NordREG
Nordic Energy Regulators

Congestion Management in the Nordic Region

A common regulatory opinion on congestion management

Report 2/2007

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Preface

This report has two main purposes, first it is to summarize the discussion regarding congestion management in the Nordic countries taking into account the new EU Congestion Management Guidelines. The second purpose is to use this background in order to identify the issues that have to be dealt with by the NordREG to introduce the harmonised implementation of Congestion Management Guidelines across the Nordic market.

A working group was established with representatives from the regulatory authorities of Denmark (DERA), Finland (EMV), Norway (NVE) and Sweden (EMI). The group was chaired by the Swedish Energy Markets Inspectorate (EMI).

The members of the group were:

DERA: Bente Danielsen
EMV: Ritva Hirvonen
NVE: Tor Arnt Jonsen
EMI: Tobias Johansson and Kristian Gustafsson (until June 2006), Henrik Gåverud and Margareta Bergström (chair).

Executive summary

This report has two main purposes, first it is to summarize the discussion regarding congestion management in the Nordic countries taking into account the new EU Congestion Management Guidelines. The second purpose is to use this background in order to identify the issues that have to be dealt with by NordREG to introduce a harmonised implementation of Congestion Management Guidelines across the Nordic market.

Congestions between Nordic bidding areas in day-ahead markets (Elspot market) are handled through market splitting, while internal congestions in general are handled through counter trade or by reducing interconnector capacity at the Elspot bidding area borders. Counter trade is mainly used on intra-day operation and to maintain firm capacity notified on day-ahead markets. Previous studies show that capacity available for trade is often reduced by one of the involved (TSO) due to internal or other reasons. While the question of internal congestions is central to the functioning of the market, the objective has not been to come up with a solution to whether counter trading or market splitting in bidding areas should be the preferred method in the Nordic area.

For market players market splitting gives an opportunity to trade such that the electricity goes from the low price area to the high price area, while at the same time keeping the system within safe limits given by the TSOs. Market splitting will give the TSO an income when there is congestion. Counter trade is basically a method where the TSOs correct the flow of electricity by market based redispatch to make sure that the flow of electricity does not exceed the security limits. Since the TSOs have to pay for this service, counter trade constitutes a cost for the TSOs, while it does not change trade transactions. This cost is normally covered by the grid tariff.

A short description of present congestion management methods in the Nordic countries is given in the report. Also revenues and costs for TSOs related to congestion management have been mapped.

There are challenges related to congestion management in all Nordic countries. NordREG has identified problems in the Nordic countries. The new congestion management guidelines imply additional responsibilities for the regulatory authorities to monitor methods and practices. Therefore, all the regulatory authorities need to build new competences in addition to the need of more transparent data and knowledge of the procedures of the TSOs and Nord Pool. However, this does not take away the TSOs responsibility for monitoring and transparency regarding the operational issues.

The competition aspects of the bidding areas are important. A common coordinated congestion management method would enhance competition. Competition aspects .are important and have to be taken into account when deciding geographical bidding areas in the Nordic market. A concentration index (HHI) has been applied to the Nordic wholesale market and it shows that even when the Nordic market is relatively well integrated, concentration is high. Another issue that could affect the optimal number of bidding areas is the competition on the retail market. It is important for future discussions regarding congestion management that competition issues are taken into account.

The roles of the regulatory authorities in the Nordic countries with regard to capacity allocation and congestion management vary. The opening of the European markets and the vision of a single market for electricity has led to a process where the roles of the regulatory authorities need to be strengthened and to be more harmonised.

NordREG needs to develop a common practical interpretation of the congestion management guidelines taking the interface with central Europe into account. Work focusing on this issue is included in the NordREG Work Programme 2007. In Appendix B to this report the work group has mapped issues that need special regulatory attention, such as the role for regulatory authorities, processes and tools for monitoring. Thus, the report is intended to give input to the new NordREG task on implementation of Congestion Management Guidelines.

It is important for the regulatory authorities to develop competence and new methods for monitoring congestion management practices. Some starting points have been presented in this report. NordREG presents the following areas for further consideration:

- the need for the regulatory authorities to define a common view on what kind of data and methods that are needed in order to identify and analyze problems,

- studies together with the Nordic competition authorities on the competition problems related to price differences in order better to understand how to find an optimal balance between competition issues and efficiency related to congestion management methods.

Finally, the current representation of the physical network in the market splitting model is very simplified. This often leads to a need for the TSOs to restrict the capacity on interconnectors given to the market due to the uncertainty regarding the physical flow that will result from the anticipated trade the following day. It may therefore contribute to a less efficient utilisation of interconnector capacity than would be possible with a more accurate model. As the number of interconnectors increases as well as the trade, this problem can be expected to increase. In the long run, therefore, new models need to be developed. The regulatory authorities have an important role in this development.

This issue has broad technical, economical and policy implications and therefore NordREG invites the Electricity Market Group to consider how to organise a study whether a better representation of the physical network in the trading model would lead to a more efficient use of the existing transmission network and thus make it possible to use the interconnector capacity more efficiently – one part of such a study could be to assess the benefits of introducing elements of the nodal pricing “philosophy”

1 Introduction

1.1 Background and purpose of the report

Congestion management is one of the most complex issues in the design of the liberalised electricity market. The Nordic market is well-developed, but improvements are still needed. A regional coordinated congestion management method is important in order to facilitate a further integration of the Nordic electricity market as well as the interaction with non Nordic markets.

The TSOs' task is to allocate as much capacity as possible to the market while maintaining the security of the power system. In the work programme for the Nordic Regulators (NordREG) for 2005, the task "***To promote adequate transmission capacity and efficient market-based congestion management methods"*** was established. It was stated under the task that:

"*The work in this project will take the Nordic mini-forum on congestion management as a starting point, where the first meeting will be held on January 19, 2005.*

The aim of this project is to establish a common Nordic regulatory opinion on congestion management. A further aim of the project is to find a harmonised way of applying congestion management guidelines within the Nordic region and a Nordic opinion on congestion rents."

According to the 2005 work programme the following tasks were given to the group:

A) Map Nordic problems with present congestion management principles/methods.

B) Identify associated arrangements which may be affected by changed congestion management principles

C) Map what needs to be harmonised to find a common Nordic harmonised implementation of congestion management guidelines

D) Evaluate congestion rents, how they are distributed, used and their impact on markets

E) Establish a common Nordic regulatory opinion on congestion management, work for a common Nordic regulation and practise on handling congestions in the national transmission grids. An important issue is that rules and practices are consistent with the aim for a well functioning market for electricity within EU.".

The work for this report started in the spring of 2006, after the study made by EMI on this area was finalised. Besides it can be noted that Nordel as a response to a request of the Nordic Council of Ministers has carried on substantial work regarding congestion management, where several of the questions in the terms of references have been addressed.

In the European regulatory framework regarding cross border trade in electricity, European regulatory authorities have been given new tasks related to congestion management. These new tasks have been specified in more detail in the new Congestion Management Guidelines that came into force on December 1, 2006

Since the work programme was written, a new process has started following the Mini-Fora. In this process it was acknowledged that the Single European Market for

Electricity needs to be approached through regional harmonisation. Thus the ERGEG Regional Initiative was launched. The Nordic countries belong to the Nordic region, which also includes Germany and Poland. Through the work in the Regional Initiative, questions related to congestion management are addressed in a wider context.

While it has not been possible to fulfil all the requests in the TOR, it is our aim that this report will contribute to that process, as well as to the further process of defining a Nordic view of how to interpret the new tasks given to the regulators in the Congestion Management Guidelines.

1.2 Organisation of the work

A working group was established with representatives from the regulatory authorities of Denmark (DERA), Finland (EMV), Norway (NVE) and Sweden (EMI). The group was chaired by the Swedish Energy Markets Inspection (EMI).

The members of the group were:

DERA: Bente Danielsen
EMV: Ritva Hirvonen
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EMI: Tobias Johansson and Kristian Gustafsson (until June 2006), Henrik Gåverud and Margareta Bergström (chair).

The group had three meetings during 2006 and three meetings early 2007.

2 Capacity allocation and congestion management in the Nordic region

This chapter describes briefly the Nordic grid and the TSOs.

2.1 The Nordic TSOs and the Nordic transmission grid

The transmission grid is the physical backbone of an electricity market. The transmission grid in the Nordic countries has been built up during many years, aiming basically to meet the national demand of each country. Early in the development of the Nordic national power systems it was recognized that the differences in generation mix-up between the countries meant that linking the systems together would enhance security of supply and make possible a more efficient use of the existing generating capacity. Therefore, the Nordic area is well linked together and the foundations for the development of a Nordic electricity market were good.

Each country has an appointed transmission system operator (TSO):

- Svenska Kraftnät in Sweden
- Statnett in Norway
- Fingrid in Finland
- Energinet.dk in Denmark

The TSOs own and operate the high-voltage grid, and they are responsible for the secure system operation. Since the national grids are interconnected, there is a need for the Nordic TSOs to cooperate. The TSOs cooperate within the organization of Nordel. Through the Nordic Grid Code the Nordic TSOs have agreed on the basic rules on how to operate the interconnected Nordic power system[1].

The Nordic transmission grid connects Finland to Sweden and Norway, Sweden to Norway, Denmark West and Denmark East and Norway to Denmark West (and vice versa). Congestions between the Nordic countries are managed by implicit auctions through Nord Pool Spot[2]. That means that capacity allocation and trade with electricity is done at the same time. Trade between the Nordic countries[3] is handled by the Nordic power exchange Nord Pool Spot. TSOs handle part of the congestion management duties through Nord Pool Spot where Nord Pool Spot has a de facto monopoly regarding cross border trade between the Nordic countries. Nord Pool Spot is regulated by the Norwegian regulatory authority.

The Nord Pool model of implicit auctions is called market splitting. Implicit auctions involving more than one exchange is called market coupling.

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[1] Nordic Grid Code 2007, Nordel

[2] The Nordic TSOs own 20% each of the shares of Nord Pool Spot. The remaining 20% is owned by Nord Pool ASA, which is owned by Statnett and Svenska kraftnät (50% each).

[3] And to a certain extent Germany (Kontek)

In the Nordic area all trading capacity over the interconnectors between bidding areas is let at the disposal of Nord Pool Spot for the day-ahead trade. There is no other capacity nomination like yearly or monthly auctions between the Nordic countries. This means that trade between bidding areas has to be done through Nord Pool Spot. There is also an intra-day market, Elbas, available in most of the Nordic countries with continuous trade. Here the remaining capacity after the day-ahead trade can be used on a first come-first serve basis. Finally, unused capacity can be used for the Nordic regulation market.

Figure 2.1 The Nordic transmission grid. Source: Nordel

The Nordic transmission grid has several connections to adjacent areas, see table 2.1. The table also shows nominal interconnector capacity.

Table 2.1 Nordic transmission links to adjacent areas

Connecting areas:	Name	Owner	Capacity (MW)		Capacity allocation mechanism
			Out:	In:	
Denmark East -Germany	Kontek	Energinet.dk	1200	800	Nord Pool Spot
Denmark West - Germany		E.ONNetz/ Energinet.dk	1500	950	Explicit auction*and Nord pool Spot
Finland – Estonia	Estlink	Nordic Energy Link AS	350	350	Merchant link, intra-day auctions for unused capacity
Finland – Russia		Fingrid	..	1300	Yearly auctions
Norway – Russia		Statnett	..	30	Contract
Norway – The Netherlands	NorNed	Statnett/TenneT	700	700	To be decided. The Norwegian license requires implicit auctions
Sweden – Germany	Baltic		610	600	At owners' disposal
Sweden – Poland	SwePol		600	300	At owners' disposal

*) If capacity is bought in the explicit auction, the capacity can be let at the disposal of Nord Pool Spot and implicit trading can take place by the CBO office and the Kontek trading platform/bidding area

For a majority of interconnectors to/from Nordic area, available capacity for electricity trade is (much) less than the nominal capacity. The dominating reason is grid constraints in one or both of the interconnected countries that prevents full utilization of the cable. This fact underlines the need for continued Nordic focus on utilization of transmission links connecting Nordic and non-Nordic countries.

Within the scope of the ERGEG Regional initiative in the Nordic region, one priority issue is efficient congestion management on the cables that link the Nord Pool area with the German and Polish markets.

Implicit auction is applied on the Kontek cable through Nord Pool Spot Kontek bidding area. A memorandum of understanding has been signed by the owners and TSOs for the two cables that connect Denmark and Germany. This memorandum of understanding aims at a procedure for market coupling between Nord Pool Spot and the German exchange EEX to be operational by the fall of 2007.

The possibilities to find more efficient congestion management models for the two cables between Sweden and Germany/Poland are also studied within the framework of the ERGEG Regional initiative.

2.2 Relief of transmission congestion within a bidding area (Elspot area)

There may be problems with internal bottlenecks within the bidding areas. When there is expected congestion within an Elspot area the TSO in question must make sure that the safety rules will not be violated during the operating hour. If it is feasible for the TSO to plan for counter trade, more trading capacity can be allocated. In some areas there may not be enough flexibility in the system to deal with possible congestions and thus, counter trade may not be possible if needed at a later stage. If counter trade would not be feasible, the trading capacity on interconnectors to and from the area in question will have to be reduced.

Previous studies show that capacity available for interconnector trade is often reduced by either one of the involved Transmission System Operators (TSO) due to internal congestions within the bidding area or other reasons. Allocating less than “normal” interconnector capacity will increase the probability for congestion leading to areas with different prices. Therefore as much capacity as possible should be given to the market. If interconnector capacity is often reduced due to internal bottlenecks, there may be reasons to consider changes in the division into bidding areas.

All economic transactions agreed on the day-ahead spot market will be effectuated. Possible situations with upcoming congestions within this time span of 38 hours will be handled by the TSOs through counter trade. Upcoming congestion may be the result of fault(s) on transmission lines or on production or consumption facilities or it could be the result of wrong forecasts of flows. This means that the TSOs relieve remaining congestions by counter trading during the operational phase. Thus the determined commercial flow is not changed, only the physical flow.

Congestions after closure of the Elspot market has to be solved by utilizing the Elbas market or the Nordic Regulating market, where producers and large consumers offer to increase or reduce production or consumption in exchange of economic compensation e.g. producers offer to increase or decrease planned level of production. Through this action the TSO orders decreased production or increased consumption upstream the congested line, and increased production or decreased consumption downstream the congested line. If no adequate bids are available the TSOs have to resort to bilateral trade in order to relieve congestions.

The current Nordic practices to reduce capacity for trade as a mean to handle internal congestions result in a less integrated Nordic market, than available physical capacity would suggest. This reduces the efficiency of the market, for example in situations with unutilized generation capacity in a low price area. In addition, security of supply in some areas can be reduced when transmission capacities are reduced. One of the main reasons for having an integrated Nordic electricity market is the differences in generation system, consumptions patterns and weather impacts on the electricity sector. Thus, large trade capacities across the Nordic countries will improve the overall reliability of electricity supply.

2.3 Country specific information on current congestion management

The four Nordic countries that form the Nord Pool trading area all have special characteristics. TSOs cooperate within Nordel in order to increase harmonisation, but still there are differences in the electricity market design between the Nordic countries.

One of the fundamentals in the operational agreement within the Nordic Grid Code is that the transmission grid is continuously planned to meet the operational n-1 criteria. This means that scheduled and unscheduled outages of any network element and production plant must be handled without unacceptable overload of the transmission system and without propagating to insecure operation.

In a market where trade is determined by the price differences, large flows may change direction from one hour to another. Therefore some TSOs have had to introduce so called ramping. Very simplified, ramping means that such changes will have to take place over several hours. According the UCTE system rules hourly deviation of flows are restricted to a more narrow band that allowed for in the Nordel area. This implies different ramping requirements in the countries connected to central Europe.

In this section the present situation and practices in each country will be briefly presented.

2.3.1 Denmark

The transmission grid is continuously planned to meet the operational n - 1 criteria. This implies, that scheduled and unscheduled outage of any network element and production plant must be handled without unacceptable overload of the transmission system and without propagating to insecure operation. Daily – hour by hour – the acceptable transmission capacity is calculated by Energinet.dk for all international connections between Denmark and neighbouring countries.

The trading capacity (NTC) on the HVDC-connection between Denmark East and Germany (Kontek) is 550MW, which is 600MW deducted by 50MW frequency controlled disturbances reserve in both directions. Congestions in this interconnector are handled by implicit auctions.

The maximum capacity between Denmark East and Sweden is 1300 MW import and 1700 MW export. The maximum trading capacities are determined by system constraints. The actual capacities determined day-ahead are quite often much lower, especially the import-capacity to Denmark East.

The reduction of the trading capacity is decided in cooperation between Energinet.dk and Svenska Kraftnät as the lowest proposed capacity by the 2 parties.

The maximum NTC between Denmark West and the southern part of Norway is 1000 MW southbound and 950 MW northbound determined by the HVDC plants and measured in Kristiansand in Norway. In 2006 problems with a transformer in Kristiansand presently reduces the NTC to 500/620 MW until approximately the summer of 2007.

In some situations the calculated NTC value between Denmark West and the southern part of Norway and Sweden depends on the power production in the Northern part of Denmark West. In periods with high wind production the import capacity to Denmark West may be reduced

Interconnector capacity between Denmark West and Germany is recently expanded to 1500 MW versus Germany and by 950 MW from Germany to Denmark. Presently congestions are handled by explicit auctioning/implicit through the Kontek bidding area to a certain degree, however day ahead market coupling is foreseen late in 2007.

2.3.2 Finland

Finland has interconnectors to Sweden, Norway and Russia. Maximum net transfer capacity (NTC) from Sweden to Finland is 2050 MW and from Finland to Sweden 1650 MW. Between Finland and Norway there exists 220 kV an interconnector having transmission capacity about 100 MW. A new merchant 350 MW DC interconnector was commissioned between Finland and Estonia in the beginning of year 2007.

Finland forms its own bidding area when power is transferred from or to Finland to and from other Nordic countries. During high transfers from Sweden to Finland, e.g. in wet hydro years, the transfers may exceed the allowed transmission capacity. To manage the congestion a bidding area has been formed between Finland and Sweden. Also during dry years the transfers from Finland to other Nordic countries exceed the allowed transmission capacity between Finland and Sweden introducing a price area to manage the congestions in these situations.

If congestions exist within Finnish power system, TSO uses counter trade as long as that is feasible. The cut P1 from northern Finland to southern Finland has been a potential bottleneck for counter trade. Counter trade is also applied if disturbances and other incidents require TSO to maintain the transmission capacity at the same level as notified to the day-ahead market. The amount of counter trade has been quite low during the last few years because transmission capacity has increased across the cut P1 and also demand has increased in northern Finland more than generation thus decreasing the need for counter trade across the cut P1.

During high export situations from Finland to Sweden limitations in transmission capacity may be required either on the interconnectors between Finland and Sweden, on the internal cut P1 or internal cuts Cut 1 and Cut 2 in Sweden. This is the trade situation when limitations in internal transmission network have been previously transferred to the interconnectors between Finland and Sweden. Other options for congestion management during these situations, e.g. market splitting within Finland or counter trade would not be possible e.g. to apply counter trading in these situations would be impossible because there is lack of generation to be used for counter trading in such situations.

During the import situations from Sweden to Finland the internal bottlenecks have been abolished because more transmission capacity has been built within Finnish transmission network and because more demand compared to generation in northern Finland has reduced transmission from northern to southern Finland. This implies that bottleneck appears nowadays first on the interconnectors during the import situation.

Due to the sporadic nature of congestions within Finland in cut P1 foreseen also in the future due the reinforcements along the cut P1 and better balance between supply and demand in southern and northern Finland the market splitting within Finland is not expected to imply more efficient utilisation of the network or production units. However, it should be noted that introduction of market splitting in cut P1 Finland or in cut 1 or cut 2 in Sweden may have interaction and this should be taken into account when decisions on new bidding areas are introduced.

2.3.3 Norway

Norway applies today at least three different methods for internal congestion management:

1. Market splitting with regional Elspot areas within Norway
2. Counter trade using bids offered to the TSO's regulating (balancing) market (special regulation)
3. Movement of the bottleneck to the border and reduction in the capacities towards other countries

1 Market splitting – Elspot areas

For ”long and stable” bottlenecks, NVE's regulation advises Statnett to create Elspot-areas. The available capacity in and out of an Elspot area is determined by Statnett, and Nord Pool determines different prices if the capacity limit is binding. All producers and consumers (suppliers) have to submit bids to the day-ahead market specifying the actual Elspot area. Bilateral trade between participants in different Elspot-areas have to be bid as sale in the producers Elspot area and purchase in the consumers Elspot area. Since 2000 there have been several Elspot area configurations, at most four different Elspot areas within Norway.

2 Counter trade – special regulation

”Small and temporary” bottlenecks are handled by counter trade paid for by Statnett.

3 Movement of bottlenecks to the border

One particular bottleneck, towards Oslo from the west, is handled by reductions in Norway's export capacity towards Sweden. The bottleneck is effective during cold winter days and at most Norway's export capacity to Sweden may be reduced from 2050 MW to 0 MW. The limitations are described at Nord Pool's web-page (http://www.nordpool.no/products/elspot/Nordel/transfercapacities.pdf).This can have security of supply consequences in southern Sweden as the Swedish import capacity from Southern Norway is reduced in periods with very high load in Oslo. In such periods, load is very high in Sweden as well.

Finally, Statnett very often restricts the flow between Southern and Middle Norway. This is a weak connection with capacity 200 MW, which is often reduced to 50 MW. From Nord Pools Elspot capacity page (http://www.nordpool.no/marketinfo/transfer/overview.cgi?area=area), we see that the flow in this cut is very often fixed by direction as well. Presumably, these restrictions are introduced because of loop-flow problems, which the current market splitting model does not handle.

2.3.4 Sweden

The Swedish transmission grid was originally designed and dimensioned to transport electricity from hydro power plats in the north of Sweden to the main consumption areas in the south of Sweden. The development of a Nordic market and the ongoing European market integration has however implied new conditions and an increased stress on the Swedish grid. Under situations with large international transit flows the demanded transmission capacity often exceeds the physical capacity of the Swedish grid. Important bottlenecks in the Swedish grid are:

- Cut 1 is situated farthest north and consists of four 400 kV lines, typical capacity is 2500 to 3200 MW.
- Cut 2 is situated in the middle of Sweden and consists of eight 400 kV lines and four 220 kV lines and constrains power in southbound direction, typical capacity limit is 6200 to 7200 MW.
- Cut 4 is situated in the south of Sweden and consists of five 400 kV lines and one 200 kV line. It constrains power in southbound direction. Typical limit is 3500 to 4000 MW.
- The west-coast corridor is situated in the south-west of Sweden and contains the lines Horred-Kilanda and Strömma Stenkullen and limits power in northbound direction. Typical limit is 2700 to 2900 MW.

A simplified picture is that cut 1,2 and 4 are associated with wet years, large hydropower production and exports, while the west-coast corridor is associated with dry years (and/or night hours and weekends) with large imports from Denmark and continental Europe.

Congestion management within Sweden is a combination of reduced allocation of trading capacities in the operational planning phase and counter trade during the operational hour. Congestions on the national borders are handled via market splitting. Sweden is one bidding area.

Most bottlenecks in the Swedish grid occur when there is a large demand for transmission capacity from the north to the south of Sweden, for example periods with high consumption or precipitation. Such situations together with an additional flow due to transit through Sweden imply that market players' demand for capacity often exceeds the physical transmission capacity. The Swedish transmission grid is not dimensioned to handle full export/import at all times. Sweden is situated in the middle of the Nordic market and connects large parts of the Nordic market to the European continent. The increased integration of the Nordic market, and the increased interaction between the Nordic and the European continent imply increased stress and a new flow pattern in the Swedish grid. In order to balance surplus and deficit areas within the Swedish control area, and given the internal capacity restrictions, Svenska Kraftnät calculates how much export- and import flows can be allowed. There is always a risk that the flow turns out to change direction compared to Svenska Kraftnäts forecasts. Svenska Kraftnät needs to take these insecurities into account. In the practical situation this often means that the trading capacity has to be below the maximum physical capacity of the interconnector.

Congestion in either cut 1 or 2 is handled through reduction of import capacity to the north of Sweden (from north Norway and Finland) and/or reduction of export capacity from the south of Sweden. How the reduction is made depends on which cut (or cuts) that is the restriction in a given situation. There is a significant difference between cut 1 and 2 compared to cut 4. The two former may be a combination of import reduction (north Norway and north Finland) and export reduction of all Swedish interconnectors south of cut 2 (south Norway and Finland, Denmark West, Denmark East, Germany and Poland) whereas congestions in cut 4 imply reduction of available capacity from Sweden through interconnectors south of cut 4 (Denmark East, Germany and Poland). There might be situations when there are several cuts in combination that lead to reductions of available capacity for trade.

Congestion due to cut 2 is handled by a special optimization where the total available export capacity related to the interconnectors in direction to south Norway, Denmark West and

Denmark East is handled jointly by Nord Pool Spot.[4] This joint handling means that the sum of the flows of these interconnectors does not exceed the total export capacity that would otherwise be related to these lines. In practice this means that if south Norway exports to Sweden, some of this export may be transited to Denmark West and or Denmark East even though the available capacity for exports in cut 2 is set to zero. This way the maximum capacity is given to interconnectors with the highest willingness to pay and thus ensure a more efficient handling of restrictions in cut 2. Note that each interconnector still has an individual ”roof” that is related to other restrictions in the grid. The available Elspot capacity for these lines is consequently dependent on both capacity available in cut 2, and the flow (or prices) on the other interconnectors in the optimization.

Congestion in the west coast corridor is different and is caused by large northbound transit flows during off-peak hours (night between 23 and 06, and during week-ends). This type of transit flow is created by the interaction between thermal and hydro intensive areas. Congestions related to this phenomenon were first noticed during the dry period 2002/2003. During periods with low filling rates in water reservoirs the hydro producers (mostly in Norway and Sweden) use their technical flexibility to decrease production during low price hours. Thermal production units (in Denmark and Germany) imply a level production and therefore their excess production can be exported at low prices during off-peak hours with low demand.

This exchange results in a strained network situation around Göteborg and it is solved by reducing export capacity to southern Norway through Hasle and if reduction of export capacity to southern Norway is not sufficient also import capacity from Denmark, Germany, Poland (in order of reduced impact) are reduced.

The network reinforcements due to the “priority cuts projects” and other internal reinforcements will mitigate the internal congestions.

At the liberalization of the Swedish market, Sweden was established as one bidding area. Given this fact, and given the fact that the flexibility in production and consumption in parts of southern Sweden is low, the congestion management options for Svenska Kraftnät are limited. The pros and cons of dividing Sweden into more bidding areas is presently studied within a broad project (POMPE) involving the Energy Markets Inspectorate, Svenska Kraftnät, Swedenergy and the Confederation of Swedish Enterprise. Results from the project will be presented in the end of May 2007.

[4] The optimization of cut 2 was introduced 15th of March in 2004.

3 Congestion management income and costs 2001- 2005

The balance that every TSO has to strike is to maximize the capacity allocated to the market while operating within the agreed security limits. Since the capacity allocation has to be done before the bidding to Nord Pool Spot, the TSOs have to make their decisions based on forecasts for trade and resulting flows for the following day. The quality of these forecasts obviously is dependent on a good cooperation between the TSOs and the level of uncertainty regarding the trade that will result the coming day.

After the spot market is closed, the TSOs can calculate the resulting flows. The Nordic TSOs have taken on to relieve congestions that might occur after the trading capacity is given to the market through counter trade. Counter trade is often done using Elbas market or during the operating hour using the regulating market. Bilateral agreements between TSO and market actors can also be applied for counter trade. There is an ongoing discussion in Nordel as to how much counter trade is feasible within the present framework.

If the market demands more trading capacity than available between bidding areas, the bidding areas will form different price areas. The price differences account for an income that is collected by Nord Pool Spot and transferred to the TSOs. The congestion income is divided between the TSOs according to an agreement between the TSOs and Nord Pool Spot[5].

According to the EC Regulation on Cross Border Trade congestion income must be used for maintaining the actual availability of the allocated capacity; network investments or increasing interconnection capacities or as an income to be taken into account by regulatory authorities when approving the methodology for calculating network tariffs. In the following NordREG task of implementation of the Congestion Management Guidelines this issue will be discussed further.

Nordel has agreed to use congestion incomes that arise from Nordic cross border trade as an earmarked source for investments in the Nordic transmission grid[6]. The current principle agreed by Nordel is to use the congestion rents to partial financing of the Nordic grid investments, while the rest of a specific investment is financed by the TSOs involved in the project.[7] While in general supporting the view that congestion income should be used to maintain and strengthen the grid, it has been beyond the scope of this study to come up with a common Nordic regulatory view on this very complex question.

Table 3.1 shows the congestion income for the years 2001 through 2005 in MEUR[8]. Since the keys for how to divide the income between the TSOs has changed over the years, the total sum can be more interesting as a measurement of the level of congestions.

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[5] Presently, there is no agreement in place as to how to divide the congestion income.
[6] Nordel (2006).
[7] For additional info see Nordel (2006) *Status of Nordel's work on Enhancing Efficient Functioning of the Nordic Electricity Market*
[8] The congestion income has been provided from Statnett in MNOK and converted according to the mean yearly conversion used by Nord Pool.

Table 3.1 Congestion income, MEUR

Year	Denmark West	Denmark East	Finland	Norway	Sweden	Total
2005	16,99	6,40	15,00	20,75	43,13	102,26
2004	11,95	3,25	8,00	11,47	13,86	48,53
2003	36,59	5,92	14,90	18,06	17,93	93,40
2002	33,41	9,18	16,20	19,68	19,81	98,29
2001	7,78	3,64	3,72	7,57	10,42	33,13

It can be seen from the table that the level of congestion income has been changing quite substantially between years. The changes are due both to changes in the production and transmission systems including interconnector capacities, to the different hydrological conditions and to the expanding trade with the continent. The price differences between areas give locational signals to the market players, but it also represents an income to the TSOs as mentioned above.

On the other hand, if the trading capacity that the TSO have allocated would lead to too high flows through some transmission line, the TSO will normally have to reduce the anticipated flow through counter trade. Counter trade will lead to a cost for the TSO and paid through the grid tariff. This cost is not carried forward to the market players. On the contrary, those players which supply the power for the counter trade will gain on the operation. Table 3.2 shows the costs for counter trade 2000 – 2005[9].

Table 3.2 Costs for counter trade, MEUR

Year	Denmark West	Denmark East	Finland	Norway	Sweden	Total
2005	0,51	1,35	0,86	18,38	5,81	26,91
2004	0,22	0,00	0,07	8,84	0,55	9,68
2003	0,69	0,14	0,30	4,17	1,75	7,05
2002	1,49	1,53	1,40	6,02	1,17	11,61
2001	0,14	0,67	0,80	0,03	0,37	2,01

If the costs for counter trade are compared with the congestion income, it is clear that the level of counter trade costs is not related to the level of congestion income. This is natural, since counter trade is mainly used to handle congestions that occur after the trading capacities have been given to the market. Counter trade is thus mainly a function of a) unexpected outages and b) forecasting errors.

For market players market splitting gives an incentive for both producers and consumers to trade such that the electricity goes from the low price area to the high price area, while at the same time keeping the system within safe limits given by the TSOs. Market splitting will give the TSO an income when there is congestion. Counter trade is basically a method where the TSOs correct the flow of electricity by market based redispatch to make sure that the flow of

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[9] The costs have been provided by the National regulators in national currencies and converted to MEUR, see above.

electricity does not exceed the security limits. Since the TSOs have to pay for this service, counter trade constitutes a cost for the TSOs, while it does not change trade transactions. This cost is normally covered by the grid tariff.

4 Identified problems regarding current practice

The working group has identified some problems regarding the current practice for congestion management in the Nordic electricity market. Finally, we refer to country specific issues and problems related to the congestion management practice.

4.1 Physical aggregation of nodes and connections

The physical interdependencies within the underlying electric network are not fully taken into account when prices, injections and withdrawals are determined in the day-ahead market. Due to the uncertainty in load and generation patterns TSOs may be obliged to deliver to the market lower transmission capacity compared to the situation where hourly load and generation patterns after day-ahead market closing are fully known. This implies that the transmission capacity of the grid may not be fully utilised in day-ahead market.

An alternative to the present physical aggregation would be to make an economic aggregation as illustrated in the figure A.1 in Appendix A thus combing physical and markets aspects within one model. In this case, bids are collected at the nodal level. The bids would then be combined with a physical network model from the TSOs in a detailed network model to calculate prices, injections, withdrawals and power flows that are efficient and consistent and feasible to the existing network.

In principle, the number and configuration of zones may be identical to the zones used in the present physical aggregation. However, the method of economic aggregation may result in better utilization of the grid. One reason is that power flows would be determined simultaneously with prices, injections and withdrawals. The uncertainty about future power flows in day-ahead and the TSOs' capacity determination based on expected and forecasted flows would be eliminated. (Still, as long as we talk day-ahead, the calculations will still be based on forecasts). Flexible generation and consumption will as well receive incentives (prices) based on the true physical network conditions.

This model may be difficult to implement in the short run since the calculation model and detailed data may not be available. It should be studied how this model would be realised and what are the possible steps in the direction of merging the physical network characteristics and bidding process. As a practical starting point the following procedure might be applicable:

- Transmission capacity between bidding areas are calculated and delivered to the day-ahead market purposes as it is done presently.

- After the day-ahead markets are closed e.g. bids are given to the power exchange and first iteration of prices on bidding area have been evaluated, the transmission capacity should be re-calculated using the available information from the market (bids, generation and load pattern) and fed back into the model. This iterative process may release more capacity to be used defining prices for bidding areas. This iterative process where transmission capacity and market prices are defined together should be substituted by the theoretical model described above in due time.

- Transmission capacity should be recalculated for intra-day market and regulation market taking account as far as possible the existing load and generation patterns caused by already closed markets, e.g. day-ahead and bilaterals.

The Swedish Energy Markets Inspectorate has in its report ”Hantering av begränsningar i det svenska överföringssystemet för el” showed that all TSOs sometimes have limited the allocated trading capacities due to internal network problems. Internal congestion within a zone is a consequence of the physical aggregation model illustrated in Appendix A.

Internal congestions may disappear if an economic aggregation is applied instead of the present physical aggregation. An economic aggregation implies that the physical conditions in the grid are specified in more detail and taken into account when prices, injections, withdrawals and flows are determined. Thus, a solution based on economic aggregation implies that "internal congestions" may be handled and resolved in a least cost manner.

It should be noted, though, that an economic aggregation – while being more efficient, would imply that the market actors provide much more geographically detailed information than today regarding production and consumption.

4.1.1 Discussion

The Nord Pool Spot model of price calculation and market splitting is based on physical aggregation. Given the present market design, we are not proposing here a totally new approach to congestion management. But it is important to be aware that the market model that is applied today is not the only possible one. There is not just the question of the optimal size of the zones where the same price will be applied under all circumstances; there is also the question of how the aggregation into zones is done.

Having in mind that simplifications are necessary, we need also to be aware that the flow of electricity is increasingly difficult to predict in an expanding market. The question is would it be optimal to require the players to provide more geographically detailed data than today in order to make a more flow based approach possible? What is the difference between the different levels of approximation in welfare terms? What would the consequences be for competition and transparency? These are not easy questions, but it is the opinion of the group that they are worth looking further into.

4.2 Country specific observations

The rest of this chapter is devoted to short illustrations of national policies regarding congestion management practice that have received attention during the last years.

4.2.1 Denmark

As has been described in section 2.2.1 the interconnector capacity to Sweden and Norway (and Germany) can be reduced due to internal reasons. The so called cut B on Denmark West was built away some years ago, which means that it rarely causes any congestions.

The Swedish problem of the “network cuts” implies reductions of capacity between Sweden and Denmark West. In seldom situations the calculated NTC value between Denmark West and the southern part of Norway and Sweden depends on the power production in the Northern part of Denmark West. In periods with high wind production the import capacity to Denmark West may be reduced.

Reductions between Denmark East and Sweden due to problems in Denmark East are rare.

The reductions of export capacity from Sweden to Denmark East lead to high prices in Denmark East due to the low production flexibility there.

In July 2006 the Danish Energy Association filed a complaint of abuse of a dominant position to the European Commission (DG COMP) regarding the congestion management method applied by Svenska Kraftnät regarding the Øresund interconnector.

It is the position of the organisation that “the curtailment of capacity in the Øresund interconnector by Svenska Kraftnät to secure only 1 price area inside Sweden”, causes losses to traders and increases prices to be paid by Danish consumers.

The complaint of the Danish Energy Association has been supported by EBL, the Norwegian Energy Association, due to the effects of Svenska Kraftnät’s likewise curtailment of interconnector capacity versus the Norwegian borders.

4.2.2 Finland

During high export situations from Finland to Sweden limitations in transmission capacity may be required either on the interconnectors between Finland and Sweden, on the internal cut P1 or internal bottlenecks Cut 1 and Cut 2 in Sweden. This is the trade situation when limitations in internal transmission network have previously been transferred to the interconnectors between Finland and Sweden. The limiting phenomenon in transmission capacity in these cases has been dynamic stability across the long transmission path from southern Finland to southern Sweden via northern AC interconnectors.

Other options for congestion management during these situations, e.g. market splitting within Finland or counter trade would not be cost-effective or even possible e.g. to apply counter trading in these situations would be impossible because there is lack of generation to be used for counter trading in such situations.

During recent years Fingrid has increased the internal transmission capacity within Finland (series compensation of lines in cut P1) and more demand compared to generation in northern Finland has reduced transmission from northern to southern Finland. This implies that bottleneck appears nowadays first on the interconnector between Finland and Sweden also during the import situation.

Due to the sporadic nature of congestions within the Finland in cut P1 foreseen also in the future due the reinforcements along the cut P1 and better balance between supply and demand in southern and northern Finland the market splitting within Finland do not imply more efficient utilisation of the network or production units within Nordic market context. Further actions in congestion management within Finland and on interconnectors to Sweden should be considered to be consistent with solutions in Sweden.

4.2.3 Norway

One particular bottleneck, towards Oslo from west, is handled by reductions in Norway's export capacity towards Sweden. The bottleneck is effective during cold winter days and if the outdoor temperature in Oslo exceeds -10^{o}C Norway's export capacity to Sweden is reduced below the normal level of 2050 MW. This illustrates behaviour in Norway that potentially reduces Sweden's security of supply as it reduces Sweden's import possibility from Norway in periods with cold weather and thus high electricity demand in Sweden as well.

A better Nordic solution would have been to define the Oslo-area as a bidding area that under cold weather conditions would get a higher price than western Norway and probably the same price as southern Sweden. This would give consumers in the Oslo area an incentive to reduce consumption (and a few producers an incentive to increase generation) and thereby make more electricity available for export to Sweden.

In Norway, all electricity consumers with an annual consumption above 100 000 kWh have equipment for hourly metering. Thus, 60 percent of the Norwegian electricity consumption is hourly metered. On this background, hourly price variations represent a strong incentive to adjust consumption. In periods with congestion from west into the Oslo-area and high prices in Sweden due to cold weather, potential consumption reductions in the Oslo area should not be underestimated. This will typically be a peak-load problem and studies indicate that consumers with hourly metering actually reduce comsumption in hours with particular high prices.

4.2.4 Sweden

As described in section 2.2.4 Sweden has four bottlenecks; cut 1, cut 2, cut 4 and the west-coast corridor. In principle, transmission congestions in the cuts 1, 2 and 4 are associated with a large hydro power production and export to the south, while congestion in the west-coast corridor are associated with the transmission of significant quantities to southern Norway from Denmark and the continent. Thus congestion in cut 1, 2 and 4 occur regularly in relatively wet years while congestion in the west-coast corridor occur more often in dryer years and during off peak periods.

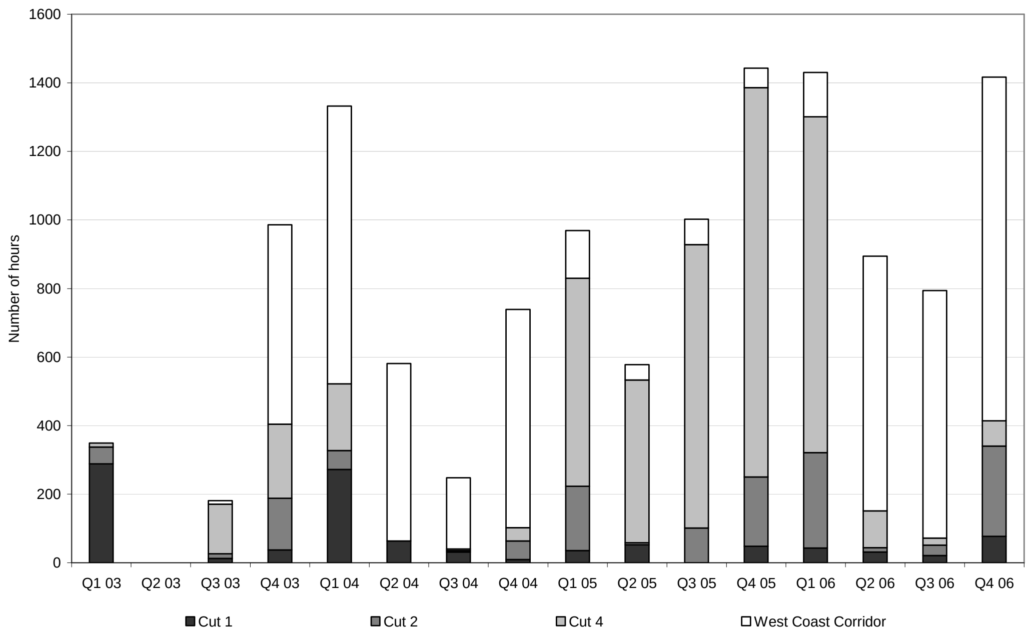

Figure 4.1 Number of indicated restrictions for respective cut 2003-2006

Source: Svenska Kraftnät and EMI

The figure 4.1 illustrates the variations between years and seasons for the congestion problems in the Swedish cuts. The figure shows the number of hours when the different cuts have indicated a need to limit interconnector capacity. This is situations when Svenska Kraftnät's forecasts have indicated that expected flows the following day would imply a risk for congestion in the internal Swedish cuts unless they would be dealt with through reductions on the interconnector capacity. Reductions increase the risk for market splitting on the borders.

Indicated restrictions due to southbound flow pattern (cut 1, 2 and 4) represent the most common restriction given normal (or above) filling rates in hydro power reservoirs. Cut 2 is the border between hydro power and thermal power in Sweden (approximately 85 percent of Sweden's hydro power capacity is located north of cut 2) consequently there is a positive correlation between hydro production and indicated restrictions due to cut 2. For the last five years cut 1 has indicated restrictions for 1071 hours, cut 2 for 1226 hours, cut 4 for 3970 hours and the west-coast corridor for 3080 hours. The shut down of the nuclear power plant in Barsebäck[10], located south of cut 4, has increased the stress on cut 4. However, the planned construction of the line Hallsberg-Malmö will be a reinforcement of cut 4. As for the west coast corridor the frequency of indicated restrictions varies between different years. As an example restrictions due to cut 4 was indicated 13 percent of the hours 2006 and as much as 39 percent of the hours 2005.

[10] The first reactor was closed in 1999 and the second in May 2005.

4.3 Monitoring

In January 2004, The Swedish government commissioned the Swedish regulatory authority to investigate into the consequences of different methods to handle congestions in the Swedish transmission network for electricity. In 2005, the report ”Hantering av begränsningar i det svenska överföringssystemet för el” was published.

In that report, EMI developed a method to determine the frequency of internal congestions and to allocate the observed price differences to congestions in the different cuts. In the following, we will give a short example of the method, as it was applied in 2005. This method seems to be one possible basis for de development of a monitoring model. This can be an example for how the regulators can develop methods for monitoring according to the Congestion Management Guidelines.

One of the challenges for the regulator was the lack of readily available information regarding the process behind the day to day allocation of capacity to Nord Pool Spot as well as information regarding counter trade. Thus, the first step in the investigation was to collect relevant information from Svenska Kraftnät and to analyse it. .

The figure 4.1 above in 4.2.4 is a representation of the first monitoring step for the internal Swedish bottlenecks. Svenska Kraftnät uses an excel spreadsheet model to determine how much trading capacity can be allocated to Nord Pool Spot for every hour the coming day taking into account known network conditions as well as the forecasted flows as well as “worst case flows” that can be anticipated. Too large flows are analysed and attributed to one or sometimes several bottlenecks within Sweden of between Sweden and the adjacent countries. Thus in the excel spreadsheet it is possible to see not only how much capacity can be allocated on interconnectors, but also which bottleneck is the limiting factor.

This diagram only shows how many hours Svenska Kraftnät has determined that less than “normal” trading capacity could be allocated to the market, not the consequences of the limitations. The interesting question is whether limitations lead to market splitting, and also how large the price differences are. In the question of how well the market works, it is also important to see which TSO has caused the largest limitation. These questions can, at least approximately, be answered by correlating the excel spreadsheet with data from Nord Pool FTP server. Ideally all TSOs should contribute their background data for limitations of trading capacity hour by hour.

The result was shown in diagrams with hours on the x-axis and SEK/MWh on the y-axis. The two diagrams below show price differences for Sweden to Denmark East and for the Hasle cut.

The diagrams show EMI calculations based on data for 2001 through June 2004. They are shown here basically as an example of what kind of data has been found useful in the analysis of the Swedish situation. It is important that the regulators have the possibilities to make their own calculations.

Figure 4.2 shows the situation between Sweden and Denmark East.

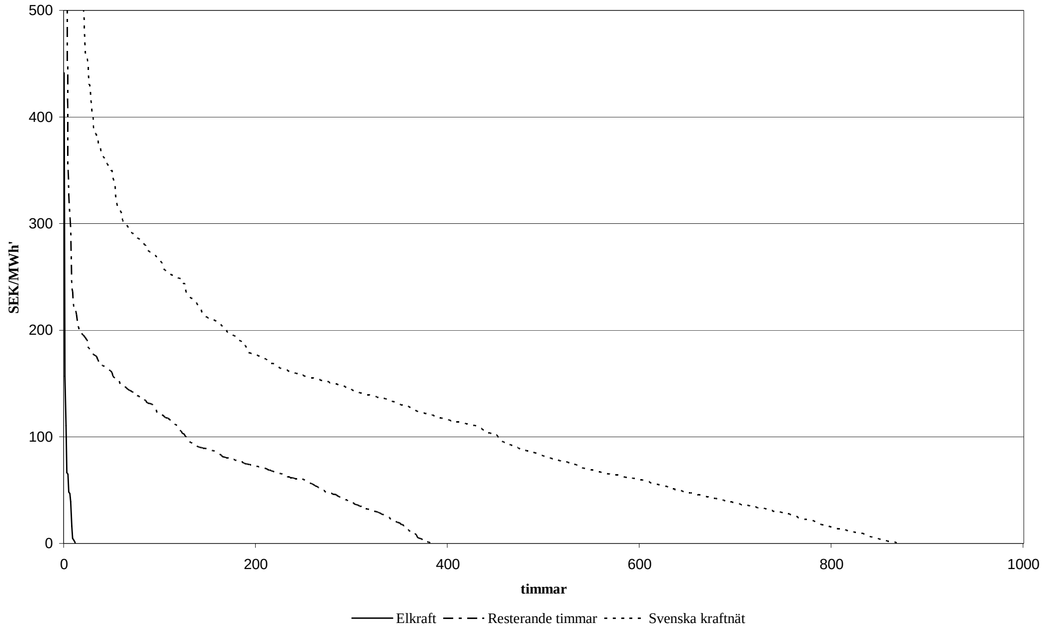

Figure 4.2 Price differences from Sweden to Denmark East, per limiting TSO, 2001 - 2004

Congestions from Sweden to Denmark East occurred during 1263 hours – 4 percent of the number of hours during the studied period. All these hours the price was higher in Denmark East than in Sweden. The largest price difference amounted to 2644 SEK/MWh and occurred during an hour when the allocated capacity had been limited by Svenska Kraftnät. During the period studied, the number of occasions was relatively low, but the price consequences for Denmark East were large.

Figure 4.3 shows the price differences for Sweden – NO1

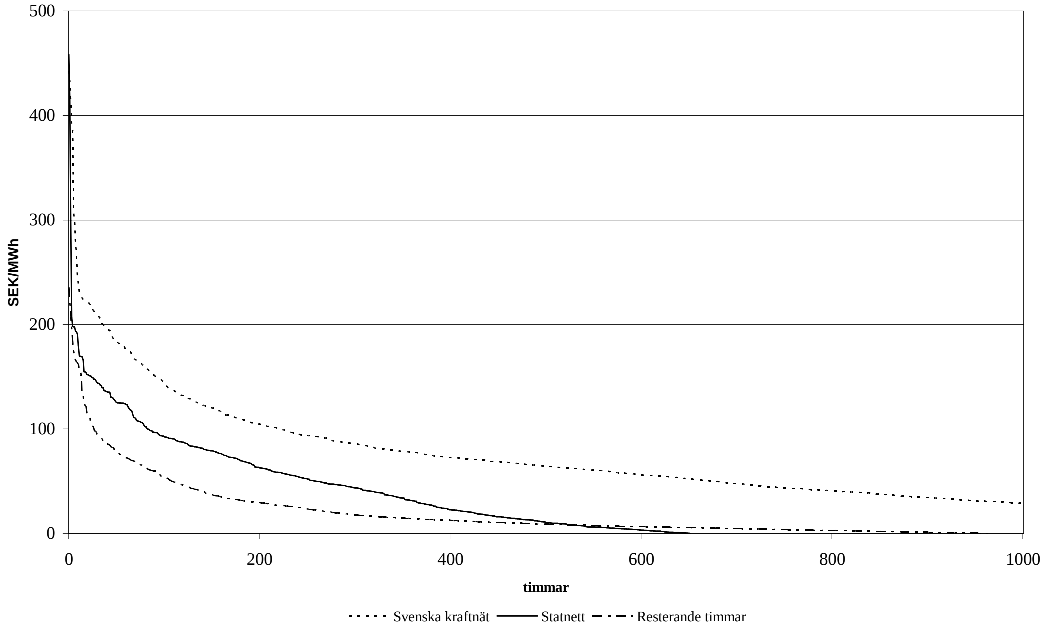

Figure 4.3 Price differences from Sweden to south Norway, per limiting TSO, 2001 - 2004

The number of hours with congestions from Sweden to southern Norway is 3656 or twelve percent of the time. During 2003 and the first half year of 2004 there were many limitations in the direction to Norway mainly due to the West coast corridor, but also due to limitations in cut 1 and 2. During the summer there were revisions that led to limitations from the Norwegian side. Problems related to the West coast corridor occurred for the first time during the dry year of 2003 and are thus related to the security of supply in Norway.

4.4 Competition issues

Competition issues are important to take into account when the issues of congestion management are discussed. The Nordic wholesale market consists of four former national markets that now form one or several bidding areas on the Nordic spot market. Since October 2005 there is also a northern German Elspot area, Kontek. Each of the national wholesale markets has a certain degree of ownership concentration when considered separately. The concentration in all bidding areas is to be regarded as high, with Norway as the least concentrated market and Denmark as the most concentrated.[11] Large national producers are often dominant in their national markets.

From this perspective the formation of a Nordic market implies a market enlarging effect, as market shares for national producers are decreased on a common Nordic market. There are a number of factors affecting the formation of price areas; the more capacity available for trade and the more similar the cost structure in terms of installed capacity in production technology between two given areas is, the more likely is the formation of a common price for the two areas. The market enlarging effect is maximized when there is a uniform Nordic spot price (about one third of the time in 2005 and 2006).

However, a congested interconnection between two Elspot areas leads to price differences between the areas. A price difference implies that producers in the two adjacent areas cannot compete on the same conditions, i.e. they do not meet the same price as marginal production capacity must come from producers in the area defined by the congested lines. Therefore market splitting implies a decreased size of the market, from one uniform Nordic market, to two or more price areas.

There exist around 50 different identified price area constellations[12] on the Nordic wholesale market; however the ten most common ones represented more than 80 percent of the hours in 2005. The ten most frequent price area constellations during 2005 are presented in table 4.1.

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[11] Refers to the results in the Nordic Competition Authorities report *A Powerful Competition Policy* from 2003.
[12] The term *Price area constellation* refer to how the Nordic Elspot areas (Kontek excluded) split in one or more area prices under a given hour.

Table 4.1 Ten most frequent price area constellations 2005

Price area constellations	Hours	Share of year
Nordic area one price	2777	31,7%
Denmark West isolated, remaining areas one price	1985	22,7%
North Norway isolated, remaining areas one price	426	4,9%
North Norway and Denmark West isolated, remaining areas one price	400	4,6%
South Norway and Denmark West isolated, remaining areas one price	357	4,1%
Denmark East and West isolated, remaining areas one price	334	3,8%
Denmark East isolated, remaining areas one price	255	2,9%
Finland and Denmark West isolated, remaining areas one price	250	2,9%
Denmark West, South Norway and North Norway isolated, remaining areas one price	207	2,4%
South Norway isolated, remaining areas one price	204	2,3%

Source: Energy Markets Inspectorate based on data from Nord Pool.

One measurement that is often used to measure concentration on markets and therefore to assess the preconditions for competition is the basic concentration measurement index Herfindahl-Hirschman Index (HHI).

Figure 4.4 shows the Herfindahl-Hirschman Index (HHI) based on capacity shares for the producers in respective Elspot area during the first four months in 2006.[13] Depending on how different areas form common price areas market concentration (or size), from the perspective of each Elspot areas, varies between isolated concentration (in general the highest figure) up to Nordic area as one common price area. It is important to note that concentration is only one indicator of one aspect of the competitive conditions on the the market; however it represents the potential and beneficial effects of a larger market resulting from the Nordic market model. Furthermore HHI can be expected to correlate with other indices of market power that in general are believed to provide a better representation of the special conditions that exist on a electricity market (RSI or PSI).[14]

[13] Calculations are based on public data, such as annual reports and/or data trade association (organization) such as Nordel or Swedenergy, or public reports by relevant authorities. Where available the 15 largest producers within in a given price areas constellation are included. This implies between 60 and 96 percent of total available capacity used in calculations.

[14] As a large producer will be pivotal (Pivotal Supplier Index) and have a positive residual demand (Residual Supplier Index) more often.

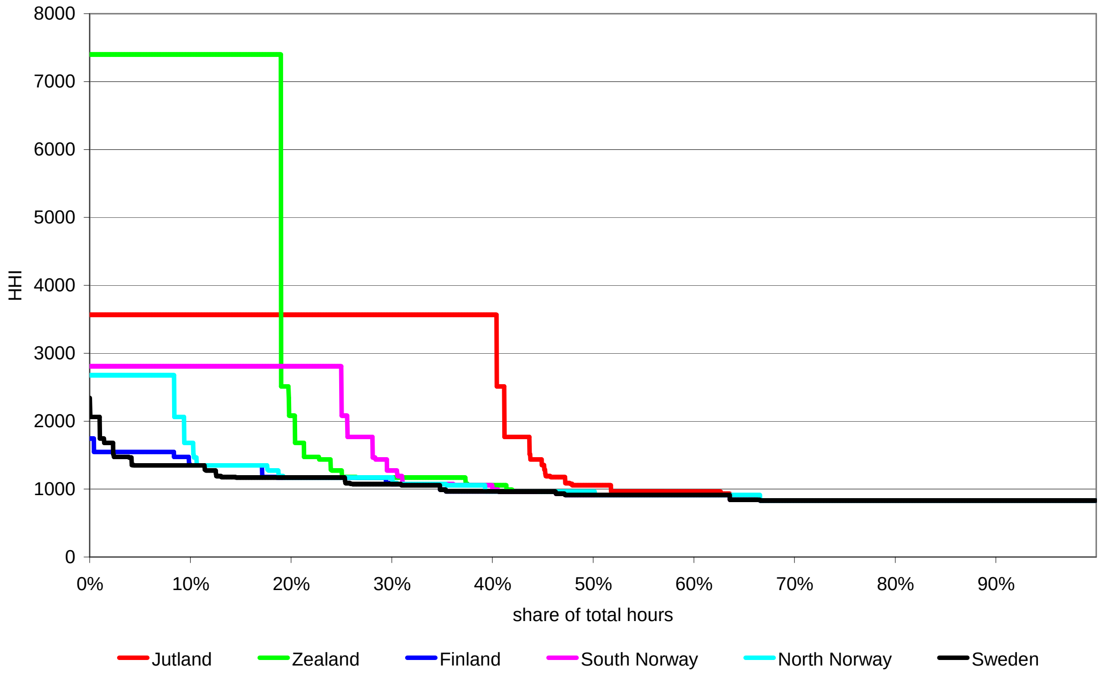

Figure 4.4 Market concentration for each Elspot area related to the share of hours. January through April 2006[15]

The market enlarging effect of the Nordic market is an important goal for the Nordic market. Consequently, the competition aspects of the question of what are the optimal bidding areas are important. The HHI measure has only been applied to the wholesale market. Another concern linked to the issue of the optimal number of bidding areas is the competition on the retail market.

It is important in the future discussion regarding congestion management to take competition issues into account.

[15] Figure 4 is constructed as duration curves where hours with the highest concentration are found on the left hand side of the diagram. The concentration measure is based on price area formations on Nord Pool Spot. A deeper description of the method can be found in Energimarknadsinspektionen (2006).

5 Congestion management guidelines

5.1 European rules regarding Congestion Management

The Regulation 1228/2003 provides in Article 8(4) for the Commission to "… amend the guidelines on the management and allocation of available transfer capacity of interconnections between national systems set out in the Annex, in accordance with the principles set out in Articles 5 and 6, in particular so as to include detailed guidelines on all capacity allocation methodologies applied in practice and to ensure that congestion management mechanisms evolve in a manner compatible with the objectives of the internal market. …"

Based on Regulation 1228/2003 Congestion Management Guidelines have been amended for the management and allocation of interconnection capacity by the 1st of December 2006. They are based on the following principles arising from the Regulation:

- economic efficiency and promotion of competition,
- maximization of capacity available and use of interconnectors,
- transparency on a non-discriminatory basis,
- secure network operation, and
- revenue neutral mechanism.

It should be noted that the Guidelines are not yet legal in Norway. The Ministry has sent the guidelines on a national hearing, and they will be treated in accordance with the EEA procedure.

The Congestion Management Guidelines define the basic requirements for coordinated congestion management, which is congestion management with a wider scope than a single, bilateral congestion of interconnection capacity between two TSOs. However, the Guidelines do not specify the details of operational procedures to be applied for coordinated congestion management. Only the basic definitions of key concepts are provided within the scope of Congestion Management Guidelines.

In this context the structural congestions shall be managed by the Guidelines. Here structural congestions are congestions that frequently limit the cross-border electricity exchange. Congestions can occur either at the interconnections between or internal to a TSO's control area. Frequent or even systematic congestions within a TSO's control area, which do not significantly limit cross-border flows, are not considered as structural congestions in these Guidelines. Structural congestions may involve one or more transmission lines.

In the context of the Guidelines, intermittent congestions are sporadic congestions, either at the interconnection between TSOs or internal to a TSO, that may occasionally limit the cross-border electricity exchange. Intermittent congestions can be solved by the TSOs concerned without permanently and significantly constraining cross-border electricity exchange. Structural congestions require the establishment of allocation procedures for the pricing of capacity. Where there is no congestion, prices will fall to zero or bidding areas have same prices.

Coordination shall be applied regionally, where seven regions exist across EU. The Nordic countries belong to Northern Europe Region together with Germany and Poland. However, the congestions management methods shall be compatible in all these regions with an ultimate goal to form a truly integrated Internal European Electricity Market.

Regulation 1228/2003 states in Article 6(1) that: "… Network congestion problems shall be addressed with non-discriminatory market based solutions which give efficient economic signals to the market participants and transmission system operators involved. …". This implies that congestion management mechanisms must include a mechanism whereby potential network users reveal the value they are willing to pay for access to the interconnectors in question. This requires some form of allocation procedure whereby network users must bid for the available capacity in some way, whether directly or indirectly and capacity is to be allocated for those who value it the most.

However, a number of assumptions relating to the European market structure has to be taken into account in order to promote the economic efficiency of the electricity market. Accordingly, congestion management methods should not hinder market contestability, should not inhibit the entry of any player, including end users, and should neither facilitate nor consolidate the abuse of any market power.

In addition, the adopted method for congestion management should not result in undue transaction costs to market participants or TSOs. Finally, in the interests of promoting competition and allowing for a range of different contract structures, any differences in the way different transactions are treated, for example short term trading between organised markets or longer term bilateral contracts, should be permitted only when they are shown not to distort or hinder the development of competition.

Article 6 of the Regulation 1228/2003 specifies the requirements on maximizing the available capacity. The need to maximise the use made of available capacity is also interpreted in the Guidelines to imply the facilitation by TSOs of integration of organised wholesale day ahead and intraday markets. This is ensured through an appropriate sequencing of allocation procedures and transfer of information. This is considered particularly relevant where such market integration automatically allows for any unused capacity to be transferred to other users. However the guidelines do not rule out other procedures to ensure that the use of available capacity is optimised.

Sufficient information should be available on a non-discriminatory basis to ensure the functioning of electricity market. Therefore special attention to the transparency of the wholesale markets in all areas affected by any congestion should be paid.

Article 5(3) of the Regulation includes already the requirements relating to transparency. In particular "… Transmission system operators shall publish estimates of available transfer capacity for each day, indicating any available transfer capacity already reserved. These publications shall be made at specified intervals before the day of transport and shall include, in any case, week-ahead and month-ahead estimates, as well as a quantitative indication of the expected reliability of the available capacity. …"

In addition, other information, e.g. information on short term forecast and realised system load and information on the installed generation capacity, is also required to ensure that the interests of economic efficiency and the promotion of competition are fulfilled and a congestion management method complying with Regulation and Guidelines shall be able to deliver transparency accordingly. Regulatory Authorities shall regularly evaluate the congestion management methods, with respect to compliance with the principles and rules established in the Electricity Regulation and Guidelines. The evaluation process shall include consultation with relevant parties and stakeholders and it shall pay special attention to the issue of transparency.

Article 6(6) of Regulation 1228/2003 discusses the use to be made of any revenues collected as a result of congestion management mechanisms. Regulators are required to implement the requirements of Article 6(6) and should therefore ensure that revenues are accounted for in a transparent way.

According to the Guidelines the use of congestion revenues for investments in maintaining or increasing the interconnection capacity should preferably be assigned to specific predefined projects with a clear compromise to accomplish them in a reasonable time. Regulators shall be transparent regarding the use of congestion revenues and they shall publish annually a report setting out the amount of revenue collected and verify that the use complies with present Regulation and Guidelines.

TSOs shall have a procedure for the distribution of the congestion revenues. The income shall be shared among TSOs involved according to criteria agreed by TSOs. These criteria shall be reviewed by respective Regulatory Authorities.

5.2 Relevant provisions of the Congestion Management Guidelines

Many of the provisions in the Congestion Management Guidelines are already in place in the Nordic countries. The allocation process between the Nordic countries is implicit auction in the day-ahead trade where both energy and transmission capacity allocation happens simultaneously. Unused transmission capacity after the day-ahead allocations can be used for intra-day trade (continuous trade model).

The dominant allocation system in Europe is explicit auction, where fractions of the capacity is allocated on for instance a yearly, monthly, weekly and often a day-ahead basis. While the Congestion Management Guidelines explicitly requires that intra-day trade shall be made available, it also gives clear acceptance to the Nordic model, where all transmission capacity on interconnectors are given to Nord Pool for allocation. According to 2.8 "in regions where forward financial electricity markets are well developed and have shown their efficiency, all interconnection capacity may be allocated through implicit auctioning. Further, in 3.3, "The regions referred to in 2.8 may allocate all interconnection capacity through day-ahead allocation."

Even though the Nordic electricity market is well developed compared to continental Europe, the Congestion Management Guidelines will lead to changes for both TSOs and regulatory authorities in Nordic countries.

For regulators the Guidelines give tasks, among others:

To publication of annual report on congestion management income –

to verify that the use of congestion management income comply with the Regulation and the Guidelines

- to be transparent regarding the use of congestion income
- to evaluate regularly the congestion management methods and their compliance with the Regulation and the Guidelines, including consultation and dedicated studies

Besides these tasks there are some issues which are subject to review by regulators or have to be notified to regulators. These issues are mapped in appendix B.

According to the Guidelines Nordic TSOs have to act in more coordinated way and they shall have a common coordinated congestion management method according to the Guidelines and this coordination requirement includes also German and Polish TSOs as they belong also to the Northern Region. The congestion management methods on the interconnectors from Nordic countries to the continental Europe are not yet fully in line with the Guidelines and this requires further work..

The issue with merchant links from Nordic countries to continental Europe shall be also solved in the context of the Guidelines. It should be noted, that the Regulation does give exceptions to new merchant links under certain conditions. The Regulation does not, however, mention existing ones (such as Swe-Pol link and Baltic Cable). According to the Commission[16], this should be interpreted in the following way: There is no exception for the requirement to open the links for third party access. On the other hand, where the Congestion Management Guidelines give provisions for how congestion income should be used, this does not apply to income that is not related to congestion. Put in other words, companies that have invested in commercial links should be allowed to have a fair payback of their investment.

According to the Guidelines, by not later than 1 January 2008, mechanisms for the intra-day congestion management of interconnector capacity shall be established in a coordinated way and under secure operational conditions, in order to maximise opportunities for trade and to provide for cross-border balancing.

According to the Guidelines TSOs are not allowed to limit interconnection capacity in order to solve congestion inside their own control area except for reasons of cost-effectiveness and minimisation of negative impacts on the Internal Electricity Market and for reasons of operational security. If such a situation occurs, TSOs have to describe transparently the situation. Such a situation may be tolerated only until a long-term

[16] Minutes from the meetings with the committee

solution is found. The methodology and projects for achieving the long term solution shall be described in a transparent way.

Besides, TSOs have to optimise the degree to which the capacity is firm and how to allocate the capacity between different time frames. This provision may affect the Nordel area since different time frames are used on other interconnectors in the Nordic Region.

Transparency on network availability, network access and network use shall be increased according to the Guidelines. This leads to revisions on information made available either on TSOs or on Nord Pool website because all required information on forecasts, ex-post information or descriptions of schemes are not yet publicly available. According to the Guidelines TSOs shall be responsible for publishing of the information, but it is more convenient and practical to publish most of the information at the Nord Pool website. Nord Pool has also an active role in search of market coupling method between the Nordic and the Continental market.

5.3 Conclusions regarding implementing of the Guidelines

The roles of the regulatory authorities in the Nordic countries with regard to capacity allocation and congestion management vary. The opening of the European markets and the vision of a single market for electricity has led to a process where the roles of the regulatory authorities need to be strengthened and more harmonised.

It is concluded that implementation of the Congestion Management Guidelines should be further evolved among the Nordic regulators. To start the further implementation process, Appendix B maps the relevant topics in the Guidelines where the priority lies for discussions among Nordic regulators in the first year of implementation.

6 Conclusions and identified issues for further work

Congestion management is one of the most important features of an integrated electricity market. The creation of the Nordic electricity market and the challenges ahead in integrating the Nordic market into the Northern regional market and eventually in a single European market creates new flow patterns. New rules have been adopted by the EU: the Directive 2003/54/EC, the Regulation 1228/2003 and the congestion management guidelines that came into force on December 1, 2006. The Nordic TSOs are working together in order to create more harmonised methods to manage congestions, and in order to enhance the market. The difficulties in this work have been huge, partly due to the international scope of cross border trade while the TSOs and the Regulatory Authorities have to follow national laws and regulation.

The increasing trade has led to new flow patterns, and the limits for the market expand continuously. This leads to increased difficulties for TSOs as well as market players to forecast flows. In order to fulfil on the provisions in the Directive, Regulation and Guidelines, the Regulatory Authorities need to develop new tools, and it is important for the Nordic Regulators to develop common tools and to implement the Guidelines in a common way.

In this report problems in the present methods of capacity allocation and congestion management have been described briefly. NordREG does not make any assessment as to how these problems should be addressed. It is important for the Regulatory Authorities to play an active role in the development of congestion management methods and recommendations for how transparency shall be ensured.

NordREG needs to develop a common practical interpretation of the congestion management guidelines taking the interface with central Europe into account. Work focusing on this issue is included in the NordREG Work Programme 2007. In Appendix B to this report the work group has mapped issues that need special regulatory attention, such as the role for regulatory authorities, processes and tools for monitoring. Thus, the report is intended to give input to the new NordREG task on implementation of Congestion Management Guidelines.

It is important for the regulatory authorities to develop competence and new methods for monitoring congestion management practices. Some starting points have been presented in this report. NordREG presents the following areas for further consideration:

- the need for the regulatory authorities to define a common view on what kind of data and methods that are needed in order to identify and analyze problems,
- studies together with the Nordic competition authorities on the competition problems related to price differences in order better to understand how to find an optimal balance between competition issues and efficiency related to congestion management methods.

Finally, the current representation of the physical network in the market splitting model is very simplified. This often leads to a need for the TSOs to restrict the capacity on interconnectors given to the market due to the uncertainty regarding the physical flow that will result from the anticipated trade the following day. It may therefore contribute to a less efficient utilisation of interconnector capacity than would be possible with a more accurate model. As the number of interconnectors increases as well as the trade, this problem can be expected to increase. In the long run, therefore, new models need to be developed. The regulatory authorities have an important role in this development.

This issue has broad technical, economical and policy implications and therefore NordREG invites the Electricity Market Group to consider how to organise a study whether a better representation of the physical network in the trading model would lead to a more efficient use of the existing transmission network and thus make it possible to use the interconnector capacity more efficiently – one part of such a study could be to assess the benefits of introducing elements of the nodal pricing "philosophy"

Appendix A: Congestion management methods in theory and practice

Electricity generation costs and availability vary by time and location and so do electricity demand and marginal willingness to pay for electricity. There are variations in generation mix, production costs and consumption patterns across the Nordic countries. Volatile amounts of precipitation to the hydro plants in Norway, Sweden and Finland are to some extent taken care of by utilization of large hydropower dams, but still there are often huge seasonal and regional differences in the hydropower production potential. In addition, the value of electric power varies over time and across regions due to:

- Demand fluctuations over the day
- The existence of thermal power plants for which starts and stops are costly
- Daily variations in supply and demand in the Nordic power exchange with non-Nordic countries

Large regional differences in the value of electric power introduce demand for transportation of electricity. In order to be able to transport electricity there is a large high-voltage transmission network in the Nordic area. This network has presently interconnectors to Russia, Poland, Germany and Estonia. In addition, an interconnector between Norway and the Netherlands is under construction.

The demand for transmission of electricity through the Nordic grid is often larger than the available transmission capacities. While substantial reinforcements in the Nordic transmission system are planned to be made in the coming years, it is in general not economically efficient to expand the network capacities to a level where the demand for transmission is met in all hours and at all interconnectors. Thus, we have at least two regulatory challenges:

1. How should the existing transmission grid be utilized?
2. How should the transmission grid be expanded?

The common Nordic challenge is to establish a market design concerning transmission utilization and expansion which leads to a truly common Nordic market which can be further integrated with the continental Europe. Below, we focus on the utilization question.

A.1 The nature of electric networks

Physical laws govern the power flow within an electricity network. The grid configuration, power injections and withdrawals determine the power flow of the network. All power injections, withdrawals and flows have to be feasible given the existing grid. If not feasible, the power system will collapse. Thus, security of supply and management of the network, injections and withdrawal are closely related.

Since electricity follows its own physical laws, the challenge for liberalized electricity markets is that they have to be designed and managed in a way that leads to feasible power flows.

The choice of market design has to strike a balance between different interests. For instance efficiency and security of supply have to be weighted towards transparency and simplicity for producers, consumers, traders and suppliers. In the area of capacity allocation and congestion management, the challenge is to find a good compromise between the theoretically optimal solution that would give the most efficient utilisation of the grid – such as nodal pricing on one hand, and the need to create larger areas with the same price in order to create a market that encourages competition and limits the risk for the market players on the other hand.

The challenge in the Nordic market is thus to find a model for congestion management that as correctly as possible reflects the physical properties of the grid while maintaining a transparent market mechanism that furthers competition.

A.2 Nodal pricing

In general, maximization of consumer and producer surplus will determine generation and consumption levels which give the maximum social welfare. Within an electric power system, the maximization is subject to restrictions given by the existing network. Electric power flows within a transmission network are governed by physical laws and these laws represent important constraints to the maximization problem. Normally, injection or withdrawal of power from the grid impact power flows, network capacities and security all over the grid. The optimal solution of the welfare maximization program would determine benefits of injections (or symmetric costs of withdrawals) across the grid. Theoretically, this welfare maximizing solution can be realized by a nodal price market design[17].

Within a nodal price system the market players submit sell and buy bids at each network node. A network node may for instance be defined as an injection and/or withdrawal point in the transmission grid[18]. Based on the bids, the physical flow pattern of the available grid and its security standards, the TSO or power exchange may then calculate the security constrained economic dispatch and the nodal prices throughout the grid. Here nodal prices, power injections, withdrawals and power flows would be determined simultaneously.[19]

This market design has several important features:

- The utilization of each transmission line is determined as an integrated part of the price calculation. The transmission system operators (TSOs) specify and submit availability, security restrictions and the physical characteristics including thermal capacity of their interconnections and power exchange submit the nodal

[17] See Schweppe et al (1988).
[18] Norway and Sweden have today around 150 such ”points” or nodes each in their central grids.
[19] When nodal prices and power flows are fixed simultaneously, transmission ”capacities” are allocated implicitly as part of the optimization procedure.

bids for injection and/or withdrawal. These data are combined together to define nodal prices and power flows

- Nodal prices have a strong justification in theory as they are the optimal prices within the existing power system, and no market participant should claim prices or power flows to be unfair[20].

The nodal pricing model described above can be seen as a theoretical benchmark for an optimal market design, implicitly combining transmission grid characteristics and price bids. In order to get a solvable and stable optimization problem some simplifications have to be introduced[21]:

- Simplified representation of the physical power flows
- Limiting the number of nodes through aggregation

The question is thus: Could the existing Nordic transmission network be more efficiently utilised with a modified pricing model?

Several North American states apply a nodal price market design, as it is standard market design in liberalized electricity markets in the US. The most well-known area is PJM (Pennsylvania, Jersey, Maryland) which have had nodal prices since 1998. New-England applies nodal prices as well[22]. Argentina and New Zealand are other countries who rely on nodal pricing systems for their power systems.

From practical experience in the PJM area in the US it has been found out that although nodal prices are defined for every node, however, zonal pricing is applied for the day-ahead market because suppliers prefer zonal pricing. Here nodal prices may differ largely from zonal prices especially during peak consumption[23]. Nodal prices represent congestions but market participants do not necessary see these due to zonal pricing.

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[20] Nodal prices do not change the physical facts. If a producer (or consumer) has market power, nodal prices may make market power abuse more visible as it will be reflected in the nodal prices if these prices are published and made thus transparent. Without nodal prices the market power may be applied in regulation market and towards TSOs.

[21] A standard approximation for active power flow calculations is that the network power flow solution is based on DC power flow. The optimal power flow is found by solving a nonlinear maximization problem.

[22] In Texas a nodal wholesale market design is planned to come into operation in 2009. This nodal implementation is expected to deliver improved price signals and dispatch efficiencies as well as direct assignment of local congestion.

[23] More information on PJM website: www.pjm.org

A.3 Zonal pricing

For practical reasons it is necessary to aggregate several nodes into one zone with identical price. How the aggregation is done is crucial for efficiency and security of supply. The figure below shows two ways to aggregate nodes into zones – economic aggregation and physical aggregation, see figure A.1. These two ways of aggregating will be described further in the following sections.

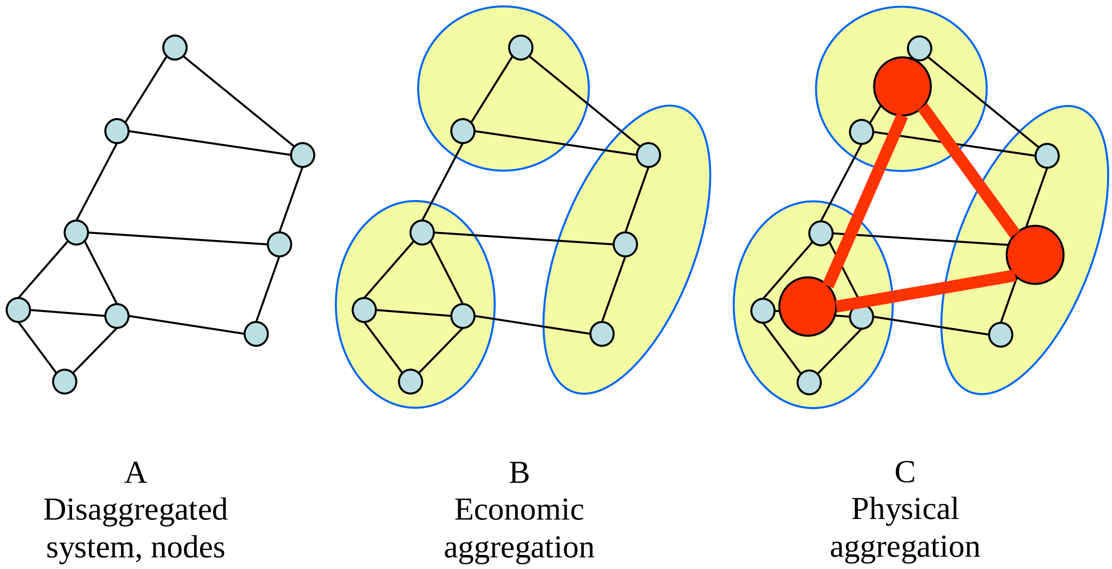

Figure A.1 Economic versus physical aggregation of nodes and network connections. Source: Bjørndal and Jørnsten (2007

A.3.1 Economic aggregation

A zonal pricing model implies a set of constraints, requiring that the prices are uniform within zones. Since we add constraints, zonal pricing through economic aggregation may be second best to optimal nodal prices in terms of social welfare. Economically aggregated zonal prices use the nodes and links of the original disaggregated network, i.e. with all the details of the DC model. This means that the resulting flows will be feasible.

One drawback of the nodal model is obviously that it requires very detailed data regarding injection and withdrawal, which may not be normally provided by the market players. This drawback also relates to the economically aggregated model.

The larger and fewer zones, the less close is the outcome to the optimal nodal solution. However, few and large zones have benefits with regard to simplicity and a level playing field for market players.

A.3.2 Physical aggregation

If we aggregate nodes before the welfare maximizing problem is solved, intra-nodal constraints are not represented and thus not taken into account explicitly. This is a relaxation giving a less restricted model. Thus, the results of this model may not be feasible in the original system. This is also the case if we aggregate lines in the network, by simply adding the capacities of the individual lines in a zonal cut. Moreover, disregarding the electrical laws of power flows (Kirchhoff's laws) represents a relaxation and a less restrictive model.

In order to have the solution of the relaxed problem to become feasible, or less infeasible, further constraints may have to be added. These are restrictions on the flow variables in the aggregated physical network model, i.e. capacity constraints. In order to set these constraints, the TSO has to "guess" the levels of production, demand, imports and exports and on this basis set the capacities through certain bottlenecks low enough to make sure that the bottlenecks will not be overloaded. Since the uncertainties are sometimes high, system operators may have incentives to be on the "safe side", in order to avoid too much costly counter trading in the regulation / balancing market and, in the extreme, to avoid system collapse.

A.3.3 Example of physical vs economic aggregation

Figure A.2 introduce the principle showing for simplicity three nodes, two generation nodes (A and B) and one consumption node (C).

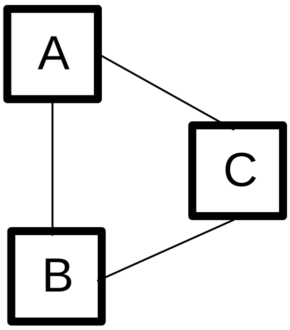

Figure A.2

We have an electrical system with three nodes; A, B and C. A and B are generation nodes, while there is consumption in node C. There are transmission lines between each pair of nodes.

Physical aggregation
Node A and B are physically aggregated into one "zone". The connections B-C and A-C are physically aggregated into one virtual transmission connection between the "zone" and node C. See figure A.3

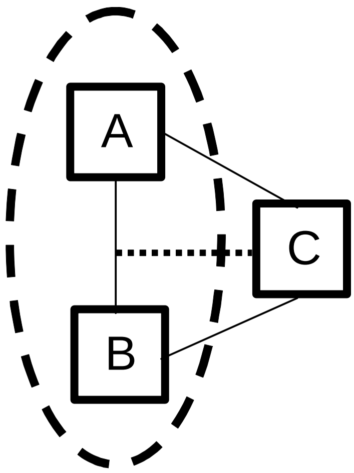

Figure A.3

The TSO has to declare transmission capacity for the ”virtual connection” between the ”zone” and node C. Given this capacity, the power exchange utilizes the ”virtual connection” in the best possible way.

Let all the connections; A-B, A-C and B-C, be identical and have a capacity of 600 MW. The identical lines leads to flows where one third of the generation in node A goes via node B to node C and two third of the generation in node A goes directly to node C. The same pattern applies for generation in node B. The transmission capacity of the ”virtual connection” will then have a maximum of 1200 MW only if there is a generation of 600 MW in each of the nodes A and B. Other distributions of 1200 MW generation will not be feasible. Since the TSO does not know the generators' sale bids, he will probably reduce the capacity of the ”virtual connection” in order to reduce the probability of overload on the lines A-C and B-C. Alternatively, there may be an export cable from C to a node D to the right in the figure. In order to reduce demand in node C, he may reduce capacity from C to D.

In order to avoid overload and/or need for counter trade, he has to reduce demand in node C (or the capacity of the ”virtual connection”) to maximum 900 MW.

Given the 900 MW limit, there will be a large probability for an outcome with spare transmission capacity.

Economic aggregation

In this case, the power exchange collects bids in node A, B and C, and calculates generation in A and B and transmission flow A to C and from B to C simultaneously given a constraint of common price in node A and B.

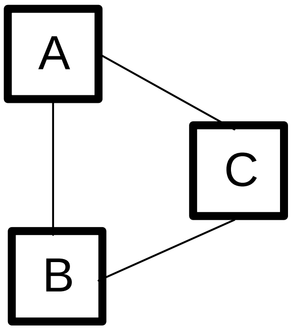

Figure A.4

It is only in the (worst) case with bids in A and B that result in 900 MW generation in one of the nodes and zero in the other, that the economic aggregation will result in the same outcome as the physical aggregation. For other distributions of the generation of 900 MW between nodes A and B, there will be spare capacity on the lines A-C and B-C, and generation may be increased in both node A and B (depending on bids), and the network will still not be overloaded. Thus, there is a large probability that this method results in a higher utilization of the transmission grid than in the case with physical aggregation.

An even better result could be obtained if prices in A and B were allowed to differ.

A.5 Congestion management methods

The Nordic market design for congestion management and Nord Pool's solution like in most European markets build on physical aggregation. Transmission constraints affect several submarkets in the Nordic power market, i.e. Elspot, Elbas and the regulation or balancing markets, however, our main focus is on the Elspot hourly day-ahead market.

The spot market constitutes simultaneous trade with energy and transmission capacity where congestions between bidding areas (Elspot areas) are handled by establishing price areas, so called market splitting. However, at Nord Pool Spot, a large number of nodal locations are grouped into a few zones or bidding areas. There is one bidding area in Sweden, one in Finland, one in Denmark West, one in Denmark East, and one for the German area Kontek. Norway is normally divided into two to four bidding areas. The number of Norwegian bidding areas may be increased further in case of long-lasting internal constraints in the Norwegian part of the market.

In the operational planning phase the Nordic TSOs have the responsibility to determine the transmission capacity of respective grid and calculate possible risk for overload, under voltages or instability. The capacity of the grid may depend on factors such as planned outages due to maintenance and the location of forecasted consumption and production within as well as forecasted flow through a bidding area. The calculated capacities result in an available capacity for trade between bidding areas. Elspot capacity for each hour, interconnector and direction is set bilaterally by involved TSOs. The lowest figure in respective direction is the available trading capacity applied by Nord Pool Spot. The TSOs determine the amount of capacity made available to the spot market from 09:30 the day before the operational phase. The Nordic Grid Code governs the capacity calculation across the interconnectors.

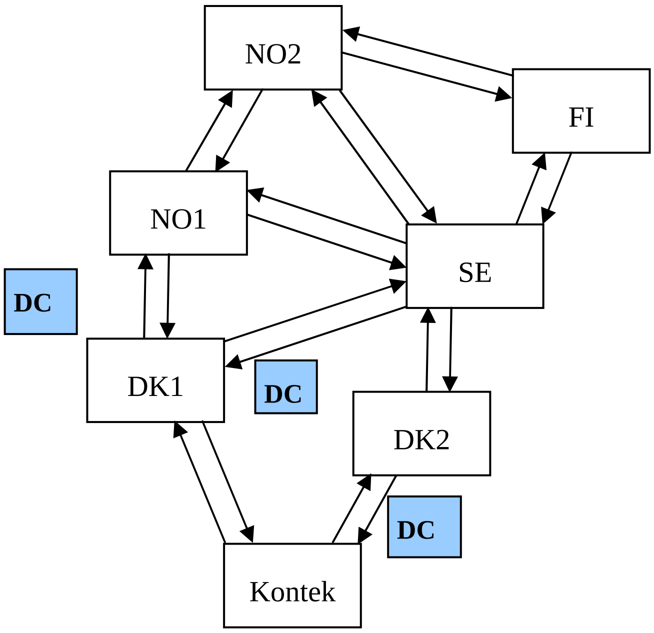

Figure A.2 The Nord Pool network model – physical aggregation

The system price that is computed on the basis of the bids to Nord Pool, corresponds approximately[24] to an unconstrained price, i.e. a price that does not take into account network constraints (except for Kontek that is always a separate price area).

In case of transmission constraints being violated in the first calculation, the computation of area prices proceeds by successively splitting the physically aggregated network into parts and computing new area prices. This procedure continues until feasible prices are found, resulting in a feasible power flow. The calculations are made with a simplified power flow model.

Thus, the following procedure is used:

1) The system operators determine transmission capacities between bidding areas for every hour the following day. Transmission capacities are communicated to Nord Pool Spot by 09:30.

2) Elspot-bids are delivered for the next 24 hours by the market players, deadline at 12.00.

3) The system price and area prices are computed ”day-ahead”, and prices are published by 13.00.

[24] Approximately because of the physical aggregation.

4) The capacities needed for the resulting trade are firm implying that congestions occurring during the operating hour are relieved by counter trade without any extra cost to the players.

Appendix B: CM Guidelines including assessment for future regulatory actions

The table consists of the EU Congestion Management Guidelines in force since 1 December 2007 copied from the original English text. Two columns have been added, the first column includes notes on tasks for the regulators. The second added column gives an assessment on the priority of the issue for the discussion on implementation.

B	Text	Regulator's tasks (**X**) and ex-post reviews (Y)	Priority issue for discussion in implementation
1	**General provisions**		
1.1	TSOs shall endeavour to accept all commercial transactions, including those involving cross-border trade.		X
1.2	When there is no congestion, there shall be no restriction of access to the interconnection. Where this is usually the case, there need be no permanent general allocation procedure for access to a cross-border transmission service.		X
1.3	Where scheduled commercial transactions are not compatible with secure network operation, the TSOs shall alleviate congestion in compliance with the requirements of grid operational security while endeavouring to ensure that any associated costs remain at an economically efficient level. Curative redispatching or countertrading shall be envisaged in case lower cost measures cannot be applied.		X
1.4	If structural congestion appears, appropriate congestion management rules and arrangements defined and agreed upon in advance shall be implemented immediately by the TSOs. The Congestion management methods shall ensure that the physical power flows associated with all allocated transmission capacity comply with network security standards.		X
1.5	The methods adopted for congestion management shall give efficient economic signals to market participants and TSOs, promote competition and be suitable for regional and communitywide application.		

1.6	No transaction-based distinction may be applied in congestion management. A particular request for transmission service shall be denied only when the following conditions are jointly fulfilled: (a) the incremental physical power flows resulting from the acceptance of this request imply that secure operation of the power system may no longer be guaranteed, and (b) the value in monetary amount attached to this request in the congestion management procedure is lower than all other requests intended to be accepted for the same service and conditions.		
1.7	When defining appropriate network areas in and between which congestion management is to apply, TSOs shall be guided by the principles of cost-effectiveness and minimisation of negative impacts on the Internal Electricity Market. Specifically, TSOs may not limit interconnection capacity in order to solve congestion inside their own control area, except for the above mentioned reasons and reasons of operational security. If such a situation occurs, this shall be described and transparently presented to all the users by the TSOs. Such a situation may be tolerated only until a long-term solution is found. The methodology and projects for achieving the longterm solution shall be described and transparently presented to all the users by the TSOs.		X
1.8	When balancing the network inside the control area through operational measures in the network and through redispatching, the TSO shall take into account the effect of these measures on neighbouring control areas.		X
1.9	By not later than 1 January 2008, mechanisms for the intra-day congestion management of interconnector capacity shall be established in a coordinated way and under secure operational conditions, in order to maximise opportunities for trade and to provide for cross-border balancing.		X
1.10	The national Regulatory Authorities shall regularly evaluate the congestion management methods, paying particular attention to compliance with the principles and rules established in the present Regulation and Guidelines and with the terms and conditions set by the Regulatory Authorities themselves under these principles and rules. Such evaluation shall include consultation of all market players and dedicated studies.	**X**	X

2	**Congestion management methods**		
2.1	Congestion management methods shall be market-based in order to facilitate efficient cross-border trade. For this purpose, capacity shall be allocated only by means of explicit (capacity) or implicit (capacity and energy) auctions. Both methods may coexist on the same interconnection. For intra-day trade continuous trading may be used.		
2.2	Depending on competition conditions, the congestion management mechanisms may need to allow for both long- and short-term transmission capacity allocation.		X
2.3	Each capacity allocation procedure shall allocate a prescribed fraction of the available interconnection capacity plus any remaining capacity not previously allocated and any capacity released by capacity holders from previous allocations.		X
2.4	TSOs shall optimise the degree to which capacity is firm, taking into account the obligations and rights of the TSOs involved and the obligations and rights of market participants, in order to facilitate effective and efficient competition. A reasonable fraction of capacity may be offered to the market at a reduced degree of firmness, but the exact conditions for transport over cross-border lines shall at all times be made known to market participants.		X.
2.5	The access rights for long- and medium-term allocations shall be firm transmission capacity rights. They shall be subject to the use-it-or-lose-it or use-it-or-sell-it principles at the time of nomination.		X
2.6	TSOs shall define an appropriate structure for the allocation of capacity between different timeframes. This may include an option for reserving a minimum percentage of interconnection capacity for daily or intra-daily allocation. This allocation structure shall be subject to review by the respective Regulatory Authorities. In drawing up their proposals, the TSOs shall take into account: (a) the characteristics of the markets, (b) the operational conditions, such as the implications of netting firmly declared schedules, (c) the level of harmonisation of the percentages and timeframes adopted for the different capacity allocation	Y	X

	mechanisms in place.		
2.7	Capacity allocation may not discriminate between market participants that wish to use their rights to make use of bilateral supply contracts or to bid into power exchanges. The highest value bids, whether implicit or explicit in a given timeframe, shall be successful.		
2.8	In regions where forward financial electricity markets are well developed and have shown their efficiency, all interconnection capacity may be allocated through implicit auctioning.		X
2.9	Other than in the case of new interconnectors which benefit from an exemption under Article 7 of the Regulation, establishing reserve prices in capacity allocation methods shall not be allowed.		X
2.10	In principle, all potential market participants shall be permitted to participate in the allocation process without restriction. To avoid creating or aggravating problems related to the potential use of dominant position of any market player, the relevant Regulatory and/or Competition Authorities, where appropriate, may impose restrictions in general or on an individual company on account of market dominance.	**X**	X
2.11	Market participants shall firmly nominate their use of the capacity to the TSOs by a defined deadline for each timeframe. The deadline shall be set such that TSOs are able to reassign unused capacity for reallocation in the next relevant timeframe — including intra-day sessions.		
2.12	Capacity shall be freely tradable on a secondary basis, provided that the TSO is informed sufficiently in advance. Where a TSO refuses any secondary trade (transaction), this must be clearly and transparently communicated and explained to all the market participants by that TSO and notified to the Regulatory Authority.	Y	.
2.13	The financial consequences of failure to honour obligations associated with the allocation of capacity shall be attributed to those who are responsible for such a failure. Where market participants fail to use the capacity that they have committed to use, or, in the case of explicitly auctioned capacity, fail to trade on a secondary basis or give the capacity back in due time, they shall lose the rights to such capacity and pay a cost-reflective charge. Any cost-reflective charges for the non-use of capacity shall be justified and proportionate. Likewise, if a	Y	X

	TSO does not fulfil its obligation, it shall be liable to compensate the market participant for the loss of capacity rights. No consequential losses shall be taken into account for this purpose. The key concepts and methods for the determination of liabilities that accrue upon failure to honour obligations shall be set out in advance in respect of the financial consequences, and shall be subject to review by the relevant national Regulatory Authority or Authorities.		
3	**Coordination**		
3.1	Capacity allocation at an interconnection shall be coordinated and implemented using common allocation procedures by the TSOs involved. In cases where commercial exchanges between two countries (TSOs) are expected to significantly affect physical flow conditions in any third country (TSO), congestion management methods shall be coordinated between all the TSOs so affected through a common congestion management procedure. National Regulatory Authorities and TSOs shall ensure that no congestion management procedure with significant effects on physical electric power flows in other networks is devised unilaterally.	**X**	X
3.2	A common coordinated congestion management method and procedure for the allocation of capacity to the market at least yearly, monthly and day-ahead shall be applied by not later than 1 January 2007 between countries in the following regions: (a) Northern Europe (i.e. Denmark, Sweden, Finland, Germany and Poland), (b) North-West Europe (i.e. Benelux, Germany and France), (c) Italy (i.e. Italy, France, Germany, Austria, Slovenia and Greece), (d) Central Eastern Europe (i.e. Germany, Poland, Czech Republic, Slovakia, Hungary, Austria and Slovenia), (e) South-West Europe (i.e. Spain, Portugal and France), (f) UK, Ireland and France, (g) Baltic states (i.e. Estonia, Latvia and Lithuania). At an interconnection involving countries belonging to more than one region, the congestion management method applied may differ in order to ensure the	Y	X

	compatibility with the methods applied in the other regions to which these countries belong. In this case the relevant TSOs shall propose the method which shall be subject to review by the relevant Regulatory Authorities.		
3.3	The regions referred to in 2.8. may allocate all interconnection capacity through day-ahead allocation.		
3.4	Compatible congestion management procedures shall be defined in all these seven regions with a view to forming a truly integrated Internal European Electricity Market. Market parties shall not be confronted with incompatible regional systems.		X
3.5	With a view to promoting fair and efficient competition and cross-border trade, coordination between TSOs within the regions set out in 3.2 above shall include all the steps from capacity calculation and optimisation of allocation to secure operation of the network, with clear assignments of responsibility. Such coordination shall include, in particular: (a) Use of a common transmission model dealing efficiently with interdependent physical loop-flows and having regard to discrepancies between physical and commercial flows, (b) Allocation and nomination of capacity to deal efficiently with interdependent physical loop-flows, (c) Identical obligations on capacity holders to provide information on their intended use of the capacity, i.e. nomination of capacity (for explicit auctions), (d) Identical timeframes and closing times, (e) Identical structure for the allocation of capacity among different timeframes (e.g. 1 day, 3 hours, 1 week, etc.) and in terms of blocks of capacity sold (amount of power in MW, MWh, etc.), (f) Consistent contractual framework with market participants, (g) Verification of flows to comply with the network security requirements for operational planning and for real-time operation, (h) Accounting and settlement of congestion management actions.		X
3.6	Coordination shall also include the exchange of		X

	information between TSOs. The nature, time and frequency of information exchange shall be compatible with the activities in 3.5. and the functioning of the electricity markets. This information exchange shall in particular enable the TSOs to make the best possible forecast of the global grid situation in order to assess the flows in their network and the available interconnection capacities. Any TSO collecting information on behalf of other TSOs shall give back to the participating TSO the results of the collection of data.		
4	**Timetable for market operations**		
4.1	The allocation of the available transmission capacity shall take place sufficiently in advance. Prior to each allocation, the involved TSOs shall jointly publish the capacity to be allocated, taking into account where appropriate the capacity released from any firm transmission rights and, where relevant, associated netted nominations, along with any time periods during which the capacity will be reduced or not available (for the purpose of maintenance, for example).		
4.2	Having full regard to network security, the nomination of transmission rights shall take place sufficiently in advance, before the day-ahead sessions of all the relevant organised markets and before the publication of the capacity to be allocated under the day-ahead or intra-day allocation mechanism. Nominations of transmission rights in the opposite direction shall be netted in order to make efficient use of the interconnection.		
4.3	Successive intra-day allocations of available transmission capacity for day D shall take place on days D-1 and D, after the issuing of the indicated or actual day-ahead production schedules.		X
4.4	When preparing day-ahead grid operation, the TSOs shall exchange information with neighbouring TSOs, including their forecast grid topology, the availability and forecasted production of generation units, and load flows in order to optimise the use of the overall network through operational measures in compliance with the rules for secure grid operation.		X
5	**Transparency**		
5.1	TSOs shall publish all relevant data related to network availability, network access and network use, including a report on where and why congestion exists, the methods		X

	applied for managing the congestion and the plans for its future management.		
5.2	TSOs shall publish a general description of the congestion management method applied under different circumstances for maximising the capacity available to the market, and a general scheme for the calculation of the interconnection capacity for the different timeframes, based upon the electrical and physical realities of the network. Such a scheme shall be subject to review by the Regulatory Authorities of the Member States concerned.	Y	X
5.3	The congestion management and capacity allocation procedures in use, together with the times and procedures for applying for capacity, a description of the products offered and the obligations and rights of both the TSOs and the party obtaining the capacity, including the liabilities that accrue upon failure to honour obligations, shall be described in detail and made transparently available to all potential network users by TSOs.		X
5.4	The operational and planning security standards shall form an integral part of the information that TSOs publish in an open and public document. This document shall also be subject to review of national Regulatory Authorities.	Y	X
5.5	TSOs shall publish all relevant data concerning cross-border trade on the basis of the best possible forecast. In order to fulfil this obligation the market participants concerned shall provide the TSOs with the relevant data. The way in which such information is published shall be subject to review by Regulatory Authorities. TSOs shall publish at least: (a) annually: information on the long-term evolution of the transmission infrastructure and its impact on cross-border transmission capacity; (b) monthly: month- and year-ahead forecasts of the transmission capacity available to the market, taking into account all relevant information available to the TSO at the time of the forecast calculation (e.g. impact of summer and winter seasons on the capacity of lines, maintenance on the grid, availability of production units, etc.); (c) weekly: week-ahead forecasts of the transmission capacity available to the market, taking into account all relevant information available to the TSOs at the time of calculation of the forecast, such as the weather forecast,	Y	X

	planned maintenance works of the grid, availability of production units, etc.; (d) daily: day-ahead and intra-day transmission capacity available to the market for each market time unit, taking into account all netted day-ahead nominations, day-ahead production schedules, demand forecasts and planned maintenance works of the grid; (e) total capacity already allocated, by market time unit, and all relevant conditions under which this capacity may be used (e.g. auction clearing price, obligations on how to use the capacity, etc.), so as to identify any remaining capacity; (f) allocated capacity as soon as possible after each allocation, as well as an indication of prices paid; (g) total capacity used, by market time unit, immediately after nomination; (h) as closely as possible to real time: aggregated realised commercial and physical flows, by market time unit, including a description of the effects of any corrective actions taken by the TSOs (such as curtailment) for solving network or system problems; (i) ex-ante information on planned outages and ex-post information for the previous day on planned and unplanned outages of generation units larger than 100 MW.		
5.6	All relevant information shall be available for the market in due time for the negotiation of all transactions (such as the time of negotiation of annual supply contracts for industrial customers or the time when bids have to be sent into organised markets).		X
5.7	The TSO shall publish the relevant information on forecast demand and on generation according to the timeframes referred to in 5.5. and 5.6. The TSO shall also publish the relevant information necessary for the cross-border balancing market.		X
5.8	When forecasts are published, the ex post realised values for the forecast information shall also be published in the time period following that to which the forecast applies or at the latest on the following day (D+1).		X

5.9	All information published by the TSOs shall be made freely available in an easily accessible form. All data shall also be accessible through adequate and standardised means of information exchange, to be defined in close cooperation with market parties. The data shall include information on past time periods with a minimum of two years, so that new market entrants may also have access to such data.		
5.10	TSOs shall exchange regularly a set of sufficiently accurate network and load flow data in order to enable load flow calculations for each TSO in their relevant area. The same set of data shall be made available to the Regulatory Authorities and to the European Commission upon request. The Regulatory Authorities and the European Commission shall ensure the confidential treatment of this set of data, by themselves and by any consultant carrying out analytical work for them on the basis of these data.	**X**	
6	**Use of congestion income**		
6.1	Congestion management procedures associated with a pre-specified timeframe may generate revenue only in the event of congestion which arises for that timeframe, except in the case of new interconnectors which benefit from an exemption under Article 7 of the Regulation. The procedure for the distribution of these revenues shall be subject to review by the Regulatory Authorities and shall neither distort the allocation process in favour of any party requesting capacity or energy nor provide a disincentive to reduce congestion.	Y	X
6.2	National Regulatory Authorities shall be transparent regarding the use of revenues resulting from the allocation of interconnection capacity.	**X**	X
6.3	The congestion income shall be shared among the TSOs involved according to criteria agreed between the TSOs involved and reviewed by the respective Regulatory Authorities.	Y	X
6.4	TSOs shall clearly establish beforehand the use they will make of any congestion income they may obtain and report on the actual use of this income. Regulatory Authorities shall verify that this use complies with the present Regulation and Guidelines and that the total amount of congestion income resulting from the allocation of interconnection capacity is	**X**	X

	devoted to one or more of the three purposes described in Article 6(6) of Regulation.		
6.5	On an annual basis, and by 31 July each year, the Regulatory Authorities shall publish a report setting out the amount of revenue collected for the 12-month period up to 30 June of the same year and the use made of the revenues in question, together with verification that this use complies with the present Regulation and Guidelines and that the total amount of congestion income is devoted to one or more of the three prescribed purposes.	**X**	X
6.6	The use of congestion income for investment to maintain or increase interconnection capacity shall preferably be assigned to specific predefined projects which contribute to relieving the existing associated congestion and which may also be implemented within a reasonable time, particularly as regards the authorisation process.		X

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