Analysis of Cross-Border Congestion Management Methods for the EU Internal Electricity Market

Study commissioned by the

European Commission

Directorate-General Energy and Transport

Final report

June 2004

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Contents

Abbreviations

AC	Alternating current
CBT	Cross-border tariff
CM	Congestion Management
DACF	Day-ahead congestion forecast
ETSO	(Association of) European Transmission System Operators
EuroPEX	Association of European Power Exchanges
FEBELIEC	Belgian Federation of Large Industrial Energy Consumers
FTR	Financial transmission right
IEM	Internal Electricity Market
Nordel	Organisation för nordiskt elsamarbete (Association of Nordic TSOs)
NTC	Net transfer capacity
PT	Power transfer
PTDF	Power transfer distribution factor
SMP	System marginal price
TSO	Transmission System Operator
UCTE	Union pour la Coordination du Transport de l'Électricité

Executive Summary

Scope and structure of the study

One of the main targets of the liberalisation of the electricity supply sector in the European Union is the creation of a truly Internal Electricity Market (IEM). By introducing competition among generators and suppliers not only in their domestic markets, but also on an international scale the economic efficiency of electricity supply shall be maximised for the benefit of the consumers and the entire economy. However, the transmission system operators (TSOs) have historically not designed the interconnections between their networks with the primary objective of facilitating international power trade. As a consequence, the integration of the national electricity markets is impeded by the limited amount of cross-border transmission capacity at several borders.

To mitigate this problem, the EU supports on the one hand measures to increase the transmission capacities, be it by investment in new network facilities or by optimisation and harmonisation of operating standards that allow to better utilise the networks. On the other hand, the rules applied for managing the utilisation of the *existing* transmission capacities – which can be summarised by the term “cross-border congestion management methods” – are of particular importance for the efficiency of the IEM in the short and medium term.

The congestion management methods that have been established over the recent years are in most cases border-specific and differ significantly from each other. Although case-specific solutions may in principle be justified by particular regional circumstances, the present situation gives rise to the expectation that at least due to this heterogeneity there is some potential for improvements.

Suggestions regarding the further development of cross-border congestion management in the IEM have been made by a number of stakeholders, mostly in the context of the Electricity Regulatory Forum of Florence. In addition, Regulation (EC) No 1228/2003, becoming effective on 1 July 2004, sets out – among other things – a framework of basic requirements to such methods. It also allows for the adoption of binding guidelines in order to harmonise and coordinate the mechanisms to be used.

On this background, the European Commission has commissioned this study with the objective to derive, on the basis of sound scientific analyses, a recommendation as to the optimal design of a cross-border congestion management regime for the IEM. Parallel to the main focus of the recent discussions in this field, the study concentrates on the situation of the Continental European transmission network where the highest potential for improvements is expected. It should be noted that the analyses mainly focus on economic and technical issues, which are the most relevant ones according to the scope of the study. In addition, legal and organisational issues have been mentioned where they appear to be relevant, yet not treated in the same level of detail.

Our analysis has been based on the following **assessment criteria**:

- Compliance with EC Regulation 1228/2003 – A prerequisite for any cross-border congestion management regime to be applied after 1 July 2004 is to be market based and non-discriminatory.
- Economic welfare – Cross-border network access should be managed such as to maximise the total amount of social welfare in the IEM. This implies the maintenance of appropriate network security standards.
- Practical feasibility – Taking into account the present, heterogeneous situation of cross-border network access, especially in Continental Europe, the aim of the study was to describe development steps that can realistically be implemented within the next years.

To ensure a comprehensive and objective treatment of the scope, the investigation had to cover the presently applied congestion management methods as well as the relevant proposed ones, yet without being limited to these. Consequently, in order to be able to on the one hand analyse the entire bandwidth of conceivable methods, but on the other hand allow for a detailed assessment and recommendation of the preferred solution, we have structured our analysis as follows:

- Firstly, we have introduced a generic description of the tasks that are covered by the term "congestion management" and discussed the key features of the capacity allocation methods being presently applied or under consideration for the IEM.
- Next we have analysed the basic options for congestion management from a general perspective, i.e. concentrating on the fundamental capacity allocation principles rather than

design details. This analysis has been complemented by a quantitative evaluation of some of the presently applied capacity allocation procedures.

- For a reduced set of remaining basic congestion management models we have then performed a detailed analysis of a number of design elements that all form part of a comprehensive congestion management regime.

As a consequence of this approach, our conclusions and recommendations pick up a number of elements that also form part of one or several previously published proposals. Notable contributors of such proposals are e.g. ETSO (association of European Transmission System Operators), EuroPEX (Association of European Power Exchanges) and FEBELIEC (Belgian Federation of Large Industrial Energy Consumers). Therefore the recommendations, as the study in total, should not be seen as an attempt to propose a completely new, unique way of managing cross-border congestion. Rather, they represent a consistent combination of individual elements that together make up an economically and technically optimal as well as feasible framework, based on the intention to provide an independent, neutral assessment.

Fundamental conclusions

From our analysis on the suitability of the different **basic mechanisms for transmission capacity allocation** we can conclude that, although a number of mechanisms currently applied or proposed for the IEM can be clearly ruled out, there is not one single optimal solution. Rather, due to the trade-off between economic efficiency and practicability, two options remain for further considerations:

- The economically most efficient mechanism would be an implicit auction, which we propose to be designed as a **hybrid of explicit and implicit auction** for practical and legal feasibility reasons.

- A purely **explicit auction** mechanism is less efficient than an implicit auction because it suffers from the lag between capacity allocation and wholesale energy market clearance, which imposes uncertainty on the network users and offers possibilities to exercise market power. On the other hand, explicit auctions are already widely used in the IEM, and a migration from legacy mechanisms to an explicit auction would not interfere with the design of the national energy markets. In terms of practical feasibility explicit auctions are thus clearly advantageous compared to the hybrid implicit/explicit auction.

In the next phase we have analysed design options for the numerous elements of which a comprehensive congestion management regime consists besides the basic allocation method. The general conclusion from this analysis is that for many elements the preferable design bears no or only little dependency of the decision between explicit or hybrid implicit/explicit auction. This allows for a stepwise improvement of congestion management methods such that early steps do not have to be revised when further developments are introduced. Keeping in mind the criterion of practical feasibility, our principal recommendation is therefore to follow a **two-step approach** as follows:

- We propose to at first **introduce (or continue to apply) explicit auctions**, because a number of substantial improvements compared to the present situation can be achieved without integrating the markets for transmission capacity and wholesale energy. The most fundamental (and probably also most beneficial) of these is the multilateral coordination of capacity allocation across several borders.
- As a further development we recommend to strive for the **implementation of a hybrid implicit/explicit auction**, i.e. implicit cross-border transmission capacity allocation between the regional power exchanges in coexistence with explicit capacity allocation for bilateral contracts. This requires TSOs to allow power exchanges to bid for transmission capacity on behalf of the power exchanges members. The details of the majority of design elements need, however, little or even no adjustment when migrating from the explicit to the hybrid auction.

It should be noted that the proposed separation into two steps is exclusively due to considerations on practicability. In cases where the regional circumstances allow for an immediate introduction of a hybrid implicit/explicit auction this direct approach should be pursued.

The realisation of both steps requires significant changes to some aspects of cross-border congestion management. In order to accelerate the fundamental development towards these approaches, we recommend accepting – at least for a transitional period – suboptimal solutions for some of the other design elements. Hence there remains an area for **fine-tuning** of aspects whose optimal design may yield additional economic welfare, but sorting these should not be allowed to delay or block the introduction and development of the main concepts.

In the following we summarise our detailed conclusions and recommendations for the two development steps as well as some aspects of fine-tuning.

Introduction of a multilaterally coordinated explicit auction

At present, cross-border congestion management in the continental part of the IEM is characterised by bilateral transmission capacity allocation which is performed individually per border and (with the exception of transmission from France to Spain) separated from the energy market. We recommend maintaining the principle of explicit capacity allocation for the time being, but develop the congestion management regime according to the following targets and guidelines:

General organisation

- The allocation of cross-border transmission capacity should be multilaterally coordinated, i.e. transmission rights for any power exchange between several countries for a specific period of time should be allocated simultaneously and by a single entity. This would increase the economic efficiency of the allocation procedure by reducing the uncertainties for the network users. Moreover, multilateral coordination is the prerequisite for the application of a transmission capacity model based on power transfer distribution factors (PTDFs, see below).
- On the one hand the larger the group of participating countries/TSOs becomes, the greater is the benefit from the multilateral coordination. On the other hand even a group of only a few adjacent TSOs can improve the efficiency of capacity allocation (and thus increase social welfare) by coordination. We therefore recommend encouraging the formation of "pilot regions" for the introduction of multilaterally coordinated capacity allocation.
- As the uniform basic method for capacity allocation we recommend explicit auctions.
- The introduction of a harmonised multilaterally coordinated congestion management method requires not only cooperation among the TSOs involved, but also supportive regulators buying into a common purpose.

Model to describe cross-border transmission capacity

- The allocation of transmission capacity should be based on a PTDF model of the transmission network instead of bilateral capacities like "Net transfer capacities" (NTCs). Through its representation of the interdependence between the different power transfers and the resulting power flows the PTDF model eliminates the TSOs' uncertainty regarding the allocation status at the other involved borders. This allows – especially in highly meshed networks – for an increased utilisation of the network and thus a significant increase in social welfare without jeopardising network security.

- Through the increase in transmission capacity, the application of a PTDF based capacity model may help mitigating the opportunities to exercise market power.
- A PTDF based capacity model also makes it feasible to take account of the netting of power flows induced by different power transfers. We recommend taking account of netting between allocation phases (when some transactions are already firmly nominated). Within allocation phases, however, netting of explicitly auctioned transmission rights induces risks and should be avoided in the first instance. As and when explicit auctions are extended to cater for rights with obligations as well as rights alone, netting will become feasible in relation to the obligations.
- The regular determination and application of a PTDF based transmission capacity model requires a minimum degree of coordination and centralisation among the TSOs. (This is independent from the question whether explicit or hybrid explicit/implicit auctioning is performed.) The gradual centralisation can, however, be organised such that it is compatible with the individual TSO's responsibility for network security in their own area. The PTDF based model even offers possibilities to increase the level of security at a technical and data provision effort comparable to that of the present NTC determination procedure.

Auction design and differentiation of allocation phases

We think that the format of the year/quarter and month ahead auctions should ideally be a dynamic ascending clock auction with the simultaneous offering of capacity on as many different interconnectors as can reasonably be coordinated.

We do not believe that a dynamic auction is practicable or necessarily desirable for the day-ahead auction and we therefore think that the appropriate form of this auction is a one shot auction based on bids in the form of demand and supply curves, supplemented by the offer of open increments and decrements that the coordinator can accept to effect optimal arbitrage.

Cross-border access to reserve power markets

- The possibility of an explicit allocation of transmission rights (which need to be rights without obligation) for cross-border access to national reserve power markets is a prerequisite for any future congestion management concept. Such a possibility can be implemented regardless of whether cross-border access to wholesale energy markets is managed by explicit or hybrid implicit/explicit auction of transmission capacity. Moreover, it is flexible enough to allow for different conceivable developments of the reserve power markets.

- Regarding the distribution of transmission capacity among participants of the wholesale and the reserve power markets, we recommend that initially there is a subsequent allocation for reserve power markets, i.e. the capacity for cross-border access to reserve power markets is allocated after the nomination of day-ahead capacity for wholesale energy delivery.

Redispatching

- Redispatching, even if designed in a market-based way, offers generators the possibility for inefficient pricing. Moreover, the causes for redispatching are difficult to trace, making it hard to achieve a fair allocation of the related cost. Therefore, when balancing the amount of transmission capacity and the expected extent of redispatching, the latter should be designed to be the exception such that the regular means to manage congestion remains the limitation of the transmission capacity.

- Nevertheless, a functioning mechanism for cross-border redispatching is required in order to have a possibility to relieve overload of network elements close to the borders between control areas. Each TSO therefore should assign a mechanism which will be used when another TSO asks for a short-term increase or decrease of the export balance. This could, for example, be the regional reserve power market or, if existing, a specific domestic redispatching mechanism. (An introduction of interruptible cross-border transmission rights is not recommended in this context as it does not yield additional benefit.)

Distribution of cost and revenues

- Ex-ante, TSOs should agree upon the process for determining the allocation of redispatch costs.

- In general, a sensible approach would appear be to leave insignificant redispatch costs remaining with those that incur them.

- Significant redispatch cost should be subject to ex-post analysis in order to determine an appropriate allocation.
- Given the difficulty in allocating redispatch costs among multiple TSOs, any congestion management scheme that leads to a notable amount of redispatching and the need for a significant amount of cost reallocation will be difficult to implement.
- With the multi-lateral allocation regime transmission rent could accrue to the TSO(s) whose constraint (i.e. flow gate) was binding.
- Where auction revenues accrue to the TSO and not to an entrepreneurial developer, the allocation between TSOs should be based upon the risk borne by respective transmission network users

Further development: Hybrid implicit/explicit auction

The introduction of implicit auctioning of cross-border transmission capacity – which for legal and practical reasons should be accompanied by a continuation of explicit auctioning – could effectively increase economic efficiency by eliminating the information lag between transmission capacity and wholesale energy markets, thereby mitigating some possibilities for exercising market power and allowing better coordination of transmission and energy markets.

Taking into account the present arrangements for congestion management in the continental part of the IEM, the introduction of implicit auctioning requires a significantly greater harmonisation effort than a purely explicit auctioning approach. In general it will thus be recommendable to progress to the hybrid auction via a phase of purely explicit auctioning. However, this is not a necessity; i.e. in regions where the direct implementation of a hybrid auction seems feasible the explicit phase can be skipped. Besides, it is also conceivable that among a larger group of TSOs that perform a multilaterally coordinated explicit auction, some areas migrate to a hybrid auction by allowing the respective power exchanges to participate in the transmission market, whereas the remainder of TSOs continue the pure explicit auction.

As mentioned above, many achievements of the multilaterally coordinated explicit auction remain effective after the inclusion of implicit auctioning. Additional benefit can be achieved through an amended treatment of netting: Since implicitly allocated transmission rights are certain to be exercised, full netting could be taken into consideration for the implicitly allocated share of the transmission capacity. However, potential operational problems arising from a significant increase of transmission volume should be carefully monitored.

Possibilities for further improvement of congestion management

In order to facilitate the realisation of the key steps towards a more efficient cross-border congestion management (listed above), we consider it acceptable to pursue a number of potential further improvements with lower priority. However, this does not imply that their introduction *needs* to be postponed until after the implementation of the key aspects. Rather, any case-specific considerations or opportunities that allow for an earlier implementation should be welcomed.

- The greater the number of areas participating in a multilaterally coordinated capacity allocation based on a PTDF model, the less the uncertainty that will remain regarding the utilisation of the network by foreign actors. This reduction of uncertainty allows to reduce the respective margins and thus leads to a further increase in transmission capacity at the same level of network security.
- A PTDF based capacity model can take account of the ability of phase shifting transformers to control the power flow. This allows TSOs to coordinate the use of these transformers in reaction to the market requirements.
- The consideration of individual transmission lines and transformers instead of flow gates may further improve the accuracy of the PTDF based transmission capacity model.
- Regarding cross-border access to reserve power markets, a simultaneous allocation of transmission capacity for day-ahead energy delivery and cross-border balancing markets could be considered. This may yield a significant increase in allocation efficiency, especially when the profitable directions for scheduled wholesale energy transmission and reserve power provision coincide. However, when designing this simultaneous allocation, measures should be applied to avoid an abuse of the use-it-or-lose-it principle by hoarding of capacity. A conceivable countermeasure would be the introduction of a fixed share of transmission capacity to be earmarked for reserve power markets.

1 Introduction

One of the main targets of the liberalisation of the electricity supply sector in the European Union is the creation of a truly Internal Electricity Market (IEM). By introducing competition among generators and suppliers not only in their domestic markets, but also on an international scale the economic efficiency of electricity supply shall be maximised for the benefit of the consumers and the entire economy. However, the transmission system operators (TSOs) have historically not designed the interconnections between their networks with the primary objective of facilitating international power trade. As a consequence, the integration of the national electricity markets is impeded by the limited amount of cross-border transmission capacity at several borders.

To mitigate this problem, the EU supports on the one hand measures to increase the transmission capacities, be it by investment in new network facilities or by optimisation and harmonisation of operating standards that allow to better utilise the networks. On the other hand, the rules applied for managing the utilisation of the *existing* transmission capacities – which can be summarised by the term “cross-border congestion management methods” – are of particular importance for the efficiency of the IEM in the short and medium term.

The congestion management methods that have been established over the recent years are in most cases border-specific and differ significantly from each other. Although case-specific solutions may in principle be justified by particular regional circumstances, the present situation gives rise to the expectation that at least due to this heterogeneity there is some potential for improvements.

Suggestions regarding the further development of cross-border congestion management in the IEM have been made by a number of stakeholders, mostly in the context of the Electricity Regulatory Forum of Florence. In addition, Regulation (EC) No 1228/2003, becoming effective on 1 July 2004, sets out – among other things – a framework of basic requirements to such methods. It also allows for the adoption of binding guidelines in order to harmonise and co-ordinate the mechanisms to be used.

On this background, the European Commission has commissioned this study with the objective to derive, on the basis of sound scientific analyses, a recommendation as to the optimal design of a cross-border congestion management regime for the IEM. The assessment should not only be based on the criterion of achievable social welfare; rather, also the practical feasibility in view of the existing organisational framework of cross-border network access had to be taken into account. Hence, a solution that can be realised within the course of the next years was to be given priority over an eventual theoretical but unrealistic “ideal”. Parallel to the main focus of the recent discussions in this field, the study concentrates on the situation of the Continental[1] European transmission network where the highest potential for improvements is expected.

To ensure a comprehensive and objective treatment of the scope, the investigation had to cover the presently applied congestion management methods as well as the relevant proposed ones, yet without being limited to these. Consequently, in order to be able to on the one hand analyse the entire bandwidth of conceivable methods, but on the other hand allow for a detailed assessment and recommendation of the preferred solution, we have structured our analysis as follows:

- In chapter 2 we introduce a generic description of the tasks that are covered by the term “congestion management” and discuss the key features of the capacity allocation methods being presently applied or under consideration for the IEM.
- In chapter 3 we set out the assessment criteria on which we base the further analysis.
- We then analyse the basic options for congestion management from a general perspective, i.e. concentrating on the fundamental capacity allocation principles rather than design details (chapter 4). This analysis is complemented by a quantitative evaluation of some of the presently applied capacity allocation procedures (annex A).

[1] Continental European transmission system in this study means the part of the IEM area belonging to the UCTE system, i.e. excluding Scandinavia, the United Kingdom and Ireland. Among the countries of the present “2nd synchronous zone” of UCTE (covering South Eastern Europe) Greece is the only EU member state. However, the considerations in this study could in principle also be suitable for this region, even though most of its countries are so far not members of the IEM.

- For a reduced set of remaining basic congestion management models we then perform a detailed analysis of a number of design elements that all form part of a comprehensive congestion management regime (chapter 5).
- Finally we present our conclusions and recommendations in chapter 6.

As a consequence of our approach, the conclusions and recommendations pick up a number of elements that also form part of one or several previously published proposals. Notable contributors of such proposals are e.g. ETSO (association of European Transmission System Operators), EuroPEX (Association of European Power Exchanges) and FEBELIEC (Belgian Federation of Large Industrial Energy Consumers). Therefore the recommendations, as the study in total, should not be seen as an attempt to propose a completely new, unique way of managing cross-border congestion. Rather, they represent a consistent combination of individual elements that together make up an economically and technically optimal as well as feasible framework, based on the intention to provide an independent, neutral assessment.

It should be noted that our analyses mainly focus on economic and technical issues, which are the most relevant ones according to the scope of the study. In addition, legal and organisational issues are mentioned where they appear to be relevant, yet not treated in the same level of detail.

2 Basic congestion management models

In this chapter we first describe from a general perspective the tasks that can be summarised by the term "congestion management" (section 2.1) and discuss the key features of capacity allocation methods being presently applied or under consideration for the IEM (section 2.2). Based on this we derive the structure for our further analysis on a future congestion management concept (section 2.3).

2.1 Generic congestion management scheme

In this report, the term "congestion" is used to denote situations in which the demand for power transmission exceeds the capabilities of the transmission network, i.e. in which the unrestricted (or too less restricted) utilisation of the network leads or would lead to a violation of network security limits. In principle, congestion may occur at any location and due to any power exchange within the interconnected network. This study however concentrates on the analysis of "cross-border congestion", i.e. congestion that relates to an excessive demand for power transfers between countries[2]. Besides the fact that this concentration is prescribed by the study's relation to the respective EC regulation [1], it is also justified because "internal" congestion usually occurs less frequently and can be managed by specific methods taking into account the uniformity of the market rules within each country[3].

In its broadest sense, the term "congestion management" comprises all actions and measures that are applied to handle network access in the presence of congestion. Irrespective of the case-specific implementation congestion management is usually organised as a sequence of four phases (cf. fig. 2.1):

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[2] This does not imply that the physical limitations restricting the volume of cross-border power exchange are exclusively related to cross-border power lines. Internal network elements may as well constitute the limitation for cross-border power exchange.

[3] Additional considerations on the relation of internal and cross-border congestion can be founding section 5.3.4

1. At first the capability of the network to transmit power must be expressed as a "transmission capacity", i.e. a volume of power exchange that can be safely made available to the network users. The amount of transmission capacity depends, among other aspects, on the foreseen network conditions (e.g. line maintenance, load level), on the considered time period, and, given the limitations of forecast accuracy, on the forecast horizon. The first phase of congestion management is thus to determine the amount of available transmission capacity according to the definitions and time frames prescribed by the subsequent allocation phase.
2. The capacity allocation step is required to distribute the available transmission capacity among the network users wishing to utilise it. The variety of methods that can be used to determine each applicant's share of the transmission capacity is outlined in section 2.2 below.
3. After the transmission capacity has been allocated and the wholesale energy markets are settled (usually in the afternoon of the day before operation), the TSOs perform a so-called congestion forecast: Based on the most recent information regarding network status and utilisation (including e.g. generation dispatch schedules which are created after the energy market has been settled) they can determine if the foreseen constellation of power generation and consumption will be feasible or if network security limits will be breached.
4. If during phase 3 a violation of network security limits is foreseen, the TSOs must take measures to relieve the network. Such measures can comprise network-inherent actions (like opening of busbar couplers or the use of phase shifting transformers) as well as re-dispatching, i.e. active modifications of the generation (and, eventually, load) patterns.

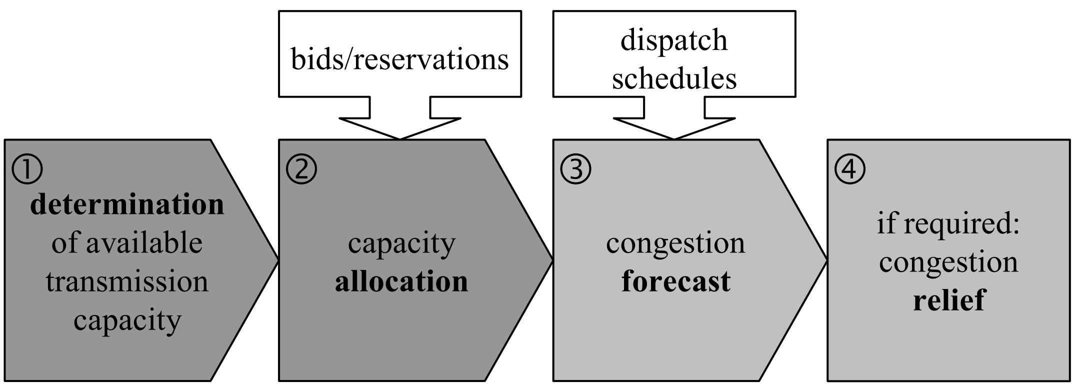

Figure 2.1: Phases of network access with respect to network congestion [2]

The task of this study, i.e. to develop a recommendation for a suitable and consistent cross-border congestion management scheme, touches aspects of each of the four phases above. Among these aspects, the question how to perform the capacity allocation (phase 2) is clearly the most essential issue, because

- the capacity determination is a preparatory step to the allocation, and thus its design depends on the requirements defined by the allocation methods, and
- the frequency and extent of congestion relief and thus the importance of phases 3 and 4 for the overall efficiency of cross-border network access largely depend on the way in which the capacity allocation is done.

Taking account of the key role that the capacity allocation method plays in the context of congestion management, we will in the following section outline some basic features of allocation methods which are currently applied or under discussion for application in the IEM. This first overview will then allow us to derive an appropriate structure for our further analysis.

2.2 Characterisation of capacity allocation methods

2.2.1 Allocation methods currently applied in the IEM

At present, a variety of different capacity allocation methods are in use in the IEM [3]. Although each implementation is unique in detail, they can be roughly grouped as follows:

- **First come, first served:** Capacity is allocated according to the order in which the transmission requests have been received by the TSO. Starting from the earliest request, all requested amounts of capacity are fully granted until the available capacity is used up.
- **Pro rata:** All requests are partially accepted in the way that each applicant is granted a fixed share of his requested capacity amount, the share being equal to the amount of available capacity divided by the sum of all requested capacity amounts.
- **Explicit auction:** Along with the requested capacity amount, the applicants have to declare how much they are willing to pay for this capacity. These bids are ordered by price and allocated starting from the highest one until the available capacity is used up. In con-

trast to the previous methods, network users incur cost for obtaining transmission capacity (usually the price is set to the bid price of the lowest allocated bid).

- **Implicit auction:** With all previously described methods, the electricity spot markets are separated from the transmission capacity allocation procedure and close after the transmission capacity has been allocated (i.e. between phases 2 and 3 of the generic congestion management model according to fig. 2.1). With implicit auctioning transmission capacity is managed implicitly by the spot markets: Network users submit purchase or sale bids for energy in the geographical zone where they wish to generate or consume, and the market clearing procedure determines the most efficient amount and direction of physical power exchange between the market zones. Hence phase 2 of the generic congestion management model is integrated with the energy market, a separate allocation of transmission capacity is not required.

Where legacy rights to physical capacity exists, the Regulation appears to assume that physical access rights will continue to be held (provided, as set out in the guidelines accompanying the Regulation, that the contracts do not breach Articles 81 or 82 of the EC Treaty, and do not have pre-emption rights when they come up for renewal).

Besides the allocation methods listed above, the term "**counter-trading**" is often mentioned in the context of congestion management methods. This is however not a capacity allocation method, but rather denotes a market-based way of congestion relief (phase 4 of the generic congestion management model) where the TSO, having detected a potential or actual violation of network security, trades power such as to induce a power exchange (and thus a power flow) in the opposite direction of congestion. At present, counter-trading is not applied to relieve cross-border congestion in the IEM, but used internally in some Member States, e.g. in Norway. (To deal with unexpected critical network conditions, cross-border counter-trading will almost certainly be required in the future. We discuss this in more detail in section 5.6.)

2.2.2 Proposals for future development of capacity allocation

Since 1998, issues related to the development of the IEM are regularly discussed in the framework of the Electricity Regulatory Forum of Florence ("Florence Forum"). In recent years, a number of organisations participating in this forum have made specific proposals about the further development of the existing congestion management regimes. As regards the methods for capacity allocation, three different streams of development can be recognised:

- The concept of explicit auctions has been extended, especially by ETSO, to allow for a multilaterally coordinated allocation, i.e. the simultaneous allocation of transmission capacity across several borders [4].
- Other proposals, e.g. from ETSO and EuroPEX, present extensions of the implicit auctioning concept, be it by inclusion of competitive allocation of explicit transmission rights [5] or with respect to a decentralised implementation through co-operation between TSOs and regional power exchanges [6, 7].
- The electricity consumers' associations FEBELIEC and UNIDEN have proposed a congestion management scheme that offers virtually infinite transmission capacity, i.e. phase 2 of the generic model according to fig. 2.1 is omitted. A limitation of the transmission volume is primarily achieved by means of counter-trading (phase 4, after closure of the electricity spot markets), complemented by an adaptive cross-border tariff to provide incentives to keep cross-border transmission on a moderate level.

2.3 Conclusions for the further analysis

When comparing the capacity allocation methods that are in use today one can recognise that many of them share similarities in some respect, but are quite different in other respects. For example, first-come-first-served, pro rata and explicit auction methods share the fact that transmission capacity allocation is separated from the wholesale energy market, whereas implicit auctioning features an integration of the two. On the other hand, explicit and implicit auctions have the common feature of being based on a valuation that each applicant assigns to his request, in contrast to first-come-first-served and pro-rata.

Basically the same applies to the extended congestion management concepts that have been proposed recently. As mentioned in section 2.2.2 above, they relate to three different capacity allocation principles. However, all proposals share the idea to introduce multilaterally coordinated capacity allocation across several borders, as opposed to the present situation where – except for the implicit auction performed in the Nordel system – capacity is always allocated bilaterally, i.e. independently for each border by the two adjacent TSOs[4].

Generally speaking, each currently applied or proposed congestion management design constitutes a specific combination of "design elements" like integration vs. separation of energy market and transmission capacity allocation, bilateral vs. multilateral allocation, etc. Consequently, the task of this study can be understood as the identification of the most appropriate combination of such design elements. In order to achieve an unbiased assessment of the different alternatives, we have therefore decided to analyse the congestion management methods and their different design elements independently from specific implementations or proposals. The analysis is carried out in three steps:

- At first, we set out the assessment criteria that form the basis of the analysis (chapter 3).
- We then analyse the basic options for congestion management (cf. section 2.2) from a general perspective, i.e. concentrating on the fundamental capacity allocation principles rather than design details (chapter 4). The result of this step is a reduced set of basic congestion management models that require further, detailed analysis before finally deciding on their suitability in terms of the assessment criteria.
- A detailed analysis of design options is then performed for this reduced number of basic congestion management models (chapter 5). Although our aim is to discuss each design element as independently as possible, interdependencies with the basic congestion management model or with other design elements are respected and highlighted wherever necessary.

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4 Also at the borders between the Netherlands and the neighbouring countries transmission capacity is allocated jointly by the four involved TSOs. Nevertheless, although this leads to a harmonisation of the related schedules and procedures it is not yet a multilateral allocation, because capacity for each border is still allocated independently, i.e. without taking into account the allocation status at the other borders.

3 Assessment criteria

This section sets out the criteria that we use to assess the different options for congestion management.

Our choice of assessment criteria is guided by the Regulation for cross-border electricity exchanges (Regulation EC No 1228/2003 dated 26 June 2003). All criteria for assessment derive from the necessity to comply with the Regulation. However, in itself, the criterion of compliance is too broad to be particularly helpful in assessing congestion management options. Therefore, we use Article 6, General principles of congestion management, to develop more detailed criteria to assess congestion management options.

Article 6, Paragraph 1 of the Regulation states that "Network congestion problems shall be addressed with non-discriminatory market based solutions which give efficient economic signals to the market participants and transmission system operators involved." This provides three criteria for a congestion management scheme:

- Non-discrimination;
- Market based; and
- Economic efficiency.

Economic efficiency can best be measured as the total amount of social welfare derived from each option. Assessment of economic efficiency takes account of several different types of efficiency:

- productive – minimise the cost of production at a point in time given a set of inputs;
- allocative - minimise the cost of production at a point in time given a free choice over the set of inputs; and
- dynamic – minimise the cost of production over time.

Other criteria set out in Article 6 such as secure network operation (Paragraph 3) and broad revenue neutrality for TSOs (Paragraph 6) are largely requirements placed on the regulation of the networks. Through regulation it would appear to be possible to meet these two criteria for any of the basic models of congestion management. We therefore address these two criteria in later sections that discuss the detailed design of each methodology.

We add practical feasibility to our list of criteria since the EC requires a solution that can be implemented over the next few years. Largely this is a qualitative comparison of the requirements for the proposed methodology with the current arrangements for cross-border capacity allocation. Given the importance of congestion management to the long term development of the IEM, in section 5 we note those design features that might not meet the criterion of practical implementation in the short term but that might form part of a longer term solution.

The impact of each solution on industry stakeholders is not in itself a criterion that directly influences the choice of allocation model. However, given the interest of stakeholders in the solution to congestion management when discussing possible mechanisms we illustrate the allocation of welfare among stakeholders.

The four assessment criteria are therefore:

- Absence of discrimination
- Compliance with market principles
- Maximisation of economic welfare, and
- Ease of implementation.

4 General assessment of congestion management methods

In this chapter we make a preliminary assessment of the basic options using the four criteria set out in chapter 3. This preliminary assessment eliminates the options of first come first served, pro-rata allocation and counter-trading. Detailed analysis is made in chapter 5 only of those options that pass this initial screening.

4.1 Non-discriminatory and market based solution

A market based mechanism implies that the price for transmission capacity should emerge to be equal to the opportunity cost of the capacity, i.e. the profit foregone by a holder relinquishing the transmission right.[5] The opportunity cost could be determined through a mechanism that reveals potential users' value preferences for gaining access to the transmission. The price for transmission capacity would, for example, be set equal to the opportunity cost of the marginal user, which in a perfect market would equal the price differential between electricity markets at either end of the transmission. The capacity would be allocated to those users who place most value on the capacity (anyone willing to pay the opportunity cost).

Clearly some form of selection is required to allocate scarce transmission capacity to users. However, given the objective of economic efficiency, and the requirement for a market-based mechanism, we assume the only allowed form of selection between potential users is on the basis of their relative willingness to pay for the transmission.[6]

First come first served and pro-rata methods of capacity allocation fail to meet the criteria of being non-discriminatory and market-based. In both cases, capacity allocation is made without reference to users' values and there is no guarantee high value users will gain access to the

[5] A pay-as-bid mechanism would not be ruled out by the market based criteria since one would expect bids to cluster around the opportunity cost of transmission capacity

[6] We refer to individuals' value in short hand as the willingness to pay although we recognise that the value of the interconnector to all participants may be identical ex-post.

transmission in preference to low value users. We therefore reject these two allocation mechanisms and do not address them in the remainder of this report.

Implicit auctions, explicit auctions and counter-trading / tariff mechanisms all appear to meet the criteria of being non-discriminatory and market based.

Under an explicit auction, transmission rights are allocated to participants on the basis of their value preferences as communicated through the auction process. Limited capacity is allocated to high value users in preference to low value users.

Under an implicit auction, physical transmission capacity is not allocated to individual market participants. Rather, transmission flows are internalised in the market-based mechanisms for clearing the energy markets and setting the geographically differentiated energy prices. In this combined energy and transmission capacity market, high value participants of the electricity market (those willing to sell electricity at a low price and/or buy at a high price) are cleared in preference to low value participants. In effect, the right to inject energy into or withdraw energy from the transmission systems of the participating countries is allocated in accordance with participants' value preferences for generation and consumption.

Under counter-trading, again transmission capacity is not allocated to individual users. TSOs coordinate transmission flows using markets for counter-trading. The outcome of the transmission allocation is revealed in the counter-trading market, where selection is made on the basis of users' value preferences to change output or consumption. Those participants who are unwilling to change their production and consumption decisions (i.e. high value users) retain the right to inject energy into or withdraw energy from the transmission systems of the countries that are part of the counter-trade mechanism.

Counter-trading could be combined with a tariff mechanism. First, cross-border transmission capacity would be sold at the tariff, which would be set to an estimate of the opportunity cost of the capacity.[7] Counter-trading would then be used to ensure technically feasible cross-

7 FEBELIEC's proposal [8] includes a tariff for interconnector use that is determined on the basis of the cost of redispatch (or new investment) to provide interconnector capacity.

border flows. If the tariff did not reflect the opportunity cost of transmission capacity, either the transmission will be under-utilised (unless the TSO is allowed to undertake arbitrage trades in the counter-trade market) or excessive counter-trading will be required to ensure a feasible dispatch.

In all three cases, users are treated in a non-discriminatory way according to their value preferences for explicit use of cross-border transmission and / or value preferences for the injection and offtake of electricity from the network.

The criteria of secure network operation and revenue neutrality are largely requirements placed on the regulation of the networks. Through regulation it would appear to be possible to meet these two criteria for any of the three basic models we are left with. We therefore address these two criteria in later sections that discuss the detailed design of each methodology.

4.2 Economic welfare

In this sub-section, we assess the economic efficiency of three basic methods for transmission capacity allocation: explicit auction, implicit auction and counter-trading. We use a simple example power system to facilitate comparison of the methods in terms of market clearing quantities and prices and welfare effects for a simple two-node system under assumptions of perfect information and no market power. A static analysis shows that the three methods result in the same level of total economic welfare but that the welfare accruing to individual stakeholders changes.

An empirical analysis of cross-border capacity allocation (see Annex A) shows that in practice there are inefficiencies with existing explicit auction methods due to market imperfections. Therefore, in a second sub-section we examine economic welfare of congestion management methods under the more general market conditions of information uncertainty and market power.

4.2.1 Simple example power system

Our basic example power system has two countries, A and B with perfectly inelastic demand of 2000 MW in each. Each country has 4 gensets with capacities and marginal costs as set out in table 4.1. Transmission capacity between Country A and Country B is limited to 150 MW.

Genset	Capacity (MW)	Marginal cost (€/MWh)
A1	600	25
A2	600	30
A3	1,100	40
A4	600	50
B1	600	35
B2	600	45
B3	600	50
B4	600	60

Table 4.1:Generation park

We apply the pricing rule that the system marginal price (SMP) is set to the offer price of the cheapest generation unit required to meet the next increment of demand. The choice of pricing rule between the cost of meeting the next increment of demand and the cost of meeting the last increment of demand affects SMP only at corner solutions, i.e. where a generator is dispatched exactly to its maximum capacity. In the case of a corner solution, the choice of pricing mechanism impacts the allocation of welfare between generation and demand but does not alter total social welfare so long as demand is inelastic.

All generators receive SMP for their output and all loads pay SMP for their consumption. In the example, the dispatch period has a duration of one hour.

4.2.1.1 Independent dispatch

Independent dispatch is a hypothetical least cost dispatch by the TSO, assuming there is no transmission between the two countries. The independent dispatch of the simple two-node system is shown in table 4.2.

Genset	Dispatch (MW)	Offer price (€/MWh)	Welfare (€)
A1	600	25	9,000
A2	600	30	6,000
A3	800	40	0
A4	0	50	0
B1	600	35	15,000
B2	600	45	9,000
B3	600	50	6,000
B4	200	60	0

Table 4.2: Independent dispatch

Fig. 4.1 illustrates the dispatch in the two countries. Generator A3 is marginal in Country A and generator B4 is marginal in Country B. Therefore, SMP in Country A is 40 €/MWh and SMP in Country B is 60 €/MWh. There is no transmission flow between Country A and Country B.

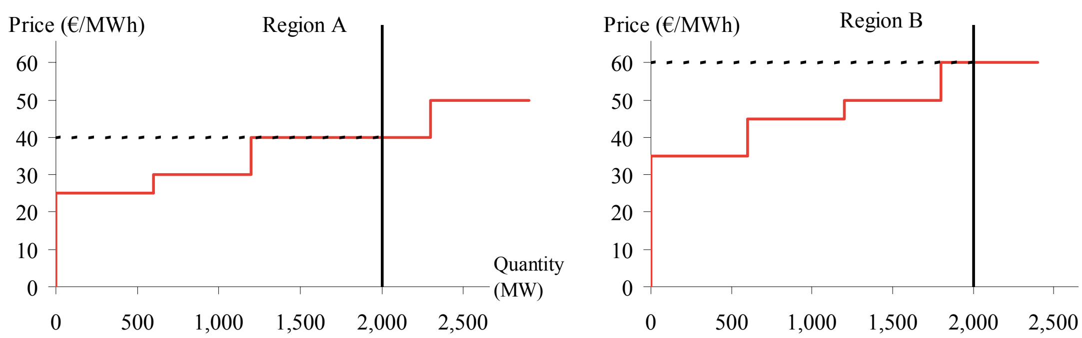

Figure 4.1: Independent dispatch

Table 4.2 lists the welfare that accrues to each generator and table 4.3 lists the welfare accruing to generators, consumers and the TSO (which would either be distributed to users or retained in accordance with regulations). Throughout the examples used in section 4, the consumer welfare we report is the difference between total consumer welfare and the consumer welfare that would accrue with SMP equal to 60 €/MWh, i.e. the highest possible price for electricity in this example system.[8] Fig. 4.2 illustrates total social welfare and its allocation between producers and consumers in Country A and Country B.

Participant	Welfare (€)
Generation A	15,000
Generation B	30,000
Demand A	40,000
Demand B	0
TSO	0
Total	85,000

Table 4.3: Independent dispatch – welfare

Total social welfare with independent dispatch is 85,000 €. Since the market price in Country B is higher than in Country A, generator welfare is higher in Country B and consumer welfare is higher in Country A. No welfare accrues to the TSO because there are zero transmission flows.

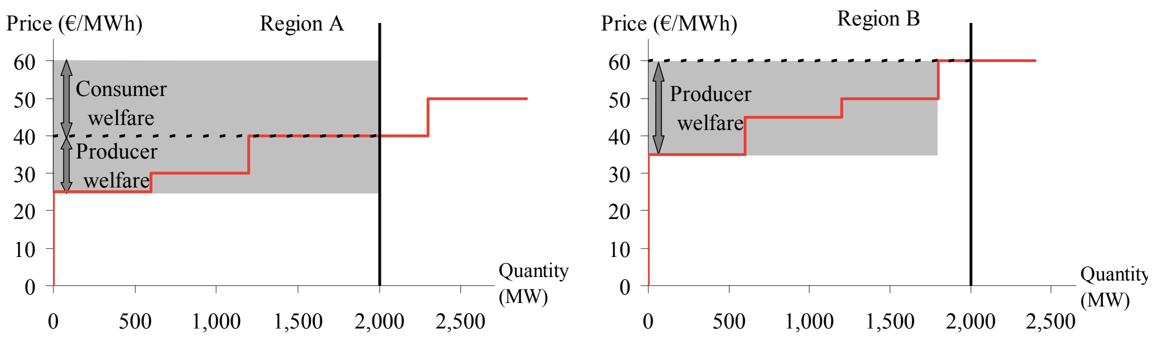

Figure 4.2: Independent dispatch - welfare allocation

8 A relative measure of consumer welfare is required because consumer welfare is infinitely large if we assume a perfectly inelastic demand

4.2.1.2 Unconstrained dispatch

As an illustration of the opposite extreme to the previous example, we present the unconstrained dispatch. Unconstrained dispatch is also the first stage of the counter-trade example shown in section 4.2.4. An unconstrained dispatch is a hypothetical least cost dispatch by the TSO, assuming unlimited transmission capacity. The unconstrained dispatch of the simple two-node system is shown in table 4.4.

Genset	Dispatch (MW)	Offer price (€/MWh)	Welfare (€)
A1	600	25	15,000
A2	600	30	12,000
A3	1,100	40	11,000
A4	0	50	0
B1	600	35	9,000
B2	600	45	3,000
B3	500	50	0
B4	0	60	0

Table 4.4: Unconstrained dispatch

Choice of dispatch between generators A4 and B3 is arbitrary since they have identical marginal costs. Generator B3 is marginal and sets the common SMP for countries A and B to 50 €/MWh. The unconstrained dispatch implies an interconnector flow from Country A to Country B of 300 MW, which clearly exceeds the 150 MW flow limit.

Fig. 4.3 illustrates the resultant dispatch. The 300 MW export from A to B effectively moves the demand curve in A to the right by 300 MW, increasing the price in A to 50 €/MWh and effectively moves the demand curve in B to the left by 300 MW, decreasing the price in B to 50 €/MWh.

Table 4.4 sets out the welfare for each generator and table 4.5 sets out the welfare for generators, consumers and the TSO. Total social welfare, at 90,000 € is 5,000 € greater than for the independent dispatch, which is the result of generator welfare increasing by 5,000 €. The increase in generator welfare is due to a decrease in total generation costs – the result of trade between the two countries. Relatively more producer welfare accrues to those generators with a lower marginal cost, i.e. generators in Country A.

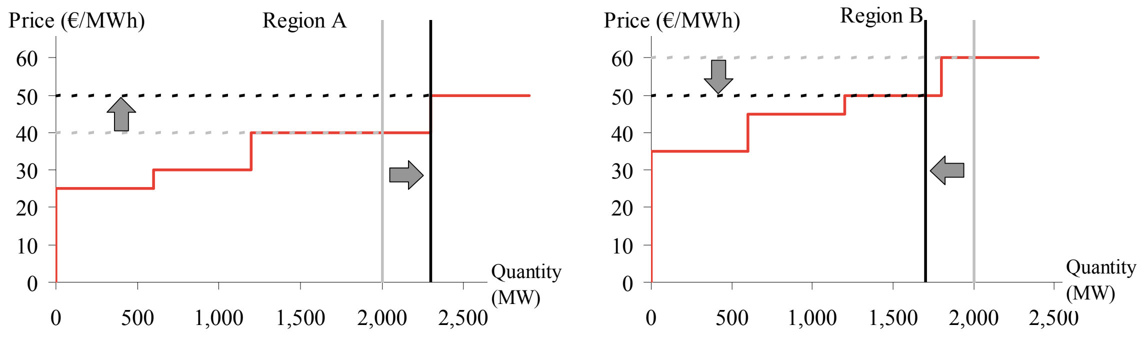

Figure 4.3: Unconstrained dispatch

Participant	Welfare (€)
Generation A	38,000
Generation B	12,000
Demand A	20,000
Demand B	20,000
TSO	0
Total	90,000

Table 4.5: Unconstrained dispatch – welfare allocation

Consumer welfare, at 40,000 €, is the same as for independent dispatch. However, welfare accruing to consumers in Country A is 20,000 € lower and welfare accruing to consumers in Country B is 20,000 € higher than for the independent dispatch. This is due to SMP being higher in Country A and lower in Country B than for the independent dispatch.

No welfare accrues to the TSO since there is no price differential across the transmission.

4.2.2 Explicit auction

Anyone could participate in an explicit auction for transmission capacity – generators in either country, loads or traders. With perfect foresight, bidders for transmission capacity would predict the electricity market outcomes with efficient use of the transmission. They would correctly predict that the market clearing price in Country A will be 40 €/MWh and the market clearing price in Country B will be 60 €/MWh and would therefore bid no more than 20 €/MW per hour (i.e. 20 €/MWh) for transmission capacity. In addition, no participant would obtain capacity if he bid below 20 €/MWh.

The market clearing outcome of the explicit auction with perfect information and no market power is given by table 4.6. Compared with the unconstrained dispatch, 150 MW less generation is dispatched in Country A and 150 MW more is dispatched in Country B. The market clearing price in Country A is 40 €/MWh (the marginal cost of genset A3) and the market clearing price in Country B is 60 €/MWh (the marginal cost of genset B4). The flow across the transmission is 150 MW.

Genset	Dispatch (MW)	Offer price (€/MWh)	Welfare (€)
A1	600	25	9,000
A2	600	30	6,000
A3	950	40	0
A4	0	50	0
B1	600	35	15,000
B2	600	45	9,000
B3	600	50	6,000
B4	50	60	0

Table 4.6: Explicit auction dispatch

Fig. 4.4 illustrates the resultant dispatch. The 150 MW export from A to B effectively moves the demand curve in A to the right by 150 MW and in B to the left by 150 MW, compared with the independent dispatch. Prices are unchanged from the independent dispatch at 40 €/MWh and 60 €/MWh respectively for Country A and Country B.

Since prices and/or quantities are different from the unconstrained and independent dispatch examples, welfare accruing to each type of market player is different. Table 4.7 shows that total welfare is 88,000 €, which is lower than total welfare in the unconstrained dispatch but greater than total welfare in the independent dispatch.

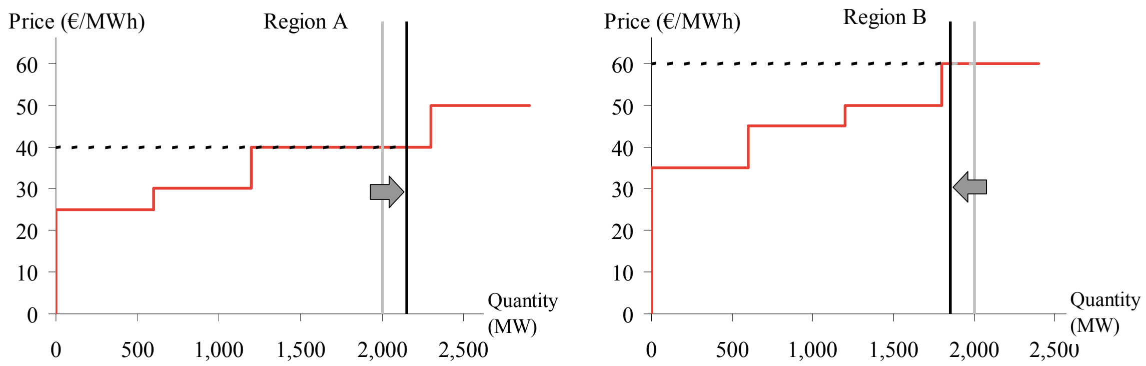

Figure 4.4: Explicit auction dispatch

Participant	Welfare (€)
Generation A	15,000
Generation B	30,000
Demand A	40,000
Demand B	0
TSO	3,000
Total	88,000

Table 4.7: Explicit auction – welfare allocation

Successful bidders for transmission capacity do not capture any welfare if the capacity is sold at the price differential between the electricity markets at either end – in this case 20 €/MWh. The TSO sells the use of the 150 MW transmission for one hour for a fee of 3,000 €, shown in table 4.7 as the TSO's welfare. Regulations would determine whether and how the TSO surplus would be allocated among participants.

Under this method, all existing and future market participants (both generators and loads) are exposed to the market price in their respective countries. The market price in each country corresponds to the marginal cost of meeting an increment in demand. Therefore, assuming no transmission constraints within a country, market prices provide efficient signals to invest in new generation and load equipment and to close uneconomic generation and factories. Therefore, explicit auctions exhibit properties of dynamic efficiency.

4.2.3 Implicit auction

Under an implicit auction for transmission capacity, the TSO compares the bids and offers in the two energy markets and maximises arbitrage trades between the two markets by scheduling flows across the transmission. With our underlying assumptions of perfect foresight and perfect competition, the dispatch outcomes for the implicit auction are identical to those of the explicit auction. Furthermore, the price outcomes and welfare distribution are also identical to the explicit auction.

As with explicit auctions, the energy market price in each country corresponds to the marginal cost of meeting an increment of demand in that country. This provides an economically efficient price signal for users and potential users to make investment and closure decisions.

4.2.4 Counter-trading

Under counter-trading, the TSO first undertakes a least cost unconstrained dispatch. If the implied transmission flows are infeasible, the TSO will trade power against the flow to ensure feasible dispatch. This requires two actions by the TSO:

- Reduce the surplus of electricity in the export zone. The TSO selects generators in the export-constrained zone to decrease output (in theory the TSO could also select controllable loads to increase consumption).
- Reduce the deficit of electricity in the import zone. The TSO selects generators in the import-constrained zone to increase output (in theory the TSO could also select controllable loads to decrease consumption).

The TSO undertakes the redispatch at least cost on the basis of offers and bids received from participants. In the examples set out below, we assume the TSO uses the offers and bids received in respect of the unconstrained dispatch to determine the least cost redispatch. An alternative rule, which doesn't change our conclusions, would allow participants to make separate offers and bids to the unconstrained schedule and to the counter-trade market.

4.2.4.1 Marginal cost dispatch

Initially we assume that all generators offer their capacity at marginal cost to the unconstrained dispatch and to the counter-trading market.

Recalling that the unconstrained dispatch in section 4.2.1.2 resulted in a hypothetical 300 MW flow across the transmission, the TSO must undertake a 150 MW redispatch. He achieves this by selling 150 MWh to generators in Country A and buying 150 MWh from generators in Country B. The least cost redispatch requires the TSO to buy electricity in Country B at the lowest price possible and to sell it in Country A at the highest price possible, i.e. the TSO buys at 60 €/MWh and sells at 40 €/MWh. We set out details of the counter-trade and accrual of welfare to generators in Annex B.

Table 4.8 summarises the allocation of welfare to participants from a static point of view. Total welfare is 88,000 €, which is the same as total welfare under the implicit and explicit auctions. Total welfare is unchanged because the final dispatch under the redispatch is the efficient (least cost) dispatch.

Participant	Welfare (€)
Generation A	38,000
Generation B	13,000
Demand A	20,000
Demand B	20,000
TSO	-3,000
Total	88,000

Table 4.8: Counter trading I – welfare

However, the distribution of welfare is different from the two auction methods. Generators in Country A are better off than they would have been under an auction mechanism and generators in Country B worse off. This is because the unconstrained price (50 €/MWh) is higher in Country A and lower in Country B than with auctions. Conversely, consumers in Country A are worse off and consumers in Country B better off than under the auction methods. Finally, the TSO is worse off than under the auction methods since he loses 3,000 €. He would probably be allowed to recoup some or all of this cost from market participants in accordance with regulations.

Our static example of counter-trading shows that there is no loss of welfare since the dispatch is efficient. However, the market price in each country equals 50 €/MWh, which does not correspond to the marginal cost of meeting an increment of demand in each country. The counter-trade price would over-incentivise new generation investment in Country A and under-incentivise generation investment in Country B. The converse is true for investment in facilities that consume electricity.

4.2.4.2 Non-marginal cost behaviour

The example market outcome described above assumes participants offer their true marginal costs into the market. With counter-trading this behavioural assumption is unrealistic because, even in a perfectly competitive market, generators would have incentives to offer their capacity at prices different from their underlying marginal costs of production. The same applies to dispatchable loads. This pricing behaviour does not rely upon market power.

Generators in Country B, aware that the TSO is willing to pay 60 €/MWh in the counter-trade market, would offer into the unconstrained schedule at 60 €/MWh. The alternative would be to withhold capacity from the unconstrained schedule in order to participate in the counter-trade market – where they could achieve a price of 60 €/MWh.

Generators in Country A would sell the maximum amount of energy possible in the unconstrained schedule, with the knowledge that they could buy-back power (thereby avoiding the need to generate) in the counter-trade market from the TSO at a price of 40 €/MWh. In a perfectly competitive market, generators would be willing to sell into the unconstrained market at a price below their own marginal cost of production but above 40 €/MWh.

In the case of our example system, with generators in A offering 40 €/MWh and generators in B offering 60 €/MWh, into the unconstrained schedule, the market clearing price is 60 €/MWh. The results of the unconstrained schedule are shown in table 4.9. We have arbitrarily assumed that the genset with the lowest marginal cost is accepted in the case of a tie in offer price. Welfare for a generator in the unconstrained schedule is calculated as the generator's scheduled quantity multiplied by the difference between the generator's marginal cost and the market price, 60 €/MWh.

Genset	Acceptance (MW)	Marginal cost (€/MWh)	Offer price (€/MWh)	Welfare (€)
A1	600	25	25	21,000
A2	600	30	30	18,000
A3	1,100	40	40	22,000
A4	600	50	40	6,000
B1	600	35	60	15,000
B2	500	45	60	7,500
B3	0	50	60	0
B4	0	60	60	0

Table 4.9: Counter trading II - unconstrained schedule

Table 4.10 shows the counter trade transactions made by the TSO. The welfare from the counter trade market for each generator is determined net of marginal costs. For example, Gen A4 buys 600 MWh at 40 €/MWh = 24,000 €. However, this transaction saves 50 €/MWh in fuel costs x 600 MWh = 30,000 €. The net result is a gain in welfare of 6,000 € for Gen A4.

Genset	Counter-trade (MW)	Marginal cost (€/MWh)	Welfare counter-trade(€)
A1	0	25	0
A2	0	30	0
A3	-150	40	0
A4	-600	50	6,000
B1	0	35	0
B2	100	45	1,500
B3	600	50	6,000
B4	50	60	0

Table 4.10: Counter trading II - counter trade

Table 4.11 shows the final allocation of welfare as a result of transactions in the unconstrained scheduled and the counter-trade. Total welfare is unchanged from previous examples because the dispatch is unchanged. However, the distribution of welfare among participants is significantly different. Generators receive higher welfare than in previous examples because they effectively sell their output at a price of 60 €/MWh. Consumer welfare is therefore reduced and the TSO has 15,000 € of counter trade costs.

Participant	Welfare (€)
Generation A	73,000
Generation B	30,000
Demand A	0
Demand B	0
TSO	-15,000
Total	88,000

Table 4.11: Counter trading II – welfare

The effective market price in both countries is 60 €/MWh, which differs from the marginal cost of meeting an increment of demand in each country. This price would give inefficient locational incentives to invest in generation and consumption facilities.

In the example used, loads are assumed not to participate in the counter-trade. In practice, while the bulk of counter-trading is undertaken with generators, loads sometimes do participate (e.g. in the UK). The effective market price and exact distribution of welfare between generators and consumers depends upon the ability of loads to participate in the counter-trade. Therefore, our finding that counter-trading benefits generators at the expense of loads may not always hold to the extent illustrated. While not an explicit criterion for assessment in its own right, any significant redistribution of welfare between stakeholders will impact the ease of implementation of a scheme since stakeholders made worse off under a methodology are likely to strongly oppose the methodology.

The key results that counter-trading may result in distorted investment signals does not depend upon the choice of system marginal price mechanism instead of a pay-as-bid mechanism. Nor does the result rely upon the exclusion of demand side bidding from the counter-trade (although demand side bidding would make the analysis more difficult).

4.2.5 Preliminary conclusion on economic welfare

A static analysis with the assumptions of no market power and perfect information shows that implicit auctions, explicit auctions and counter-trading all achieve efficient market outcomes. However, the analysis reveals the key disadvantages of counter-trading compared with the other two methods: it provides inefficient market signals for entry and exit and may result in an undesirable distribution of welfare, which may make practical implementation difficult.

With counter-trading, indirect mechanisms would be required to incentivise efficient locational investment. The FEBELIEC proposal for co-ordinated redispatching [8] attempts to address this issue by introducing mechanisms to create locational investment signals similar to those of other mechanisms. However, the proposal is complex and there is a high risk that its centrally determined price signals would be incorrect – resulting in inefficient market clearing outcomes.

We conclude that it is likely to be more practical to propose a method of transmission allocation that directly provides efficient investment signals to generators and loads. Therefore, we reject the basic counter-trade methodology on the basis of economic efficiency. (Note: Other specific advantages of the FEBELIEC proposal, such as an integrated approach, reduction in pancaking, etc, can be incorporated in other capacity allocation mechanisms.)

4.3 Economic welfare under different market assumptions

This is the second sub-section that analyses economic welfare for the different allocation capacity methodologies. In this sub-section we abstract from the previous assumption of a near perfect market by introducing imperfect information and market power. Having rejected counter-trading, we undertake this analysis only for the implicit and explicit auction methodologies.

4.3.1 Uncertain information

Analysis of allocation mechanisms under the assumptions of a perfect market does not differentiate between the implicit and explicit auction mechanisms. In this sub-section we generalise from the perfect market to a market where there is imperfect foresight of future events.

Suppose there is uncertain information related to generation availability. Unknown to the market, a large genset is about to fail. Fig. 4.5 illustrates three possible times for the event to occur in relation to the timing of the transmission capacity market and the energy market. Timeline 1 shows the transmission allocation as separate from the energy market clearing, as would be the case under an explicit auction. Timeline 2 shows a combined transmission / energy market clearing as would be the case under an implicit auction.

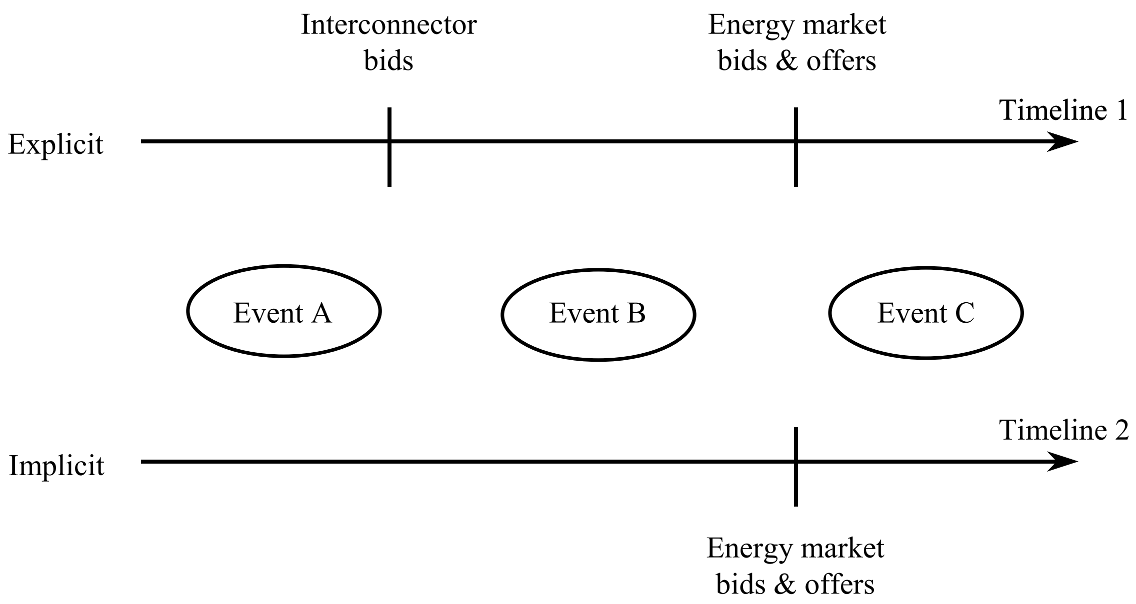

Figure 4.5: Timing of uncertain event

If the event (Event A) occurs before bids are made for transmission capacity and market participants have full knowledge of the event, they can alter their bids accordingly. The choice of implicit or explicit auction does not affect market outcomes. However, if Event A is unknown to the market, participants could not alter their transmission bids to take account of the event under the explicit auction. In contrast, allocation of transmission capacity under the implicit auction would take account of Event A.

If the event (Event C) occurs after the energy market or combined energy / transmission market has cleared, markets cannot respond and the choice of implicit or explicit auction does not affect market outcomes.

However, when the uncertain event falls sometime between when bids are made for transmission capacity and energy market clearing or combined energy / transmission market clearing (Event B), the choice of implicit or explicit auction affect market outcomes.

An explicit auction requires participants to forecast market price differentials when bidding for transmission capacity. If Event B causes market prices at either end of the transmission to change, inefficient transmission outcomes could result. Suboptimal transmission schedules imply inefficient energy market outcomes - since the energy market in one country can only react to an event in another country via transmission.

In contrast, an implicit auction would allow the transmission and energy markets in all countries to take account of Event B if the failure occurred at any time prior to market clearing. This is because demand for use of the transmission and energy market clearing adjust automatically on the basis of the most recent information about availability and participants' value preferences for injection and offtake. Participants do not need to forecast market clearing outcomes in one market (i.e. the energy market) before participating in a second market (i.e. the transmission market).

The information problem is exacerbated in the case of multiple borders. The difference in timing of markets widens the window during which an event has the potential to result in inefficient market outcomes. In addition, the interrelated nature of energy and transmission markets throughout Europe mean that a single event has the potential to effect several markets. Finally, participants' preferences for transmission and energy market transactions are often inter-dependent. For example, a participant may only want to gain access from Country A to B if he also gains access from Country B to C. Furthermore, his preference for participation in the energy market in A and C may depend upon the results of the two transmission markets. Even if the imperfect coordination between markets does not directly result in inefficient dispatch and transmission use, lack of coordination may deter participation thereby reducing competition.

In the case of multiple borders, a coordinated transmission auction would reduce the size of the information problem with both an implicit and explicit auction mechanism.

We conclude that the coordination of transmission and energy markets through implicit auctions has the potential to result in more efficient outcomes than an explicit auction under the assumption of uncertain information.

4.3.2 Market power

In this sub-section we consider some implications of market power in relation to implicit and explicit auction allocation mechanisms.

Under implicit auctions, participants must decide whether or not to exert market power prior to market outcomes being known. Coordination of transmission and energy markets may allow some market response to the exercise of market power through the use of transmission capacity that might not have been used in the absence of market power. This may have some mitigating impact on the ability to exercise market power in energy markets.

Under explicit auctions, a dominant participant could observe the outcome of the transmission allocation before deciding how to respond in the energy market. If the dominant player gains significant transmission capacity, he would have relatively more incentive to raise the energy price in the importing market. However, if the dominant player does not obtain transmission capacity, he would have relatively less incentive to raise the energy price in the importing market. This systematic correlation between transmission market outcomes and energy market outcomes may allow the dominant player to deter others from bidding efficiently for transmission capacity even under assumptions of perfect information. The result being that the dominant player could capture rent through the energy market and the transmission market.

We demonstrate the potential issue of market power in relation to the explicit transmission auction through use of an example. In this example, the generation park is identical to the examples used previously. However, we increase the size of the transmission to 250 MW in order to demonstrate the potential impact of market power. Fig. 4.6 illustrates the dispatch for the competitive basecase. The market clearing price in Country A is 40 €/MWh and 50 €/MWh in Country B. With perfect foresight of demand and available generation capacity (and hence energy market clearing prices), participants purchase transmission capacity in the direction A to B at a price of 10 €/MW per hour, i.e. 10 €/MWh.

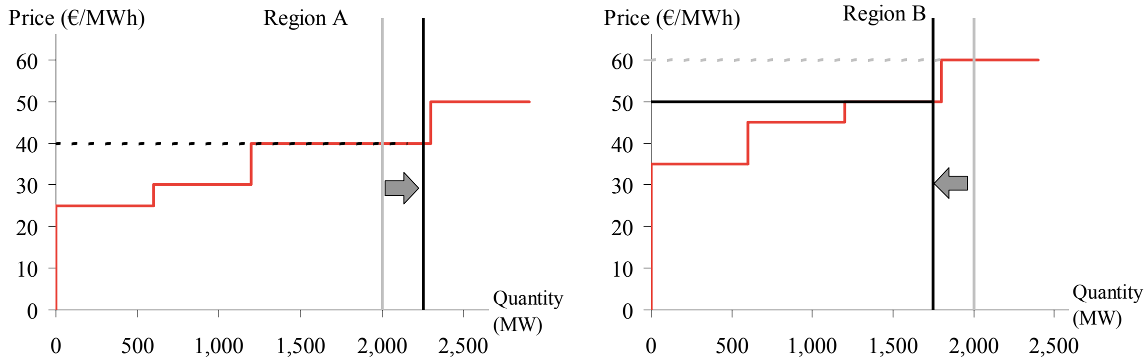

Figure 4.6: Market power example - basecase

Suppose Country B has a dominant incumbent, Gen B that uses the following strategy:

- If Gen B obtains transmission capacity, he withholds capacity in the energy market; and
- If Gen B doesn't obtain transmission capacity, he does not withhold capacity.

A possible outcome of the transmission auction is that other participants assume Gen B will not exert market power and would bid 10 €/MW for the transmission. If Gen B bid above 10€/MW, it would obtain transmission capacity. Following the strategy described above, Gen B would withhold 50 MW of generation capacity from the market, forcing the energy price in Country B up to 60 €/MWh. Gen B would make an additional 10 €/MWh profit on its generation capacity in Country B (although this would be partially offset by forgone profit on the 50 MW of generation capacity withdrawn from the energy market) and on the transmission capacity obtained through the auction.

Another possible outcome of the transmission auction is that other participants assume Gen B will exert market power in Country B and they would bid 20 €/MW for transmission capacity. If Gen B bid slightly above 10 €/MW as before, it would gain no transmission capacity. Following its energy market strategy, it would not withhold capacity and the energy market clearing price would be 50 €/MWh. Any participant who paid more than 10 €/MWh for transmission capacity would lose money.

Participants might be expected to make a probabilistic assessment of the likely outcome of the energy market. Sometimes other parties would obtain the majority of the transmission capacity and sometimes Gen B would. Gen B has a systematic advantage because it can observe the outcome of the transmission auction before deciding upon its action in the energy market. The correlation between transmission auction outcomes and energy market outcomes allows Gen B to capture additional rents by punishing others who obtain transmission capacity.

It could be argued that a dominant generator would always withhold capacity in the energy market in order to drive prices up to 60 €/MWh and therefore its behaviour in the energy market could be predicted and the transmission auction outcome would reflect this. We observe that there are typically implicit or explicit regulatory constraints on the energy market behaviour of large generators. If the regulatory constraint took the form of a cap on the average energy market price over the year, the game described above might be one effective way of a dominant generator complying with the price cap while maximising profits. Whenever the energy market price is high, the dominant generator delivers higher volumes to the market through the combination of transmission and generation capacity. Whenever the energy market price is low, the dominant generator delivers lower volumes into the energy market through its generation capacity alone.

Suppose the regulator capped the average annual price at 55 €/MWh. For simplicity we assume the demand and supply curves are constant throughout the year. Table 4.12 illustrates Gen B's annual profits for three possible strategies that meet the regulatory constraint. Gen B maximises profit when he follows Strategy 3, for which his energy market bid is contingent upon the transmission auction outcomes.

In the case of Strategy 1 and Strategy 2, Gen B's profit consists only of generation welfare. To the extent that he obtains transmission capacity he makes no welfare from the capacity (since purchasers pay the market price for transmission capacity). In the case of Strategy 3, Gen B's profit consists of: (i) generation welfare when the market price is 50 €/MWh, (ii) generation welfare when the market price is 60 €/MWh, and (iii) profit from using the interconnector. Gen B is able to make 10.95 €m profit from the transmission (10 €/MWh x 250MWh x 4380 hours) because his strategy deters others from bidding above 10 €/MW for transmission capacity. Gen B makes 10 €/MWh rather than 20 €/MWh profit from the transmission capacity he obtains since he would need to bid fractionally above others' bids of 10 €/MW, i.e. Gen B must pay 10 €/MW for transmission capacity. Gen B plays the high priced strategy for no more than half the year to stay within the regulatory constraint.

Strategy	Description	Annual profit (€m)	Avg. market price (€/MWh)
1. Marginal cost	Gen B offers generation capacity at marginal cost in Country B	105 [15 €/MWh x 600 MW + 5 €/MWh x 600 MW] x 8760 hours	50
2. Bid at regulatory constraint	Gen B offers generation capacity at 55€/MWh	182 [20 €/MWh x 600 MW + 10 €/MWh x 600 MW + 5 €/MWh x 550 MW] x 8760 hours	55
3. Mixed strategy	Gen B offers generation capacity at 60€/MWh or marginal cost, depending upon transmission auction outcomes	193 [15 €/MWh x 600 MW + 5 €/MWh x 600 MW] x 4380 hours + [25 €/MWh x 600 MW + 15 €/MWh x 600 MW + 10 €/MWh x 550 MW] x 4380 hours + [10 €/MWh x 250 MWh] x 4380 hours	55

Table 4.12: Profit from different bidding strategies

Table 4.13 shows the allocation of welfare to each participant for a single hour for Strategy 1 and 2 and, in the case of Strategy 3, the average allocation of welfare to each participant for a single hour. Total welfare is constant under the three strategies since generation dispatch is unchanged. However, welfare is transferred from consumers to Gen B when market power is exerted under Strategy 2 and 3. In addition, welfare is transferred from the TSO to Gen B under Strategy 3.

Participant	Welfare (€)		
	Strategy 1	Strategy 2	Strategy 3
Generation A	15,000	15,000	15,000
Generation B	12,000	20,750	22,000
Demand A	40,000	40,000	40,000
Demand B	20,000	10,000	10,000
TSO	2,500	3,750	2,500
Total	89,500	89,500	89,500

Table 4.13: Welfare allocation for different bidding strategies

We conclude that the explicit auction allows interconnector rent to be captured by a generator wielding market power under certain regulatory arrangements. An implicit auction would not suffer this problem.

4.4 Practical Issues

The above section sets out the theoretical differences between implicit and explicit auctions when uncertainty and market power are introduced. It concludes there may be some advantages with implicit auctions. The realisation of a pure implicit auction for the IEM would ideally require that a joint co-ordination of energy markets and transmission allocation throughout the EU be implemented. All cross-border exchanges would be traded through the formalised energy markets. In effect, power exchanges would be monopolies that would require regulation.

However, this is very different from the decentralised approach to energy markets and cross-border trade in place at the present time. Legislation, or at least additional regulatory measures, would probably be needed to require that energy markets coordinate and that all cross border trade go through those markets (cf. also [9])[9]. Therefore, it is unlikely that a pure version of an implicit auction approach can be implemented throughout the EU in the next few years.

An alternative to the pure implicit auction is a mechanism that allows for voluntary participation in integrated transmission and energy markets – a hybrid of explicit and implicit auctions. Under such a mechanism, power exchanges (using the curves derived from energy bids of their participants) would bid alongside other market participants for transmission capacity. In addition, all participants could offer locationally specific increment and decrement offers and bids. Sometime prior to the transmission allocation, participants could make bids and offers for energy into the power exchanges at either end of the transmission. Bids from the power

[9] This may for example, require the establishment of a nominated and regulated market operator in all Member States, something which is not currently required.

exchanges for use of the transmission would be developed on the basis of aggregated supply and demand curves from all participating power exchanges. The power exchanges and other market participants would then bid for transmission capacity and the transmission market would clear. Knowing their transmission allocations, the power exchanges would then clear their respective energy markets. Such a mechanism allows for energy and transmission trade to take place outside the formalised power exchanges and it allows for competing power exchanges. The voluntary nature of this mechanism would avoid the need for many of the changes that compulsion requires. Coordination of the timing of markets and balancing arrangements would be required. Instead of being regulated monopolies, power exchanges could compete with one another and with other trading platforms.

Explicit auctions are more reflective of the current decentralised arrangements for trading energy and allocating transmission capacity. The key implementational issue would be the coordination over the timing of transmission, energy and balancing arrangements across countries.

4.5 Conclusions of preliminary assessment

The key conclusion from our preliminary assessment of congestion management methods using the four assessment criteria is that both implicit and hybrid explicit/implicit auctions are worth further analysis.

An implicit auction would appear to be the economically most efficient mechanism, but for practical and legal feasibility reasons we recommend a hybrid explicit/implicit auction. An explicit auction would appear to be less efficient than such a hybrid auction because of the information gap between allocation and wholesale energy market clearance. However, explicit auctions are already widely used in the internal electricity market and would have advantages of ease of practical feasibility compared to a hybrid auction mechanism.

It would be possible for an allocation mechanism to use a combination of pure explicit and hybrid auctions. For example, it might use explicit auctions in respect of auctions prior to day-ahead and a hybrid auction on the day-ahead. We consider the use of auction combinations in chapter 5.

We also consider the feasibility of using a step-by-step approach to implementation, for example, an initial migration from legacy mechanisms to an explicit auction and later migration to a hybrid mechanism.

5 Design elements of congestion management methods

5.1 Overview

In the previous chapter we have concluded that, out of the broad range of basic congestion management methods, the explicit auctioning and the hybrid implicit/explicit auctioning approaches are the most suitable options for the development of the internal market. While the latter approach facilitates achievement of the greatest economic welfare, the former one is easier to implement in the short term. Consequently, it seems appropriate to strive for a progression via explicit auctioning to a hybrid implicit/explicit auctioning regime (if the hybrid approach cannot be implemented at once). The question of whether this progression can be efficient and thus recommended requires a detailed analysis of the different design elements which together comprise a complete congestion management concept (cf. section 2.3). The following discussion of the different design elements therefore serves two purposes:

- to derive a "complete" suggestion for a future congestion management concept, i.e. a consistent design covering all phases of the generic congestion management model (cf. fig. 2.1), and
- to provide a basis for the decision on the basic congestion models by considering for each design element which impact the integration or separation of transmission capacity and wholesale electricity markets has on its optimal implementation .

Our list of design elements to be analysed aims at being comprehensive with respect to the generic congestion management model, thereby covering all relevant topics dealt with in the various proposals for future congestion management solutions as well as the requirements set out by the European Commission. After outlining the key features of the two remaining basic models (section 5.2), we will discuss the following elements:

- Model to describe cross-border transmission capacity (section 5.3)
- Harmonisation and coordination (section 5.4)
- Integration with reserve power markets (section 5.5)
- Treatment of unexpected critical network conditions (section 5.6)
- Treatment of different time horizons (section 5.7)

- Auction design (section 5.8)
- Mitigation of market power (section 5.9)

The chapter is completed by an analysis of possibilities for the distribution of allocation rents (section 5.10).

5.2 Key features of acceptable congestion management options: Explicit auctioning and hybrid explicit/implicit auctioning

In this sub-section we outline key features of the two basic models to provide additional context for the discussion throughout the remainder of the report. Details such as the timing of the auctions, the definition of the products to be auctioned and the design of the auctions are not addressed in this sub-section. In the description, we refer to a single transmission link and two energy markets. The remainder of section 5 generalises the discussion to multiple links and multiple energy markets.

5.2.1 Explicit auction

Under an explicit auction, the relevant TSOs would auction cross-border transmission capacity using a mechanism that revealed users' value preferences and the capacity would be allocated to those with the highest value preferences. The auctioned product could either be an obligation to use the cross-border capacity or a right without obligation. The choice of product would depend upon the auction timing in relation to the timing of the energy market.

Broadly speaking, with the possible exception of exclusions related to market power concerns (which are discussed later in chapter 5), any participant could participate in the auction.

5.2.2 Hybrid auction

As with the explicit auction, the relevant TSOs would auction cross-border transmission capacity and the capacity would be allocated to those users with the highest value preferences. Both rights with obligation and rights without obligations would be auctioned.

Market participants and power exchanges would be allowed to bid into the cross-border capacity auction. They could either bid directly for the cross-border capacity between two countries or regions. Alternatively, both power exchanges and individuals could inform the TSOs of their value preferences for delivering increments and decrements of energy in a given region or country and the TSOs would use these value preferences when clearing the transmission capacity markets. Power exchanges are likely to prefer bidding for rights with obligations to reflect the firm nature of their own participants' bids and offers.

Two power exchanges operating in two different energy markets could affiliate in order to develop a bid function for the transmission capacity between the two energy markets. Alternatively, a single power exchange could operate on both sides of a transmission link and develop its own bid function for the transmission capacity. Indeed, there could be more than one power exchange pair bidding for a single transmission capacity product. These bids would compete with unilateral bids for the same transmission capacity from market participants.

In the case of more than two countries or regions, it may not be possible for power exchanges to develop consistent bid functions for all transmission capacity. Therefore, power exchanges and participants would be able to submit increment and decrement information to the TSOs and the TSOs would use this information when clearing the multi-country transmission capacity auction. This auction would aim at maximising total transmission value. Hence, depending on the specific situation of bid prices and transmission capacities, it may lead to transmission in the opposite direction of bid price differentials between some pairs of areas for the sake of increased arbitrage profits between other areas. This phenomenon will be discussed in more detail in section 5.3.3 (pp. 52 ff.).

The hybrid auction requires different coordination between the energy and transmission markets than the explicit auction mechanism, as illustrated in figure 5.1. For the hybrid mechanism, firstly power exchange(s) would close bid and offer acceptances for the energy markets. From bid and offer information, each power exchange pairing could develop a demand curve for country-to-country transmission capacity. The demand curve would be based on arbitrage opportunities between affiliated power exchanges at either end of the transmission. Under multilaterally coordinated capacity allocation the potential limitations of this pair concept could be overcome by generalising it such that each individual power exchange uses the bid-offer information to develop incremental and decremental functions per TSO area.

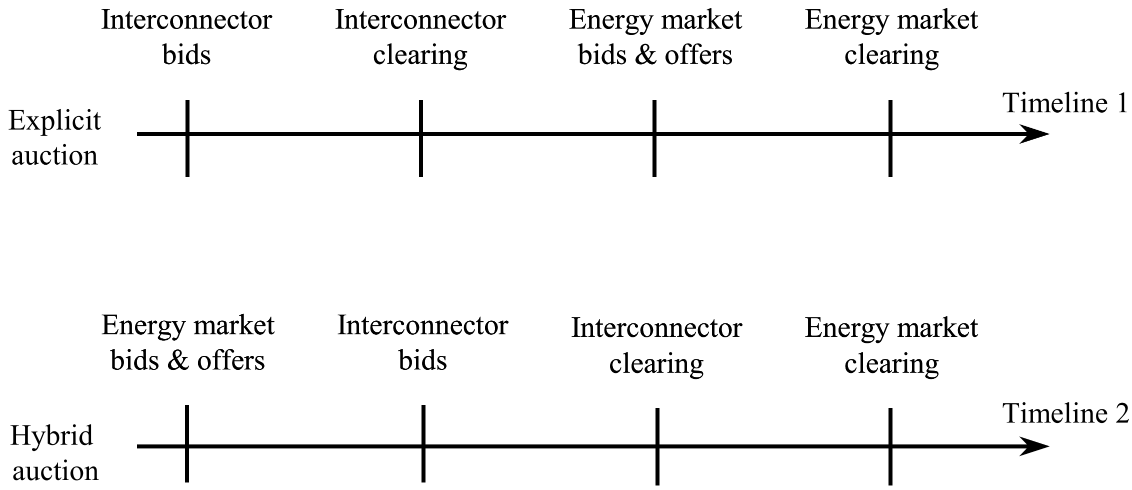

Figure 5.1: Timing of energy and transmission markets under explicit and hybrid implicit/explicit auctions

Secondly, the TSOs open the transmission capacity auction. Each power exchange pairing may submit its transmission demand curve into the auction as a bid or a power exchange may submit an incremental / decremental value function in respect of delivery to a single country. Participants may submit unilateral bids for transmission capacity or may submit their own incremental and decremental value function. Bidding closes, the TSOs clear the transmission capacity auction and the results are sent to the power exchanges and other auction participants.

Finally, the power exchanges clear their markets taking account of their obligations under the transmission auction. i.e. the market for transmission clears before the power exchanges clear.

In some respects the hybrid auction described is similar to EuroPEX's Decentralised Market Coupling proposal [6]. However, the hybrid proposal described here also allows transmission capacity to be procured by participants independently from power exchanges, allows for competing power exchanges and allows for participants and power exchanges to nominate incremental and decremental information directly to the TSOs for central clearing. The centralised clearing would deal with the specific details of national energy markets such as block products – thereby avoiding the need for an iterative solution. In summary, the key feature of the hybrid proposal is that it allows the market to decide which of the various trading options to use rather than being prescriptive about a single option.

Legal and credit issues related to the hybrid approach need to be examined in more detail prior to implementation. However, these issues are not within the scope of this study.

5.3 Model to describe cross-border transmission capacity[10]

5.3.1 Fundamental relation between bilateral transmission capacities and PTDF-based capacity model

The cross-border transmission capability of the UCTE network is mostly restricted by the admissible line currents, which, given the relatively constant voltage level, can approximately be expressed in terms of active **power flows** (unit: MW). From the network users' perspective, however, the transmission network mainly serves to enable **power exchange between areas**. Today, cross-border transmission capacity is therefore defined as a limitation of such exchange.

In the following, we will demonstrate that this allows only for an indirect and therefore rough limitation of the flows, leading to a certain risk for the TSOs as well as a partly avoidable restriction of cross-border power exchange. A more direct control of power flows is therefore in the interest of TSOs (in order to ensure network security more effectively), but also the key to higher social welfare. We will show that a capacity allocation based on so-called "power transfer distribution factors" (PTDF) is the solution to satisfy both sides, i.e. offering exchange volumes to the network users *and* considering power flows as the primary limitation of cross-border power exchange.

For the analysis we have to distinguish between two formally completely different capacity models:

- Bilateral capacity (such as NTC), i.e. maximum amount of power exchange to be allocated between two adjacent areas

- PTDF model based on maximum flow to be allowed on critical network elements or "flow gates"[11].

The difference between the two capacity models is however less fundamental than one might expect at a first glance. To demonstrate this, we start by analysing a two-area situation (i.e. a bilateral capacity allocation regime between area A and area B[12]). The application of bilateral capacity limits can be expressed as follows[13]:

$$NTC_{A \to B} \geq PT_{A \to B} \tag{5.1}$$

with NTC: net transfer (bilateral) capacity

PT: power transfer (i.e. power exchange) between two areas

[10] The quantitative analyses for this section have been contributed by the Institute of Power Systems and Power Economics (IAEW) of Aachen University of Technology (RWTH Aachen).

[11] A flow gate is a group of power lines (e.g. all tie lines between two countries) that is formally considered as one fictitious line. The maximum admissible flow of the flow gate denotes the joint capacity of the individual lines (usually being lower than the total of the maximum flows of the individual lines). Transforming lines to flow gates is an optional step when constructing a PTDF model. Since an individual line can be considered as a degenerated flow gate, we use the more general term "flow gate" throughout this section independently of the actual implementation of the PTDF model.

[12] irrespective of whether the electrical system comprises only these two or a larger number of areas

[13] For the sake of simplicity we assume that congestion is only relevant for exchange from A to B.

A PTDF is the share of a power transfer[14] that flows on a considered flow gate[15]. Multiplied by the amount of the power transfer, we get the power flow on the flow gate. This allows the limited capacity of the network to be expressed in terms of the "flow gate capacity", i.e. the maximum admissible flow on the flow gate:

$$FGC_{A \to B} \geq PTDF_{A \to B, A \to B} \cdot PT_{A \to B} \tag{5.2}$$

with FGC: flow gate capacity

Obviously, for $NTC = FGC / PTDF$ equations (5.1) and (5.2) become identical. This means that in the two-area case, the two capacity models coincide.

Consequently, a benefit from a PTDF model can only become effective when there are more than two areas involved (multilateral allocation of transmission capacity). This can be illustrated by starting from an NTC based model and stepwise developing it to a multilateral PTDF based one:

- For capacity allocation between three areas A, B and C, the NTC based model would, as a generalisation of eq. (5.1), consist of the following independent capacity constraints:

$$\begin{pmatrix} NTC_{A \to B} \\ NTC_{B \to C} \\ NTC_{A \to C} \\ \vdots \end{pmatrix} \geq \begin{pmatrix} PT_{A \to B} \\ PT_{B \to C} \\ PT_{A \to C} \\ \vdots \end{pmatrix} \tag{5.3}$$

[14] If deemed necessary a PTDF model can also reflect the isolated impact of unilateral actions (i.e. power injection or offtake), e.g. by introducing a so-called hub area as the fictitious counterpart of all unilateral actions.

[15] The precise relation between power transfers and power flows is non-linear. Under conditions that are fulfilled in the UCTE network (especially due to the fact that it is highly meshed) it can however be approximated by a linear relation with good accuracy.

- If capacity allocation for all borders was done by a single entity, but still based on NTCs, these individual capacity constraints could be written in an equivalent way as a single matrix inequality:

$$\begin{pmatrix} NTC_{A\to B} \\ NTC_{B\to C} \\ NTC_{A\to C} \\ \vdots \end{pmatrix} \geq \begin{pmatrix} 1 & 0 & 0 & \cdots \\ 0 & 1 & 0 & \\ 0 & 0 & 1 & \\ \vdots & & & \ddots \end{pmatrix} \cdot \begin{pmatrix} PT_{A\to B} \\ PT_{B\to C} \\ PT_{A\to C} \\ \vdots \end{pmatrix} \tag{5.4}$$

  Here, the “0” values of all elements except those on the main diagonal express the independence of the individual constraints, i.e. the fact that the amount of capacity allocated at one border does not affect the allocation at any other border. The equivalence of equations (5.3) and (5.4) demonstrates that in terms of allocable capacity, there would be no benefit from multilaterally coordinated capacity allocation if it was done on the basis of bilateral capacity figures.

- A PTDF model for the three-area case has a mathematical form that is identical to the previous model, but now the matrix considers the physical distribution of power flows:

$$\begin{pmatrix} FGC_{A\to B} \\ FGC_{B\to C} \\ FGC_{A\to C} \\ \vdots \end{pmatrix} \geq \begin{pmatrix} PTDF_{A\to B,A\to B} & PTDF_{A\to B,B\to C} & PTDF_{A\to B,A\to C} & \cdots \\ PTDF_{B\to C,A\to B} & PTDF_{B\to C,B\to C} & PTDF_{B\to C,A\to C} & \\ PTDF_{A\to C,A\to B} & PTDF_{A\to C,B\to C} & PTDF_{A\to C,A\to C} & \\ \vdots & & & \ddots \end{pmatrix} \cdot \begin{pmatrix} PT_{A\to B} \\ PT_{B\to C} \\ PT_{A\to C} \\ \vdots \end{pmatrix} \tag{5.5}$$

  As a result the constraints of the network, which in eq. (5.4) have been formally independent, are coupled. This means that on the one hand a single power transfer influences several (in principle, all) flow gates, and on the other hand each flow gate is influenced by several (in principle, all) power transfers.

The NTC based capacity model can thus be interpreted as a PTDF model which is based on the simplified assumption that the amount of power that can be transferred between two areas does not depend on the amount of transmission between any other two areas. The fact that such a dependency physically exists must in this case be considered implicitly by reducing the NTCs. The degree of this reduction is based on assumptions on the (uncertain) outcome of capacity allocation at other relevant borders. Such assumptions usually do not comprise the worst case (which would in most cases reduce the NTC to zero) but rather conceivable bad cases [10].

In contrast, the "true" PTDF model according to eq. (5.5) explicitly reflects the actual distribution of load flows as a function of inter-area power exchanges. The amount of capacity being allocated at the other borders can hence be considered as certain information. (Of course, due to remaining uncertainty, e.g. regarding network topology and generation dispatch inside the individual areas, the PTDF model can still only be an approximation; in contrast to the NTC model, however, it aims at achieving the best possible approximation of physics for a given, inevitable level of uncertainty.)

The "transformation" of uncertain to certain information leads to the technical and, consequently, economic superiority of the PTDF based capacity model (aspects of practicability will be discussed later in section 5.4.2). In the following section, this will be demonstrated by comparing PTDF and NTC based models with respect to their ability to adapt to the volatility of energy market prices. Moreover, a PTDF based model allows for a comprehensive consideration of "netting", i.e. the physical compensation of power flows in opposite directions; this will be discussed in more detail in section 5.3.3.

5.3.2 Consideration of volatile energy market prices

In this section we compare NTC and PTDF capacity models with respect to their ability to adapt to fluctuations of energy price differentials between regional power markets. We start with a simple, fictitious example and then extend the analysis to a more realistic model. As basic capacity allocation model we assume explicit auctioning; similar effects could however also be demonstrated for implicit auctioning. The effect of netting is not considered here since this is subject of a separate analysis in section 5.3.3.

The fictitious model system comprises three areas A, B and C of which A is considered to be the high price area. The physical flow limits and PTDF figures can be seen from fig. 5.2; the flow gate between B and C has infinite capacity. For the sake of simplicity we assume that both flow limits and PTDF are constant over time, so that market price relations between the three areas remain as the only time-variant values.

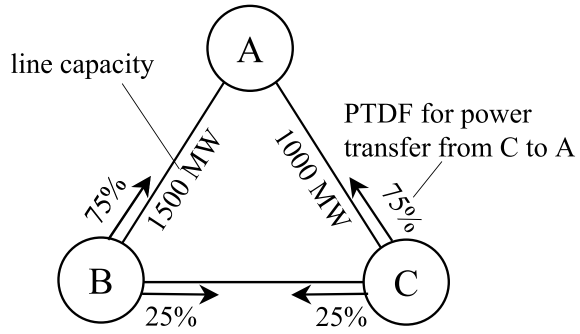

Figure 5.2: Fictitious model system

The question to be answered is how to determine the economically optimal distribution of power export to A from B and C, respectively. If we consider a static situation (i.e. a fixed point of time) this optimum can be achieved under NTC based allocation by using an optimal set of NTC values:

In situation a) in fig. 5.3 the market price difference between A and B amounts to 9 €/MWh, between A and C to 10 €/MWh. (We assume completely elastic generation supply.) The diagram shows the social welfare from export to A depending on the ratio between C→A transfer and total export to A. The grey and white parts of the diagram indicate that for low shares of C→A transfer the flow gate between B and A is the first one to be overloaded ("congested line"), whereas for higher shares of C→A transfer the physical bottleneck is the flow gate between C and A. If export from C amounts to 30 % of the total export to A, both flow gates reach their limits simultaneously. For the considered market price relations this ratio yields the highest social welfare. The optimal ratio of $NTC_{C\rightarrow A}$: $NTC_{B\rightarrow A}$ is thus 30:70.

However, under NTC based capacity allocation generators in C have both the economic power and the possibility to export more than 30 %. By booking transmission capacity from C to B they can overbid B's generators and thus also obtain transmission capacity between B and A. (This effect is known as the contract path phenomenon.) Since physical export would ultimately be only between C and A, the network would be overloaded. In order to achieve the economically optimal distribution of export from B and C, the TSOs therefore must set the NTC between C and B to zero. Obviously, this reduces the network users' flexibility to adjust their trading arrangements to changing market conditions.

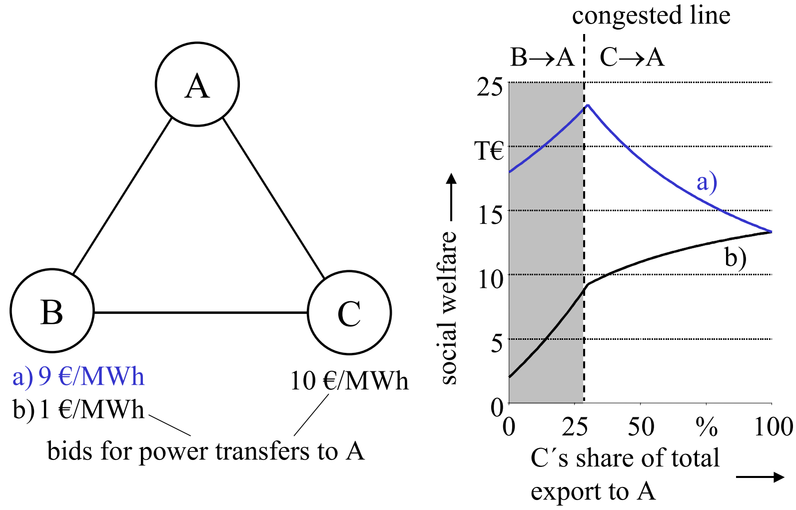

Figure 5.3: Social welfare for different distributions of export capacity to A and different market price situations

This can be shown by investigating situation b) in fig. 5.3. Due to the larger price difference between C and B it is now economically optimal if only C exports to A. If this situation was static, NTCs between C and B and between A and B could be set to zero allowing for an increased NTC between C and A. Obviously, however, this new set of NTCs would not be optimal for market price situation a) any more.

A compromise to overcome this problem of missing flexibility is to offer non-zero NTCs at all borders. This creates however (as mentioned above) opportunities to misuse the contract path principle, which must be considered by reducing the NTCs. In order to maintain a constant level of network security, this reduction must be based on a worst-case assumption. Fig. 5.4 shows that, compared to the optimal set of NTCs (30:70 ratio) for situation a) (left hand side), an increase of $NTC_{C \rightarrow B}$ to 1000 MW (right hand side) requires a significant reduction of the other NTCs. As a consequence, this set of NTCs is on the one hand more flexible with respect to volatile market conditions, but on the other hand leads to suboptimal social welfare in both situation a) and b).

A PTDF based capacity model overcomes these problems. For both situations discussed above, the respective optimal ratio between C to A and B to A power transfers would be determined through the inherent joint consideration of bid volumes and physical network properties. The economic efficiency of the PTDF based allocation is thus equivalent to the theoretical case of an NTC based model where the NTCs are automatically adjusted to each (hourly!) market price scenario.

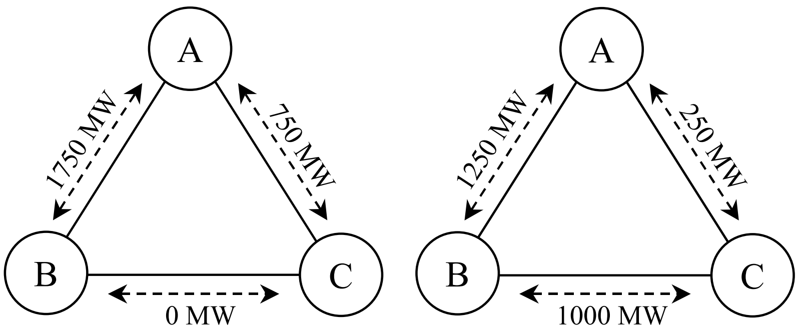

Figure 5.4: Different NTC settings under consideration of misuse of the contract path principle

In the next step we have estimated how significant this theoretical advantage of the PTDF based capacity model can be under more realistic conditions. For this purpose we have set up a model system for the region of France, Belgium, Germany and the Netherlands. In this region, three power exchanges (in F, NL and D) provide public data on market prices. (Since such information is missing for Belgium, this country had to be treated as a pure transit area.) Our analysis is based on actual hourly spot market prices for the entire year 2003.

Due to the limited availability of network-related data (including information on generation dispatch etc.) the network properties could be modelled only very roughly so that the resulting network model consists of three areas (F, NL+B and D) with flow limits expressed by estimated capacities of fictitious flow gates between the areas. Nevertheless, a cross-check with publicly available data, e.g. NTC values, gives rise to the expectation that the model allows reasonably realistic conclusions to be derived. In particular, it is detailed enough to differentiate between NTC based and PTDF based capacity allocation.

Based on this model, we have simulated the allocation of hourly transmission capacities under a number of simplifying assumptions, like perfect information on market prices, absence of market price elasticity, constant network conditions, and neglecting of interdependencies between the considered region and the rest of the UCTE system.

The realistic case of NTC based allocation with all NTC being non-zero (and constant throughout the year) has been used as a reference (fig. 5.5). As an alternative, we have reduced the NTC between France and Germany to zero. Since this eliminates opportunities for misusing the contract path principle, NTCs for export to the Netherlands can be increased. Under the conditions of the model system this NTC setting yields a slightly higher level of social welfare (increase of 5 %) that can be achieved with a smaller volume of cross-border power exchange. The amount of aggregated physical flow across the flow gates increases by the same percentage as social welfare.

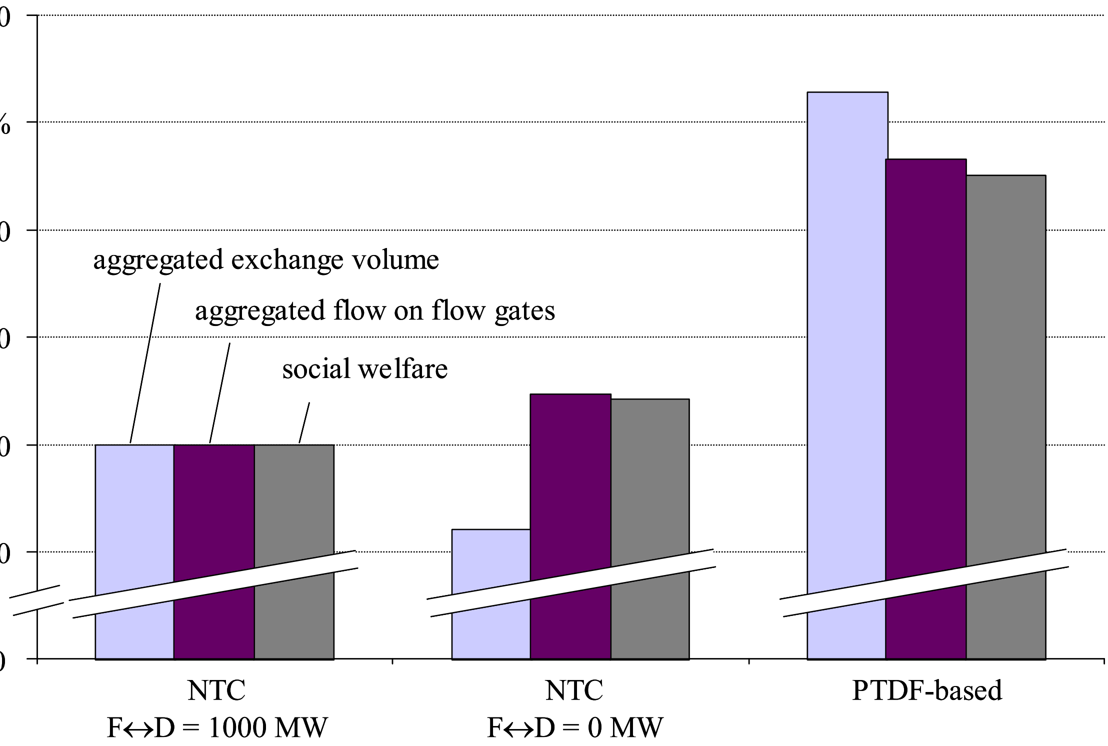

Figure 5.5: Social welfare for different allocation methods (model system F-(NL+B)-D, spot price data as of 2003)

If capacity is allocated using a PTDF based model, social welfare increases by 25 % compared to the reference case. This result underpins the conclusion that the inherent adaptation to market price volatility is a significant advantage of PTDF based capacity allocation, and that this effect is relevant under realistic market conditions. At the same time, both the volume of cross-border power exchange and the aggregated physical flows on the flow gates increase by the same order of magnitude. This is, however, not a sign of network security being threatened since both allocation models have been parameterised on the basis of the same security criteria. Rather, PTDF based allocation, as a consequence of reduced uncertainties, allows for a more even utilisation of the different flow gates.

5.3.3 Consideration of netting

In electrical networks, power flows in opposite directions cancel out each other. This effect is known as "netting" since only the net amount of flow is physically relevant. Two different kinds of netting can be distinguished:

- Netting of flows resulting from power transfers between a single pair of countries: When power transfers are nominated both from country A to B and from B to A, there is obviously some chance of netting (at least if it is certain that A and B are the physical sources and sinks of the respective transactions). Such cases are however only likely when capacity for a given time period is allocated several times and market price expectations vary over time.
- The more relevant case applies to situations of multilateral capacity allocation: For example, in the fictitious system used in the previous section (cf. fig. 5.2), power transfers from B to A relieve the flow gate between C and B and vice versa. Obviously, this effect can only be captured by means of a PTDF based capacity model.

Technically, a PTDF based capacity model can be adjusted so that the effect of netting is either considered or not. (Hybrid solutions, i.e. a partial consideration of netting, are feasible as well.) The decision as to which option to choose depends on the general set-up of the congestion management method, in particular on the allocation method and on the question of whether transmission capacity is allocated as rights with obligation or without obligation (table 5.1).

	Type of transmission rights	
Allocation method	**Rights with obligation**	**Rights without obligation**
Explicit auction	Commercial risk for network users	Risk of network security violations
Implicit auction	No risk	(not useful)

Table 5.1: Risk consequences if netting is considered, depending on the design of the congestion management method

- In an explicit auction regime it is not certain at time of the allocation whether the transmission capacity obtained can be used for profitable power trade (cf. section 4.3.1). Hence, when transmission rights are allocated *without* the obligation to exercise them, the

TSOs cannot be sure that the "counter flow" required to relieve a congested network element will actually take place. Netting of transmission rights within an allocation phase would therefore create the risk of network security violations. By allocating rights *with* obligation, the TSOs' operational risk would be transformed to a commercial risk for the network users: While the TSOs would be able to consider all transmission rights as being physically exercised, those users who fail to settle a trading arrangement matching their transmission rights would have to buy and sell the equivalent amount of balancing energy[16].

The inevitable risk of the consideration of netting *within* an allocation phase can, however, be mitigated by using the fact that transmission rights have to be firmly exercised (in part or totally) *between* allocation phases: As a consequence of the "use it or lose it" principle network users usually have to nominate firmly which part of the transmission capacity that they have obtained from early allocation phases (e.g. year or month ahead) they will use prior to the start of the subsequent allocation phase (month or day-ahead, respectively). The netting effect of these firm nominations can be considered free of risk, thereby increasing the amount of transmission capacity remaining for the next allocation phase[17].

- In contrast, implicit auctioning allows for the allocation of rights with obligations because transmission rights are automatically and implicitly exercised by the auctioning entity. Therefore, in the hybrid auction netting can be taken into account for the implicitly allocated share of transmission rights without imposing additional risk on the involved parties.

From the above considerations one can conclude that the (risk free) *possibility* to consider netting exists, irrespective of the basic congestion management model, at least for a part of the

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[16] For example, if a trader obtains a transmission right (with obligation) of 100 MW from country A to B for one hour, but fails to conclude a corresponding energy transaction, he will have a balance deviation of 100 MW in both countries, i.e. he will be charged 100 MWh of positive balancing energy in A and 100 MWh of negative balancing energy in B.

[17] This is similar to the treatment of the "base case exchanges" in the present procedures for NTC calculation [2]: When setting up the "base case" load flow situation, the netting effect of all base case exchanges is implicitly considered.

transmission rights. In the following, we want to assess the potential *benefits*, i.e. which effect the consideration of netting may have in principle on the results of transmission capacity allocation. For this analysis we compare the extreme cases of full netting (like it is possible in an implicit auction regime) vs. no netting at all (like an explicit auction regime where only one allocation phase exists).

As a first step we return to the model system of fig. 5.2 with the following assumptions on the energy prices: we assume fixed prices of 6 €/MWh in A and 5 €/MWh in C. Regarding the price in B, we consider two different scenarios (table 5.2):

- When the price in B is equal to A (5 €/MWh), the consideration of netting leads to a marked increase in social welfare (about 50 %). The total volume of commercial power exchange between the three areas is increased by the same percentage, and physical flows across the flow gates increase by 63 %.
- A significantly different result can be observed when a price of 7.5 €/MWh is assumed in B. Here, the netting yields a more modest increase of social welfare (about 33 %), but the total cross-border exchange volume is tripled. The average incremental welfare (in € per MWh of commercial exchange) is thus relatively small. (Due to the physical flow compensation the relative increase in aggregated power flow across the flow gates [160 %] is smaller than the increase of commercial exchanges, but with still notable.)

  To illustrate the reason for this effect, fig. 5.6 shows the optimal power transfers and resulting power flows for this scenario. Without netting, the most profitable power transfer is from A to B, because the low flow gate capacity between C and B prevents profitable export from the low-price country C. When netting is considered, A exports 800 MW to C (losing 1 €/MWh) in order to relieve the bottleneck (flow gate C→B). Since this relieving effect is now considered, more power can be transferred from A to B (earning 1.5 €/MWh). Ultimately, C becomes a net importer although having the lowest price level.

The simple example shows that the economic benefit of netting strongly depends on the system conditions. In particular, netting may motivate power transfers against the profitable energy price differentials if this enables other transfers that are (maybe only slightly) more profitable.

	Without Netting			With Netting		
Energy price in B [€/MW]	**Aggregated exchange volume [MWh]**	**Aggregated flow on flow gates [MWh]**	**Social welfare [€]**	**Aggregated exchange volume [MWh]**	**Aggregated flow on flow gates [MW]**	**Social welfare [€]**
5	1,600	1,600	1,600	2,400 (+50%)	2,600 (+63%)	2,400 (+50%)
7.5	800	1,000	1,200	2,400 (+200%)	2,600 (+160%)	1,600 (+33%)

Table 5.2: Effects of netting for model system according to fig. 5.2 (Energy prices: 6 €/MWh in A and 5 €/MWh in C)

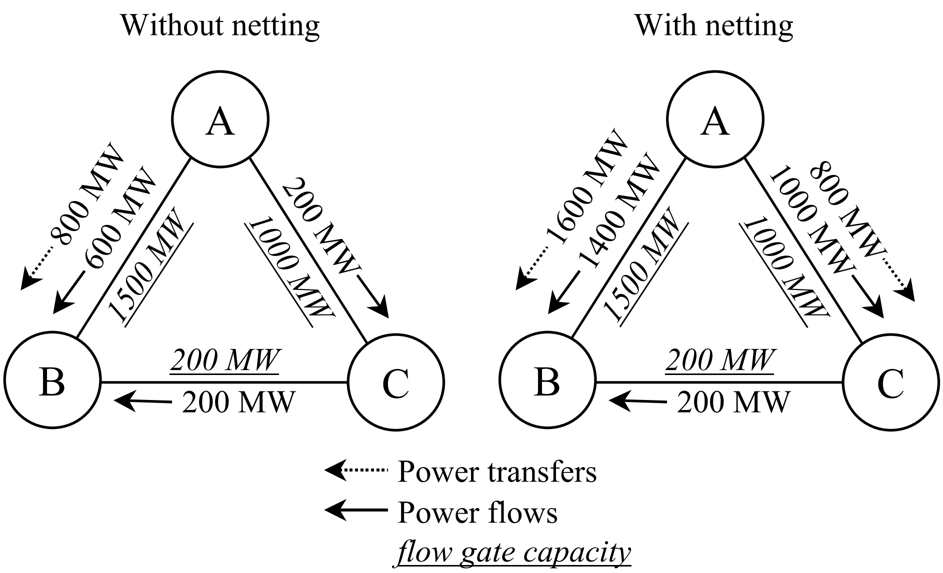

Figure 5.6: Effect of netting on power transfers and flows (Energy prices: 6 €/MWh in A, 7.5 €/MWh in B, 5 €/MWh in C)

As a second step, we have repeated the simulation of capacity allocation for the F-(NL+B)-D model system under consideration of netting. With the NTC based results again set to 100 %, netting leads to an increase of social welfare by 6 % as compared to PTDF based allocation without netting (fig. 5.7). The incremental benefit of netting is thus notable, yet much smaller than the difference between NTC based and PTDF based capacity models.

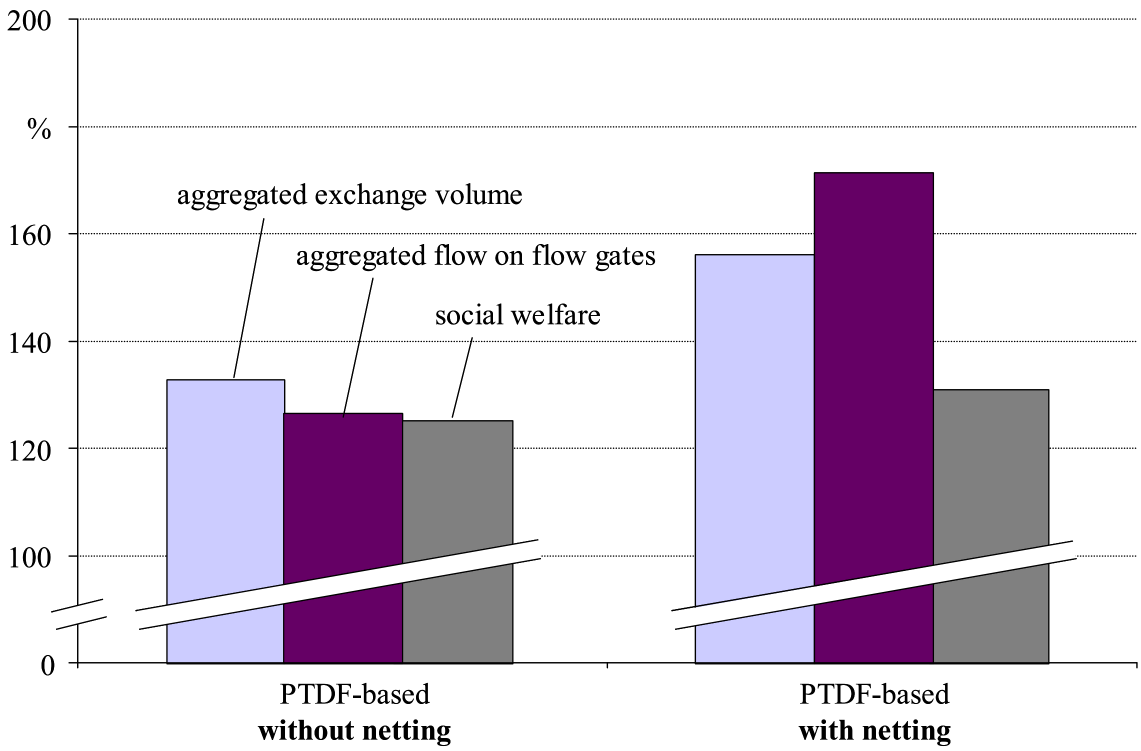

Figure 5.7: Effects of Netting on the amount of transmission volume and on social welfare (model system F-(NL+B)-D, spot price data as of 2003)

As a general[18] result we can conclude that the benefit from the consideration of netting can vary significantly and therefore requires case-specific investigations. While the increase in social welfare may be notable, there might also be a notable increase in the volume and volatility of both commercial power exchange and physical flow across the flow gates (especially if individual hours are regarded instead of averages). This may cause considerable operational challenges for the TSOs. Besides, at least in the model simulation for the F-(NL+B)-D region, the increase of social welfare from PTDF based capacity allocation as compared to an NTC based model is by far more significant than the additional benefit from the consideration of netting.

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[18] Naturally the simulation results are depending on the case-specific data and assumptions. It is however important to remark that they are not substantially determined by the simplifications of the network model that we have used. Exemplary investigations with a more realistic network model (including more areas as well as flow limits on individual lines instead of flow gates) yield qualitatively similar results.

As a consequence of our analysis, our **recommendation** as to the consideration of netting in the context of transmission capacity allocation is not a simple yes or no. Rather, when weighing both the risks and the potential benefits the treatment of netting should be adapted to the allocation phases:

- **Netting between allocation phases** (e.g. between monthly and day-ahead allocation) should be considered for those transmission rights that have already been firmly exercised.
- Regarding **netting within the same allocation phase**, the recommended treatment is different for the two basic congestion management models under consideration:
    - Hybrid implicit/explicit auction: In general, netting should be considered for the implicitly allocated share of the transmission capacity, but potential operational problems arising from a significant increase of transmission volume should be carefully observed.
    - Explicit auction: Here, the consideration of netting imposes a certain risk, either on the network users (if transmission rights are allocated with the obligation to exercise them) or on the TSOs (if rights without obligation are not exercised). Our basic recommendation for the explicit auction is that rights remain without obligation. Hence we do not recommend to apply netting in this case[19]. However, we consider that it may well be possible to extend explicit auctions to deal with rights with obligations as well as rights without. We anticipate that clearing prices would for the two would differ by the value of the right to transmit in the direction opposite to the expected flow. When participants are not forced to assume the risks associated with rights with obligations,

[19] The complete neglecting of netting ensures that network security is maintained even under worst case assumptions on the utilisation of transmission rights. Similar to the discussion of NTC vs. PTDF in section 5.3.1 above, the consideration of "conceivable bad cases" instead of the worst case could mitigate the reduction of social welfare when allocating rights without obligations. Translated to the netting issue, this could be achieved by considering partial netting even within an allocation phase. However, given the risk-free possibility to consider full netting between the allocation phases and the unclear economic advantage of further netting, any netting within an allocation phase should be left for "fine tuning" and not be introduced as the first step.

they can reasonably be left to optimise whether they buy rights with or without obligation. However, we should stress that we have not done a cost benefit study of such additional complexity and, in any event, we think it would be appropriate to trial this before proceeding to wider adoption.

5.3.4 Options for the size of trade areas

Today, cross-border transmission in the IEM is managed by means of power exchange schedules that are defined between areas. In the broad majority of cases these areas coincide with the TSOs' control areas. Hence, the distribution of total generation within each control area is not affected by cross-border congestion management measures. In turn, when determining cross-border transmission capacities, the TSOs cannot rely on a specific internal generation pattern and therefore must consider the missing locational information as an uncertainty.

In principle, this uncertainty could be reduced by defining trade areas that are smaller than a TSO's control area. This could allow for an increase in transmission capacity. Moreover, the cross-border congestion management mechanism could then also be used to deal with internal congestion, i.e. the TSOs would be able to limit, if necessary, the amount of inter-regional power exchange inside their control areas[20].

On the other hand, the separation of a domestic market into smaller areas could also have negative effects, e.g. by increasing the imbalances of balance responsible parties or by reducing market liquidity. In order to be able to increase cross-border transmission capacity, any domestic power transfer between different areas would require the network users to obtain transmission rights through the cross-border allocation mechanism.

[20] The example of Norway (being split into three zones of a total of seven zones in the Scandinavian market) shows that internal and cross-border congestion can indeed be managed within the same framework. The extreme case in this respect is the so-called "nodal pricing" approach (being applied in a number of overseas electricity markets, e.g. PJM in the USA) where each network node becomes an area of its own.

From these general considerations one can conclude that the question of the “optimal” area size (including the definition of optimality itself) does not have a simple answer, even if only economical and technical aspects are considered. Moreover, practical and, eventually, legal arguments need to be taken into account when deciding on the feasibility of a division of the existing trade areas.

As regards the selection of a basic capacity allocation method as well as the capacity model the specification of the trade areas is of a gradual nature and thus has no impact on any fundamental recommendation with respect to the congestion management method. (For simplicity we therefore continue to assume that trade areas coincide with TSOs’ control areas in the remainder of this report. This does, however, not imply any anticipation regarding the future area specification; most considerations also apply to smaller areas when the term “cross-border” is generalised to “cross-area”.)

5.3.5 Further aspects

Our analysis has shown that – regardless if transmission capacity is allocated by explicit or implicit auctioning – a PTDF based capacity model is superior to bilateral capacities in terms of both economic welfare and network security, even when only three areas coordinate the transmission capacity allocation using a rather simple PTDF model. The technical effort to create such a model is comparable to the calculation of bilateral capacities such as NTCs. (Organisational issues regarding the model determination are dealt with in section 5.4.2.)

Starting from a basic PTDF based capacity model, the utilisation of the network could be improved even further by considering technical and organisational options:

- The more areas participate in a multilaterally coordinated capacity allocation based on a PTDF model, the less uncertainty remains regarding the utilisation of the network by foreign actors. This reduction of uncertainty allows to reduce the respective margins and thus leads to a further increase in transmission capacity at the same level of network security.

  (It is however important to note that a large number of areas is not a necessity. Rather, the application of a multilaterally coordinated capacity allocation on the basis of a PTDF model is both beneficial and feasible even if only a small group of TSOs participates. In this case the allocation of transmission rights between members of the “coordinating group" and other areas continues to be performed border by border and on the basis of bilateral capacities.)

- A PTDF based capacity model allows to take account of the ability of phase shifting transformers to control the power flow [12]. This allows TSOs to coordinate the use of these transformers in reaction to the market requirements.
- The consideration of individual transmission lines and transformers instead of flow gates may further improve the accuracy of the model.

5.4 Harmonisation and coordination

5.4.1 General considerations

At present, cross-border congestion management in the continental part of the IEM is characterised by bilateral transmission capacity allocation which is performed individually per border and (with the exception of transmission from France to Spain) separated from the energy market. The individualisation relates to a number of aspects, e.g.

- allocation method (cf. section 2.2.1),
- time schedules (e.g. gate closure for submission of bids/applications, notification of allocation result),
- type of transmission rights (e.g. yearly, monthly, hourly),
- firmness of transmission rights,
- rules for secondary trade of transmission rights.

This situation does not only constitute a practical burden for network users trading between more than two countries, but is also a clear reason for economic inefficiency of the allocation process as we have discussed in section 4.3.1.

For these reasons, we recommend to strive for a harmonisation of the above aspects. Moreover, such harmonisation is the prerequisite for the introduction of a multilaterally coordinated allocation based on a PTDF capacity model, the advantages of which we have discussed in section 5.3.

A multilateral allocation of transmission capacity that takes into account the interdependencies between the participating countries' transmission systems requires the core allocation procedure to be executed by one single entity. In an explicit auction regime this entity would gather all bids for transmission capacity from the network users. With a hybrid solution of implicit and explicit auctions it would also be the counterpart for the national power exchanges who implicitly manage cross-border transmission for their respective participants.

From the network users' perspective the introduction of such a single, centralised entity would be clearly an advantage compared to the present situation, because they could manage all (explicit) purchase of transmission capacity at a single place. For the TSOs however, it is important to ensure that the degree of centralisation is limited, i.e. that there remains a shared responsibility for the transmission capacity and the utilisation of the transmission network. This may be a legal requirement due to the regional system responsibility of each TSO and thus a prerequisite for an implementation of the multilateral capacity allocation in the short term.

The example of the capacity auctioning procedure between the Dutch TSO TenneT and its three neighbours demonstrates the feasibility of multilateral capacity allocation in the UCTE system [13, 14]. The auction is managed by a central "auction office", and identical rules and schedules apply for all three involved borders. (However, the allocation is still based on individual, bilateral transmission capacities.)

Obviously, the implementation of a multilaterally coordinated allocation of transmission capacity requires at least the involved TSOs to agree on joint procedures. But also the respective regulators need to develop a harmonised attitude regarding the acceptance of the proposed congestion management methods. As regards the introduction of a hybrid implicit/explicit auction, further consent needs to be achieved among the power exchanges and between these and the above mentioned parties. In any case, the harmonisation of cross-border network access regulations may be limited by restrictions of the domestic market rules (like the absence of week-end trade in Austria, for example), which may require special treatment.

In the following sections, we discuss in more detail coordination issues related to the determination of a joint transmission capacity model (section 5.4.2) and a potential integration of transmission capacity and wholesale electricity markets (section 5.4.3). Section 5.4.4 summarises our conclusions on harmonisation and coordination in the framework of cross-border congestion management.

5.4.2 Determination of transmission capacity model

In section 5.3 we have concluded that a PTDF based capacity model is superior to bilateral capacities with respect to the assessment criterion of economic welfare. Since the determination of a common PTDF model for a number of TSO areas requires some coordination among the involved TSOs, it is necessary to check if also the criterion of practical feasibility is met. We are approaching this question from two viewpoints: We first analyse the data provision effort and then discuss the consideration of shared responsibility for system security.

Regarding the **data** requirements, it is important to note that common load flow files (that can be used as the basis for the determination of the PTDF model) are already prepared regularly by UCTE members and e.g. used for the NTC calculation. If these were used to derive a PTDF model instead, benefits from the multilaterally coordinated allocation could already be realised without additional effort for network data provision and handling. Further benefit could then possibly be achieved by updating the model before each auction round (leading to a reduced level of uncertainty that allows for smaller uncertainty margins and thus an increased amount of transmission capacity). Such a regular model update is conceivable because there exists already some experience in the frequent creation of common UCTE load flow files through the so-called “day-ahead congestion forecast” (DACF) mechanism of UCTE[21].

The **shared responsibility** for the transmission capacity, i.e. the fact that each TSO is responsible for system security in his area, could be respected by two alternative approaches:

[21] DACF load flow files are however not directly usable as input for the capacity allocation process. The reason for this that the DACF procedure aims at providing forecasted load flow models for the following day. These are based on data obtained *after* the allocation of day-ahead transmission capacity and closure of the day-ahead energy markets.

- When setting up the common load flow model which is used to derive the linear PTDF model for the allocation procedure, each TSO is responsible for his contribution, i.e. for the part of the load flow model that reflects his network area. This is similar to the organisation of the DACF procedure, with the difference that a central entity would have to be responsible for merging the individual TSOs' contributions (whereas the DACF files are merged independently by each TSO) and computing the PTDF model. Consequently, the individual TSO's control over the utilisation of his network could be considered rather indirect with this approach.
- As an alternative, each TSO could compute the part of the PTDF model that represents the flow constraints in his area. This way each TSO would have direct control over the maximum utilisation of his network, including the consideration of, for example,
    - individually adapted load flow data in order to reflect the best possible forecast of future system conditions, and
    - individual network security criteria.

  On the other hand, these possibilities for individualisation would make the process of the PTDF determination less transparent and auditable.

A decision between these alternatives ultimately depends on the assessment of the balance between TSOs' requirements on the one hand and regulatory concerns, e.g. regarding transparency, on the other.

The theoretical third alternative that each TSO has to confirm the allocation result (including the transmission rights to and from his area) is unrealistic, because this would have to take place after the allocation when there is not enough time for regular re-negotiation of the transmission rights.

At a first glance this seems to be a disadvantage compared to the present situation: Today each TSO formally has full control of all NTCs to and from his area. However, he has not the power to reject patterns of transmission rights between other areas that, if exercised, threaten system security in his area. Hence, regarding a TSO's ability to fulfil his regional system responsibility, the power to control his respective part of the PDTF model or to contribute his area to the common load flow model (together with a prior approval of the PTDF calculation algorithm) constitutes an improvement over the present situation, because it allows a more direct control of the flows in his area, which are the physically relevant measure.

5.4.3 Coordination of transmission capacity and energy markets

Coordination of transmission capacity markets and energy markets is required to maximise the likelihood of efficient outcomes. This sub-section discusses several coordination issues.

The minimum duration for which use of transmission capacity can be nominated, i.e. its granularity, should ideally be coordinated with the granularity of balancing markets in the countries concerned. If the granularity of transmission capacity were coarser than the balancing market, two problems could arise:

- The value of transmission could be eroded if the shortest possible duration transmission nomination resulted in a flow with positive value during one balancing period and negative value during the next balancing period. The value of transmission would equal the average of the (positive and negative) values across the two balancing periods.
- The value of transmission could be eroded if a transmission nomination forced parties to be exposed to the balancing market and the balancing market had penal prices, e.g. a spread between balancing prices, or volatile prices. If the specific balancing arrangements of a country allowed interconnector imbalances to be offset by adjustments to domestic generation, exposure to imbalance prices may be reduced.

There would be no such problem if the granularity of transmission capacity were finer than the balancing market. However there would be no advantage of using finer granularity than necessary and the additional detail could potentially increase the cost of the transmission allocation and nomination mechanisms.

European balancing market granularity ranges from one hour (e.g. Spain) to 15 minutes (e.g. Belgium). To be consistent, participants should be allowed to nominate transmission capacity in blocks of 15-minutes. The alternative, i.e. extending the granularity of all European balancing periods to, say, one hour may result in additional balancing costs to TSOs and would appear to be an unnecessary sacrifice for the harmonisation of cross-border trade.

In the case where rights to use interconnector capacity rather than obligations are auctioned, the granularity of the right auctioned need not be aligned with the granularity of the capacity nomination and balancing mechanism. For example, rights to use capacity might be auctioned in daily or hourly blocks and firm nominations to use capacity might be made in respect of 15-minute intervals.

The duration and timing of transmission capacity release in advance of the day-ahead also requires coordination between transmission and energy markets since it is likely that participants who operate across borders would want to match transmission transactions with their energy market transactions. In section 5.7 we analyse participants' relative preferences for energy market transactions of different contract durations.

At the day-ahead stage, the implicitly allocated share of capacity under a hybrid auction would be sold as rights with obligations. To maximise transmission value, transmission capacity would ideally need to be allocated in blocks of the finest granularity, i.e. 15-minutes or 96 products per day.

Under an explicit auction, rights could either be sold with or without obligations. Rights with obligations would allow netting and therefore greater release of transmission capacity to the market. As before, rights with obligations would ideally require transmission capacity to be allocated in blocks of the finest granularity. In addition, if the transmission auction occurs prior to energy market clearing, participants would need to forecast energy market outcomes prior to taking part in the transmission auction. Alternatively, if energy market clearing occurs prior to the transmission auction, participants would need to forecast transmission auction outcomes prior to taking part in the energy market.

Rights without obligations would prevent netting and therefore would potentially constrain the amount of transmission capacity sold to the market. In the case of power transfers between two countries, netting would only release additional capacity if there were simultaneous nominations in opposite directions (e.g. see the analysis of IFA in Annexe 2), which implies possible problems with the energy markets. Rights without obligations would however allow the sale of transmission capacity in blocks longer than the finest granularity and may facilitate the coordination of transmission and energy markets.

The various alternatives for explicit auctions require tradeoffs and there is no perfectly efficient solution. As described in section 5.3.3, the benefits of netting may be small depending upon the situation specific circumstances. Therefore, given the problems of coordination between energy and transmission markets under an explicit auction, on balance the greatest benefit is likely to be achieved through the sale of rights without obligations at the day-ahead stage. However, as noted above (cf. section 5.3.3), explicit auctions dealing in rights both with and without obligations could be developed.

Prior to the day-ahead stage granularity should be coarser than 15 minutes in order to reduce transaction costs. This implies the sale of rights, which in turn implies the use of explicit auctions rather than the hybrid auction. Use-it-or-lose it provisions would be applied prior to the day-ahead auction in order to prevent the hoarding of unused capacity. This requires capacity nominations to be made prior to the day-ahead auction in respect of rights held or for rights to be surrendered into the day-ahead auction contingent upon price.

Information release about the transmission and energy markets also requires coordination. Knowledge of available transmission capacity and available generation plant at the day-ahead stage would assist in coordination of the energy and transmission markets. This would be relatively more important in the case of explicit auctions. A disadvantage with information release of this type is that it could assist coordination between large market participants, which would potentially exacerbate any market power problems.

5.4.4 Conclusions

From the above considerations we can draw the following conclusions:

- The allocation of cross-border transmission capacity should be multilaterally coordinated
    - in order to reduce the amount of uncertainty for the network users and
    - in order to be able to realise the benefits from a PTDF based capacity model (cf. section 5.3).
- The larger the group of participating countries/TSOs becomes, the greater is the benefit from the multilateral coordination. Yet even a group of only three adjacent TSOs can improve the efficiency of capacity allocation (and thus increase social welfare) by coordination.

- The determination and application of a PTDF based transmission capacity model requires a minimum degree of coordination and centralisation among TSOs. This is independent from the question if explicit or hybrid explicit/implicit auctioning is performed. The gradual centralisation is compatible with each individual TSO's responsibility for network security in his area. The PTDF based model even offers the possibility of increased at a technical and data provision effort that is comparable to the present procedure for NTC determination.
- Ideally rights with obligations would be sold with granularity equivalent to the corresponding balancing markets. In the case of rights without obligations, the granularity of capacity nominations would ideally equal the corresponding balancing markets.
- With explicit auctions, on balance the greatest benefit is likely to be achieved through the sale of rights without obligations at the day-ahead stage but development to include rights with obligations should also be feasible.
- At the day-ahead stage, the implicitly allocated share of capacity under a hybrid auction would be sold as rights with obligations.
- Prior to the day-ahead stage, rights without obligations would be sold in order to allow coarser granularity of the capacity product auctioned.

5.5 Integration with reserve power markets

One of the essential requirements for the functioning of power systems is that total generation and load (including losses) must always be balanced. In order to have the possibility to ensure this balance in real time, the TSOs must procure reserve power, i.e. they contract a predetermined amount of generation capacity[22] as an option of which only a part will be actually

[22] Reserve power can also be provided by controllable loads; however, generators are the most relevant providers of reserve power.

exercised, depending on the actual system (im)balance[23]. The procurement thus takes place significantly before real time.

Since on the one hand quick activation of reserve power is needed for short-term balancing and on the other hand slower reserve is cheaper to provide, reserve is differentiated into several categories. For example,

- the TSOs of the Nordel interconnected network distinguish between primary (automatic) and secondary (manual) control, and
- the TSOs of the UCTE interconnected network have agreed on three control mechanisms, namely primary and secondary control (both automatic) and tertiary control (manual).

Originally reserve power was exclusively provided by generators inside the respective TSO's control area. In recent years some markets for reserve power – especially for "slow" reserve power which is manually activated with several minutes notice – have been opened for foreign participants (e.g. France/Switzerland, Sweden/Finland). It is not the goal of this study to propose an optimal design for the European reserve power market(s). Nevertheless, any congestion management concept to be proposed should allow for a flexible provision of reserve power across borders irrespective of the specific reserve power market design[24]. This is not just because of a political will to create international markets for all market segments, but rather because both the demand for reserve power (especially due to the recent wind power development) and the potential suppliers (e.g. hydro power plants) are distributed heterogeneously across the EU. Consequently one can expect an increase in social welfare from cross-border access to reserve power markets.

[23] The term "reserve power" is sometimes mixed up with "balancing power" or "balancing energy". The latter is the result of the allocation of the TSOs balancing cost – which he incurs by procuring and utilising reserve power – to the network users, e.g. by socialisation or by identifying each balance responsible party's contribution to the total imbalance.

[24] The specific market rules may, for example, restrict the import and/or export of reserve power to manual reserve. In principle, however, the considerations in this section apply to any kind of reserve power.

Obviously, under these circumstances reserve power markets compete with wholesale energy markets for the limited cross-border transmission capacity. Nevertheless, at least under the assumption of completely transparent market conditions the partial reservation of cross-border transmission capacity for the eventual delivery of reserve energy leads to an increase in social welfare [15].

In contrast to wholesale energy markets, the products traded in a reserve power market always constitute options. Consequently, the related transmission capacity must also be “rights without obligations”, irrespective of the respective specification of the transmission rights for wholesale energy delivery.

In general, the allocation of cross-border transmission capacity for the provision of reserve power could be organised in two different ways:

1. **Subsequent** allocation: The allocation of transmission capacity for reserve power takes place after the nomination of day-ahead capacity for wholesale energy delivery. Since this would be equivalent to the introduction of another allocation phase the netting effect of wholesale power transfers could be fully considered regardless of whether there was an explicit or implicit capacity allocation (cf. section 5.3.3). On the other hand there would be no true competition between the two purposes of transmission capacity; rather, the participants to the foreign reserve power markets would have the lower priority and thus get the remaining capacity[25]. (To our understanding, this method is currently applied in the Elbas market of Finland and Sweden.)
2. **Simultaneous** allocation of capacity for day-ahead energy delivery and cross-border access to reserve power markets. Technically such an integration would be feasible: Both the explicit and the hybrid implicit/explicit auction concept already offer rights without obligation. Hence it would be sufficient to allow network users to use these rights either for scheduled delivery or for the provision of reserve power.

[25] The severity of this general disadvantage depends on the question to which extent the profitable directions of wholesale energy transmission coincide with those for reserve energy delivery.

In theory, this second option should be the more efficient one since it allows for competition between the different types of network utilisation. In practice, however, network users could possibly abuse the opportunity to reserve capacity without the intention to use it: They could hoard capacity obtained in medium-term (e.g. yearly or monthly) allocation phases by declaring the unused part as an option to participate in the reserve power market. Hence the use-it-or-lose-it principle could be undermined. To avoid this, two solutions are conceivable:

a. A pre-determined fixed percentage of the transmission capacity is allocated for cross-border reserve power provision. This percentage could be updated regularly, e.g. once a year, based on market experience.

b. The network users could be monitored in order to trace whether the capacity allocated for providing balancing power is actually used, i.e. if the owners of the transmission rights for reserve power actually bid at a realistic price into the reserve power market beyond the respective border.

From the above considerations we can draw the following conclusions:

- An explicit allocation of transmission rights (without obligation) for cross-border access to national reserve power markets is possible regardless of whether the wholesale energy market is integrated with, or separated from, the allocation of cross-border transmission capacity.

- The easiest way to integrate transmission capacity allocation for reserve power provision is to perform it subsequent to the allocation of capacity for wholesale energy delivery. Alternatively, a competitive allocation of both kinds of transmission capacity is conceivable and may be more efficient, but would probably require special measures to prevent abuse of the use-it-or-lose-it principle.

- Since the market rules for international access to reserve power markets are still evolving, it is essential that the arrangements for transmission capacity allocation do not impose unnecessary restrictions on this development. While it is impossible to anticipate future market rules exactly, the concepts discussed above are at least compatible with a reasonably broad range of conceivable reserve power market designs, e.g.:
    - Independent national/regional reserve markets (present situation). The minimum requirement for compatibility with the existing structures is that the schedules for par-

ticipation in reserve power markets and the product schedules (e.g. quarter-hourly call of reserve power) must be compatible with the arrangements for cross-border capacity allocation and nomination.

- As regards cross-border transmission, the same prerequisites would even make a unified international balancing market with implicit allocation of the required transmission capacity possible. (This would, however, require significant work regarding the design of the respective energy markets; for example, to realise a competitive allocation of transmission capacity for day-ahead delivery and reserve power provision (option 2 above), energy and reserve power markets would have to be cleared simultaneously.)

5.6 Treatment of unexpected critical network conditions

As mentioned in the introduction of the generic congestion management scheme, the TSOs need to have access to reliable measures for short-term relief of potentially or actually overloaded network elements, even with transmission capacity allocation procedures (cf. section 2.1, phase 4). Technically speaking, the TSOs need a previously prepared list of generators to call for increase or decrease of generation[26]. Depending on the location of the critically loaded network elements a coordinated increase and corresponding decrease must be performed in two (or more) control areas. In the following, we call this kind of measure redispatch (or cross-border redispatch in case two or more areas are involved), irrespective of the mechanism by which the generators are selected.

It is important to note that on a case by case basis it may be very difficult to decide between domestic and cross-border redispatch. On the one hand, cross-border redispatch may also be used to reduce overload of internal network elements, e.g. if one considers a cross-border power exchange to be the primary reason for the overload. On the other hand, it may be economically efficient to relieve a line by domestic redispatch although it is considered to be

[26] Additionally, controllable loads may be used.

overloaded by foreign actors. Obviously, clear rules will have to be agreed on in order to enable TSOs to make transparent, non-discriminatory decisions. In this context, three aspects need to be discussed:

- In order to comply with the EC Regulation [1], the **mechanism for the selection of generators** must be market-based[27]. For cross-border redispatch there are two possibilities:
  - Since cross-border redispatch requires the opportunity for a (coordinated) change of generators' output, there is some similarity to the reserve power markets. Hence, the *national* reserve power markets could be used for *cross-border* redispatch by simultaneously activating positive reserve in one country and negative reserve in the other. (However, in order to ensure the desired physical impact, it would be necessary to skip any foreign generators that are part of the merit order.)
  - Alternatively, one may decide to set up a special redispatching market. The advantage of this solution would be that the generator-specific impact on the power flows could be considered, thereby reducing the amount of redispatching. Moreover, the same mechanism could be used for domestic and cross-border redispatch.

  The design of the selection mechanism may be TSO- (or regulator-)specific. Generally speaking, it would be sufficient if each TSO assigned a market-based mechanism to be used for cross-border redispatch that allows him to quickly alter the physical export/import balance of his control area.

  Sometimes the introduction of interruptible cross-border transmission rights is discussed as a further alternative for cross-border redispatching: In order to increase the amount of transmission capacity, the generator and the consumer enter into an agreement with the TSOs allowing these to disconnect both generation and load instantaneously after certain network contingencies. A closer look reveals, however, that this would be equivalent to a bundle of an "ordinary" cross-border transmission right with a positive reserve power op-

[27] We refer in this section to the majority of situations in which there is enough time for a selection of generators based on economic criteria. Obviously TSOs need the right to deviate from such rules in emergency situations.

tion in the sink area and a corresponding negative reserve power option in the source area. The same effect could thus be achieved if the TSOs agreed to rely on coordinated access to reserve power in order to increase transmission capacity. Hence, interruptible transmission rights would add complexity without improving the efficiency of cross-border redispatching. (Moreover, it may be questioned if the preferred selection of holders of cross-border transmission rights for redispatching would meet the criterion of non-discrimination.)

- The TSOs have the possibility to control the (statistical) **extent of cross-border redispatch**. When determining the transmission capacity, the security margins constitute parameters whose settings influence the risk of critical network situations. In section 4.2.4 about counter-trading we have demonstrated that redispatching, even if it is market-based and under idealistic assumptions, allows for non-marginal cost pricing. Therefore, when balancing the amount of transmission capacity and the expected extent of redispatching, the latter should be designed to be needed rather infrequently such that the regular means to manage congestion remains the limitation of the transmission capacity.
- Moreover, a fair and efficient **allocation of redispatching cost** is hard to establish as we will explain in detail in section 5.10.2.

We can therefore conclude that redispatching (including cross-border redispatching) mechanisms need to be established for network security reasons, but that their application should be planned as a rather infrequent measure[28]. Consequently, the efficiency of any redispatching market (which is limited anyway) is of relatively low priority.

[28] Hence, for transmission across borders with rare congestion it might be an option to – at least for a transitional period – apply redispatching as the only congestion management mechanism (i.e. to abstain from installing a capacity allocation mechanism). However, as soon as the involved areas take part in a multilateral allocation procedure they would have to adopt the uniform allocation mechanism for the sake of overall economic welfare.

5.7 Treatment of different time horizons

There are two interrelated timing issues that need to be addressed in congestion management:

- How far prior to use is the cross-border capacity allocation made?
- What is the duration of the product(s) allocated?

The Regulation is not prescriptive over the issue of timing. For example, the Guidelines for explicit auctions within the Annex to the Regulation require that an explicit auction offers capacity in a series of auctions and suggests that auctions could be held on a yearly, monthly, weekly, daily or intra-daily basis. The Guidelines also suggest that capacities may be auctioned for different durations.

The further in advance of use that transmission capacity is allocated, the more time participants have to coordinate their actions in the transmission market and energy market. For example, successful procurement of interconnector capacity might be followed by contract procurement or sales in related energy markets. Alternatively, secondary trading of allocated transmission capacity would allow parties to procure capacity if they missed out on the initial allocation and would allow parties to sell capacity that they subsequently find they do not require. However, as the time to use increases, so does uncertainty over the value of transmission capacity at the initial allocation.

The longer the duration of the capacity product allocated, the greater is the credit requirement for participants in the initial allocation. Credit requirements in respect of long duration products might effectively exclude smaller participants thereby reducing competition in the market. In addition, there is the issue with long duration products that the procurer requires capacity for only a relatively limited period of time and not the entire duration of the product being allocated. If the capacity being allocated may be unbundled into shorter duration products for re-sale, this concern would be largely mitigated. On the other hand, the shorter the duration of the capacity allocated, the higher the transaction cost for the TSOs and the potential procurers. In the extreme, the transaction costs of running 17520 separate allocations of half-hourly products one year in advance would be very high.

There is no single correct answer to the question of timing and duration of the allocation. The market's choice over these parameters is likely to be related to individuals risk preferences and a party is likely to want to hold a portfolio of capacity products of differing durations. This suggests that a range of products should be allocated over a range of time frames.

Since the transmission and electricity markets are linked, when considering the timing and duration of the cross-border capacity allocation, it is useful to consider the preferences of participants in the electricity markets. EEX provides insights into the preferences of participants to hold electricity market contracts. Table 5.3 presents a snapshot of the open interest (MW) in EEX futures contracts as at 29 April 2004. Monthly and quarterly contracts have approximately the same level of open interest, at around 2,500 MW. Annual contracts have a significantly higher level of open interest at approximately 4,500 MW. Open interest drops away rapidly for all contract durations as delivery moves further into the future.

This analysis does not take account of contracts with a duration shorter than 1 month. Trades in EEX's auction spot market averaged 6,600 MW for each hour for the period 1 January to 26 May 2004. The combination of spot market trades and open interest in longer-term contracts are not directly comparable but do provide an approximate picture of preferences in respect of contract durations and time to delivery. Using the information available, table 5.4 presents an estimate of the relative preferences for different contract durations in EEX.

Table 5.4 does not consider weekly and intra-daily contracts. Weekly contracts would likely partially substitute for both daily and weekly contracts, i.e. if weekly contracts were included, the relative preference for daily and monthly contracts would fall.

To the extent that security of supply issues allow, it would seem reasonable to attempt to broadly match the market's preferences when deciding upon the allocation of transmission capacity to contracts of different durations. Any undue constraints on preferred market behaviour could result in less efficient outcomes. This should be balanced with the need to release sufficient capacity of a product duration to ensure a liquid market in the primary allocation and secondary markets.

Delivery start	Duration (months)	Open interest (MW)
1-May-04	1	2,380
1-Jun-04	1	2,545
1-Jul-04	1	130
1-Aug-04	1	125
1-Sep-04	1	196
1-Oct-04	1	5
1-Nov-04	1	0
1-Jul-04	3	2,694
1-Oct-04	3	2,653
1-Jan-05	3	396
1-Apr-05	3	180
1-Jul-05	3	178
1-Oct-05	3	219
1-Jan-06	3	25
1-Jan-05	12	4,520
1-Jan-06	12	1,752
1-Jan-07	12	150
1-Jan-08	12	25
1-Jan-09	12	25
1-Jan-10	12	25

Table 5.3: Open interest in EEX futures contracts (as at 29 April 2004)

Contract duration	Relative size
Daily	40%
Monthly	15%
Quarterly	15%
Annual	30%

Table 5.4: Relative preferences for EEX contracts

When considering how far in advance of its use a product should be released, we note that EEX's annual contracts are mainly traded one or two years out, quarterly contracts are mainly traded one or two quarters out and monthly contracts are mainly traded one or two months out.

Trading of already allocated transmission rights would allow parties to fine tune their holdings to meet their specific needs and to respond to changes in their circumstances and risk preferences. Secondary trading could be achieved through bilateral trading and through release of unused capacity into subsequent allocation rounds. Use it or lose it provisions could be invoked between auction phases, e.g. between a monthly auction and weekly auction, to force release of surplus capacity. The downside is that any requirement to make firm nominations well in advance of actual flows could severely reduce the value of capacity in respect of those periods for which flow direction is uncertain.

In order to prevent hoarding of unused capacity and to facilitate efficient use of capacity, prior to the final allocation round unused capacity would ideally be compulsorily released to the market. Sale proceeds from the release of capacity could be returned to the party who released the capacity. However, as discussed in section 5.5, there may be the need to allow holders of transmission capacity to declare some unused capacity to be withheld for balancing purposes.

Transmission capacity could be released in advance through explicit auctions either through a financial or a physical allocation.

With financial allocation, TSOs would sell a financial transmission right (FTR) to players. The TSOs would either pay the holder of the FTR the electricity market price spread between one country and another country multiplied by the number of MWs specified in the FTR or pay the holder the cash revenue arising from the day-ahead auction, depending upon the market arrangements. A party might purchase an FTR in order to hedge an energy market transaction that spanned one or more borders. An advantage with FTRs is that purchasers would not be required to enter agreements required for participation in the physical market. This is likely to broaden participation in the FTR market and improve liquidity. Also, FTRs do not interfere with the physical use of interconnector capacity. Holding an FTR in respect of cross-border transmission would not prevent the transmission from being used to achieve least cost dispatch. A key disadvantage of FTRs is that they require well-defined reference prices (e.g. spot electricity market prices) for settlement purposes. Lack of robust reference prices, e.g. due to the threat of market power, could deter parties from procuring FTRs.

Physical allocation of transmission capacity could be made in the form of an option contract or a contract for an energy profile. An option contract prevents TSOs from netting sales in opposite direction since they cannot predict for which periods the option will be exercised. An energy profile contract has the advantage of allowing netting since it is both a right and an obligation. However, an energy flow contract has the disadvantage that the purchaser must commit to flowing well in advance of actual delivery. Standardised shapes would be needed to enhance liquidity in the market but any differences between the standardised flow shape and the actual efficient flow shape will detract from the value of the capacity. Long duration energy profile contracts sold well in advance of delivery could have much of their value eroded.

Capacity that is allocated more than, say, a day in advance of actual use should either be allocated in the form of an FTR or a physical option. Given the infant state of wholesale energy markets throughout much of Europe, it is likely that physical options would initially be the preferred choice of contract.

In order to maximise the use of capacity through netting and the use of PTDFs, at some stage the physical options must become firm commitments. Ideally this transformation of rights to obligations would occur some time prior to the final transmission allocation, e.g. one day-ahead of use. This would allow the allocation to maximise capacity release (cf. section 5.3.3, netting between allocation phases). The requirement for physical options to turn firm would, however, not be appropriate if the auction were to cater for rights both with and without obligations.

5.8 Auction design

Under either explicit auctions or our hybrid alternative there will be auctions that sell rights for a year, rights for a month and rights/obligations day-ahead.

In determining the appropriate form of the auctions the questions to address are:

- What is the nature of the product(s) being sold?
- Which products should be sold simultaneously?

- What is the level of competition for the products? (Will any of the participants have significant market power?)
- What is the value of what is sold and therefore the likely trade-off between the efficiency of the outcome and the transaction costs of the auctions?

5.8.1 The nature of the product

In relation to auction design the key characteristics of each of the products that will be auctioned are:

- They are essentially divisible commodities, and not individual objects; and
- Subject to a caveat related to the exercise of market power, they have common value, by which we mean all bidders should ultimately attach the same value to them.

The divisible nature of each product points towards either clock auctions, if dynamic, or the bidding of supply and demand curves if a static auction is used.

The importance of common value suggests that, if practicable, there is an advantage to the use of a dynamic auction in which the participants get to learn of the values that other participants place on the products. Dynamic auctions mitigate the problem of winner's curse, a phenomenon which will tend to make sealed bid auctions less efficient. In a sealed bid auction the winner is likely to be the party that has accidentally overvalued the product and sophisticated bidders in this environment will tend to under bid to avoid this.

Although one shot auctions are the most common transmission auctions used at present, dynamic auctions are used for the sale of transmission capacity, e.g. for capacity on the France – England interconnector (IFA) In addition, dynamic auctions are in use in a number of cases elsewhere in the energy business, e.g. for the auctioning of generation capacity in France and elsewhere, and are commonly used in other industries, e.g. for the sale of telecommunications licences.

Our caveat in relation to market power concerns situations in which one party can influence subsequent outcomes and has been explained in section 4. This is less likely to be a problem for the auctions which are selling large blocks of product, e.g. year ahead, but could be an issue in day-ahead auctions. Market power may create an element of private value. If other participants always know they will be outbid they will tend not to bother participating. Dynamic auctions make it relatively easier for someone to ensure that they outbid another and therefore the incidence of market power that may actually be used may militate in favour of a sealed bid auction at the day-ahead stage.

5.8.2 Extent of simultaneous offering

Another characteristic of the products being sold is that their values are interdependent. Where values are interdependent outcomes are generally more efficient when participants are able to make choices in relation to one product with good knowledge on the prices of others. This militates in favour of a simultaneous offering of products in a dynamic auction.

5.8.3 Level of competition

If there was very limited competition expected in an auction, this might tend to favour a one shot sealed bid format rather than a dynamic auction. However, although we have recognised in theory that the incidence of market power could inhibit participation, we would not in general expect there to be any particular lack of companies wishing to bid for interconnection capacity and therefore we think there is no great reason to favour sealed bid auctions on this account although there is clearly room for case specific judgements to be made.

5.8.4 Value of the products

Transmission rights as blocks over time are quite valuable and therefore the differential transaction costs of different auction types will definitely not be a factor in year ahead auctions and are unlikely to be significant in month ahead auctions. On the other hand values in day-ahead auctions will be much less and the transactions costs of time consuming, sophisticated auctions are likely to be much harder to justify. This suggests that in the year ahead and month ahead auctions dynamic auctions could be justified, but that day-ahead they might well not be.

5.8.5 Conclusions in relation to auction design

Taken together the above considerations lead us to conclude that **year ahead and month ahead** auctions should be dynamic ascending clock auctions with the simultaneous offering of as many interconnectors as can be reasonably encouraged to participate in a coordinated auction. Given that capacities ultimately made available should ideally be adapted to emerging values, it would seem desirable to have the quantities offered in these dynamic auctions vary with emerging values. However, we are not sure that it would be feasible to ensure sensible convergence. In any event we do not believe that this a material problem. It is quite possible to arrive at sensible fixed capacities for the earlier dynamic auctions and only introduce interdependent capacities in the final day-ahead.

The determination of economic efficient fixed capacities can be demonstrated by the example of a three-area model system in the case of month ahead allocation (fig. 5.8; for the PTDF values cf. fig. 5.2)[29]. The technical consequence from the requirement to have fixed, independent capacities is that capacity ranges must be defined for each bilateral capacity such that any combination of power exchanges is physically feasible[30] as long as each of them stays within the respective capacity range. Obviously there are, in general, an infinite number of feasible solutions, i.e. of sets of fixed capacities that fulfil the above constraints.

The challenge is now to determine prior to the auction the optimal set of capacities in terms of social welfare. Since bid prices are not available at that time, the assignment of values to the different transfer directions must be based on assumptions.

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[29] The quantitative analyses for this example have been contributed by the Institute of Power Systems and Power Economics (IAEW) of Aachen University of Technology (RWTH Aachen).

[30] It should be noted that, due to the uncertainty regarding future network conditions, the TSOs would in a year or month auction define "physical feasibility" on the basis of uncertainty margins that are higher than for the day-ahead auction.

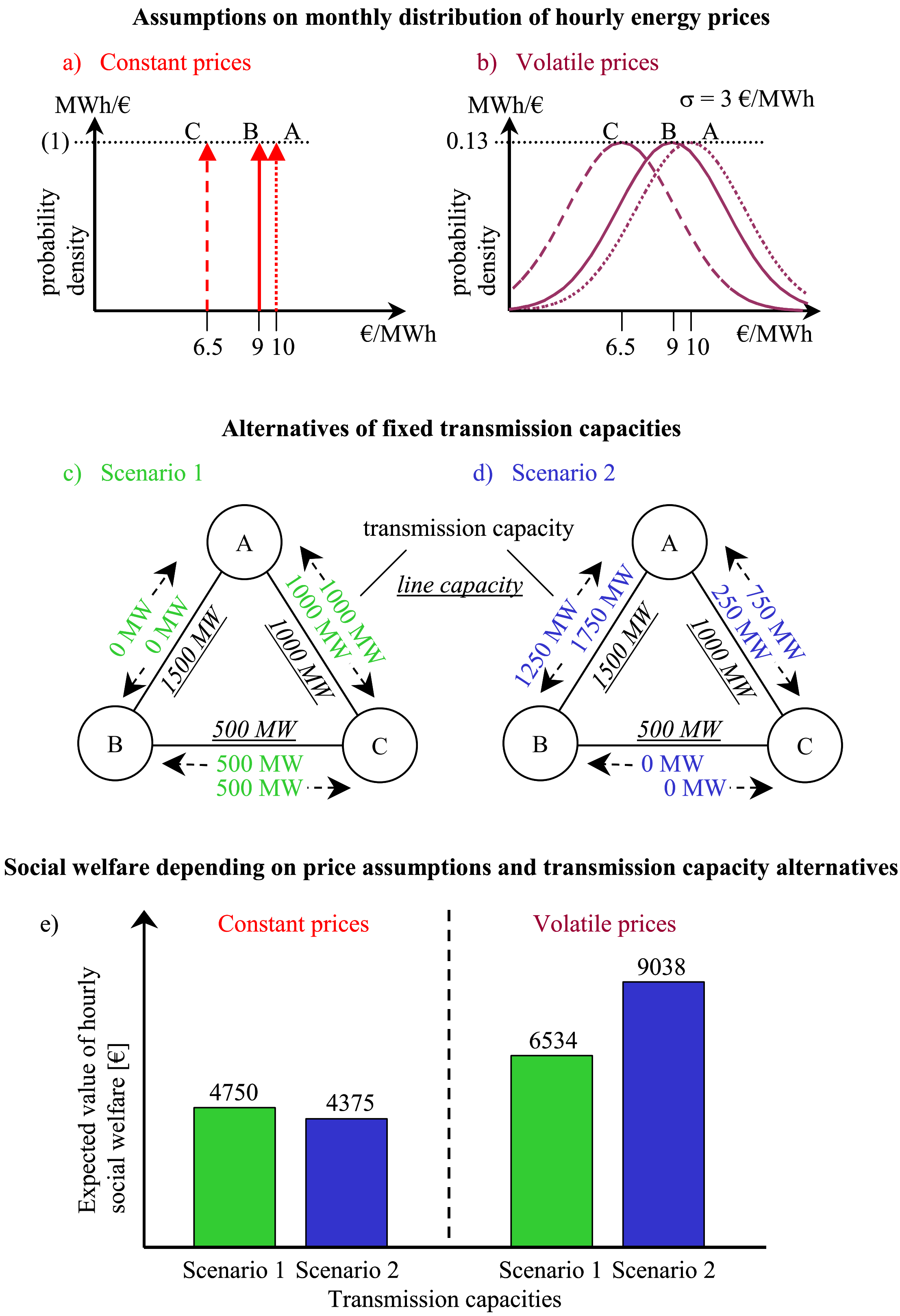

Figure 5.8: Choosing fixed transmission capacities for monthly allocation

One alternative would be to exclusively use the forward price differences between the areas A, B and C, i.e. to assume that the actual hourly prices will be constant and equal to their respective expected values (fig. 5.8 a). Under this assumption and for the given network properties, the optimal set of fixed capacities is [-1,000; 1,000] between A and C, [-500; 500] between B and C, and zero between A and B (fig. 5.8 c). If the hourly prices were really constant, these capacities would yield an average hourly social welfare of 4,750 EUR (fig. 5.8 e, left).

In reality, however, the hourly prices are volatile. If we assume a standard deviation of 3 EUR/MWh in each area (fig. 5.8 b), the obtained fixed capacities can on average be used in a more profitable way so that the expected value of hourly social welfare increases to 6534 EUR (fig. 5.8 e, right).

An even better result can be achieved when the volatility is taken into account during the determination of the fixed capacities. For example, the capacity set “scenario 2” (fig. 5.8 d) yields an expected value of hourly social welfare of 9,038 EUR, which is 38 % higher than the welfare achieved with “scenario 1”, although the latter had been optimal under the assumption of constant prices.

The example shows that it is possible to determine, on the basis of a PTDF model, fixed capacities in advance of the year or month auction, and that by taking account of the price volatility the capacities can be determined such that the expected value of social welfare is maximised.

Day-ahead auctions should be based on one shot submission of demand for specified cross-border capacity or a demand and/or supply curve for energy at a specific location. In our view these auctions are likely to operate best as market clearing auctions rather than as pay as bid.

5.9 Mitigation of market power

Measures discussed to mitigate market power include a limitation on the amount of cross-border capacity able to be obtained by a dominant player or even exclusion of dominant players from cross-border access.[31] Such specific arrangements may prove futile because the affected players may bypass such restrictions by having others do the cross-border trade on their behalf. The use of third parties to obtain cross-border capacity could be prevented if it could be shown that their actions constituted abuse of a dominant position. However, if this could be shown, one must question why it could not be shown in the absence of the rule to exclude the dominant player from cross-border access.

The exercise of market power in relation to transmission capacity will be linked to market power in related energy markets. An increase of competition in an energy market by increasing the volume of supply can most effectively tackle the market power phenomenon. In the short term, an increase in supply can be most easily achieved by increasing the usable amount of cross-border capacity. In addition, asymmetrical information held by the incumbent should be minimised. As we set out in chapter 4.3.2, it would appear that an explicit auction facilitates the use of asymmetric information whereas an implicit auction does not.

However, one should not expect that market power would reduce proportionally to the increase in cross-border transmission capacity. Under conditions where market power is present, the dominant player(s) could theoretically increase prices in the energy market well above marginal cost. However, due to the presence of explicit or implicit regulatory constraints, they will be restrained in the use of this theoretical market power in order to avoid regulatory intervention. The energy price thus reflects the combination of market power and regulatory “threat”. This combination of effects makes it difficult to anticipate the price decrease resulting from an increase of cross-border transmission capacity.

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[31] For example, see paragraph 7 of the *Guidelines for explicit auctions* which form part of the Annex to Regulation 1228/2003 or see Gilbert et al, *Allocating Transmission to Mitigate Market Power in Electricity Networks*, December 16 2003.

This discussion centres on the use of cross-border capacity to mitigate market power in energy markets. The question of market power applied to the market for cross-border capacity is largely addressed by two key aspects of the allocation mechanisms: the auctions are open to all participants (which means the price in the auction is likely to reflect the value of the cross-border capacity) and the use-it-or-lose-it principles to prevent hoarding of capacity as discussed in chapter 5.7.

The role of power exchanges in aggregating many individuals' preferences may effectively concentrate market power with the power exchanges in relation to capacity auctions. Conduct of the power exchanges may therefore require monitoring.

5.10 Distribution of allocation rents

Under either an explicit auction framework, or one of hybrid implicit / explicit auctioning, where congestion exists the framework will give rise to a revenue surplus. This surplus will accrue to the party administering the arrangements (e.g. to the auctioneer under an explicit auction framework).

Equally, while the *ex ante* allocation of access rights might give rise to a situation in which no congestion is expected, from Gate Closure through to real time TSOs will have to co-operate to ensure the security of the network and the availability of allocated rights through redispatching.

There are therefore important issues to be considered in relation to the allocation of revenue surplus and redispatch costs. In this section, we discuss these issues in turn and then, in the light of this discussion, briefly consider the importance of regulatory oversight in relation to capacity calculations.

5.10.1 Revenue surplus allocation

Regulation EC 1228/2003 states (clause 6(6)) that any revenues resulting from the allocation process must be used for any of the following:

- guaranteeing the actual availability of allocated capacity;
- network investments maintaining or increasing interconnection capacities; or

- as an income [for the TSO] to be taken into account when approving the methodology for calculating network tariffs.

An exemption to this condition can apply[32] for new (or enhanced) interconnectors which are "entrepreneurially built" – where, *inter alia*, the investment enhances competition in supply, the owner is legally separate from the system operators in the interconnected systems and no part of the capital or operating costs of the interconnector has been recovered through national use of system charges since the start of market opening.

These requirements are consistent with an approach which allocates rent to the developers of new or expanded interconnectors if they genuinely bear commercial risk associated with the extent of potential congestion and hence the price paid for use of the incremental capacity. This approach ensures that developers of entrepreneurial interconnectors face appropriate price incentives in relation to investment. In approving an exemption to the relevant clauses of the Regulation, national regulators will need to ensure that there is no implicit risk (e.g. parent company guarantees) being borne by users of the national transmission or distribution networks.

Where new interconnection capacity is funded through network charges, or for existing capacity, the three options given in clause 6(6) ensure that the revenue surplus eventually accrues to customers (i.e. those paying network charges) rather than the TSO itself, as they would otherwise have to bear the cost of, respectively:

- redispatching to ensure that allocated capacity was available;
- increased network investment to maintain or increase interconnection capacity (through higher future tariffs); or
- higher (current) tariffs.

[32] At the discretion of the „regulatory authority" – there would clearly need to be coordination between national regulators in granting such an exemption.

The choice between these options is likely to have an impact on the distribution of revenue between network users. For example, if the revenue is used to offset redispatch costs, to the extent that these costs are shared between multiple national TSOs (see below), the network users in the two directly interconnected countries may receive a smaller proportion of the revenue. In contrast, if the revenue is used to offset tariffs in the two or more countries concerned, they will receive all of the benefit.

The TSOs, in conjunction with national regulators, will need to agree a basis for splitting the revenue surplus between the interconnected countries. With the multi-lateral allocation regime transmission rent could accrue to the TSO(s) whose constraint (i.e. flow gate) was binding. Alternatively, based on the principles which underpin the clauses in the Regulation, an appropriate basis might be the extent to which the network users in each country funded and bore risk associated with the development of the transmission capacity. This would need to be assessed and agreed on a case by case basis.

5.10.2 Redispatch cost allocation

As with the allocation of revenue arising from existing interconnectors funded by network users, TSOs will need to agree a basis for allocating any international redispatch costs incurred in ensuring the security of the network and the availability of the firm access rights allocated. A requirement for such redispatch would arise following changes to transfer capabilities either on interconnector circuits themselves or changes elsewhere in national transmission / distribution systems which impact on transmission transfer capabilities[33].

Before turning to considerations in an efficient allocation of redispatch costs, it is worth considering where redispatch costs will fall *initially*. This will depend on the way in which TSOs agree to co-ordinate balancing aimed at managing international transfers. Taking a two coun-

[33] While changes in the dispersion and volumes of generation and load can also clearly impact on transmission capabilities, we assume that imbalance arrangements in relation to programmed interconnector transfers coupled with imbalance arrangements for national participants will address the associated cost allocation issues in relation to these.

try example where country A is a net exporter to country B, a reduction in transfer capability could be managed in a variety of ways each with potentially different implications for initial incidence of cost – for example:

- **Participants in A bid directly into balancing mechanism in country B (and *vice versa*)**: the incidence of redispatch costs in this situation would depend on how the TSOs agreed to manage the flow. If they agree that TSO A should use their national balancing mechanism to manage any redispatch, the costs will fall with TSO A, and *vice versa*.
- **International transfers are managed in national balancing mechanisms only**: the redispatch costs in this case would fall on the TSOs in an arbitrary manner. If the export from system A to B had to be reduced with TSO A backing down national generation and TSO B ramping up plant, then TSO A would receive payments from (relatively cheaper) generators not to generate roughly equating to avoided fuel costs and TSO B would pay (relatively more expensive) generators to generate.

Ideally, an allocation mechanism for redispatch costs should allocate the costs to the TSOs who failed to forecast accurately their transmission capabilities in order to ensure that TSOs face incentives to ensure that capabilities are accurately estimated *ex ante.* In turn, this should ensure that the prices emerging through the allocation mechanism (which act as signals to energy market participants and potential investors in transmission capacity) accurately reflect actual physical conditions.

From a theoretical viewpoint, to achieve an efficient allocation, it would be necessary to:

- Identify the cause of the need for redispatch actions;
- Identify the redispatch actions taken, and their cost; and
- Allocate costs to the network deemed to have caused the need for the actions.

While it should be relatively straightforward to identify the cause of the need for redispatch actions (in that transmission capacities will deviate from that which was expected *ex ante*) in reality it is likely to be difficult to define a set of *ex ante* rules to identify the resulting actions, a basis of a costing, and therefore an efficient allocation.

Within a meshed power system, identifying the balancing actions associated with specific events is not an exact science. Faced with a reduction in capacity on a line, operators will face a choice of a number of potential actions, and their preferred action is likely to depend on a range of factors unrelated to the initial cause of the redispatch action. For example, the choice of redispatch action to reduce generation output in the light of reduced export capability may depend on a range of national system stability criteria (e.g. nature of future national transmission constraints and hence relative value of spinning reserve between locations, ability of plant to provide reactive power, etc.). The cheapest possible redispatch action to manage a specific event will therefore not always be taken, as a relatively more expensive action may be viewed as representing “value for money” against a wider range of criteria.

Therefore, while it may be possible to identify the most significant redispatch actions taken to deal with specific and significant events (e.g. significant capacity reduction), more “routine” redispatch actions (e.g. if there had been only a small forecast error in transmission capability across a particular border) may be difficult to separate from wider balancing activities and hence to attribute.

Equally, even where it is possible to identify unambiguously a set of redispatch actions as resulting solely from international events, if there is no formal reserve market it may be difficult to identify transparently the cost of particular actions (for example, they may be part of a longer term reserve contract).

Finally, allocation of costs to the network deemed to have cause the need for the redispatch action may actually require financial flows between TSOs which are not directly connected (for example, if a specific event created loop flows which resulted in the need for redispatch actions).

In the light of the difficulties highlighted above, it may be appropriate to specify a threshold below which redispatch costs will simply remain where they fall:

- It is likely to be easier to attribute the redispatch actions resulting from significant system events which will cause higher redispatch costs; and
- Since deriving a cost allocation is likely to involve non-trivial *ex post* analysis of the chain of events, the benefit of attempting an allocation is more likely to outweigh the cost of the analysis in relation to significant events.

Under such an approach, TSOs could multilaterally agree to a process under which, following an event which led to a „significant“ redispatch cost, there would be an analysis of the magnitude of costs involved and the appropriate allocation of the cost between TSOs. This analysis could be undertaken by a third party, potentially with an appeals route to national regulators or to the Commission. TSOs could then go through a multilateral settlement process which took the initial incidence of redispatch costs and, via a series of payments, ensured an equitable allocation.

Equally, any cost allocation under such a scheme would need to be taken into account in national regulation. To incentivise TSOs to forecast transmission capabilities more accurately, it may be considered appropriate to allow only a proportion of the cost to be passed through to network users (this issue is addressed further in the next sub-section). However, this would need to be balanced by the need to ensure TSOs remained solvent. This would clearly be a matter for national regulatory policy.

Given the difficulty in allocating redispatch costs among multiple TSOs, any congestion management scheme that leads to a notable amount of redispatching and the need for a significant amount of cost reallocation will be difficult to implement.

This discussion is cast as if there will definitely be a redispatch cost. There could also be a redispatch revenue (where there is an underforecast of transmission capability). For example, NGC, the England and Wales TSO, is allowed to make arbitrage trades in NETA’s Balancing Mechanism. Allowing such trades improves the static efficiency of the market. The rules for allocating the revenue would be broadly similar to those for allocating the cost.

5.10.3 Regulatory oversight of capacity calculations

From the above discussion, it is clear that the need to redispatch as a result of failure to forecast transmission capabilities accurately can result in a cost to TSOs. The Regulation, as noted above, requires that the revenue from all existing interconnections is allocated in such a way that, in general, the TSO will have no direct interest in the amount of the surplus. Therefore, TSOs will typically have an incentive to underforecast the capability of their networks in order to minimise the amount of any potential redispatch cost.

It will therefore be important to ensure a degree of regulatory oversight of the capacity calculations performed by the TSO in order to ensure that, as required by clause 6(3) of the Regulation, 'the maximum capacity of the interconnections and/or the transmission networks affecting cross-border flows shall be made available to market participants, complying with safety standards of secure network operation'.

6 Conclusions and recommendations

6.1 Overview

The objective of this study is to derive recommendations as to the further development of cross-border congestion management in the Internal Electricity Market (IEM). The following conclusions and recommendations are based on an analysis of a broad range of options for the design of congestion management methods, including, but not limited to existing proposals of the involved stakeholders. Our analysis has been based on the following **assessment criteria**:

- Compliance with EC Regulation 1228/2003 – A prerequisite for any cross-border congestion management regime to be applied after 1 July 2004 is to be market based and non-discriminatory.
- Economic welfare – Cross-border network access should be managed such as to maximise the total amount of social welfare in the IEM. This implies the maintenance of appropriate network security standards.
- Practical feasibility – Taking into account the present, heterogeneous situation of cross-border network access, especially in Continental Europe, the aim of the study was to describe development steps that can realistically be implemented within the next years.

In the first phase of our analysis we have assessed the suitability of the different **basic mechanisms for transmission capacity allocation**. Although a number of mechanisms currently applied or proposed for the IEM can be clearly ruled out, there is not one single optimal solution. Rather, due to the trade-off between economic efficiency and practicability, two options remain for further considerations:

- The economically most efficient mechanism would be an implicit auction, which we propose to be designed as a **hybrid of explicit and implicit auction** for practical and legal feasibility reasons.
- A purely **explicit auction** mechanism is less efficient than an implicit auction because it suffers from the lag between capacity allocation and wholesale energy market clearance, which imposes uncertainty on the network users and offers possibilities to exercise market power. On the other hand, explicit auctions are already widely used in the IEM, and a migration from legacy mechanisms to an explicit auction would not interfere with the design

of the national energy markets. In terms of practical feasibility explicit auctions are thus clearly advantageous compared to the hybrid implicit/explicit auction.

In the next phase we have analysed design options for the numerous elements of which a comprehensive congestion management regime consists besides the basic allocation method. The general conclusion from this analysis is that for many elements the preferable design bears no or only little dependency of the decision between explicit or hybrid implicit/explicit auction. This allows for a stepwise improvement of congestion management methods such that early steps do not have to be revised when further developments are introduced. Keeping in mind the criterion of practical feasibility, our principal recommendation is therefore to follow a **two-step approach** as follows:

- We propose to at first **introduce (or continue to apply) explicit auctions**, because a number of substantial improvements compared to the present situation can be achieved without integrating the markets for transmission capacity and wholesale energy. The most fundamental (and probably also most beneficial) of these is the multilateral coordination of capacity allocation across several borders.
- As a further development we recommend to strive for the **implementation of a hybrid implicit/explicit auction**, i.e. implicit cross-border transmission capacity allocation between the regional power exchanges in coexistence with explicit capacity allocation for bilateral contracts. This requires TSOs to allow power exchanges to bid for transmission capacity on behalf of the power exchanges members. The details of the majority of design elements need, however, little or even no adjustment when migrating from the explicit to the hybrid auction.

It should be noted that the proposed separation into two steps is exclusively due to considerations on practicability. In cases where the regional circumstances allow for an immediate introduction of a hybrid implicit/explicit auction this direct approach should be pursued.

The realisation of both steps requires significant changes to some aspects of cross-border congestion management. In order to accelerate the fundamental development towards these approaches, we recommend accepting – at least for a transitional period – suboptimal solutions for some of the other design elements. Hence there remains an area for **fine-tuning** of aspects whose optimal design may yield additional economic welfare, but sorting these should not be allowed to delay or block the introduction and development of the main concepts.

In the following we present our detailed conclusions and recommendations for the two development steps as well as some aspects of fine-tuning.

6.2 Introduction of a multilaterally coordinated explicit auction

At present, cross-border congestion management in the continental part of the IEM is characterised by bilateral transmission capacity allocation which is performed individually per border and (with the exception of transmission from France to Spain) separated from the energy market. We recommend maintaining the principle of explicit capacity allocation for the time being, but develop the congestion management regime according to the following targets and guidelines:

General organisation

- The allocation of cross-border transmission capacity should be multilaterally coordinated, i.e. transmission rights for any power exchange between several countries for a specific period of time should be allocated simultaneously and by a single entity. This would increase the economic efficiency of the allocation procedure by reducing the uncertainties for the network users. Moreover, multilateral coordination is the prerequisite for the application of a transmission capacity model based on power transfer distribution factors (PTDFs, see below).
- On the one hand the larger the group of participating countries/TSOs becomes, the greater is the benefit from the multilateral coordination. On the other hand even a group of only a few adjacent TSOs can improve the efficiency of capacity allocation (and thus increase social welfare) by coordination. We therefore recommend encouraging the formation of "pilot regions" for the introduction of multilaterally coordinated capacity allocation.
- As the uniform basic method for capacity allocation we recommend explicit auctions.
- The introduction of a harmonised multilaterally coordinated congestion management method requires not only cooperation among the TSOs involved, but also supportive regulators buying into a common purpose.

Model to describe cross-border transmission capacity

- The allocation of transmission capacity should be based on a PTDF model of the transmission network instead of bilateral capacities like "Net transfer capacities" (NTCs). Through its representation of the interdependence between the different power transfers and the resulting power flows the PTDF model eliminates the TSOs' uncertainty regarding the allocation status at the other involved borders. This allows – especially in highly meshed networks – for an increased utilisation of the network and thus a significant increase in social welfare without jeopardising network security.
- Through the increase in transmission capacity, the application of a PTDF based capacity model may help mitigating the opportunities to exercise market power.
- A PTDF based capacity model also makes it feasible to take account of the netting of power flows induced by different power transfers. We recommend taking account of netting between allocation phases (when some transactions are already firmly nominated). Within allocation phases, however, netting of explicitly auctioned transmission rights induces risks and should be avoided in the first instance. As and when explicit auctions are extended to cater for rights with obligations as well as rights alone, netting will become feasible in relation to the obligations.
- The regular determination and application of a PTDF based transmission capacity model requires a minimum degree of coordination and centralisation among the TSOs. (This is independent from the question whether explicit or hybrid explicit/implicit auctioning is performed.) The gradual centralisation can, however, be organised such that it is compatible with the individual TSO's responsibility for network security in their own area. The PTDF based model even offers possibilities to increase the level of security at a technical and data provision effort comparable to that of the present NTC determination procedure.

Auction design and differentiation of allocation phases

We think that the format of the year/quarter and month ahead auctions should ideally be a dynamic ascending clock auction with the simultaneous offering of capacity on as many different interconnectors as can reasonably be coordinated.

We do not believe that a dynamic auction is practicable or necessarily desirable for the day-ahead auction and we therefore think that the appropriate form of this auction is a one shot auction based on bids in the form of demand and supply curves, supplemented by the offer of open increments and decrements that the coordinator can accept to effect optimal arbitrage.

Cross-border access to reserve power markets

- The possibility of an explicit allocation of transmission rights (which need to be rights without obligation) for cross-border access to national reserve power markets is a prerequisite for any future congestion management concept. Such a possibility can be implemented regardless of whether cross-border access to wholesale energy markets is managed by explicit or hybrid implicit/explicit auction of transmission capacity. Moreover, it is flexible enough to allow for different conceivable developments of the reserve power markets.
- Regarding the distribution of transmission capacity among participants of the wholesale and the reserve power markets, we recommend that initially there is a subsequent allocation for reserve power markets, i.e. the capacity for cross-border access to reserve power markets is allocated after the nomination of day-ahead capacity for wholesale energy delivery.

Redispatching

- Redispatching, even if designed in a market-based way, offers generators the possibility for inefficient pricing. Moreover, the causes for redispatching are difficult to trace, making it hard to achieve a fair allocation of the related cost. Therefore, when balancing the amount of transmission capacity and the expected extent of redispatching, the latter should be designed to be the exception such that the regular means to manage congestion remains the limitation of the transmission capacity.
- Nevertheless, a functioning mechanism for cross-border redispatching is required in order to have a possibility to relieve overload of network elements close to the borders between control areas. Each TSO therefore should assign a mechanism which will be used when another TSO asks for a short-term increase or decrease of the export balance. This could, for example, be the regional reserve power market or, if existing, a specific domestic redispatching mechanism. (An introduction of interruptible cross-border transmission rights is not recommended in this context as it does not yield additional benefit.)

Distribution of cost and revenues

- Ex-ante, TSOs should agree upon the process for determining the allocation of redispatch costs.
- In general, a sensible approach would appear be to leave insignificant redispatch costs remaining with those that incur them.
- Significant redispatch cost should be subject to ex-post analysis in order to determine an appropriate allocation.
- Given the difficulty in allocating redispatch costs among multiple TSOs, any congestion management scheme that leads to a notable amount of redispatching and the need for a significant amount of cost reallocation will be difficult to implement.
- With the multi-lateral allocation regime transmission rent could accrue to the TSO(s) whose constraint (i.e. flow gate) was binding.
- Where auction revenues accrue to the TSO and not to an entrepreneurial developer, the allocation between TSOs should be based upon the risk borne by respective transmission network users

6.3 Further development: Hybrid implicit/explicit auction

The introduction of implicit auctioning of cross-border transmission capacity – which for legal and practical reasons should be accompanied by a continuation of explicit auctioning – could effectively increase economic efficiency by eliminating the information lag between transmission capacity and wholesale energy markets, thereby mitigating some possibilities for exercising market power and allowing better coordination of transmission and energy markets.

Taking into account the present arrangements for congestion management in the continental part of the IEM, the introduction of implicit auctioning requires a significantly greater harmonisation effort than a purely explicit auctioning approach. In general it will thus be recommendable to progress to the hybrid auction via a phase of purely explicit auctioning. However, this is not a necessity; i.e. in regions where the direct implementation of a hybrid auction seems feasible the explicit phase can be skipped. Besides, it is also conceivable that among a larger group of TSOs that perform a multilaterally coordinated explicit auction, some areas migrate to a hybrid auction by allowing the respective power exchanges to participate in the transmission market, whereas the remainder of TSOs continue the pure explicit auction.

As mentioned above, many achievements of the multilaterally coordinated explicit auction remain effective after the inclusion of implicit auctioning. Additional benefit can be achieved through an amended treatment of netting: Since implicitly allocated transmission rights are certain to be exercised, full netting could be taken into consideration for the implicitly allocated share of the transmission capacity. However, potential operational problems arising from a significant increase of transmission volume should be carefully monitored.

6.4 Possibilities for further improvement of congestion management

In order to facilitate the realisation of the key steps towards a more efficient cross-border congestion management (listed in sections 6.2 and 6.3 above), we consider it acceptable to pursue a number of potential further improvements with lower priority. However, this does not imply that their introduction *needs* to be postponed until after the implementation of the key aspects. Rather, any case-specific considerations or opportunities that allow for an earlier implementation should be welcomed.

- The greater the number of areas participating in a multilaterally coordinated capacity allocation based on a PTDF model, the less the uncertainty that will remain regarding the utilisation of the network by foreign actors. This reduction of uncertainty allows to reduce the respective margins and thus leads to a further increase in transmission capacity at the same level of network security.
- A PTDF based capacity model can take account of the ability of phase shifting transformers to control the power flow. This allows TSOs to coordinate the use of these transformers in reaction to the market requirements.
- The consideration of individual transmission lines and transformers instead of flow gates may further improve the accuracy of the PTDF based transmission capacity model.
- Regarding cross-border access to reserve power markets, a simultaneous allocation of transmission capacity for day-ahead energy delivery and cross-border balancing markets could be considered. This may yield a significant increase in allocation efficiency, espe-

cially when the profitable directions for scheduled wholesale energy transmission and reserve power provision coincide. However, when designing this simultaneous allocation, measures should be applied to avoid an abuse of the use-it-or-lose-it principle by hoarding of capacity. A conceivable countermeasure would be the introduction of a fixed share of transmission capacity to be earmarked for reserve power markets.

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Glossary

A number of terms that are used throughout this study frequently occur in thematically related publications, but sometimes with different meanings. In order to avoid misunderstandings, this sections specifies how these terms are to be understood in this report.

Continental Europe: Continental European transmission system in this study means the part of the IEM area belonging to the UCTE system, i.e. excluding Scandinavia, the United Kingdom and Ireland. Among the countries of the present "2nd synchronous zone" of UCTE (covering South Eastern Europe) Greece is the only EU member state. However, the considerations in this study could in principle also be suitable for this region, even though most of its countries are so far not members of the IEM.

Redispatching: This is the most general term to describe the action when a TSO requests generators to deviate from their generation schedules for the sake of network security. Eventually, interruptible loads may be used for redispatching in addition to generators.

Counter-trading: This is a special, market-based form of →redispatching where the modification of the generation pattern is achieved by the TSO trading power between different (groups of) generators and/or interruptible loads.

Multilateral transmission capacity allocation: Today, transmission capacity is in most cases allocated bilaterally, i.e. for a single border by the two concerned TSOs. In a multilateral allocation regime capacity is allocated for more than one border at once and by one entity. This allows to take into account the interdependencies between the bilateral capacities, i.e. to trade off between the different transmission directions in reaction to the value that the network users place on them.

Annex

A Quantitative analysis of presently applied capacity allocation procedures

A.1 Overview

When trying to derive the most appropriate congestion management solution for the future, it is a logical step to try and learn from the presently applied methods. We have therefore checked the results of congestion management methods at some European borders for signs of inefficiency that might be a motivation for amendments. The possibilities for such analyses of historical data are however quite limited:

- The analysis must be restricted to the capacity allocation procedures (phase 2 of the generic congestion management model, cf. fig. 2.1 on p. 5), since no comparable public data is available regarding the procedures of transmission capacity determination or the frequency and efficiency of measures to resolve critical network conditions. In particular, the amount of transmission capacity was outside the scope of this analysis.
- Historical data on the results of capacity allocation are not available for all European borders. Moreover, our analysis is partly based on a comparison between capacity allocation results and market prices. A prerequisite for inclusion in the analysis was therefore the existence of power exchanges on both sides of the border with energy products comparable to the transmission capacity allocation procedure.

For these reasons we have focused

- on the explicit auctioning results at the borders between Germany and the Netherlands, Germany and Denmark and France and Great Britain and
- on the question if in particular the fact that at these borders transmission capacity allocation is separated from the wholesale energy markets might constitute a reason for not fully efficient allocation of the offered capacity.

(Although public data is also available from Nordpool, it is not possible to draw substantial conclusions from the implicit day-ahead auction, because in its region capacity allocation is efficient by principle, and a comparison with a different allocation method in a different region would be distorted by the notable differences in other fields such as network situation and market conditions.)

A.2 German-Dutch and German-Danish borders

Our analysis is structured in two sub-sections: Section A.2.1 concentrates on capacity allocation in the presence of varying directions of congestion. In section A.2.2 the analysis is extended by comparing the transmission cost to the arbitrage opportunities between the respective energy markets.

A.2.1 Bi-directional congestion

On both investigated borders congestion does not always occur in the same direction. This may cause inefficiency

- of the allocation if transmission capacity is not completely booked, but turns out to be beneficial in the view of the energy market prices (which are determined after capacity allocation), or
- of the market if transmission capacity is booked at a significant price, but later turns out to be valueless.

The published records of the cross-border auctions [14, 16] show that almost all capacity is always completely allocated in both directions, so that the former aspect of inefficiency has no relevance here. To analyse the latter aspect we investigated in a **first step** to which extent there were **bids of notable prices**[1] **in both directions**. Such bi-directionally congested periods can be a sign of inefficient allocation because the market opportunities expected by the network users have partially been contradictory. Table A.1 shows the aggregated capacity

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1 Since capacity is usually completely allocated, there are at least small bid prices in both directions. In many time intervals the price in at least one direction is however negligible. We assume that in these cases the transmission capacity in the concerned direction has been booked as a means of risk management, but there is no real congestion.

auction revenues (separated for day-ahead, monthly and annual auctions) at the Danish-German and Dutch-German borders in 2002 and 2003. In case of bi-directional congestion we defined the smaller clearing prices to be contrary to the dominant market expectation for the respective time interval.

	Total auction revenues [mill. €]		**Auction revenues in opposite direction of market expectations [mill. €]**		**Ratio of revenues in opposite direction of market expectations to total revenues [%]**	
Year	2002	2003	2002	2003	2002	2003
DK-West – D						
Day-ahead	18.6	11.6	0.12	0.05	0.65	0.43
Monthly	23.5	25.3	2.93	4.25	12.45	16.79
Annual	5.6	10.8	1.86	3.43	33.44	31.85
Total	47.7	47.1	4.91	7.72	10.29	16.39
NL – D						
Day-ahead	37.9	46.9	0.27	0.18	0.72	0.38
Monthly	55.7	42.5	0.26	0.21	0.47	0.50
Annual	90.7	34.1	0.66	0.52	0.73	1.52
Total	184.3	123.4	1.19	0.91	0.65	0.74

Table A.1: Aggregated auction revenues at D-DK (West) and D-NL borders in 2002 and 2003 (source of underlying data: [16, 14])

In most auctions the revenues from bids contrary to the dominant market expectation account for less than 1 % of total revenues and are thus negligible. Yet, a significant level of bi-directional congestion can be observed for the monthly and annually auctions at the German-Danish border. This is however not a sign of inefficiency of the auction, but rather of the fact that the network users take into account the short-term volatility of the congested direction at this border: Since the direction of congestion often changes between day and night the time intervals of the monthly and annually auctions cover periods of northbound and southbound congestion, whereas in the day-ahead auction capacity is offered for one-hour intervals. It is therefore on the one hand logical that at the monthly and annually auctions significant prices are paid for both directions; on the other hand the price levels should reflect the expectation that these capacities will only be used during a part of the time that they have been obtained for.

This can be verified by comparing clearing prices between annually and day-ahead auctions. If we assume a full utilisation of the annually auctioned capacities (i.e. 8760 h), the relation of the average prices per MWh between annually and day-ahead auctions amounts to 0.8 for the German-Danish border. For the German-Dutch border, this ratio is 1.8; obviously, network users at this border (correctly) anticipated a higher degree of utilisation of the annually capacity and therefore bid relatively higher prices.

A clear proof of inefficient allocation could thus – if at all – only be derived from the day-ahead auctions. Here however, the revenues from bids contrary to the dominant market expectation are negligible at both investigated borders. This means that in most cases the network users have a common expectation of the beneficial direction of power transmission. In fig. 6.1 this can be exemplarily seen for the German-Danish border for September 2003: Although there is a frequent variation of the congested direction, simultaneous bids in both directions (marked in red) occur only rarely. (The only exception is the indicated period of September 22/23 where in northbound direction only 5 MW of transmission capacity have been available.)

We can thus conclude that by mere analysis of the auction results the auctions at both investigated borders cannot be considered to be inefficient. In a **second step** we have analysed to which extent the network users' **bidding behaviour** (which has shown high correlation among the bidders) is **correlated with the respective market outcome**. When comparing the hourly spot market prices on both sides of the respective borders (i.e. hourly day-ahead prices of EEX [17], APX [18] and Nordpool–Denmark West [19]) one can see that both borders show a significant number of hours with market price differentials in either direction (fig. 6.2). (Note that this evaluation does not take into account the *amount* of differences between the market prices.)

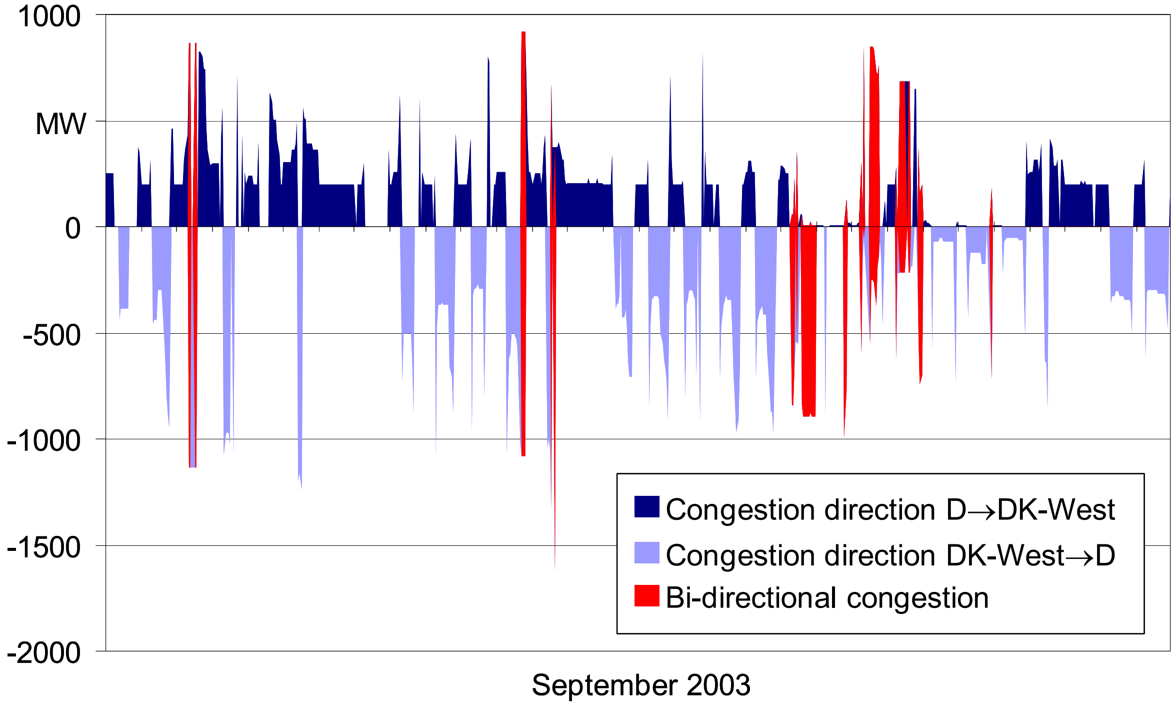

Figure 6.1: Allocated capacity volumes in congested hours during September 2003 for transmission between Germany and Denmark (West)

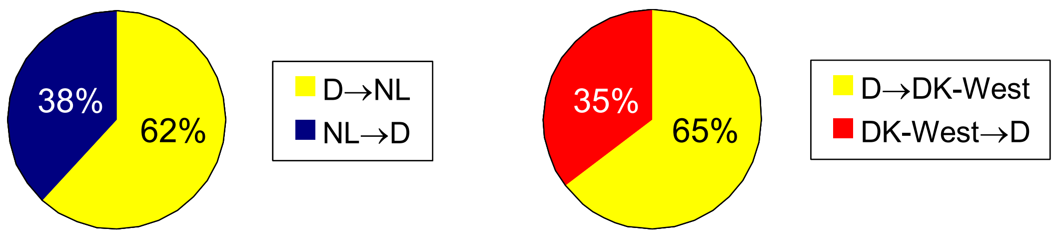

Figure 6.2: Share of hours in 2003 with positive respectively negative price differentials between energy spot markets (example: "D→NL" means that spot price in D is lower than in NL)

Using this information, we can amend the definition of inefficient capacity allocation: A bid price paid at the capacity auction is inefficient whenever the market price differential for the respective hour is such that using the capacity would mean selling into the low-price energy market. (I.e. even when during the allocation phase there was only congestion in one direction, it might turn out to be an "inefficient" hour if the congested direction is contrary to the later observed market price difference.)

Based on this definition, the ratio of day-ahead auction revenues for hourly capacity in "inefficient" directions rises to 6 % for the German-Dutch and 16 % for the German-Danish border (table A.2). Network users thus incur significant cost because of wrongly anticipated market opportunities. (However, even in such hours the transmission capacity can still practically always be used in an efficient way because – as mentioned above – it is usually fully allocated in both directions.)

Day-ahead auction	Total auction revenues [mill. €]	Auction revenues in opposite direction of market-price difference [mill. €]	Ration of revenues in opposite direction of market-price difference to total auction revenues [%]
D – NL	46.9	2.88	6.14
D – DK (West)	11.6	1.81	15.69

Table A.2: Aggregated day-ahead auction revenues at D–DK (West) and D-NL borders in 2003 (source of underlying data: [17, 18, 19])

A.2.2 Relation of day-ahead auctioning prices and energy price differentials

In the previous section we have analysed the capacity allocation procedures as such; market price differentials have only been used to indicate in which direction the allocated capacity could be profitably used.

In addition to this we have analysed if the auction revenues show a quantitatively plausible relation to the arbitrage opportunities of the energy markets. For this evaluation we have assumed that for every hour the obtained day-ahead[2] transmission capacity is completely used in the direction from the low-price to the high-price market. Wherever applicable, the as-

2 The evaluation is limited to the day-ahead auctions, because on the one hand they impose the highest risk on the network users (whereas monthly and annual transmission rights can be priced on the basis of energy forward prices and are open to secondary trade) and on the other hand information on the utilisation of monthly and annual capacities is not publicly available.

sumed transmission volume is charged with the respective cross-border tariff (CBT, [20]). For capacity allocation in the contrary direction, the incurred auction cost are considered, but we assume that this transmission capacity remains unused so that neither CBT nor losses from selling energy to the low-price area are incurred. The network users' cost (auction cost for both directions plus CBT for the profitable direction) can then be compared to the profit on the energy market, i.e. the positive differential between the spot prices of the two adjacent power exchanges.

In a previous analysis we already showed that an hour-by-hour comparison of cost and profit seems to show only little correlation [2]. A monthly aggregation, e.g. for transmission from Germany to the Netherlands (fig. 6.3) however reveals that on average, profits outbalance losses. Moreover, the auction price level obviously follows the variation of the average market price differential over the year. (The exception to this is the month of August, where price peaks at APX of up to 2000 €/MWh on three days make up about 85 % of the aggregated price differential.)

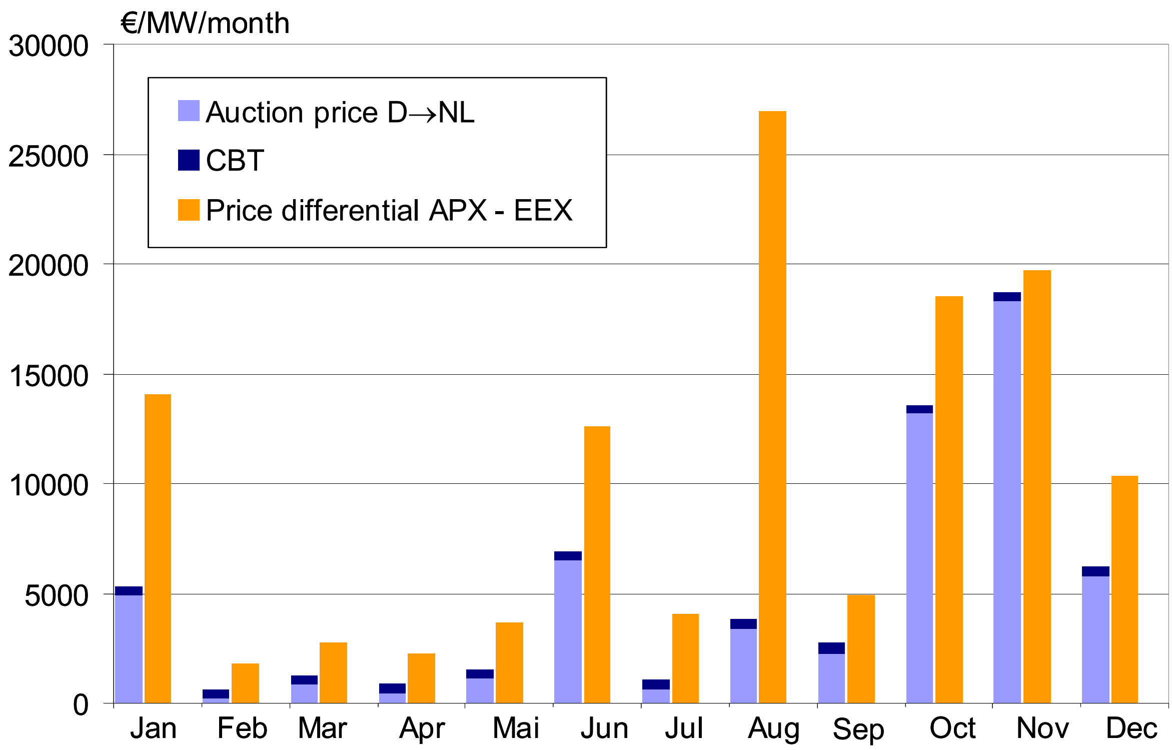

Figure 6.3: Monthly totals of hourly day-ahead transmission capacity auctioning results direction D→NL (2003)

Results for transmission from Germany to Denmark-West (fig. 6.4) are qualitatively similar to the German-Dutch case, but on a lower average price level. Again one month is exceptional due to temporary spot price peaks (7 hours in September with prices of about 500 €/MWh in Western Denmark) that have not been anticipated at transmission capacity allocation time.

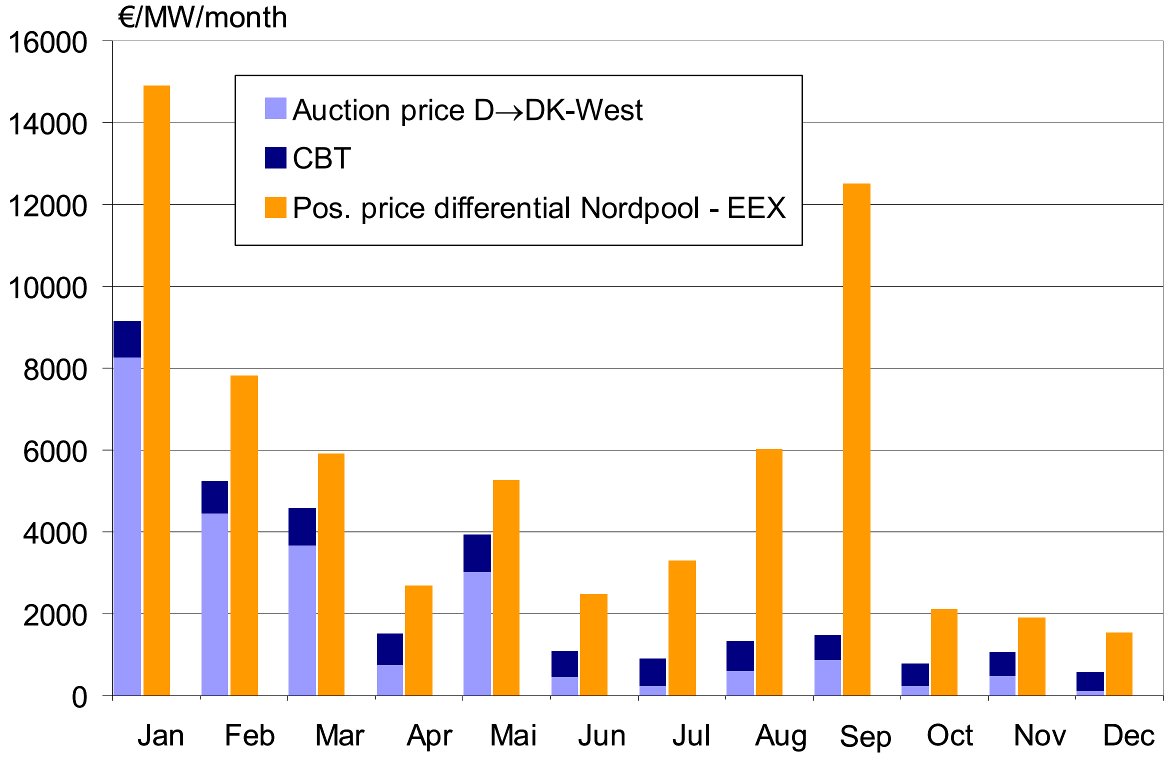

Figure 6.4: Monthly totals of hourly day-ahead transmission capacity auctioning results D→DK-West (2003)

For transmission from Denmark-West to Germany (fig. 6.5) the relative difference between the spot price differentials and the transmission prices is significantly higher than for the opposite direction. The absolute difference is however quite similar, so that the high relative margin is probably due to the low level of absolute prices.

In combination of fig. 6.4 and 6.5 network users seem to compensate the forecast error regarding the profitable direction of transmission (cf. table A.2) by adapting their bid prices so that in total a positive net margin remains. This net margin is remarkably high when one takes into account that under perfect market conditions it should be zero on average. Obviously the network users obtain a significant part of the congestion rent, which thus is not earned by the TSOs for distribution to the network users.

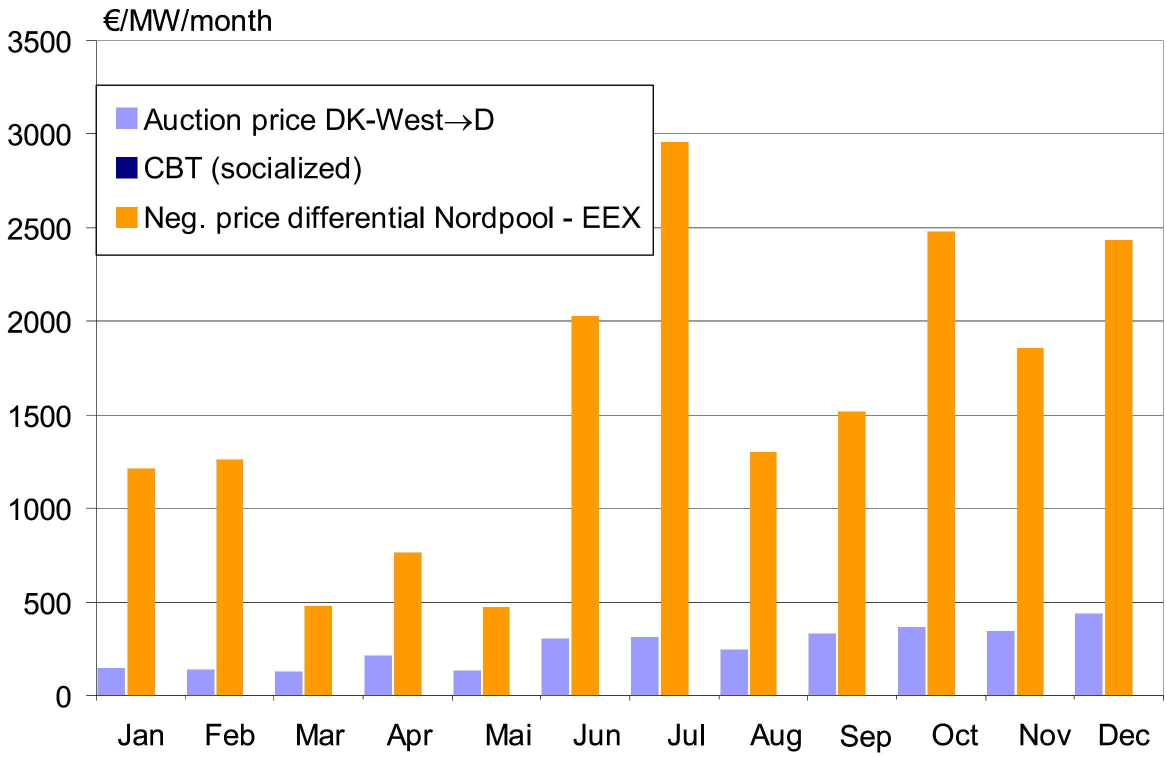

Figure 6.5: Monthly totals of hourly day-ahead transmission capacity auctioning results DK-West→D (2003)

Beside the AC-links between Denmark-West and Germany we analysed the KONTEK-connection, a 400 kV DC-link with a capacity of 600 MW connecting the grids of Elkraft (DK-East) and Vattenfall Europe Transmission (D). There is day-ahead auctioning in both directions, whereas monthly auctioning exists in northbound direction only. Auctioning started in January 2002, detailed data concerning the auctioning results is publicly available since October 2003 [21]. Our evaluation of the auctioning results in northbound direction (fig. 6.6) shows similar effects as for the previously discussed borders: Again the auction price level follows the variation of the average market price differential over the year, and again the aggregated market price differential clearly exceeds the sum of auction prices and CBT payments. This indicates the market participants' ability to frequently predict the profitable direction of transmission and to achieve favourably low auctioning prices. In general, this can also be observed for the southbound direction (fig. 6.7), although the net margin is smaller here because of fewer hours of profitable transmission.

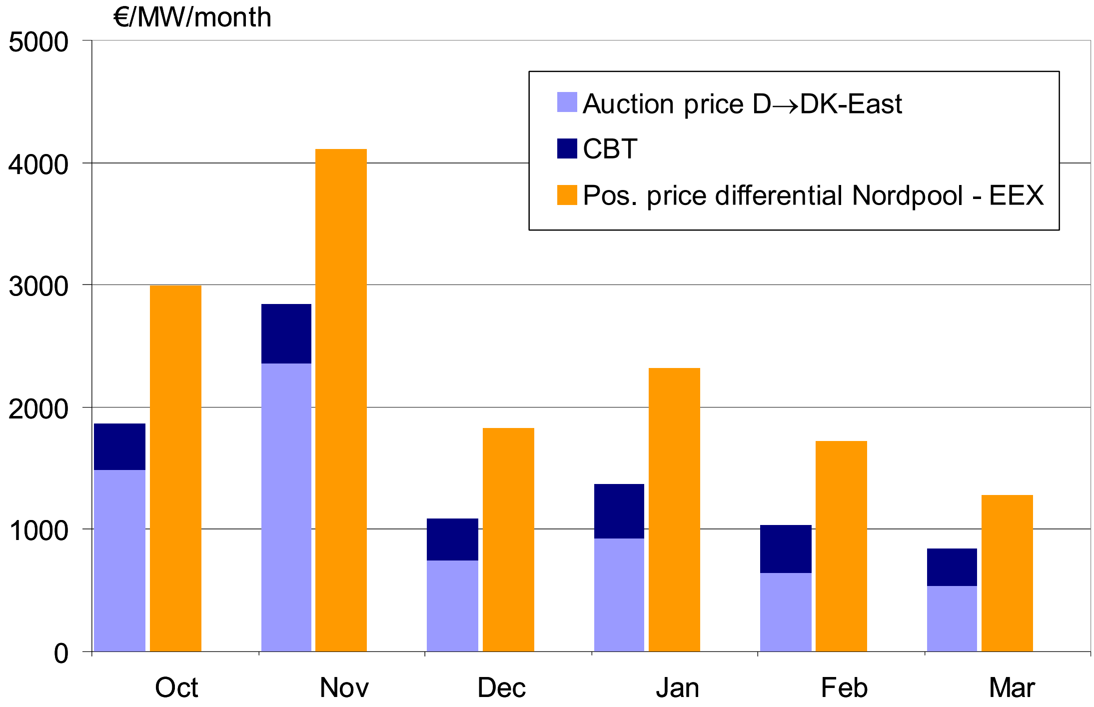

Figure 6.6: Monthly totals of KONTEK hourly day-ahead transmission capacity auctioning results D→DK-East (Oct. 2003 – Mar. 2004)

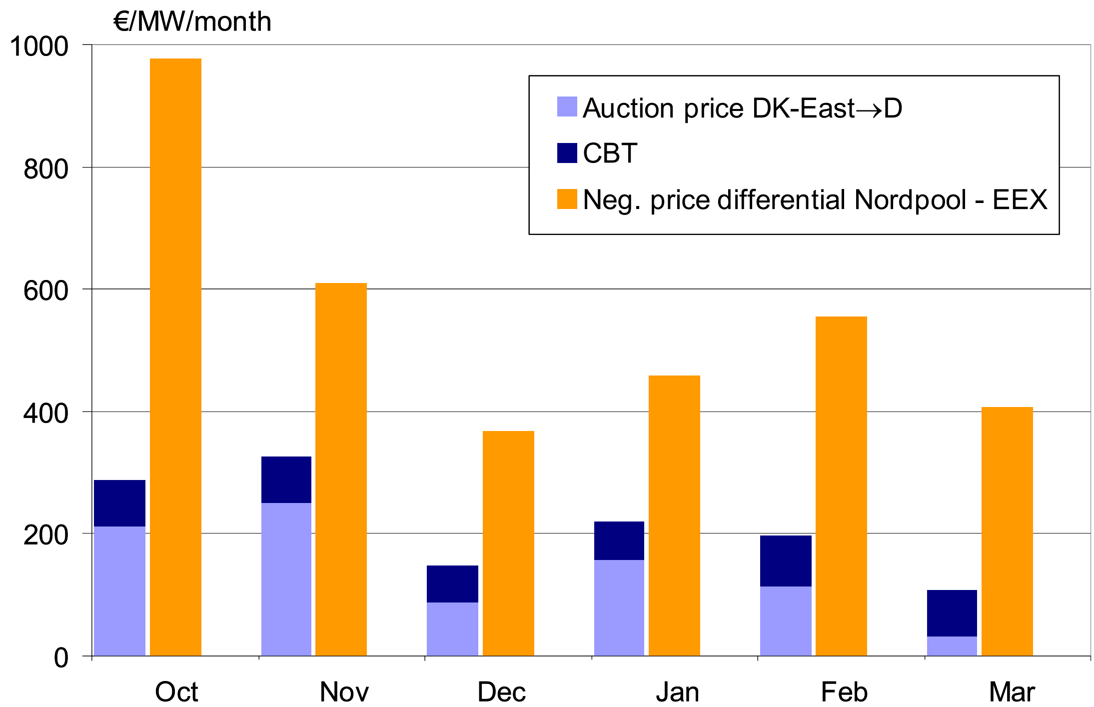

Figure 6.7: Monthly totals of KONTEK hourly day-ahead transmission capacity auctioning results DK-East→D (Oct. 2003 – Mar. 2004)

A.3 Border between France and Great Britain

The capacity of the France-England Interconnector (IFA) is sold through auctions of a variety of rights to use the capacity that range in duration from one year to one day. Capacity may be purchased in both directions. Nominations for flow quantities (exercise of rights) must be made prior to gate closure in respect of RTE's balancing mechanism. The deadline for interconnector nominations occurs after the French (Powernext) energy market clears, while the UKPX (the leading UK power exchange) is open and prior to gate closure in respect of the England and Wales balancing mechanism.

Our analysis of IFA is based on 8760 hourly nominations of power flows between France and England for the period January to December 2003 and on hourly price differentials between the two wholesale power markets.

Table A.3 shows that during 2003, a total of 6,034 GWh of flows were nominated in the direction from France to England and 3,590 GWh were nominated in the opposite direction. This result is intuitively sensible since the wholesale electricity price in England and Wales is typically higher than that in France.

During a single hour it is possible for two parties to nominate flows in opposite directions on IFA. Such an outcome is counterintuitive because in a rational market electricity should flow from the low price market to the high price market, in the absence of loop flows.[3] In fact during 3015 hours, i.e. 34% of the time, there were nominations in both directions across IFA.

Further, as illustrated in table A.3, the quantity of bi-directional nominations was significant. Of the 6,034 GWh nominated to flow from France to England, 1,310 GWh were nominated during an hour when flows were nominated in the opposite direction. Of the 3,590 GWh nominated to flow from England to France, 1,742GWh were nominated during an hour when flows were nominated in the opposite direction.

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[3] There is only a single interconnector between the continent and UK and therefore there are no loop flows across IFA.

The high magnitude of reverse flows suggests that the interconnector market may be operating inefficiently. However, it would not be unreasonable for flows to be nominated in two directions if the price spread between the two energy markets was small. For example, participants might prefer to flow electricity from the high to the low priced market in order to avoid exposure to balancing prices at both ends of the interconnector and if faced with illiquid energy markets.

Direction	**Sum of nominations (GWh) [A]**	**Sum of nominations faced with a simultaneous nomination in opposite direction (GWh) [B]**	**Proportion of bi-directional nominations [B] / [A]**
F – E	6,034	1,310	22%
E – F	3,590	1,742	49%

Table A.3: IFA analysis – quantity of nominations

Table A.4 shows the value of nominations in each direction across the interconnector. The flow value is estimated by multiplying the price spread between France and England by the flow size.[4] We decompose this net value of flows into periods when (i) the flow is from the low priced market to the high priced market and (ii) the flow is from the high priced market to the low priced market. In the direction from France to England, the net value of flows was 14.5€m. This comprised 36.6€m of flows with a positive value and 22.1€m of flows with a negative value.

The monetary value of negative value flows from France to England is 60% of positive value flows in the same direction. The proportion of negative value flows in the direction of Eng-

4 The source of the French price is the Powernext day-ahead price. The source of the England and Wales price is UKPX's RPD series. The RPD price for a half hour is the average price of all trades in respect of delivery in the half-hour where trading opens approximately several days ahead of dispatch and closes one hour ahead of dispatch.

land to France is smaller, at 12%. The high proportion of negative value flows from France to England suggests that the market may be operating inefficiently.

Direction	**Net value of nominations (€m) [A] = [B] – [C]**	**Sum of positive valued nominations (€m) [B]**	**Sum of negative valued nominations (€m) [C]**
F – E	14.5	36.6	22.1
E – F	35.6	40.4	4.8

Table A.4: IFA analysis – value of nominations

We next consider the average net flow in each direction. Unless the interconnector is the marginal producer in one or other energy market one would expect it to be constrained at maximum output in the direction of the high priced market. The average flow from France to England was 1012MW and the average flow from England to France was 804MW.[5] When compared with the capacity of the interconnector of approximately 2000MW, this result suggests the interconnector is underutilised. One reason for this underutilisation is that netting is not applied to the interconnector.

Finally, we investigate the relationship between price and interconnector flow. Regression analysis shows that the wholesale price differential has a statistically significant influence on net flows in the direction of the high priced market. However, the influence itself is very low.

Fig. 6.8 compares the wholesale price spread (England minus France) with net exports from France and counter-flows for 2003. Net exports are, shown in red, sorted along the x-axis from minimum exports (i.e. maximum import) from France of -1998MW on the left to maximum exports from France of +2000MW on the right. A black column represents the gross flow in the same direction as the net flow, with the counter-flow being the difference between the height of the black column and the red column. The corresponding price spread is shown

[5] We calculate the average flow only when the interconnector is flowing in the direction concerned.

separately above. The price spread is colour coded: red for a higher French price and blue for a higher English price.

The graph shows the large quantum of counter-flows and indicates that price is related to flows.

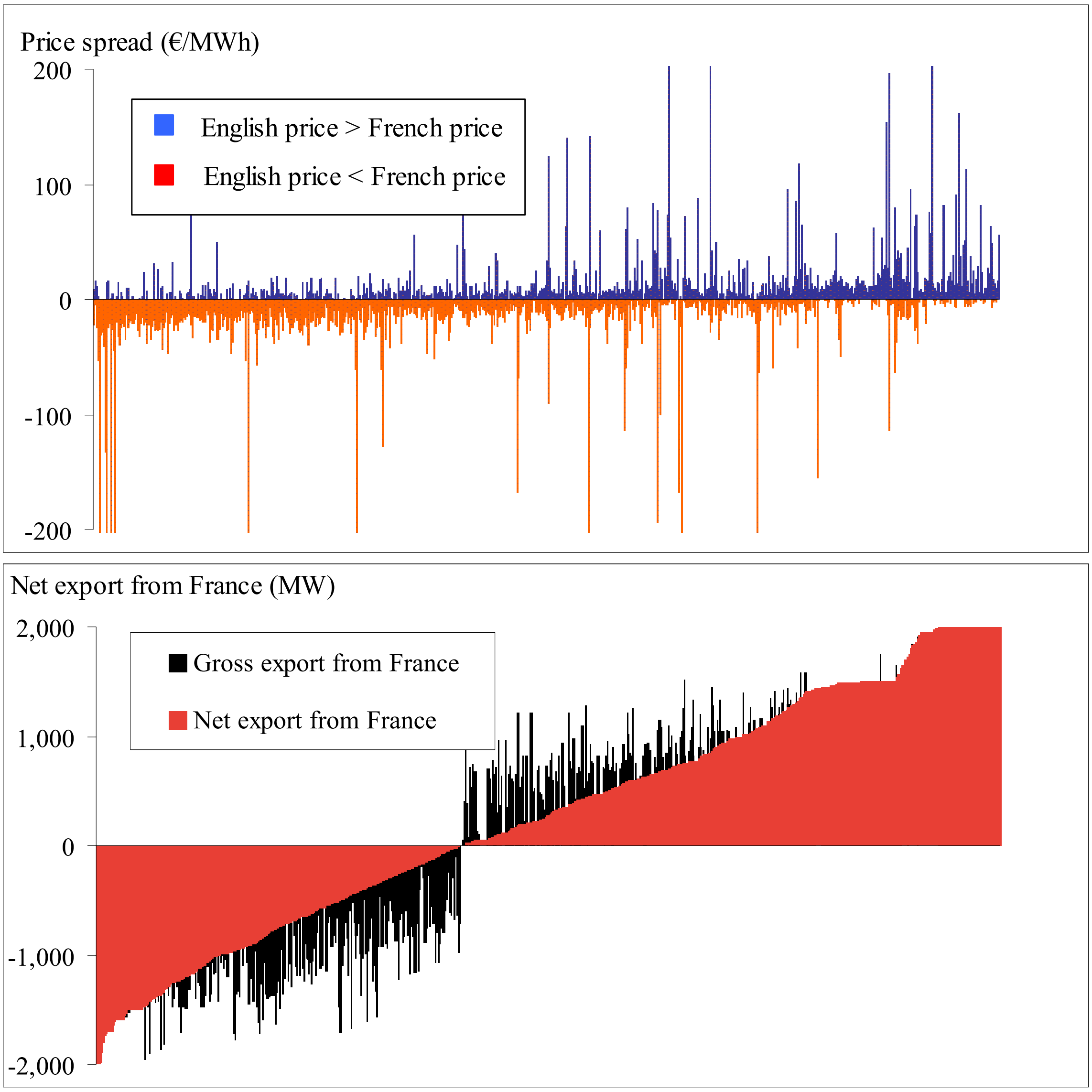

Figure 6.8: IFA - comparison of price and flows (2003)

B Counter-trading dispatch

Under the counter-trading example of section 4.2.4, the TSO is faced with a hypothetical 300 MW flow across the interconnector and must undertake a 150 MW redispatch at least cost, using counter-trading. This annex illustrates the counter-trades made by the TSO in more detail and the accrual of welfare to generators from the unconstrained dispatch, counter-trade and the dispatch.

The TSO is faced with a demand curve from the generators in Country A to buy electricity from the TSO at their marginal cost. The least cost response is to reduce output (i.e. TSO sells electricity) from Genset A3 since it has the highest marginal cost of those generators who are producing in Country A. The TSO faces a supply curve from generators in Country B to sell electricity to the TSO at their marginal cost. The least cost response is to increase output from the lowest priced generator with spare capacity, i.e. Genset B3 at a price of 50 €/MWh. However, since B3 can only supply 100 MWh of additional generation, the TSO must procure 50 MWh from Genset B4 at a price of 60 €/MWh.

Assuming a system marginal price mechanism in each country for the redispatch, the TSO spends 9,000 € to purchase 150 MWh of electricity at 60 €/MWh in Country B and receives 6,000 € by selling 150 MWh at 40 €/MWh in Country A. The TSO loses 3,000 € on redispatch.[1]

The resultant dispatch and welfare accruing to each generator are shown in table B.1. Welfare may be calculated from the sales and purchases in the unconstrained schedule at the unconstrained market price of 50 €/MWh, adjusted for receipts or payments in the redispatch, less the marginal costs of actual production. For example, welfare for Gen A3 is 11,000 € = 1,100 MW x 50 €/MWh – 150 MWh x 40 €/MWh – 950 MWh x 40 €/MWh).

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[1] The same example could be set out using a pay-as-bid redispatch mechanism. Such a pricing mechanism adds complexity but would not change the outcome of the example under the assumption of perfect information since participants would price their output increments and decrements at or very close to the relevant market price.

Genset	Dispatch (MW)	Offer price (€/MWh)	Welfare			
			Uncon-strained schedule	Counter-trade	Fuel cost	Total
A1	600	25	30,000		-15,000	15,000
A2	600	30	30,000		-18,000	12,000
A3	950	40	55,000	-6,000	-38,000	11,000
A4	0	50	0		0	0
B1	600	35	30,000		-21,000	9,000
B2	600	45	30,000		-27,000	3,000
B3	600	50	25,000	6,000	-30,000	1,000
B4	50	60	0	3,000	-3,000	0

Table B.1: Counter trading I -— dispatch