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CONGESTION MANAGEMENT IN LIBERALIZED MARKET ENVIRONMENT

Working Group C5.04

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Following unbundling and liberalization of the electricity market, the interconnected network is more and more becoming a marketplace for electric energy. However, due to the different state of pre-liberalized national energy systems, state of unbundling and government policies, electric energy prices at regional markets differ. As market participants look for the cheapest electrical energy no matter where it is located, large and difficult to predict unscheduled power flows often appear in the interconnected network. Consequently, it comes as no surprise that international interconnections very often become congested, meaning that the transmission system cannot be operated securely under the requested pattern of generation and demand. This congestion has to be relieved before physical or security limits are breached.

There are numerous ways to handle transmission constrains. However, there is no *one size that fits all*. Contrary, depending on how the electricity market is organized, a method should be chosen so as to best meet local requirements. However, which is the interaction between the way transmission congestion is managed and the electricity market? How to make a choice of an application of a congestion management scheme?

Cigré Study Committee SC5 on Electricity Markets and Regulation set up in 2002 has initiated a Working Group to study these issues. During the works if this Working Group it has been found that there is a need to develop a common understanding of terms related to management of transmission constraint. Such a commonly understood terminology could contribute to a better and more fruitful exchange of ideas and thought on the subject. This report is a result of the works of the Working Group WG 5.4 on Congestion Management. The aim of this report is to introduce a problem of transmission constraints management in market environment and contribute to a better understanding of the interactions between the technical and economic aspects of congestion management. All important terminology necessary when discussing congestion management is introduced, allowing for further investigation of the subject.

Electricity Market

The introduction of electricity markets and breakdown of the national monopolies has been seen as a means to increase efficiency of electrical energy generation and supply. Competition provides stronger cost-minimizing incentives than a typical cost based regulation and has the ability to trigger innovation.

In a liberalized market, electricity is a bundle of many services, requiring new markets to be established. Electricity market can be thus subdivided into many submarkets, the division depending of the degree of unbundling and vertical integration. Submarkets in turn can be again subdivided, describing a certain type of market. Moreover, national or multinational markets are linked by cross-border transfer capacity market. In order to successfully create a competitive electricity market, it is essential to optimally use the limited capacity interconnecting regional markets. Apart from legal matters, both technical requirements and regulatory mechanisms have to be re-defined. As in any market, physical boundaries have to be handled, in order to avoid hindering of the liquidity of energy exchanges. At present there is little coordination between electricity markets. They function largely independently generating exports and imports as a result of their activities. A better coordination and information exchange between the SOs can help to improve the prediction of the large power flows appearing in the interconnections and therefore help to optimize the transfer capacities offered to market participants.

Congestion Management

Congestion is a situation where the demand for transmission capacity exceeds the transmission network capabilities, which might lead to a violation of network security limits, being thermal, voltage stability limits or a (N-1) contingency condition. Therefore, in a physical sense congestion is merely an indication of a presence of transmission constraints. However, often due to the chosen market organization and the way congestion is managed, some transmission constraints can be managed different than the others. Consequently, there is a division between an internal and cross-border congestion. Though physically transmission congestion is always caused by limitations of a technical nature, both above types of congestion are treated differently. Internal congestion is a problem of a single system operator, while cross-border congestion involves more system operators, often acting under different market conditions. Moreover, while internal congestion occurs on physical lines, cross-border congestion management often comes down to allocating the transfer capacity agreed upon by the System Operators involved. This means that the cross-border congestion management can be seen as only indirectly linked to power flows on physical lines.

Given the meshed nature of the electricity networks, problems of technical interdependency have to be dealt with. Transactions between two areas via a non-congested interface may induce important power flows and can create security problems on another border somewhere else in the meshed interconnected system (i.e. loop flows). Variations of internal dispatch within control zones causes cross-border flows to vary, resulting in even more increased loop flows. Therefore, the zonal network model, together with the unpredictable internal dispatch pattern due to self dispatch freedom given to the market participants, is to a great extent responsible for the loop flows on cross-border interconnections. As the model substitutes the control areas by single equivalent nodes, the actual nodal dispatch information within the control areas, and consequently their impact on power flows outside is unknown to all other system operators in the surroundings.

Where it comes to cross-border congestion, capacity auctioning is one of the most widely applied congestion management methods. There are two main variants of the method: explicit and implicit auctioning. Implicit auctioning allocates the cross-border transfer capacity as a function of energy prices on organized markets. However, this method requires a certain degree of harmonization of rules of the markets involved. Explicit auctioning on the other hand considers transfer capacity and energy as separate markets. Even though the economic efficiency is less than in the case of its implicit variant, separating both markets allows to couple energy markets without the need for harmonization of all market rules.

There are numerous ways to handle transmission constrains. However, there is no one size that fits all. Contrary, depending on how the electricity market is organized, a method should be chosen so as to best meet local requirements. As there is a strong interaction between the way transmission congestion is managed and the electricity market, the choice of a particular congestion management method should be preceded by a techno-economic analysis of the performance of the method considered, as well as an analysis of the consequences of its application.

Abstract

This technical brochure introduces a problem of transmission constraints management in market environment. Its aim is to contribute to a better understanding of the interactions between the technical and economic aspects of congestion management. Detailed mathematical formulations of each congestion management method are given along with the discussion of their pros and cons. Moreover, all important terminology necessary when discussing congestion management is introduced, allowing for further investigation of the subject.

Key words: *congestion management, electricity market.*

Abbreviations

AAC	Already Allocated Capacity
ATC	Available Transfer Capacity
CA	Capacity Auctioning
CfD	Contract for Differences
CM	Congestion Management
CR	Congestion Revenue
DPA	Discriminatory Price Auction
FGR	Flowgate Financial Transmission Right
FMC	Flow based Market Coupling
FTR	Financial Transmission Right
IEM	Internal Electricity Market
IPP	Independent Power Producer
ISO	Independent System Operator
LMP	Locational Marginal Pricing
MC	Market Coupling
MCP	Market Clearing Price
MS	Market Splitting
NTC	Net Transfer Capacity
OTC	Over The Counter
PTDF	Power Transfer Distribution Factor
PX	Power Exchange
SCC	Socio-Economic Cost of Congestion
SO	System Operator
TDF	Transaction Distribution Factors
TFC	Financial Transmission Contract
TLR	Transmission Loading Relief
TRM	Transmission Reliability Margin
TSO	Transmission System Operator
TTC	Total Transfer Capacity
UPA	Uniform Price Auction
VIU	Vertically Integrated Utility

Congestion Management in Liberalized Market Environment

1. Introduction

The transition from vertically integrated utilities to the liberalized electricity market happened only a while ago. The performance of the regulated monopolies was often questioned. In developing countries the sector was characterized by low labour productivity, poor service quality, high system losses, and inadequate investment in power supply facilities. High operating costs, construction cost overruns on new facilities, and high retail prices required to cover these costs were the main drivers for changes that would reduce these costs [1]-[3]. In order to use the resources more efficiently competition in generation and supply has been introduced. Privatization of transmission companies, combined with budget constraints imposed on regulated network companies, provided cost-reducing incentives and improved service quality [4],[5].

Following unbundling and liberalization of the electricity market, the interconnected network is more and more becoming a marketplace for electric energy. However, due to the different state of pre-liberalized national energy systems, state of unbundling and government policies, electric energy prices can differ from country to country [6]-[8].

Due to the behaviour of players looking for the cheapest electricity, no matter where it is located, large and difficult to predict unscheduled power flows often appear in the interconnected network. Consequently, it comes as no surprise that international interconnections very often become congested [9], meaning that the transmission system cannot be operated securely under the requested pattern of generation and demand. This congestion has to be relieved before physical or security limits are breached.

The aim of this technical brochure is to introduce a problem of transmission constraints management in market environment and contribute to a better understanding of the interactions between the technical and economic aspects of congestion management. All important terminology necessary when discussing congestion management is introduced, allowing for further investigation of the subject.

This technical brochure is divided into two parts. First part discusses the structure of the electricity market, its architecture and design issues. It serves as an introduction to the topic of congestion management in liberalized market environment. The second part focuses on management of transmission constraints. Detailed mathematical formulations of each congestion management method are given along with the discussion of their pros and cons.

2. Electricity Market

The introduction of electricity markets and breakdown of the national monopolies has been seen as a means to increase efficiency of electrical energy generation and supply. Competition provides stronger cost-minimizing incentives than a typical cost based regulation and has the ability to trigger innovation. The other advantage of a competitive market is its ability to reduce prices to marginal costs. Well functioning markets are therefore critical success factors for the liberalization.

In a liberalized market, electricity is a bundle of many services, such as transmission, frequency control, voltage support. Each of these services requires a separate market, some of them being regulated. Moreover, national or multinational markets are linked by cross-border transfer capacity market. Additionally, prime energy markets such as oil and gas markets also form such a link. It is therefore very difficult to define *the* market [10].

Generally speaking, electricity market can be subdivided into many submarkets, the division depending of the degree of unbundling and vertical integration. Submarkets in turn can be again subdivided, describing a certain type of market. Currently, either among academics or in the industry, no consensus has been reached on the choice of these submarkets. One of the possible subdivisions within an electricity market is the following [11]:

- Wholesale energy market. Wholesale energy trade can be realized in a number ways and even if a certain type of a market is not developed by the market design rules, it may develop as a private initiative.
- Transfer capacity market. This market is provided by the TSO and offers linkages between different submarkets of a fragmented electricity market. An example is the cross-border capacity market coupling national markets in Europe. In some of the states in U.S. where Locational Marginal Pricing LMP is applied, transfer capacity market is integrated with wholesale energy market.
- Ancillary services market. These markets deliver services that are of fundamental importance for the delivery of electrical energy. Ancillary services markets are managed by the transmission system operators. The services are provided by market participants, and procured by the System Operators.

Each of these submarkets can be organized according to a different principle, forming a different type of market.

2.1. Wholesale energy market

Trade of electrical energy begins years in advance and continues until the actual delivery time, being the moment the power flows from the generator to supply the load. Electrical energy can be sold or purchased on many markets depending on the time to actual delivery. Generally the wholesale market can be divided into three time horizons:

- Long-term market
- Day-ahead market
- Real-time market

However, depending on chosen market architecture, the significance of these markets may differ. If by law a certain market is made obligatory, i.e. obligatory Power Pool, this market becomes the most significant as it is the only way to physical delivery. On the other hand, if no day-ahead market is designed and none developed, other markets grow in significance.

2.1.1 Long-term market

The long term market is usually bilateral, also called *Over The Counter* OTC market. It involves trading of tailor made contracts such as forward contracts. A basic forward contract is an agreement between a buyer and a seller to deliver and pay for something in the *future* at a price agreed upon in the *present*. Forward contracts are non-standard contracts and imply actual physical delivery of the electrical energy. The trade of forward contracts is a continuous, terminating when daily generation schedules need to be submitted to the system operator. This is usually one day ahead of delivery. OTC trading can be made using brokers : a broker is generally Internet-based, and offers a screen where all bids and offers can be visualized. Then the trader can make a transaction only by clicking on the desired bid.

Some brokers act as counter-parties for both sides involved. The advantage of such approach is that the sides do not know each other identities, and thus do not get any insight in their contracts positions - information which could be regarded as market sensitive.

Next to a physical market, there exists also a financial market, where financial products coupled to the physical market are sold. These products are often called *derivatives* as they are derived from the physical market [12],[13]. There are many types of products that can be traded on financial markets. One of them is *futures contract*. These contracts are quite similar to the forward contracts as they are also contracts to buy or sell a good at a pre-agreed future point in time. However, as futures contracts are often traded with the help of financial institutions, or exchanges, they are standardized. Futures contracts are characterized by the amount of delivered good, strike price and the reference price[1]. Negotiated prices of the trades are made public by the institution organizing the trade. Moreover, the contractors deal with an exchange rather than each other, and thus do not need to assess each others' credit worthiness. Buying a futures contract comes down to an agreement for a daily settlement procedure. Throughout the duration of the contract, the buyer is credited or debited with the difference between the reference and the strike price, times the quantity contracted. Typical futures contracts cover a month of power delivered during on-peak hours, and are sold up to two years in advance.

A variation of a futures contract is an *option*. The only difference between both types of contracts is that the holders of options can only be credited for the difference between the reference and the strike price. In case this difference is negative, holders of options do not have to be debited. Option can be seen as a *right* to the difference between the reference and the strike price. Naturally, this right must come at a price and therefore buying an option usually involves paying a fixed premium in advance.

2.1.2 Day-ahead market

A day-ahead market is important from the viewpoint of the system operator. It allows collecting of daily generation and consumption schedules, which in turn is essential to secure the reliable and safe operation of the power system. As in the liberalized market the generating companies get the freedom of scheduling their power output independently, the system operator needs to check the feasibility of a given schedule. The provisional day-ahead power commitments offer such a possibility with a reasonable advance.

The day-ahead market, as opposed to a longer-term market such as bilateral OTC market, is usually an organized market, meaning that it produces a single price. Generally, day-ahead markets can be described as auctions for the commodity electrical energy. For the purpose, the delivery periods i.e. days are divided into a number of time periods, i.e. hours, and each of the periods is auctioned independently[2]. The exact implementation of the auction is subject to an ongoing discussion [14].

The energy auctions can be divided in two categories:

- Cost-based auctions - usually centralized auctions run by the system operator. Based on marginal fuel costs, and the technical characteristics of the generating units, unit commitment is centrally determined. Cost-based auctions are often used in hydro-dominated systems, where factors like fuel availability and water reservoir levels need to be taken into account as, for instance, is the case in Brazil [15]. Price in a cost-based market is determined using complex optimization scheme [16],[17].

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[1] In case of electrical energy, the reference price could be the price on the day-ahead market.

[2] Special kind of auctioned products, like block bids covering several time periods, can cause the time periods to be dependable.

- Bid-based auctions - based on bids and offers submitted by the market participants involved. The market price is determined according to the marginal pricing principle, and is discovered at the intersection of the demand and supply curves. Depending on the auction design, demand may also participate in the bidding procedure and submit demand bids (Figure 1). If however, no demand participation is allowed, the volume of demand is forecasted by the entity responsible for the market making and the energy price is found at the intersection of supply offered and demand forecasted (Figure 2). Bids may be simple price-quantity pairs, or more complex combinations to account for the specific characteristics of electrical energy production, and include start-up costs, ramp rate limits. In the presence of complex bids however this price might sometimes be infeasible, as it could be possible that some market participants would have to operate at a negative profit [18]. This calls for special measures [19]-[21].

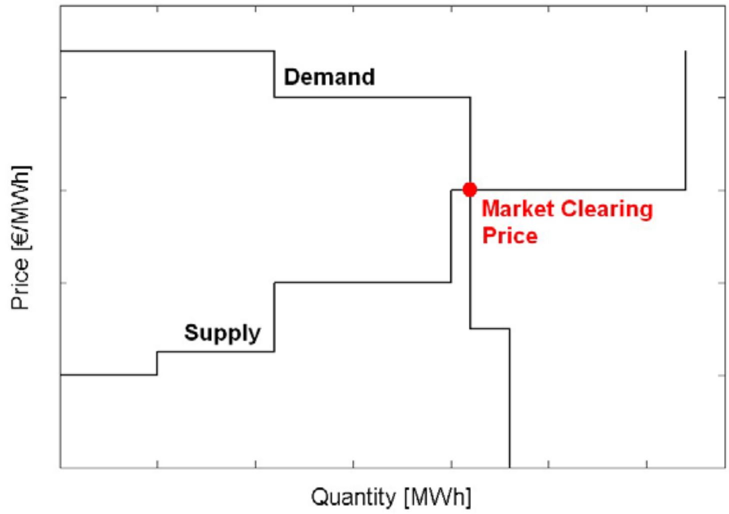

Figure 1. Price discovery at the intersection of demand and supply

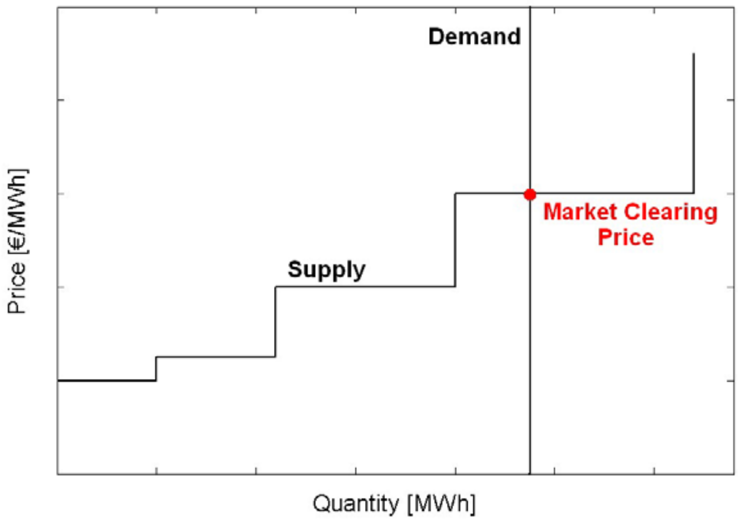

Figure 2. Price discovery at the intersection of supply and the forecasted demand

Generally, two forms of organized day-ahead market can be considered:

- Obligatory Power Pool
- Voluntary Power Exchange

2.1.2.1 Power Pool

Power Pools are obligatory markets where all eligible market participants are obliged to offer all their electrical energy. The main idea behind the creation of a Power Pool is a belief that centralized scheduling is more efficient and produces fair prices [22]. Though some of the pools are voluntary, the off pool energy trade is usually discouraged via incentives for the pool participants, such as capacity payments [23]-[25]. Moreover, as the pool is used as a commitment scheduling entity, all energy transactions need to enter the pool as price-indifferent offers[3].

The common feature of Power Pools is that the energy commitments produced are firm, meaning that the bids and offers matched in the market clearing process result in an obligation to take or deliver the matched volumes and their financial settlement. There are different types of Power Pools, the differences being demand participation, the bidding scheme and the treatment of internal transmission congestion. Two main types of power pools are single price pools, and locational priced pools.

Single price pools produce a single price for the whole market. In the matching process the network is treated as a *copper plate* and the demand is matched with the supply as if there were no transmission constraints. In the second stage, the technical feasibility of the solution achieved is examined. If there is congestion, some out-of-merit generators are dispatched at cost of in-merit generators. This is the so-called “constrained-on” generation and the cost of this action constitutes the uplift charge and is added to the obtained energy price. The cost of internal congestion is thus socialized among all market participants.

Economic theory suggests that transmission constraints do influence the electrical energy prices [26]-[30]. Therefore *locational price pools* differ from single price pools in the way transmission constrains are treated. In the matching process both energy market and transmission constraints are a factor in determining the market prices. The objective of the optimization function used to determine the unit commitment is the maximization of economic surplus subject to generation and transmission capacity constraints. Detailed representation of a network makes it possible to take losses, parallel flows, voltage stability and reliability criteria into account. As a result, first-order conditions associated with the maximization of economic benefits under constraints yield the so-called nodal prices, which represent the change in the total cost (as defined by market participants’ bids and offers) [31] of meeting the system energy requirements caused by a change in load or generation at each location, usually a node (hence the term *nodal pricing*). As a consequence, instead of a one single price, there are many market prices depending on transmission constraints [32]. The result is a market price per location, being a node or a zone according to a chosen approach. The geographical spread of the chosen location, thus nodal or zonal approach, greatly influences the pricing efficiency [33]. This implies that congestion costs are no longer socialized, but each market player pays for the congestion caused. Highlighting the significance of the transmission limitations is considered as the major advantage of this market arrangement. Locational price differences give clear signals regarding the location of new investments in both transmission and generation [34]. Such a market is called the

[3] Price-indifferent offer is an offer at a minimum price allowed and implies a price-taker’s behavior. Such offer is virtually always accepted.

Locational Marginal Pricing (LMP) based market and has been adopted in many markets especially in the North America such as the New England ISO [35], PJM [36], etc.

2.1.2.2 Power Exchange

Power Exchanges PX are places where electrical energy can be traded on a voluntary basis. These institutions offer matching services for anonymous demand and supply willing to exchange standardized products. In principle, Power Exchanges are quite similar to single price Power Pools, although there are significant differences as far as types of bids are concerned. Contrary to Power Pools which often have a competence of scheduling the unit commitment, Power Exchanges are electrical energy only markets and are merely a trade platform. Power Exchanges usually cover a small portion of electrical energy demand and function next to OTC-based markets. Though Power Exchanges offer significant benefits for the market participants, they are not the central point of the wholesale market and play rather a complementary role. Depending on the maturity of the market and market rules concerning the cross-border trade, the wholesale volume of physical contracts traded at a PX ranges from some 1-2% till over 20%[4]. PXs are often developed on the initiative of market participants. The Power Exchange is a special type of grid user, as it does not inject nor withdraw any power from the network, its net position being by definition zero. From the System Operator point of view, a Power Exchange is a best customer imaginable, as it is never imbalanced.

Power Exchange, being supplementary to OTC bilateral trade, offers important benefits to market participants:

- More price transparency – contrary to OTC trade the prices on Power Exchanges are public. Moreover, on the majority of PXs the aggregated bid curves are also made available.
- No counter party risk – the PX plays an intermediate role between the two contractors, taking the credit risk on itself. This alleviates market participants from the risk of being unable to execute their deals.
- Anonymous trading – thanks to anonymous trading no information on contract positions is revealed to other market participants, which is especially important in the competitive market environment.
- Tool to optimize trading portfolio – the PX offers the possibility to fine-tune the trading portfolio by allowing a trade close to real time. Moreover, it might sometimes be possible to acquire the electrical energy on a PX cheaper than to produce it by own resources.
- Transaction costs reduction – the costs of trading on PX are often lower than shopping for counter-party on an OTC market and bargaining, especially if time constraint is important.
- Power Exchanges provide price indexes, which are often used as a reference for bilateral trade and help facilitating the energy trade.

Power Exchanges trade energy only products. Usually the bids consist of price–quantity pairs, though also complex bids covering more than one time period are often allowed. As PX trade

[4] The differences in traded volumes often result from differences in market rules and regulations, i.e. coupling of transfer capacity market and the energy traded at some PXs. In The Netherlands the energy entering the Dutch control zone via a day-ahead cross-border transfer capacity market has to be offered at the Dutch Power Exchange APX. In the Nordic Power Market, Nord Pool, where PX is used as a means of cross-border transfer capacity allocation, it is obligatory to bid into a PX if one wants to access a different price area (i.e. a foreign energy market). Consequently, the volumes traded at APX and Nord Pool are relatively high (averaging 12-13% and 30% respectively) compared to other European PXs, such a 1.5% at Polish POLPX, 2-3% at French PowerNext and 2% at Austrian EXAA.

has nothing to do with unit commitment, no unit-commitment bids are present avoiding all problems entailed, like the need for *side payments*[5].

A special feature of some Power Exchanges is the fact, that the clearing of energy market is often linked to cross-border capacity allocation. This is the case for the power exchange spanning the Nordic market Nord Pool, and for the Dutch APX. Moreover, according to the EU guidelines, allocation of cross-border capacity in the European Market should in the long-term be linked to Power Exchanges energy market clearing [37]. Due to the European market architecture where wholesale markets are not organized and dominated by bilateral OTC trade, Power Exchanges are especially popular in Europe. The list of countries includes the Netherlands (APX), France (Powernext), the Scandinavian countries (NordPool), Germany (EEX), Poland (PolPX), Austria (EXAA) and Belgium (BepPex starts operation beginning 2006). Moreover, Power Exchanges can coexist competing with each other, as was the case in Germany (EEX and LPX) and is still the case in England (UKPX , APX UK, PowerEX and IPE). Figure 3 shows the location of Power Exchanges in Europe.

Figure 3. Power Exchanges in Europe

2.1.3 Real-time market

Electrical energy is a special commodity, as it has to be consumed at the same time it is generated. As it is difficult to predict the load, it is also difficult to correctly asses the quantity of energy that has to be contracted. The gap between the closure of day-ahead market and the physical delivery is in that respect huge.

Due to the above, the actual generation and load will virtually always deviate from the scheduled. Any deviation from generation and demand equilibrium results in frequency deviating from the nominal. As the correct frequency level is essential for the proper operation of many electrical appliances, maintaining the rated frequency value and thus balancing the generation and demand is of key importance.

5 Side payments are typical of a Power Pool. Due to the presence of complex bids covering multiple time periods, it is possible that the solution is unacceptable for some market participants i.e. they would need to sell the electrical energy below the offered price. To compensate for this, such market players receive side payments.

2.1.3.1 Balancing market / mechanism

Real-time markets provide a market-based mechanism to balance generation and demand. There are different approaches to the provision of balancing services. One possibility is that the system operator purchases the necessary reserve requirements in a market and charges the system users for it on a *pro-rata* basis. It can also assign an obligation on each generator to supply a fraction of the total system requirements specified. However, both approaches eventually come down to the same: a real-time balancing market. When generators obliged to offer balancing services find it too expensive, they try to contract them from other parties and the market eventually develops.

The parties deviating from their schedules are priced for these deviations individually according to the common real-time balancing price. In competitive markets, the real time market provides an indication of the upper bound for the average wholesale price levels. If average prices in the day ahead or intra-day market were higher than these paid on average for imbalances, market players would have an incentive to incur imbalances rather than contract for energy day-ahead.

2.1.3.2 Intraday market

Intra-day market is a tool to correct the wrongly assessed schedule forecasts and adjust the energy purchases accordingly before the imbalances are settled by the System Operator. This market can take different forms, such as a bulletin board, broker service, or an OTC bilateral bargaining. Also the time horizons may differ, and range from 24 hours ahead of physical settlement till even after the settlement[6]. The time-frame of an intra-day market is shown on Figure 4.

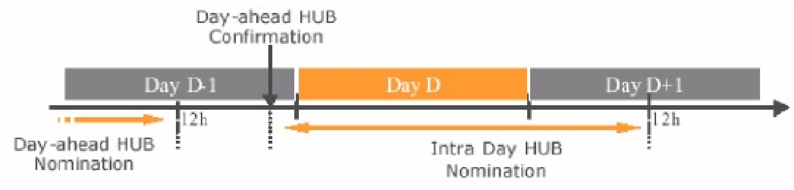

Figure 4. Illustration of the intra-day market in Belgium (source: Belgian TSO ELIA).

2.2. Transfer capacity market

In the liberalized market, transfer capacity market and electrical energy market may be separated depending on the shape of the market. When these are separated, transfer capacity markets offers transfer capacity contracts with no energy commitments entailed. Transfer capacity contracts can be either offered by the system operator or by a transmission assets owner i.e. merchant transmission lines. Such contracts can be either rights (options), or rights and obligations. Three possibilities of interaction between energy and transfer capacity markets can be considered

- Energy market and no transfer capacity market
- Separate energy and transfer capacity markets
- Integrated energy market and transfer capacity markets

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6 In some markets, under defined circumstances, the market participants get the possibility to correct their schedules even the day after the settlement took place. This is e.g. the case in Belgium, where such market is available since 1st October 2003

The first case concerns an isolated market under the jurisdiction of single TSO that applies a flat transmission tariff. A flat transmission tariff implies no locational differentiation of injected active power, meaning that the transmission network is available to everyone under the same conditions.

Separate energy and transfer capacity markets are the case of cross-border trade between two control areas managed by different System Operators. As often different market rules apply on both sides of the border, energy and transmission markets can be separated. A cross-border transfer capacity market offers the possibility to trade between the energy markets involved, allowing for arbitrage.

Integrated energy and transfer capacity markets are based on locational pricing principle. Different locations are coupled by the transfer capacity market settled according to the settlement of individual energy markets. Transfer capacity is thus allocated and priced in function of locational energy prices.

Transmission market and congestion management is discussed in detail in further part of this document.

2.3. Ancillary services market

Ancillary services are the services identified as necessary to realize a transfer of electricity between sources and sinks, and which a provider of transmission services must include in an open access transmission tariff. These services are provided by the System Operator. However, as it does not posses the physical means to fulfil this task, it has to somehow acquire these means either by laying an obligation on network users to make them available, or by buying them on a free market. For a discussion of design issues of ancillary services markets see [38].

Ancillary services include:

- System reserves
- Reactive power and black-start capability
- Losses

2.3.1 Reserves market

The reserves market is very important for the short-term security of supply. As the frequency in the interconnected power system is equal for all its users, no market participants have an explicit interest in maintaining its correct level. As this is a costly process, everyone prefers to have others take care of it (*free riding*). As a result, the system operator is designated as the entity competent for maintaining the system frequency at a rated level. Demand for electrical energy fluctuates constantly. In order to cope with it and be able to balance the system at all instances of time, thus also in case of contingencies, System Operator needs to contract a reserve power. Reserve power can take different forms, corresponding to different levels of frequency control.

The demand for the reserve power is determined by the System Operator and regulated. The procurement of these reserves, on the other hand, is a function of the system frequency and is organized as a balancing market or a balancing mechanism[7]. Market participants unable to maintain a balance between their injections and withdrawals are penalized. These penalties are not included in the transmission tariffs. On the contrary, each market participant has to bear the consequences of its inability to balance its portfolio.

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[7] The balancing market is often called real-time market, as described in 2.1.3

2.3.2 Reactive power and black-start capability market

Reactive power, unlike active power, cannot be transported over long distances. When too much reactive power is locally consumed, voltage in the direct neighbourhood sags. To counter this, reactive power needs to be delivered by a capacitance, power plant or a special reactive power compensating equipment i.e. a synchronous condenser or FACTS device.

A reactive power market is a very delicate issue. It is very difficult to measure the reactive power required by the grid users. Therefore, a reactive power market is complex and expensive to run. Moreover, reactive power is generally quite cheap to produce which makes an establishment of such a market questionable. In the present, the simplest approach seems to be regulating the reactive power purchase requirements and allowing the System Operator to contract what is needed, and where it is needed.

Black start capability is an ability of a generating unit to go from a shutdown to an operating condition and start delivering power without assistance from the grid. This service can be offered only by certain types of power plants equipped with special systems. Most power plants need to take energy form the grid in order to start-up, which means that in case of complete system black-out they are unable to help in the system restoration process. Some power plants are equipped with additional equipment allowing for independent start-up and re-building the system voltage. This black-start service is essential in the functioning of a power system. Though it is not used very often (hopefully never), the system operator has to be able to procure this service if needed.

2.3.3 Losses

Some System Operators are obliged to compensate for the power losses arising from the transfer on the medium, high and extra high voltage power transmission network. These losses, mainly depending on energy consumption and voltage profile, represent about 3 to 5% (including medium voltage) of the demand. To make up for these losses, SO turns to the wholesale market and organises a call for tenders. The energy purchased for losses compensation is mainly in the form of standard products such as *forward base load* and *peak load*, etc. However, being a function of the generation and demand dispatch, losses are difficult to predict, there is a need for some balancing capability. This takes often a form of *option* contracts.

Another way to compensate for losses is that a market participant is directly responsible for their compensation. In other words, he needs to inject in the grid more than his scheduled load, the surplus covering the losses arising from his off-takes. This surplus is allocated to the Balancing perimeter of the party. In zones where Locational Marginal Pricing is implemented, cost of marginal losses can be included in the LMP.

3. Basics of congestion management

3.1. Definition of congestion

Congestion is a situation where the demand for transmission capacity exceeds the transmission network capabilities, which might lead to a violation of network security limits, being thermal, voltage stability limits or a (N-1) contingency condition. Congestion, being a result of power flows, may occur at any location in the interconnected network. It is thus a problem of physical network elements, and has nothing to do with commercial transfer capacity.

In order to prevent the violation of security limits, System Operator SO must define the limits on commercially available transfer capacity between zones. If, for a given interconnection, there is more demand for cross-border capacity than commercially available, the interconnection is also treated as congested, meaning that no additional power can be transferred. This congestion is visible for market players as a limit on their cross-border transactions.

At the same time, it is possible that even though the available commercial interconnection capacity is not fully allocated to market players, some lines, being internal or cross-border, become overloaded. This physical congestion is a problem of the System Operator and has to be dealt with by this entity. System Operators try to avoid such unforeseen congestion by carefully assessing the commercially available capacities and reliability margins.

In a physical sense congestion is merely an indication of a presence of transmission constraint. However, often due to the chosen market organization and the way congestion is managed, some transmission constraints can be managed different than the others. Consequently, there is a division between an internal and cross-border congestion.

3.1.1 Internal congestion (Intra-zonal)

Internal congestion is situated within a single System Operator's control area. When intra-zonal congestion costs are socialized, the congestion may not be visible to a large number of market players. Therefore the control of its intensity has to be monitored and regulation has to intervene in case a socially unacceptable drift is found. When intra-zonal congestion costs are addressed through nodal or zonal pricing, transmission grid users are made responsible for the transmission constraints they cause.

3.1.2 Cross-border congestion (Inter-zonal)

Cross-border congestion, also called seams issues, is congestion between System Operator's control areas. The biggest issue is that market organization, regulation and investment framework on both sides of the interconnection can be different, making the allocation of cross-border capacity and settlements of congestion costs more difficult.

3.2. Causes of congestion

Many factors can contribute to the creation of congestion. The most obvious ones are the following:

- Market organization
- Electricity price differences
- Fuel availability

Market organization can be a source of congestion if it gives no incentives for the efficient use of the grid. A *"copper plate"* network model, typical for markets with Power Exchanges, is a prominent example [39]. In this model, network constraints are managed by the System Operator, and market players do not have to bother about them. This can obviously lead to an inefficient use of the grid, or incorrect behaviour of market players trying to create congestion and make profit out of it. Moreover, the assumed network model can also contribute to creation of congestion. Given the self dispatch freedom of the European market participants and consequently an unpredictable internal dispatch pattern, the zonal network model is to a great extent responsible for the loop flows on cross-border interconnections. Zonal network model approximates the nodal reality by substituting control areas with single nodes, implying that the actual nodal dispatch information within zones is unknown for the neighbouring System Operators. The ever changing demand entails the even changing generation dispatch. Moreover, in the presence of wind parks the generation dispatch becomes even more unpredictable. This is one of the most significant factors contributing to the ever changing fluctuation of cross-border flows.

Electricity prices are a function of the available fuel. Some countries due to their geographical location rely on hydro power. Other countries have lots of lignite coal, or gas resources, which determines their fuel mix. Political choices can also be a significant factor, as for instance it is the case for the use nuclear power. The same holds for subsidizing green energy. With no legal barriers to cross-border electricity trade, market players look for the cheapest source of electric energy available. Therefore it is very important to organize the international electricity trade in such a way, that nobody takes a free ride making use of peculiarities.

Availability of fuel is closely linked to energy price differences, as fuel shortages naturally lead to price increases. Systems experiencing fuel problems tend to have very high prices, which in turn attracts foreign traders. Moreover, the local demand in a system with generation shortages cannot be met by domestic sources, requiring more import and congesting interconnections.

3.3. Nodal vs. zonal network models

Physically, the electrical grid consists of nodes (busses or busbars) connected by lines and/or transformers. However, as a consequence of a chosen market organization, very often groups of nodes are aggregated into areas. Areas are parts of the grid considered as copper-plates, meaning that the internal transmission constraints are initially ignored, and corrected in the planning phase. Areas are connected with other areas by means of transmission lines called interconnections. The control zone of one System Operator can consist of more than one area. Each of these areas may have a different energy price (price area).

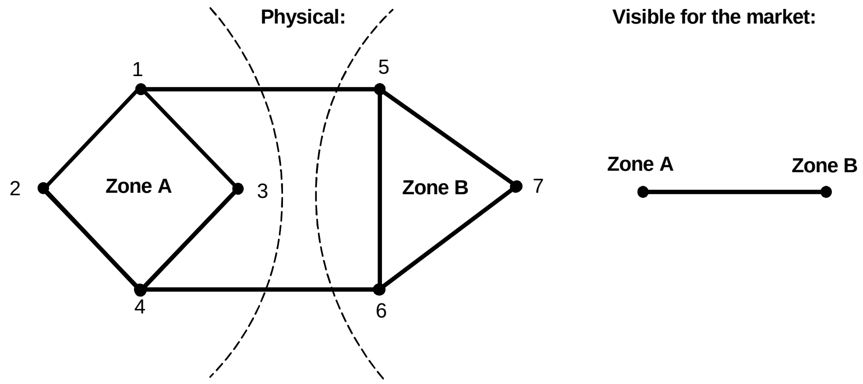

Figure 5. From a nodal physical reality to a market oriented network representation

The difference between nodal and zonal network representations is illustrated on Figure 5, where a 7-node system is replaced by its 2-zone equivalent. The physical capacity of the lines interconnecting zones A and B, 1-5 and 4-6, is replaced by an aggregated commercial capacity A-B. Since SOs must ensure that the power flows always comply with security limits, some restrictions might be put on the cross-border flows. These limits are expressed in terms of cross-border transfer capacities, expressing the maximum power exchange between the zones concerned. However, the latter is not equal to the sum of the physical capacities, but is a result of existing or forecasted network conditions, strongly depending on nodal power injections and power flow patterns. It serves as an index, helping market players to estimate transfer capacities.

Aggregated transfer capacities in a zonal network model can also be affected by the shifts of generation within a control zone, as these shifts influence the power flows on the interconnections. Depending on the network topology and the predictability of the internal dispatch pattern, the variations of nodal power injections can have a significant influence on the variation of cross-border flows.

3.4. Parallel/loop flows[8] - the relation between physical flows and commercial exchanges

Physical flows differing from commercial exchanges are a natural phenomenon in an AC interconnected power system. Physically, power system consists of power plants and loads connected by a transmission grid consisting of lines, cables, substations and transformers. Due to laws of physics, power flows along the path of the least electric impedance and thus the power flow pattern depends only on the location of sources, sinks and the grid topology. This means that any transaction between two nodes in a meshed network induces *some* power flow in each of its lines, except the isolated ones.

From the commercial point of view, the grid is considered as a market place that should allow maximum trading flexibility for different types of products. In a zonal network model these products are exchanged without any specification of origin or destination: they are purely commercial. However, the final real-time settlement of the trade will find a physical translation in generation schedules and load levels.

In congestion management, the term parallel or loop flows is usually used to refer to a situation where the actual physical flows differ from the expected ones due to transactions accepted in other parts of the interconnected power system. The more transactions and the more meshed the network, the higher the chance for mismatch between commercial exchanges and physical flows.

4. Cross-border transfer capacity definitions

Interconnection, or cross-border capacity, is defined as the capacity between two control areas or zones. This interconnection capacity is not a physical one, but results from the aggregation of line capacities connecting these areas.

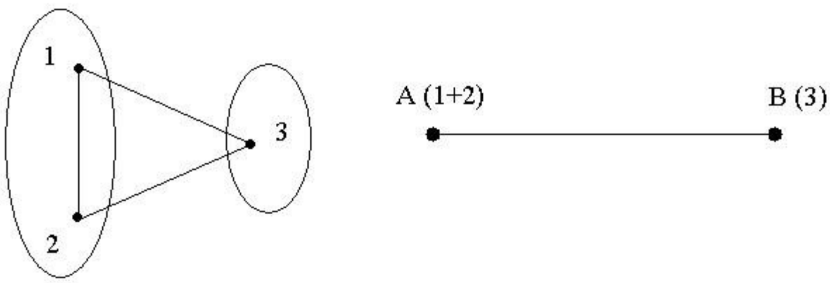

Figure 6. Aggregation of interconnection capacity

The physical capacity connecting zones A and B is a sum of 1-3 and 2-3 physical line capacities. However, the cross-border capacity available for commercial trade is A-B, being less or at most equal to the sum of capacities of cross-border lines individually (Figure 6). It approximates, typically in a bilateral way, the complex constraints of allowable regional imbalances and transmission security rules that apply to control areas. This aggregated capacity can be calculated based on different principles. One of the possibilities is the method proposed by the European Association of Transmission System Operators ETSO [41].

8 The term *loop flow* used in Congestion Management should not be confused with the same term used to depict circular power flows in the ring-shaped power systems [40].

4.1. ETSO definitions of cross border transfer capacity

4.1.1 Total Transfer Capacity TTC

Total Transfer Capacity TTC is defined as a maximal possible power transfer between two adjacent areas [42]. The calculations begin by choosing the base case scenario, stating the energy balances of both areas, e.g. $\Delta A= + 100$ MW, $\Delta B= - 100$ MW. The base case scenario includes information on the exact location of each power injection and sink in the interconnected grid.

In order to find the TTC, the power exchange between areas is increased until there is a breach of security constraints, being it internal or cross-border congestion. This is done by increasing generation in one area, and lowering it in the other. Using load flow calculations and detailed topology data, feasibility of such border exchanges is tested. The highest exchange without violating security limits yields the TTC [43]. The same procedure holds in both directions. Depending on the base case, TTC can be different in both directions.

4.1.2 Transmission Reliability Margin TRM

Transmission Reliability Margin is a part of cross-border capacity withdrawn from the market to account for the random threats to the security of the interconnected grid, such as unexpected activity of load frequency control e.g. to cope with the loss of a generating unit. These values are determined by the SO to guarantee security of real-time operation. In case of UCTE, the values of TRM for a given control zone are calculated based on the size of the biggest unit in the synchronous area and the domestic generation park of a control zone. TRM is revised on a yearly basis.

4.1.3 Net Transfer Capacity NTC

Net Transfer Capacity is the maximum exchange program between two areas compatible with security standards, taking into account the technical uncertainties on future network conditions.

$$NTC = TTC - TRM \tag{1}$$

4.1.4 Already Allocated Capacity AAC

Already Allocated Capacity is the total sum of all allocated transmission rights, being capacity rights or exchange program, depending on the allocation method. This includes existing contracts, often concluded before the liberalization of electricity market.

4.1.5 Available Transfer Capacity ATC

Available Transfer Capacity is the cross-border capacity available for commercial trade and is a result of subtraction of Already Allocated Capacity from Net Transfer Capacity.

$$ATC = NTC - AAC \tag{2}$$

4.1.6 Application of ETSO definitions

In Europe, these cross-border transfer capacities are the basis of pan-European congestion management. Though there is no common congestion management scheme, the available capacities are calculated using the same principles in all countries belonging to ETSO (Norway, Switzerland and Romania plus all EU countries excluding Cyprus and Latvia). NTCs are calculated for each border independently by both SOs, involved, and the lower of the two is made publicly available. NTCs are published twice a year (winter and summer) and serve as the cross-border capacity indexes, sending a signal to market participants concerning the physical limitations of the grid. However, care should be taken while interpreting them, as the differences between forecasted NTCs and the commercially available ATCs may be significant.

4.2. Towards a flow-based modelling of meshed networks

There is a consensus that the current transfer capacity definitions applied by ETSO are not optimal. Commercial exchange capacities must be published before real-time to give traders the opportunity to use the information. System Operators, by assuming a base case scenario, have to predict the behaviour of market players. Not only the active power injection pattern within a control area is important, but there is often a bias towards a more-likely-to-be-used path for cross-border trade. This is clearly a case of a good old chicken-and-egg problem (Figure 7).

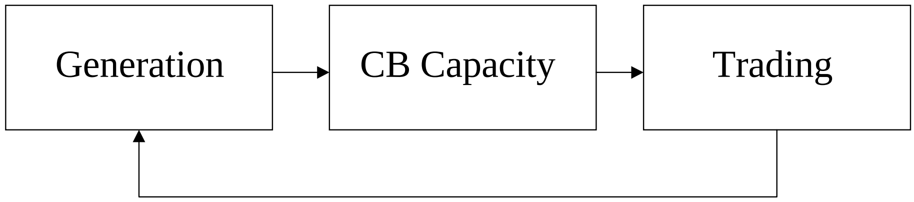

Figure 7. Chicken-and-egg problem of evaluating cross-border transfer capacities

The current contract path mechanism can be replaced by a better one, taking the reality in the interconnected grid into account. The relation between cross-border flows and zonal injections could be illustrated using a simplified linear relationship, the so called Power Transfer Distribution Factors (PTDF). Though the model remains imperfect due to tremendous simplifications of going from a nodal to zonal network representation, it is more flexible as no transmission path is preferred at the cost of the other.

4.3. Power Transfer Distribution Factors

Power Transfer Distribution Factors PTDF is a concept that helps to understand the interaction between power flows in the meshed interconnected network. Modelling these interactions is important to make the best use of the scarce cross-border capacity. Power flows are determined by impedances of individual lines and branches, as well as system state variables such as nodal voltages or power injections. Knowing all parameters of the system does not directly indicate which is the influence of a given transaction on a given line flow. The PTDF matrix does offer such a possibility as it translates nodal injections into individual line flows by explicitly stating the contributions of each nodal injection to a given line flow. It can be calculated based on network topology and line parameters. In its simplest form, assuming a DC representation of a transmission network, PTDFs can be calculated directly from line parameters. However, it is also possible to build a set of PTDFs that assumes other network models, such as a zonal model.

Any $PTDF_{n,i\text{-}j}$ shows how much of a given transaction P_n between nodes n and the reference node flows through a line i-j (Figure 8). By assuming a reference node and referring all transactions to it, the PTDF matrix can be limited to only nodal injections. However, it has to be noted that the PTDF matrix must not be misused. This matrix shows the incremental influence of a transaction, or nodal injection referred to a reference node for that matter, on a given line. In order to get the actual flow, all transactions in the system have to be considered.

$$PTDF = \begin{array}{r} \\ line_{1-2} \\ line_{1-3} \\ \\ line_{i-j} \end{array}\!\!\begin{array}{c} \begin{array}{cccc} node_1 & node_2 & .. & node_n \end{array} \\ \left|\begin{array}{cccc} PTDF_{1,1-2} & PTDF_{2,1-2} & .. & PTDF_{n,1-2} \\ PTDF_{1,1-3} & PTDF_{2,1-3} & .. & PTDF_{n,1-3} \\ .. & .. & .. & .. \\ PTDF_{n,i-j} & PTDF_{n,i-j} & .. & PTDF_{n,i-j} \end{array}\right| \end{array}$$

Figure 8. Example PTDF matrix.

One of the ways to derive the PTDF matrix is to assume a DC representation of the power system and derive the PTDF matrix directly from the line parameters of the network. In DC power flow terms, PTDF matrix depends only on the line parameters and not on the dispatch of production and demand. In other words, such a flow factors matrix does not depend on the operating point. However, it still needs to be considered as incremental because it represents the increase of the line flow resulting from varying a nodal power injection.

The flow factors matrix can be derived as follows. First the DC power flow equations, being nodal active power balances (3) and line flows (4) are written down, for example for the network seen on Figure 9.

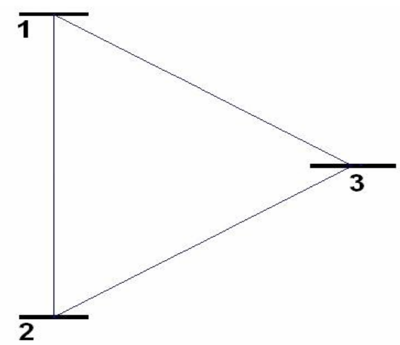

Figure 9. Example 3-node network

$$\begin{bmatrix} B_{1-2}+B_{1-3} & -B_{1-2} & -B_{1-3} \\ -B_{1-2} & B_{1-2}+B_{2-3} & -B_{2-3} \\ -B_{1-3} & -B_{2-3} & B_{2-3}+B_{1-3} \end{bmatrix} \cdot \begin{bmatrix} \delta_1 \\ \delta_2 \\ \delta_3 \end{bmatrix} = \begin{bmatrix} Inj_1 \\ Inj_2 \\ Inj_3 \end{bmatrix} \tag{3}$$

$$\begin{bmatrix} B_{1-3} & & -B_{1-3} \\ B_{1-2} & -B_{1-2} & \\ & B_{2-3} & -B_{2-3} \end{bmatrix} \cdot \begin{bmatrix} \delta_1 \\ \delta_2 \\ \delta_3 \end{bmatrix} = \begin{bmatrix} Flow_{1-3} \\ Flow_{1-2} \\ Flow_{2-3} \end{bmatrix} \tag{4}$$

As the equations are linearly dependent, one of the nodes needs to be removed. Therefore an arbitrarily chosen node, in this case node 3, is designated as a reference node and erased from both above sets of equations.

$$\begin{bmatrix} B_{1-2}+B_{1-3} & -B_{1-2} & -B_{1-3} \\ -B_{1-2} & B_{1-2}+B_{2-3} & -B_{2-3} \\ -B_{1-3} & -B_{2-3} & B_{2-3}+B_{1-3} \end{bmatrix} \cdot \begin{bmatrix} \delta_1 \\ \delta_2 \\ \delta_3 \end{bmatrix} = \begin{bmatrix} Inj_1 \\ Inj_2 \\ Inj_3 \end{bmatrix} \tag{5}$$

$$\begin{bmatrix} B_{1-3} & & -B_{1-3} \\ B_{1-2} & -B_{1-2} & \\ & B_{2-3} & -B_{2-3} \end{bmatrix} \cdot \begin{bmatrix} \delta_1 \\ \delta_2 \\ \delta_3 \end{bmatrix} = \begin{bmatrix} Flow_{1-3} \\ Flow_{1-2} \\ Flow_{2-3} \end{bmatrix} \tag{6}$$

Substituting δ from equation (5) to equation (6) gives

$$\begin{bmatrix} B_{1-3} & \\ B_{1-2} & -B_{1-2} \\ & B_{2-3} \end{bmatrix} \cdot \begin{bmatrix} B_{1-2}+B_{1-3} & -B_{1-2} \\ -B_{1-2} & B_{1-2}+B_{2-3} \end{bmatrix}^{-1} \cdot \begin{bmatrix} Inj_1 \\ Inj_2 \end{bmatrix} = \begin{bmatrix} Flow_{1-3} \\ Flow_{1-2} \\ Flow_{2-3} \end{bmatrix} \tag{7}$$

$$\begin{bmatrix} PTDF_{1,1-3} & PTDF_{2,1-3} \\ PTDF_{1,1-2} & PTDF_{2,1-2} \\ PTDF_{1,2-3} & PTDF_{2,2-3} \end{bmatrix} \cdot \begin{bmatrix} Inj_1 \\ Inj_2 \end{bmatrix} = \begin{bmatrix} Flow_{1-3} \\ Flow_{1-2} \\ Flow_{2-3} \end{bmatrix} \tag{8}$$

$$\begin{bmatrix} \\ PTDF \\ \\ \end{bmatrix} \cdot \begin{bmatrix} \\ Inj \\ \\ \end{bmatrix} = \begin{bmatrix} \\ Flow \\ \\ \end{bmatrix} \tag{9}$$

Note, that due to erasing one of the nodes from equations (5) and (6), PTDFs in equations (7) and (8) are coupled to a reference node. This means that $PTDF_{k,n-m}$ is a flow on line *n-m* spanning nodes *n* and *m* caused by a unit of injection in node *k* and withdrawal at the reference node. This allows the PTDF matrix to be limited to one number per node per line, instead of having to store all the possible combination of nodal transactions. Such a nodal-based PTDF matrix is a factor *(NrNodes-1)* smaller than a full transaction-based PTDF matrix. However, it is very easy to derive a transaction-based PTDF matrix from a nodal-based one. If one wants to know the influence of a transaction between nodes *j* and *k* on a line *n-m* between nodes *n* and *m*, it can be easily calculated by subtracting the corresponding factors from each other.

$$PTDF_{j-k,n-m} = PTDF_{j,n-m} - PTDF_{k,n-m} \tag{10}$$

The concept of PTDF matrix is well established in the literature [45]-[47]. However, usually nodal PTDF factors are discussed which quantify the influence of nodal transactions on individual line flows. Extending the concept to the interaction between the zonal exports and imports, and aggregated cross-border flows yields a set of zonal PTDF. However, this is not straightforward due to the inherent loss of granularity when going form a nodal to a zonal world.

5. Congestion Management methods

There are many Congestion Management (CM) methods [37],[48]-[50]. Moreover, they can have different goals, as depending on the market organization different problems have to be solved. Some methods are applied on a day-ahead basis to prevent congestion, other have to be solved in real time. Therefore the division of CM methods into subcategories is not evident.

A first line can be drawn between cross-border and intra-zonal congestion management methods, as these kinds of congestion are handled differently. Intra-zonal congestion is defined as a constraint within a system operator’s control zone. If a transmission network treated as a copper plate, this means that the network users do not have to bother about transmission constraints, as the latter are a problem of the System Operator. Cross-border congestion management on the other hand comes down to allocating a previously agreed upon amount of transfer capacity to market players wanting to trade between control areas. However, in real-time some of the assumptions might prove to be incorrect or some grid users may behave in a way that is inconsistent with their commitments. This in turn can cause real-time congestion that needs to be dealt with instantaneously. Methods to deal with such unforeseen situations constitute a third category of congestion management methods.

- Intra-zonal congestion management methods
- Cross-border congestion management methods (capacity allocation methods)
- Congestion alleviation methods (real-time congestion management)

5.1. Intra-zonal congestion management

Intra-zonal congestion arises inside a control zone of a given System Operator. It is detected on a day-ahead basis, typically when unit commitment decisions of market players are communicated to the System Operator. Depending on the market organization, this congestion can be dealt with in different ways:

- Socialization of congestion costs in transmission tariffs – a bilateral market model
- Socialization of congestion costs as uplift payments – a pool market model
- Locational Marginal Pricing LMP (nodal pricing)

5.1.1 Socialization of congestion costs in transmission tariffs – Bilateral market model

A bilateral market, often called Over the Counter OTC market, is a market where the majority of energy is traded on a voluntary bilateral basis. There are no standard products and tailor-made types of contracts prevail. Such a market is usually accompanied by a Power Exchange, where market players can anonymously sell or buy power on a day-ahead basis. The Power Exchange also delivers a price indication, serving as a basis for negotiations of bilateral contracts.

A bilateral market organization poses no obligations on market players to participate in one or another type of market, being that day-ahead, mid or long-term. This decision is left completely to the market players and the only condition is that they need to communicate their dispatch decisions to the System Operator, so that he can check whether the proposed dispatch is feasible as far as the grid is concerned. It means that this market organization requires a well-developed and strong electric grid, as the grid limitations are not visible to market players [51]. Congestion in this case has to be solved by the System Operator and the latter has to cover the incurred costs. These costs are normally socialized, meaning that grid users pay them as a part of transmission tariffs.

Congestion is dealt with usually either by changing the topology of the grid or if the former proofs insufficient by re-dispatching of generation units. The latter often takes the form of a balancing market [52],[53], where market players are paid for up and down regulation of their units or even for switching off the load, either partially of completely.

5.1.2 Socialization of congestion costs as uplift payments – Pool market model

An alternative market organization is a centralized pool model. It implies that all energy transactions have to go via the organized market and that there is a uniform energy price in the whole control area. As discussed in 2.1.2, the price P_C and the traded volume Vc can be discovered at the intersection of demand and supply curves (Figure 1), or the supply and the forecasted demand (Figure 2). The volume of demand can also be forecasted by the market operator, and thus the market clearing price would be then found at the intersection of the supply bid ladder and projected demand volume.

During the matching process the grid is treated as a copper plate, meaning that the cheapest generation gets priority no matter the grid limitations. In the second stage the feasibility of the achieved solution is examined. If there is congestion, some out-of-merit generators are dispatched at the cost of in-merit generators, involving financial compensation to these market parties who have to deviate from their planned dispatch. Among other, the cost of this action constitutes the uplift charge $P_{congestion}$ and is added to the energy price.

$$P_{energy} = P_C + P_{congestion} \tag{11}$$

As discussed in [54], depending on the pool regime implemented, minimizing the uplift charge $P_{congestion}$ may in some cases lead to a decrease of the aggregate total wealth. Moreover, consumer costs may rise, not fall, as a result of reducing congestion. Therefore many economists prefer the approach of minimizing the socio-economic costs of congestion, focusing on re-dispatching costs [55],[56]. These indicate the change in production costs resulting from out-of-merit dispatch due to congestion.

5.1.3 Locational Marginal Pricing LMP (nodal pricing)

A Locational Marginal Pricing LMP market model can be defined as a centralized, security constrained, bid-based, optimal economic dispatch [22],[27]. The pricing of energy is defined as pricing based on the marginal cost of supplying the next increment of electric energy demand at a specific location in the electric power network, taking into account both generation marginal cost and the physical aspects of the transmission system. The consequence is that instead of one price, a price per location, usually a node is produced; hence the term nodal pricing. This implies that congestion costs are no longer socialized, but each market player pays for congestion caused. The congestion charge in a LMP-based market organization is the difference between energy prices at the generation and consumption nodes. Market participants can hedge against this congestion charge by entering into Financial Transmission Contracts FTC [57].

Mathematically, the objective of an optimization function is maximization of economic surplus subject to generation and transfer capacity constraints. Detailed representation of a network makes it possible to take losses, parallel flows, voltage stability and reliability criteria into account. As a result, first-order conditions associated with the maximization of economic benefits under constraints yield so-called nodal prices. Nodal prices represent the change in the total cost of meeting system energy requirements, as defined by market participants' bids and offers, caused by a change in load or generation at each node.

LMPs can be illustrated using the following components:

$$\lambda_i = \lambda_{P\_cost} + \lambda_{CC} + \lambda_{losses} \quad (12)$$

where:

λ_{P_cost} energy price

λ_{CC} congestion charge

λ_{losses} cost of losses

The energy price λ_{P_cost} is defined as the price of the unconstrained system, or the price at a reference node, also called a hub. The congestion charge component λ_{CC} depends on the difference of active power generation cost between the unconstrained and the constrained case. Losses and their cost λ_{losses} are usually defined based on marginal losses being cost of losses induced by additional withdrawal of a unit of energy.

LMP is often considered as *the* market organization as the nodal prices perfectly reflect all costs of supplying electricity at given nodes, at the same time managing congestion [58]. It is the most market-based and economically efficient among all congestion management methods. Nodal prices send very clear signals to market players so as to the location of a new generating capacity or transmission lines. The drawback of LMP is that it requires a central dispatch. Moreover, as the energy market is fragmented into many locational markets (due to transmission constraints), the problem of liquidity needs to be coped with. Additionally, this market fragmentation results in a significant number of prices, which might be perceived less understandable and transparent. However, some variants of LMP allow the price paid by the demand within a price zone to be the weighted average of nodal prices within this zone. The generators then are compensated at their corresponding node price in order to keep the locational price signals present.

5.2. Cross-border congestion management methods (capacity allocation methods)

Cross-border congestion management aims at allocating the previously agreed upon amount of transfer capacity to market players wanting to trade between control areas. Therefore these methods can also be called capacity allocation methods.

The need for such methods arises from the fact that the management of cross-border flows involves more than one System Operator. As different market organizations and legislation may exist within the different control zones, the issue becomes more complex.

The basis of cross-border congestion management is the cross-border transfer capacity. It is often a result of aggregating of a number of physical lines into one index value for a given border. The entities responsible for its estimate are the System Operators involved. Once the cross-border transfer capacity is agreed upon, SOs allocate it to the requesting market players. The capacity can be allocated on a number of time horizons, i.e. yearly, monthly, or daily (on hour-by-hour basis). If the demand for transfer capacity exceeds the available transfer capacity, interconnection is treated as congested.

Allocation of transfer capacity can be organized in many different ways. The best-known examples are:

- Pro-rata rationing
- Priority based rules (such as first come, fist served)
- Transfer Capacity Auctioning

- ◻ Explicit Auction
- ◻ Implicit Auction
- ◻ Hybrid Explicit-Implicit Auction
- ■ Market Splitting and Market Coupling

5.2.1 Pro-rata rationing

Pro-rata rationing is based on a principle of pro-rata curtailment of transactions. In other words, if demand for capacity exceeds the Available Transfer Capacity ATC, all transactions are partially curtailed, in proportion to the requested capacity.

$$P_{AB\_n} = P_{AB\_n\_requested} \cdot \frac{ATC_{AB}}{P_{AB\_total\_requested}} \qquad (13)$$

where:

P_{AB_n}	allowed quantity for the n^{th} transaction between zones A and B
$P_{AB\_n\_requested}$	requested quantity for the n^{th} transaction between zones A and B
$P_{AB\_total\_requested}$	total requested quantity for all transactions between zones A and B
ATC_{AB}	available transfer capacity between zones A and B

The principles of the method can be demonstrated on a simple example of two zones interconnected by a link having 100 MW transfer capacity (Figure 10). Table 1 presents the outcome of the method in terms of the amount of curtailment needed in case of congestion

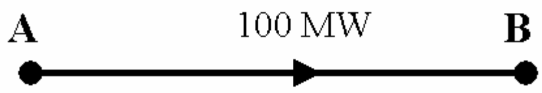

Figure 10. Example 2-node network.

Table 1. Illustration of pro-rata transfer capacity allocation

	Requested quantities [MW]	**Quantities after curtailment [MW]**
P_{AB1}	50	$P_{AB\_1} = 50 \cdot \frac{100}{160} = 31.25$
P_{AB2}	100	$P_{AB\_2} = 100 \cdot \frac{100}{160} = 62.5$
P_{AB3}	10	$P_{AB\_3} = 10 \cdot \frac{100}{160} = 6.25$
Total capacity requested	160 >100	100

The method provides neither the system users nor the system operator with any incentives as to an efficient use of the grid. On the contrary, the method may very likely induce unwanted behaviour such as gaming. Knowing in advance that there is congestion, market players may overestimate their capacity needs and by doing so secure the quantity requested. Anti-gaming measures such as obligation to use the designated capacity seem to be a necessity if the method is to be of any use.

On the other hand, as far as real time congestion management is concerned, this method will most likely remain to be used. In many cases it will remain a last resort when all other measures fail to alleviate congestion.

5.2.2 Priority-based rules

Priority-based rules are characterized by the fact that they use published values of the ATC, and based on some simple mechanism allocate this capacity to the users of the transmission system. The allocation mechanism itself can differ depending on the implementation. The most common method uses chronological ranking of the reservations until the ATC is completely filled up and subsequent reservations have to be denied, as in first come first served principle (Figure 11).

The main drawbacks of priority-based rules are that they do not convey any economic incentive to market players. Moreover, it favours long-term trade as such contracts always get priority over recent ones. Incumbents are implicitly favoured at the cost of new players. A more fair and unambiguous approach is so-called grand-fathering, where incumbents are allowed to retain the transmission rights they possessed before liberalization. The remaining capacity could then be allocated using the same priority list, establishing an earliest time to request. However, first come first served leaves not much room for a short-term market. An improvement could be to devote an upfront chosen fraction of the ATC for short-term market. Yet the share of the long and short-term markets is a never-ending debate.

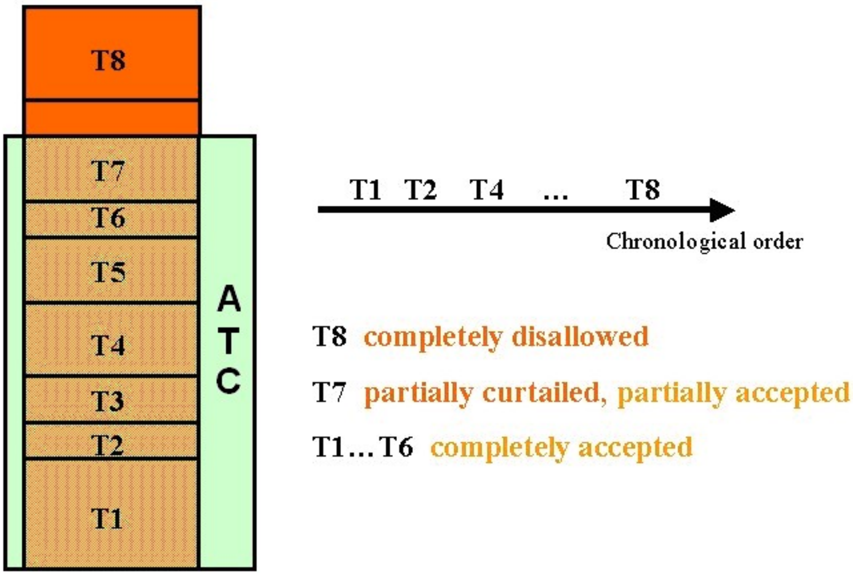

Figure 11. Illustration of priority rules

5.2.3 Transfer Capacity Auctioning

Under Transfer Capacity Auctioning market parties compete for transfer capacity by submitting bids [59],[60]. In the clearing process, the allocation of transfer rights is determined using an auction procedure. There are many variants of the capacity auctioning. [61]-[63] provide a discussion on different implementation aspects of the method. However, the most important division is into explicit and implicit auctioning. Explicit Transfer Capacity Auctioning makes a clear distinction between transfer capacity and energy, both markets being separated. Transfer capacity is reserved for the market party who bought it, not minding the energy prices. Implicit Transfer Capacity Auctioning on the other hand combines the transfer capacity and energy markets. Transfer capacity needed for a given energy transaction is implicitly reserved as a function of energy prices.

Due to the fact that the differences between both kinds of transfer capacity auctioning greatly influence their effectiveness and operational principles, both auction schemes are discussed separately.

5.2.3.1 Explicit Transfer Capacity Auctioning

Explicit Transfer Capacity Auctioning makes a distinction between transfer capacity and energy. In the auctioning process, market players bid for transfer capacity that they want to reserve. Those who are granted capacity can, but do not have to, use it.

Two alternatives can be considered:

- Single border capacity auctioning
- Coordinated capacity auctioning

Single-border capacity auctioning is one of the simplest ways to determine the economic value of an interconnector. It aims at maximizing the market value created by auctioning transfer rights.

$$\begin{aligned} &\max \sum_{b} \left(C_b . T_b \right) \\ &s.t. \quad \sum_{b=1}^{n} T_b \leq ATC \end{aligned} \tag{14}$$

where:

b transaction bid number

T_b quantity of transaction b [MW]

C_b price offered by transaction b [€/MW]

Figure 12 shows the graphical interpretation of a single border capacity auctioning. Bids for transfer capacity stacked in C_b-T_b price-volume pairs constitute the demand curve, while supply is a vertical line indicating the available transfer capacity. The capacity price is typically set to the price of the last accepted bid on this interconnection (marginal price principle), though pay-as-bid is also sometimes used. However, in meshed networks, where more than one bottleneck capacity can be put onto auction and thus having an economic value, the method has important drawbacks. Several independent auctions in the same region can lead to infeasibilities, as transactions could incur unforeseen flows on other borders due to interdependencies of power flows in meshed networks, contributing to so-called loop or parallel flows. Moreover, transactions between non-adjacent areas have to be split into single border capacity acquirements and face the danger of being cleared unequally.

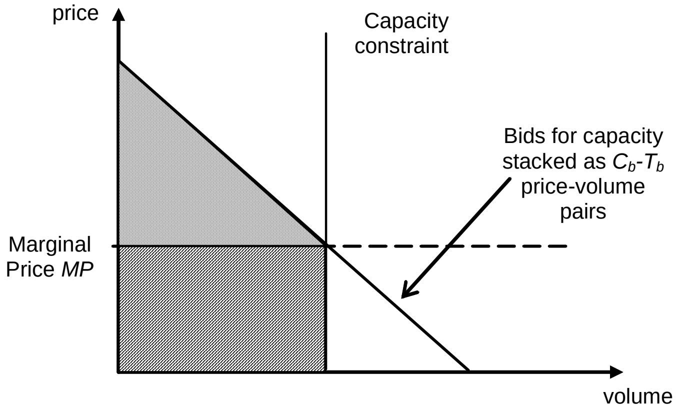

Figure 12. Graphical representation of single border explicit transfer capacity auctioning

Due to the drawbacks of single border capacity auctioning, the allocation of transfer capacity in meshed networks should be coordinated. This implies, that instead of bidding for a specific interconnector, transfer rights from one area to another should be auctioned, covering all transfer capacity required for a given transaction. Each transaction bid *b* consists of an origin node *i*, destination node *j*, quantity T_b and price C_b (15). This has many advantages compared to a single border auction. First of all, transactions between non-adjacent areas are processed better, bearing no risk of unfeasibility such as allowed at one border, but curtailed at the other. Moreover, more cooperation between System Operators allows more precise calculation of NTCs and ATCs and no ex-ante choices have to be made concerning the amount of capacity given to the market at one border at the cost of the other.

$$\begin{aligned} &\max \sum_b \left(C_b . T_b\right) \\ s.t. \quad &\forall_k \sum_b \left(T_b \cdot PTDF_{b,k}\right) \le ATC_k \end{aligned} \tag{15}$$

The major advantage of explicit auctions, being the fact that capacity is not coupled to energy, is at the same time its biggest flaw. On one hand, it allows easier establishment of a market based capacity allocation scheme as no energy market or any kind of energy market standardization is required. However, capacity reservation by means of an explicit auction introduces sequentiality into the cross-border capacity allocation process. Most of all the short-term market is affected, as transfer capacity has to be valued under tremendous price uncertainties, leading to unused arbitrage possibilities, or to making a loss.

5.2.3.2 Implicit Transfer Capacity Auctioning

Implicit Transfer Capacity Auctioning, contrary to the Explicit Auctioning, deals with energy trade treating the transfer capacity as a by-product. As such it does not make a distinction between energy and transfer capacity.

Implicit auctioning of transfer capacity is coupled to organized electricity markets. Bids are submitted locally, and consist of quantity, price and zone information. The central auction office gathers all bid information and solves an optimization problem with constraints, maximizing total gains from trade calculated as brut utility minus cost of supply (16). The optimal set of offers is determined by comparing the market value potential of all possible energy transactions. Constraints (17)-(18) guarantee the overall balance between supply and demand. Moreover, the zonal energy exchanges are limited by a constraint (19), stating that the power flow on a given interconnection $Flow_k(I_i,PTDF_{i,k})$ resulting from different zonal exports/imports I_i must not exceed the allowed transfer capacities. The contributions of import/exports to cross-border flows is acquired using a PTDF matrix, as explained in 4.3.

$$\max\left(\sum_{i=1}^{nr\_zones}\sum_{j=1}^{n_d} P_{ij}^{D}\cdot d_{ij}-\sum_{i=1}^{nr\_zones}\sum_{j=1}^{n_s} P_{ij}^{S}\cdot s_{ij}\right) \tag{16}$$

$$\sum_{i=1}^{nr\_zones}\left(\sum_{j=1}^{n_d} d_{ij}-\sum_{j=1}^{n_s} s_{ij}+I_i\right)=0 \tag{17}$$

$$\sum_{i=1}^{nr\_zones} I_i = 0 \tag{18}$$

$$\sum_{k=1}^{nr\_borders}\quad\sum_{i=1}^{nr\_zones} Flow_k(I_i, PTDF_{i,k}) \le capacity_k \tag{19}$$

where:

n_d, n_s	number of demand/supply bid
P^D_{ij}, P^S_{ij}	price of the demand/supply bid *j* submitted in zone *i*
d_{ij}, s_{ij}	accepted quantity of the demand/supply bid *j* submitted in zone *i*
I_i	aggregated power injection of zone *i*

Figure 13 shows a graphical representation of the movement of demand and supply curves in case of implicit transfer capacity auctioning. The three market areas are interconnected as in a triangular topology. For the sake of simplicity, linear demand and supply curves were assumed[9]. Initially, if no imports and exports are allowed, each of the energy markets clears independently, producing a set of price-volume pairs P_0-V_0. As no exports/imports are allowed, the cleared volumes of demand and supply in a given market are then equal. If the markets are coupled by means of implicit auctioning, exports and imports lead to the increase of total wealth of market participants. The areas having a surplus of inexpensive supply will export it to the areas having a more expensive supply. This export is illustrated by a *virtual shift* of the demand curve to the right (dashed red line) as the local demand is increased by export. In the importing areas, the opposite takes place, as the demand curve is shifted to the left. The new energy price is discovered at the intersection of the *virtual demand curve* and the supply curve. Clearly, there will be a price increase in the exporting area and price decrease in the importing area. The prices in importing and exporting areas move until all arbitrage possibilities are taken. In case of unlimited transfer capacities, and thus unlimited export/import possibilities, the local energy prices converge towards a *single* energy price equal for all areas. If however, there are limits on the border exchanges, exports and imports need to be limited, and the energy prices will be somewhere between the initial price (no exchanges) and the single system price (unlimited exchanges).

---

[9] Thanks to the use of linear curves, it is easier to explain the change of prices in function of exports/imports. The use of stepwise linear curves implies that sometime the price remains the same even though the export/import changes (i.e. due to the *block* nature of the stepwise curves).

Export or import means that there is a mismatch between the local supply and demand, which is either exported or imported. The exact volumes of the cleared (allowed) demand and supply can be found by comparing the new price level P_1 and the original demand and supply curves. The volume of the local supply V_{S1} is found at the intersection of P_1 and the supply curve, and the volume of local demand V_{D1} at the intersection of P_1 and the demand curve. The sum of locally cleared volumes of demand must equal those of the supply.

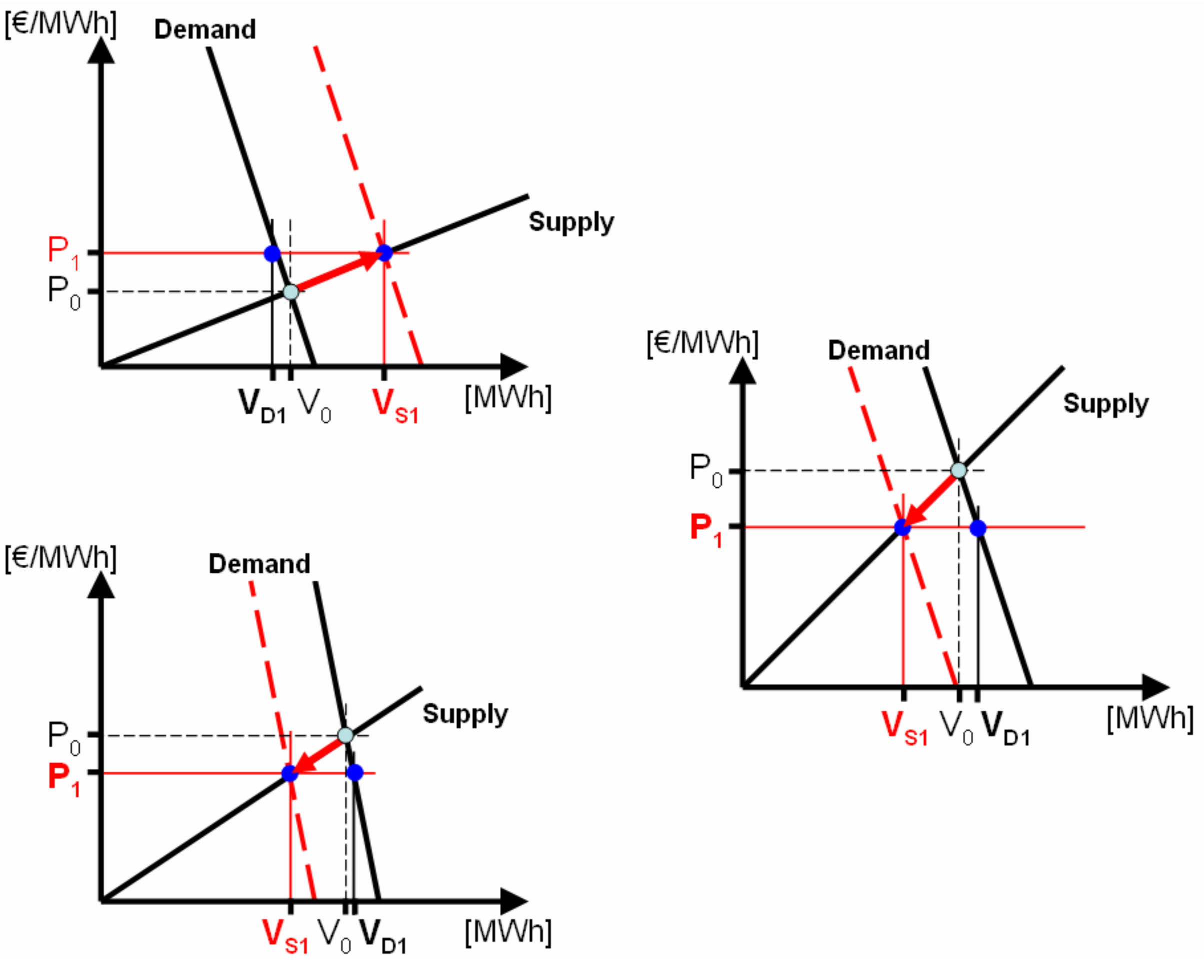

Figure 13. Graphical representation of implicit transfer capacity auctioning for a 3-node network

An organized energy market seems to be a prerequisite for its implementation, as in this auction mechanism the allocation of transfer capacity is a result of the energy market clearing process. Each market player submits bids and offers to its regional energy market and subsequently all bids are matched. If there is transfer capacity available between regions, the auction algorithm automatically takes all arbitrage possibilities in order to match as much demand and supply as possible. If there is enough transfer capacity (no congestion) prices in all areas become equal, meaning that there is only one system price throughout all market regions. If however there is congestion, regional markets effectively split into differently priced regional markets, called price areas, as due to the presence of transfer constraints the energy prices are unable to approach the system price. Market logics imply that high market prices are obtained in the regions downstream of congestion, whereas low market prices are visible upstream.

Congestion and subsequent regional price difference mean that interconnection between differently priced regions assumes a certain value. As each market party is obliged to put his bids in its price area, it only receives or pays the energy price of this area. This means that a market party always receives/pays his local energy price, even when exporting to another, more expensive price area. The difference between export and import prices constitutes the transmission charge for the use of the interconnection, also called congestion charge. This congestion charge is collected by the System Operator and is paid implicitly by all users of the interconnection.

In Implicit Auctioning, cross-border flows are a result of the energy market clearing process, and therefore can be considered as firm, in the same way as nominations on Power Exchanges are firm. This firmness allows netting of opposite flows created by zonal exports and imports, and consequently the scarce cross-border capacity is used more efficiently. Contrary to explicit auctioning, no inefficient capacity reservation is necessary as the capacity value as well as the direction of power flows are dictated by the market and energy prices. Moreover, coupling energy and transfer capacity alleviates market players of extra costs entailed to trading on a separate capacity market.

5.2.3.3 Hybrid Explicit-Implicit Auction

Even though both variants of transfer capacity auctioning, explicit and implicit, differ in a great deal, they can be hold simultaneously in a hybrid model [64]. This means that firm unilateral energy bids can be handled together with not firm, bilateral capacity bids. The latter could be then accepted if they were valued more than a price difference between origin and destination nodes. Moreover, bilateral capacity bids can also be offered as firm and as such net off with unilateral energy bids.

Market participants could bid for the cross-border transfer capacity either directly submitting a bid for a fraction of cross-border capacity, or by submitting bids at the power exchanges at both sides of the border concerned. Both types of bids would compete for the same transfer capacity. As the capacity auctioning aims at maximising the value of the transfer capacity auctioned, depending on the submitted bids and offers from both types of bids, the value created by bilateral trade is compared with these coming from PX-based trade, determining the winners and losers.

The hybrid auction requires a special coordination between the energy and transmission markets than the explicit auction mechanism. The biggest challenge is the development of an algorithm comparing the values created by both types of bids. As the commitment decision resulting from the clearing of a given type of bid influences the values created by both types of bids, the clearing procedure would be quite complex and involve iterations between the capacity and energy markets.

5.2.3.4 Market Splitting and Market Coupling as special forms of Implicit Capacity Auctioning

Market splitting is a congestion management method used in the Scandinavian electricity market Nord Pool [65]. Nord Pool is a voluntary Power Exchange, with one interesting feature: cross-border transfer capacity market can be only accessed by submitting bids and offers to the Power Exchange. As a result, cross border transactions can be far better controlled and appropriately charged. Market Splitting rests on the same principles as implicit transfer capacity auctioning [66]. However, its current implementation in Nord Pool makes it not applicable to meshed networks.

Market Coupling is a congestion management method proposed by the European Association of Power Exchanges, EuroPEX [67]. Theoretically it is very similar to Market Splitting as both methods rely on the same principles as implicit auctioning. However, it will most likely be implemented differently than in the Nordic region, possibly causing differences in effectiveness and applicability to meshed networks. As the method and its implementation are still under discussion, no statements can be made on its performance.

It must be noted however, that implicit transfer capacity auctioning as such, has no theoretical limitation to applicability to meshed networks. However, in the same way practical implementation can differ from theory, the applicability of the implemented congestion management scheme can differ from its theoretical possibilities.

5.3. Congestion Alleviation Methods

Congestion Alleviation Methods, as opposed to the former group, deal with real-time congestion. Their goal is to bring the system back to secure operating conditions.

Congestion as such, being a consequence of security limits violations, either thermal or voltage stability related, is a problem of physical components, not of aggregated index values such as ATC or NTC. As the latter are calculated based on assumptions (i.e. base case scenario), they represent only an approximation of the reality forecasted on the previous day (D-1). On the actual day (D) the situation can be different calling for special measures. Usually the problem is not that too much power is transferred across the border, but that the cross border lines are not equally loaded, leading to overload of one line and surplus capacity on the other. Congestion Alleviation Methods can be seen as means to bring the system back to a secure operation by re-arranging the generation-load pattern i.e. re-dispatch of production units and/or shedding load.

5.3.1 Transmission Loading Relief TLR

Transmission Loading Relief TLR is a curtailment scheme applied in North America. It is based on the principle of curtailing transactions contributing to congestion the most. PTDF, called in U.S. Transaction Distribution Factors TDFs, representing the impact of an interchange transaction on a given constraint are calculated on a Control Area to Control Area basis. Sending and receiving Control Area information is used to analyse if a given interchange transaction affects a specific constraint. Those having TDF ≥ 5% on the flowgate are subject to curtailment. The amount of curtailed transaction is given by

$$curtailed\_amount_k = PTDF_k \cdot Initial\_transaction_k \cdot \frac{total\_amount\_to\_curtail}{\sum_i PTDF_i \cdot Initial\_transaction_i} \tag{20}$$

There are different levels of TLR, ranging from 1 (flows approach acceptable limits) to 6 (high level emergency). Firstly, all non-firm transactions are curtailed. If this fails to resolve congestion, the system can be re-dispatched to allow firm contracts to be scheduled. In case of higher-level emergency, even firm contracts are curtailed.

In its current implementation source and sink information indicating the dispatch of specific generators within a control area are not generally used for TDF factors calculation. They are estimated by increasing on-line generation in the source control area and decreasing in the sink control area, such that the net control area exchange is 1 MW. In general, the amount that a particular unit participates in a transaction is based on the ratio of the capacity of that unit to the total generating capacity of the units within the control area. If a unit is off-line or has been identified by the Reliability Coordinator as a non-participating unit, its capacity is set to zero. The generator participation in a Control Area is the same for both imports and exports. It is important to note that using this method, intra-Control Area transactions have a TDF netting to zero for all Flowgates.

Experience has shown that the current TLR procedure assuming linear, reciprocal responses for the source and sink Control Areas doesn't correctly account for movement of specific generators scheduled separately or as part of a central economic dispatch within Control Areas and larger balancing markets. The lack of precise information is generally referred to as a lack of granularity. These potentially incorrect assumptions become more obvious and problematic when large numbers of Control Areas are to merge into much larger balancing markets. Moreover current TLR often takes a significant amount of time to implement.

As the current implementation of TLR does not correctly recognize and address the true impacts of market dispatch and other point-to-point energy transactions occurring between and into control areas, it results in growingly imprecise and often ineffective congestion management. Moreover, TLR can sometimes be a source of load curtailment. Unless other generation could be scheduled in place, curtailment of a certain transaction involves shedding load. As there is always a need to increase efforts to "keep the lights on", any curtailments whether non-firm or firm have the potential to affect load curtailment. Declaring TLRs can limit the most, if not all, import directions making it difficult to import power. This in turn again increases the risk that firm or non-firm curtailments may result in curtailment of the actual load.

Since the establishment TLR procedure, the use of control areas as the level of granularity when calculating flow factors and needed relief has been a compromise. It has always been recognized that better impact results could be calculated if the individual source generators and ultimate load zones of each transaction are known and used in the calculation. As markets are expanding and control areas merge and become larger, the shortcomings of the existing system are getting worse. Therefore actions are planned to improve the resolution of TLF, or granularity for that matter. This leads to the creation of additional zones modeled within control areas, allowing for a more efficient use of TLR.

In the longer term, as indicated in [68], the way the relief responsibilities are assigned is to change. The relief responsibility would be assigned to Reliability Coordinators who are in the best position of achieving the most effective and efficient means of relief through re-dispatch of generating units and dispatchable loads. The units affected are then financially compensated through financial compensation mechanisms or associated tariff changes. This would provide a long-term congestion management process allowing a great deal of flexibility and effectiveness in relieving congestion.

As such, the current TLR procedure is very similar to Counter Trading discussed in Chapter 5.3.2 and the proposed improvements show a great deal of similarities with coordinated re-dispatching discussed in Chapter 5.3.3.

5.3.2 Counter trading

The basis of Counter Trading is to make use of the laws of physics governing electricity. Electric power flows in opposite directions can be net off, allowing alleviation of congestion. In order to provoke a power flow in the direction opposite to congestion, the SO steps into the market and intervenes. It uses a balancing market to purchase the electric energy in the control zone downstream of congestion and sells it back in the control zone upstream. However, this intervention comes at a price. Control zone downstream of congestion is usually a high price area. Therefore, counter-trading involves buying expensive electric energy to sell it back in the low price area, making a loss. This loss is usually socialized in transmission tariffs.

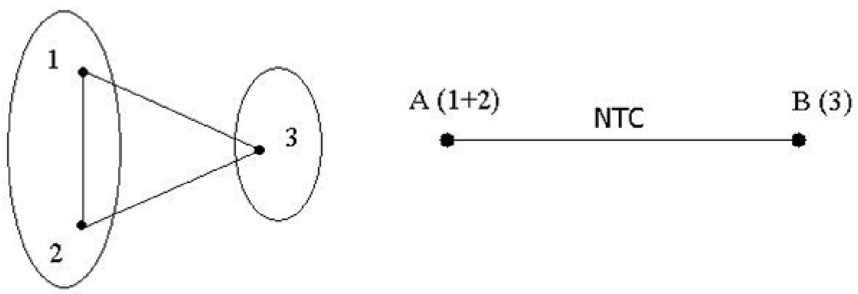

Figure 14. Creation of the virtual cross border interconnection

The principles of this method can be illustrated using an example network Figure 14. Assume that line 1-2 has unlimited transmission capacity, i.e. it is never congested as opposed to lines 1-3 and 2-3. Nodes 1 and 2 are assumed to be typical injection nodes, implying that they have a surplus of cheap electric energy. Node 3 is a sink node implying that the consumption exceeds the generation at this node, leading to a need for import and a higher electricity price. Consequently power flows from nodes 1 and 2 to node 3. Due to the network constraints and power flow pattern, nodes 1 and 2 are aggregated to form one zone. The result is two zones A and B, interconnected by a virtual link A-B of capacity $NTC_{A\text{-}B}$.

When there is physical congestion between zones A and B, one of the lines 1-3 or 2-3 is overloaded. In order to relieve this congestion using counter-trading, the SO has to enter the market and buy energy in zone B (high price area) and sell it back in zone A (low price area). However, in reality such transaction involves trade between nodes, not zones. The laws of physics imply that transactions between different nodes have a different influence on individual line flows, as quantified by Power Transfer Distribution Factors PTDF. If one assumes each line to be electrically identical i.e. having the same impedance, the trade between 3-1 and 3-2 have a different influence on the interconnections. In case of congestion present on line 1-3 counter-trading between node 3 and node 1 has a two times higher effect on the congested line than the transaction between nodes 3 and 2, as given by (21). Consequently, in order to net 10 MW of flow on the congested line 1-3, the SO has to trade 15 MW between nodes 3 and 1, but as much as 30 MW between nodes 3 and 2. The exact interaction between nodal power injections and line flows is given by the PTDF matrix. However, when contracting electric energy the SO is often unaware of its origin and therefore does not know the exact effects of this transaction on the congested line. There is no guarantee that trading x MW is enough to net off y MW of congestion, which questions the effectiveness of counter-trading.

$$
\begin{aligned}
Flow_{A-B} &= Flow_{1-3} + Flow_{2-3} \\
\\
Flow_{1-3} &= PTDF_{1,1-3} \cdot P_1 + PTDF_{2,1-3} \cdot P_2 \\
Flow_{2-3} &= PTDF_{1,2-3} \cdot P_1 + PTDF_{2,2-3} \cdot P_2
\end{aligned}
\tag{21}
$$

The method, though simple, is seriously flawed by the loss of granularity resulting from zonal aggregation of nodes. This in turn hinders the estimation of the needed amount of counter-trade. The assumption that transactions between zones have an identical effect on the cross-border lines connecting them is obviously incorrect for any zones interconnected by more than one line. The error increases with the increased level of meshing and the zones size. In order to be able to effectively solve congestion, the SO would have to know the topology of the network and the exact location of the power injection and sink points involved.

Counter trading is also used in Nord Pool. However, its Nordic version is actually a coordinated re-dispatching used to handle intra-zonal constraints and therefore differs from the counter-trading described above. Both should not be confused, otherwise the success of one method, coordinated re-dispatching, is projected on the other far less effective method, being counter-trading.

5.3.3 Re-dispatching and coordinated re-dispatching

Re-dispatching and coordinated re-dispatching involve re-dispatching of generating units as a means of relieving congestion. It comes down to the introduction of corrections to the initial generation dispatch, usually based on prices that generators communicate to the System Operator for up and down regulation. This service can be organized on individual contract basis, or managed by a market, either integrated with a balancing market or separate. Two alternatives of re-dispatching actions can be considered. If the SO only intervenes within its own control area, the system can be optimized locally (internal re-dispatch). A more comprehensive approach involves several SOs trying to find a global optimum by re-dispatching units on both sides of the congested interconnector (coordinated re-dispatch). The latter has the advantage of being more efficient, since there are more nodes where power injections can be modulated. However, it requires a strong co-ordination between the SOs involved and a certain degree of harmonization of market rules in areas involved.

The nodes that can be modulated need to be able to vary their power injections, i.e. need to be either generators or dispatchable loads. The nodes that have the biggest potential to relieve a given congestion can be found by analyzing the PTDF matrix. One has to simply check elements of the row corresponding to a desired line and modulate the adequate nodal injections (i.e. output of a generator located at this node). Obviously, the more nodes can be modulated, the higher the chance that such an effort is successful. Consequently, independent actions of one SO only at one side of the congested bottleneck are less effective than the joined actions of both bordering SOs.

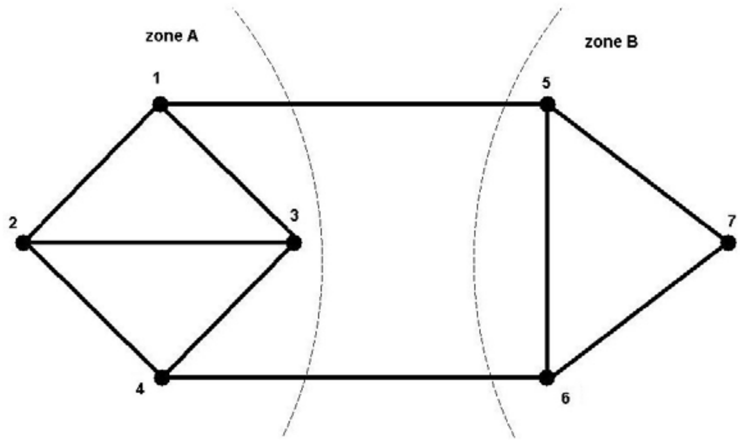

Figure 15. Physical network reality versus aggregated transfer capacity

The principles of the methods discussed can be illustrated on a simple network (Figure 15). It consists of 7 nodes, aggregated into two zones connected by two interconnections. Each line is assumed to be electrically identical, thus having the same impedances. Cross-border lines have a limited transmission capacity of 60 MW each. Assuming the initial injections pattern as in Table 2, results in the overload of line 1-5. If the SO of area A tries to solve this congestion on its own (or increase the NTC between the zones for that matter) and takes re-dispatching actions, he has to re-schedule some 30 MW of generation. Assuming an equal cost of up and down regulation for each generator (1 €/MW), the costs of this operation sum up to 60 €. On the other hand, if SOs chose to cooperate and carry out coordinated re-dispatching, much less dispatch changes are needed and the cost drops to 25.7 €.

Re-dispatching means incurring costs that cover payments to generators for up and down regulation. This cost is borne first by the SO, and can be charged in a second phase to market participants as these costs usually constitute the costs of system services and are socialized via the transmission tariffs. However, they can also be charged to specific users causing congestion.

Re-dispatching is an effective method to solve congestion if enough resources are available to change the load flow pattern and balance the line loading better. If more than one SO is involved the effectiveness increases even more, as more units are available for the purpose, reducing the overall costs of power re-dispatched. In some cases re-dispatching can fail to alleviate congestion, which calls for special measures as emergency pro-rata curtailment.

Table 2. Illustration of re-dispatching and coordinated re-dispatching

	Initial dispatch [MW]	Re-dispatching of area A [MW]	Coordinated re-dispatching [MW]
P_1	100	100 - 30 = 70	100 - 12.85 = 87.15
P_2	-40	-40	-40
P_3	20	20	20
P_4	20	20 + 30 = 50	20
P_5	-100	-100	-100
P_6	-20	-20	-20
P_7	20	20	20 + 12.85 = 32.85
A-B exchange MW]	100	100	87.15
line 1-5 [MW]	68.18	60	60
line 4-6 [MW]	31.82	40	27.15
Incurred costs [€]	-	30 * (1 + 1) = 60	12.85 * (1 + 1) = 25.7

5.4. Financial Products

Generally speaking congestion is something that should be avoided. It decreases market value, being the sum of producer's and consumer's surpluses, by disallowing cheap, but remote, generation capacity and allowing more expensive local one. Congestion introduces regional price differences, which is not always desired. Unequal prices lead to unequal business opportunities. Moreover, due to technical limitations, constant fluctuations of demand and non-storability, it is very difficult to predict prices, in turn translating into difficulties in business making.

In order to guarantee an acceptable level of price stability, price risk hedging instruments have been developed. These are financial products, meant as hedges against unstable prices. A result is that a company can be more certain of its price at the cost of having to pay slightly more on average. Financial products are derived from organized power markets and are not congestion management methods as such, but are rather complementary to them. Therefore they are often called *derivatives*. They give a possibility to hedge against one's physical location. However, these financial contracts can be also considered independently from integrated energy markets i.e. Contract for Difference between prices on a Power Exchange in country A and B, offered by a financial institution.

5.4.1 Financial Transmission Rights FTR

Stochastic locational prices create a demand by risk-averse market players for locational price hedging instruments [69]. One of such instruments is a Financial Transmission Right FTR. An FTR gives the holder a right (or/and obligation) to a share of congestion rents received by the System Operator during congestion. The allocation of FTRs typically occurs as an auction, where the benefit of the buyer or seller is maximized. The auction determines the amount of FTRs allocated to market players and market clearing prices. The design of the auction is decided by the System Operator and depends on the market structure. However, FTRs may also be allocated to transmission service customers who pay the embedded costs of the transmission system.

FTRs are typically longer term and may have durations from months to years. They can take different forms such as point-to-point FTRs and flowgate FTRs, both of the obligation and option type.

5.4.1.1 Point-to-point Financial Transmission Right

Point-to-point FTRs entitle (or oblige) the holder to the difference in locational prices times the contractual volume. The mathematical formulation for the payoff is given by

$$FTR = Q_{ij} \cdot (P_j - P_i) \tag{22}$$

where:

P_j bus price at location *j*,

P_i bus price at location *i*

Q_{ij} quantity *Q* of active power scheduled on the path from *i* to *j*.

An FTR obligation may be viewed as an injection of quantity of active power Q_{ij} at bus *i* and a withdrawal of the same Q_{ij} at bus *j*. If the contractual volume matches the actual volume traded between two locations, an FTR is a perfect hedge against volatile locational prices.

As FTRs are allocated in a way that ensures revenue adequacy for the SO. The difference between congestion rent and payments to FTR holders should be positive, resulting in a surplus to the SO. The surplus is then redistributed to FTR holders and transmission service customers. However, if payments to FTR holders exceed the congestion rent, the SO proportionally reduces payments to FTR holders or requires that the transmission owners make up for the deficit.

Point-to-point FTRs obligations are considered to be the most feasible hedging instrument in practice. Point-to-point FTRs options are technically possible and have been already introduced i.e. in PJM in 2003. However, the computational demands are more substantial.

5.4.1.2 Flowgate Financial Transmission Rights

Flowgate Financial Transmission Rights are constraint-by-constraint hedges that give the right to collect payments based on the shadow price associated with a particular transmission constraint called a flowgate. Flowgate Financial Transmission Rights, often abbreviated as FGR, is based on a decentralized market design. This approach results from a belief that the point-to-point FTR markets may work inefficiently in practice and therefore, are not able to provide effective hedging. The idea behind flowgates is that since electric power flows along many parallel paths, it may be natural to associate congestion payments with the actual power flows. Key assumptions include a power system with relatively few, known in advance, commercially significant flowgates resulting in a limited set of FGRs, as well as relatively stable power transfer distribution factors PTDFs that decompose each transaction into the flows over these flowgates.

The payoff from the FGRs can be negative, zero or positive and is determined by taking the associated flowgate shadow price times the amount of FGR, totalling them for all lines *k* affected by the transaction between buses *m* and *n*.

$$\mathrm{FGR} = \sum_k \eta_k \cdot PTDF_{k,m-n} \cdot Q_k \tag{23}$$

where:

η_k shadow price associated with flowgate *k*,

Q_k contracted volume of FGR.

In an AC transmission network, the power flows are determined by the line impedances, and therefore cannot be controlled effectively. A given transaction may thus affect more than one flowgate (transmission constraint). Parties that want to be fully hedged against congestion should purchase a mix of flowgate FGRs matching the distribution of flows from its transaction.

In practice, the assumptions of a limited set of commercially significant flowgates and relatively unchanging PTDFs might be difficult to ensure in a dynamic power system, where unanticipated transmission constraints may become binding. Furthermore, the flowgate approach assumes that all constraints that are binding in the dispatch have been previously designated as flowgates, and therefore the SO have made FGRs available for them. If some constraints are designated, but not become binding, there is no mechanism that could allow market parties to purchase a perfect hedge. Not charging for the non-predicted constraints and socializing costs instead can be a solution here.

5.4.2 Contracts for Differences CfD

Contract for Differences (CfD) is a risk management tool allowing to hedge against differences between a volatile price and certain value. There are different alternatives of CfD available. The CfD as available in Nordic market Nord Pool is used to hedge against the difference between two uncertain sport prices, being a regional price and a system price [70]. The CfD as available in the British market hedges the difference between the spot price and a pre-defined reference price or a price profile. The Nordic CfD can be considered as a locational swap, while the British CfD is settled based on the difference between spot and reference prices. The pay off from the Nordic CfD is given by

$$\mathrm{CfD} = \mathrm{Q_i}\ (\mathrm{AP_i} - \mathrm{SP}) \tag{24}$$

where

AP_i area price in area *i*,

SP System Price

Qi contracted volume of CfD contract.

Payments from CfDs are calculated as the average of the difference between the daily area price and the System Price during the delivery period (season or year) times the contracted volume. Each time the area price is higher than the System Price, the holder receives a rebate equal to the price differences times the contracted quantities. Otherwise, the holder must pay the difference. The market price of a Nordic CfD can thus be positive, negative or zero, depending on the expected market conditions. The contracts are available for all spot areas. However, as there is only one contract with reference to the area Norway 1 (Oslo), it is impossible to hedge against price differences within Norway. Nord Pool is considering listing CfDs with reference to Norway 2 (Trondheim) and with reference to the German EEX price. Moreover, the possibility of introducing CfDs with shorter delivery periods such as weeks is also studied.

6. Congestion management and investments

Congested interconnections indicate that the demand for cross-border capacity exceeding the available. Therefore, the market-based capacity allocation procedures generate revenue for the TSO, called the congestion revenue CR. Transmission constraints limit the wealth that can be created by exchanging energy across borders. The lost of wealth results from inability to use the most economical generation resources and is often referred to as the socio-economic cost of congestion SCC. As the congestion revenue received by the TSO is paid by the market participants, the cost of congestion for becomes a sum of SCC and CR. Relieving transmission constraints alleviates market participants of both SCC and CR, as additional supply of transfer capacity lowers its prices (thus CR) and allows for a more efficient use of generation resources (lower SCC) [71].

Electricity transmission is a regulated business. However, as the electricity markets are relatively immature, the electricity industry faces a lot of regulatory uncertainties. The importance of a stable regulatory framework to ensure adequate investments in Europe has been underlined on numerous occasions [72]. Generally speaking, transmission developments are driven by the location of a new generation. Therefore, regulatory uncertainty also affects investing in bottlenecks.

Next to their own capital, TSOs have three additional sources of funding for interconnection investments:

- EU Subsidies
- Cross-border compensation system
- Congestion revenue

6.1. EU subsidies

EU subsidies can be granted under a framework of the Trans European Networks program TEN-Energy. In 1996 the European Community has established guidelines on Trans-European Energy Networks, covering objectives, priorities and line of actions including the identification of Projects of Common Interest. The objectives of TEN-E is to contribute to:

- effective operation of the Internal Market in general, particularly the Internal Energy Market;
- strengthening economic and social cohesion by facilitating the development and reducing the isolation of the less-favoured regions of the Community;
- reinforcing the security of energy supply.

TEN-Energy annual budget of about 20 Million € is spent for both gas and electricity investments [73]. The program generally co-finances feasibility studies – up to 50 % of their budget. In a limited number of cases (3 since 1998) it also co-finances investment projects – up to 10 % of their budget. The TEN-E financing has a relatively minor effect on the overall budget of the project, but can act as an important stimulator at an early and risky stage of the project. The electricity projects that received funding from the TEN-E program in 1995-2003 are listed in [74].

6.2. Cross-border compensation system

Cross-border compensation system was established by ETSO in 2002. To stimulate cross-border energy trade, explicit transmission charges associated with energy imports/exports across the internal borders of the EU has been removed, avoiding pancaking of tariffs, and successively reducing transaction based network access charges. However, network investments usually lead to increasing transit flows. The operational costs linked to this increased transit resulting from increased cross-border transfer capacity need to be somehow compensated. An interim inter-TSO compensation mechanism set up by ETSO aims at compensating for the hosting of energy transits. The compensation received is calculated based on the costs of the infrastructure *used* by the transit flows [75].

6.3. Congestion revenue

In absolute terms, the revenue from selling cross-border transfer capacity constitutes the most significant source of capital in funding the transmission investments. However, according to EU Regulation 1228/2003 [76] the congestion revenue is not a source of extra income to the TSO, but needs to be put into a separate fund. Regulation 1228/2003 states that any revenues resulting from the allocation of interconnection capacity can only be used for one or more of the following purposes:

a) Guaranteeing the actual availability of the allocated capacity;

b) Network investments maintaining or increasing interconnection capacities;

c) Income to be taken into account by regulatory authorities when approving the methodology for calculating network tariffs, and/or in assessing whether tariffs should be modified.

The above points differ significantly concerning their consequences. Option (a) and (b) have a potential of increasing the transfer capacity available for the cross-border trade. This in turn can decrease the cost of congestion for market participants, as both CR and SCC decrease, benefiting the market wealth created. Option (c) on the other hand comes down to reimbursing CR to market parties via a transmission tariff reduction, the cost of congestion for market parties being reduced to SCC.

There is a theoretical optimal point of congestion where the costs of remedying offset the benefits. Given the weak interconnectivity at the moment in Europe, it is in the benefit of market parties to use CR to reduce SCC (a-b). However, the regulators are often biased towards a short term tariff reduction (c). The Council of European Energy Regulators (CEER) has already stressed the importance of regulatory guidelines for evaluating such regulated bottleneck investment projects [77]. Leaving the options open can cause under-investment. CR is a result of locational price signals given to the market participants in case of congestion. As in the case of electricity business load and generation are not very mobile, these locational signals will not easily alleviate SCC. Socio economic cost of congestion can only be alleviated by transmission investments, improving the infrastructure.

7. Conclusions

The technical brochure introduced the problem of transmission constraints management in a new, liberalized market environment. Many issues related to the problem of congestion were tackled, including the causes of congestion, interaction between congestion and market architecture, and finally network models used to manage it. In a liberalized market environment, congestion is a function of many factors. The most important factor however is economics, as electrical energy price differences are the main driver behind wheeling of electric power, especially on cross-border level. Though the limits of maximal allowed power flows are determined by the technical capabilities of the electricity grid, network reinforcements offer only a temporary solution. Eventually, as long as there are price differences there will always be an incentive to trade. With no legal barriers to cross-border electricity trade, market players look for the cheapest source of electric energy available. Therefore, it is very important to organize the cross-border energy trade in a correct way. If market architecture gives no incentives to the efficient use of the grid, it does contribute to congestion.

An economically efficient way to solve congestion is unlikely to be achieved without coordinating the allocation of power injections and securing their simultaneous feasibility. Given the meshed nature of the electricity networks, problems of technical interdependency have to be dealt with. What may be easy on the national level, within one control area, proves to be very difficult where more system operators managing different control areas are involved. Transactions between two areas via a non-congested interface may induce important power flows and can create security problems on another border somewhere else in the meshed interconnected system (i.e. loop flows), especially if not announced to the SO concerned. Variations of internal dispatch within control zones causes cross-border flows to vary, resulting in even more increased loop flows. Therefore, the zonal network model, together with the unpredictable internal dispatch pattern due to self dispatch freedom given to the market participants, is to a great extent responsible for the loop flows on cross-border interconnections. As the model substitutes the control areas by single equivalent nodes, the actual nodal dispatch information within the control areas, and consequently their impact on power flows outside is unknown to all other system operators in the surroundings. In order to secure the operation of the grid system operators have to lower Transfer Capacities, leaving a certain margins unused.

In order to successfully create a competitive electricity market, it is essential to optimally use the limited capacity interconnecting regional markets. Apart from legal matters, both technical requirements and regulatory mechanisms have to be re-defined. As in any market, physical boundaries have to be handled, in order to avoid hindering of the liquidity of energy exchanges. At present there is little coordination between electricity markets. They function largely independently generating exports and imports as a result of their activities. A better coordination and information exchange between the SOs can help to improve the prediction of the large power flows appearing in the interconnections and therefore help to optimize the transfer capacities offered to market participants.

Congestion can be generally divided into two types: internal and cross-border congestion. Though physically transmission congestion is always caused by limitations of a technical nature, both above types of congestion are treated differently. Internal congestion is a problem of a single system operator, while cross-border congestion involves more system operators, often acting under different market conditions. Moreover, while internal congestion occurs on physical lines, cross-border congestion is only indirectly linked to power flows on physical lines as it occurs on virtual border links.

Where it comes to cross-border congestion, transfer capacity auctioning is one of the most widely applied congestion management methods. In Europe, it is considered as the only acceptable solution to allocate cross-border transfer capacity. There are two main variants of the method: explicit and implicit auctioning. Implicit auctioning allocates the cross-border transfer capacity as a function of energy prices on organized markets, meaning that the transfer capacity is procured only when justified by the energy price differences and arbitrage possibilities. This method implicitly couples all national energy markets involved. Though the implicit auctioning as such requires a certain degree of harmonization of rules of the markets involved, there exist variants allowing for less harmonization, such as Decentralized Market Coupling [67]. Explicit auctioning, on the other hand, considers transfer capacity and energy as separate markets. Even though the economic efficiency is less than in the case of its implicit variant, separating both markets allows to couple energy markets without the need for harmonization of all market rules.

As seen in this technical brochure, there are numerous ways to handle transmission constrains. However, there is no *one size that fits all*. Contrary, depending on how the electricity market is organized, a method should be chosen so as to best meet local requirements. As there is a strong interaction between the way transmission congestion is managed and the electricity market, the choice of a particular congestion management method should be preceded by a techno-economic analysis of the performance of the method considered, as well as an analysis of the consequences of its application.

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Appendix A : Survey of the Congestion Management practices

This appendix is contains the results of a survey conducted by the Working Group C5-4 on Congestion Management. The purpose of the survey was to make an inventory of various practices of the System Operators related to the management of congestion in market environment. The major difficulty is that the questionnaire's respondents may interpret the same terms in various ways, making comparisons sometimes very difficult. These findings showed that there is a need for the common understanding of terms, which initiated the work on this Technical Brochure. This Chapter describes thus the *2004 state of the art* practices for the time the survey was conducted.

There are very many approaches to congestion management as each power grid has its own typical features such as a high number of cross-border tie-lines, long distance between load and generation, geographical location (i.e. in the meshed interconnected system). This makes the existence of one universal solution for congestion management unlikely.

The results of the survey are presented as follows. First, various market conditions and institutional arrangements in the 18 countries participating in the survey are described. Then, internal and cross-border congestion management in these countries are presented.

A.1. General conditions of data collection

This report is based on data collected at the beginning of 2004 from C5 members, using questionnaires answered by 18 participants : Belgium (BE), Czech Republic (CZ), France (FR), Norway (NO), Romania (RO), Slovakia (SK), Slovenia (SI), Spain (ES), United Kingdom (UK), Finland (FI), United States – PJM, Canada – Ontario, Brazil (BR), Japan – Kepco (JP), South Korea (KR), India (IN), Australia (AU), South Africa (ZA).

A.2. Market conditions and institutional arrangements

Participating countries have various experiences concerning the market organization, system operator and number of interconnections with other systems, as shown in Table 1. The only AC merchant lines are in South Africa and India and are operated by another entity than the System Operator (SO).

Table 1. Summary of market conditions and institutional arrangements

	Market organization	Futures trade	System operator[10]	neighboring countries / SOs	Interconnection capacity / peak load
Belgium	Bilateral (PX in 2006)		TSO	2 / 2	40 %
Czech Rep	-		TSO	4 / 5	35 %
France	Bilateral+PX Powernext	X	TSO	6 / 9	12 %
Norway	Bilateral+PX NORD POOL	X	TSO	4 / 4	16 %
Romania	Bilateral contracts		TSO	5 / 5	12 %
Slovakia	-		TSO	-	50 %
Slovenia	Organized market (Borzen)		TSO	3 / 3	30 %
Spain	Organized market OMEL		TSO	4 / 4	7 %
UK	Bilateral NETA + PXs		TSO	2 / 3	8 %
Finland	Bilateral+PX NORD POOL	X	TSO	3 / 3	-
PJM	Organized LMP	X	ISO	1 / 5	-
Ontario	Organized LMP		ISO	2 / 5	16 %
Japan	Bilateral (PX in 2005)		VIU	4 (Kepco)	23 %
India	Organized market		TSO	~20	-
S. Africa	Organized market		VIU	-	-

A3. Internal congestion management

Internal congestion is defined as congestion within a control area of a single System Operator's area (see Chapter 3.1.1). From the participating countries, BE, ES, AU, SI, KR and JP either seldom or never experience internal congestion. For other countries (Table 2).

Table 2. Frequency, duration of congestion within countries with frequent congestion

	Frequency	Typical duration
France	Almost everyday (some part of network)	12 hours in the day during peak hours
Norway	Almost everyday, especially often in Summer	Approximately 8 - 10 hours a time
United Kingdom	Around 300 balancing actions a year	From transitory in nature to longer periods
PJM	Almost every day. Use of reliability "backstop" ("TLR") several times a week	Typical 1 - 2 hours per incident. Duration for reliability "backstop" would be in the 2 - 3 hours range.
IMO (Ontario)	One particular interface often congested, however the amount of congested capacity is insignificant	
Romania	50 times a year	8 hours (Values estimated for 2003)

[10] TSO: own + operation, ISO: operation, VIU: Vertically Integrated Utility.

In many participating countries there is no capacity allocation in the market area. At the time of the survey, in PJM, the transmission capacity was allocated to participants that served native load and to those who obtained financial transmission rights through a yearly auction. In 2005 PJM has initiated an annual auction (conducted in three phases) of financial rights that is opened to all participants.

In some countries, market participants must submit their schedule according to specific gate closures. Schedule changes are sometimes possible. However, unannounced deviations can lead to penalties (Table 3). If the market participant's schedules result in congestion, SO solves it, either real time or on a day-ahead basis by introducing corrections in the schedules. There are different methods to deal with internal congestion, and they can be categorized into 5 main measures as in Table 4

Table 3. Gate closure, schedule and penalties

<table>
<tr><th></th><th>Gate closure</th><th>Schedule change</th><th>Penalty</th></tr>
<tr><td>United Kingdom</td><td rowspan="2">Several a day</td><td>-</td><td>Imbalance charge</td></tr>
<tr><td>France</td><td rowspan="4">Possible</td><td rowspan="4">No</td></tr>
<tr><td>Norway</td><td rowspan="7">Once a day</td></tr>
<tr><td>Romania</td></tr>
<tr><td>Japan</td></tr>
<tr><td>IMO (Ontario)</td><td rowspan="2">Impossible</td><td>Imbalance charge</td></tr>
<tr><td>Slovenia</td><td>Yes</td></tr>
<tr><td>Finland</td><td>-</td><td rowspan="2">Imbalance charge</td></tr>
<tr><td>Belgium</td><td>-</td></tr>
</table>

Table 4. Methods for Congestion management in each area.

	System reconfiguration	Transaction curtailments	Re-dispatch	Counter trade	Market Splitting
PJM	X	X	X		
Belgium	X		X		
Japan	X		X		
Australia			X		
Brazil			X		
IMO (Ontario)			X		
Spain			X		
United Kingdom				X	
France	X		X		
Finland			X		
Romania				X	
Norway			X		X
Spain			X		

Note that *market splitting* can also be considered as a method for handling of cross-border congestion as is the case in Nord Pool. Moreover, even though the method used to handle internal congestion in Nord Pool (NO, FI) is called *counter trading*, it is actually a *coordinated re-dispatching* used to handle intra-zonal or cross-border congestion.

In North America, real-time congestion is alleviated using the Transaction Loading Relief (TLR) procedure developed by NERC. The principle is to curtail transactions from external areas that have a greater than 5% effect on the constraint.

A.3.1 Payment of congestion costs - Interaction between market and internal congestion

There are two approaches to the allocation of congestion cost. One is to socialize these costs (UK, FR, BE NO, FI, IMO, KR and JP). The other is that the cost is borne by the responsible (PJM), or predetermined parties, as is the case in Spain where the cost incurred are paid by the scheduled demand.

From the perspective of the SO and incentives for new transmission facilities, the interaction between the electricity market and internal congestion can be divided into 4 categories:

- Congestion management at planning and scheduling phase:
  - U.K: In the long-term, generators requiring capacity compete in a national market for TEC (Transmission Entry Capacity)
  - PJM: The LMP System provides participants with the correct incentives through transparent price signals. The costs re-dispatch are covered by the load and those who do not protect themselves from congestion by acquiring Financial Transmission Rights (FTRs).
- Congestion management in a Day-Ahead Market or Real-Time Market:
  - Norway: Market splitting (structural) & Counter trade (temporal) by the SO. Market splitting gives incentives for construction of new generating units in higher price area. In Norway and Finland, incentives for new transmission line building are provided by the SO’s expenses on managing internal congestion.
  - Japan: Market splitting after establishment of electric power exchange in April 2005.
  - U.K and France: SO manages congestion by using Balancing mechanism.
  - Spain: once the power transactions are adjusted in order to solve the congestion, the market operator readjusts the schedule taking into account the limitations established by the SO, so that the production – demand balance is verified in each of the hours affected by the congestion.
- The Market is used as the way for cost allocation:
  - IMO: Real time market prices are calculated assuming no internal congestion. The congestion cost is borne by all loads via uplift charge.
  - South Korea: due to internal congestions, generation cost will increase market price, which will affect end users’ charge. But the price system is regulated by government.
- No relation:
  - Belgium: none, the grid is a "virtual copper-plate".
  - Brazil: additional cost is bear only by the distribution utilities.
  - Romania: internal congestions are solved without supplementary market costs (except the payments for ancillary services). In real time internal congestion are solved through Ancillary services.

A.4. Cross-border congestion management

Cross-border congestion is defined as congestion between SO's control areas (Chapter 3.1.2). Only two countries (JA, RO) explicitly stated no experiences with cross-border congestion. Several countries declared occasional congestion (IN, PJM, SI, ZA, UK, IMO). All other (BE, CZ, ES, FR, NO, SK), declared congestion as typical for at least some of its cross-border interconnectors.

Explicit transmission access charges for cross border trade (nominated schedules) have been removed in the European countries, India and PJM. In some countries (ES, CZ, SK, UK) grid access tariff applied for exported generation were implemented, but had been removed in 2004. In other countries, cross border charge can be regulated like in Japan (to be abolished in 2005) and Canada, or negotiated like in South Africa.

In most countries, the demand for cross-border transfer capacity usually exceeds the available. There are typically two ways to solve this – ex ante (define the transfer capacity and allocate it to the market participants – Chapter 5.2) and real-time (alleviation of congestion on psychical lines – Chapter 5.3). Main cross-border transfer capacity allocation mechanisms are shown in Table 5. It is clear that there is a tendency towards the use of market-based methods. Coordinated market-based measures seem to be the most effective.

Table 5. Cross-border transfer capacity allocation mechanisms

	Priority rules of a kind set by SO	**First come first served**	**Pro-rata curtailmen t**	**Explicit auction**	**Implicit auction**	**Combined explicit-implicit mechanism**	**Coordination with neighbouring SO**
Belgium	X		X	X			X
Czech Rep			X	X			X
France		X	X	X			X
Norway					X		X
Romania		X					
Slovakia			X	X			X
Slovenia			X	X			
Spain						X	
UK			X	X			X
Finland					X		X
PJM		X					X
Ontario					X		X
Japan		X					
India			X				
S. Africa	X		X				X

The interesting case here is the combined explicit/implicit allocation of cross-border capacity in Span. The procedure is as follows:

- Firstly, bids/offers submitted to the Power Pool, together with Physical Bilateral Contracts (PBCs) are communicated to the Market Operator (OMEL),
- Initially, OMEL clear the market assuming no cross-border capacity limitations,

- If congestion appears on any interconnector, its capacity in it is split into two blocks, one for the pool (as in implicit auctioning), and one for PBCs (as in explicit auctioning). The size of these blocks is determined *pro rata* to the total amount of each type of transactions,
- The capacity for the participants of the pool is allocated according to the merit order of bids and offers, with no further charge for the agents who obtain the capacity,
- The capacity for PBCs is allocated to them by means of an explicit auction, involving thus an explicit charge for those PBCs obtaining capacity.

Coordination with neighbouring SO seems to be a necessary prerequisite for efficient congestion management. Countries that do not coordinate the management of their congestion management with the neighbours are considering adoptions of the procedures (ES, RO). On the other hand, there is little standardization and cooperation in scheduling procedures and gate closure times. Each SO has its own mechanisms and timing for accepting cross-border schedule notifications from interconnection users, as shown in Table 6.

Table 6. Gate closure for cross-border trade

Gate closure	Close to real time or continuously accepted	One for all schedules	Separate for long term and daily schedules	Week-ahead	Intra-day allowed	Coordination of CM and market
Belgium			X		X	
Czech Rep			X			
France		X			X	
Norway		X				Mkt. splitting
Romania		X				
Slovakia			X			
Slovenia		X				
Spain		X			X	
UK		X			X	X
Finland		X				Mkt. splitting
PJM	Non-firm schedules[11]				X	LMP
Ontario	X				X	X
Japan		X			X	
India	Continuously accepted					
S. Africa				X		

For cross border congestion management, it is essential to know whether the nominated schedules can be changed after nomination. If schedules can be changed by market participants in, or close to real time, netting of firm schedules (also named "netting of counter flows") is very difficult to be taken into account at any stage of Transfer Capacity allocation or definition, as the latter is by definition based on assumption of existing (nominated) flows. Three categories of systems can be identified:

[11] In PJM, gate closure is D-1 with no further changes for firm contracts.

- Systems with firm schedules and no curtailment option for the SO – only market based methods can be used (CZ, NO, ZA, UK, FI)
- Systems with firm schedules and curtailment option for the SO (RO, SI, BE-NL, SK)
- Systems with flexible schedules and curtailment option for the SO (FR, BE-FR, PJM, JP, ES, IN, IMO)

Generally speaking, congestion is typical for open market arrangements. Unfortunately in most systems and especially in those being in the early stages of market opening, system operations are not much coordinated with electricity market.

Administration of cross border schedules in the majority of system operators takes place on 7 days-a-week basis. In some systems (JP, ZA, UK) Saturday, Sunday and Monday schedules are required to be nominated on Friday.

Another important factor in market operations and CM mechanisms is information distributed among market participants with respect to the cross-border transfer capacities available. This information includes yearly Cross-border Transfer Capacity forecasts available as monthly fixed values, monthly ATC forecasts as well as daily ATCs. In UK this information is detailed up to half hourly values.

Table 7. Netting, administration, information

	Netting of firm schedules	Administration of schedules	Information exchange
Belgium		week + weekend	web page
Czech Rep		week + weekend	web page
France	X	week + weekend	web page
Norway	X	week + weekend	web page
Romania		week	web page
Slovakia		week + weekend	web page
Slovenia		week + weekend	web page
Spain	X	week + weekend	web page
UK	X	week	web page
Finland	X	week + weekend	web page
PJM	X	week + weekend	web page
Ontario	X	week + weekend	web page
Japan	X	week	Individually upon request
India	X	week + weekend	web page
S. Africa		Week	Individually upon request

A.4.1. Loop flows on cross-border interconnectors and real-time alleviation of congestion

In a market environment, regional energy price differences allow arbitrage, and players look for the cheapest source of electricity. Zonal network model, assumed everywhere in Europe and in many countries around the world, entails working with aggregated index ATC values instead of individual line capacities. Calculation of ATC, being a result of aggregation of individual tie lines into an index value, is based on assumptions, such as the base case scenario constituting of generation/load patterns within each control area. Commercial transfer capacities ATC are determined in all systems by entity responsible for system operations (ISO, TSO, VIU).

One of the most significant factors that should be taken into account while discussing transfer capacities and congestion management in general, is the estimation of the difference between the physical flows, and the scheduled flows resulting from commercial nominations. This difference is referred to as loop flows (or parallel flows – see Chapter 3.4). Loop flows on cross-border interconnections can sometimes be very significant and sometimes even exceed 50% of the commercial interconnection capacity. Therefore the unpredictable loop flows substantially affect the calculation of ATC values by introducing the uncertainty over the real physical flows on the interconnection. This uncertainty is taken into account by high security margins, lowering thus the commercial transfer capacity available for market participants.

However, even taking all these precautions into account, congestion can occur during real time operation, be that a result of incorrect base case scenario assumptions or a cumulative outage of generation units and network elements. This congestion is often invisible to market players, as the limits on commercial transfer capacity are still respected. When some cross-border lines become overloaded, it is up to the SO to solve the problem. There are number of different mechanisms that are able to handle such situations (Table 8). For explanation of these methods see Chapter 5.3.

Table 8. Real time congestions management tools

	***Pro-rata* curtailment**	**Priority curtailment**	**Negotiated curtailment**	**Optimal line switching**	**Internal re-dispatch**	**Coordinated cross-border re-dispatch**	**Counter-trading**
Belgium		**X**		**X**			
Czech Rep							**X**
France	**X**			**X**	**X**		
Norway						**X**[12]	
Romania	**X**						
Slovakia	**X**						
Slovenia	**X**						
Spain	**X**						
UK							**X**
Finland						**X**	
PJM		**X**			**X**	**X**	
Ontario	**X**						
Japan		**X**					
India						**X**	
S. Africa			**X**				

[12] In the Nordic countries (NO, FI), coordinated cross-border re-dispatch is referred to as *counter-trading*

A.5. Conclusion

Currently, the existing real time congestion management measures are mostly non-market based, but there is a tendency towards the use of market-based methods. Coordinated market based measures seem to be the most effective. There are however few systems that have experiences with it (PJM, IMO, FI, NO). For further market integration, especially in meshed and highly interconnected systems with many system operators present, it is essential to establish a well-functioning and efficient real-time congestion management tools. Otherwise, with increasing cross border trade and uncertainties related with it, security margins would have to be significant, decreasing the amount of transmission capacity available for market purposes.