Congestion Management in the Nordic Market - evaluation of different market models

Final Report

The study was carried out for the Nordic Council of Ministers by Ea Energy Analyses, Hagman Energy and COWI.

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Contents

1 Results, conclusions and recommendations

The question of market splitting versus counter trade has long been the focus of the Nordic discussion regarding congestion management (CM). The main purpose of this project is to evaluate and analyse these two approaches for CM in the Nordic power market and on the basis of this analysis make concrete recommendations for a Nordic solution,, aiming at an optimal balance between competition issues and efficiency.

The backbone of the Nordic electricity market is the Elspot day-ahead market with market clearing every day based on hourly supply and demand bids. Elspot prices are determined for every hour of the next day for each Elspot area. The prices are the same in all areas if there is no congestion. Market splitting is used if there is congestion, i.e. different Elspot area prices are determined to reduce power flows through congestion to the allowed limit. If there is perfect competition, all producers have an inclination to bid in at their *marginal cost* and the consumers to bid in according to their *marginal willingness to pay.* If there were no grid losses, if congestion management was optimal and if there was no market power, such a market would yield the true electricity price, the optimal dispatch and the optimal investment incentives.

Today the Nordic spot market is divided into seven Elspot areas of different size. The boundaries of these areas are mainly the national borders, but Norway and Denmark are subdivided into different price areas. Today, there is internal congestion within all countries, which causes reductions in the import/export capacities between the Elspot areas. Counter trade is used to guarantee the Elspot capacities if the prerequisites are altered e.g. due to outages after the Elspot market clearing. Counter trade or special regulations are also used as complements if there is congestion that cannot be entirely relieved by reduced export/import capacities.

The starting points for our conclusions and recommendations are the many studies already performed but also on new quantitative and qualitative analyses of benefits and disadvantages of different alternatives. These new analyses can be grouped into two types of analyses: a) quantitative analyses of the Nordic electricity market assuming ideal competition, using the market model Balmorel, and b) quantitative and qualitative analyses of the ability and incentive to exercise market power by using market concentration indexes and descriptive “case story” analyses.
The most important tool in CM is timely grid planning in order to expand the interconnection capacity whenever such an expansion is thought to be socio-economically profitable. Such grid reinforcements improve the market integration and increase security of supply but can take many years to plan and build.

In 2004, Nordel agreed on five prioritised interconnections. This winter, one of the planned links, the so-called South Link in Sweden has been changed to a South-West Link with twice the capacity of the originally planned South Link. It will increase the capacity to South-Eastern Norway and the capacity between South-Eastern and South-Western Norway by 1200 MW. Our analysis is based on the assumption that

these interconnections are built and put into operation before 2015. If these plans are not fulfilled by the Nordic TSOs, congestion will increase in the Nordic area. In their new Nordic Grid Master Plan, Nordel have, in addition to theses interconnections, recommended the Nordic TSOs to invest in a number of new projects.

During the last decade, some market players have expressed the vision of the Nordic area as becoming a single Elspot area. It has been discussed whether the vision has ever been realistic, but it is definitely not realistic in a broader North European or European perspective. Market splitting within the Nordic area is therefore necessary. The questionis which market splitting and which combination of market splitting with counter trade and reduction of transmission capacities is most feasible.

The EU Congestion Management Guidelines define the basic requirements for coordinated congestion management but they do not specify the details of the operational procedures. Only the basic definitions of key concepts are provided within the scope of the Congestion Management Guidelines. Coordination shall be applied regionally, and seven regions are currently defined across the EU. However, in all these regions the congestion management methods shall be compatible with an ultimate goal of forming a truly integrated internal European electricity market.

1.1 Conclusions regarding efficient resource utilization

In our analysis, the current seven spot areas of the Nordic market and the current practice of transmission capacity restrictions to resolve internal congestion have been defined as the baseline and then compared to a market divided into more spot areas (11) or into less spot areas (one, four and six). In these new cases, no capacity reductions are performed and counter trade is practised internationally between the Nordic countries to resolve internal congestions within any given spot price area. In all calculations, market conditions are assumed to be ideal in the spot and counter trade markets as is common practice for this type of market analysis.

The results of this analysis show that all changes from today's practice regarding capacity reductions yield a socioeconomic benefit in the range of EUR 15 – 30 million a year with the 11 area case being the most beneficial. The total benefit in all the cases is in the same range, but the costs and benefits are distributed quite differently between stakeholder groups and countries. Introducing an 11 area division of the spot market will generally benefit the Nordic generators and TSOs and yield a loss to consumers. On the Continent, consumers will benefit and generators will lose. The main reason for this is that the Nordic area will have slightly higher prices and the Continent slightly lower prices due to better utilisation of the southbound interconnections.

There is by definition no counter trade in the 11 area case as we have only modelled congestion between the 11 areas – not within the 11 areas. Capacity reductions or extensive counter trade are needed in all other cases to solve internal congestions

within the spot areas. In the ideal world of the model, this is not a problem. In practices, however, there are several very important problems.

Management of internal congestions within the spot areas by reduced capacity allocation between the spot areas presupposes that the TSOs make a forecast of the resulting power flows from the spot market. When the TSO forecast is not perfect, the capacity reductions will result in reduced resource efficiency compared to market splitting. If the TSO forecast is aimed at reducing counter trade costs instead of optimal resource efficiency, the result will also be reduced resource efficiency. For these reasons and due to the assumption of ideal markets with no strategic behaviour, the results from our model will underestimate the socioeconomic benefit of changing from today's practice of capacity reductions to an 11 area case. The effect of strategic behaviour in markets with anticipated counter trade is elaborated further below.

1.2 Conclusions regarding competition

A prerequisite for the calculated results regarding socioeconomic benefits is that there is full competition in the market. Two indexes of supply-side market concentration have been calculated for the situation in 2007; the Herfindahl-Hirschman Index (HHI) and the Pivotal Supplier Index (PSI).

HHI has been calculated for all the constellations which a specific Elspot area belonged to during 2007. US guidelines stipulate that a HHI index under 1000 indicates a market with low concentration and an index above 1800 indicates a highly concentrated market. Taking into account the frequency of different area price constellations, the Danish areas had high concentration more than 20% of the time in 2007, Northern Norway had high concentration nearly 20% of the time and Sweden had high concentration 5% of the time. No area had a time-weighted HHI that indicates a low concentrated market. When there are no congestions within the Nordic region, the HHI is 933 or just under the threshold 1000 for moderate market concentration. Considering the special characteristics of the power market, this means that the market concentration can be problematic even when all Nordic areas have a common price.

From 2007 to 2015, two counter-acting trends can be expected regarding the market concentration. On the one hand, the newly decided transmission links will further integrate the markets and thereby reduce the number of hours with high concentration and reduce the time-weighted HHI for the different areas. On the other hand, mergers and acquisitions will probably continue to increase the HHI for the common Nordic market. The result can for some areas be an increased time-weighted HHI. It should be noted that the HHI will not be lower in hours when the Nordic area by market coupling has a common price with the Continent since the HHI for Germany and the HHI for EU 15 is much higher.

The PSI analysis shows that during 2007 there were hours in all spot areas when a specific company was necessary or pivotal for clearing of the Elspot market. In Finland, Sweden and Eastern Denmark a company was pivotal more than 60 % of the time in 2007. Also, the PSI index indicates thus that market power can be exercised in the Nordic area if such strategies are chosen by generators.

A generator with market power in a specific area can exert its power and increase its profit by strategic bidding whether the area is a separate spot area or the area is included in a bigger spot area and the TSO has to relieve congestions by counter trade. There are no general conclusions as to whether market splitting or counter trade give the best scope for profit increases for a generator with market power. Different examples give different results and the scope for increasing profit is also dependent on the efficiency of market surveillance.

However, there are different payers of the extra profit in the two CM regimes. Because of market power in an area, all consumers and retailers are directly affected by the higher spot price if there is market splitting and strategic bidding. On the other hand, counter trade and strategic bidding mean that the TSO pays most of the extra profit as extra costs for counter trade. These extra costs for counter trade mean an extra cost basis for the grid tariffs and the TSO grid tariffs are in the end mostly paid by the consumers through their network tariffs.

Retailers selling on fixed price contracts have to hedge the spot price and this hedge is normally done by independent retailers as a separate hedge of the system price and a separate hedge of the difference between the area price and the system price. Both system price contracts and contracts for difference (CfD) are listed by Nord Pool. There is, however, in all CfD products on Nord Pool a lack of sellers, and participation by financial traders is low. One reason is that the CfD products are seen as much more affected by market power than system price products.

It is important for the competition in the retail market that independent retailers are not facing higher costs and risks than retailers belonging to an integrated group or retailers that buy bilaterally from one producer. Many spot areas, instead of a few, mean that more CfD products are needed and an obvious risk for even lower liquidity and higher “insurance premiums” in the different CfD products. The risks associated with hedging disappear for the retailer if the customers choose variable price. Most customers in Norway choose variable price while most customers in Sweden and Finland choose fixed price. Many spot areas also mean smaller balancing areas and an increased risk for price spikes in the regulation market because of market power.

1.3 Conclusions regarding counter trade

Counter trade gives incentives for strategic bidding to Elspot when market players are able to anticipate internal congestions that have to be managed by counter trade. All market players will have incentives to divert their Elspot bids from the marginal cost

or marginal willingness to pay in order to increase their profits in the needed counter trade if they forecast such counter trade. The result of this gaming is market distortions and suboptimal dispatch. None of these two important problems are captured in the model and the socioeconomic cost of counter trade cases is therefore underestimated.

The main result of our principle model analyses is that in situations when congestion is anticipated, there is more strategic bidding and less resource efficiency if counter trade is used instead of market splitting. The main advantage of counter trade is that it enables the use of fewer spot areas and thereby more competitive retail markets, at least in areas where the customers choose fixed price contracts. Negative effects of strategic bidding and less resource efficiency have to be compared with negative effects on the retail competition on a case by case basis in order to reach an optimal balance between efficiency and competition.

For instance, during the last decade, Nordenergi has often advocated guaranteed capacity levels to the day-ahead market. Our conclusion is that we will not get a more efficient market if Nordic TSOs are obliged to guarantee that the transmission capacities are always a certain percentage of the normal levels. In a developed market, changes in dispatch because of changes in the physical transmission capacities are managed more efficiently in the day-ahead market than by the TSOs. A market clearing of the day-ahead market which reflects the physical realities should be encouraged – not concealed.

1.4 Conclusions regarding possible use of new bid areas

Presently, there are internal congestions in all Nordic countries which are managed in the day-ahead market by reduced capacity allocations to Elspot. The alternatives are market splitting and counter trade. The most preferable counter trade alternative is counter trade in Elspot. The bids to Elspot include all possible production and consumption changes while today's counter trade is done bilaterally or within the regulation market and normally includes only larger bids within the TSOs' respective operating areas. Today's counter trade can therefore not give the same resource efficiency as counter trade in Elspot.

A necessary prerequisite for CM by counter trade in Elspot is that there are different bid areas so that bids in the surplus area can be separated from bids in the deficit area. In that case it is possible to calculate one uniform Elspot price for the Elspot area and simultaneously perform counter trade in Elspot that relieves the congestion and gives an effective resource utilisation in the day-ahead market. All bids in the common Elspot area will meet the common spot price, except the bids that are counter traded.

There is a method for counter trade in Elspot that result in the same price signals in other Elspot areas and the same dispatch in all areas as if all bid areas had been different Elspot areas and only market splitting had been used.

This means an important improvement in relation to CM by reduced capacity allocations to Elspot. Reduced capacity allocations to Elspot result in other power flows with adjacent areas and another dispatch compared to the results of full market splitting. Thus, CM by reduced capacity allocations to Elspot gives reduced resource efficiency. Also, an alternative with no capacity reductions to Elspot and full counter trade after Elspot give reduced resource efficiency since it results in other power flows with adjacent areas and another dispatch compared to the results of full market splitting.

However, there are still two possible problems compared with the resource efficiency that is achieved with full market splitting. The first problem arises if the market players anticipate the counter trade in Elspot and change to strategic bidding. The scope for strategic bidding is, however, reduced compared to an alternative with full counter trade after Elspot. With our proposed method for counter trade in Elspot, counter trade is reduced to the change in dispatch between the surplus and deficit areas that is needed to restore the dispatch achieved in the first calculation with full market splitting. Full counter trade after Elspot, however, also means that power flows with other Elspot areas normally also has to be counter traded. Such an extensive counter trade can create a much higher scope for strategic bidding by market players than our proposed method for counter trade in Elspot.

The second problem relates to the long-term signals for production and consumption investments. The relevant price for most of the production and consumption in the common Elspot area is the common spot price instead of the spot prices that would have been achieved with full market splitting. This can give wrong incentives for investments if there is a significant difference between the prices. Our simulations of spot prices 2015 in section 4 show, however, that only one of the four new area borders in the eleven area case result in an average spot price difference higher than 0,1 EUR/MWh. That area border is cut 2 in Sweden with the spot price difference 0,8 EUR/MWh between Northern and Central Sweden. Even such a difference is relatively small compared to all other differences and difficulties that are characterising possible investment alternatives.

If counter trade is performed in Elspot An important issue is how to perform CM in the intra-day market after Elspot. There will be misleading incentives for intra-day trade if there is only one common price in the intra-day market in situations when the counter trade in Elspot has resulted in different prices for counter traded volumes in the surplus and the deficit areas. Our conclusion is that the different bid areas in the day-ahead market should transform into different bid areas in the intra-day and the regulation markets as a natural consequence of counter trade in Elspot.

The consequence of new bidding areas and counter trade in Elspot is for retailers without price-elastic demand that the same uniform Elspot price applies to all their planned purchase in the Elspot area but that it can be different balance prices in the surplus and deficit areas for their imbalances. The retailers can thus hedge their planned purchase in the same way as if it is only one spot area. However, their imbalance risk is changed. Whether the changed imbalance risk is a serious problem or not for the retailers depends on the regulation power markets in the two separate bid areas but the changed imbalance risk will nevertheless only relate to their imbalance volumes, not to their total purchase.

1.5 Recommendations

1) We recommend that new areas are established as separate Elspot areas or separate bid areas within existing Elspot areas for CM of cut 2 and cut 4 in Sweden, cut P1 in Finland and the congestions west of Oslo

We have no firm recommendation as to whether the new areas should be established as separate Elspot areas or separate bid areas within existing Elspot areas. Negative effects of strategic bidding and less resource efficiency have to be compared with negative effects on the retail competition on a case by case basis in order to reach an optimal balance between efficiency and competition. However, we want to stress that the most important prerequisite for resource efficiency is that the present reduced capacity allocations to Elspot come to an end. If there is uncertainty regarding the division of a certain Elspot area into bid areas or spot areas, it is better to establish the new areas as separate bid areas first and then later decide if they are to be changed to separate Elspot areas based on experience of the amount of counter trade in the common Elspot area. The worst alternative is to postpone the decision and thereby not end the present reduced capacity allocations to Elspot.

2) We recommend the following method as a feasible method for counter trade in Elspot if new bid areas are established within an Elspot area.

The new bid areas shall be established within the Elspot area so that bids on the deficit and surplus sides of the congestion can be separated from each other. In the first Elspot calculation, all bid areas are treated as Elspot areas. Congestions between bid areas are thus managed by market splitting and the result is the same market clearing and the same power flows as if the bid areas had been Elspot areas. Afterwards, a second calculation is performed for a certain Elspot area if the first calculation has resulted in different prices for bid areas that are within that Elspot area. As input,the second calculation uses the same power flows with other Elspot areas that were established in the first calculation. The purpose of the second calculation is only to establish a common spot price for the Elspot area and to perform the most cost-effective counter trade to relieve the congestion that arises as a consequence of the common spot price. The most cost-effective counter trade is a counter trade that gives the same dispatch within the Elspot area as the dispatch that was achieved in the first calculation. Thus, the second calculation does not change the power flows

with adjacent Elspot areas. The final result in the Elspot market will be the same price signals in other Elspot areas and the same dispatch in all areas as if all bid areas had been different Elspot areas and only market splitting had been used.

3) We recommend that all bid areas and Elspot areas are treated as separate areas in the intra-day market (Elbas) and the regulation market

There will be misleading incentives for intra-day trade if there is only one common price in the intra-day market in situations when the counter trade in Elspot has resulted in different prices for counter traded volumes in the surplus and the deficit areas. The recommendation will enable efficient intra-day markets and regulation markets with less special regulations and unnecessary reductions in transmission capacities. It will also enable better management of peak-load situations.

4) We do not recommend that the TSOs shall always allocate a guaranteed transmission capacity to the Elspot market even if the physical capacity is lower because of e.g. outages.

The Elspot market is not a more efficient market if TSOs are obliged to guarantee that the transmission capacities are always a certain percentage of the normal levels. A market clearing of the day-ahead market that reflects the physical realities should be encouraged – not concealed.

2 Background

This is the final report from the project "Congestion Management in the Nordic Market - evaluation of different market models" carried out for the Nordic Electricity Market Group, the Nordic Council of Ministers by Ea Energy Analyses, Hagman Energy and COWI.

The terms of reference stated that a uniform standard for congestion management is important for a well functioning power market. The electrical system in the Nordic countries was from the beginning primarily designed to support national power demand. The development of an integrated Nordic market, with steady increased power trade and changed power flows, has pointed out the need for adjustments. The package of five prioritised Nordic grid reinforcements is one important step forward in this respect.

The question of market splitting vs. counter-trade remains for all congestions/bottlenecks. This question seems to be a highly political issue with strong national views – which method is most beneficial and effective for the future development of the Nordic electricity market; Dynamic price areas or few and large areas, with counter trade. The most controversial issue is how the different models influence the cross-border trade.

The main purpose of the project is to evaluate and analyse the two approaches for congestion management in the Nordic power market and on the basis of this analysis present concrete recommendations for a Nordic solution, aiming an optimal balance between competition issues and efficiency.

This requires synthesis of the many studies already performed but also new analysis of benefits and disadvantages of different alternatives. We have chosen the electricity market model Balmorel as an appropriate tool for much of the needed analyses.

3 Key issues regarding congestion management in recent studies and proposals

Several studies and proposals regarding congestion management (CM) in the Nordic power market have been presented during the last years. The Nordic Council of Ministers, the Nordic Energy Regulators, the Nordic Competition Authorities, Nordel have presented studies. A joint Swedish report has also been presented as well as statements from the energy associations. On the European level, EU has presented the result of the Energy Sector Inquiry and the 3rd electricity liberalisation package. ETSO and EuroPEX have presented an interim report dealing with coordinated CM models.

3.1 Report from the Nordic Council of Ministers

The report *Steps for improved congestion management and cost allocation for transit (TemaNord 2007:537)* was presented in April 2007 and produced by Ea Energy Analyses and COWI for the Nordic Council of Ministers. The report emphasized the increase of cross-border trade. It described how the transmission capacities for the market are reduced due to various reasons and that they have been on average 75 % of the full capacity. This has welfare-economic consequences for the Nordic power system as it increases total generation costs in the system.

Simulations of power balances and electricity prices in 2015 were presented for normal, wet and dry years. Economic gains and losses from electricity trade were analysed as well as the marginal benefit of increased capacities in 2015. The largest marginal benefit is at the links to the continent. Within the Nordic region, the largest marginal benefit is at the link from Norway to Jutland and at the link from North to South Norway.

One part of the study was interviews with representatives from the TSOs, the energy regulators and the associations of energy producers in the four countries. All stakeholders stated that the question of CM is presently the most pressing issue to be solved in the Nordic electricity market. Several stakeholders felt that also a fair transit compensation mechanism is extremely important, and that the two questions are interlinked. Several stakeholders stated that the reasons for reducing the transmission capacity at national borders are not sufficiently justified. All stakeholders felt that the current controversy is seriously threatening the Nordic cooperation. All stakeholders agreed that counter trade is not the best way to handle structural congestion. The majority pointed out that the current practice is not transparent, does not yield the “true” prices, and that unnecessary price fluctuations are induced.

The report proposed five concrete steps for moving forward with respect to CM and three steps with regard to transit compensation. The first step was to make a new

division into price areas with no special respect to national borders. Steps 2 and 3 were to develop objective criteria for market division and to publish data and methods. As steps 4 and 5 it was suggested that intra-day trading should be increased and that the advantages and drawbacks of nodal pricing in the Nordic system should be studied. Steps 6 and 7 were to define local benefits of transit and to harmonise the value of the transmission grid. Step 8 was to prioritise transmission lines to the continent.

3.2 Reports from NordREG

NordREG published in June 2007 the report *Congestion Management in the Nordic Region – A common regulatory opinion on congestion management (Report 2/2007)*. It summarised the discussion regarding CM in the Nordic region in light of the new EU Congestion Management Guidelines.

NordREG found that there are challenges related to CM in all Nordic countries. 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.

The competition aspects were seen as important and have to be taken into account when defining bidding areas in the Nordic market. A common coordinated CM method would enhance competition. A concentration index (HHI) for the Nordic wholesale market 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. Studies together with the competition authorities were proposed to find an optimal balance between competition issues and efficiency related to CM methods.

The current representation of the physical network in the market splitting model was seen as very simplified. NordREG invited 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. One part of such a study could be to assess the benefits of introducing elements of the nodal pricing philosophy.

In September 2007, NordREG published the report *Congestion Management Guidelines – Compliance report (Report 8/2007)*. The report evaluated the current status of compliance with the CM guidelines and set out the further work of TSOs and regulators for ensuring full compliance.

The report stated that the CM method applied to allocate all interconnector capacity in the Nordic market, i.e. implicit auction, fulfils the requirements set in the CM guidelines. In case of limiting cross-border capacity due to TSOs internal congestions, the guidelines set pre-conditions for allowing such limitations. Procedures must be further developed by the TSOs to ensure that the reasons for limitations and their effects

are transparently described. More attention should be paid in the future to the joint network planning in order to avoid long lasting limitations in transmission capacity due to either insufficient cross-border infrastructure or internal congestions.

The report concluded that generally the current procedures meet the requirements for coordination and also the timetable for market operations if the Nordic market is considered. However coordination within CM should include also Germany and Poland as they belong to the Northern Europe region and the CM methods on the interconnectors between Nordic countries and continental Europe are not yet fully in line with the CM guidelines. This requires further work. Furthermore, compatible CM procedures shall be defined in all seven EU regions with a view to forming a truly integrated internal energy market.

3.3 Report from the Nordic competition authorities

The Nordic competition authorities presented in September 2007 the report *Capacity for Competition – Investing for an Efficient Nordic Electricity Market* (Report 1/2007).

Merger cases and activities by the Nordic competition authorities since the earlier report in 2003 were summarized. The Finnish competition authority found in its assessment of Fortum´s acquisition of E.ON Finland that Fortum has a dominant position in Finland in periods when the wholesale market is national due to transmission constraints. The approval of the merger was therefore conditional on Fortum renouncing some of its production capacity. The Danish competition authority identified 900 hours in 2003-2004 and 1484 hours in 2005-2006 in which a supplier had abused its dominant position by imposing excessive wholesale prices in Western Denmark. There is an ongoing investigation of the price formation in 2003-2006 on the market in Eastern Denmark.

The report emphasised the importance of new investments in production and transmission capacity in order to improve the competition in the market. If Nordel´s five prioritised are carried out, the competition problems will be reduced. Investments in increased production capacity from new producers/entrants were viewed more favourably than similar investments from incumbents. It was proposed that competition analysis should be included in the TSOs´ investment decisions.

It was recognized that separate relevant markets can occur even in situations without a bottleneck. Major producers may by strategic bidding to a certain extent control when a connection to a neighbouring country will be congested.

The report criticised the present ITC (Inter TSO Compensation) mechanism. Developing cross-border trade in a more efficient way and not establishing any hampering mechanism is of vital importance. It is essential that an ITC mechanism takes into account benefits and costs of trade supplied by market mechanisms.

3.4 Joint Swedish report

The Energy Markets Inspectorate, Svenska Kraftnät, Swedenergy and the Confederation of Swedish Enterprise presented in May 2007 the joint report *Price Areas in the Electricity Market (EMIR 2007:02).* The report is often called the POMPE-report after its Swedish acronym.

The four organisations found that it is crucial for the customers that there is efficient resource utilization as well as effective competition both in the wholesale power market and in the retail market. The conclusion was that an efficient market should be characterized by both efficient resource utilization and effective competition, together with a market integration that is as far-reaching as possible. The ambition should be that the price areas are as few and large as possible and that the development and operation of the Nordic grid is based on a Nordic perspective instead of national perspectives.

The organisations considered it important that the package of five prioritised cross-sections, on which Nordel has agreed, is implemented as soon as possible. They also considered it important to implement the additional reinforcements that are identified as being socio-economically profitable in a Nordic perspective.

It was stated that far-reaching market integration can be achieved by counter trade of those congestions that are not socio-economically profitable to eliminate by grid reinforcements. The decisive question is whether those who benefit from a certain counter trade are prepared to pay the cost. The organisations considered it essential for the function of the Nordic market that Nordel as soon as possible establish principles for counter trade of various cross-sections, based on the principle that those who benefit from counter trade also finance the counter trade.

The report found that a price area division at cut 2 in Sweden (north of the river Dalälven) may give more efficient utilization of resources in certain situations without impairing the competitive conditions in the wholesale market. However, as long as the retail market is national, any price area division in Sweden – also a division at cut 2 – will impair the competitive conditions in the retail market. On the other hand, the Nordic hydropower generation varies widely throughout the day, the week, the year and between the years. The variations are so large that it is not realistic to maintain the vision of the Nordic countries as one single price area.

The organisations suggested that the Nordic Council of Ministers, Nordel or NordREG should take the initiative to assess a price area boundary between the Nordic hydropower and thermal power areas that runs through cut 2 in Sweden and, for example, through northern Finland and south-eastern Norway. The assessment should refer to whether such a price area boundary would give an effective market characterized by efficient utilization of resources, effective competition and far-reaching market integration.

3.5 Reports from Nordel

Nordel has presented a number of reports regarding congestion management during the last years.

In 2002 Nordel presented a possible change in the division into Elspot areas. Norway was divided into four areas, Sweden was divided into three areas, Denmark was divided into two areas and Finland was a common area. It was proposed that counter trade in Elspot should be used up to a certain cost limit for congestions between the Swedish areas, between Sweden and Finland, between Sweden and Eastern Denmark and between the two areas in Southern Norway. 100 MNOK was mentioned as an appropriate cost limit for the yearly counter trade costs. The report pointed out that rules for financing of counter trade costs were needed but proposed no such rules.

The report was sent out to stakeholders on a hearing. All answers agreed that common and unambiguous rules are needed but disagreed regarding the proposals. Norwegian stakeholders proposed that other area divisions should be analysed. Finnish stakeholders supported the proposals and concluded that they in reality would mean bigger price areas. Swedish stakeholders were against a division of Sweden while Danish stakeholders were critical to increased counter trade.

In 2004 Nordel presented a report regarding the possibilities for increased counter trade. The report concluded that the main advantage would be increased trading capacities and thereby better ability for market players to make predictions and reduced risk costs for the players. Another advantage would be increased trust in the common Nordic market. On the other hand the report concluded that counter trade will not give the right economic signals to the players. Counter trade in Elspot was seen in the report as the only realistic alternative for an increased counter trade. The report pointed out that counter trade costs should be allocated according to the benefits for players in different areas but presented no model for such cost allocation.

In a letter to the European Commission and ERGEG in January 2008 Nordel proposed to merge the existing Central West European and Northern Regional Initiatives. Nordel pointed out that an efficient market integration requires common market structures and harmonisation of the trading rules. One market with separate forums for the market design can lead to diverging development in the sub-regions and jeopardize the progress in the European integration.

The Nordic Grid Master Plan 2008 was presented by Nordel in March 2008. Nordel recommends the Nordic TSOs to invest in a number of new projects.
The following is said regarding congestion management:

Congestions in the grid will naturally occur, and must be handled. Transmission investments are resource demanding and the lead times are also long. It is therefore important to have clear principles on how to operate the existing grid in the most

efficient way. This is particularly important for so-called internal congestions. Efficient handling of congestions will then benefit the common Nordic electricity market, Nordic consumers or producers in general. The principles for congestion management are:

• Congestions are in general handled where they are physically situated
• Structural congestions are removed or reduced by grid investments whenever socio-economically viable, otherwise market splitting is applied, i.e. dividing the market into separate price areas
• Temporary congestions shall be handled by counter trade (redispatching), if counter trade is possible

3.6 Position papers from energy associations

The Nordic energy associations have presented several position papers on congestion management through their common organisation Nordenergi. A position paper in 2006 stated that the system operators should, in a predictable way, guarantee the highest possible transmission capacity available for commercial trade on price area borders, corresponding to at least 70 percent of the net transfer capacity (NTC). A clear economic sanction should be set on TSOs in case of failing to guarantee the capacity.

It was also stated that transmission investments should be evaluated in a socio-economic perspective taking into account the whole Nordic electricity market. Nordel should undertake and publish a thorough cost-benefit analysis on further investments in transmission capacity aiming to reduce negative effects of bottlenecks as far as economically justified from the Nordic electricity market perspective. This preparation for new transmission investments should be a continuous process, including an annual report of next prioritized projects.

Finnish Energy Industries distributed in November 2007 a special position paper regarding their views on CM and their comments to the joint Swedish report in May 2007. The organisation believes that a major part of the problems in CM that have been disturbing the good functioning of the Nordic electricity market will be solved after realization of the five big grid investments agreed by the Nordic TSOs. It is very important that the investment plan is implemented rapidly and forcefully. The so called South link in Sweden is most essential. The Nordic electricity market needs a transitional solution for the time before the investments and a more permanent solution for the time after the investments.

Finnish Energy Industries emphasises that the decisions concerning CM must be made through Nordic co-operation with focus on the entire Nordic market area. Counter trade is the most efficient way of managing temporary congestion. The best primary market place for counter trade is Nord Pool's Elspot market. One solution to congestion management within Sweden could be the introduction of several bidding areas.

This solution would make it possible to carry out counter trade on the basis of bids made to the spot market without price area division.

The organisation is in favour of the use of large price areas. It considers that in order to intensify the functioning of the Nordic electricity market and to promote competition on the market, price areas where there are no significant structural congestion on the connections between the price areas (such as Finland - Sweden - Zealand) should be joined together.

Finnish Energy Industries cannot accept the proposal in the Swedish report to divide the Nordic countries into two price areas so that the boundary of the price areas splits Finland into two areas. The price area division solution should be based on the physical properties of the transmission system instead of the properties in electricity production. Within Finland, there are no significant transmission congestions which would require a price area division. Dividing Finland into several price areas would bring more business risks to the market players and complicate the functioning of the retail market in particular.

3.7 EU documents

The EU Congestion Management Guidelines under Regulation 1228/2003 were amended in the beginning of December 2006. NordREG's compliance report regarding the new guidelines was described above in section 3.2.

Issues regarding congestion management are commented in the 3rd EU electricity liberalisation package and the energy sector inquiry report. The 3rd EU electricity liberalisation package and the energy sector inquiry stress the importance of independent neutral TSOs for an efficient functioning of the market. The need for improved regional cross-border electricity trade is reaffirmed. Market fragmentation along national borders, a high degree of vertical integration and market concentration is seen as roots of the lack of a truly internal market.

It is stated that electricity and gas markets differ fundamentally from other traded goods because electricity and gas are network-based products that are impossible or costly to store. This makes them sensitive to market abuse and regulatory oversight needs to be increased.

The energy sector inquiry states that the current balancing zones are too small and that the markets for balancing energy are highly concentrated. This can result in entry barriers for new suppliers facing a high risk of high imbalance prices.

3.8 ETSO and EuroPEX Interim Report

ETSO (Association of European Transmission System Operators) and EuroPEX (Association of European Power Exchanges) were charged with an action from the Florence

Forum of September 2007. The action was to produce a common discussion paper dealing with issues of organisation, roles, governance and practical implementation of coordinated congestion management models. The associations published on 10 April 2008 the joint interim report *Development and Implementation of a Coordinated Model for Regional and Inter-Regional Congestion Management*. After a consultation process, a final discussion paper will be presented in September at the 2008 Florence Forum.

The interim report is focused on the key options for inter-regional integration of the day ahead markets. The report finds that implicit auctions are generally superior to explicit auctions, at least in well developed markets. The key issue is how to establish an integrated European market using implicit auctions. Different forms of market coupling between power exchanges are described. One possible way is to determine the flows between the various market regions in the first step. The market regions subsequently determine the prices and flows within the own regions using their own regional solutions. Such a market coupling approach involves the development of a new volume coupling platform able to interface with the platforms operating at regional level.

The second part of the report describes different capacity allocation models. The Classic Net Transfer Capacity (NTC) approach identifies separately for each border the maximum capacity that is compatible with operational security standards. The advantage of the method is a straightforward allocation of cross-border transactions based on a single value for each hour, the NTC. The disadvantage is the large uncertainties in calculating the NTC value when flows are interdependent and when there are congestions within the areas.

The Combined NTC model goes one step further by identifying additional constraints which better represent the flows that can be created by the interaction of different markets. An example is the German C-function which puts an upper limit on the exchange with the Netherlands, France and Switzerland.

The Enhanced NTC model has the ambition to make use of a flow-based model with locational information while preserving the NTC approach. However, the model is still in an experimental stage. The main advantage of flow based models is that the TSOs can reduce the amount of own assumptions on the future market situation to quantify NTCs for the different borders. The allocation process is instead based on the pricing of the bids and on the flow distribution resulting from the allocation. This shall in theory lead to optimal use of the network while at the same time maintaining security of the system.

The adoption of flow based approaches for calculation of NTC can be evolutionary and the level of sophistication may evolve over time. The border capacity model uses a simplified flow based network representation where each control area is represented as a single node that is connected to each neighbouring area by a single interconnec-

tor. The critical branches model is an enhanced model that allows several critical branches and nodes per control area and has therefore a more accurate description of the network. The models are still in development and have to be proven to work in practice. An outstanding issue is the transparency of the allocation process and the determination of market results.

4 Efficiency of resource utilization

4.1 Introduction

The two extremes with respect to CM are nodal pricing on the one hand and a single Nordic price area on the other. The essential difference between these two is that nodal pricing ideally takes complete account of the technical aspects of operating the transmission system, whereas a single Nordic price area does not take any grid information into account.

Market splitting is a simplification in comparison with nodal pricing, where adjacent nodes, which are perceived to be connected by a strong grid, are aggregated into zones. The market splits into price zones (or areas) when the power flows between zones reach the capacity between the zones. This does not, however, resolve congestion within a zone nor strictly adhere to electrical laws.

Counter trade traditionally takes offset after a given spot market solution and the responsible TSO resolves residual congestion in bilateral trade by providing incentives for generators, and possibly consumers, to diverge from their spot market position. Counter trade is presently conducted by individual TSOs using the resources available in their operating area. The daily process is based on bilateral communication between TSOs and a limited number of generators and on occasion some larger consumers. By this process neither local resources nor resources outside individual TSOs operating area are used efficiently. The practice is normally combined with export or import capacity reductions in the spot market, which reduce the need to counter trade, but which often have questionable side effects with respect to overall efficiency.

This section presents general consequences and results of quantitative analyses focusing on the efficiency of resource utilization under different CM regimes. Two main issues are analysed:

- How different CM regimes influence the total welfare
- How different CM regimes influence the welfare distribution between countries and between different interests, i.e., consumers, producers, TSO's and public proceeds in each country

Effects on power prices, power flows including cross-border trade and transit are analysed and presented, as well as flows between the Nordic countries and between the Nordic countries and the Continental Europe.

We also look at how the volume of counter trade relates to the market setup.

4.2 Approach to analyses

The purpose of the analyses is to simulate resource utilization under different CM regimes.

The Balmorel model (www.balmorel.com), which is a technical/economic partial equilibrium model, is used for these analyses. The model finds optimal solutions for the electricity and heat markets, taking into account:

- Electricity and heat demand;
- Technical and economic characteristics for each kind of production unit, e.g. capacities, fuel efficiencies, operation and maintenance costs, and fuel prices;
- Environmental taxes and quotas;
- Transmission capacities between regions and countries.

As output, the model derives production and transmission patterns. The model also generates estimates of electricity prices assuming liberalised and well-functioning markets with full competition among power producers. The model is deterministic and therefore does not reflect uncertainty issues in the power system. Based on the electricity prices as well as the consumption and generation in each country, the welfare-economic consequences of different counterfactual scenarios can be calculated for different player groups.

The electricity demand in the model is assumed to be price elastic. Based on a Nordel analysis carried out in 2003 (Statistical analysis of price response of the aggregated electricity demand), the demand reduction in Norway was up to 1000 MW. For the other Nordic countries, the electricity demand is reduced correspondingly relative to total electricity demand (see Annex 1 for further details).

Counter trade is handled in the model by first simulating the spot market, in which appropriate transmission constraints are relaxed, and subsequently reintroducing these constraints and resolving the model. Spot prices and quantities are output from the first simulation, counter trade prices, from the second and counter trade quantities by the difference between the two model executions. In essence, the market is simulated by a two step optimization approach.

The counter trade calculated by the model is very idealized beyond what is realistic in the current market setup.
The following Elspot area divisions are analysed:

- Market splitting in the Nordic Electricity market along all bottlenecks (simplified to 11 Elspot areas due to the availability of data– i.e. the Balmorel dataset used in Ea and COWI (2006) with 10 areas plus the P1 division of the Finnish grid).
- Present Elspot division (7 areas)

- An alternative with 6 Elspot areas based on a Position paper from the Finish Energy Industries.
- An alternative with 4 Elspot areas based on the POMPE recommendation
- A single Elspot area

The first division is representative of the full market splitting regime, where all the most important cuts are handled by market splitting. The second is the current elspot price area division. The final three are different Nordic price area divisions which aim at integrating the Nordic countries into fewer and larger price areas.

It is important to note that in all cases, in the final solution, the results adhere to the same constraints in the electricity grid, namely the ones included in the Market splitting case (see Figure 14

The five Elspot area divisions are illustrated on Figure 1.

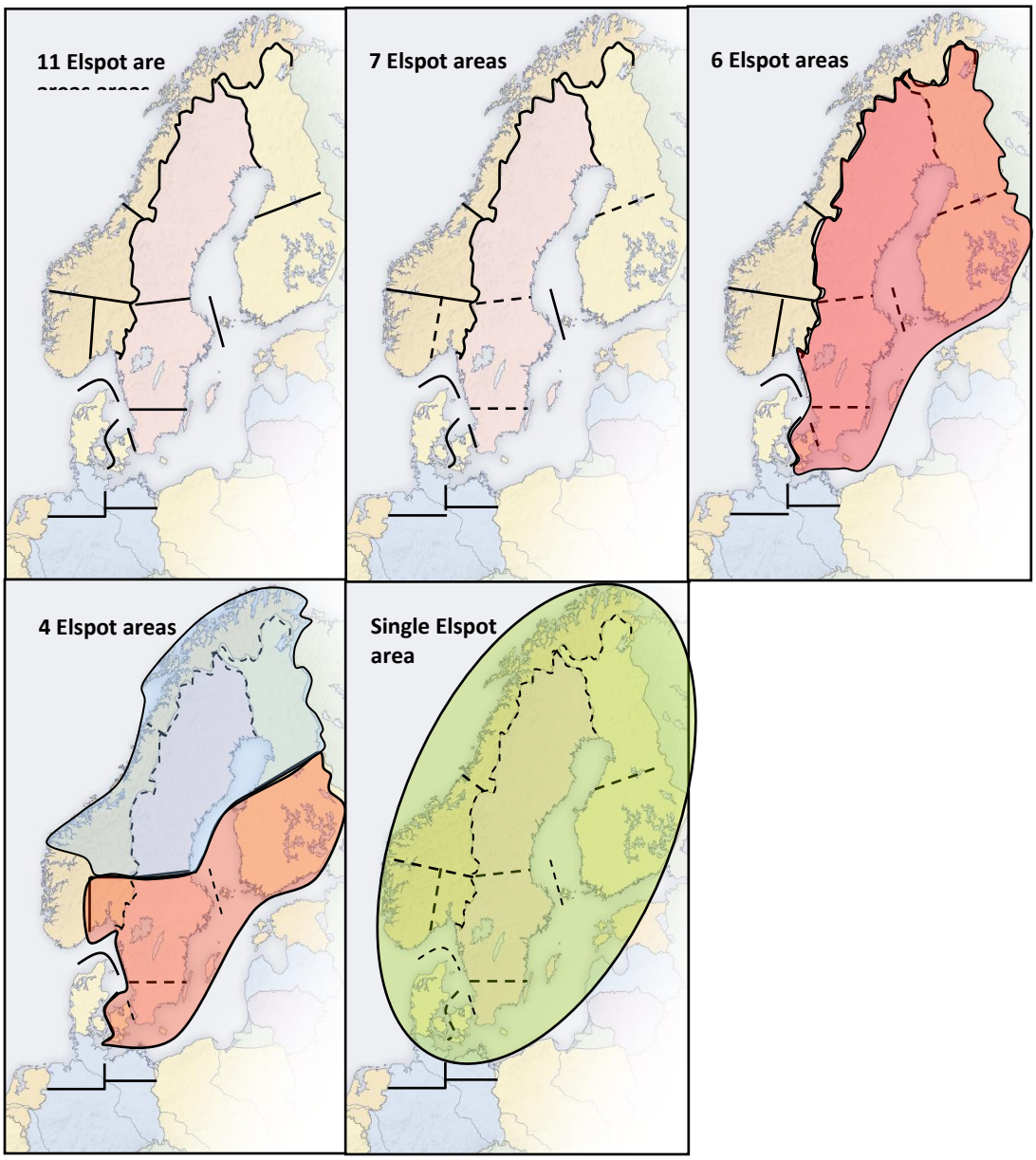

Figure 1: Market divisions in the 5 analysed settings.

The model simulations are carried out for the Nordic power system in year 2015 (with the 5 prioritized links).

4.3 General consequences of different CM regimes with respect to resource efficiency

The principal difference between congestion management regimes based on market splitting and counter trade is that market splitting resolves congestions in the spot market clearing whereas counter trade solves congestion after the spot market has been cleared. The two regimes result thus in different electricity prices in the spot market and thereby different economic consequences to power producers and consumers.

If counter trade is carried out optimally, including counter trade across borders, it will in this ideal model lead to the same final power dispatch and thereby the same overall resource utilization as market splitting in the competitive market setting.

However, different electricity prices in the spot market will have consequences on the distribution of welfare, e.g., between producers and consumers and among countries depending on how the costs for counter trade are divided. Moreover, there will be implications for long-term investment signals as spot prices are different in the two regimes.

The fact that use of this ideal counter trade has impact on welfare distribution is illustrated in the figure below. The figure illustrates the loss to generators in an area with congestion on the import capacity in the counter trade situation compared to the market splitting situation.

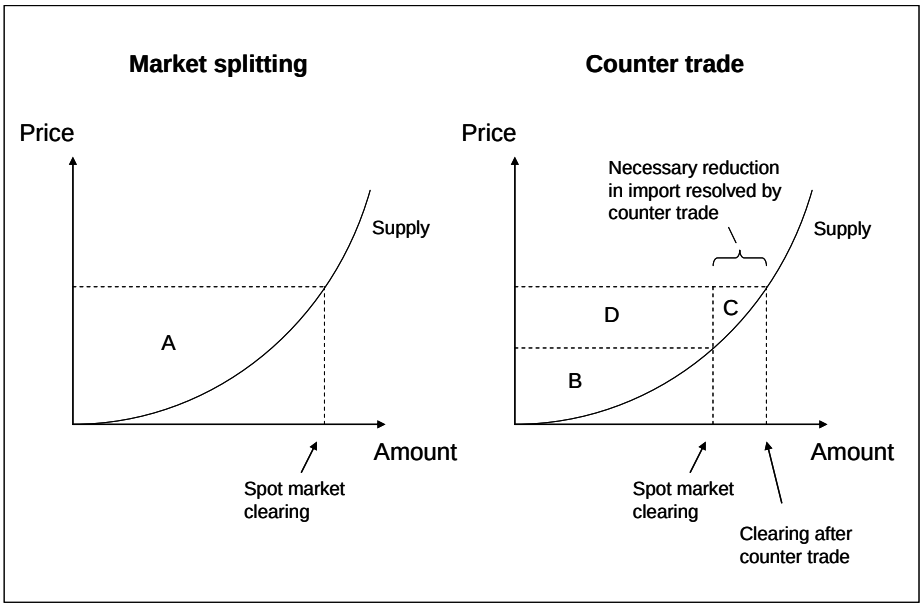

Figure 2: Consequence in deficit area

It should be noted, that we assume that a counter trade market, as well as the spot market, is subject to a clearing price. In today's practice, counter trade is conducted bilaterally and is more accurately represented as a pay-as-bid market. As the model is based on full information, one can expect that rational, profit maximizing market players will in a pay-as-bid market bid precisely the clearing price, as they are able to correctly anticipate the need and supply potential of counter trade.

In the situation with market splitting, the spot market will clear as shown in the left hand side of the figure and the generators will obtain the producer surplus corresponding to the area "A".

In the situation with counter trade, i.e., the congestion on the import capacity to the area is not initially taken into consideration, the spot market will clear as shown in the right hand side of the figure. The generation level found in this spot market clearing is lower than in the market splitting situation because a larger amount of electricity is calculated as being imported to the area from an area with lower marginal generation costs. In this situation, the generators in the spot market obtain the producer surplus "B".

To ensure the operational security, the TSO has to buy additional generation locally as the higher import compared to the market splitting situation is impossible due to congestion on the import line. The TSO therefore pays some of the local generators for up regulation and these generators obtain the producer surplus "C".

After ideal counter trade, the generated electricity is the same in the situation with counter trade as in the situation with market splitting (and the same generators will be in play). However, the generators in the importing area have lost the producer surplus "D". Conversely, in the exporting region the generators would oppositely have gained from the counter trade situation (see figure below).

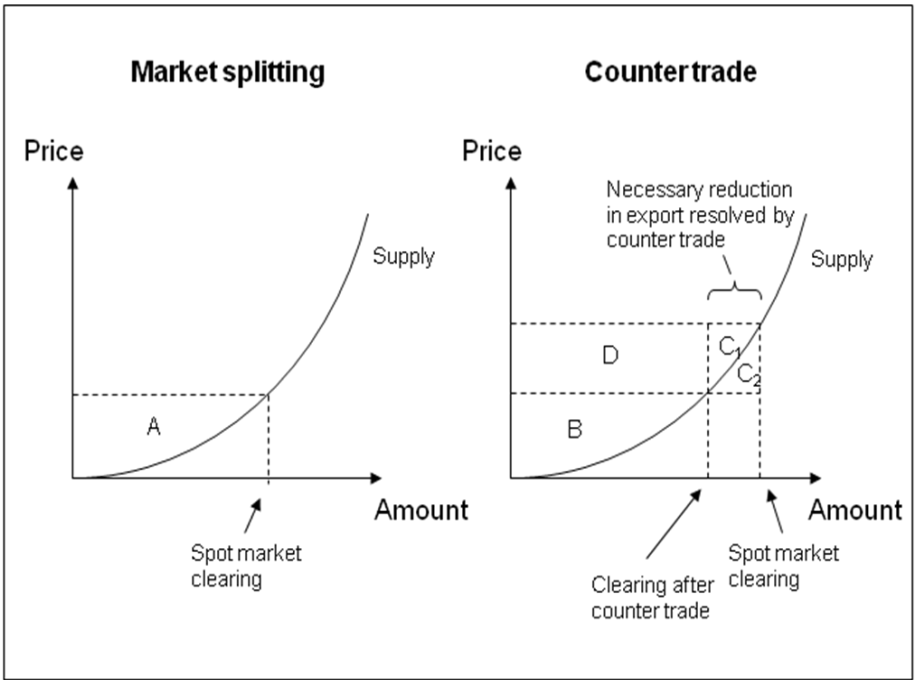

Figure 3: Consequence in producer surplus (export region)

In the situation with market splitting, the spot market will clear as shown in the left hand side of the figure and the generators will obtain the producer surplus corresponding to the area "A".

In the situation with counter trade , i.e., the congestion on the export capacity to the neighbouring area is not initially taken into consideration, the spot market will clear as shown in the right hand side of the figure. The generation level found in the spot market clearing is higher than in the market splitting situation because a larger amount of electricity is calculated as being exported to the neighbouring area with higher marginal generation costs. In this situation, the generators in the spot market obtain the producer surplus "B" + "C1" + "D".

To ensure the operation of the transmission line, the TSO will ask some local generators not to produce in spite of the fact that they have been selected in the spot market. These generators will, while retaining their spot contract, be willing to pay back some of their revenue to the TSO, in order to save the costs associated with generation. These generators get a profit of "C1" + "C2". In the case they bid their marginal costs and are awarded by the pay as bid principle, they would only retain the profit "C1", but in this case they do not have incentive to take part in the counter trade.

After counter trade, the generated electricity is the same in the situation with counter trade as in the situation with market splitting (and the same generators will be in play). However, the generators in the exporting area have gained the producer surplus "D", "C1" and "C2" compared to the market splitting situation.

The changes in incentives and surplus for demand response in connection with counter trade is analogous to the situation for generators.

If counter trade is executed by using only part of market, the available physical resources for resolving congestions are limited compared to full counter trade and market splitting. This is in fact the situation today where all countries conduct counter trade internally (and not across cross-borders), which is demonstrated in the 7 area simulation.

Counter trading in practice

There are a number of key differences in the way we represent ideal counter trade in the model and the way it is currently conducted in practice. First, counter trading should ideally take advantage of all resources in the system in order to ensure total efficiency. Incentives should be visible to all market players and the process should be transparent so that players know how to engage in the market. A real cost-effective system of counter trade has to be executed in Elspot where the bids include all possible production and demand changes. Today's counter trade is done bilateral or within the regulation market and includes normally only bigger bids in the country of the TSO. The other very important problem is that the use of counter trade gives incentives for *strategic bidding* to all players then they anticipate counter trade (this issue is further analysed in section 5.4). None of these two important problems are caught in the model and thus not in the calculations. The results for the cases with extensive counter trade shall therefore not be seen as indications on what can be achieved in reality with extensive counter trade.

Counter trade and consequences in the analyses

CM today combines capacity reductions and some counter trade within national borders. A representation of this practice with the current 7 Elspot areas is used as the baseline case. The capacity reductions are described below in section 4.4.

In an alternative 7 area case, only counter trade, not capacity reductions, is used internally in Sweden, Finland and Norway, to resolve congestion on cut 2, cut 4 and P1 and west of the Oslo Fjord area. This is to asses the implication of capacity reductions versus national counter trade.

The 11 area case has no need for counter trade (as all bottlenecks in the model have been taken into consideration). Counter trade may occasionally be needed to resolve temporary bottlenecks; however this form of counter trade is disregarded for the purpose of the model analyses.

Finally, the 3 cases with larger trans-national Elspot areas (6, 4 and 1 areas) assumes that the counter trade can use all possible changes in production and consumption in the entire Nordic region.

4.4 Capacity reductions

CM in the 7 area baseline is done by transmission capacity reductions. Capacity reductions are part of the current practice; in Sweden to prevent congestion on cut 2 and cut 4; in Finland to prevent congestion on P1; and in Norway to prevent congestion west of the Oslo Fjord.

The situations handled are illustrated on Figure 4**Fejl! Henvisningskilde ikke fundet.** for Sweden, Figure 5 for Finland and Figure 6 for Norway. Congestion which remains after the spot market simulation with reduced capacities is resolved using counter trade.

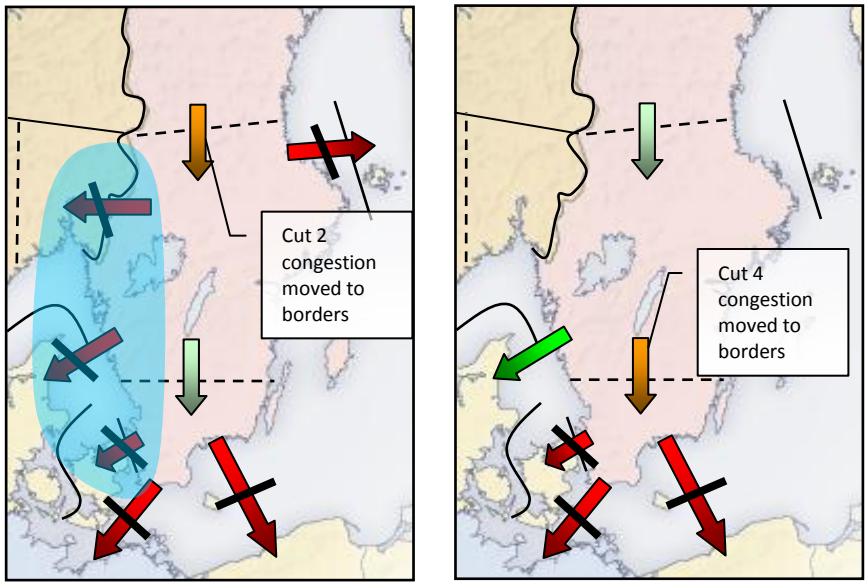

Figure 4: Export capacity reductions to resolve internal Swedish congestion on cut 2 and cut 4. The congesting flows (orange arrows) are prevented by reducing export capacities pro-rata along the red arrows. The blue field indicates that the reductions to resolve cut 2 are performed using an Elspot optimization area.

Swedish capacity reductions

The Swedish practice of capacity reductions has implication for flows to Southern Norway, to Southern Finland on Fenno-Skan, to Denmark on Konti-Skan and Øresund, to Poland on Swe-Pol, and to Germany on the Baltic cable. Capacity reductions are performed *pro-rata* on the relevant export lines, however the connections to Southern Norway and Denmark are reduced collectively by the introduction of an optimization area. Pro-rata implies that capacities are reduced on each connection in proportion to the rated capacity in relation to the sum of all rated capacities on the relevant export lines.

When capacity reductions are insufficient to prevent congestion on the two cuts, residual congestion is resolved by counter trade internally in Sweden.

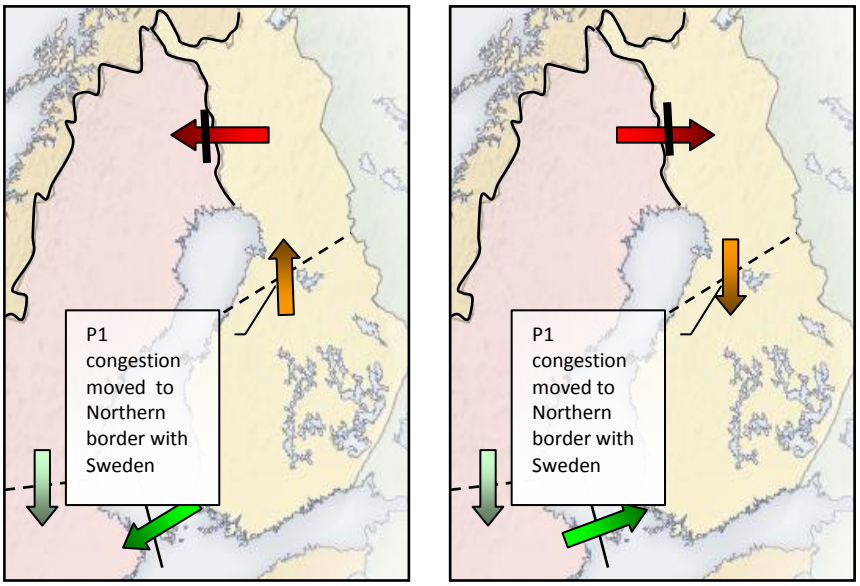

Figure 5: Export capacity reductions to resolve internal Finnish congestion P1. Capacity reductions are used to resolve P1 congestion in both directions. Predominantly, northbound congestion occurs when hydro production in Northern Finland is low, whereas southbound congestion occurs when hydro production in Northern Finland is high.

Finnish capacity reductions

In Finland, congestion has been observed in both directions across P1. High hydro production in Northern Finland may cause congestion on P1 in the southbound direction. To prevent this, it has been practice to reduce import from the north of Sweden. Conversely, when there is a low hydro production in Northern Finland, congestion can occur in the northbound direction on P1. To prevent this, it has been practice to reduce export to the north of Sweden.

Norwegian capacity reductions

Norway is the Nordic country with most Elspot areas and changed earlier often the area division. However, at times when there is high demand in the Oslo area, congestion west of Oslo from the western part of Norway has been managed by reducing export capacity on the border to Sweden. This reduction follows the load in the Oslo area as illustrated in Figure 7.

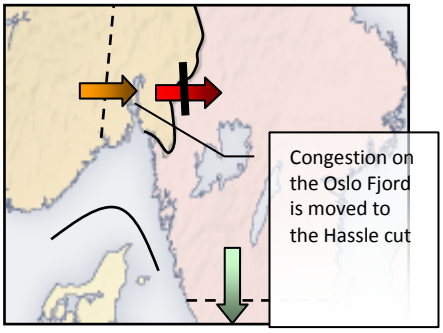

Figure 6: Export capacity towards Sweden from the Oslo area is reduced to prevent congestion west of Oslo.

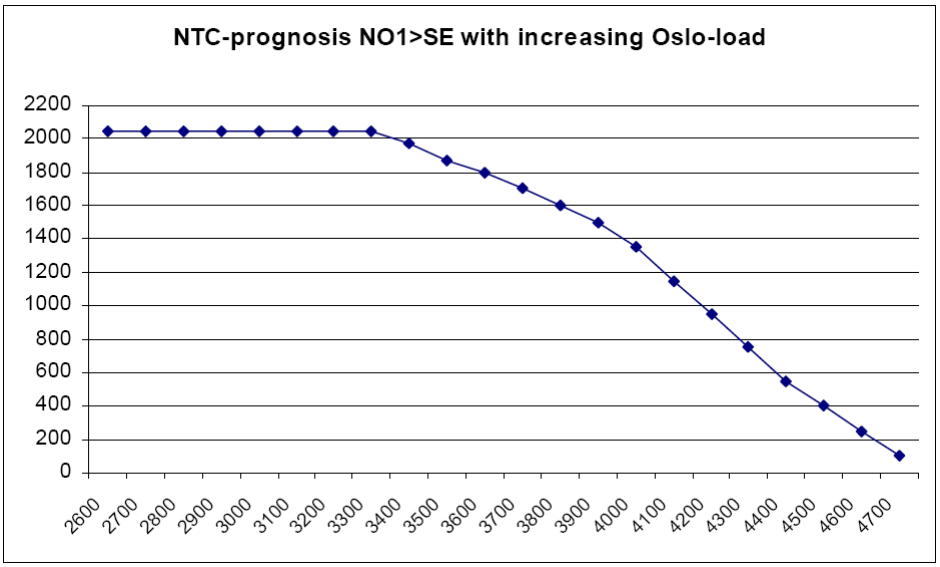

Figure 7: Capacity reductions from the Oslo area to Sweden dependent on the Oslo-load.
Source: *Principles for determining the transfer capacity in the Nordic power market*, Nordel, January 23, 2008

Note that the export reductions are determined on the basis of nominal load. The actual load determined in the model may differ from this as load is price responsive.

Note also that the South-West link is assumed to transport power from west of the Oslo Fjord, to Sweden, thereby reducing congestion west of Oslo.

These are the capacity reductions that we have simulated in the model. No capacity reductions are simulated for Denmark. The only relevant practice is reduction of capacity on Konti-Skan and Skagerak, which are not the result of internal congestion, but rather a consequence of the two connections being connected to the same substation. Administratively moving congestion to the border only occurs in very special circumstances such as outages in the transmission grid.

Regarding implementation of capacity reductions

The scope of capacity reductions necessary to eliminate the need for counter trading for exports cannot be calculated accurately, before the market clearing. At times capacity reductions do not take care of all the congestion, and at other times capacity reductions may remove congestion while restricting trade excessively. This is an issue in practice and also in the model, and we cannot claim that the simulated reductions precisely emulate the current practice, nor give any least cost arguments to that effect. Also, pro-rata reductions are by no means optimal with respect to resource utilization. It is however the current practice, and as such, we have conducted our simulations accordingly. It must also be emphasised that electricity market models such as Balmorel assume full foresight with respect to the congestions, and although the model is not used to generate the “optimal” reductions, full foresight will in practice be more likely to get better results than is practical, without using bid information from Elspot. In the current practice, reductions are made before this bid information

is accessible, and therefore the TSO's make capacity reductions on the basis of anticipated congestion. This implies that in actuality, the economic impact of the capacity reduction practice is a too low estimate.

4.5 Results of analyses (normal hydrological year)

In the following, the results of each case are described with respect to power balances, electricity prices, power flows, and the costs and benefits. The analysed cases are:

- 11 Elspot areas (full market splitting - does not involve counter trade)
- 7 Elspot areas with capacity reductions (current Elspot – **Baseline**)
- 7 Elspot areas with counter trade within national boundaries
- 6 Elspot areas with full counter trade in the Nordic countries
- 4 Elspot areas with full counter trade in the Nordic countries
- 1 Elspot area with full counter trade in the Nordic countries

The case with 11 areas is here called "full market splitting" as it takes all congestion represented in the model into consideration in the spot market clearing, and therefore involves neither counter trade nor capacity reductions. 4 of the other analysed CM regimes involve extensive counter trade. The baseline includes limited counter trade as complement for situations when capacity reductions are not enough to solve the congestion. However, full market splitting could in reality be a CM regime with more than 11 areas or even a "nodal pricing" system depending on the number of congestions that are taken into consideration in the day ahead market.

Energy balances

The tables below show the energy balance in 2015 for each of the six analyzed CM regimes, i.e., the generation in each country divided by main technologies as well as the net import and consumption (including network losses). The assumptions regarding available capacity in each country is described in more detail in the appendix.

Table 1: Simulated energy balance in 2015 - 7 areas reduced - Baseline

	Denmark	Finland	Norway	Sweden	Total
Total generation	49,323	89,135	127,236	156,760	422,454
- Nuclear power	0	35,027	0	67,941	102,968
- Other thermal power	38,703	39,918	2,517	14,915	96,053
- Hydro power	0	12,574	114,969	62,701	190,244
- Wind power	10,620	1,616	9,750	11,203	33,189
Net import	-12,135	8,949	7,776	-318	4,272
Total consumption (including network losses and electric boilers)	37,188	98,085	135,014	156,497	426,784

From Table 1 it appears that the total generation in the Nordic countries is around 422 TWh and that the net import to the Nordic countries is around 4 TWh summing up to a total consumption of 427 TWh. The hydro power generation covers app. 45% and the wind power 8% of total generation. The assumptions regarding wind power are based on the Nordel study: *Wind Power in Nordel - system impact for the year*

2008. In the simulation Denmark is the largest net exporter of electricity whereas Finland is the largest net importer of electricity.

Compared with today, there is an increase in total nuclear output. This is mainly due to the 1600 MW nuclear plant in Finland, which is assumed to be completed before 2015.

There are considerable net exports from the Nordic region to the Continent (i.e. Germany, Poland and the Netherlands) in these simulations. However, there is also a fixed import to Finland of 11 TWh from Russia and 2 TWh from Estonia annually.

Energy balances for the alternative cases are shown in Annex 2.

Electricity prices

Table 2 shows the spot prices in the analysed cases. Areas which are a part of the same Elspot area are colour-coded accordingly.

Table 2: Simulated spot prices 2015 in the analysed CM regimes (EUR/MWh)

	DK_E	DK_W	FI_N	FI_S	NO_N	NO_M	NO_S	NO_O	SE_N	SE_M	SE_S
11 areas	0.5	0.5	0.0	0.0	0.0	0.0	0.5	0.5	0.0	0.7	0.6
7 areas reduced (baseline)	40.8	40.7	41.0	41.0	36.6	36.6	41.9	41.9	41.0	41.1	41.1
7 areas	0.0	0.0	0.2	0.2	0.0	0.0	0.0	0.0	0.2	0.2	0.2
6 areas	0.4	0.1	0.2	0.2	0.0	0.0	0.0	0.0	0.1	0.1	0.1
4 areas	0.0	-0.3	-0.3	-0.2	4.1	4.0	-0.9	-1.0	-0.3	-0.2	-0.2
1 area	0.0	0.1	-0.2	-0.2	4.2	4.2	-1.1	-1.1	-0.2	-0.2	-0.3

The spot price varies according the number of Elspot areas and also on whether transmission capacities are reduced or not. Also, the spot prices are very much dependent on the power flows with the Continent. Generally, when transmission constraints internally in the Nordic region are relaxed, more power will be transmitted towards the often higher prices on the Continent. Therefore the residual power balance in the Nordic countries becomes tighter resulting in higher prices.

Table 3: Simulated counter trade prices relative to spot prices (EUR/MWh)

	DK_E	DK_W	FI_N	FI_S	NO_N	NO_M	NO_S	NO_O	SE_N	SE_M	SE_S
11 areas	-	-	-	-	-	-	-	-	-	-	-
7 areas reduced (base)	-	-	-0.1	-0.1	-	-	-	-	-0.2	0.7	0.7
7 areas	-	-	0.0	-0.1	-	-	-	-	-0.3	2.5	2.5
6 areas	0.3	-1.3	-0.1	-0.1	0.0	0.0	0.6	0.6	-0.1	0.6	0.7
4 areas	0.3	0.7	0.3	0.2	-4.1	-4.0	1.6	1.7	0.3	1.0	1.0
1 area	0.3	0.2	0.2	0.2	-4.2	-4.2	1.7	1.8	0.2	1.0	1.0

Table 3 shows the differential between average spot area prices and the local price of counter trade within all 11 areas where applicable. 11 Elspot areas has no counter trade and therefore no price differentials. The Finnish counter trade price differentials in both 7 area situations are an expression inaccuracy since congestions does not appear in P1 in a normal hydrological year.

In the 7 Elspot area cases, the counter trading price differentials in Sweden are negative north of cut 2 and positive south of cut 2, indicating that cut 2 is the most import internal Swedish congestion after the South-West link is completed. The average counter trade price differentials are numerically greater if Sweden abstains from performing capacity reductions in the 7 area setting, as one would expect.

In the 6 Elspot area setting, the North and Middle areas in Norway have no counter trade price differential in a normal hydrological year. Southern Norway, Sweden south of cut 2 and Eastern Denmark all have positive CT price differentials, indicating congestion on cut 2 and perhaps Fenno-scan.

In the 4 and single Elspot area settings it is most notable that counter trading prices are only negative in North and Middle Norway. Everywhere else, including Northern Sweden, there is a generally positive counter trade price differential.

Cost and benefits

The tables below show the changes in costs and benefits. The costs and benefits are only provided for the alternative CM regimes (alternatives to the baseline), as each of these are evaluated relative to the baseline, i.e., the 7 Elspot area situation with capacity reductions.

We have assumed in the model that congestion rents on national borders are divided 50/50 between the respective TSOs and that congestion rents on Elspot borders within a country is referred to the national TSO. The Nordic TSOs uses a more complicated model for the division of congestion rents between the TSOs.

Counter trade costs are financed by the TSOs. These costs will most likely be allocated via the grid tariffs to mostly the consumers and partly the generators. In the 7 Elspot area case we assume that national TSOs bear the cost of counter trade. In the 6, 4 and single Elspot area cases it will be necessary to agree upon a common financing scheme.

Table 4: Change in costs and benefits – 7 areas with full national counter trade in relation to the baseline with capacity reductions (mEUR)

	Denmark	Finland	Norway	Sweden	Continent	Sum
Generator profits:	1	16	2	44	-158	-94
Consumer surplus:	-1	-30	-2	-20	149	97
Public proceeds:	0	0	0	0	1	1
Subtotal	0	-14	0	24	8	3
Congestion rents	-3	2	0	14	30	44
Counter trade (gen.)	0	0	0	-18	0	-18
Counter trade (DR)	0	0	0	-10	0	-10
Socio economic benefit:	-3	-11	1	11	22	19

Table 4 shows the consequence of the 7 area case with full national counter trade compared to the current spot market situation with capacity reductions. It appears that the total benefit of not using capacity reductions has been estimated to 19 million EUR. It also appears that the benefit is largest for the Continent and that that the Nordic region as a whole would actually loose 2 million EUR from not using capacity reductions. This is because export capacity reductions prevent export of power below generation costs to the Continent.

Looking at the welfare distribution consequences, it appears that the Nordic generators in general benefit from not using capacity reductions whereas Nordic consumers in general lose, and opposite for the Continent.

The table below shows the changes in costs and benefits in the 11 area case compared to the baseline.

Table 5: Distribution of costs and benefits – 11 areas compared to baseline (mEUR)

	Denmark	Finland	Norway	Sweden	Continent	Sum
Generator profits:	33	1	72	74	-152	28
Consumer surplus:	-26	-2	-74	-117	144	-75
Public proceeds:	1	0	-1	0	1	1
Sub total	7	0	-3	-43	-7	-46
Congestion rents	-7	4	0	49	21	67
Counter trade (gen.)	0	0	0	4	0	4
Counter trade (DR)	0	0	0	4	0	4
Socio economic benefit:	0	3	-3	15	14	30

In this situation, the total benefit compared to the baseline is 30 million EUR. Compared to

Table 4, it also appears that the 11 area situation is 11 million EUR better than the 7 area case.

Also in this case, the Nordic generators benefit compared to the baseline and the Nordic consumers lose, and opposite at the Continent. For the Nordic countries and the Continent as a whole, there is a benefit to the producers and a loss to the consumers.

The following three tables show the changes in costs and benefits in the 6, 4 and single area cases, respectively. The 6 area situation is based on the market division proposed in a position paper from the Finnish Energy Industries whereas the 4 area situation is based on the market division as proposed in the POMPE study. The single area situation illustrates the consequences of having all Nordic areas a one common price area.

In all three situations, the total benefit compared to the baseline situation varies from 17 to 27 million EUR; this also means that these three situations – although the model is based on ideal counter trade – from a direct economic point of view are worse than the 11 area situation in which the benefit was 30 million EUR.

Table 6: Distribution of costs and benefits – 6 areas compared to baseline (mEUR)

	Denmark	Finland	Norway	Sweden	Continent	Sum
Generator profits:	23	18	3	22	-148	-82
Consumer surplus:	-5	-17	-1	-27	141	91
Public proceeds:	1	0	-1	0	1	2
Subtotal	19	1	1	-5	-5	10
Congestion rents	-5	2	-1	10	29	35
Counter trade (gen.)	45	18	-90	0	0	-26
Counter trade (DR)	-1	0	-2	1	0	-2
Socio economic benefit:	58	21	-92	7	23	17

Table 7: Distribution of costs and benefits – 4 areas compared to baseline (mEUR)

	Denmark	Finland	Norway	Sweden	Continent	Sum
Generator profits:	0	-31	261	-152	-197	-120
Consumer surplus:	9	14	-41	22	189	192
Public proceeds:	0	0	-1	0	1	1
Subtotal	9	-18	219	-130	-7	73
Congestion rents	-5	-1	-61	-18	37	-49
Counter trade (gen.)	0	0	0	4	0	4
Counter trade (DR)	-1	0	-2	1	0	-2
Socio economic benefit:	2	-18	155	-142	30	27

Table 8: Distribution of costs and benefits – 1 area compared to baseline (mEUR)

	Denmark	Finland	Norway	Sweden	Continent	Sum
Generator profits:	12	-7	263	-30	-198	40
Consumer surplus:	6	13	-33	27	194	207
Public proceeds:	0	0	-1	0	1	1
Sub total	19	6	230	-3	-3	248
Congestion rents	-10	-2	-67	-25	38	-66
Counter trade (gen.)	15	-14	-78	-77	0	-154
Counter trade (DR)	-1	0	-2	1	0	-2
Socio economic benefit:	23	-11	82	-104	35	26

From the tables it appears that the best of all analysed cases is the 11 area situation, i.e., the full market splitting situation which does not involve counter trade.

The reason why all situations involving counter trade come up with a total welfare-economic loss compared to the full market splitting situation is that counter trade is not executed using the whole analysed region.

In the 7 area situation counter trade is carried out only internally in each country. In the 6, 4 and single area situation, counter trade is carried out in the whole Nordic region. However, counter trade is not carried out using flexibility on the Continent, and therefore also in these situations there is a total loss compared to the 11-area situation. It appears that the loss in these two situations is of same size (and not very large).

However, since the important problems with extensive counter trade are not caught in the model and thus not in the calculations, the results for the cases with extensive counter trade shall not be seen as real indications on the benefit with extensive counter trade.

4.6 *Sensitivity:* Effects in different hydrological Dry year

The table below shows the energy balance in the baseline situation in a dry year.

Table 9: Simulated energy balance in 2015 - 7 areas reduced - Baseline - Dry year

	Denmark	**Finland**	**Norway**	**Sweden**	**Total**
Total generation	50,955	94,716	110,584	150,729	406,984
- Nuclear power	0	35,027	0	67,941	102,968
- Other thermal power	40,335	47,363	3,991	18,335	110,024
- Hydro power	0	10,710	96,843	53,250	160,803
- Wind power	10,620	1,616	9,750	11,203	33,189
Net import	-13,790	3,320	24,336	5,616	19,482
Total consumption (including net-work losses and electric boilers)	37,189	98,089	135,008	156,482	426,768

Compared to the normal hydrological year (Table 1), the total generation in Norway and Sweden and also the total Nordic generation is lower in this situation.

The table below shows the changes in costs and benefits in the 11 Elspot area case compared to the baseline.

Table 10: Distribution of costs and benefits – 11 areas (mEUR) - Dry year compared to baseline –Dry year

	Denmark	Finland	Norway	Sweden	Continent	Sum
Generator profits:	25	-4	53	57	-132	-2
Consumer surplus:	-19	0	-54	-87	125	-35
Public proceeds:	1	0	-1	0	1	2
Sub total	6	-4	-2	-30	-5	-35
Congestion rents	-6	7	0	35	18	53
Counter trade (gen.)	0	1	0	1	0	3
Counter trade (DR)	0	0	0	3	0	3
Socio economic benefit:	0	4	-2	10	12	24

In this situation, the benefit of the 11 area case compared to the baseline case is 24 million EUR, which is 6 million EUR less than in the normal hydrological year (Table 5). The main bottlenecks which are treated differently in the two cases are bottlenecks from the hydro intensive areas, towards the thermal/consumption intensive areas. Congestion rents in the 11 area case are higher than in the baseline, but relatively less than in the normal hydrological year. Likewise, the counter trade costs in the baseline with scarce hydropower, are less than in normal hydrological baseline.

Wet year

The table below shows the energy balance in the baseline case in a wet year.

Table 11: Simulated energy balance in 2015 - 7 areas reduced - Baseline - Wet year

	Denmark	**Finland**	**Norway**	**Sweden**	**Total**
Total generation	46,323	85,549	134,970	161,515	428,357
- Nuclear power	0	35,027	0	67,941	102,968
- Other thermal power	35,703	34,813	1,523	12,407	84,446
- Hydro power	0	14,093	123,697	69,964	207,754
- Wind power	10,620	1,616	9,750	11,203	33,189
Net import	-9,134	12,535	128	-5,079	-1,550
Total consumption (including net-work losses and electric boilers)	37,190	98,085	135,100	156,503	426,878

The table below shows the changes in costs and benefits in the 11 area situation compared to the baseline.

Table 12: Distribution of costs and benefits – 11 areas (mEUR) - Wet year

	Denmark	Finland	Norway	Sweden	Continent	Sum
Generator profits:	37	3	83	76	-152	47
Consumer surplus:	-30	-3	-86	-123	145	-96
Public proceeds:	1	0	-1	0	1	1
Sub total	8	0	-4	-46	-6	-48
Congestion rents	-8	4	1	50	18	65
Counter trade (gen.)	0	0	0	8	0	8
Counter trade (DR)	0	0	0	5	0	5
Socio economic benefit:	0	3	-3	17	12	30

In this situation, the benefit of the 11 area situation compared to the baseline situation is 30 million EUR, which is similar to the normal hydrological year (Table 5).

4.7 *Sensitivity*: Simulations without some of the prioritized links.

It has been concluded in numerous studies that the five prioritized links will reduce congestion issues between Nordic areas greatly.

The table below shows the energy balance in the baseline situation in the situation without Skagerrak 4 and the South-West link.

Table 13: Simulated energy balance in 2015 - 7 areas reduced - Baseline - Without Skagerrak 4 and the South-West link

	Denmark	**Finland**	**Norway**	**Sweden**	**Total**
Total generation	48,707	87,678	133,571	153,201	423,157
- Nuclear power	0	35,027	0	67,941	102,968
- Other thermal power	38,087	39,095	2,644	14,352	94,178
- Hydro power	0	11,940	121,177	59,705	192,822
- Wind power	10,620	1,616	9,750	11,203	33,189
Net import	-11,524	10,405	1,421	3,268	3,570
Total consumption (including network losses and electric boilers)	37,189	98,085	135,007	156,501	426,782

The table below shows the changes in costs and benefits in the 11 area situation compared to the baseline.

Table 14: Distribution of costs and benefits - 11 areas (mEUR) - Without Skagerrak 4 and the South-West link

	Denmark	Finland	Norway	Sweden	Continent	Sum
Generator profits:	30	10	35	93	-175	-8
Consumer surplus:	-24	-10	-36	-145	167	-49
Public proceeds:	1	0	0	1	2	2
Sub total	6	-1	-1	-52	-6	-54
Congestion rents	-5	5	1	61	21	83
Counter trade (gen.)	0	0	0	1	0	1
Counter trade (DR)	0	0	0	2	0	2
Socio economic benefit:	1	4	0	13	15	33

In this situation, the benefit of the 11 Elspot area case compared to the baseline situation is 33 million EUR, which is similar to the normal hydrological year (Table 5). It should be emphasized, that the figures on Table 14 in no way reflect the value of the connections, as the connections are assumed not to be present in both the baseline and alternative scenarios. What can be derived is that the benefit of a market which ensures optimal dispatch is roughly the same before and after these two important infrastructure investments are completed.

5 CM, Competition and Market Power

The impact on the different market players due to market concentration will vary under different CM regimes. Ideally, we should as in chapter 3 base the analysis on the situation in 2015 after the five prioritized links have been realized. However, it is much more difficult to forecast changes in the market structure than changes in the production and transmission system. New production plants and transmission links have long lead times. Most of the physical changes that will occur in the coming seven years are already decided or at least publicly announced. Mergers and acquisitions have on the contrary much shorter lead times. Only a few of the market structure changes that will occur in the coming seven years are already decided or publicly announced.

We have therefore chosen to start with a description regarding 2007 of the concentration in Nordic wholesale markets using two different indices, HHI and PSI. We will discuss possible development of the market concentration between 2007 and 2015. We will also summarize the HHI and PSI calculations done by London Economics regarding six European markets in 2003-2005.

We describe thereafter consequences of different CM regimes for competition and market power in the financial and retail markets.

Finally, we illustrate some principle models for market power in wholesale markets in alternative CM regimes.

5.1 Herfindahl-Hirschman Index in the wholesale markets

The Herfindahl-Hirschman Index (HHI) is a measure of the concentration in a market. The HHI indicator is calculated as the sum of the squares of the market shares of all companies in the market. The higher HHI, the more is the market concentrated. The maximum HHI is 10 000 and corresponds to a monopolistic market with one company having a market share of 100 %.The US Federal Trade Commission/Department of Justice guidelines stipulates that a HHI over 1800 corresponds to high market concentration and a HHI under 1000 corresponds to low market concentration. A HHI between 1800 and 1000 corresponds to moderate market concentration.

The power market has special characteristics compared to other markets. Real time balancing is needed because electricity is practically not storable. There are many transmission constraints that divide the power market into shifting constellations of relevant geographic markets. The demand is very inelastic. The power market with day-ahead markets and continuous intra-day markets has also the character of a repeated game that reduces the uncertainty regarding the behaviour of other players.

These special characteristics indicate that the thresholds for high concentration and moderate concentration should be lower for power markets than for other markets.

HHI in Nordic markets

We have calculated HHI for the different relevant geographic markets based on total installed capacity in 2007. Ideally the calculations should be based on available capacity for each hour but we have not had the needed data for such calculations. The relevant geographic markets have been defined as the different Elspot areas or the constellation of Elspot areas that have common price. The capacities of interconnectors to other areas with other prices are not included in the calculations. This means that the calculated HHI for an area constellation is an indicator of the market power to lift the price to the level in an adjacent area constellation – not to the maximum price. Our aim has been to adjust the figures for installed capacity per company for direct and indirect financial ownerships. The figures for Norway are based on the very thorough report "Ownership relations and cooperation in the Norwegian power market" (SNF-report No. 35/2006). The figures for other markets are not as precise and can underestimate the real HHI in these markets.

The following HHI have been calculated for the different Elspot areas within the Nordic market. We have only calculated a common HHI for NO2 and NO3 since the SNF-report does not distinguish between these areas.

Elspot area	**HHI**
DK1 (Western Denmark) with full wind production	1731
DK1 (Western Denmark) with no wind production	3287
DK2 (Eastern Denmark)	5782
FI (Finland)	1576
NO1 (Southern Norway)	1967
NO2+NO3 (Northern Norway)	2975
SE (Sweden)	3204

The wind power capacity is so significant in Western Denmark that HHI has been calculated for both situations with full wind production and situations with no wind production. In the first situation with full wind production, Western Denmark is together with Finland the only Elspot areas under the threshold 1800 for high market concentration. When there is no wind production, the market concentration in Western Denmark is as high as in Sweden and in Northern Norway. The highest market concentration is in Eastern Denmark.

We have also calculated HHI for all possible constellations of Elspot areas with common price. The lowest HHI, 933, is when all Nordic areas have common price. This HHI is just under the threshold 1000 for moderate market concentration. Considering the special characteristics of the power market mentioned above, this means that the

market concentration can be problematic even when all Nordic areas have common price.

Normally, the HHI is lowered when different Elspot areas get common price and become a common market. However, the HHI increases from 1576 to 1874 when Finland gets a common market with only Sweden. The HHI increases in the same way from 1188 to 1275 when the constellation Southern Norway and Denmark gets a common market with only Sweden.

The following figures illustrates HHI for all the constellations that a special Elspot area belonged to during 2007. Hours with constellations with the highest HHI are to the left in the figures while hours with the lowest HHI (common Nordic price) are to the right in the figures.

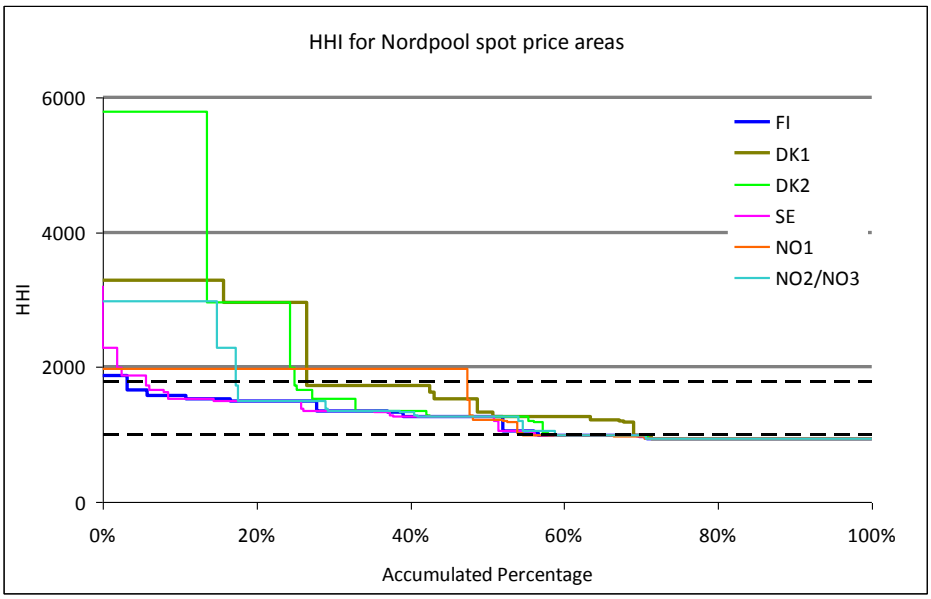

Figure 8: HHI index for the current Nordpool price areas.

The average time-weighted HHI in 2007 was 1212 for Finland, 1221 for Sweden, 1438 for Northern Norway, 1449 for Southern Norway, 1752 for Western Denmark and 1958 for Eastern Denmark. This means that all Nordic areas had in 2007 a time-weighted HHI over the the threshold 1000 for moderate market concentration.

The development in market concentration between 2007 and 2015 can be expected to follow two trends. The first trend is that the new decided transmission links will further integrate the markets. Nordel presented in its Nordic Grid Master Plan 2008 a calculation showing that the number of hours with common price in the Nordic market – or at least area price differences under 2€/MWh – will increase from 44 % in 2005 and 2006 to 65 % in 2015. However, it is also calculated that the percentage of time with common price or nearly common price will only be 25 % if 2015 is a dry year and 38 % if 2015 is a wet year. This market integration by new transmission links

means that the curves in the figures are moved to the left and that the time-weighted HHI is decreased in the different Nordic areas.

The other expected trend is that mergers and acquisitions will continue to increase the market concentration in most of the different market areas and in the Nordic region as a whole. Mergers and acquisitions mean that the curves in the figures are moved upwards and that the time-weighted HHI is increased in the different Nordic areas. For example will ceteris paribus an acquisition of 2000 MW by Vattenfall, Statkraft or Fortum increase the HHI for a common Nordic market to about 1000. Dependent on the assumptions regarding mergers and acquisitions will the net effect 2015 of market integration by new transmission links and market concentration by mergers and acquisitions be a decreased or an increased time-weighted HHI in the different Nordic areas.

HHI in European markets

The Commission published in April 2007 a study by London Economics regarding market performance in six European wholesale markets. The study covered Belgium, France, Germany, the Netherlands, Spain and Great Britain and included an analysis of every hour during 2003, 2004 and 2005.

The Commission collected hourly primary data per generation unit as one part of its sector inquiry. About 500 million data points were collected. The hourly data made it possible to calculate marginal costs, HHI, RSI and PSI for each hour. The data collection and analysis was on a scale that is unprecedented in the electricity-economics field globally.

The calculated HHI were as follows for the six countries.

Country	**HHI**
Belgium	8307
France	8592
Germany	1914
Great Britain	1068
Netherlands	2332
Spain	2790

The results indicate that Belgium and France have very high market concentration and that they are almost monopolistic markets. The Netherlands and Spain have high market concentration. Also Germany has high market concentration but it is on the threshold to moderate market concentration.

London Economics reported also the calculated price-cost mark-up for all countries except Belgium and France. The calculated average price-cost mark-up for 2003-2005 was 27 % for Germany, 21 % for Spain, 11 % for Great Britain and 6 % for the Netherlands. It was noted that the low calculated average margins for the Netherlands was

likely a result of must-run CHP plants. The conclusion was that the mark-up was broadly in line with what one might expect given the results of the market concentration indicators.

Professor Jacques Percebois presented this winter a paper regarding the position of the main nine electricity companies in the EU ("Electricity Liberalization in the European Union: Balancing Benefits and Risks", The Energy Journal, Vol. 29, No. 1 (2008)). Many of the main companies are dominant in their origin markets. There is also an increasing market power in an integrated European market due to mergers and acquisitions. He calculated that the market shares of these nine companies correspond to a HHI of 1434 for EU 15. This means that a common European power market will give a more problematic market concentration than just a common Nordic power market.

5.2 Pivotal Supplier Index in the wholesale markets

The HHI indicator focuses on the market shares of the companies but is not affected by the demand conditions. The pivotal supplier index (PSI) focuses instead on the indispensability of companies to meeting the demand. The more indispensable/pivotal a company is the more market power that company is considered to have. In a tight market, several suppliers can be pivotal at the same time. With pivotal suppliers, either firm has the possibility to raise prices well above costs.

PSI is a binary (zero-one) measure. PSI is 1 if some output is necessary from the supplier in order to achieve clearing of the market and 0 if clearing can be achieved without the supplier.

Although the PSI addresses the issue of whether a company is pivotal it does not provide any indication of the extent to which it is needed to meet demand. The answer to this question is provided by the Residual Supply Index (RSI). The RSI for a given company is equal to the total supply of available capacity in the market less the available capacity of the given company, divided by the total demand. If the RSI is less than 100 %, the given company is indispensable for the market. If RSI is calculated for many hours and suppliers, one practicable way of aggregating the results is to sum all hours with RSI less than 100 %, i.e. to sum all hours with a PSI value of 1.

The Federal Energy Regulatory Commission (FERC) in the US applies a threshold of 20 % for PSI in its market analysis (LE page 76). The threshold means that there is an indicative of a pivotal supplier if the PSI value is 1 for more than 20 % of the time. The threshold is not a steadfast rule in relation to overall conclusions but is used as an indicator of possible market power issues.

PSI in Nordic markets during 2007

One part of our analysis has been to assess to what extent the largest suppliers in the Nordic countries are pivotal. One possible basis for such an assessment is to examine if there is still a market clearing in Elspot if the sale bids from a given supplier are

eliminated from the price calculations. Nord Pool Spot has on request from the Electricity Market Group performed such recalculations and presented aggregated results to us.

The recalculations have been performed for each of the five largest suppliers in the Nordic market but have been limited to the second week in each month during 2007. For each of the investigated days the sale bids from a given supplier have been excluded and a recalculation of the hourly prices has been performed. If market clearing has not been achieved for the system price area or a certain Elspot area, the PSI value has been set to 1 for that hour and area. The percentage of hours with PSI value of 1 in relation to the number of investigated hours gives the PSI for each of the areas for the examined supplier. Table 15 below summarizes the aggregated results for each area for the five largest suppliers.

Table 15: PSI during 2007 for each area for the seven largest suppliers

	FI	SE	DK1	DK2	NO1	NO2	NO3	System
Company A	71	27	6	25	0	18	9	9
Company B	42	70	22	62	0	32	18	18
Company C	3	9	3	9	0	8	3	2
Company D	1	1	1	1	1	3	1	1
Company E	0	0	8	33	0	0	0	0

The table shows that four companies were at some time during 2007 pivotal for clearing of the system price area. One company was pivotal in 18 % of the time. That company was during 4 months pivotal more than 20 % of the time. Another company was during 3 months pivotal more than 20 % of the time for clearing of the system price area

One company was pivotal at some time during 2007 in all Elspot areas. Three companies were pivotal at some time during 2007 in all Elspot areas but Southern Norway. This means that a company can be pivotal for market clearing in an area even if it has no supply in that area. The reason is that when sale bids in other areas are excluded in the Elspot calculations, imports from these areas will not be available and it can be impossible to achieve market clearing without curtailment of the demand.. Strategic behaviour in one area can thus give serious consequences also in other areas.

In Finland were two companies pivotal more than 20 % of the time. One company was during all months in 2007 pivotal more than 20 % of the time and the other company was during 10 months pivotal more than 20 % of the time.

In Sweden were two companies pivotal more than 20 % of the time. One company was during all months in 2007 pivotal more than 20 % of the time and the other company was during 7 months pivotal more than 20 % of the time. A third company was during 2 months pivotal more than 20 % of the time.

In Western Denmark was one company pivotal more than 20 % of the time. That company was during 5 months in 2007 pivotal more than 20 % of the time and another company was during 2 months pivotal more than 20 % of the time.

In Eastern Denmark were three companies pivotal more than 20 % of the time. One company was during all months in 2007 pivotal more than 20 % of the time. A second company was during 9 months pivotal more than 20 % of the time. A third company was during 7 months and a fourth company was during 2 months pivotal more than 20 % of the time.

In Mid-Norway was one company pivotal more than 20 % of the time in 2007 and it was pivotal in that sense during 8 months. A second company was during 5 months pivotal in that sense while a third company was pivotal during 2 months.

In Northern Norway was no company pivotal more than 20 % of the time in 2007. One company was during 5 months pivotal more than 20 % of the time while a second company was pivotal in that sense during 3 months.

Companies can be indispensable for market clearing also in other months than months with high demand. Hours with pivotal suppliers exist throughout the year. One possible explanation can be decreased supply because of maintenance of important plants or transmission lines.

The results above shall only be seen as indications of the real PSI in Nordic markets for several reasons. One reason is that the recalculations have only been performed for the second week in each month of 2007. Recalculations for other weeks and for 2008 can give other results. Variations in e.g. the hydrological situation give changes in the supply and variations in the temperatures give changes in demand.

Another reason is that that the residual supply in the calculations is the sale bids from other companies in Elspot. There is normally capacity that is not sold or bid into the market. The disappearance of one main supplier could call out that supply. On the other hand, the reality is that most of the time is not all possible capacity bid into Elspot and that creates extra opportunities to execute market power in Elspot.

A third reason is that withdrawal of capacity will result in changed power flows that may change the physical need for limitations in transmission capacities between Elspot areas. On the other hand, the TSOs allocate transmission capacities to Elspot 2,5 hours before the auction. That allocation is firm and will be met by counter trade if one supplier withdraws his capacity after the allocation of transmission capacities.

A fourth reason is that three of the five biggest suppliers give gross bids to Elspot while two give net bids. A gross bid means that the total production of a supplier is bid as sale bids to Elspot while power for the bilateral sale of the group is acquired by

purchase bids to Elspot. A net bid means that only the net of total production and bilateral sale is bid into Elspot. This means that the indispensability of net bidders is probably underestimated in the calculations in relation to the indispensability of gross bidders. An integrated company that sells at variable prices or hedges its direct sale separately can have incentives to execute market power by strategic bidding even in hours when it is not a net seller in Elspot.

A fifth reason is that the PSI indicator focuses on the indispensability of a supplier. In reality, the target of a possible execution of market power will nearly always be a significant price increase, not the extreme prices that are associated with non-clearing of the market. Such situations can be exploited even in hours when the company is not pivotal. One example is when there is a lower price in an area because of insufficient export capacity. One possible use of market power can then be to restrict the production to just such an extent that the area gets the same price as adjacent areas.

Finally, the PSI indicator does not measure the real possibility to use market power. It is only a rough indicator.

PSI in European markets during 2007

The Commission published in April 2007 a study by London Economics regarding market performance in six European wholesale markets. The study covered Belgium, France, Germany, the Netherlands, Spain and Great Britain and included an analysis of every hour during 2003, 2004 and 2005.

The Commission collected hourly primary data per generation unit as one part of its sector inquiry. About 500 million data points were collected. The hourly data made it possible to calculate marginal costs, HHI, RSI and PSI for each hour. The data collection and analysis was on a scale that is unprecedented in the electricity-economics field globally.

The results of the PSI analysis were as follows for the largest companies in the six markets.

Table 16: PSI for the largest companies in six European markets

Country	Company	PSI 2003	PSI 2004	PSI 2005	PSI 2003-2005
Belgium	A	100	100	100	100
	B	0	0,1	0	0
Germany	A	11	11	13	12
	B	0	0	0	0
	C	45	54	51	50
	D	0	0	0	0
Spain	A	12	22	26	20
	B	0	0	0	0
	C	23	28	27	26
	D	0	0	0	0,1
France	A	0	0	0	0
	B	100	100	100	100
	C	0	0	0	0
Netherlands	A	0,3	0	0	0,1
	B	19	15	10	15
	C	33	30	31	31
	D	4	7	4	5
Great Britain	A	0	0	0	0
	B	0	0	0	0
	C	0	0	0	0
	D	0	0	0,1	0

One company was pivotal all the time in France and the situation was the same in Belgium. In Germany was one company pivotal half the time. In the Netherlands was one company pivotal one third of the time. Two companies in Spain were at the FERC threshold of 20 %. In Great Britain was no company pivotal.

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5.3 Consequences of different CM regimes for competition and market power in the financial and retail markets

The fundamental purpose of the financial electricity market is to facilitate risk relief for the players in the physical electricity market. End-customers, retailers and producers may wish to hedge themselves from risks associated with rising or falling prices. If there is no financial market, these players have to hedge themselves through bilateral physical agreements.

The real benefit of a financial market is that it gives opportunities for the players to decouple their physical agreements and their hedging. They can continuously adjust their hedging to the need they define without making new purchase agreements.

The liquidity in the financial market is provided by players with different needs for fundamental hedging and by financial players. Financial players trade with the purpose to make profit, either by exploiting arbitrage opportunities or by taking posi-

tions. Such trade is a lubricant for the market and makes it possible for other players to always hedge themselves. In 2007, the total turnover in financial contracts cleared by Nord Pool was 2 369 TWh, i.e. about six times higher than the total consumption in the Nordic area.

The Swedish Energy Markets Inspectorate listed in its report regarding the price formation the following criteria for a well-functioning financial electricity market (ER 2006:13 p 26): High liquidity, small spreads between best sale and buy bids, many sellers and buyers in the market, absence of market power and full transparency. Full transparency included that all players act on the same information and that no player has an information deficit in relation to another player.

Different CM regimes mean different needs of hedging products. One single area means that it is sufficient to use system price products and that the fundamental hedging can be executed in very liquid financial products with small spreads. This reduces the “insurance premiums” associated with hedging.

Market splitting means a need of different area price products. Nord Pool lists contracts for difference (CfD) as a tool for area price hedging. A CfD refer to the difference between an area price and the system price. A player that wants to hedge on Nord Pool the price in a certain area uses therefore both a system price product and a CfD. The following figure shows that until July 2007 were the prices for all 2008 CfD contracts showing higher area prices than system price. This indicates substantial ”insurance premiums” since all area prices should not be expected to be higher than the system price.

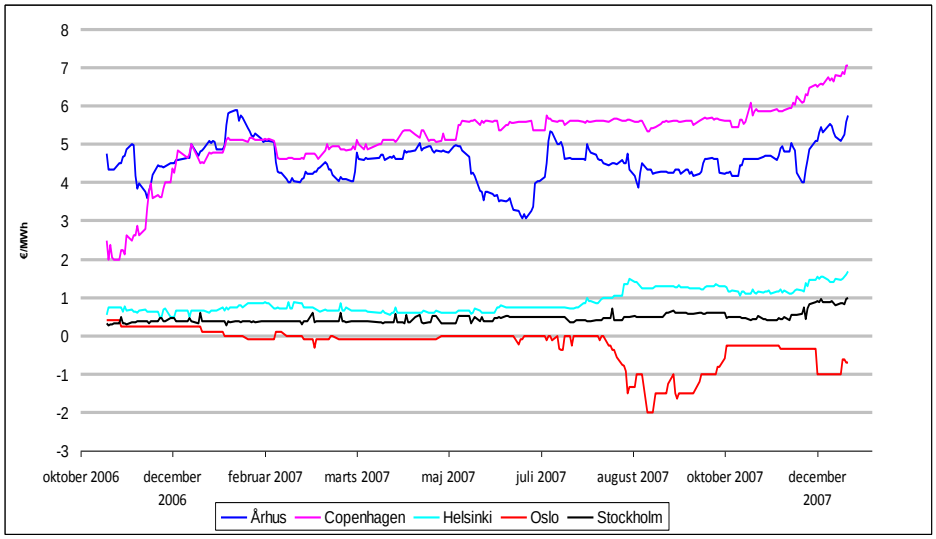

Figure 9: Closing prices October 2006 - December 2007 for 2008 CfD contracts on Nord Pool.

The total open interest (the sum of unnetted positions at Nord Pool Clearing) in CfD contracts for May 2008 is about 5000 MW while the open interest in the system price

contract for May 2008 is about 10600 MW. This means that nearly half of the open positions in system price contracts are complemented by open positions in CfD contracts. The turnover in CfD contracts is however only a very small percentage of the total turnover. This indicates that CfD contracts are hedging products – not trading products. There is in all CfD contracts a lack of sellers and the participation by financial traders is small. One reason is that the CfD contracts are seen as much more affected by market power than system price contracts. Many price areas instead of a few means that more CfD contracts are needed and an obvious risk for even lower liquidity and higher ”insurance premiums” in the different CfD contracts.

Nodal pricing means that the system operator calculates a power price for each node (location) in the grid. Congestion results in price differences among the nodes reflecting their influence on the congestion. It is nearly impossible to organise a financial market covering all nodes. There are examples on liquid points in markets with nodal pricing with an extensive bilateral trading or OTC trading. This trading is however concentrated to the largest players and nearly all fundamental hedging is done through bilateral physical agreements.

Smaller end-users have no possibility to direct participate in the wholesale market. They have instead to purchase electricity from a retailer. An effective competition between retailers necessitates both that the customers can choose between many retailers and that the retailers can acquire power on the same terms in the wholesale market. It is important that independent retailers are not facing higher costs and risks than retailers belonging to an integrated group or retailers that buy bilaterally from one producer.

There are different preferences from the customers in the Nordic countries regarding variable or fixed price. Most customers in Norway choose variable price while most customers in Sweden choose fixed price.

The economy of a retailer is dependent on the price margin between sold and purchased electricity, administrative costs and risks. The two major risks are spot price variations (if the customer has chosen fixed price) and costs for imbalances. These risks can be mitigated by bilateral agreements with a producer or by financial hedges and careful balance planning.

An independent retailer has a worse situation if CfD contracts are associated with high premiums and there is market power in the regulation market that can influence regulation prices. It can in such situations be tempting to withdraw from the market or to conclude a bilateral agreement with a producer.

Different CM regimes mean different risk levels for a retailer. One single area means that no CfD contracts are needed in addition to system price contracts and that regulation prices are little affected by market power. Such a market will require a lot of

special regulations from the TSOs but that does not affect a retailer. The costs for special regulations are paid by the TSOs and financed by grid tariffs.

Market splitting means that CfD contracts are needed in addition to system price contracts and a risk that regulation prices are more often affected by market power. There are less special regulations financed by the TSOs. Many price areas instead of a few means that more CfD products are needed and a risk for even higher premiums for CfD products.

Many price areas means also smaller balancing areas and an increased risk for price spikes because of market power in these areas. The risks associated with hedging disappear for the retailer if the customer chooses variable price. The risks associated with price spikes in the regulation market will however not disappear since the basis for the variable price paid by the customer is the spot price – not the price for imbalances.

Nodal pricing will probably mean that most retailers conclude bilateral agreements with producers.

5.4 Principle models for strategic behaviour in alternative wholesale markets in alternative CM regimes

In this section we use small scale models for illustration of different strategies for using market power in different CM regimes. This includes applying market power in the spot market, as well as applying market power in subsequent counter trading. The model illustrations are based on game theoretical setups to describe strategic options of dominant producers in two CM regimes.

Emphasis is on the potential to engage in the exercise of horizontal market power. This implies gaming between generators, with different strategic resources, i.e. generation facilities, at their disposal. The following key strategic options are hypothesised:

- “Standard” price manipulation through limiting quantities to attain a premium on production portfolio. This is probably the most general form of horizontal market power, which is independent of the type of good, service or market.
- Gaming against the transmission network can result in a market player either congesting or decongesting a transmission line, in order to prevent competitors’ access to market, or to capture congestion rents which would otherwise be claimed by a system operator.
- Multi-settlement manipulation, i.e. a market player may reframe from revealing true marginal costs in the first stage of a market setting, in order to attain a premium on power sold in a second stage.

Since we have two market set-ups not all strategy elements pertain to both.

Modelling of market power in electricity systems has been given much attention in academic work in recent years. We employ a Nash-Cournot approach, as this is relatively simple to implement and is probably the most studied approach, giving us a solid foundation for our analysis. We define a positive elasticity of demand (or that there is a competitive fringe of generators who's supply function is subtracted from the inverse demand function) in order to ensure that equilibrium prices fall short of infinity. We do not distinguish between demand elasticity and fringe competition, for the sake of simplicity. We employ a demand elasticity which is high in comparison with observed electricity markets for this reason. The Cournot assumption can be perceived as a harsh assumption to pin on players in the market. However, it is not our intention to simulate specific players or markets, but to use counter factual assumptions in different market designs to get an indication of market power issues.

The approach of these analyses is the use of two extreme counterfactual assumptions with regard to competition to test two alternative market designs with respect to vulnerability to market power. In all analyses we assume that all market players which respond strategically have perfect information about each other and about the system and market in general. Strategic market players feature profit maximizing behaviour, and are able to rationally deduce the reactions of their competitors, the sole exception being when no pure strategy equilibria exist.

Pure competition is the first counterfactual assumption implying that all market players are *price takers* with respect to energy and transmission capacity. Price takers disregard the impact for their own actions on prices in the market and respond to perceived prices as given. Effectively this implies that no market players game the market.

Cournot competition, is used in the second counterfactual. Each player assumes that the other player will also play Cournot, and therefore is aware that the market equilibrium will be a so called *Nash-Cournot* equilibrium. This equilibrium is stable on the basis of the Cournot disposition of the gaming players, since at equilibrium no gaming market player can increase his total profits by altering his quantity bid unilaterally. Since no players have incentive to deviate from their strategy at equilibrium, they do not.

The two market designs differ, as in the previous chapter, by market splitting being a one settlement system broadly as Nordpool spot is today, and the market design which uses counter trading is a two settlement system for market players that are counter traded. It follows that we disregard any effects, strategic or otherwise on intra-day markets or on balancing markets.

A small example

To illustrate the various implications of market power in conjunction with our two regimes for congestion management, we use a small example. Consider a network with two nodes connected by a transmission line. Alternatively, two zones situated on each side of a structural bottleneck. Assume that in each area we have either price responsive demand, alternatively demand and a fringe of competitors whose supply is subtracted from the demand function a priori. In each area, a single market player is gaming a la Cournot.

We employ a rather rudimentary representation of the network in our example, by limiting flow between the two areas to a predefined thermal capacity limit. When the network constraint is integrated in the market design, a system operator or clearing house performs spatial arbitrage between the two markets. By design, arbitrage is performed until prices in the two areas are the same, or until the network becomes congested. Once the network is congested, the price difference between the two areas is increased so that the transmission between regions is equal to the transmission capacity.

For reasons of modelling and computational tractability, the transmission capacity constraint is relaxed in some part of the model. In its stead, a transmission price function is selected with a “sudden” steep rise (e.g. a polynomial function of high order) once the transmission approaches the capacity. The effect of this, as with the congestion charge described above, is that there is a low and presumably negligible charge for transmission when under capacity limit, but when the transmission value is near the capacity limit, this transmission charge rises almost vertically with increased transmission. The reason for introducing this function, is that we can then describe not only the transmission charge as a continuous function, but also have a well defined continuous first-order derivative, which the producers use to predict the price effect of increased generation, upstream or downstream from the generation increment. We hereby are able to avoid a discontinuous model.

Results

Firstly, we present the results assuming that there is perfect competition among the generators, and that bids appear in the spot market without regard for network tariffs. We regard neither collection of congestion rents nor costs of counter trade.

As input to the principle models supply and demand data is assumed. Generators are assumed to have quadratic marginal costs and consumers (net of fringe competitors) are assumed to have linear decreasing marginal willingness to pay.

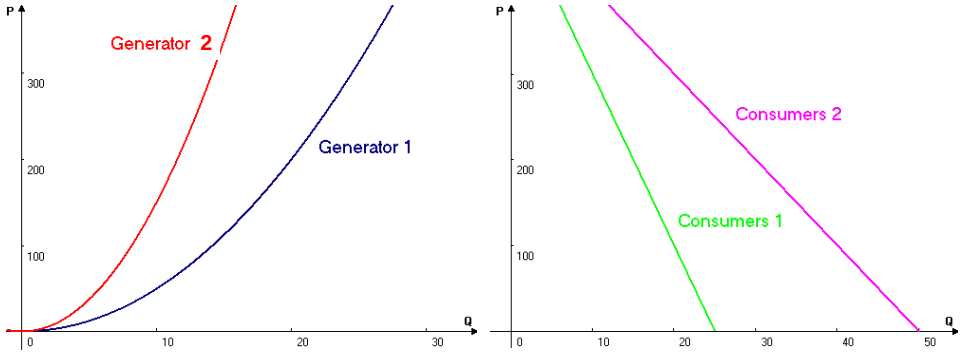

Figure 10: Left: marginal costs of the generator in area 1 and in area 2. Right: marginal willingness to pay for consumers in area 1 and area 2.

From the marginal cost curves and marginal willingness to pay curves in Figure 10, it can be interpreted that Area 1 is generally a surplus area with low consumption and abundance of low cost generation capacity. Area 2 on the other hand is a deficit area, which high consumption and limited or expensive generation capacity. Transmission therefore naturally flows from Area 1 towards Area 2.

The transmission constraint is relaxed for computational reasons and instead a functional relationship is used describe congestion rents.

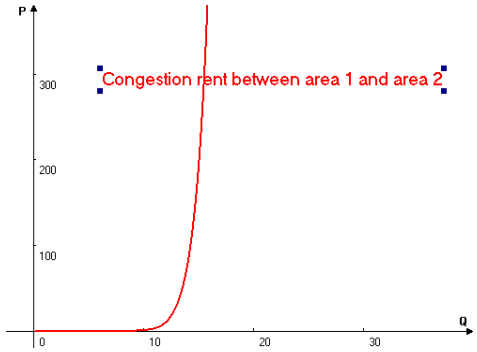

Figure 11: Congestion rent for transmission from Area 1 to Area 2 is function of the level of transmission. This is a relaxation of a hard transmission constraint of around 12-15.

Results from calculations with perfect competition

When perfect competition is assumed, the final dispatch as well as final area prices should be the same both with market splitting and with counter trade following a common Elspot area market.

Table 17: Profits and surplus in simulations with perfect competition

	Generator 1 (Money/h)	Generator 2 (Money/h)	TSO (Money/h)	Consumers (Money/h)	Social Welfare (Money/h)
No trans. Constraints					
- perfect competition	3956	2284	-	4315	10555
Market splitting					
- perfect competition	1785	3511	29	4187	9513
Counter trading					
- perfect competition	4228	2374	-2063	4975	9513

The results for perfect competition are in accordance with the theoretical reasoning from Chapter 4. The presence of transmission constraints in general, lowers total welfare. Assuming perfect competition and that all the entirety of supply and demand is bid into all markets; the total social welfare will be the same regardless whether market splitting or counter trade is used to manage congestion. However, there are differences for the individual players. The TSO collects congestion rents under market splitting, but must pay counter trade costs when counter trade is employed. Counter trade gives higher profits to both generators compared with a situation without transmission constraints. Market splitting means that generators in deficit areas generally receive greater remuneration for their generation, whereas generators in surplus areas receive less. Consumers pay less for their consumption at least in this case. More generally the functional form of marginal supply and willingness to pay determine the fallout for consumers. How the difference in the TSO's revenues/costs is covered ultimately decides who is best off and who is worse off. Currently, the consumers pay most of the TSO tariffs.

Results from perfect competition – augmented with strategic bidding

A key function of the market place is to decentralize the decision making process, so that the stakeholders, who are in possession of information which is relevant for the system, take this information and put it to the best possible use for their interests as well as for the system as a whole. The optimal dispatch is derived centrally by means of a bidding process where individual producers have incentive to reveal their true marginal generation costs. This is what is assumed in the simulations regarding perfect competition above as well as in Chapter 4.

We use the following definitions in this chapter:

Strategic bidding – is performed by a market player who responds to weaknesses in the market design or that player's position in the market, and on that basis bids differently from true marginal costs or true marginal willingness to pay. Strategic bidding can be the exertion of market power, but is not limited to this.

Exertion of market power – is performed by a market player, who irrespectively of weaknesses in the market design is able to change the outcome of the market in his own favour by means of strategic bidding. Market power can be exerted by players with a dominant position within the relevant market

When congestion is managed by market splitting, market players that do not have market power will not engage in strategic bidding. The exception could be if the player elects to withdraw from the spot market altogether i.e. in order to respond to the intra-day or regulating markets, an exception that we disregard further in this chapter.

When congestion is handled by market splitting, market players who do not have the capability to exert market power, i.e. they are unable to unilaterally affect prices, serve their own interests best by bidding their marginal generation costs. This ensures that the generator is dispatched whenever the market presents an opportunity to earn positive marginal return, which is anytime prices exceed marginal costs. As the generator is unable to unilaterally affect prices, bidding his marginal generation costs is the best strategy.

On the other hand, if congestion is managed through counter trade, the optimal strategy for a generator may not be to bid his marginal costs, even if that player does not have the capability to exert market power, i.e. to unilaterally affect prices. Consider a deficit area, i.e. Area 2 in the simulation above. A small generator, whose marginal generation costs are below both the spot price and the counter trading price, has a choice to make. If he bids his marginal costs he will be selected in the spot market, thus getting the lower of the two prices for the deficit area. If on the other hand, he correctly anticipates both prices and places a generation bid in between the two, he will be remunerated according to the higher counter trade price (or according to his higher bid if the counter trade market is pay-as-bid). In short a generator who bids towards a spot market and subsequent counter trade market has incentive to perform strategic bidding regardless of his capability to exert market power. Individual market player bids will be based on their individual expectation of the market clearing prices; spot and counter trade. This creates a situation of high risk that a fraction of the generation capacity is bid at a higher price than other generation capacity with higher true marginal costs, thereby creating a situation where the final dispatch is suboptimal.

The conclusion, that congestion management based on counter trading generates an incentive for even small generators to bid strategically, gives cause for reservations against wide spread use of counter trade to manage congestion where market splitting can practically be employed. The core of an effective market design, ought to be to discourage gaming by market participants and to ensure overall efficiency through correct price signals and incentives.

Results with strategic bidding and market power

In continuation of the simple two area example, we now move to investigate how incentives and opportunity towards the exertion of market power differs in the two market designs.

As before, there is one generator located in each area. These generators are now assumed to game the market.

The main economic results of the conducted games are presented in

Table 18. In addition to the market power games, the results of the simulations with perfect competition are echoed for comparison.

Four different games have been conducted.

- One game without congestion between the two areas is included mainly for comparison and to assist in interpretation.
- Market splitting and possibility of congestion one game is conducted, where each generator strides to optimize his total profits by manipulating the price is his own area, conscious to the fact that the TSO or power exchange arbitrate between the areas by transmission. Note that the generators are not price takers towards the transmission system.
- Counter trade is employed to resolve congestion in the final two games. Each game involves a spot market situation, as before, where the transmission constraints are ignored, followed by a round of counter trade with an area specific clearing price. Again all generators and consumers have the option to engage in counter trading, contrary to the current practice in the Nordic countries. In the third game, the generators make decisions one market at a time, attempting to capture as much value as possible from each market individually, without regard for their opportunity in subsequent markets. This means that when exerting market power in the spot market, the players do not consider how this affects their opportunity to exert market power in the counter trade markets. Note the solution to this game is not a Nash-equilibrium if viewed across both markets, however viewed individually the first stage and second stage are Nash-equilibria.
- The fourth game extends upon the third, but now the players accurately predict the outcome of the counter trade market when gaming in the spot market. Thereby the players exploit all their options towards extracting value of the markets.

Table 18: Main economic results from the simulated market games in terms of total profit and surplus

	Generator 1 (Money/h)	Generator 2 (Money/h)	TSO (Money/h)	Consumers (Money/h)	Social Welfare (Money/h)
No trans. constraints					
- perfect competition	3956	2284	-	4315	10555
- Cournot	4433	2691	-	3116	10239
Market splitting					
- perfect competition	1785	3511	29	4187	9513
- gaming the grid	2889	3695	13	2021	8618
Counter trading					
- perfect competition	4228	2374	-2063	4975	9513
- no foresight to CT	4447	2915	-1693	3835	9503
- full information	6792	3693	-7529	5777	8733

The results of the games are intriguing and seem to indicate that the presence of two subsequent markets – one without congestion and one with – has a positive effect on total output. However, the degree of gaming is much greater when both markets are gamed simultaneously.

The total exertion of market power increases when generators think strategically across both markets. Observe the difference in quantities committed in the spot market (Table 19) at the upstream (Area 1) and downstream (Area 2) areas respectively on Table 19, between the "no foresight" and the "full information" games. Notice that in Area 2, the deficit area, no generation is committed in the spot market in anticipation of subsequent counter trading. Notice also that in Area 1, the surplus area; there is an increased commitment of generation even beyond the reduced commitment in Area 2, also in anticipation of downward counter trade.

Table 19: Spot market position quantity in the games

	Demand		Generator 1	Generator 2
	Area 1 (Quantity/h)	Area 2 (Quantity/h)	(Quantity/h)	(Quantity/h)
No trans. constraints				
- perfect competition	12	24	23	13
- Cournot	10	20	19	12
Market splitting				
- perfect competition	17	15	18	15
- gaming the grid	11	13	11	13
Counter trading				
- perfect competition	12	24	23	13
- no foresight to CT	10	20	19	12
- full information	11	23	34	0

The final dispatch in the games is given on

Table 20. Note that with market splitting the generation in the surplus area is notably less than in counter trading scenario. This is the situation where an upstream generator (Generator 1) will gauge out the TSO's congestion rents, by decongesting the line towards the deficit area, thereby increasing his sales price. The downstream generator (Generator 2) is in less of a position to extract excess profits and only reduces output slightly to increase prices.

In the counter trade game without foresight between markets, the generator have restricted their generation to the same level as the reference Cournot game without transmission capacities, oblivious to the opportunities of the subsequent counter trading market. This leaves limited opportunity to exert market power for the upstream generator (Generator 1). By abstaining from decreasing his generation significantly, as is necessary to resolve congestion, demand resources (or competitive fringe generation) to increase demand in the surplus area are employed, causing the area price to fall, and Generator 1 receives a premium for making only a slight reduction in generation.

When the market players in the "full information" game, where spot market bidding is done in anticipation of the results of counter trade, the upstream generator (Generator 1), having flooded the market in the spot market withdraws most of his generation, thereby earning a positive profit for generation that never occurs. The downstream generator takes the converse position, abstaining from any bid to the spot market (or bidding in excess of the expected spot price) in order to earn the area price for the player's entire generation portfolio. This is actually not as much a question of market power, but strategic bidding between the two markets which can be conducted by any player with capacity in the deficit area.

Table 20: Final dispatch in the games

	Demand		**Generator 1**	**Generator 2**	**Transmission**
	Area 1	Area 2			Flow (1->2)
	(Quantity/h)	*(Quantity/h)*	*(Quantity/h)*	*(Quantity/h)*	*(Quantity/h)*
No trans. constraints					
- perfect competition	12.0	24.0	22.8	13.2	10.8
- Cournot	10.2	20.4	18.6	12.0	8.4
Market splitting					
- perfect competition	12.0	24.0	22.8	13.2	10.8
- gaming the grid	10.9	12.9	11.1	12.7	0.1
Counter trading					
- perfect competition	12.0	24.0	22.8	13.2	10.8
- no foresight to CT	17.7	14.9	17.9	14.7	0.2
- full information	23.0	12.9	23.1	12.7	0.2

In Table 21 the prices in the games are presented. A number of observations:

- In perfect competition, the area prices with market splitting are equal to the area prices in the counter trading game. This is contingent on the property that in these games, all supply and demand can be bid into each market. Therefore, also the transmission price wedge is the same.
- Further in the perfect competition games, the common price without transmission constraints is equal to the common price (or spot price) in the counter trading regime.
- The transmission price wedge between the two areas is expanded in counter trading when there is market power. The positions that the two players take in spot market gives incentives to hold on to these positions for longer than if no position was taken vis-à-vis the market splitting game.

Table 21: Prices in the games

	Area prices		**Common**	**Trans. Price**
	Area 1	Area 2		(1->2
	(Money/MWh)	*(Money/MWh)*	*(Money/MWh)*	*(Money/MWh)*
No trans. constraints				
- perfect competition	-	-	260.1	-
- Cournot	-	-	296.2	-
Market splitting				
- perfect competition	153.1	346.5	-	193.5
- gaming the grid	281.7	371.2	-	89.5
Counter trading				
- perfect competition	153.1	346.5	260.1	193.5
- no foresight to CT	145.7	351.4	296.2	205.8
- full information	40.8	371.0	270.4	330.2

In market power situations such as the ones modelled here, the most mitigating effect comes from the presence of price-responsive players such as active demand response and competitive fringe producers. This again is a reason to stress that effort should be made to ensure that all generation bids and demand response bids are present in a counter trading market.

6 Security of supply and incentives for investments.

It is the responsibility of the national system operators to handle security of supply according to EU and national legislation. This task is performed through careful and timely planning of investments, agreements with actors in the market, grid and system operations and cooperation with other system operators. In the operational phase the electricity system is monitored according to a range of criteria and a number of operational tools are activated when danger of exceeding certain limit values is anticipated. These tools include the activation of regulating resources and controlling power flows where possible.

An important security of supply issue is the system adequacy. Adequacy is a measure for the amount of production, transmission and regulation resources to satisfy the demand for electricity at all times. In a liberalised electricity market the adequacy issue is to a certain extent expected to be satisfied by the market actors on a commercial basis..

Different types of congestion management in an international electricity market can affect the actors incentive to invest, and also affect the incentive to make existing resources available in the market. Examples of this could be market power where producers are hesitant to invest or in strategic bidding situations where producers are withholding resources from the market in order to profit from scarcity situations. Another example is when transmission lines between areas are reduced so that scarcity in one area can not be served by resources in neighbouring areas.

Due to the overall TSO responsibility such effects will probably not severely affect the level of security of supply, but they can reduce the viability of more market based solutions and force the TSOs to increase their responsibility for adequacy in the system.

It has been shown in chapters 4 and 5 that electricity prices and actor benefits are affected by congestion management. However, these effects can seem quite small when looking at annual average prices in the perfect competition situation.

The Oslo area in Norway and Sweden south of cut 4 are both deficit areas, but are affected quite differently by the different CM regimes. Table 22 below shows the modelled average prices in those two areas. By definition the eleven area case yields the true prices, thus giving optimal investment signals to producers and consumers.

Table 22: Average electricity prices in two deficit areas normal hydrological year

	Norway Oslo	Sweden South
Base Case	41,9	41,1
- after counter trade	41,9	41,8
7 Area – No reduction	41,9	41,3
- after counter trade	41,9	43,8
-11 area (market splitting).	42,4	41,7

It is seen in the table that the base case (seven areas with capacity reduction) and the seven area case (without capacity reduction) yields lower prices for the Oslo area. These lower prices are to the benefit of the consumers in the short term, but distort the investment signal in the long term.

For Sweden South the picture is similar for resources that are not counter traded. However, when the effect of counter trade is included the average prices for counter traded resources are in fact highest in the seven area case with no capacity reduction on interconnectors. In this case, the investment signal to counter traded resources is amplified relative to the 11 area price signal because of higher southbound export out of Sweden South based on lower spot prices and because counter trade is restricted to Sweden only. For resources that are not expected to be counter traded, the investment signal is the spot price.

The conclusion from table 22 is that the market based investment signals are distorted to some extent when moving from market splitting to counter trade and/or capacity reduction in the model.

In figure 12 below, the modelled electricity prices in the Oslo area are shown for the thousand hours with highest prices in a normal year in 2015. It must be stressed that the prices are modelled prices under idealised conditions but using pro-rata capacity reductions in the base case. Anyway, the figure shows that even if average prices are quite similar there will be time segments with very different prices depending on the chosen CM method. Such time segments can be valuable market based incentives for investments if they are frequent enough, or for activation of potential resources on the demand side.

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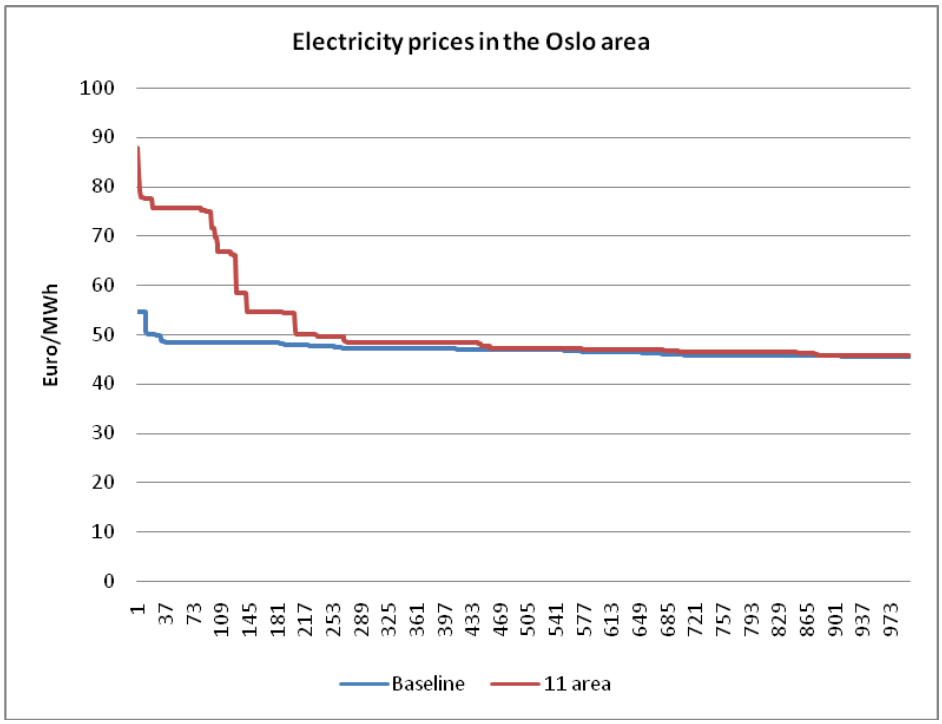

Figure 12: Congestion rent for transmission from Area 1 to Area 2 is function of the level of transmission. This is a relaxation of a hard transmission constraint of around 12-15.

In chapter 5 the implications of strategic bidding caused by an anticipated secondary market was shown. One main result of this analysis with implications for investments and security of supply is the effect on prices and producer profits in surplus and deficit areas.

The observations in tables 20 – 21 clearly show that with extended use of counter trade, it can be possible for producers in surplus areas to increase their profits substantially by gaming the grid and receive profits from counter trading without producing electricity. Such activities can severely affect the electricity price as an efficient locational signal for producers, and send distorted signals to invest in surplus areas.

The main conclusion regarding security of supply from the analysis is, that extensive use of counter trade might affect the market based incentives for security of supply negatively in mainly three ways:

- If limited counter trade is combined with systematic reduction of transmission capacity on the borders this will affect resource efficiency but it will probably not seriously affect security of supply in the short term.
- If extended counter trade is used as a general form of congestion management this could have serious implications for market based incentives in the long term due to the lack of “true” price signals.

Regarding Grid investments

The prevailing model for the TSO mandate in the Nordic region is that TSOs are obliged to perform grid investments in accordance with a socio-economic criterion. Ideally the criterion should be Nordic benefit, but in practice all investments must be approved in national processes focusing on national costs and benefits.

A key issue regarding grid investments is that the Nordic (European) value of such investments must be visible to the TSO. Another key issue is that the TSO must have the right incentive to make the decisions and the financial ability and permissions to carry them out.

- In the Nordic electricity market the stakeholders play an important role in the decision making process. The more visible congestion is in the market place, the more open and qualified debate among market players about grid adequacy can be expected. This is an important incentive for the TSO´s to justify their decisions to invest or even not to invest. With more visible congestion such justification will be carried out in a more transparent manner.

7 Starting points and conclusions regarding future congestion management in the Nordic Electricity Market

The question of market splitting versus counter trade has long been the focus of the Nordic discussion regarding congestion management (CM). The main purpose of this project is to evaluate and analyse these two approaches for congestion management in the Nordic power market and on the basis of this analysis make concrete recommendations for a Nordic solution to CM aiming at an optimal balance between competition issues and efficiency.

We have evaluated recent studies and proposals and have also performed new quantitative and qualitative analyses of benefits and disadvantages of different alternatives. Based on this we have made our conclusions regarding future CM in the Nordic area.

From national and Nordic market integration towards European market integration

Cross-border trade is driven by price differences. If the price in an adjacent area is higher, it is profitable for producers to export to that area if possible. If the price in an adjacent area is lower, it is profitable for consumers to import from that area if possible..

The Nordic market is characterized by structural differences between different areas. Norway, Northern Sweden and Northern Finland are the hydro power areas. Southern Sweden and Southern Finland are the nuclear power areas. Denmark and Southern Finland are the thermal power areas. Denmark, especially Western Denmark, is the present wind power area but will probably be complemented by big projects in Northern Norway and Northern Sweden.

Wind power and nuclear power have low short-term marginal costs compared to thermal power. It is therefore normally profitable to use available wind power and nuclear power instead of thermal power. Hydro power has also low short-term marginal costs, but the water in reservoirs is a resource which has high value if the water can be stored and used later instead of high-cost thermal power. The production of hydro power is therefore optimised over the day, the week and the year (or even several years if it is a multi-year reservoir) in order to maximise the earnings from the available water in the reservoirs. A special problem is that the available water can vary considerably between different years. The total Nordic hydro power production

can vary by up to 80 TWh between a very dry year and a very wet year. These fluctuations are mostly managed by changes in thermal power production and changes in the power exchange with non-Nordic areas and also to a certain extent by changes in demand due to low or high prices.

There is also a difference between the Nordic countries regarding peak-load capacity. Instead of thermal peak-load plants, Norway has many hydro power plants with high maximum capacity in relation to the average production. The biggest potential security of supply problem in Norway is therefore not capacity peaks but energy shortage during very dry years.

The more the national markets have been integrated into a Nordic market, the more the structural differences between different areas have resulted in increased power flows and consequently in increased congestions. In the same way, the ongoing integration with non-Nordic markets has resulted in increased power flows and this trend can be expected to continue.

Nord Pool Spot, EEX and the three concerned TSOs made a joint announcement recently that they will launch a day-ahead market coupling between Denmark and Germany on 29 September 2008. Access to the new NorNed interconnector between Norway and the Netherlands will be granted by an explicit auction until January 2009, after which the intention is to make a market coupling between Nord Pool Spot and APX. Market coupling improves market efficiency and promotes the further integration of Nordic markets and the Continental markets.

Even in a situation with the same average price in the Nordic market and in the Continental markets, high gross power flows and congestion can be expected during many hours. Congestion can in such situations be anticipated in the northbound direction during night hours and in the southbound direction during day hours. The reason is that the hourly prices fluctuate more on the Continent than in the Nordic region due to structural differences. Peak-load EEX contracts for 2009 are at present 25 EUR/MWh more expensive than base-load contracts while peak-load Nord Pool contracts for 2009 are only about 3 EUR/MWh more expensive than base-load contracts. Bringing together the Nordic and the Continental hourly price variations would require so many new interconnectors with the Continent that it is probably totally unrealistic.

Today, the power flow on the interconnections between Finland and Estonia and Russia is a stable power import to Finland. Changed structures in the energy markets in the Baltic countries and in Russia may change this situation drastically. A joint Nordic-Baltic project was launched in November 2007. The aim of the project is to establish a day-ahead Elspot market and an intraday Elbas market in one or more of the Baltic countries. Fingrid has proposed a long-term development of the trading framework with Russia. The proposal includes direct bids to Nord Pool Spot, intra-day trading and an upgrade of the interconnection that will also make power exports to Russia

possible. A long-term goal is market coupling between Nord Pool Spot and a Russian power exchange.

The market integration development during the last decade can thus be expected to continue. The national perspectives have to be followed by broader perspectives. Also CM regimes have to be designed from a broader perspective than the national.

The perspective has also to be broader than a Nordic perspective. The EU has highlighted the need for improved regional cross-border trade and the need to address the integration of regional markets into the EU internal market. The region of Northern Europe now comprises the Nordic countries, Germany and Poland, and it has been discussed to expand the region further. In January 2008, Nordel proposed a merger between the existing regional initiatives for Central West Europe and Northern Europe.

During the last decade, some market players have expressed the vision of the Nordic area as one price area. It has been discussed whether the vision ever has been realistic but it is not realistic in a broader North European or European perspective. Market splitting within the Nordic area is therefore necessary. The issue is which market splitting and which combination of market splitting with counter trade and reduction of transmission capacities is most feasible.

The EU Congestion Management Guidelines define the basic requirements for coordinated congestion management but they do not specify the details of the operational procedures. Only the basic definitions of key concepts are provided within the scope of the Congestion Management Guidelines. Coordination shall be applied regionally, and seven regions are currently defined across the EU. However, the congestion management methods shall be compatible in all these regions with an ultimate goal to form a truly integrated internal European electricity market.

The importance of new interconnections

The most important tool in CM is timely grid planning in order to expand the interconnection capacity whenever such an expansion is thought to be socio-economically profitable. Such grid reinforcements improve the market integration and increase security of supply but can take many years to plan and build.

In 2004, Nordel agreed on five prioritised interconnections. One of the planned links, the so-called South Link in Sweden has this winter been changed to a South-West Link. The planned capacity of the South-West Link, 1200 MW, is twice the capacity of the originally planned South Link and it will also increase the capacity to South-Eastern Norway and the capacity between South-Eastern and South-Western Norway by 1200 MW.

In their Nordic Grid Master Plan 2008, Nordel has recommended further grid reinforcements that are cost-effective according to socioeconomic cost-benefit calculations. If the newly proposed Nordic reinforcements are built, congestion within the Nordic area should be further reduced.

However, the increased power flows due to Nordic and European market integration have created more congestion. It is neither economically sound nor economically realistic to make so large grid reinforcements that congestion disappears entirely in the Nordic countries. In addition to socio-economically profitable grid reinforcements, CM methods are needed for managing congestions that may continue to arise and for managing congestions until the grid reinforcements have been made.

The interaction between day-ahead, intra-day and regulation markets

The EU Congestion Management Guidelines are not limited to CM in the day-ahead markets. From 2008 mechanisms for intra-day CM 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. Each capacity allocation procedure shall allocate any remaining capacity not previously allocated and any capacity released by capacity holders from previous allocations. In the Nordic market all interconnection capacity for intra-day trade between Finland, Denmark and Sweden is allocated through the continuous Elbas market organised by Nord Pool Spot. The intention is that also Norway shall be included in the Elbas market during 2008.

The guidelines leads to that it is not enough to define CM regimes in the day-ahead market. CM regimes in the intra-day market have also to be defined. The regimes do not necessary have to be the same but have to be coordinated. The guidelines stipulate that the methods adopted for CM shall give efficient economic signals to market participants and TSOs, promote competition and be suitable for regional and communitywide application.

As the guidelines are written, it is not possible to choose either a CM regime that gives efficient economic signals or a CM regime that promotes competition. The chosen CM regime has to give efficient economic signals and to promote competition. The assessment of a potential CM regime shall include effects on the day-ahead market, the intra-day market and the regulation market.

Conclusions regarding efficient resource utilization

In our analysis, the current seven spot areas of the Nordic market and the current practice of transmission capacity restrictions to resolve internal congestion have been defined as the baseline and then compared to a market divided into more spot areas (11) or into less spot areas (one, four and six). In these new cases, no capacity reductions are performed and counter trade is practised internationally between the Nordic countries to resolve internal congestions within any given spot price area. In all calcu-

lations, market conditions are assumed to be ideal in the spot and counter trade markets as is common practice for this type of market analysis.

The results of this analysis show that all changes from today's practice regarding capacity reductions yield a socioeconomic benefit in the range of EUR 15 – 30 million a year with the 11 area case being the most beneficial. The total benefit in all the cases is in the same range, but the costs and benefits are distributed quite differently between stakeholder groups and countries. Introducing an 11 area division of the spot market will generally benefit the Nordic generators and TSOs and yield a loss to consumers. On the Continent, consumers will benefit and generators will loose. The main reason for this is that the Nordic area will have slightly higher prices and the Continent slightly lower prices due to better utilisation of the southbound interconnections.

There is by definition no counter trade in the 11 area case as we have only modelled congestion between the 11 areas – not within the 11 areas. Capacity reductions or extensive counter trade are needed in all other cases to solve internal congestions within the spot areas. In the ideal world of the model this is not a problem. In practices, however, there are several very important problems.

Management of internal congestions within the spot areas by reduced capacity allocation between the spot areas prerequisites that the TSOs make a forecast of the resulting power flows from the spot market. When the TSO forecast is not perfect, the capacity reductions will result in reduced resource efficiency compared with market splitting. If the TSO forecast is aimed at reducing counter trade costs in stead of optimal resource efficiency, the result will also be reduced resource efficiency. The results from our model underestimate therefore the socioeconomic benefit of changing from today's practice of capacity reductions to an 11 area case.

The results from our model underestimate also the socioeconomic benefit of the 11-area case instead of full counter trade between fewer spot areas. Today's counter trade is done bilaterally or within the regulation market and includes normally only larger bids within the TSOs' respective operating areas. It can therefore not give the same optimal dispatch as market splitting or counter trade in the spot market. Another very important problem is that use of anticipated counter trade gives incentives for strategic bidding to Elspot when market players are able to anticipate internal congestions that have to be managed by counter trade. All market players will have incentives to divert their Elspot bids from the marginal cost or marginal willingness to pay in order to increase their profits in the needed counter trade if they forecast such counter trade. The result of this gaming is market distortions and suboptimal dispatch. None of these two important problems are captured in the model and the socioeconomic cost of counter trade cases is therefore underestimated.

Conclusions regarding competition

A prerequisite for the calculated results regarding socioeconomic benefits is that there is full competition in the market. Two indexes of supply-side market concentration have been calculated for the situation in 2007; the Herfindahl-Hirschman Index (HHI) and the Pivotal Supplier Index (PSI).

HHI have been calculated for all the constellations that a special Elspot area belonged to during 2007. US guidelines stipulate that a HHI index under 1000 indicates a market with low concentration and an index above 1800 indicates a highly concentrated market. Taking into account the frequency of different area price constellations, the Danish areas had high concentration more than 20% of the time in 2007, Northern Norway had high concentration nearly 20% of the time and Sweden had high concentration 5% of the time. No area had a time-weighted HHI that indicates a low concentrated market. When there are no congestions within the Nordic region, the HHI is 933 or just under the threshold 1000 for moderate market concentration. Considering the special characteristics of the power market, this means that the market concentration can be problematic even when all Nordic areas have common price.

From 2007 to 2015 two counter-acting trends can be expected regarding the market concentration. On the one hand will the new decided transmission links further integrate the markets and thereby reduce the number of hours with high concentration and reduce the time-weighted HHI for the different areas. On the other hand will mergers and acquisitions probably continue to increase the HHI for the common Nordic market. The result can for some areas be an increased time-weighted HHI. It should be noted that the HHI will not be lower in hours when the Nordic area by market coupling has a common price with the Continent. The HHI for Germany is calculated to 1914 by London Economics and the HHI for EU 15 is calculated to 1434 by professor Jacques Percebois.

The PSI analysis shows that during 2007 there were hours in all spot areas when a special company was necessary or pivotal for clearing of the Elspot market. The Federal Energy Regulatory Commission (FERC) in the US applies a threshold of 20 % for PSI as an indicator of possible market power issues. In Finland, Sweden and Eastern Denmark was a company pivotal more than 60 % of the time in 2007. Also the PSI index indicate thus that market power can be exercised in the Nordic area if such strategies are chosen by generators.

A generator with market power in a special area can exert its power and increase its profit by strategic bidding whether the area is a separate spot area or the area is included in a bigger spot area and the TSO has to relieve congestions by counter trade. There are no general conclusions whether market splitting or counter trade give the best scope for profit increases for a generator with market power. Different examples give different results and the scope for profit increases is also dependent on the efficiency of market superveillance.

However, there are different payers of the extra profit in the two CM regimes. All consumers and retailers are directly affected by the higher spot price if there is market splitting and strategic bidding because of market power in an area. Counter trade and strategic bidding means on the other hand that the TSO pays most of the extra profit as extra costs for counter trade. These extra costs for counter trade means an extra cost basis for the grid tariffs and the TSO grid tariffs are in the end mostly paid by the consumers through their network tariffs.

Retailers selling on fixed price contracts have to hedge the spot price and this hedge is normally done by independent retailers as a separate hedge of the system price and a separate hedge of the difference between the area price and the system price. Both system price contracts and contracts for difference (CfD) are listed by Nord Pool. There is however in all CfD products on Nord Pool a lack of sellers and the participation by financial traders is small. One reason is that the CfD products are seen as much more affected by market power than system price products.

It is important for the competition in the retail market that independent retailers are not facing higher costs and risks than retailers belonging to an integrated group or retailers that buy bilaterally from one producer Many spot areas instead of a few means that more CfD products are needed and an obvious risk for even lower liquidity and higher “insurance premiums” in the different CfD products. The risks associated with hedging disappear for the retailer if the customers choose variable price. Most customers in Norway choose variable price while most customers in Sweden and Finland choose fixed price. Many spot areas means also smaller balancing areas and an increased risk for price spikes in the regulation market because of market power.

Conclusions regarding counter trade

Principle two-area Nash-Cournot equilibrium analyses was presented in section 5.4 comparing market splitting and counter trade as tools for congestion management in order to illustrate the effect of gaming in perfect competition on the one hand and in a concentrated market on the other hand.

Assuming perfect competition and no strategic bidding, the total social welfare and the final dispatch will be the same regardless whether market splitting or counter trade is used to manage congestion.

However, market players can even when it is perfect competition increase their profits by strategic bidding in situations when they anticipate counter trade. All players, irrespective of size, have incentive to bid strategically in order to increase their counter traded volume in situations when they anticipate counter trade. All generators have in the deficit area an incentive to bid strategically so that they are paid by a higher counter trade price instead of the spot price. In the surplus area all generators have an incentive to bid even their high-cost production just under the common spot price so that they thereafter are paid a counter trade price in order to abstain from a

production they never wanted to execute. The possible profit from strategic bidding increases substantially if it is a generator with market power in a concentrated market and the generator anticipates and/or creates a need of counter trade.

The main result of these analyses is that in situations when congestion is anticipated, there is more strategic bidding and less resource efficiency if counter trade is used instead of market splitting. The main advantage of counter trade is that it enables the use of fewer spot areas and thereby more competitive retail markets, at least in areas where the customers choose fixed price contracts. Negative effects of strategic bidding and less resource efficiency have to be compared with negative effects on the retail competition on a case by case basis in order to reach an optimal balance between efficiency and competition.

Market players have during the last decade often advocated guaranteed capacity levels to the day-ahead market. Nordenergi said e.g. the following in a position paper in 2006. “The system operators should, in a predictable way, guarantee the highest possible transmission capacity available for commercial trade on price area borders, corresponding to at least 70 percent of the net transfer capacity (NTC). A clear economic sanction should be set on TSOs in case of failing to guarantee the capacity.”

Our conclusion is that we will not get a more efficient market if Nordic TSOs are obliged to guarantee that the transmission capacities are always a certain percentage of the normal levels. In a developed market, changes in dispatch because of changes in the physical transmission capacities are managed more efficient in the day-ahead market than by the TSOs. A market clearing of the day-ahead market that reflects the physical realities should be encouraged – not concealed.

Conclusions regarding possible use of new bid areas

There are presently internal congestions in all Nordic countries that are managed in the day-ahead market by reduced capacity allocations to Elspot. The alternatives are market splitting and counter trade. The most preferable counter trade alternative is counter trade in Elspot. The bids to Elspot include all possible production and consumption changes while today’s counter trade is done bilaterally or within the regulation market and includes normally only larger bids within the TSOs’ respective operating areas. Today’s counter trade can therefore not give the same resource efficiency as counter trade in Elspot.

A necessary prerequisite for CM by counter trade in Elspot is that there are different bid areas so that bids in the surplus area can be separated from bids in the deficit area. In that case it is possible to calculate one uniform Elspot price for the Elspot area and simultaneously perform counter trade in Elspot that relieves the congestion and gives an effective resource utilisation in the day-ahead market. All bids in the common Elspot area will meet the common spot price, except the bids that are counter traded.

We propose the following method as a feasible method for counter trade in Elspot. New bid areas are established within an Elspot area so that bids on the deficit and surplus sides of the congestion can be separated from each other. In the first Elspot calculation, all bid areas are treated as Elspot areas. Congestions between bid areas are thus managed by market splitting and the result is the same market clearing and the same power flows as if the bid areas had been Elspot areas. A second calculation is thereafter performed for a certain Elspot area, if the first calculation has resulted in different prices for bid areas that are within that Elspot area. The second calculation uses as input the same power flows with other Elspot areas that were established in the first calculation. The purpose of the second calculation is only to establish a common spot price for the Elspot area and to perform the most cost-effective counter trade to relieve the congestion that arises as a consequence of the common spot price. The most cost-effective counter trade is a counter trade that gives the same dispatch within the Elspot area as the dispatch that was achieved in the first calculation. The second calculation does thus not change the power flows with adjacent Elspot areas. The final result in the Elspot market will be the same price signals in other Elspot areas and the same dispatch in all areas as if all bid areas had been different Elspot areas and only market splitting had been used.

This means an important improvement in relation to CM by reduced capacity allocations to Elspot. Reduced capacity allocations to Elspot result in other power flows with adjacent areas and another dispatch compared to the results of full market splitting. CM by reduced capacity allocations to Elspot gives thus reduced resource efficiency. Also an alternative with no capacity reductions to Elspot and full counter trade after Elspot gives reduced resource efficiency since it results in other power flows with adjacent areas and another dispatch compared to the results of full market splitting.

However, there are still two possible problems compared with the resource efficiency that is achieved with full market splitting. The first problem arises if the market players anticipate the counter trade in Elspot and changes to strategic bidding. The scope for strategic bidding is however reduced compared to an alternative with full counter trade after Elspot. With our proposed method for counter trade in Elspot, counter trade is reduced to the change in dispatch between the surplus and deficit areas that is needed to restore the dispatch achieved in the first calculation with full market splitting. Full counter trade after Elspot means however in addition that power flows with other Elspot areas has also normally to be counter traded. Such an extensive counter trade can create a much higher scope for strategic bidding by market players than our proposed method for counter trade in Elspot.

The second problem relates to the long-term signals for production and consumption investments. The relevant price for most of the production and consumption in the common Elspot area is the common spot price instead of the spot prices that would have been achieved with full market splitting. This can give wrong incentives for investments if there is a significant difference between the prices. Our simulations of

spot prices 2015 in section 4 show however that only one of the four new area borders in the eleven area case result in an average spot price difference higher than 0,1 EUR/MWh. That area border is cut 2 in Sweden with the spot price difference 0,8 EUR/MWh between Northern and Central Sweden. Even such a difference is relatively small compared to all other differences and difficulties that are characterizing possible investment alternatives.
A special question at issue if counter trade is performed in Elspot is how to how to perform CM in the intra-day market after Elspot. There will be misleading incentives for intra-day trade if there is only one common price in the intra-day market in situations when the counter trade in Elspot has resulted in different prices for counter traded volumes in the surplus and the deficit areas. Our conclusion is that the different bid areas in the day-ahead market should transform into different bid areas in the intra-day and the regulation markets as a natural consequence of counter trade in Elspot.

The consequence of new bidding areas and counter trade in Elspot is for retailers without price-elastic demand that the same uniform Elspot price applies to all their planned purchase in the Elspot area but that it can be different balance prices in the surplus and deficit areas for their imbalances. The retailers can thus hedge their planned purchase in the same way as if it is only one spot area. However, their imbalance risk is changed. Whether the changed imbalance risk is a serious problem or not for the retailers depends on the regulation power markets in the two separate bid areas but the changed imbalance risk will nevertheless only relate to their imbalance volumes not to their total purchase.

Our conclusion is that new bid areas and counter trade in Elspot is a better CM regime than present reduced capacity allocations to Elspot for the internal congestions we have assessed in our study; cut 2 and cut 4 in Sweden, cut P1 in Finland and the congestions west of Oslo. It is possible that there are further internal congestions that also are feasible to manage by establishing new bid areas but we have not made such assessments.

New spot areas and CM by market splitting give even better resource efficiency than new bid areas and counter trade in Elspot since there is no risk for strategic bidding because of anticipated counter trade and there are also more efficient long-term price signals. On the other hand, new spot areas can give negative effects on the competition, especially the competitive situation for independent retailers in areas where the customers choose fixed price contracts. Negative effects of strategic bidding and less resource efficiency have thus to be compared with negative effects on the retail competition on a case by case basis in order to reach an optimal balance between efficiency and competition. We have not made such case by case assessments and we have therefore no firm recommendation as to whether the new areas should be established as separate Elspot areas or separate bid areas within existing Elspot areas. However, we want to stress that the most important for resource efficiency is that the present reduced capacity allocations to Elspot comes to an end. If

there is uncertainty regarding the division of a special Elspot area into bid areas or spot areas, it is better to first establish the new areas as separate bid areas and then later decide if they are to be changed to separate Elspot areas based on experience of the amount of counter trade in the common Elspot area. The worst alternative is to postpone the decision and thereby not end the present reduced capacity allocations to Elspot.

Main assumptions in Balmorel (ANNEX 1)

7.1 Geography

The specific model version used for this scope of work contains the electricity and CHP system in the Nordic countries (Denmark, Finland, Norway and Sweden) and Germany. The countries are subdivided into areas with limited transmission capacities between the areas. The Nordic countries are divided into 11 areas and Germany is divided into three areas.

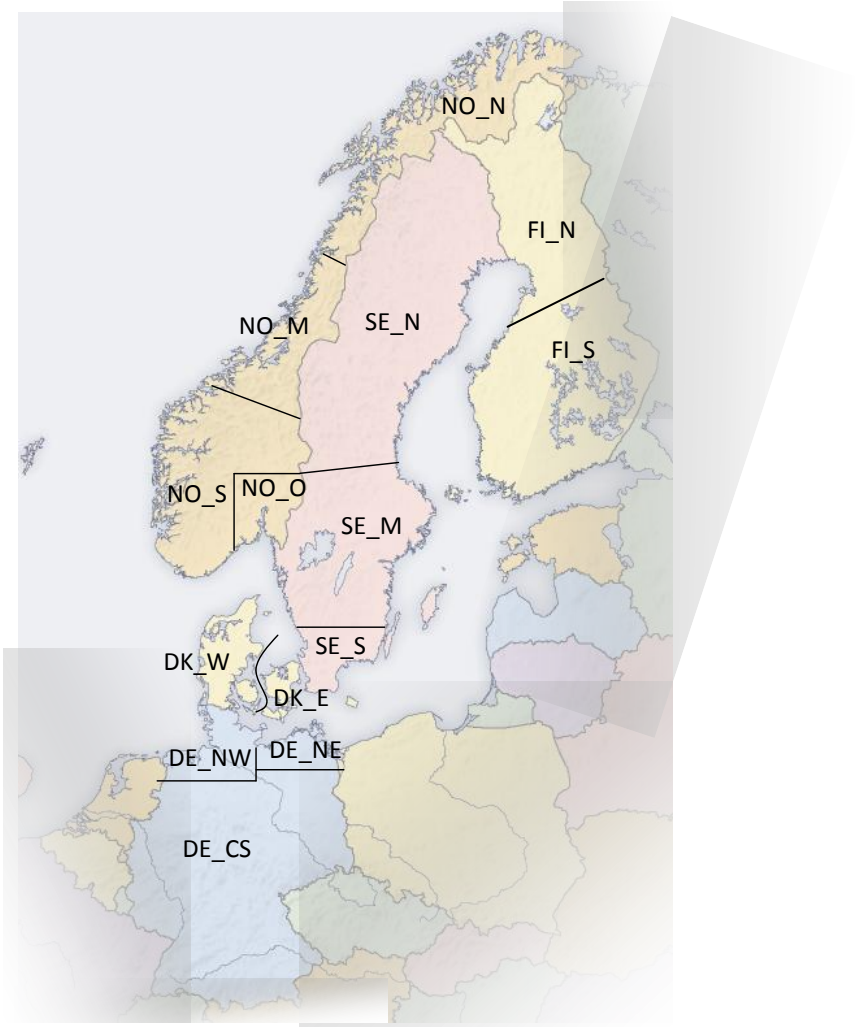

Figure 13: Areas in the model (11 in the Nordic countries and 3 in Germany).

7.2 Electricity and heat demand

The electricity demand in each country is shown in Table 23 below. In average, the electricity demand is assumed to increase by 0.8% per year until 2015.

Table 23: Electricity demand ab power plant used in the model analyses, TWh

	Denmark	Finland	Norway	Sweden	Germany
2006	35.7	85.0	125.9	147.3	533.8
2015	37.2	98.1	134.9	156.1	585.8

The variation in electricity demand follows the demand profile for 2001 for each country.

The development in heat demand is shown in Table 24 below. The heat demand included in the model is only the demand for district heating (DH). Depending on the composition of power plants, fuel prices etc., the model optimises whether heat should be produced at heat-only boilers or at combined heat and power plants (CHP).

Table 24: District heat demand used in the model analyses, PJ

	Denmark	Finland	Norway	Sweden	Germany
2006	125.4	122.5	5.9	120.5	337.0
2015	125.4	127.4	7.1	125.4	337.0

The analyses are carried out assuming the same electricity and heat demand for all scenarios. However, the electricity consumption is reduced when the price is high due to price elastic demand. Based on a Nordel analysis carried out in 2003 (Statistical analysis of price response of the aggregated electricity demand), the demand reduction in Norway was up to 1000 MW.

The demand reduction is assumed to be 71.4 MW when the price is 50 EUR/MWh, 500 MW when the price is 100 EUR/MWh, and 1000 MW when the price is 2000 EUR/MWh.

For the other Nordic countries, the electricity demand is reduced correspondingly relative to total electricity demand.

7.3 Installed capacities

As background information, the table below shows the electricity generation at power plants in the Nordic countries and Germany in 2006 (this, however, is not an assumption in the model).

Table 25: Nordic and German power balance in 2006 (for Germany 2005)

	Denmark	Finland	Norway	Sweden	Germany
Total generation	43,328	78,590	121,715	140,314	579,300
- Nuclear power	-	21,982	-	64,982	155,000
- Other thermal power	37,198	45,119	1,123	13,167	343,900
- Hydro power	23	11,342	119,919	61,176	80,400
- Wind power	6,107	147	673	987	
Net import from Nordic countries	-5,053	-25	642	4,436	-8,500
Net import from other countries	-1,883	11,546	215	1,616	
Total consumption (including network losses and electric boilers)	36,392	90,111	122,572	146,366	561,500 (+ pump 9,400)

Source: Nordel Annual Report, 2006 and Eurostat

Capacities

Table 26 below shows the installed capacity in the Nordic countries and Germany in 2015.

Table 26: Power capacities in 2015, MW

	Denmark	Finland	Norway	Sweden	Germany
Total					
- Hydro					
- Nuclear					
- Natural gas					
- Coal (incl. lignite)					
- Peat					
- Oil					
- Waste					
- Biomass					
- Wind					

Regarding new thermal investments, it is assumed that 900 MW new gas capacity will be established in Norway South and 670 MW new gas capacity will be established in Sweden (Malmø and Göteborg). In Finland, a new nuclear power plant with a capacity of 1,600 MW will be established.

The development in wind power capacity from 2006 to 2015 is shown in the table below.

Table 27: Development in total wind power capacity

Power capacity in MW	Denmark	Finland	Norway	Sweden	Germany
2006	3212	105	350	525	19.000
2015	4353	610	3250	4000	36.000

Source: "Wind Power in Nordel - system impact for the year 2008"

The development in wind power capacity is particular high in Germany. The development takes in particular place in the North Sea (18.7 GW of the German capacity will be located there).

The analyses are carried out, assuming the same decommissioning and expansion plan for all scenarios.

7.4 Fuel prices

The table below shows the **fuel prices** used for the analyses. The prices do not include taxes.

Table 28: Fuel prices, €/GJ

	Coal	Nuclear	Gas	Fuel oil	Light oil	Peat	Straw	Wood chips	Waste
2006	2.0	0.6	5.7	6.4	11.2	1.8	4.5	4.4	0.0
2015	1.8	0.6	6.0	5.8	10.1	1.7	4.5	4.4	0.0

Source: World Energy Outlook 2007

In Norway, the gas price is assumed to be 10% lower than shown in the table due to a better gas availability. Opposite, in Sweden, the gas price is assumed to be 10% higher due to higher transportation costs.

7.5 Taxes and emission policies

The simulations take account of the most relevant taxes. However, energy taxes and subsidies in the simulated region are in themselves a complicated study, often with specific taxes on specific power plants. The model includes taxes on emissions of NO_x and SO_2 as well as taxes on district heating and cogeneration. Also, CO_2 emission certificates are taken into account.

CO_2-price

The CO_2 allowance price is estimated at 20 €/ton.

SO_2-tax

SO_2-taxes are in Sweden 12.3 kr./kg, in Denmark 10 kr./kg, and in Norway 15 kr./kg. Three is no SO_2-tax in Finland.

Fuel taxes on district heating

In Norway, Sweden, Denmark and Finland are used existing taxes on district heating production.

7.6 Transmission capacities

Figure 14 below shows the transmission capacities in 2015, where it has been assumed that the five prioritised links have been established. The left column is the "from region" and the upper row is the "to region". For instance, the transmission capacity from SE_S to DK_E is 1,300 MW (and 1,700 MW in the opposite direction).

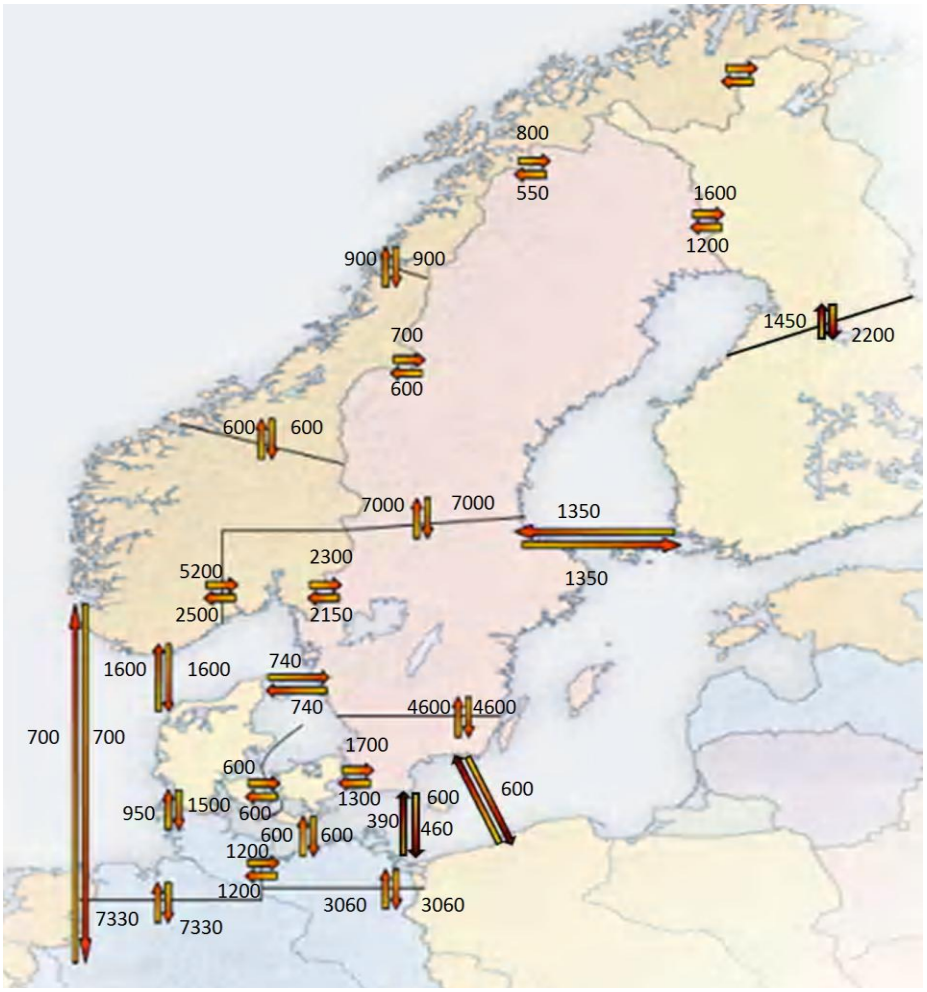

Figure 14: Transmission capacities between price areas (MW), 2015. (note: Baltic cable runs between SE_S and DE_NW even though the figure may lead one to believe otherwise).

7.7 Electricity exchange with the Continent and import from Russia

Electricity exchange with the Continent is taken into consideration by including the German system in the model.

The transmission link between Sweden and Poland is connected to North Eastern Germany assuming that this area is representative for the prices in Poland, and the

link between Norway and the Netherlands is connected to Central and Southern Germany assuming that this area is representative for the prices in the Netherlands.

Apart from the power exchange with the continent, a fixed annual import to Finland from Russia of 11 TWh and from Estonia of 2 TWh is included in the analyses. The import from Russia may change in future as Russia may come to face increased demand and environmental requirements that may influence electricity prices.

7.8 Time division

The analyses are carried out by use of an hourly time resolution.

7.9 Water inflow

The analyses are carried out for both a normal year, wet year and dry year. Based on statistical variations in water inflow, a representative dry and wet year has been defined as a year with 17% lower and 12% higher water inflow, respectively. The probability of a "representative" wet and dry year is 15% each, and the probability of a normal year is 70%.

Additional results (ANNEX 2)

Energy balances

Table 29: Simulated energy balance in 2015 - 11 areas

	Denmark	Finland	Norway	Sweden	Total
Total generation	49,490	89,258	127,419	157,723	423,890
- Nuclear power	0	35,027	0	67,941	102,968
- Other thermal power	38,870	40,049	2,521	14,842	96,282
- Hydro power	0	12,566	115,148	63,737	191,451
- Wind power	10,620	1,616	9,750	11,203	33,189
Net import	-12,314	8,828	7,558	-1,247	2,825
Total consumption (including net-work losses and electric boilers)	37,189	98,087	135,012	156,517	426,805

Table 30: Simulated energy balance in 2015 - 7 areas

	Denmark	Finland	Norway	Sweden	Total
Total generation	49,326	89,677	126,765	158,083	423,851
- Nuclear power	0	35,027	0	67,941	102,968
- Other thermal power	38,706	40,209	2,513	15,359	96,787
- Hydro power	0	12,825	114,502	63,580	190,907
- Wind power	10,620	1,616	9,750	11,203	33,189
Net import	-12,142	8,406	8,231	-1,774	2,721
Total consumption (including net-work losses and electric boilers)	37,185	98,085	134,998	156,480	426,748

Table 31: Simulated energy balance in 2015 - 6 areas

	Denmark	Finland	Norway	Sweden	Total
Total generation	47,908	89,278	128,728	157,850	423,764
- Nuclear power	0	35,027	0	67,941	102,968
- Other thermal power	37,303	40,040	2,547	14,808	94,698
- Hydro power	0	12,595	116,431	63,898	192,924
- Wind power	10,605	1,616	9,750	11,203	33,174
Net import	-10,737	8,808	6,246	-1,379	2,938
Total consumption (including net-work losses and electric boilers)	37,184	98,087	135,010	156,514	426,795

Table 32: Simulated energy balance in 2015 - 4 areas

	Denmark	Finland	Norway	Sweden	Total
Total generation	49,172	89,215	128,549	157,582	424,518
- Nuclear power	0	35,027	0	67,941	102,968
- Other thermal power	38,552	39,972	2,524	14,747	95,795
- Hydro power	0	12,600	116,275	63,691	192,566
- Wind power	10,620	1,616	9,750	11,203	33,189
Net import	-11,999	8,871	6,425	-1,109	2,188
Total consumption (including net-work losses and electric boilers)	37,186	98,087	135,010	156,515	426,798

Table 33: Simulated energy balance in 2015 - 1area

	Denmark	Finland	Norway	Sweden	Total
Total generation	48,981	89,143	128,994	157,424	424,542
- Nuclear power	0	35,027	0	67,941	102,968
- Other thermal power	38,361	39,910	2,527	14,711	95,509
- Hydro power	0	12,590	116,717	63,569	192,876
- Wind power	10,620	1,616	9,750	11,203	33,189
Net import	-11,807	8,942	5,980	-952	2,163
Total consumption (including net-work losses and electric boilers)	37,186	98,087	135,010	156,515	426,798

Hydro power follows Nordels normal year scenario. The slightly difference discrepancy has cause in the way water is handled in model. By using a time aggregated version of the model, water values are derived for each week based on total annual quantities. These values are then used in individual simulations of weeks, using an hourly time resolution basis. These same water values are shared in all the simulations, since the scenarios which involve counter trading cannot be used to generate applicable water values.

Comparing the different situations, it appears that the overall picture is more or less the same. Even though counter trade is not carried out in the whole analysed region, the three CM regimes that involve counter trade almost comes to the same generation dispatch as in the 11 area situation (without involving counter trade).

Compared with the baseline situation, it appears that in the 7 area situation there is a reduction in hydro generation which is a result of the method of generation water values. The true water values in this scenario are somewhat higher than the applied values. It should be noted, however, that there is very limited total economic impact of this shortcoming of the simulations. The unused water is considered with a positive value in the economic costs and benefits, and therefore the economic discrepancy is the difference between the applied water values and the true water values, multiplied by the unused water quantity]