the Dutch market price.

In other words, the market price in Norway is much more resistant to market integration, while the price in the Netherlands is more sensitive and more likely to change as a result of market integration. As can be seen in Figure 7. 2, the drop in the Dutch price is immediate as soon as importing the Norwegian bids happens. The prices significantly drop as the cheap Norwegian bids are selected in the Dutch market.

However, according to Figure 7. 4 (for downward regulation), firstly, the price reduction does not happen immediately, simply because in this case, the Netherlands is an exporter, and the effect of the exported bids on the market price might not be noticeable unless the Dutch demand is high or when high bid volumes are sent to Norway. And secondly, the price reduction is much more limited in size compared to the case for upward regulation. In other words, the drop in the Dutch balancing costs (for upward regulation) is significantly higher than the jump in the Dutch balancing costs (for downward regulation). We conclude that enabling BSP-TSO trading in this case has a positive (desirable) effect on lowering the balancing costs in total, and does not endanger system security.

7.4.2. Norway-Germany

The power plant list of Germany according to [90] is used. Two main scenarios for peak and off-peak hours are generated, using two different day-ahead prices (same as the case of the Netherlands). The German demand in the balancing energy market is the system imbalance, which is (according to 2009 data) a normal distribution with a mean of -19 MW and a standard deviation of 664 MW. Obviously, the size of the market demand is much higher than the Dutch market.

Figure 7. 6 shows the upward regulation prices in Germany for 4 different available interconnection capacity values (0, 400, 800 and 1700 MW). As can be seen, the German prices dramatically reduce due to the Norwegian bids. However, one difference with the case of the Netherlands can be seen in the graph for 1700 MW. This interconnection capacity value is sufficient for the entire German demand to be met with Norwegian bids, however, the market price does not go down to the Norwegian market price. In other words, the graph is not flat. In this case, because of the high demand in the German market, the Norwegian bidders have more opportunity to increase the market price. In contrast to the case of the Netherlands, where competition among Norwegian bidders kept the price the same as the Norwegian price, in case of Germany the demand can be so high (compared to supply) that the Norwegian bidders can use their market power and bid at prices noticeably higher than their operating costs. In other words, because of higher demand, the Norwegian bidders bid more aggressively in the German market than in the Dutch market.

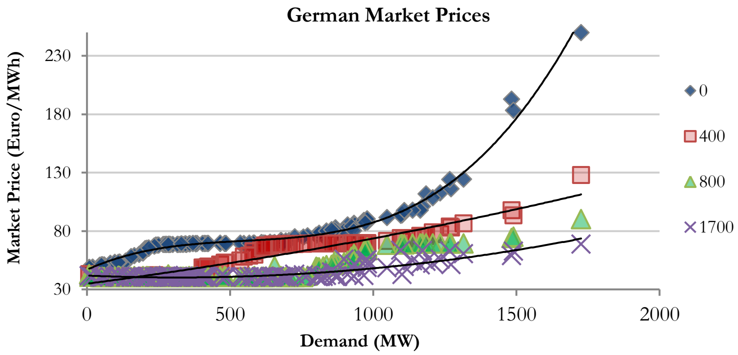


Figure 7. 6. Upward regulation prices in Germany for four available interconnection capacity values- Peak hours

Figure 7. 7 shows the same graph for 1700 MW of interconnection capacity. The issue raised above can be clearly noticed in the figure. The Norwegian suppliers bid at higher prices when the demand in Germany is high; the curve is far from flat.

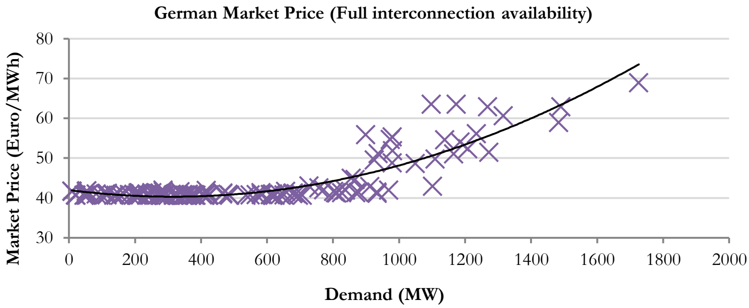


Figure 7. 7. Upward regulation prices in Germany for full interconnection capacity available (1700 MW)- peak hours

Figure 7. 8 compares the reduction in upward regulation prices for the Netherlands and Germany. The x-axis shows four sets of interconnection capacity. The bar for “0-200” shows the difference between the market prices when zero interconnection capacity is available and when 200 MW is available. As can be seen for small values of interconnection capacity, a significant price reduction can be achieved in case of the Netherlands (much higher than in Germany), which can be explained by the small size of the Dutch market.

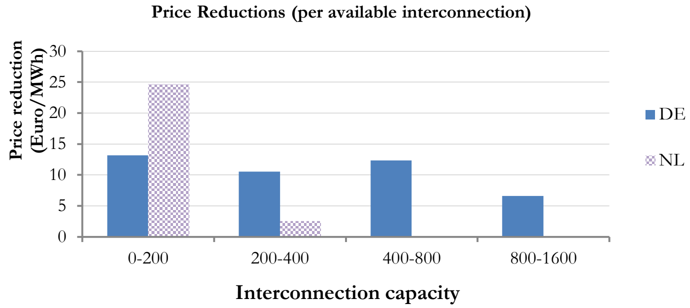


Figure 7. 8. Price reductions as a result of importing upward regulation from Norway - Peak hours

Figure 7. 9 illustrates the upward regulation prices in Norway for different available interconnection capacity values. As can be seen, the high demand in Germany (high export from Norway) can increase the Norwegian market price up to 25%. However, generally speaking, the Norwegian price is not influenced considerably by enabling cross-border exchanges; the huge supply in Norway can still handle the German demand without significant undesirable effects on the Norwegian price.

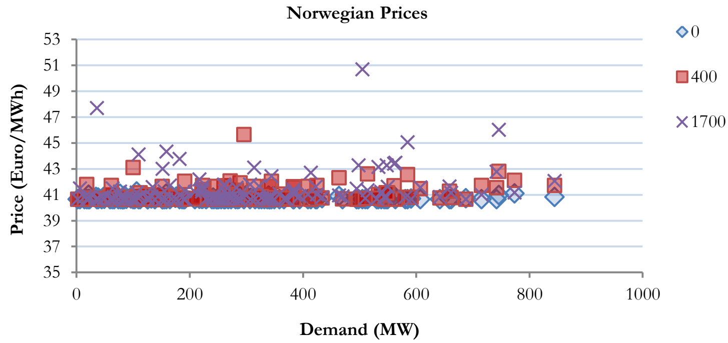


Figure 7. 9. Upward regulation prices in Norway for different available interconnection capacity values- Peak hours

During peak hours, Germany can export downward regulation to Norway. Figure 7. 10 shows the German downward regulation prices for peak hours. As can be seen, the German price is influenced by the export to Norway (price reduces, equivalent of a price increase for upward regulation), up to 32% for high demands when 400 MW interconnection capacity is available. However, this undesirable effect is limited for the typical demand values.

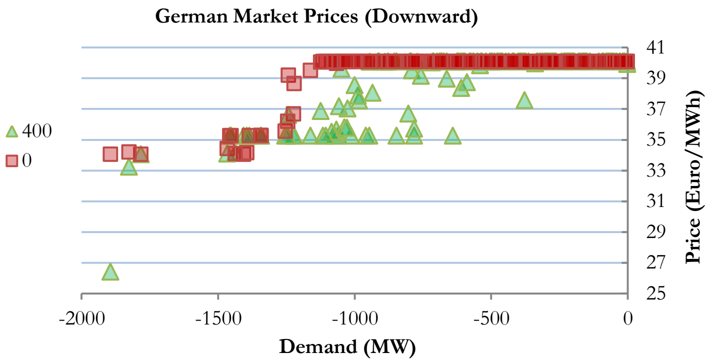


Figure 7. 10. Downward regulation prices in Germany for different available interconnection capacity values- Peak hours

This price reduction is more prominent for higher values of available interconnection capacity (more room for export from Germany). Figure 7. 11 illustrates the downward prices in Germany when 800 MW interconnection capacity is available. The price reduction can be huge (depending on demand); the price even changes sign, which is a significant undesirable effect on the German market.

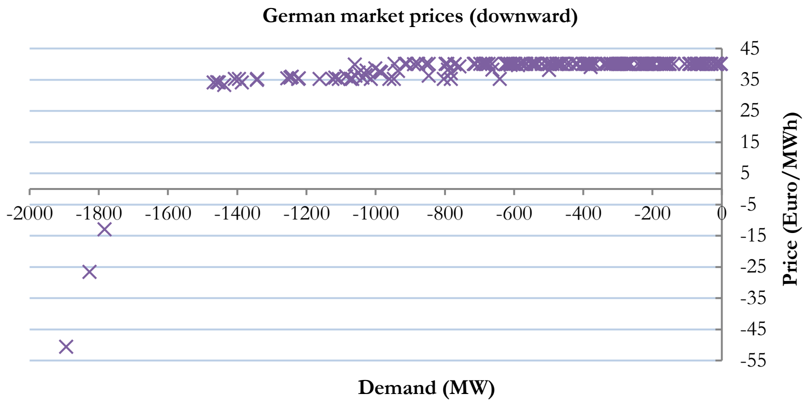


Figure 7. 11. Downward regulation prices in Germany when 800MW interconnection is available- Peak hours

Figure 7. 12 shows the 'average' price reductions for downward regulation in peak hours when the Netherlands or Germany are exporting to Norway. The price reduction is averaged over all demand values (samples taken). As can be seen, for low interconnection capacities, the price reduction is not significant 'on average', but exporting large amounts of downward regulation to Norway can significantly influence the German market price in an undesirable way.

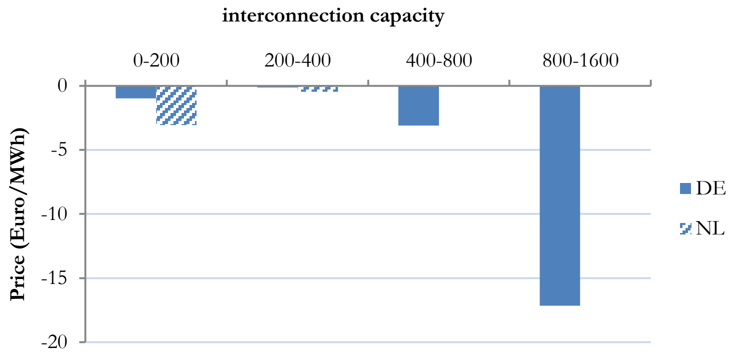


Figure 7. 12. Price reductions as a result of exporting downward regulation to Norway- Peak hours

7.4.3. Conclusions

The main concern about BSP-TSO trading is, since the TSO of the exporting country is not involved and has no control over which bids leave for the foreign market, too much capacity may leave the cheaper (exporting) area leading to significantly high prices (low prices in case of downward regulation) in the exporting area. The answer to this issue in general, depends on many different factors, however, in the specific case of Northern Europe, based on our results this concern can be considered as a factor without a decisive influence. Norway, with its huge excess of supply, can handle the demand in Germany and the Netherlands, without a significant change in the Norwegian market price. In case of downward regulation in peak hours, when Norway can be an importer, the market price in Germany (as the exporting area) can be significantly influenced for high demand values (and high available interconnection capacity). Generally speaking, enabling bidding across borders, in case of the Netherlands would result in large savings (cost reductions), even for small values of exchange (because of the small size of the Dutch market). To reach the same size of price reductions in Germany, significantly higher exchange volume is needed. In addition, considering the presented graphs, the cost reductions for upward regulation are generally much larger than for downward regulation.

7.4.4. Low reservoir levels in Norway

Since the Norwegian generation portfolio is hydro, the reservoir levels in Norway can play an important role in determining the results of market integration, and the consequent exchanges and price changes. Year 2010, in contrast to 2009, was a dry year with low reservoir levels in Norway. The Norwegian day-ahead prices, as a result, increased by 50% in 2010 reaching an average of 53 €/MWh. Both in peak and off-peak hours, the day-ahead price in Norway was higher than in the Netherlands or Germany, and that can potentially change all the insights discussed so far about balancing exchanges between Norway, the Netherlands and Germany. The model was run given the new inputs for 2010. The results, although different from the previous case (wet year), have some similarities with the results of the other case. We first look at the Norway-Netherlands case and then Norway-Germany.

Since the day-ahead price in the Netherlands is lower, balancing bids are generally lower as well, and so one might think that the direction of the balancing exchanges would be the opposite of the previous case. On the other hand, since the Dutch balancing market is dominated by thermal plants (oil and gas), the Dutch bid ladder is quite steep: as the marginal cost of these thermal plants increases, their bid prices in the balancing market would increase as well. Therefore, although the day-ahead price in the Netherlands is lower, the Dutch balancing bids can compete with the Norwegian bids only up to a certain extent. If the demand in the Netherlands is low and the very cheap bids are available, the Netherlands can export to Norway, but if those cheap bids are needed in the Netherlands, the next bids may not be able to compete with the Norwegian bidders.

Another basic difference is that in this case, since the Dutch day-ahead price is lower, the Nor-Ned cable is most of the time congested from the Netherlands to Norway, and that means that there is plenty of room for balancing power to flow from Norway to the Netherlands. Figure 7. 13 compares the upward Dutch market prices (for peak hours) in case there is no exchange with the case for which there is 100MW interconnection capacity available from the Netherlands to Norway. According to the figure, for low Dutch demand values, because some Dutch providers bid in the Norwegian market and leave the small market of the Netherlands, the Dutch market price would increase. However, because of the steep bid ladder in the Netherlands, after a certain point, the Dutch bids cannot compete with the Norwegian ones anymore. The Dutch balancing price becomes so high that not only there's no exchange possible from the Netherlands, but also the Norwegian bidders can be selected in the Dutch market. Therefore, the direction of the exchange changes depending on the demand value in the Netherlands. For low demand values, the Netherlands exports to Norway and for higher demand values the other way around. That is the basic difference between a dry and a normal year in Norway: Dutch bids can compete in the Norwegian market for low demand values, and that would probably lead to market price increases in the Netherlands. For higher demand values, the same phenomenon as for the previous case can be seen: immense exchange from Norway to the Netherlands.

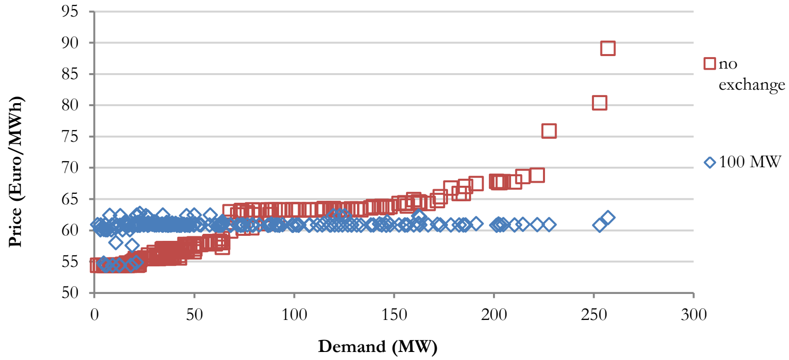


Figure 7. 13. Upward regulation prices (in peak hours) in the Netherlands for two available interconnection capacity values, using the 2010 data (dry year in Norway)

Figure 7. 14 can clarify the issue further. The figure shows the exchange volumes between the Netherlands and Norway, for different demand values in the Netherlands (assuming 100MW interconnection capacity is available to Norway). As can be seen, for low demand, there is exchanges up to 100 MW from the Netherlands to Norway because the Dutch bids are attractive as a result of lower day-ahead price in the Netherlands. As the demand increases, the exchange changes direction: for higher demand values in the Netherlands, there is large amount of imports from Norway.

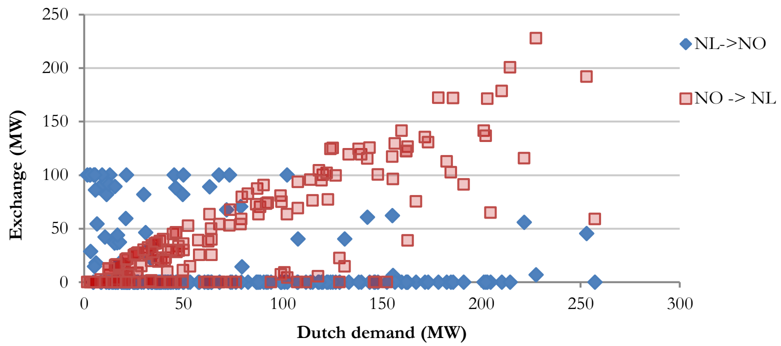


Figure 7. 14. The amount of balancing exchanges (upward, for peak hours) between the Netherlands and Norway for the case of a dry year (2010)

Therefore, the difference between a wet and a dry year in Norway is that in a dry year, the Dutch bids can compete in the Norwegian market, but only to a limited extent, and after a certain point, again it will be the Norwegian bids which are cheaper and more likely to be selected.

The same effect can be seen in case of Norway and Germany. For low demand values, Germany exports upward balancing power to Norway but for higher demand values, Germany is only an importer. Figure 7. 15 shows the upward regulation prices in peak hours for Germany, corresponding to Figure 7. 13 for the Netherlands.

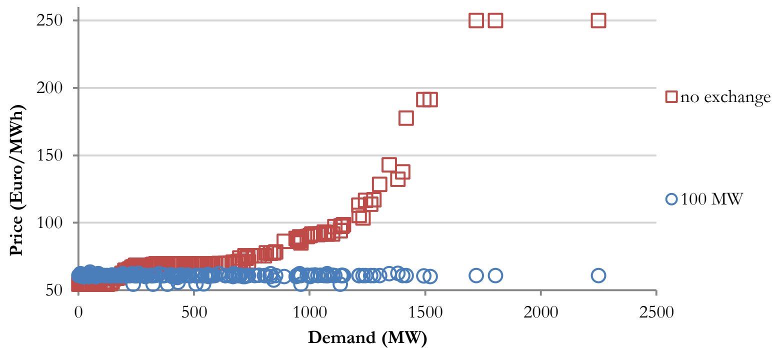


Figure 7. 15. Upward regulation prices (in peak hours) in Germany for two available interconnection capacity values, using the 2010 data (dry year in Norway)

The only difference between this case and the case of Norway-Netherlands is the volume of exchanges. Since the day-ahead price in Germany is lower, the interconnector is most of the time congested from Germany to Norway which leaves large room for export of upward regulation bids from Norway to Germany. Figure 7. 16 shows the amount of balancing exchanges (upward, in peak hours) between Germany and Norway.

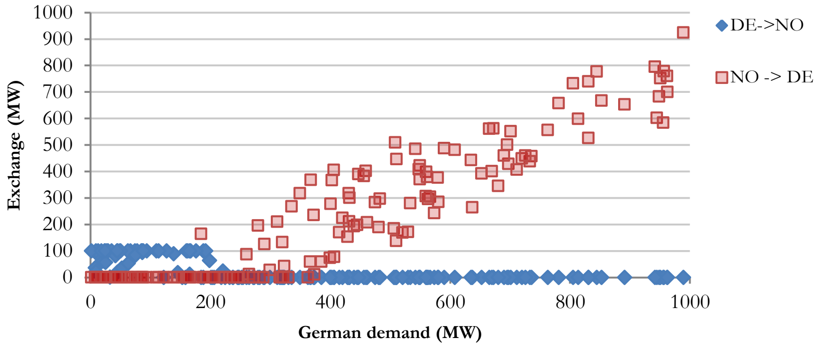


Figure 7. 16. Amount of balancing exchanges (upward, for peak hours) between Germany and Norway for the case of a dry year (2010)

7.5. TSO-TSO trading

In this arrangement, both TSOs are directly involved. The TSO of the exporting area decides on what will be shared with the other area. Thus, the exporting TSO functions as an intermediary between the bidders of the exporting area and the importing TSO. Two variations of this arrangement can be conceived.

In the first variation, the exporting TSO directly offers balancing energy in the other area. In this case, the bid price is not based on the bids actually submitted to the exporting TSO, but the TSO decides on the bid price based on its anticipation of the bid prices that it will receive from its service providers later. An example of this arrangement is the agreement between the UK (National Grid) and France (RTE) [112]. The arrangement allows for submission of a buy and sell price by each TSO. When services are requested by the National Grid, they are cleared at the prices submitted by RTE and vice versa for the services requested by RTE. At present, each TSO submits a single pair of prices that covers the price of utilization for the subsequent calendar day. So the TSOs, based on the forecast of the bids they will receive from their service providers (throughout the next day), decide on the price of their bid in the other market.

The main concern about this arrangement is the direct financial involvement of the exporting TSO, which is in contrast with the functions of a TSO who should mainly focus on security of supply and ideally not be financially involved in the workings of the market. Even if the TSO does not intend to make profit (out of a cross-border exchange), since the TSO has the financial responsibility, it will naturally try to hedge against the risks of bidding at a price that is too low to be compensated by the bids it will later activate in its own area. Of course the TSO can accept losses in some hours, but a situation with consistent financial losses for the TSO cannot be sustainable. Financial involvement of the TSO (or any third party) would probably influence the prices (increase them). If the TSO is risk neutral, then it will seek a 'positive expected profit', which obviously influences the economic efficiency of the process. And if it's willing to take risks and sometimes loses in the process, the question is who is going to make up for the difference? Even in the optimistic case of the TSO not seeking any profit, this whole process would be more expensive and less efficient with involvement of the TSOs. The TSO, in order to avoid financial loss, will (even without a profit-seeking intention) overestimate the bid prices. And that limits the potential profits of the cross-border exchange.

In the second variation, the TSOs offer the bids they have already received from the service providers in their area. Obviously, in this arrangement the TSOs will have to be able to bid in the foreign market after they have received all the bids in their own area and that needs cooperation between the TSOs much closer to the real-time (compared to the first variation). In this arrangement, the bids are shared and the TSOs do not have financial involvement, even though they are directly involved in deciding which bids will be shared. In this case, the TSOs might not be willing to share their cheap bids with the other area. In other words, the TSO will probably share only the bids he already knows he is not going to use; only the bids with higher prices will be shared while cheaper bids stay in the domestic market and maybe not be used at all. This can significantly impact the potential cost reductions as a result of enabling cross-border exchanges. Thus, even in this arrangement, although the TSOs do not have a financial involvement in the exchanges, they still decide on which bids will be shared, which obviously would influence the efficiency of this arrangement.

7.6. BSP-TSO or TSO-TSO?

Our simulation results for BSP-TSO trading in case of Northern Europe suggest that this arrangement can be enabled without a serious concern about significant undesirable change in market prices, or too much capacity leaving the cheaper area (security of supply issue). Nonetheless, it is very logical that the TSOs will be concerned about the issue of security anyway. Since they are the sole entities responsible for system security, they will not be willing to consider any option that may potentially endanger system security.

TSO-TSO trading, on the other hand, while solving that problem, as explained above, is not efficient from a market perspective; financial involvement of the TSOs and their natural tendency to hedge against financial risks would lead to higher prices and inefficiencies. In any cross-border balancing exchange, the TSOs have the key role simply because they are responsible for security. So they are already the ones who decide on all the technical issues (and basically give permission to cross-border exchanges). Giving them control over the workings of the market as well (getting them involved in determining which bids can be shared with another area and with which price) does not represent a free competitive market. The TSO of a control area is the "buyer" of balancing services in that area (by definition of balancing services markets). In a TSO-TSO cross-border arrangement, the TSO is not only the buyer in its own area but also the seller in the other area (using its service providers' bids, or their estimations).

Thus, on the one hand, we have a cross-border arrangement which is based on full freedom of market players, there is no intermediary and the market players in one area can freely decide whether they would bid in the internal or the foreign market, and they can freely decide on their bid price (BSP-TSO trading). This arrangement naturally raises security concerns, because in theory the TSO of the cheaper area may end up with not sufficient resources (as a result of too much capacity leaving the market in search for a higher profit). However, although the other market has a higher price in the beginning, as significant foreign capacity is offered in the market, the price would go down eventually and a new equilibrium would be reached. In case of Northern Europe, our results show that the large excess of supply in Norway would help reach a new equilibrium with considerably lower prices in the Netherlands and Germany and without a really noticeable price increase in Norway (let alone ending up with insufficient bids). Nonetheless, the TSOs' concern regarding security is valid. The TSOs cannot afford any risks to security of supply of their own area.

On the other hand, we have the TSO-TSO arrangement in which both TSOs are directly involved and they decide on which bids to be shared and with which price. This arrangement although eliminates the security concern, raises market efficiency concerns, especially since the TSOs are already involved in all the technical aspects of a balancing exchange, as explained above.

7.7. Restricted BSP-TSO

In addition to the two basic arrangements proposed in various reports/papers and discussed above, it seems there is need for an in-between arrangement, which can help ensure market efficiency (to some extent) and relieve TSOs' concerns regarding system security at the same time.

In order to accommodate TSOs' concerns regarding security (in a cross-border exchange of balancing energy), the TSOs do not have to necessarily be the entity who decides on the bid volume and bid prices for any cross-border exchange (as in TSO-TSO trading). In both variations of TSO-TSO trading explained above, the exporting TSO (directly or indirectly) determines the size and price of the cross-border exchange. Nonetheless, if the TSO is after ensuring security of its system, it should only be concerned with volumes of the shared resources, and not with the prices.

The first variation of TSO-TSO trading (explained above) allows TSOs to directly determine the price of cross-border exchanges. That is unnecessary and can be avoided. In the second variation, the TSO does not determine the prices, but it determines which bids will be shared with the other area, which means the TSO still has all the saying about the prices (depending on which bids it selects to share, the price of the exchange will change).

We need an arrangement that gives the TSO control over the amount of capacity that goes to the other market (the volume), while the TSO does not have full control deciding exactly which bids can leave. In the arrangement that is propose here, service providers can be free to decide whether they want to offer their capacity in the domestic or the foreign market (similar to BSP-TSO trading), but at the same time, the TSOs can have control over how much capacity can leave the domestic market and be offered in the other market.

One simple and practical way to achieve that is to let the (exporting) TSO impose a *maximum allowed capacity* that each service provider can offer in foreign markets. For example, the service providers can be free to bid in foreign markets (and at their desired price) as long as they offer at least 80% of their total available capacity in the domestic market. In other words, a certain part of each service provider's capacity would be locked and cannot be offered in any foreign market, however, it is still up to the service provider which part of its available capacity that is. A service provider with a decent and flexible generating portfolio would be free to choose that 20% of its capacity that it can offer in other markets from any of its units; it can decide to offer its expensive or cheap resources in the foreign market, and with the price it desires. The service provider enjoys a certain level of freedom and the TSO ensures that it will have enough resources to meet its domestic demand.

This arrangement is essentially a *restricted BSP-TSO* arrangement. It should be noted that the *maximum capacity* that the TSO allows to be offered in other markets, has to be calculated carefully, on a case-specific basis, taking into consideration the excess of supply in the area (for each type of balancing services). This maximum capacity, for example, can be much higher for Norway than for Germany or the Netherlands (because of its large excess of supply). Obviously, this maximum capacity would preferably be calculated separately for different time periods (different seasons, peak/off-peak hours, etc.) so that this capacity cap can follow the changes of supply and demand in the domestic reserve capacity market. This cap on the shared capacity (final possible size of a cross-border exchange) also needs to be negotiated by the involved TSOs on a case-specific basis.

7.8. Practical complications

In addition to the market-related issues discussed above, there are some complications that can influence the practicality of enabling cross-border exchanges for balancing energy. These issues arise as a result of differences in market designs of the areas involved in market integration.

7.8.1. Bidding frequency

Difference in bidding frequency of the markets can significantly influence the efficiency of the cross-border exchanges. The case of Germany is a perfect example for clarifying this issue. As discussed earlier in this thesis, bidding for balancing energy happens on a monthly basis in Germany. Service providers bid once per month and the bids will be fixed throughout the month. If the status quo is maintained, then the Norwegian providers wanting to bid in the German market have to submit monthly bids, while the domestic market in Norway is run on hourly bids. Although feasible, submitting monthly bids in the German market can cause distortions in the Norwegian market because as soon as some Norwegian capacity is offered in Germany (and is selected in that market), it cannot be used in Norway for the entire month anymore. In addition, as explained in previous chapters, bidding in a monthly market for balancing energy (while the market is cleared on a quarter-hourly basis) leads to higher prices (because of the lost opportunity costs). And that will limit the potential gains as a result of enabling cross-border exchanges.

The same challenge applies to the case of Norway and the Netherlands; the bidding period in the Netherlands is 15 minutes while in Norway it is one hour. Thus, when bidding in the Dutch market, Norwegian bidders have to bid on a quarter-hourly basis. In that case, when a Norwegian bid goes to the Dutch market (for a particular 15-minute period), then that bid cannot be offered in the Norwegian market for the other three quarter hours of the same hour. So although the bid is offered on a quarter-hourly basis in the Dutch market, the Norwegian market loses that bid not for one quarter of an hour but for four. That can also cause distortions in the Norwegian market.

Nonetheless, none of these differences in market design makes cross-border exchanges infeasible. It imposes more complexity on the service providers who have to bid at different time scales in different markets. It increases complexity and probably leads to higher prices but cross-border exchange is possible.

7.8.2. Coordination of imbalance settlement

When the bid of a service provider is selected in the market, he will be paid for his selected bid regardless of whether or not he delivers the energy. This issue is straightforward to deal with in case of one single market. When a bid is selected, the bidder will be paid the regulation price. If he does not deliver, then he will have an imbalance (after real-time) and thus, he will have to pay the imbalance price (to the TSO). And the imbalance price is, generally speaking, either equal to or higher than the regulation price (depending on the details of the imbalance settlement system). Therefore, if he does not deliver, while he has received the regulation price, he will have to pay the imbalance price which is generally higher, leading to proper incentive for service providers to deliver the energy they are supposed to deliver.

However, in a multinational context, this incentive issue is more complicated. Assuming that two areas are involved, there will be two imbalance prices (one for each area). Let's consider the case of Norway-Netherlands. If a Norwegian service provider bids in the Dutch market and his bid gets selected, he will receive the Dutch regulation price. If he does not deliver though, he will pay the Norwegian imbalance price. And given that the prices in Norway are generally lower than in the Netherlands, the service provider will have a clear incentive to not deliver; he receives a high price (Dutch price) and pays a low price (Norwegian price) and so makes profit by doing nothing.

Therefore, enabling cross-border exchange of balancing energy is not only about arranging a real-time multinational market in which balancing energy can be traded across borders. It also needs close cooperation of TSOs in settling the imbalances. Solving the above mentioned challenge is not complex but it does need dedication at the TSOs level, so that an international mechanism for settling imbalances can be developed: a mechanism in which the service providers are needed to pay the imbalance price of the area they bid in, in case they do not deliver.

7.9. Conclusions

Regarding exchange of balancing energy across borders, ACE netting is the basic arrangement that allows for imbalances in opposite directions to cancel each other out. This will reduce the amount of balancing energy that needs to be activated in the corresponding areas. According to the results of the model, BSP-TSO trading which enables foreign bidding for service providers can dramatically reduce the market prices in Germany and the Netherlands. The huge excess of supply in Norway can handle the Dutch and the German demand without a sudden change in the Norwegian prices.

Nonetheless, BSP-TSO trading will logically raise TSOs concerns regarding system security, because in this arrangement, bidders are free and the exporting TSO does not have control over which bids leave the domestic market. TSO-TSO trading on the other hand, can significantly influence the efficiency of the cross-border exchanges because of the direct financial involvement of the TSOs. Therefore, an in-between arrangement was proposed in this chapter: a *restricted BSP-TSO arrangement,* which gives service provider the freedom to make effective decisions on their bid price and bid volume, while puts a cap on the capacity that each service provider can offer in foreign markets and thus gives the TSOs the tool to guarantee that the reserve capacity that is leaving its domestic market will not endanger its system security.

And lastly, the difference in the bidding frequencies of the markets involved can impose considerable complexity on the service providers because they have to bid in markets with different time horizons. However, the difference in time horizons does not make cross-border exchanges impossible. It would rather increase the bid prices and limit the potential cost reductions. In addition, to ensure proper incentive for service providers regarding actually delivering the balancing energy they are supposed to deliver, an imbalance settlement mechanism has to be developed by the TSOs so that the service providers who do not deliver will have to pay the imbalance price of the area they bid in.

8. Summary and Policy Recommendations

8.1. Critical characteristics of balancing markets

Although integration of balancing markets is generally seen as the next step after integration of day-ahead and intra-day markets, complexity of balancing markets is an important factor distinguishing these markets from wholesale electricity markets. What is known as 'balancing market' is a mechanism consisting of various markets for trading of various services. Different areas (countries) use their own definition of balancing services and use market designs that in some cases have fundamental differences with each other. That is the reason why integration of balancing markets is much more complex and challenging compared to integration of day-ahead or intraday markets.

In addition, since balancing markets are aimed to balance generation and consumption and prevent frequency deviations, these markets have a direct influence on security of supply. Therefore, TSOs' foremost concern (regarding any change in their balancing market) is to ensure that system security is not compromised in any sense. This factor complicates market integration even further, and requires us to be more cautious in proposing arrangements for cross-border exchanges of balancing services.

8.2. Short and long term view

Because of the basic differences in the market design (in different countries), the direct influence of balancing markets on system security, and TSOs' reluctance to make changes in the basics of their market design, a cautious step-by-step approach should be taken regarding integration of balancing markets. Designing the path of this gradual change needs accurate short- and long-term planning.

Integration of balancing markets requires some kind of convergence of the market designs across Europe. Based on this study, we believe the path to fully integrated balancing markets goes through changes in the market design at the 'national' level. National reforms improve the efficiency of the national market and if these reforms follow a general direction pre-determined by an overarching European-wide view in mind, these reforms will lead to more harmonized markets across Europe, or in other words, convergence of the market designs, which will make fully integrated balancing markets across Europe practically achievable.

These reforms are medium and long-term plans. However, in the short run, limited exchange of services across borders can be enabled in some cases. The details of these two long-term (national reforms) and short-term (limited cross-border exchanges) plans are explained in the following sections.

8.3. Long-term view: National reforms

It seems that because of the main objective of balancing markets (system security), in some cases, the balancing markets were not designed with 'market efficiency' as the main goal in mind. Historical factors and path dependency of market designs can be seen as other influential factors which make balancing markets across Europe, although effective, in some cases not efficient, from a market perspective. In order to improve the performance of balancing markets some reforms at the national level are recommended:

1. **Defining services in a more specific way**: Services should be distinguished and ideally, separate markets should be held for different services. A distinction between peak and off-peak hours is essential for higher efficiency (in case hourly markets are not used). In addition, a distinction between upward and downward capacities needs to be made. In case of balancing energy, this distinction is already in place across Europe, but for reserve capacity, in many cases, one single market is used without a distinction between up- and down-ward capacity.
2. **Moving towards shorter term markets**: Especially in case of reserve capacity markets, using long term contracts, although effective, raises market efficiency concerns. Use of shorter term markets would lead to lower demand, easier new entries, higher competition, lower opportunity costs, and more proper incentives for system operators.
3. **Using the same frequency for bidding and market clearance**: Especially in case of balancing energy markets, service providers should be able to submit different bids for each period of market clearance. Otherwise, the number of market players would be limited and an opportunity cost component will be indirectly added to the bid prices of the service providers resulting in lower price efficiency (lower cost-reflectivity of prices).

8.3.1. National reforms for Northern Europe

Based on the results of our study, the following can be seen as the case-specific recommendations regarding national reforms (of balancing markets) in Northern Europe:

- In case of **the Netherlands**, the balancing energy market is functioning satisfactorily and no major institutional change seems necessary. Nevertheless, the reserve capacity market (for secondary control) is far from efficient. Because of the five reasons mentioned in the fourth chapter, a step-by-step reform leading to short-term markets for reserve capacity is recommended to be seriously considered. In the first step, the bilateral contract arrangement can be abolished and monthly auctions can be used. In a further step, a distinction between up and down capacity can be made, as well as a distinction between peak and off-peak hours. And in the last step, weekly or preferably daily markets can be considered. Implementation costs play a decisive role and it is very understandable that abstract arguments such as higher competition/liquidity/efficiency can possibly be easily dismissed using 'the cost argument'. However, the considerable reduction in the demand for reserve capacity (as a result of calculating reserve requirements on a more frequent basis) is a concrete factor justifying consideration of short-term auctions for reserve capacity.

- In case of **Germany**, the reserve capacity markets are noticeably more efficient than the one in the Netherlands. However, especially for secondary control, considering the extremely low excess of supply ratios, there is room for improvement, and daily markets, just like the market for tertiary control, are recommended. Balancing energy markets in Germany however, need serious attention. A monthly market with fixed bids for the entire coming month, not allowing any new bidders close to real-time, significantly increases the bid prices, adds a lost opportunity cost component to the bids, and limits the number of bidders. Germany seems to need to move towards auctions close to real time (as close as possible, ideally quarter-hourly markets similar to the Netherlands) for balancing energy.

8.3.2. How to stimulate reforms

Reform at the national level comes from national initiatives, however, it does not mean that nothing can be done at the international level. The first step can be developing guidelines at the European level. By guidelines, we do not mean a single 'desired' design for balancing markets, but the general characteristics that the market design should have. To achieve that, European entities should perform thorough studies and publish guidelines which directly address the design characteristics that a national balancing market should have, not in vague terms such as transparency, liquidity and efficiency, but actually addressing issues such as the pricing mechanism and timing of markets.

Although the national TSOs cannot be forced to make changes, publishing these guidelines can raise awareness. The national TSOs will be able to see what can be improved in their market, and actually, how far they are from a properly functioning balancing market. Making TSOs aware of the inefficiencies, and showing them what can be gained by reforming their market design, seems to be the first step.

Adoption of the Third Energy Package in 2009, which introduced a new institutional framework for EU's energy market is a promising sign. By this new legislation package, ACER (Agency for the Cooperation of Energy Regulators) was born whose overall mission according to its founding regulation is to assist national regulatory authorities (NRAs) to perform their duties at EU level and to coordinate their actions whenever necessary. ACER cooperates with EU institutions and stakeholders, notably NRAs and European Network of Transmission System Operators (ENTSO), to deliver a series of instruments for the completion of a single energy market. If the new network codes (to be developed by ENTSO and then to be approved by ACER) will be concrete enough addressing the real market design challenges, creation of ACER can then be seen as an effective stimulant for national reform and eventually successful integration of balancing markets.

8.4. Short-term view: Limited cross-border exchanges

Although there are basic differences in the market design between different areas, even if the status quo is maintained (no fundamental change in market designs), balancing services can still be exchanged across borders in case there exists a minimum level of cooperation between the TSOs. Next to our long term view which follows national reforms, a short-term strategy can be used to enable cross-border exchanges with minimal structural changes in the market design. We address reserve capacity and balancing energy markets separately:

8.4.1. Integration of reserve capacity markets

The key in enabling cross-border exchanges for reserve capacity is the issue of interconnection capacity management. Since reserve capacity markets are rather long-term markets, reservation of interconnection capacity will result in lost opportunity costs (loss of trades in other markets) for quite long periods of time. The economic justification of reserve capacity exchanges across-borders highly depends on these opportunity costs. Opportunity costs need to be calculated on a case-specific basis using the historical data on market prices (especially the day-ahead prices) and only if the opportunity costs are lower than the price difference in the reserve capacity markets, cross-border exchanges will make economic sense.

In addition, opportunity costs can be controlled if reservation is done for short time horizons and with a distinction for peak and off-peak hours; reservation on a yearly basis, indiscriminately, can result in significant opportunity costs. Reservation for short time horizons will result in a more intelligent and flexible way of managing interconnection capacity, enabling the areas to benefit both from reserve exchanges as well as day-ahead trades. However, reservation for short time horizons can be done only if the reserve capacity markets have a short time horizon; if the market is yearly, reservation of interconnection capacity has to be done on a yearly basis as well. Therefore, moving towards markets with shorter time horizons (which was recommended from a national perspective) does have a positive effect on performance of the future multinational markets as well. Reforming the markets at the national level, cautiously and in a step-by-step approach, not only improves the performance of the national markets, but also paves the way for integration of the national balancing markets by eliminating the critical differences in market design.

8.4.2. Integration of reserve capacity markets in Northern Europe

Since the reservoir levels in Norway play a decisive role in the market situation in Norway and consequently on the desirability of market integration in Northern Europe, the data of two consecutive years were studied: 2009 as a normal year and 2010 a dry year with low reservoir levels in Norway.

According to our case studies, in case of Norway and Germany, when there is no particular shortage of hydro power (e.g. 2009), the opportunity costs incurred by day-ahead trade losses are so high that integrating the two markets loses its basic economic justification. However, in a dry year such as 2010, high day-ahead prices in Norway would lead to almost no opportunity costs and so exchange of reserves from Norway to Germany would be economically desirable. Nonetheless, the price difference in the reserve capacity markets (in a dry year) seems to be rather too small to justify the costs and efforts of market integration.

In case of Norway and the Netherlands, although in a normal year (e.g. 2009) the opportunity costs are significant but the Dutch prices are believed to be sufficiently high to make market integration a very logical decision. In a dry year, there are almost no opportunity costs and therefor, exchange of reserves would be even more beneficial and would lead to even higher cost savings.

8.4.3. Integration of balancing energy markets

Although timing of balancing energy markets varies widely across Europe, cross-border exchange of balancing energy is still possible. The first step seems to be enabling ACE netting, which does not require foreign bidding. In this basic arrangement, balancing energy bids are not activated; ACEs (in the opposite directions) offset each other without any bid activation. When ACE netting is performed between two areas connected with HVDC lines, the power surplus in one area has to be transferred to the other area, therefore, the TSOs have to change the power flow on the DC line. However, within a synchronous system, ACE netting does not require any physical power exchange; ACE netting is only a matter of adjusting the ACE signals.

In addition to this basic arrangement, using the multinational arrangement proposed in the previous chapter (restricted BSP-TSO trading), service providers can bid in other markets while the TSO makes sure that not too much capacity leaves its own market. However, the differences in timing of the markets (frequency of bidding specifically) can have quite some undesirable consequences on the efficiency of the multinational arrangement. Bidding in markets with different time horizons imposes significant complexity on service providers. This factor will probably limit the number of players who participate in the multinational arrangement. Because of the added complexity (and the subsequent confusion, especially on the service providers' side) and the structural differences in timing of markets, distortions in the national markets are likely to happen.

The other critical factor in cross-border exchanges of balancing energy bids is the procedure used for settling imbalances. In case no multinational mechanism for imbalance settlement is developed, service providers might have a considerable incentive to not deliver the energy they are asked to. Since the service provider, in case it does not deliver, pays the imbalance price of its own area but receives the regulation price of the other area, depending on the difference between these two prices, the service provider might have a strong incentive to not deliver. The TSOs involved need to develop a simple mechanism in which the service providers are needed to pay the imbalance price of the area they bid in, in case they do not deliver.

8.4.4. Integration of balancing energy markets in Northern Europe

We studied the possible consequences of BSP-TSO trading using the model presented in the previous chapter. Since in this arrangement, the TSO of the exporting country is not involved and has no control over which bids leave for the foreign market, The main concern about this arrangement is that too much capacity might leave the cheaper (exporting) area leading to significantly high prices (low prices in case of downward regulation) in the exporting area. The answer to this issue in general, depends on many different factors, however, in the specific case of Northern Europe, based on our results this concern can be considered as a factor without a decisive influence. Norway, with its huge excess of supply, can handle the demand in Germany and the Netherlands, without a significant change in the Norwegian market price. In case of downward regulation in peak hours, when Norway can be an importer, the market price in Germany (as the exporting area) can be significantly influenced for high demand values (and high available interconnection capacity). Generally speaking, enabling bidding across borders, in case of the Netherlands would result in large savings (cost reductions), even for small values of exchange (because of the small size of the Dutch market). To reach the same size of price reductions in case of Germany, significantly higher exchange volume is needed. In addition, the cost reductions for upward regulation are generally much larger than for downward regulation.

Although based on our results, the BSP-TSO trading in Northern Europe, would not result in higher prices in the cheaper area (Norway), this arrangement will logically raise TSOs concerns regarding system security, because in this arrangement, bidders are free and the exporting TSO does not have control over which bids leave the domestic market.

Although TSO-TSO trading can relieve that concern, it can significantly influence the efficiency of the cross-border exchanges because of the direct financial involvement of the TSOs. Therefore, we proposed an in-between arrangement, which tries to ensure market efficiency and to relieve TSOs concerns regarding system security. The proposed *restricted BSP-TSO arrangement,* which gives service provider the freedom to make effective decisions on their bid price and bid volume, while puts a cap on the capacity that each service provider can offer in foreign markets and thus gives the TSOs the tool to guarantee that the reserve capacity that is leaving its domestic market will not endanger its system security.

8.5. Notes on further research

One of the basic issues that needs special attention seems to be physical limitations. Exchange of electric power across borders throughout Europe needs available interconnection capacity. The size of the installed interconnectors across Europe does not seem to be proportional to the scale of the ambition of creating a pan-European market. Thus, incentivizing investment in transmission (across-borders) is a critical issue, especially given the complexity of the political and financial aspects of the problem.

Regarding integration of balancing markets, studies which address the specific technical challenges are necessary. One basic challenge is effective real-time communication among the

TSOs. As a good example, in order to enable ACE netting, an automatic control system needs to be developed and implemented, which receives the system frequency and system imbalances as an input and automatically determines the ACE signals of each area. Implementation of such a system in case there are multiple areas could be quite a challenge. This issue is even more complicated when one (or more) area does not use an ACE signal (does not have Automatic Generation Control, e.g. Norway). In addition, since in case of HVDC lines the power needs to be physically transferred, managing the interconnector (the flow on the line) requires real-time communication and cooperation among the TSOs.

Additionally, market design issues need special attention from economists, engineers and policy analysts. Developing a roadmap for integration of balancing markets cannot be done in isolation from other wholesale electricity markets; day-ahead and intra-day markets. Since the players in these markets are essentially the same, these markets are highly interrelated. We believe there is a need for studies which directly address these interrelations and dependencies. In other words, studies which focus on integration of balancing markets should be part of an overarching plan that addresses integration of electricity markets in general.

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APPENDIX A

The appendix presents the mathematical details of the simulation model used in chapter 5. As explained earlier, an agent based model is used which models generators as agents who can offer their available capacity in the day-ahead (DA) and/or the reserve capacity (RC) market. Each agent has to decide on its bids in the RC and DA markets, and the bids consist of a volume (in MW) and a price (in €/MWh for the DA market and in €/MW/hour for the RC market). We have defined two types of agents: "Risk-averse" agents who do not try to influence the market clearing price, and "Risk-prone" agents who do try to increase the market price by increasing their bid prices. In each round of the simulation, each agent decides on its bid prices for the next round by adapting its current bids, using the market information of the last round. In addition to the bid price, each agent adapts its offered capacities in the two markets (for the next round) by comparing its individual relative profits in the two markets and shifting some capacity (depending on the size of the difference in profit) from the less profitable to the more profitable market.

A.1. Bid Price Adaptation Strategy

Risk-averse agents: If their bid is selected in a market (in a specific round), they keep their current bid price in the corresponding market for the next round. If their bid is not selected, they reduce their bid price in order to be among the selected bids in the next round. The price step size for a generating unit, by which the bid price of that unit is reduced for the next round, is assumed to be a percentage of the unit's total operating costs and fixed throughout the simulation.

Risk-prone agents: They use the same strategy as risk-averse agents for reducing their bid prices in case of not being selected in a market. The difference is that risk-prone agents do not necessarily keep their current bid price (for the next round) if they are selected, but they will try to influence (increase) the market clearing price by increasing their bid price if their bid is selected. So they take the risk of not being selected (in the next round) in order to increase the market clearing price. The price step size, by which the bid price of an agent is decreased or increased for the next round, is assumed to be a percentage of the unit's total operating costs, and it might be decreased throughout the simulation. Assume that the bid of agent *i* (a risk-prone agent) is not selected at round *n-1* but is selected at round *n*. This means that the bid price of the agent has been reduced by $Pss_{i,n-1}$ (the Price Step Size of unit *i* at round *n-1*) for round *n* and the new bid price is low enough to get selected in the market. Since the agent is risk-prone, it will try to increase its bid price for round *n+1*. Using the same price step size will put the agent in the same situation as in round *n-1*. In other words, using the same high step size will put the agent in a cycle of not being selected in one round and being selected in the next, constantly increasing and decreasing its bid price in subsequent rounds. Thus, the agent should use a lower step size for increasing its bid for round *n+1* which means competition among bidders limits the opportunity of influencing the market price by risk-prone agents. We introduce a variable, ε, (between 0 and 1), which is the factor by which the price step size of a risk-prone agent is reduced in this situation; in case a risk-prone unit's bid is not selected in one round (n-1) and gets selected in the next round (n). Therefore, adaptation of the price step size is performed as follows:

$$PSS_{i,n+1} = \begin{cases} PSS_{i,n} \times \varepsilon \ ; \quad \text{if} \quad BP_{i,n-1} > MP_{in-1} \text{ AND } BP_{i,n} \le MP_n \\ PSS_{i,n} \ ; \quad \text{Otherwise} \end{cases} \qquad \text{(A. 1)}$$

Where MP_n is the market price at round n.

A.2. Bid Volume Adaptation Strategy

In each round, all agents adapt their offered volumes in the DA and RC markets for the next round, based on market outcomes of the current round. They calculate their average profit per MW of their capacity (in €/MW/hour) in the two markets and withdraw some of their capacity from the less profitable market and add it to their offered capacity in the other market. The volume step size of an agent, by which the offered volume is shifted between the two markets for the next round, depends on the agent's difference in profit in the two markets. The higher the difference in profit, the more capacity is shifted between the markets. A simple linear relationship is used in this simulation:

$$Vss_{i,n} = Vss_i^{\max}(1 - profratio_{i,n-1}) \qquad \text{(A. 2)}$$

where $Vss_{i,n}$ is the volume step size of agent *i* at round *n*, $Vss_i^{\max}$ is the maximum volume step size for agent *i*, and $profratio_{i,n-1}$ is the profit ratio (average profits per MW of capacity) in the two markets for unit *i* at round *n-1*. Thus, in case an agent's profit in one of the two markets is zero at one round, the maximum volume is shifted to the other market for the next round. And in case an agent's profits in the two markets are equal, no volume is shifted between the two markets for the next round (the current level of offered volumes is used for the next round).

The fixed costs of generating units are neglected in this study, so the cost of producing power for each unit is equal to its operating costs. Thus, a unit's profits in the RC and DA markets are calculated as follows (if its bids are selected in the two markets):

$$prof_{i,n}^{DA} = V_{i,n}^{DA} \times (MCP_n^{DA} - OC_i) \qquad \text{(A. 3)}$$

$$prof_{i,n}^{RC} = V_{i,n}^{RC} \times MCP_n^{RC} \qquad \text{(A. 4)}$$

where $V_{i,n}^{DA}$ and $V_{i,n}^{RC}$ are the offered volumes in the DA and RC market respectively, $prof_{i,n}^{DA}$ and $prof_{i,n}^{RC}$ are agent *i*'s profits in the DA and RC markets at round *n*, respectively, MCP_n^{DA} and MCP_n^{RC} are the market clearing prices of the DA and RC markets at round *n*, and OC_i is the operating cost of unit *i*. If an agent's bid is not selected in a market, its profit in the corresponding market in zero.

A.3. The three cases

As mentioned earlier, three cases are defined, representing the three alternative designs regarding coordination of timing of the DA and RC markets.

Case A

The first case represents simultaneous closure and clearance of the two markets. Each agent decides on its bid prices and bid volumes in the two markets, based on the market outcomes of each round. Since in simultaneous clearance, agents have to split their available capacity between the two markets (no capacity can be offered in both), the only constraint for agents in case A is on the total offered volumes:

$$V_{i,n}^{DA} + V_{i,n}^{RC} = V_i^{Avai.} \qquad \text{(A. 5)}$$

where $V_{i,n}^{DA}$ and $V_{i,n}^{RC}$ are agent *i*'s offered volumes in the DA and RC markets for round *n*, respectively, and $V_i^{Avai.}$ is the total available capacity of agent (generating unit) *i*. In addition, the lower boundary of a unit's bid price in the DA market, for all rounds, is the unit's operating costs:

$$P_i^{DA} \geq OC_i \qquad \text{(A. 6)}$$

where P_i^{DA} is the bid price of unit i in the DA market. The inequality constraint in equation $P_i^{DA} \geq OC_i$ (A. **6**) applies to all the three cases.

Case B

In the second case, first the RC market is closed and cleared and the DA market is cleared afterwards. Because of sequential clearance of the markets, bid prices in the RC market (the first market in the sequence) will include a lost opportunity cost component. Using the following inequality constraint, agents make sure that, in the next round, no potential profit in the DA market (second market) is lost by offering their capacity in the RC market (first market):

$$P_{i,n+1}^{RC} \geq MCP_n^{DA} - OC_i \qquad \text{(A. 7)}$$

where $P_{i,n+1}^{RC}$ is the bid price of unit *i* in the RC market for round *n+1*. The right hand side of the inequality constraint represents the unit's profit (per MW) in the DA market for round *n*. Therefore, by assuring that the RC bid price for the next round is higher than the unit's profit in the DA market at the current round, the unit ensures that no possible profit would be lost in the DA market (for the next round) by offering its capacity in the RC market.

Case C

The third case represents the design in which the DA market is closed and cleared first and the RC market is second. Since the lost-opportunity-cost component in bids of agents originate from the sequential clearance of the markets (not from the nature of the products traded in the two markets), the DA bid prices of agents in case C will include the lost-opportunity-cost component because the DA market is first and agents should make sure that no potential profit is lost in the RC market (second market) by offering part of their capacity in the DA market (first market). Thus, the following inequality constraint is applied to bid prices in the DA market for case C:

$$P_{i,n+1}^{DA} \geq MCP_n^{RC} + OC_i \qquad \text{(A. 8)}$$

where $P_{i,\,n+1}^{DA}$ is the bid price of unit *i* in the DA market for round *n+1*. The right hand side of the constraint represents the unit's profit (per MW) in the RC market at round *n* plus the operating costs of the unit (which is the minimum bid price in the DA market).

A.4. Parameter setting

The initial values of the step sizes and initial bid prices used in the simulation are summarized in Table A. 2.

Table A. 2. The initial price and volume step sizes and the initial bid prices (at round 1)

Variable	$P_{i,1}^{RC}$	$P_{i,1}^{DA}$	$Vss_i^{\max}$	$Pss_{i,1}^{RC}$	$Pss_{i,1}^{DA}$
Initial Values	$0.1\times OC_i$	$1.1\times OC_i$	$0.1\times V_i^{Avai.}$	$0.1\times OC_i$	$0.3\times OC_i$

The initial bid prices (at round 1) in the RC and DA markets are 10% and 110% of unit's operating costs (a profit margin of 10% of the operating cost in both markets is considered in the initial bids). The initial price step sizes for each unit are 10% and 30% of unit's operating costs, for the RC and DA market bids respectively. The volume step size (the maximum volume shift of a unit in each round) is 10% of the unit's available capacity. At round 1, each unit divides its capacity between the RC and DA markets proportional to the total demand in the corresponding markets.

Curriculum Vitae

Alireza Abbasy was born in 1981, in Tehran, Iran. In 2003, he received his BSc in Electrical Engineering from Sharif University of Technology, Tehran, Iran. He received his MSc degree in Electrical Power Systems in 2006 from the same university. In 2008, seeking something different than pure engineering, he moved to Delft, the Netherlands, to work on his PhD in the faculty of Technology, Policy and Management, which has a general multi-disciplinary scope.

He has been part of an international research group which has been working on integration of balancing markets in Northern Europe, specifically on the project 'Balance Management in Multinational Power Markets'. The work of the project was divided into two main parts: the technical aspect which the research group in Norway (from the faculty of power engineering in NTNU) worked on, and the institutional/economic challenges of integrating balancing markets which was studied by the research group in Delft, which Alireza was part of. He published various articles and was the co-author of the final project reports which were finalized by SINTEF in Norway.

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