Analysis of Capacity Remunerative Mechanisms (CRMs) in Europe from the Internal Electricity Market Point of View

Elforsk rapport 14:22

Roland Meyer, Olga Gore, Gert Brunekreeft, Satu Viljainen March 2014

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Preface

Several EU Member States have recently announced plans for the introduction of capacity remuneration mechanisms. These national arrangements risk distorting cross-border trade or even act as barriers to trade if they are designed without taking into account their cross-border impact or are not coordinated with neighbouring markets.

Market Design therefore commissioned a team of researchers from Lappeenranta University of Technology in Finland and Jacobs University Bremen in Germany to assess the impact of different capacity remuneration mechanisms on cross-border trade and on the functioning of the internal European electricity market. The result of their assessment is presented in this report.

The project's reference was made up by:

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The Market Design research programme has been operating for more than 10 years. For more information please visit www.marketdesign.se.

Johan Linnarsson for Market Design,
Stockholm, April 2014

Sammanfattning

De senare årens debatt om försörjningssäkerhet har i många europeiska länder kommit att kretsa kring en hög och växande andel intermittent förnybar kraftproduktion, RES. En av de viktigaste frågorna är den om en marknad som uteslutande belönar produktion av energi skapar tillräckligt med incitament eller om även tillgänglighet av kapacitet behöver belönas. Det finns en oro att mer säker kapacitet behövs i systemet och i många länder finns därför tankar om att införa någon form av betalning för kapacitet i tillägg till energipriset. I denna studie undersöker vi två typer av mekansimer för kapacitetsbetalning, strategisk reserv (strategic reserve, SR) och tillförlitlighetsoptioner (reliability options, RO). Båda mekanismerna har analyserats både empiriskt och teoretiskt, och har rönt visst intresse i den allmänna debatten.

Frågan är vilken marknadsdesign som bäst leder mot målet, den Europeiska Interna Marknaden? Finns det målkonflikter, och finns det gränsöverskridande problem med *free riders* eller negative externa effekter? Vår studie granskar närmare de möjliga gränsöverskridande effekter som olika val av marknadsdesign kan ha.

I studien simulerar vi effekterna av kombinationer av marknadsdesign mellan två modell-länder. Vår spelteoretiska simulering antar marknadsdesign som strategisk variabel. Beslutet om marknadsdesign fattas ensidigt men utfallet berör båda länderna. Vi redovisar priser, välfärd och investeringar som resultat från simuleringen.

Simuleringsresultaten visar att en ensidig implementering av marknadsdesign kan ha negativa gränsöverskridande konsekvenser. För att undvika en situation där länderna på grund av detta väljer suboptimala strategier kan en central koordinering av strategierna vara att föredra.

Beroende på sin utformning påverkar olika marknadsdesigner prisbildning olika, och kan i värsta fall medverka till en ineffektiv prisbildning. Även den variant av strategisk reserv som vi modellerar, med begränsad marknaspåverkan, visar sig kunna ha negativa effekter.

Slutligen, kapacitetsmekanismernas effektivitet inom och mellan marknader kan också vara lägre än våra simuleringar visar. Till exempel vet vi inte med säkerhet vilka problem vi har med försörjningssäkerheten, och vilken storlek problemet har. Vi vet heller inte hur de föreslagna mekanismerna påverkar investeringsincitament eller marknadsutvecklingen. Det är fortfarande osäkert, empirsikt såväl som teoretiskt, hur olika mekanismer påverkar aktörernas faktiska budgivningsbeteende.

Summary

The high penetration of renewable energy sources (RES) in most European electricity markets has reinforced the debate on generation adequacy in energy-only markets. The concerns about a "missing-money problem" have motivated many countries to reconsider their market design and think about introducing capacity remunerative mechanisms (CRMs). Two possible mechanisms, the strategic reserves (SR) and reliability options (RO) have gained much attention and have been analyzed both theoretically and empirically.

However, given that Europe aims to foster the European Internal Market (EIM), the question is whether market design changes on the level of EU member countries are conflicting with the European goals of a single market. The possible cross-border effects like free-rider problems or negative externalities have yet received little attention. These spillover effects will be the focus of this study.

We simulate the effects of CRMs based on a two-country model. We consider the different market design options as "strategic variables" of the two markets within a game theoretic approach. Both countries decide unilaterally whether or not to implement a CRM, while the impacts on welfare, prices and investments will be determined by both markets' decisions.

Our results show that a unilateral implementation of a capacity mechanism may have negative spillover effects which may force the neighbouring markets to change their market design as well. In order to avoid at least temporary negative effects that conflict with the idea of the EIM, coordination of policy measures is advisable.

Depending on their form and design, capacity mechanisms may involve inefficiencies caused by price distortions. Even though the SRs are only limited market intervention compared to ROs that may constitute a market-wide change with many possibly inefficiencies in setting the parameters and rules for money flows, SRs too might involve large efficiency losses due to the central dispatch of reserves outside of the regular market.

However, efficiency of CRMs within and between integrated markets may be further depressed due to imperfect information about the characteristic of the missing-money problem, investment incentives and market developments. Among other factors, it may be unclear how the generator's bidding or investment behaviour may change after the implementation of a capacity mechanism.

Contents

1 Introduction

1.1 The missing-money problem

In energy-only markets, electricity generators are paid for the volume of electricity (MWh) that has been produced and sold, while they are not compensated for keeping capacity available. They provide capacity reserves voluntarily, based on the expected profit they will obtain in the real-time market. Generators must recover their variable and fixed costs from sales of electricity over the whole lifetime of the generating equipment. In a competitive energy-only market, generators bid their short-run marginal costs (fuel, CO2 and variable operational costs) and the hourly market clearing price equals the marginal cost of the last generating capacity or the demand response resource that clears supply and demand given that demand does not exceed available capacity (as illustrated in Figure 1 by Demand 1). The fixed costs of dispatched generators is recovered through the so-called inframarginal rent that is given be the area between the market clearing price (Price 1 in Figure 1) and the marginal costs of the generators. In a relatively small number of hours per year there could be scarcity situations when demand exceeds available capacity (Demand 2 in Figure 1). In this case, the day-ahead market should be cleared "on demand side" (Joskow, 2006). The day-ahead market purchase bids are curtailed so that the demand curve intersects with the supply curve at maximum price. Under competitive scarcity conditions the maximum price, at which the day-ahead market is cleared in undersupply situations should reflect the value of lost load (VOLL) - the price that consumers place on reducing consumption by a significant amount. It should be noted that the demand could still be covered through the intraday market (e.g. by industrial price elasticity) or balancing market (through imbalance settlement).

During scarcity situations, generators earn "scarcity rents" which amount to the area between VOLL and Price 2 in Figure 1). These scarcity rents may constitute a significant share of the total revenue that generators receive during the entire year. For peak capacities operating mainly during scarcity situations, scarcity rents are an important source of revenue to cover the fixed costs. However, the lack of the short-term demand response gives generators the possibility to exercise market power during scarcity situations. Therefore, a threat of market power abuse may force regulators to set a price cap on the energy-only market and the day-ahead electricity markets are cleared at the day-ahead market ceiling price (or price cap) in scarcity situations. The price caps protect customers against high prices, but as the same time reduce scarcity revenues, causing the "missing-money" problem. A market with too low price caps is not able to provide long-term investment because as a result of capped scarcity prices, generators are not able to make a return on their investments (Cramton & Stoft, 2006; Joskow, 2006).

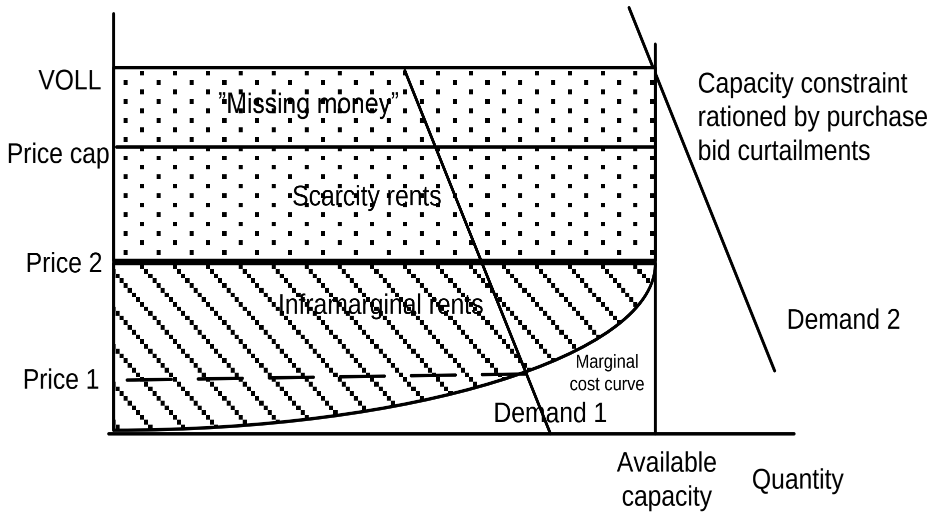

Figure 1. Electricity pricing and "missing-money problem"

Source: adapted from Joskow, 2006

The "missing money" problem in many European energy-only markets became even more topical with the rapid penetration of renewable generation. First, the growth of low marginal cost RES generation creates a merit order effect, when the supply curve shifts to the right (see Figure 2). It suppresses electricity prices and, moreover, creates periods with zero or even negative electricity prices due to the fact that for many generators the costs of reducing the output are higher than the production costs (Brunekreeft et al., 2011). Second, load factors of existing conventional power plants are reduced because they are dispatched much less frequently than before. Consequently, peak generators fail to recover their fixed costs as a result of reduced number of operating hours, suppression of real scarcity prices due to oversupply and scarcity price capping when the market is tight. As a result, even most modern gas-fired power plants do not operate on profitable basis, preferring to mothball unless market provides a higher remuneration (Meulman and Merey, 2012). Conventional gas units have been closed more widely (e.g. in Great Britain and Slovakia), and in Germany at least one CCGT decommissioning is announced but not yet approved by the regulator. In the long term the reduced number of operating hours of conventional power plant increases the risks of investing in new conventional back-up capacity.

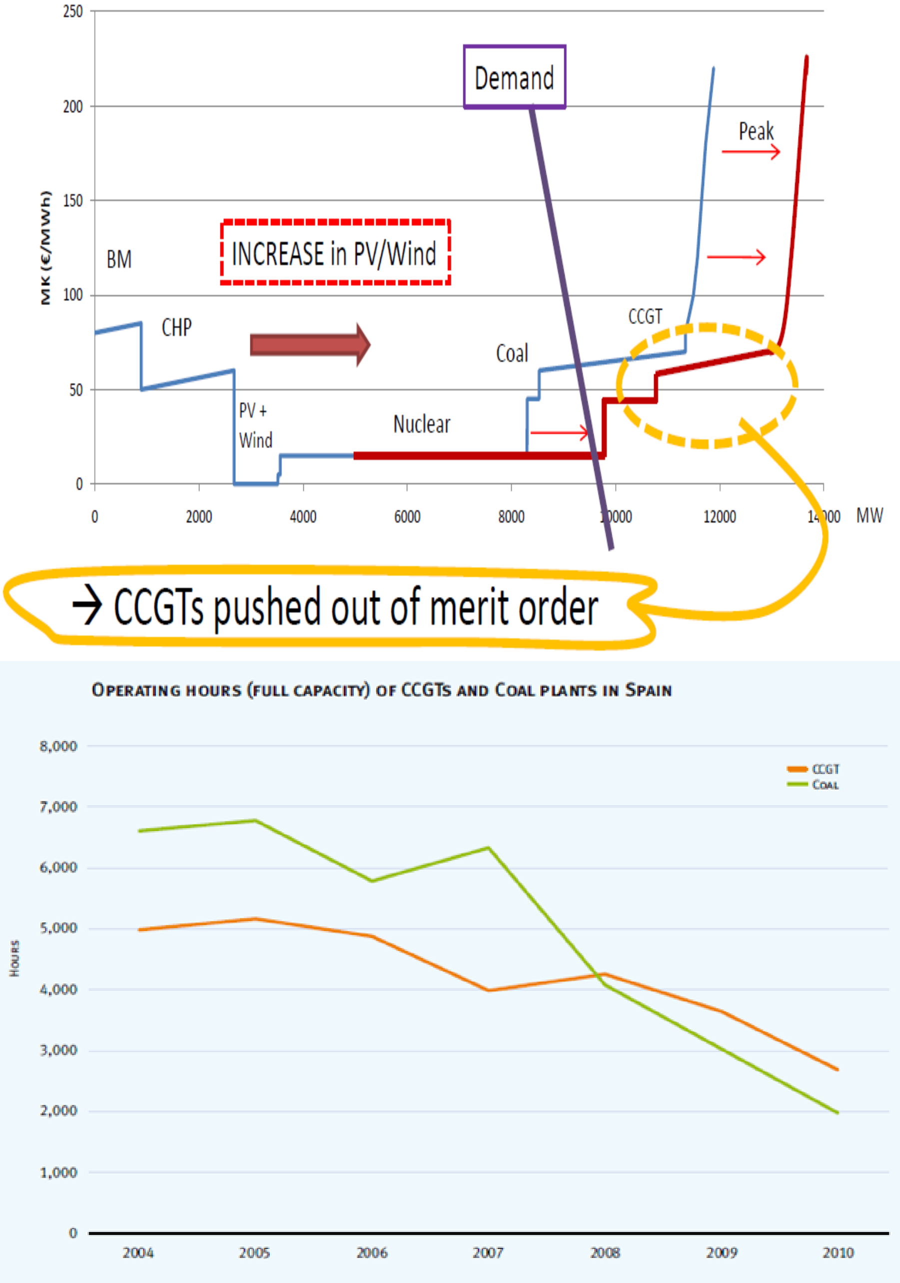

Figure 2. Market outcomes due to increased share of RES

Source: Red Eléctrica de Espana

Current investment decisions are complicated by uncertainty over long-term marginal electricity prices, fuel and CO2 prices, number of operating hours of conventional power plants, regulatory interventions. Investors will not likely approve an investment decision unless market delivers predictable return (Eurelectric, 2011). However, a high speed of changes in market design, rules, and regulations makes investment climate even more challenging. In the long run, delayed investment decisions in new back-up capacity together with continuous depreciation of the existing ones might lead to a resource adequacy problem. However, due to an increasing share of RES with high variability and low predictability of the output, even more flexible back-up capacity is required in order to ensure that peak demand is met during low availability of RES. Therefore, in order to cope with a future resource adequacy problem, many EU-members consider re-design or introduction of additional elements to the current model of energy-only markets.

1.2 The need for capacity mechanisms

Due to the concern that energy-only market alone would not be able to bring forward sufficient capacity required to back up unpredictable RES due to the continuous plant closures and lack of sufficient investment incentives in new capacity, policy makers in several EU-member states are evaluating measures to deal with future resource adequacy problem. There are many ongoing discussions that introduction of capacity remunerative mechanism in addition to energy-only market could be the only safety valve to ensure resource adequacy (Nicolosi, 2012, Brunekreeft et al., 2011). In contrast to energy-only markets, in energy plus capacity markets generators are paid separately for producing electricity and for being available to produce. The aim of the capacity remunerative mechanism is to ensure the profitability of existing power plants and to guarantee or at least support investments in new power plants while restoring "missing money" through filling the gap between fixed cost and inframarginal rents plus scarcity rents received on the energy-only market. Implementation of capacity markets should take into account the specific national market conditions in terms of capacity and flexibility needs and consider possible distortions it might bring along (ACER, 2013). Many questions on proper capacity market design are still unsolved since the current "missing-money" problem in Europe is not simply based on the classical price-cap argument. The recent decline in the generators' profitability is mainly due to excess power generation caused by the growth in RES capacity which, due to their intermittency, still needs conventional backup capacity. The current discussion on capacity markets addresses the issue of how to prevent the continuing closure of flexible peak generators unable to recover their fixed costs due to the decreased load factors and, at the same time, how to ensure that there is enough capacity to back up growing share of RES in the long-term. Postponing decisions on the introduction of capacity markets might lead to further shut downs of peak power plants, which, in case of low demand response, might lead to increased electricity prices and increased hours of power shortages driven by decreased availability of peak generation during high demand and low RES situations in the long-run. Alternatively, increased prices might lead to more demand response and new investments balancing the situation and thus avoiding shortages. Introducing a CRM will allow some or all generators to recover the share of their costs not remunerated through energy-only market. While providing the guaranteed stream of revenue in the form of capacity payments for being available to meet the peak demand, capacity markets provide security of supply of the power system, but might discourage demand response and new interconnector investments thus leading to lower security of supply until demand side resources and interconnectors can participate in CRMs.

1.3 Capacity mechanisms and the Internal Electricity Market

Europe aims at the Internal Electricity Market (IEM): achieving the single market for electricity is a key part of EU 2020 strategy. Market integration is expected to create values such as benefits for consumers through lower prices, and security of supply through more efficient use of supply resources. The first one is expected to result in increased social welfare, and the latter one is becoming more and more important with high penetration of RES.

However, the idea of a single European electricity market may be conflicting with the fact that market design decision are mainly with the single member states and are weakly harmonized on the European level (European Commission, 2013a,b).

The increased penetration of RES has reinforced the debate on generation adequacy in energy-only markets. An increasing number of countries in Europe plan to establish different forms of capacity remunerative mechanisms (CRMs) to sustain the security of supply. The introduction of CRMs may change the value of cross-border trade, and cause inefficiencies in cross-border flows and underutilization of cross-border lines, thus having an impact on the distribution of welfare amongst consumers and producers. There are also other concerns about possible distortions that capacity markets can bring to normal operation of markets such as merit order effects, and impacts on investment signals.

Capacity mechanisms affect both short-term pricing and long-term investments. The impact of CRMs on cross-border trade depends on the degree of market integration, the correlation of scarcity situations and the design of the CRM. In the short-term, CRMs may lead to cross-border effects if regulation directly affects bidding behaviour or market pricing on the energy-only market. Moreover, CRMs may in the long-run have impacts on investment decisions and thus long-term generation mix, electricity prices, and cross-border electricity trade. Dampened energy prices due to the introduction of CRMs may be exported to a neighbouring energy-only market, damping the incomes of the generators which not receive capacity payments (ACER, 2013). It may thereby force decommissioning of existing power plants and decline investments in generation in neighbouring energy-only markets. The pros and cons of capacity mechanisms are fairly well analyzed on national levels, but the issues of cross-border effects within a European market that is heading for a stronger integration, has yet received little attention. The focus of our study is exactly on these spillover effects.

There are few real-life examples of the interaction of energy-only and CRM markets: PJM and the Midwest ISO control areas in the US, Ireland and Great Britain, and Russia and the Nordic market. Inefficient cross-border flows have been observed in all the above cases. Experience in these markets exemplifies how challenging the integration of electricity markets with different market designs can be.

CRMs can have several cross-border effects:

- *Price effects*. Significant decrease in super peak and peak prices. Capacity markets typically aim to reduce peak prices by replacing the sole energy-based remuneration of generators with two-part payments consisting of an energy-based payment and a capacity-based payment.
- *Capacity effects*. Even those forms of capacity mechanisms that do not directly influence the domestic price mechanism, may have an indirect capacity effect by inducing more investments that affect the merit order, and hence energy prices. Furthermore, generation investments may concentrate in regions that have CRMs instead of regions where they would otherwise occur.
- *Welfare effects*. In case of positive externalities, the introduction of capacity markets involves a "free-riding" effect. Consumers in the country with a capacity market may pay for an increase in generation capacity that partly leaks to the neighbouring energy-only market. Given the integration of markets via market coupling, consumers in the energy-only market may act as "free-riders", since they benefit from an increase of reliability and lower energy prices without having to pay for the additional capacity. In this case, consumers in the CRM market experience a welfare loss. On the other hand, CRMs may also incur negative externalities. A reduction of price spikes in the CRM market limits the export prospects of the neighbouring energy-only market. Generators now depend on domestic price spikes, which may cause or aggravate the "missing money problem". In other words, a capacity market in one country may partly "export" the missing money problem to the neighbouring country, forcing it to change its own market design.
- *Infrastructure investment*. CRMs can distort investments incentives to build new interconnectors because the prospects for cross-border trade may appear less promising thus meaning lower congestion rent income for the interconnector owners (TSOs).

The remainder of this report is structured as follows. Section 2 describes two basic capacity mechanisms which have gained much attention in the European debate on market designs. Section 3 describes the two-country model which is used to simulate the effects of different capacity mechanisms within markets as well as cross-border. Section 4 defines the "strategic options" both markets have with regard to their market design. Based on these options, welfare and investment effects are simulated and described in section 5. Section 6 concludes.

2 Overview of capacity mechanisms

2.1 Strategic reserve

The goal of strategic reserve is to ensure that a certain amount of reserve capacity is available in addition to the ancillary service capacities contracted by the TSOs to ensure security of supply. The main part of the market remains energy only, while in addition to that a strategic reserve is established to remain available to be used in the day-ahead market in shortage situations. The required volume of strategic reserve is determined and tendered by a central authority, which is typically the transmission system operator (TSO) or the energy market regulator. The TSO does not own the strategic reserve, but rather contracts power plants to provide availability when needed. The total cost for maintaining strategic reserve is collected through grid charges or balancing market charges. Generators selected for strategic reserve are withheld from the spot market and strategic reserve is activated only in scarcity situations. In theory, strategic reserve should be dispatched only when the market price equal to the value of lost load in order not to distort peak prices during shortages and thus investment incentives (Brunekreeft et al., 2011). Strategic reserves are already introduced in Sweden and Finland. However, the reserve is rather small and activated at the most only a few hours per year.

The modified version of the strategic reserve which is under consideration in Germany aims to address a different kind of problem as compared to Sweden. Even though the decision on implementation of the strategic reserve is not yet approved in Germany, German Association of Energy and Water Industries has issued a conceptual Framework for Implementing a Strategic Reserve in Germany (BDEW, 2013). Strategic reserve in Germany is considered as a temporary measure to prevent continuous closure of power plants that are needed as a backup capacity for RES. Therefore, it will be designed to support existing peak power plants to recover their fixed costs which they are unable to recover due to reduced load factors until the plants become again profitable based solely on increasing peak energy prices and balancing market revenues. Strategic reserve will consist of either old power plants that would be otherwise decommissioned or new flexible power plants that will be built for these purposes. Specified amount of strategic reserve is procured through a tendering procedure. The first tendering procedure in Germany is planned for 2016 with the lead-in time of three to six years giving on opportunity to power plants planning to shut down to participate in the procedure. Further, the tendering procedure will be annual with longer lead time in order to give the possibilities for new power plants to participate (BDEW, 2013).

Defining the proper size and dispatch price of the strategic reserve is the crucial element in the design of the strategic reserve. According to the ENTSO-E recommendations, the available reserve margin should be set at 5 per cent of the annual peak load. Information about planned plants closures should be used in order to determine the required volume of reserve capacities (BDEW, 2013). Strategic reserve will be withheld from spot market and will be activated only when the demand cannot be met.

The key issue is to decide the market price at which the reserve is dispatched. If the strategic reserve is dispatched at a price below the average value of lost load it would eliminate scarcity pricing in the spot market and therefore would result in reduced income and investment incentives for generation participating in spot market, which in turn should be compensated by a larger volume of strategic reserve. Thus, the lower the dispatch price the more investments will be suppressed and the larger the reserve needs to be. Figure 3 shows that introduction of the strategic reserve with the dispatch price below the highest market price observed before introduction of strategic reserve eliminates scarcity pricing. Consequently, generators outside the reserve miss their peak revenues. The loss of peak revenues in turn can be compensated by adjusting the volume of the strategic reserve under a certain dispatch price in a way that generators outside the strategic reserve restore their missing peak revenues. The lower the dispatch price, the bigger the share of lost scarcity revenues, the bigger the volume of strategic reserve consequently (Brunekreeft et al, 2011).

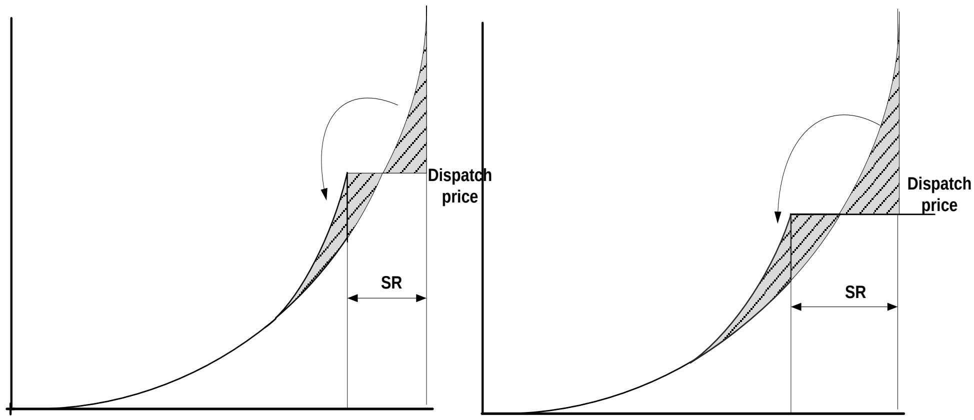

Figure 3. Effect of strategic reserve on price formation in the spot market.

Due to the uncertainties of the impact of strategic reserve on spot market and investment decisions, it is very difficult to estimate the required volume of the strategic reserve under a given dispatch price which will exactly fill the gap between the existing volume of generation and the desired volume of generation. However, the volume of the reserve and the activation rules can be adjusted to market developments.

2.2 Reliability options

Reliability options are a comprehensive capacity mechanism which covers total generation capacity in the market. The optimal (target) level of capacity is provided for by an auction process. Unlike a strategic reserve, however, the auction is not physical but only financial by means of call options. The TSO purchases call options (reliability contracts) from generators on behalf of consumers. The volume of reliability contracts should be equal to the forecasted peak demand plus the reserve margin. Generators submit their capacity bids to the auction, stating the volume of capacity they want to sell and the price. The auction is cleared and all accepted generators receive the price of the last accepted bid in case of the uniform auction, or each generator receives the price of its bid in case of the 'pay as bid' auction. All generators accepted at the auction are obliged to guarantee their availability; non availability is penalized when the option is called (de Vries et al., 2004; de Vries, 2007; Bidwell, 2005). The TSO or regulator sets the strike price on the energy market slightly higher than the marginal cost of the most expensive unit in the system in order not to discourage other generators in the system from producing. Both producers and consumers are hedged against price spikes, though in the opposite direction. The missing money problem is solved, as peak generators do no longer subject to risky price spikes in the market, but receive reliable capacity payments to cover (part of) their fixed cost. Whenever the price in the energy market becomes higher than the strike price, generators that have been accepted in the capacity auction must pay the difference between the actual price and strike price for each MW sold in capacity auctions to the TSO and indirectly to consumers (Vázquez et al., 2004). Generators´ loss of peak revenues above the strike price is now compensated by a more stable and predictable premium received by selling reliability options. The size of the reliability option premium depends on generator´s loss of revenues after setting a certain strike price on spot market.

Figure 4 illustrates the possible impact of an RO mechanism on the spot market. The strike price is set on the energy market at the level of marginal cost of the most expensive power unit in the system. In the energy-only market, strategic bidding of generators (when prices are not aligned with marginal costs) is observed during shortage of supply situations in this theoretical example. Setting the strike price on the spot market at the highest marginal cost of the most expensive unit in the system might incentivize generators to bid their true marginal cost or, at least, to reduce their mark-ups on marginal cost. On the left figure, the market price after the introduction of RO is lower than the market price before RO. The generators will try to compensate inframarginal rents lost after introduction of RO and needed to cover fixed costs though option premiums in capacity auctions. On the right figure, generators prefer not to change their bidding behaviour after the introduction of RO. In this case, the market price is above the strike price, and therefore generators that were accepted in the capacity auction are obliged to refund the difference between the market price and the strike price for each MW sold in the capacity market. However, the loss of inframarginal rents is lower compared to the loss made on the left figure. Thus, the size of the reliability option premium depends on generator´s loss of revenues after setting a certain strike price on spot market.

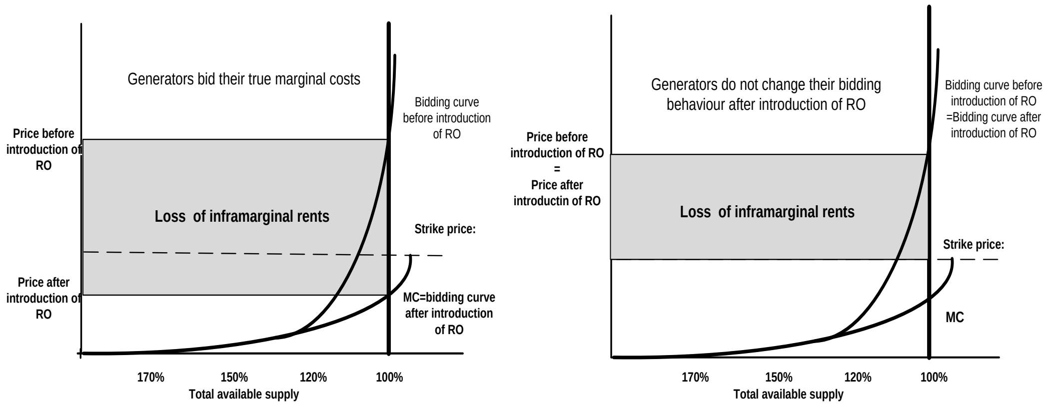

Figure 4. Impact of reliability options on the spot market with inelastic demand

3 Modelling the impact of capacity mechanisms

3.1 Modelling approach

The aim of this project is to analyze the effects of different capacity remunerative mechanisms (CRMs) on welfare, prices, trade and investment incentives for generation and interconnector capacity. The focus will be on cross-border effects between integrated markets as it is typical for the European situation.

The model analyzes two interconnected electricity markets 1 and 2. Both markets are presented with their supply and load duration curves. Markets are connected via implicit auctions (market coupling), i.e. electricity and interconnection prices are determined simultaneously.

We will start our analysis with the status quo, where both markets are assumed to be energy-only markets. In the short-run equilibrium we assume generation adequacy (there is enough available generation to cover the peak load) for both markets, which appears to be a realistic setting for most European markets at the moment. However, in some market regions there is reason to doubt whether generation adequacy is sustainable in the long-run under energy-only markets. For this reason, we will assume a certain degree of "missing money" problem as a result of too rare or limited price spikes at peak demand levels. Hence, a certain volume of peak load generators in both markets is lacking the scarcity revenues needed to cover their fixed cost so that capacity will be reduced in the long run unless a capacity market is implemented.

In order to avoid the resource adequacy problem, we assume that both markets consider the implementation of a capacity mechanism to tackle the risk of insufficient generation capacity caused by the missing-money-problem in energy-only markets. One option is a strategic reserve, and the other option is a reliability option mechanisms. For the analysis we use a game-theoretic approach from the national policymakers' points of view. Given that both countries decide on their own whether or not to implement a capacity mechanisms, we end up with a 2x2-matrix of political strategies for each capacity mechanism. Based on the results of these four matrix cells, we find the Nash Equilibrium(s) and welfare effects for both markets and in total.

The aim of this study is to evaluate the cross-border effects of capacity mechanisms for interconnected markets. We will analyze two capacity mechanisms described in section 2 as alternatives to an energy-only market. We do not aim not analyze the relevance or magnitude of the missing-money problem itself; the focus is on the strategic interaction between the countries' welfare if one of the other country decides to implement a capacity mechanism.

3.2 Modelling supply

Electricity supply in both markets is characterized by the merit order which determines the order of dispatch of generation units from the lowest to the highest marginal supply bids. For the analysis we assume two asymmetric markets which differ in their marginal cost. Market 1 is supposed to have strictly lower marginal cost than market 2, i.e. market 1 represents the exporting country. An explanation for the cost differences may be different fuel prices, taxes or shares of renewable generation which is associated with low marginal cost. Without loss of generality we will assume both countries to have the same amount of available capacity in the initial situation, which is K_1=K_2=100 GW. However, these amounts of capacity only apply to the short-term equilibrium.

Marginal cost curves are described by an exponential function which slightly increases in generation output to account for the fact that peak generators face higher marginal cost than base load units (see e.g. Takashima et al., 2007).

We explicitly distinguish between the marginal bid curves and the marginal cost curves. We allow for supply bids above marginal cost, i.e. depending on relative scarcity of capacity, generators may be able to add a mark-up on their marginal generation cost to raise additional revenues for fixed cost recovery. From empirical observations of electricity markets we know that the merit order is typically flat for low output levels and increases strongly at high output levels when generation capacity in the market is scarce due to the need of much more expensive fuels and plant start-up costs. The dependence of price mark-ups on demand level has been implemented empirically by the concept of the "residual supply index" (RSI) developed by the California Independent System Operator (CAISO, 2004).[1] We basically follow this concept by modelling a mark-up on marginal cost which is an exponential function of the relative availability of capacity (the ratio of the current output and total available generation capacity or scarcity ratio).

The modelling details and the parameters for scarcity mark-ups are given in Annex 1. Figure 5 shows the marginal cost and supply curve for market 1. Figure 6 illustrates the supply curves for both markets for given capacity constraints.

[1] See Green and Newbery (1992) and Newbery (1998) for a theoretical foundation and application of this concept to electricity spot markets.

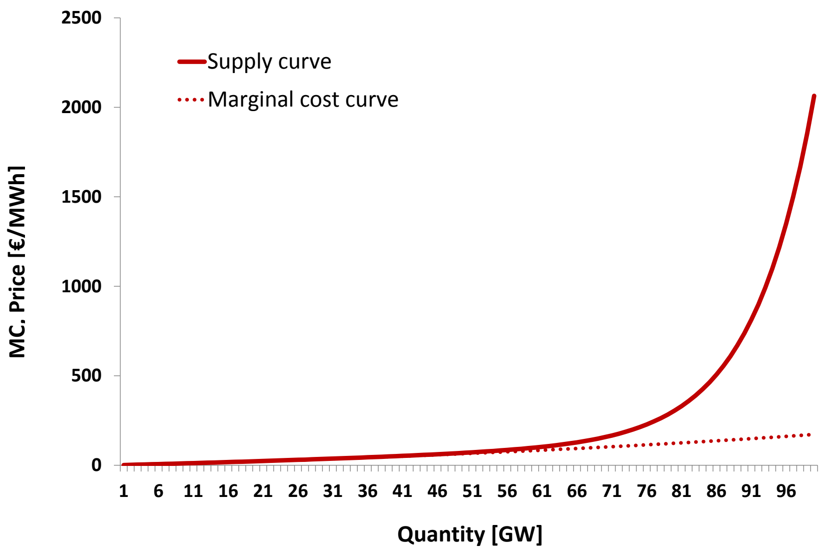

Figure 5. Marginal cost and bid curve for market 1

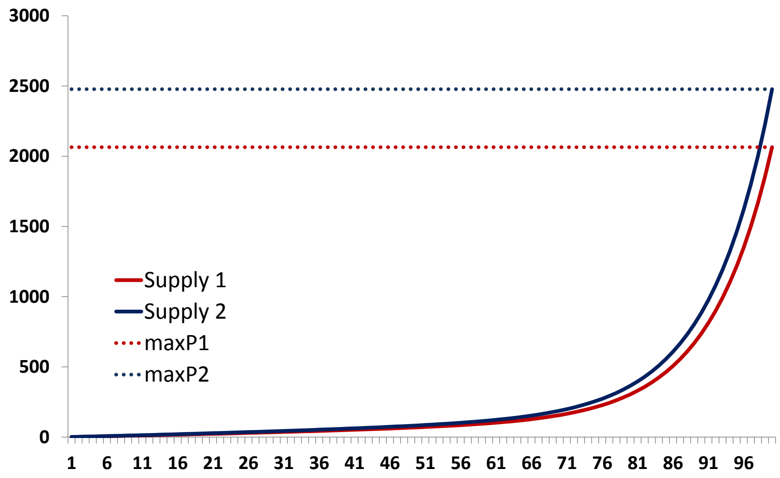

Figure 6. Marginal bid curves for market 1 and market 2

3.3 Modelling demand

We assume that demand is price inelastic. Variation of demand over time is defined by a load duration curve which is assumed to be the same for both markets. To simplify the model and focus on the impacts of market design we assume that the demand level is the same in each moment. In other words, we neglect differences in stochastic variations between the two markets. We are aware of the fact that by neglecting the stochastic feed-in of RES we disregard an important argument for the missing-money problem. However, the focus of this study is not to explain or evaluate the missing-money effect, but to measure the impact of market design options given that there is a certain degree of missing money in the energy-only market. The modelling procedure for the missing-money problem is outlined below in section 4.1.

Load is supposed to vary between a given minimum and maximum values. Minimum demand is assumed to be 20 GW, while maximum demand (peak load) is 100 GW. Hence, we assume that in the initial equilibrium (reference case) peak demand in both markets can be met by total available capacities.

We use an exponential function to model the load duration curve. The parameters of load duration curve are given in Annex 2. Figure 7 illustrates the load duration curve graphically for two different shape parameters.[2]

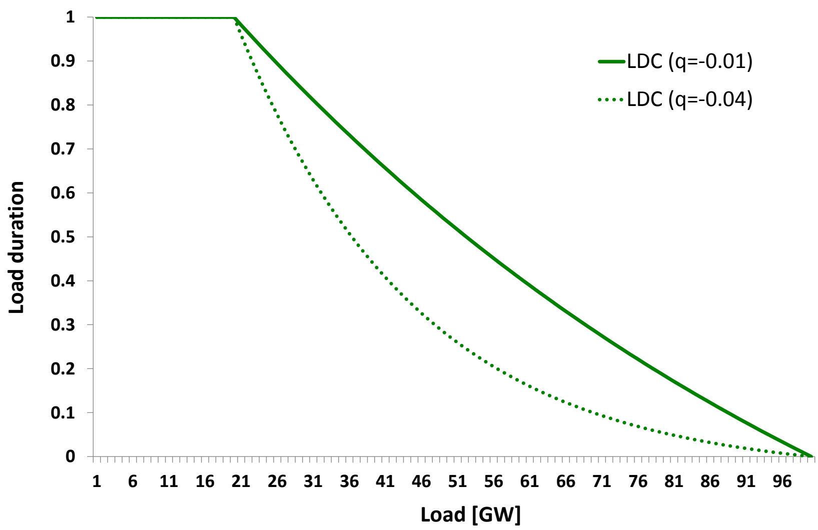

Figure 7. Load duration curve

3.4 Cross-border trade

Both markets are integrated and connected via interconnection with a given capacity. The interconnection constraint is denoted by IC. The interconnection capacity (IC) is assumed to be 5 GW which appears to be sufficient large to allow for a full price convergence for any demand level in the absence of any generation constraints.

For the trade arrangement we assume market coupling, i.e. there is an implicit auctioning of both electricity and interconnection capacity. The

[2] For the analysis we use a flat load duration curve (with q= – 0.01) to give a stronger probability for peak load situations which are the focus of our analysis. As sensitivity analysis shows, the curvature has an influence on the quantitative strengths of our model results but is does not change the overall picture.

auctioneer combines supply and demand side bids of both markets and optimizes trade for given interconnection constraint. If IC is not binding, prices in both markets will fully converge as in a single market. In case of constrained exports, however, prices will remain different and a congestion price equal to the price difference will be charged per MWh of trade for the use of the interconnection. We assume that connection charges will be split equally between the (network operators of the) two markets. The algorithm of market coupling optimization is given in Annex 3.

Market coupling optimization yields the optimal production, dispatch schedule and equilibrium prices for both markets for any given demand level. Further, we simulate producer surpluses representing producers` benefit from selling the output at a market price that is higher that the marginal cost of production, consumer surpluses representing the benefit from buying energy at a market price lower than consumers` willingness to pay. The aim of the model is to simulate the market results for the two countries as described by the parameters above. This is done by repeatedly solving the market coupling optimization for the full range of demand levels. The resulting values for production, trade, prices and surpluses are summed up for one year, i.e. 8760 hours, weighted by the respective number of hours that each demand level persists. While the load duration curve remains the same over time, the available generation capacities, K_1 and K_2, will change depending on investments or disinvestments made in both markets.

4 Market design options

4.1 Energy-only market

Short-run equilibrium

For the initial market equilibrium we assume two energy-only markets which are characterized by total available generation capacities of 100 GW, which is equal to the highest peak load according to the load duration curve.

According to our assumption, market 1 has lower marginal cost than market 2. Hence, for the initial capacity constraints, market 1 is the exporting country. Figure 8 illustrates the short-term equilibrium graphically for a given demand level. The green vertical line (D) shows the demand level which is assumed to be price inelastic and equal for both markets. The supply curve is given by S, the marginal cost curve by MC. The black solid lines (Q) give the production values, while total available capacity is shown by the dashed vertical lines. The prices are indicated by the dotted horizontal lines.

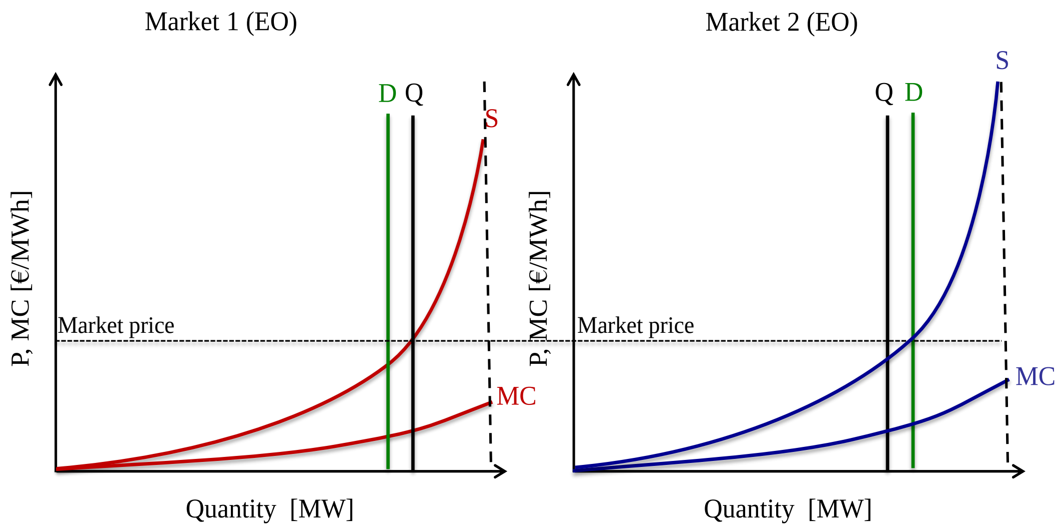

Figure 8. Short-run equilibrium for EO-EO case for given load

Long-run investment equilibrium (reference case)

The short-term situation above defines the status quo of energy markets. However, we assume a certain degree of missing money which will result in a shortfall of generation capacity in the long-run if both countries decide to stay energy-only. This long-term scenario will be denoted as the "EO-EO" case and provides the reference case for our analysis.

Our missing-money assumption is simple: we define a "reference generator" which is assumed to be the last generator in the merit order which is able to recover its total cost in the energy-only market. This reference (zero-profit) generator in both markets is assumed to be at 95 GW in the merit-order, while the remaining 5 GW of generation suffers from a shortfall of revenues.[3] From the zero-profit assumption for the reference generator, we can derive the fixed cost of this peak load generator, which is then equal to the inframarginal rents is receives in the market. For simplicity, we assume these fixed costs to be approximately the same for all peak load units, so we can derive the long-term investment equilibrium.

The equilibrium condition is that the last generator in the new merit order will earn zero profits in both markets, respectively. While the marginal and fixed costs are given, the revenues have to be calculated based on the load duration curve (see Annex 4). Since the supply curve shifts upwards as soon as some generators leave the market, the equilibrium capacities will be higher than the 95 GW, where the zero-profit line was drawn in the short run. We end up with a capacity of K_1=96.2 GW and K_2=97.1 GW, respectively. Figure 9 illustrates the long-run (investment) equilibrium for the energy-only case.

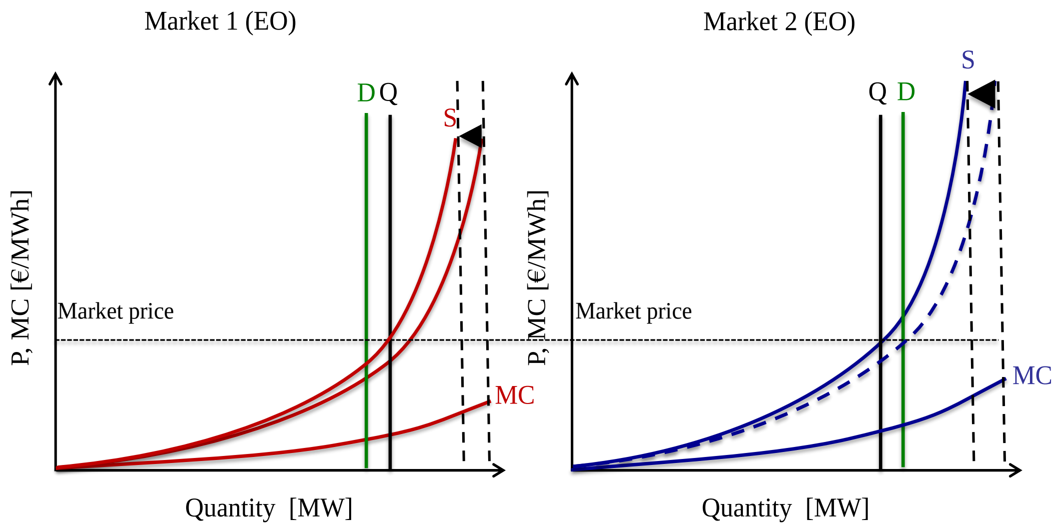

Figure 9. Long-run equilibrium for EO-EO case

The detailed results for this long-term "EO-EO" market equilibrium will serve as the reference case for the evaluation of capacity mechanisms in the following two sections. Obviously, the assumption on the magnitude of the missing-money problem is critical for the relative benefits of a capacity mechanism compared to an energy-only solution. However, our focus is mainly on the qualitative effects of capacity mechanisms, while quantitative effects are only presented for illustrative reasons. Nevertheless, we will critically discuss the missing-money assumption in the analysis below.

[3] Note that we do not specify in detail, why the scarcity prices for the remaining generators would not increase accordingly in order to allow for full cost recovery. Instead we leave the question open, whether this market failure is due to investment risks, regulatory risks or implicit or explicit price caps in the market (see e.g. Joskow, 2006 for a discussion).

4.2 Strategic reserve

In modelling strategic reserve we follow the idea that some of the peak load generators may not be able to cover their costs in the energy-only market and will therefore be centrally acquired (typically by an auction) and dispatched by a non-market authority (see e.g. Brunekreeft et al., 2011). Hence, a SR is a selective capacity mechanism in which only a certain amount of capacity units receives both capacity payments (for fixed cost recovery) and energy payments (to cover marginal costs for actual dispatch). As it was discussed in chapter 2.1, for a SR there is a critical relationship between the dispatch price and the size of the reserve market. Since the reserves are dispatched when the market price is equal to the dispatch price, the latter basically functions as a price cap on the market. If the dispatch price is too low it might distort investment invectives and result in a larger required reserve to ensure generation adequacy. Finding the optimal size for the reserve market may be difficult in practice, given that both investment incentives and the future development of peak demand are uncertain. We neglect this difficulty in our model, and focus on the systematic effects. Given that peak demand is known to be 100 GW in our model, we define the target capacity to be also 100 GW. Hence, the size of the SR in both markets results as the difference between 100 GW and the amounts of capacity which remain in the energy-only markets in the long run. As mentioned in the last section, the investment equilibrium for the energy-only case ("EO-EO") is K_1=96.2 GW and K_2=97.1 GW. Hence, in case of implementation of a SR, the optimal size would be SR_1=3.8 GW and SR_2=2.9 GW for market 1 and market 2, respectively.

The lowest efficient dispatch price in our model therefore results by the highest energy-only peak price that occurs in the long run after some peak units have left the market. These dispatch prices are PD_1=1,943 €/MWh and PD_2=2,366 €/MWh for both markets, respectively. In other words, these are the lowest dispatch prices to avoid a further market distortion. Setting a higher dispatch price would not do any harm, but neither would it induce additional investment incentives given our assumption that the missing-money problem is caused by a shortfall of peak prices in the energy-only market.

For our analysis we therefore assume that a SR does not prevent the regular market to decline in the same way it would in an energy-only market design. It will, however, provide the additional capacity units through the acquisition of reserves, i.e. it prevents the purchase bid curtailments in the day-ahead market that might otherwise occur in the long run.

Figure 10 illustrates the market equilibrium for a given load in case that only market 1 introduces a SR, while market 2 stays energy only ("SR-EO"). The investment incentives are basically modelled in the same way as for the energy-only markets. The difference is that in case of a SR, the last generator always receives the dispatch price during its hours of operation.

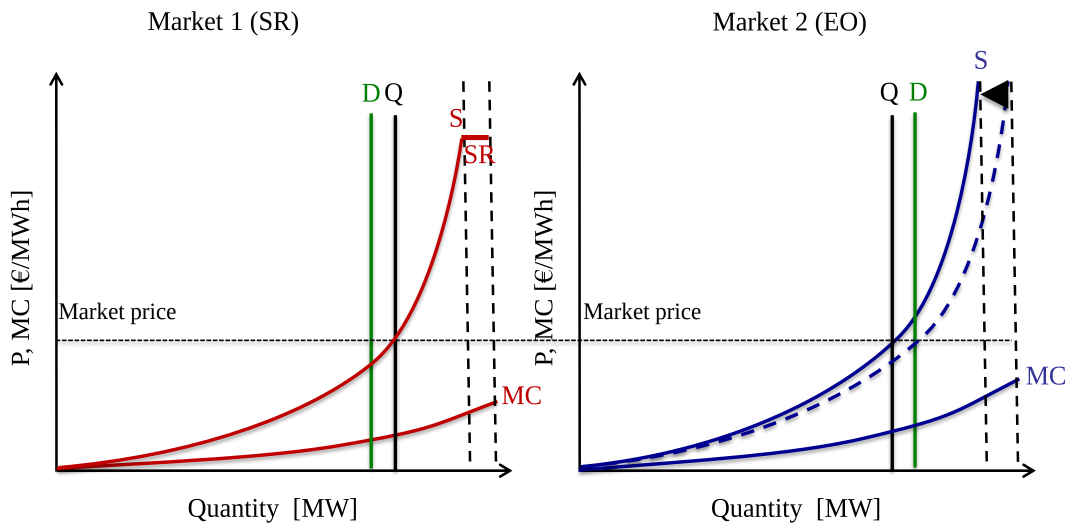

Figure 10. Long-run equilibrium for SR-EO case for given loa

4.3 Reliability options

The TSO tenders option contracts from generators for the optimal level of capacity, which in case of this study would be considered to be 100 GW. These options define the "strike price" at which generators are willing to sell electricity to consumers in exchange for the option premium they receive in the auction. For our model, we assume a strike price of 300 €/MW. The option premium represents the capacity payments, while the strike price acts as a price cap on energy payments in the domestic electricity market (see section 2.2). Whenever the market price exceeds the strike price, the auctioneer (acting in the consumers' interest) calls the option and thereby commits the involved generators to provide electricity physically or financially at the determined strike price. Assuming a financial obligation, generators can sell their electricity at the actual market price and refund the difference between the market prices and the strike price for each MW sold to consumers, when the reliability option is called. Figure 11 illustrates the principle for market 1 for a strike price of 300 €/MWh.

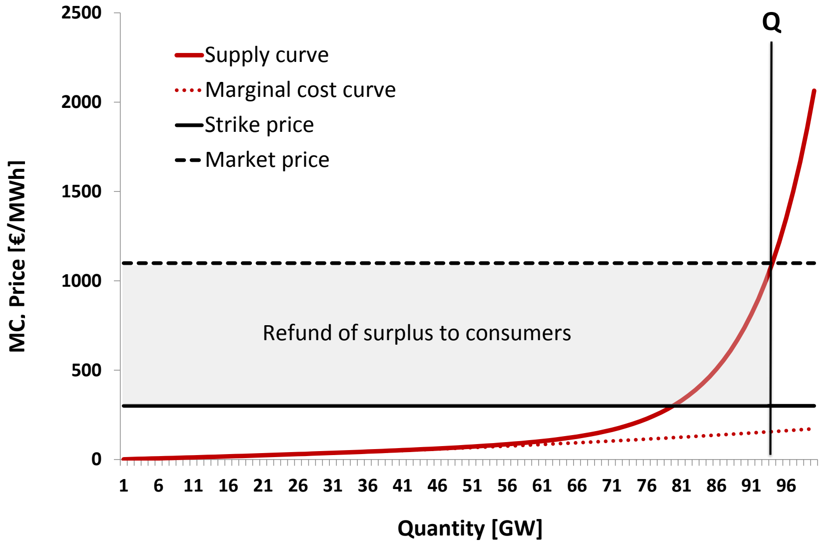

Figure 11. Mechanism of reliability options

Both producers and consumers are hedged against price spikes, though in the opposite direction. The missing money problem is solved, as peak generators do no longer subject to risky price spikes in the market, but receive reliable capacity payments to cover (part of) their fixed cost.

The capacity payments are determined in the auction process which we assume to rely on competitive and truthful cost bids. Our best guess for these payments is that they cover the difference between the producer surplus due to the implementation of reliability options, i.e. generators would ask for an option premium that compensates them for the refund to consumers they are obliged to by the expected call of these options. However, this estimation has to be corrected for those generation units that would leave the market in the case of energy-only markets. If the target capacity is 100 GW, we need an assumption for the capacity bids of the "missing-money-generators". Given our information on marginal costs and our assumption about the peak generators' fixed cost, we make the conservative assumption that the capacity payments at least guarantee zero profits for these peakers. The fact that the target level of capacity is part of the market, we do not have to make further assumptions about cost of new entry (CONE) which would apply to new investments.

The capacity payments themselves only have a distributive effect between producers and consumers. The important question, however, is how the bidding strategy on the market will change through the implementation of the RO mechanism. Two border cases are possible. One assumption might be that the market bidding remains the same, thus following the same supply curve which applies to the energy only market. The net revenue of generators for domestic supply would not change in cases when the reliability options are called; it remains to be the strike price multiplied by electricity sales. A second assumption could be that the generators' market bids will be lowered to marginal cost. This would require that the option premiums gained in the

RO auction are high enough to cover all of the fixed costs to that the fact that generators do no longer depend on mark-ups will shift the competitive pressure fully to the electricity market. Neither of these border cases seems likely, so the "truth" is probably in between. But without an explicit modelling of strategic behaviour of firms it is difficult to say how the new supply curve will look like. We therefore consider both "mark-up-bidding" and "marginal-cost-bidding" to compare the differences and find an indication for the most probable effect of the RO mechanism.

5 Results

5.1 Strategic reserve

Figure 12 shows the aggregated welfare effects for both markets and in total for all four market design strategies. The values are the differences to the reference case "EO-EO", which is the "do-nothing" scenario in which both markets stay energy only. Table 1 shows the welfare and investment effects for the policy combinations, also as differences to the reference case.

Producer and consumer surpluses are corrected for the capacity and energy payments in case a SR is implemented. We assume that reserve generators receive their fixed cost as capacity payments, and their marginal cost as energy payments. Hence, we implicitly assume a competitive and truthful bidding in the capacity auction. Note that this may not be guaranteed in practice due to asymmetric information and strategic behaviour of bidders. Accordingly, we neglect additional distortions and distributive effects that may occur in the capacity auction.[4]

[4] On the issues of auction design for a strategic reserve see e.g. Brunekreeft et al., 2013.

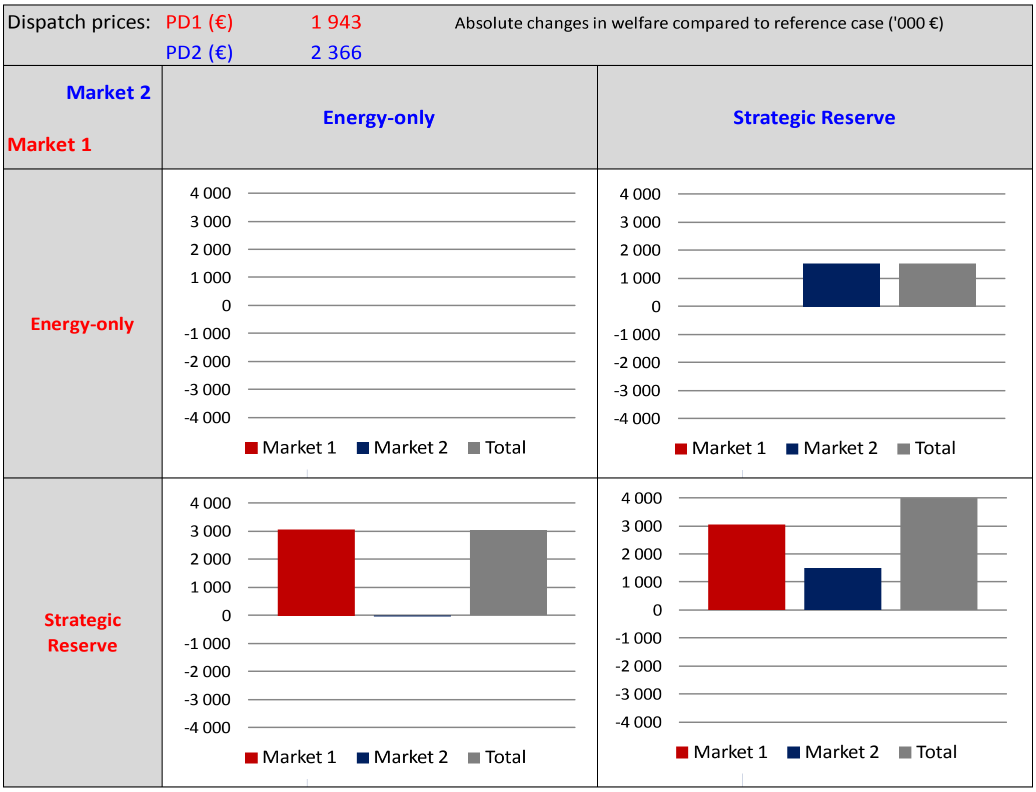

Figure 12. Strategy matrix with welfare effects for SR

Table 1. Welfare and investment effects of a SR

PD1 (€) 1 943 PD2 (€) 2 366		Absolute changes compared to reference case			
	Market 1 Market 2	Cases EO EO	SR EO	EO SR	SR SR
Market 1					
Producer Surplus 1	'000 €	0	1 395	0	1 395
Consumer Surplus 1	'000 €	0	1 660	0	1 660
Capacity Payments 1	'000 €	0	1 395	0	1 395
Total Welfare 1	**'000 €**	**0**	**3 055**	**0**	**3 055**
Market capacity 1	GW	0,0	0,0	0,0	0,0
Strategic Reserve 1	GW	0,0	3,8	0,0	3,8
Total capacity 1	**GW**	**0,0**	**3,8**	**0,0**	**3,8**
Energy not supplied 1	GWh	0	-379	0	-379
Market 2					
Producer Surplus 2	'000 €	0	-239	874	635
Consumer Surplus 2	'000 €	0	218	645	863
Capacity Payments 2	'000 €	0	0	874	874
Total Welfare 2	**'000 €**	**0**	**-21**	**1 519**	**1 499**
Market capacity 2	GW	0,0	0,0	0,0	0,0
Strategic Reserve 2	GW	0,0	0,0	2,9	2,9
Total capacity 2	**GW**	**0,0**	**0,0**	**2,9**	**2,9**
Energy not supplied 2	GWh	0	0	-199	-199
Both Markets					
Total trade	GWh	0	-9	0	-9
Total Welfare	**'000 €**	**0**	**3 032**	**1 519**	**4 551**

With an assumption of no demand response, from an aggregate welfare perspective, all policy options are welfare improving compared to the energy-only reference case. If both markets aim to maximize their total welfare, we find one Nash Equilibrium "SR-SR" which also appears to be welfare maximizing from an aggregate point of view.

If market 2 decides to stay energy-only, while market 1 opts for a SR, we have cross-border effects. As column 2 in Table 1 shows, the volume of trade has decreased in case of "SR-EO" (-9GWh). The reason is that the dispatch of reserves in market 1 replaces the imports from market 2. In the reference "EO-EO" case there is a reversal of trade (market 1 imports from market 2) when market 1 is at full capacity, but market 2 can still export because of higher available capacity in market 2 than in market 1. But in case of "SR-EO", it is cheaper for market 1 to dispatch SR than imports from market 2, because the dispatch price is lower than the highest import price. It has negative effects on market 2: the welfare in market 2 decreased compared to the reference case (-21mln. €). The crowding out of imports can be avoided by changing the dispatch rules, for instance if SR in market 1 is triggered only when the capacity limit is reached in market 1 and there is no import available from market 2. In this case no cross-border effects would occur, but the question is why consumers in market 1 have to buy more expensive import from market 2 if they can use cheaper strategic reserve instead?

If market 1 decides to stay energy-only, while market 2 opts for a SR, there appear to be no cross-border effects for market 1. The reason is that the SR in market 2 is dispatched outside of the regular market and does neither influence trade nor investment incentives in market 1 compared to the energy-only case. There is no import replacement by SR which was the case of "SR-EO", because the dispatch price for SR in market 2 is higher than the maximum import price.

To conclude, the direction of trade appears to be important for cross-border effects. Given the uncertainty about how severe the missing money problem is, the most important task is not to under- or overestimate the generation adequacy problem. A coordination of market design policies is advisable in order to avoid trade distortions that countervail the European Internal Market for Electricity.

5.2 Reliability options

Figure 13 shows the welfare effects for the four strategy combinations of reliability options versus energy-only market. Table 4 shows the welfare and investment effects for the policy combinations. Again, all values are in differences to the reference case.

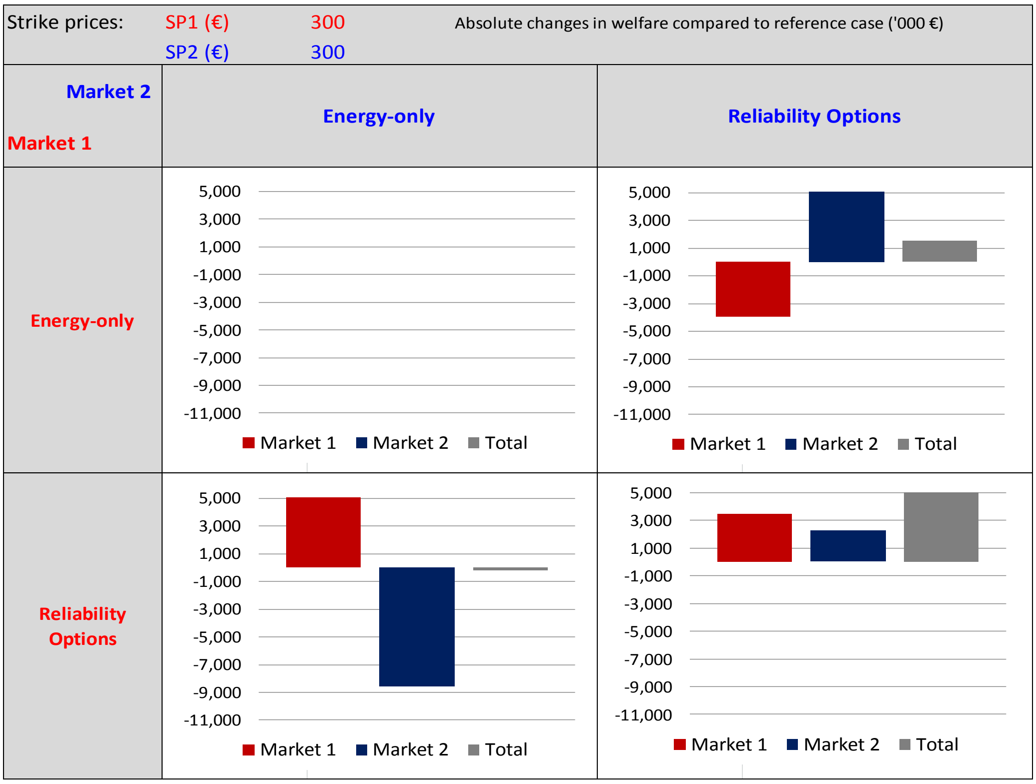

Figure 13. Strategy matrix with welfare effects for RO with "mark-up-bidding"

Table 2. Welfare and investment effects of a RO with "mark-up-bidding"

Strike price 1 (€)	300	Absolute changes compared to reference case			
Strike price 2 (€)	300				
		Cases			
	Market 1	**EO**	**RO**	**EO**	**RO**
	Market 2	**EO**	**EO**	**RO**	**RO**
Market 1					
Producer Surplus 1	'000 €	0	-27,527	-7,297	-27,527
Consumer Surplus 1	'000 €	0	35,907	3,357	30,974
Capacity Payments 1	'000 €	0	84,143	0	91,233
Total Welfare 1	**'000 €**	**0**	**8,381**	**-3,941**	**3,447**
Total capacity 1	GW	0	4	-2	4
Energy not supplied 1	GWh	0	-379	86	-379
Market 2					
Producer Surplus 2	'000 €	0	-8,606	-39,092	-39,092
Consumer Surplus 2	'000 €	0	54	44,573	41,349
Capacity Payments 2	'000 €	0	0	83,733	89,076
Total Welfare 2	**'000 €**	**0**	**-8,552**	**5,482**	**2,257**
Total capacity 2	GW	0	-4	3	3
Energy not supplied 2	GWh	0	410	-199	-199
Both Markets					
Total trade	GWh	0	9,286	-859	2,012
Total Welfare	**'000 €**	**0**	**-171**	**1,541**	**5,705**

Two observations are striking. First, a unilateral implementation of RO has a negative effect on the neighbouring market. By holding the former “missing-money-generators” in the market, exports in times of peak demand from these units will increase so that producer surplus in the other market will be significantly reduced. In other words: introducing reliability options in one market worsens the missing-money problem in the other market so that, compared to the “EO-EO” case, more peak generators will be pushed out of the market.

The second observation is that the overall welfare effect in case of two RO-markets is welfare improving. This appears to be the Nash Equilibrium in our simulation. From an aggregate point of view, the reliability option mechanism is an efficient solution for the missing-money problem. Compared to a strategic reserve, this capacity mechanism avoids an out-of-market dispatch of generators. However, reliability options have other big risks with more money channelled through ROs instead of the energy market. Table 2 shows that total trade between both markets increases in the “RO-RO”-equilibrium, while it is reduced in case of “SR-SR”-equilibrium. The problem of these central reserve units is that they may replace the import if SR is more efficient option to cover demand. It will of course depend on the dispatch rules for SRs, which in practice can be different from those we modelled.

An alternative model assumption for the supply curve is that generators may alter their bidding behaviour if reliability options are implemented. This may happen, if the capacity payments intensify competition in the spot markets. For electricity sales to the domestic market, the maximum price generators can earn is the strike price which is slightly above maximum marginal cost. Thus, lowering bids may increase the volume of sales, while – in case the options are called – the net price does not change. This may incentivize generators to compete more intensively in the market by reducing their own bids.

Table 3 shows the welfare results for the case of “marginal-cost-bidding” in which generators would not charge any mark-ups. Although this is an extreme assumption, it helps to identify the qualitative impacts of such strategic effects.

Table 3. Welfare and investment effects of a RO with "marginal-cost-bidding"

Strike price 1 (€)	300	Absolute changes compared to reference case			
Strike price 2 (€)	300				
		Cases			
	Market 1	EO	RO	EO	RO
	Market 2	EO	EO	RO	RO
Market 1					
Producer Surplus 1	'000 €	0	-27,527	-27,985	-27,527
Consumer Surplus 1	'000 €	0	33,948	14,205	30,560
Capacity Payments 1	'000 €	0	122,176	0	122,546
Total Welfare 1	**'000 €**	**0**	**6,421**	**-13,780**	**3,033**
Total capacity 1	GW	0	4	-6	4
Energy not supplied 1	GWh	0	-379	970	-379
Market 2					
Producer Surplus 2	'000 €	0	-17,528	-39,092	-39,092
Consumer Surplus 2	'000 €	0	8,015	44,609	41,876
Capacity Payments 2	'000 €	0	0	111,444	118,704
Total Welfare 2	**'000 €**	**0**	**-9,513**	**5,517**	**2,784**
Total capacity 2	GW	0	-5	3	3
Energy not supplied 2	GWh	0	710	-199	-199
Both Markets					
Total trade	GWh	0	18,630	8,558	15,075
Total Welfare	**'000 €**	**0**	**-3,092**	**-8,263**	**5,817**

In this case, the negative welfare effects of a unilateral implementation of a RO mechanism appear to be even stronger than in case of usual "mark-up-bidding". The explanation is straightforward. As long as both markets use a mark-up, the effects are mainly distributive between consumers and producers. If mark-ups are lowered in one market but not in the other one, the distortive effects on the dispatch of generation are much stronger which reduces overall welfare. This distortion is only avoided if both markets opt for reliability options so that mark-ups in both markets are reduced. In case of the "RO-RO"-equilibrium, overall welfare increases – even compared to the short-term situation. Obviously, the effect of marginal-cost-bids is that inefficiency in dispatch is fully avoided, which is not the case as long as there are (at least slightly different) mark-ups in the electricity markets. The detailed results in Table 3 confirm this efficiency effect. It shows that the volume of total trade is the highest among all analyzed policy options..

Similar to a SR, however, a coordination of market design policies is important to avoid temporary negative effects cross border.

6 Conclusions and policy implications

A capacity mechanism aims to counteract the so-called "missing-money problem" according to which energy-only markets may not provide sufficient revenues for generators to ensure generation adequacy. We analyse two forms of capacity mechanisms which are discussed or already implemented in electricity markets around the world, namely a strategic reserve (SR) and reliability options (RO). Our analysis focuses on cross-border effects of such mechanisms.

A strategic reserve is a selective mechanism which establishes a centrally dispatched group of reserve units in addition to the energy-only market. Reliability options are a financial mechanism based on call options which apply to total generation capacity which is expected to be needed in the market. Therefore, policy makers need to have good knowledge about the target generation and import capacity which is required to serve the inelastic part of the demand. Furthermore, the costs and benefits of a capacity mechanism obviously depend on whether and to what degree a missing-money problem exists in the electricity markets. Our main research question is what the effects of different capacity mechanisms are if the markets are not autarkic but integrated via trade.

National policy maker would typically base their decision on their own country's welfare, thereby neglecting cross-border effects on their neighbouring countries. Obviously, this is not in the interest of the European Union aiming at a European Internal Market for Electricity. Depending on the cross-border effects of different capacity mechanisms, coordination of market design policies between countries may be required to avoid welfare losses from a European point of view.

The aim of this study is to analyse the strategic interaction between policy makers within a two-country model. We analyse these strategies in a game-theoretic approach. Given that both countries decide unilaterally whether or not to implement a capacity mechanism, we can analyse the welfare and trade effects of the market design options within a 2x2 strategy matrix to investigate whether uncoordinated policy measures lead to welfare losses.

Our main finding is that an uncoordinated, unilateral implementation of a capacity mechanism may have negative welfare effects on the neighbouring market. Notably in case of reliability options, the missing-money problem is further aggravated in the passive market which causes a pressure on this country to change its own market design as well. Hence, there are strong reasons for a coordination of market design policies to avoid at least temporary negative effects on the internal market.

If both markets choose their optimal market design strategy, however, overall welfare effects are positive. Assuming there is a missing money problem and high loss-of-load probability in the energy-only markets, both the strategic reserves and reliability options can help to alleviate the problem.

A strategic reserve modelled as being centrally dispatched outside of the regular market at the fixed dispatch price, tends to have negative cross-border effects while suppressing the import from the neighbouring market if the strategic reserve is triggered by the dispatch price which is below the maximum import price. We would like to stress that cross-border effects of SR are very sensitive to dispatch rules for SR and designs for SRs in practice may differ from our model design and thus their impacts would also differ. Cross-border effects can be avoided by setting dispatch price above the maximum import price or by triggering the strategic reserve only when there is no import available regardless of its price. However, it might reduce consumers´ benefits in market that has SR in case if the strategic reserve is cheaper option than the import.

Reliability options turn out to be one alternative efficient CRM solution. A welfare improvement may be even stronger, if the capacity payments change the bidding behaviour of generators in the direction of marginal-cost bidding. But we note that it is not clear whether the change of bidding strategies reduces inefficiencies in market dispatch. If mark-ups become lower but more "asymmetric", least-cost dispatch of generation is not guaranteed. Furthermore, the negative cross-border effects of a unilateral implementation can be large, and thus may force neighbouring markets also to establish a capacity mechanism. This effect may be a good reason to reach for a coordination of market design policies.

Finally, we should note again that many practical difficulties have not been analysed in this model. As mentioned earlier, information about the dimension of the missing-money problem, strategic bidding and investment behaviour and efficiency of the auction design for capacity may further contribute to the costs and inefficiencies of capacity mechanisms.

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Annex 1: Marginal cost curve estimation

The marginal cost curve for both markets i=1,2 is given by:

$$MC_i = a_i \cdot [\exp(b_i \cdot Q_1) - 1] \tag{1}$$

Mark-up on marginal cost is given by:

$$\frac{(P_i - \mathrm{MC}_i)}{MC_i} = c_i \cdot \exp\left(d \cdot {Q_i}/{K_i}\right) \tag{2}$$

Where (Q_i/K_i) is the relative availability of capacity, i.e. the ratio of the current output level Q_i and total available generation capacity K_i.

Accordingly, the marginal bid curve (supply curve) $P_i(Q_i)$ – is described by:

$$P_i(Q_i) = MC_i(Q_i) \cdot \left[1 + c_i \cdot exp\left(d \cdot {Q_i}/{K_i}\right)\right] \tag{3}$$

or

$$P_i(Q_i) = a_i \cdot exp[\exp(b_i Q_i) - 1] \cdot \left[1 + c_i \cdot exp\left(d \cdot {Q_i}/{K_i}\right)\right] \tag{4}$$

The term in brackets defines the mark-up on marginal cost which depends on the scarcity ratio Q_i/K_i.

Since d>1, this mark-up is only zero for Q_i=0.

Table 4. Parameters for supply functions

Supply Parameters		
	Market 1	**Market 2**
MC		
a	100	120
b	0.01	0.01
Scarcity		
c	0.0005	0.0005
d	10	10
K	100	100

Annex 2: Load duration curve estimation

The load duration curve for both markets is given by:

$$L(D) = p \cdot exp(q \cdot D) + r \tag{5}$$

Table 5. Parameters for the load duration curve (LDC)

LDC parameters	
p	2.22
q	-0.01
r	-0.82

Parameter q defines the shape of the curve, while p and q are used to calibrate the function such that the relevant part of the curve (between 20 GW and 100 GW) varies between 1 and 0, respectively. Hence, the function value L(D) gives the percentage share of hours per year where demand is equal to or lower than D.

Annex 3: Consumer and producer surpluses

The market coupling procedure can be described as a maximization of total welfare which is the sum of producer surplus (PS) and consumer surplus (CS) for both markets subject to the constrains given by generation and interconnection capacity. Market coupling optimization can be stated as:

$$Max\{PS_1 + CS_1 + PS_2 + CS_2\} \tag{6}$$

$$s.t. \quad Q_1 + Q_2 \leq 2 \cdot D_1 \quad \text{(no oversupply)} \tag{6a}$$

$$Q_1 \geq 0;\ Q_2 \geq 0 \quad \text{(non negative outputs)} \tag{6b}$$

$$Q_1 \leq K;\ Q_2 \leq K_2 \quad \text{(generation constraints)} \tag{6c}$$

$$Q_1 \leq IC + D;\ Q_2 \leq IC + D \text{(interconnection constraint)} \tag{6d}$$

with Q_1: generation output in market 1

Q_2: generation output in market 2

K_1: generation capacity constraint (maximum output) in market 1

K_2: generation capacity constraint (maximum output) in market 2

D: demand level (equal for both markets)

IC: interconnection constraint

Producer surplus is calculated as:

$$PS_i \ = P_i(Q_i) \cdot Q_i - \int_0^{Q_i} MC_i\,(q_i)\; dq \tag{7}$$

Where

Using equation (1) this yields:

$$PS_i \ = a_i[\exp(b_i Q_i) - 1]\left[Q_i + c_i exp\left(d_i \frac{Q_i}{K_i}\right) Q_i - \frac{1}{b_i}\right] + a_i Q_i \tag{8}$$

Consumer surplus is typically calculated as

$$CS_i = (Voll - P_i(Q_i) \cdot D,$$

where *Voll* denotes the *value of lost load* which serves as a measure for the marginal (and here also average) willingness to pay for electricity consumption. Empirical studies suggest that the average VOLL is between 8,000 and 12,000 €/MWh (see e.g. de Nooij et al., 2007). We assume a VOLL of 10,000 €/MWh for this study.

More precisely, CS for both markets has to be defined as

$$CS_1 = (Voll - P_1(Q_1) \cdot \min(D; Q_1 - X), and$$

$$CS_2 = (Voll - P_2(Q_2) \cdot \min(D; Q_2 + X).$$

The reason for the use of this minimum function is that there may be cases where demand is not met by domestic supply and imports. This may be due to generation constraints caused by a shortfall of generation capacity as a result of the missing money problem. These cases are not directly implemented in the optimization procedure but they are taken care of in the surplus calculations for the respective scenarios.

Annex 4: Calculation of long-run capacities

In order to calculate the available capacities in the long-run, we have to solve the following system of three equations:

$$[P_1(K_1) - MC_1(K_1)] \cdot L(K_1 - X) \cdot 8760 - FC1_{peak} = 0 \quad \text{(zero-profit 1)} \qquad (9)$$
$$[P_2(K_2) - MC_2(K_2)] \cdot L(K_1 + X) \cdot 8760 - FC2_{peak} = 0 \quad \text{(zero-profit 2)} \qquad (10)$$
$$P_1(K_1) = P_2(K_1 - 2 \cdot X) \quad \text{(price convergence)} \qquad (11)$$

Equations (9) and (10) state the zero-profit conditions for the last generators K_1 and K_2 in the long-run. The first term in both equations defines the revenues net of marginal cost, while the last two terms give the number of hours in which these peak generators are dispatched according to the load duration curve L(D) given by equation (5). In case of lower peak prices in market 1, its last generator produces whenever demand is equal to K1 minus exports to market 2, and vice versa. Equation (11) requires price convergence for exports X. This condition only holds if the interconnection constraint is not binding. Due to the slope of the supply curves at the capacity constraint, this is always the case.