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Simulation of Congestion Management and Security Constraints in the Nordic Electricity Market

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Simulation of Congestion Management and Security Constraints in the Nordic Electricity Market

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***Abstract* -- Presently in the Nordic day-ahead market, zonal pricing or market splitting is used for relieving congestion between a predetermined set of price areas. Constraints internal to the price areas are resolved by counter trading or redispatching in the regulation market. In a model of the Nordic electricity market we consider an hourly case from winter 2010 and present analyses of the effects of different congestion management methods on prices, quantities, surpluses and network utilization. We also study the effects of two different ways of taking into account security constraints.**

***Index Terms*—Congestion management, Zonal pricing, Day-ahead market simulation**

I. Introduction

THE Nord Pool Spot area presently covers Norway, Sweden, Denmark, Finland and Estonia. Previously, prices were also calculated for a German price area (Kontek). However, since November 2009 this price area has been replaced by market coupling with the Central Western European area. At Nord Pool Spot, area prices are calculated for the day-ahead market. Since this market is settled many hours before real time, imbalances occur and they are settled by intraday trading in Elbas and in the close to real time regulation market. Nord Pool Spot is a voluntary pool; however, trades between Elspot areas are mandatory. Nord Pool Spot covers about 70 % of the physical power in the Nordic region (except Iceland), and the pool is used not only for mandatory trades but also to increase legitimacy of prices and as a counterpart.

There are three types of bids at Nord Pool Spot. These are hourly bids for individual hours, block bids that create dependency between hours, and, finally, flexible hourly bids, which are sell bids for hours with highest prices. Here we illustrate different congestion management methods in a single hour market, and we treat all bids as hourly bids. Accepted block bids are part of the bid curves, as price independent buy or sell bids.

The day-ahead market takes grid constraints partly into account by calculating different prices for relatively few price areas. Presently there are 13 price areas in the Nord Pool area. Transfer capacities between these areas are given by the system operators before the market agents submit bids, and Nord Pool Spot then calculates area prices. This means that zonal pricing or market splitting is used in the day-ahead market for congestions between a predetermined set of price areas. Constraints internal to the price areas are resolved by counter trading or redispatching in the regulation market. Thus two congestions management methods are in action simultaneously. For more detailed descriptions of congestion management methods in the Nordic market we refer readers to [2], [4], and the websites of Nord Pool Spot and the Nordic TSOs. The system operators in the Nord Pool area are transmission system operators owning and controlling the national grids. They are incentive regulated and the net effects of the incomes from zonal pricing and the expenses from redispatching are passed on to domestic customers.

The chosen congestion management method affects the efficiency of the Nordic electricity market and the prices quoted in the day-ahead market at Nord Pool Spot. In our research we particularly want to study how the implementation of a more detailed network model and load flow calculation of the spot price will contribute to more efficient price signals to producers and consumers, price signals that will depend to a larger extent on location.

II. Research Agenda

An important element in the design of the Nordic electricity market is the market clearing procedures when capacity constraints in the transmission network are binding. The general design of the electricity market, for example, with regards to the time dimension, which products are traded and the bidding rules, determines simultaneously the constraints and opportunities that we have in the choice of methods. For the analysis of congestion management within an exchange area, with a market infrastructure that allows a certain number of geographic prices on an hourly basis, the optimal economic load flow model is often used as the reference point. This is normally a single period model that maximizes economic profit, given the supply and demand curves that exist for each

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node in the network, as well as the limitations imposed by thermal and other capacity constraints in the transmission system. The optimal load flow is a snapshot, and the dynamic adjustment over time is left to the players, which means that supply curves for a period include opportunity costs such as water values for hydro power producers, etc. The question then is whether the procedures for market clearing can achieve something similar to the optimal load flow with optimal prices for each generation and load point (optimal nodal prices).

An analysis of the effects of various methods for congestion management in the Nordic electricity market may take as a starting point an hourly optimal load flow model. The effectiveness of the mechanism can then be evaluated based on the degree to which one can realize the optimal load flow. In the Nordic power market this is dependent on the formulation of practical rules for area price determination at Nord Pool Spot. These involve a number of simplifications and approximations in terms of assumptions underlying the optimal load flow calculation. For a start, prices are not noted for each node in the system, instead prices are uniform within larger areas of the network. The number of price areas and how the boundaries of these are exactly determined, therefore, affects economic efficiency. Another simplification is that the companies supply their bids within each zone and not at each generation or load point. This results in uncertainty regarding the effects of a bid on the system, and consequently a possibility that the capacity control is imprecise. Likewise, area prices imply that transmission capacities are often aggregated over several transmission lines. This also results in a less fine-tuned capacity control compared to if line capacities were used individually. In the whole Nordic system there is a practice of *moving* a transmission constraint within a price area to an area boundary by reducing the capacity between price areas. Previous work [1] and [2] has shown that this is a practice that can be costly and greatly affects the levels of area prices in different regions. Incentives for this practice are also influenced by the network regulation models and the fact that the two congestion management methods described above normally differ in how they affect grid revenues and system operation costs.

We distinguish between two variants of price aggregation: economic and physical, later referred to as optimal and simplified zonal prices. Under economic aggregation the topology of the network is represented in full while prices within zones are required to be uniform. Under physical aggregation the network is highly simplified thus neglecting the physical characteristics of the power flow, resembling the current practice in the Nordic market. In our analysis, zone allocations are as defined by the Nordic TSOs for both types of aggregation. Fig. 1 demonstrates the current map of the market.

Optimal zonal prices have been studied by [1]. They are second best compared to optimal nodal prices. Different divisions are preferred by different agents (producers and consumers in a node have opposite interests for instance) and

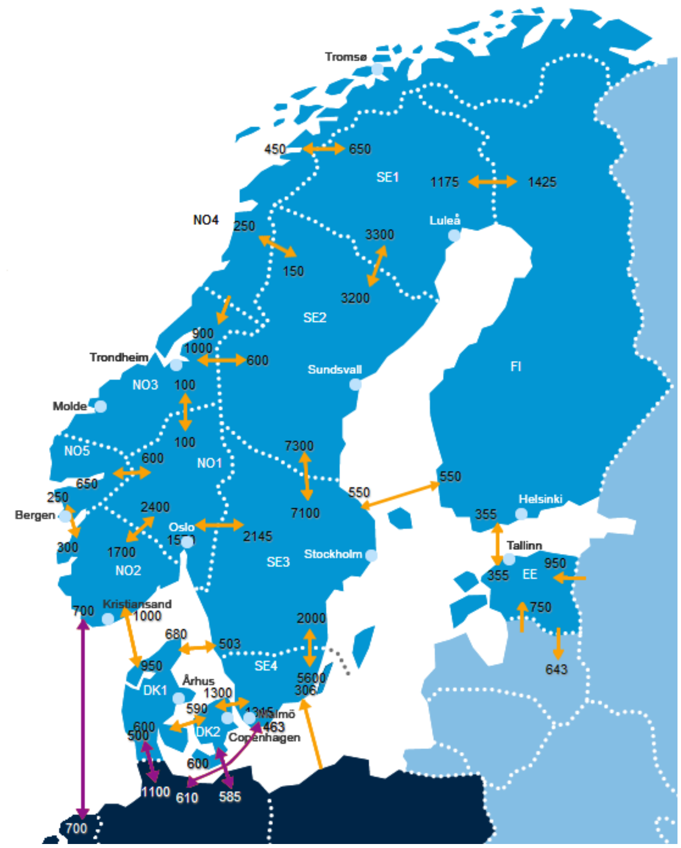

Fig. 1. Elspot market overview, March 2012. Source: www.nordpoolspot.com.

grid revenues may be negative under optimal zonal prices. There may be many variants of “adverse flows”, i.e. power flowing from high prices to low prices, and it is very difficult to find an optimal zone division. Moreover, the optimal zone allocation depends on market characteristics and hourly costs, topology of the network etc., which makes it difficult to decide upon a division if it is to be fixed for a longer period. If there are too few zones, it may be impossible to find prices that are uniform within predefined areas and in addition clear the market subject to all relevant constraints.

In the simplified zonal price model, detailed information on nodal bids is lost, and constraints within a zone are not represented. Setting capacities on aggregated lines is difficult, if they are too restrictive, the power system may not be fully utilized, if they are too encouraging, the market outcomes may result in infeasible flows.

The rest of the paper is organized as follows. In Section III we briefly describe the model and calibration of the data as well as simulations run to ensure that the model approximates the real-life case. Section IV compares prices and quantities obtained from the two types of zonal aggregation to the nodal solution. In Section V we describe changes in surpluses under different models. Section VI compares prices and quantities with an alternative implementation of security constrains in the models. Conclusions to the analyses are presented in Section VII.

III. The OptFlow Model and Calibration of Data

We analyze the effect of different congestion management methods on hourly prices/quantities for the case of a winter supply/demand scenario based on hour 19 on December 15, 2010. The Norwegian part of the network model is presented in detail and roughly corresponds to the Norwegian central grid. The network model for Sweden is simpler while the other Elspot price areas and adjacent countries are represented as a single node each, see Fig. 2.

We have also included security constraints for the Norwegian part of the network. These may be considered heuristics used by the system operator to express *N*-1 constraints. Each security constraint models the potential outage of a network component. The outage of a component will typically lead to a redirection of the power flow, which could be determined endogenously as part of the optimization procedure or it could be specified in advance. The latter approach can be modeled as so-called "cut" constraints where total capacity is specified over a number of lines, or a combination of lines and generation/load quantities. As mentioned earlier we do not include block bids and ramping restrictions and assume that the choice of congestion management method does not affect the bid curves. In practice this might not be true, since the chosen bottleneck method will affect prices, and hence the expected water values that are embedded in the bid curves.

The OptFlow formulation can be roughly expressed as the following:

Max (consumer benefit – production cost)
s.t. load flow constraints
thermal capacity constraints
security constraints.

The model above provides a solution to the nodal pricing problem. The objective function represents the total social welfare given as total consumer benefit less total production cost. Load flow constraints represent Kirchhoff's laws and thermal constraints define transmission capacities on the lines. Security constraints determine total flow over a set of transmission lines and possibly generation/load quantities that cannot be exceeded.

For the economic aggregation solution an additional set of constraints ensures that prices are equal within zones. For the physical aggregation solution Kirchhoff's second law is disregarded and flow capacity constraints are defined only for the interzonal flows.

We have calibrated hourly supply and demand curves based on Nord Pool Spot sale and purchase bids, Statnett data on nodal production and exchange, information on generation technologies and capacities, the location of energy-intensive industry, as well as information about imports and exports provided online by Nord Pool Spot.

The supply bid curves that we have used have between one and six linear segments. Actual capacities and generation source types are reflected. Demand bid curves are also piece-wise linear and include inelastic and elastic segments. The aggregated OptFlow demand curves closely follow the Nord Pool bid curves in shape; however, they give higher demand for any price level. This is not unexpected, since the OptFlow curves are based on total load, including load that is not channeled through Nord Pool Spot.

Fig. 2. OptFlow Nordic grid map.

Table I below compares the actual Elspot prices (I) to the prices obtained from the OptFlow model solved with the real (II) and calibrated (III) bid curves. For the OptFlow computations we have used the actual Nord Pool capacities for (aggregate) interzonal connections. Intrazonal capacity constraints, constraints related to Kirchhoff's second law, as well as security constraints, have all been relaxed. Hence, the OptFlow model closely resembles the model used for the computation of Elspot prices. From Table I we see that the Elspot prices (I) and the area prices calculated by the OptFlow model with Nord Pool Spot bid curves (II) match exactly. This shows that the OptFlow model is capable of reproducing the Elspot results when using the same bid curves. Moreover, the differences between the actual Elspot prices (I) and the OptFlow area prices calculated on the basis of the disaggregated OptFlow bid curves (III) are quite small. Contrary to (I) and (II), the disaggregated bid curves cover 100 % of production and consumption, thus it is difficult to calibrate the bid curves so as to match the prices of the aggregated curves exactly. However, the relatively small differences between (I) and (III) show that the disaggregation we have developed works reasonably well in aggregate, although it still leaves a great deal of uncertainty with respect to how accurate the distribution of production and consumption on the nodes within the bidding areas is. This is, however, as close as we can come with the data provided.

TABLE I
BID CURVE CALIBRATION – ELSPOT AND OPTFLOW PRICES

Bidding area	(I) NPS actual area prices	(II) OptFlow prices with NPS bid curves	(III) OptFlow prices with calibrated bid curves
NO1	104,56	104,56	105,63
NO2	104,56	104,56	105,63
NO3	130,50	130,51	130,70
NO4	130,50	130,51	130,70
NO5	104,56	104,56	105,63
DK1	130,50	130,51	130,70
DK2	130,50	130,51	130,70
SE	130,50	130,51	130,70
FI	130,50	130,51	130,70
EE	38,95	38,95	38,95

The OptFlow production and consumption quantities with Elspot bids (II) differ somewhat from the OptFlow quantities with calibrated bid curves (III), especially for Norway, but the exchange quantities match quite well as presented in Table II below. Based on the limited data available on disaggregated bid curves, we conclude that the disaggregation in (III) is a reasonable starting point for analyzing different congestion management methods for our case. In order to evaluate the effects on the disaggregated power system, we need all production and consumption represented. Thus, the prices and quantities corresponding to column (III) are the starting point of our comparisons, i.e. in the following analyses column (III) represents the "Nord Pool Spot" area price solution.

TABLE II
BID CURVE CALIBRATION – ELSPOT AND OPTFLOW QUANTITIES

Bidding area	(I) NPS net exchange	(II) OptFlow net exchange with NPS bid curves	(III) OptFlow net exchange with calibrated bid curves
NO1	-1775	-1775	-1734
NO2	2610	3311	3300
NO3	-166	-166	-204
NO4	1305	1278	1292
NO5	565	565	534
DK1	330	556	556
DK2	-300	-753	-753
SE	-2715	-3115	-3091
FI	-219	-1606	-1606
EE	365	437	437

In the following section, we compare prices and quantities for different congestion management methods, including nodal pricing, optimal zonal pricing (taking into account all constraints) and simplified zonal pricing (area prices like Nord Pool Spot, disregarding loop flow and intrazonal constraints).

IV. PRICE COMPARISONS

Table III compares four sets of prices for our case hour in winter 2010. Actual Nord Pool Spot prices are given in the first price column (corresponding to (I)/(II) in Table I), while the second and third columns show, respectively, the simplified and optimal zonal prices calculated by the OptFlow model. The simplified zonal prices correspond to (III) in Table I, while optimal zonal prices take into account the specific locations of all bids on the nodes and all constraints of the disaggregated power system. The three rightmost columns show descriptive statistics for the optimal nodal prices within each price zone.

TABLE III
NODAL VS ZONAL PRICES

Bidding area	Actual NPS	Zonal prices		Optimal nodal prices		
		Simplified	Optimal	Average	Min	Max
NO1	104,56	105,63	132,21	131,15	131,12	131,28
NO2	104,56	105,63	132,10	131,13	131,13	131,14
NO3	130,50	130,70	132,66	131,44	131,33	131,72
NO4	130,50	130,70	86,59	80,09	74,89	120,09
NO5	104,56	105,63	1999,86	774,29	125,22	2000,00
DK1	130,50	130,70	124,77	131,13	131,13	131,13
DK2	130,50	130,70	172,00	131,13	131,13	131,13
SE	130,50	130,70	132,35	130,54	93,65	132,52
FI	130,50	130,70	130,16	129,27	129,27	129,27
EE	38,95	38,95	36,10	38,95	38,95	38,95

We see that when moving from simplified zonal prices to optimal zonal or nodal prices; prices increase in zones NO1, NO2 and NO5 while prices decrease in NO4. Prices in other areas remain almost the same or vary around the corresponding simplified zonal prices. NO5 experiences a tremendous price increase compared to the simplified zonal prices, and the maximum nodal price in NO5 is equal to the price cap at Nord Pool Spot of 2000 Euros/MWh (the optimal zonal price in area NO5 is also close to the price cap). Note, however, that the price vectors are not directly comparable, since actual and simplified zonal prices do not take into account all constraints in the system. We will come back to this point later.

In Fig. 3 below we have sorted the optimal nodal prices from the lowest to the highest. The colors show which bidding area the nodal prices belong to. On the first axis the price columns are weighted by the consumption in the nodes. The figure shows that only a few prices are close to the maximum price, whereas the other prices take on values mostly below 132 Euros/MWh. We see that most of the price variation is linked to a small share of the total consumption.

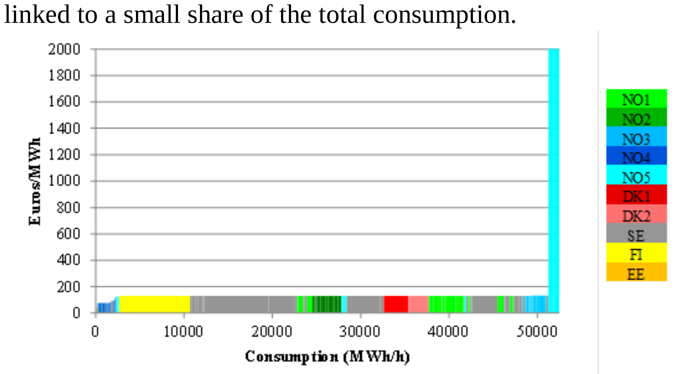

Fig. 3. Variation in nodal prices.

Looking more closely at the price data, we study the nodes with prices equal to the price cap. We see that at the market clearing consumption quantity in one of those nodes, Arna, is on the horizontal extension of the demand curve that represent the price cap of Nord Pool Spot.

This is illustrated in Fig. 4. This is the optimal solution returned when allowing for nodal pricing and taking into account all constraints of the problem, i.e. both the thermal capacity constraints and the cut constraints imposed for security reasons. The solution is technically feasible in the OptFlow model, however, in economic terms, we are dealing with an infeasibility. The difference between the inelastic demand and the "market clearing" demand can be interpreted as the necessary curtailment of consumption in the node in order to obtain a feasible flow.

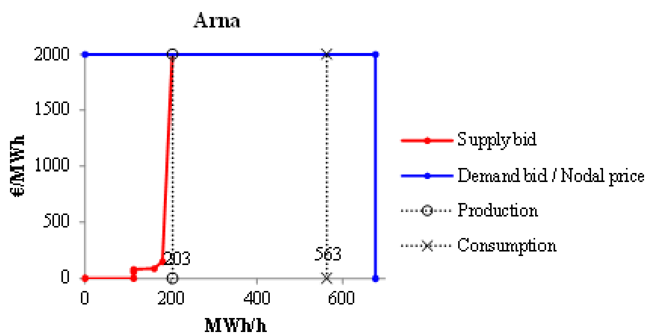

Fig. 4. Bid curve and market clearing price and quantity, Arna (NO5).

This corresponds to the situation referred to by [3]; saying that for long periods the Norwegian power system has been operated at below agreed upon security standards due to high loads and/or lack of transmission capacity. In a nodal pricing system this becomes very visible, as do the representations of the security constraints imposed. In the following analyses we relax the infeasible cut constraints (in our case particularly in the Bergen area): two cut constraints are removed from the disaggregated optimization problems of the OptFlow model. The relaxation will change the optimal nodal and zonal prices, while the simplified zonal prices will be unaffected, since the cut constraints are not directly included in this price calculation anyway[1].

Summary data of the new prices is given in Table IV and shows that all prices are now below 141 Euros/MWh. Moving from simplified zonal prices to optimal zonal or nodal prices results in price increases in NO1, NO2, NO3, NO5, and FI. Prices decrease in NO4, while for the rest of the areas optimal zonal and nodal prices vary around the simplified zonal prices or are fairly unaffected by the change (EE). Again, the price vectors are not directly comparable, since actual and simplified zonal prices do not take into account all constraints in the system, thus at these prices, the resulting flows will not comply with all of the system constraints.

[1] In practice, the cut constraints may affect the import and export capacities that the system operators set between the bidding areas and that are given to the Elspot market clearing.

TABLE IV
NODAL VS ZONAL PRICES WITHOUT BERGEN CUT CONSTRAINT

Bidding area	Actual NPS	Zonal prices		Optimal nodal prices		
		Simplified	Optimal	Average	Min	Max
NO1	104,56	105,63	140,42	139,25	139,21	139,40
NO2	104,56	105,63	140,26	139,23	139,23	139,24
NO3	130,50	130,70	140,94	139,59	139,45	139,91
NO4	130,50	130,70	88,17	80,74	74,77	126,58
NO5	104,56	105,63	140,26	135,65	125,22	139,24
DK1	130,50	130,70	124,77	139,23	139,23	139,23
DK2	130,50	130,70	120,61	139,23	139,23	139,23
SE	130,50	130,70	140,59	138,51	93,65	140,83
FI	130,50	130,70	138,08	137,09	137,09	137,09
EE	38,95	38,95	36,10	38,95	38,95	38,95

Fig. 5 shows the optimal nodal prices for consumption and production respectively, where prices are sorted from lowest to highest, and column widths represent volumes. For a quick visual comparison of aggregate price differences, the simplified zonal prices are shown in a similar way represented by the thick black line. Since the simplified zonal prices are also sorted from lowest to highest, the curves cannot be compared directly for each MW, in the sense that a specific

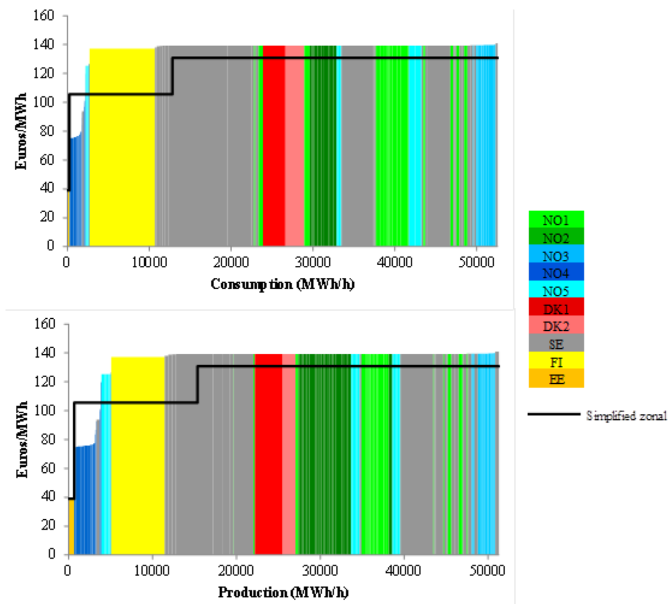

Fig. 5. Variation in nodal prices without Bergen cut constraint.

point on the first axis may represent different geographical locations in the two curves. Thus the zones may have different sequencing in the two figures and in the two curves shown.

Comparing the total volume weighted prices (i.e. the areas under the curves) we notice that for this hourly case, the nodal prices are on average higher than the simplified zonal prices. The reason for this is that nodal prices include shadow prices for all transmission constraints (except the cut constraints that we excluded), whereas the simplified zonal prices do not, thus implying a solution that results in infeasible flows. We also notice that the nodes in specific bidding areas like NO1 and NO5 are placed at different locations along the first axis, i.e. some nodes should be in the lower end of the price distribution, whereas others should be in the high price end, although for NO1 and NO5 especially, the nodal price differences within the zones are not very large.

In Fig. 6 we compare simplified and optimal zonal prices. The figures are similar to those in Fig. 5 except that we have sorted simplified zonal prices from lowest to highest and shown the corresponding optimal zonal price in the same sequence of zones. Thus it is easier to compare the changes that result in the zonal prices from taking into account all constraints and the specific location of bids to nodes (optimal zonal prices) instead of only a subset of the constraints or some indirect representation of the constraints (simplified zonal prices). Fig. 6 elaborates on what was already shown in Table IV; that some zonal prices increase while others decrease. Moreover, as a weighted average, prices increase when all constraints are taken care of in the optimal zonal prices. The simplified zonal prices are lower on average (volume weighted), but on the other hand, they result in infeasible power flows.

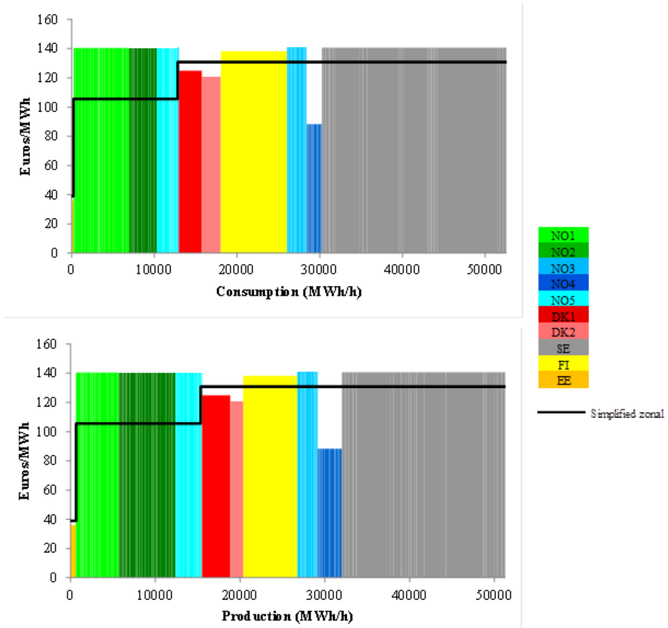

Fig. 6. Variation in optimal zonal prices without Bergen cut constraint.

V. Surpluses

In Table V we show the changes in surplus for the three pricing solutions compared to the unconstrained market solution. The absolute values of consumer surpluses are not very meaningful, since demand is very inelastic, at least for high prices, and we have capped the consumer surplus at the price cap of 2000 Euros/MWh. This way, the consumer surplus and the total social surplus are very much affected by the price cap. Moreover, since the surpluses of the simplified zonal solution are not comparable to the optimal nodal and zonal prices that take into account all constraints, we have shown the number of overloaded thermal and security constraints in the last row of the table.

For the present case, we see that moving from simplified zonal prices to optimal zonal or nodal prices leads to a reduction in consumer surplus, and an increase in producer surplus and grid revenue. Since we disregard many constraints in the simplified zonal solution, the total surplus goes down somewhat, however, this must be balanced off by the infeasibilities that are left in the simplified zonal solution and which are dealt with in the optimal zonal and optimal nodal solutions. In the end the infeasibilities must be taken care of in the simplified zonal solution too. This may be costly for society, and this cost is not reflected in Table V. Alternatively, we could model counter trading, and take into account any efficiency effect from that. However, it is not straightforward how to do that, so we choose here to compare solutions by a combination of surpluses and a summary description of infeasibilities.

TABLE V
Unlimited Surplus and Surplus Differences (1000 Euros)

	Unconstrained	Simplified zonal	Optimal zonal	Nodal
Producers	6799,5	38,0	650,3	624,8
Consumers	99249,1	-111,7	-757,9	-761,4
Grid	0,0	68,6	90,3	120,9
Total	106048,7	-5,1	-17,3	-15,6
Infeasibilities	2 lines 1 cut	2 lines 1 cut	None	None

VI. Security Constraints

In this section we consider a different approach to incorporating approximate security constraints. Instead of the cut constraints described above we reduce the capacities of the individual lines to a fraction of the nominal thermal capacities, like in [5]. Graphs in Fig. 7 demonstrate price changes (weighted by consumed quantities on the first axis) and the utilization of the cut constraints in the corresponding solutions. Only the cuts on the left hand sides of Fig. 8, Fig. 10 and Fig. 12 with utilization above 100 % are violated. In the price diagrams in Fig. 7, Fig. 9 and Fig. 11 we compare nodal prices with the reduced individual line constraints to nodal prices with thermal and cut constraints (solid lines) and simplified zonal prices (dotted lines).

When capacities decrease, the nodal prices increase and the price differences increase. On the other hand, the number of overloaded cuts decreases, and when the capacity is set to only 70 % of the nominal capacity only 3 cut constraints are overloaded, i.e. the infeasible Bergen cuts and the Nordland cut (NO4). We can also see from Fig. 9 and Fig. 11 that prices in NO1 are most affected when capacity is decreased.

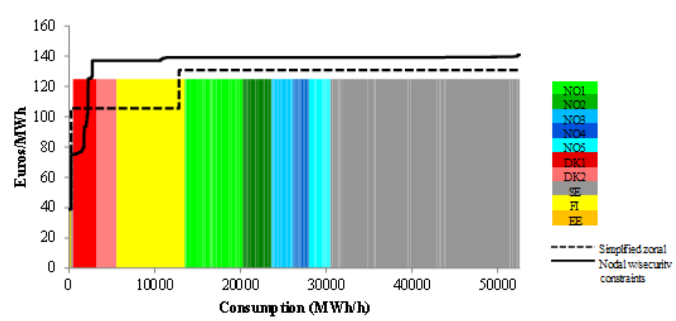

Fig. 7. Nodal prices with line capacities set to 100% of nominal capacities.

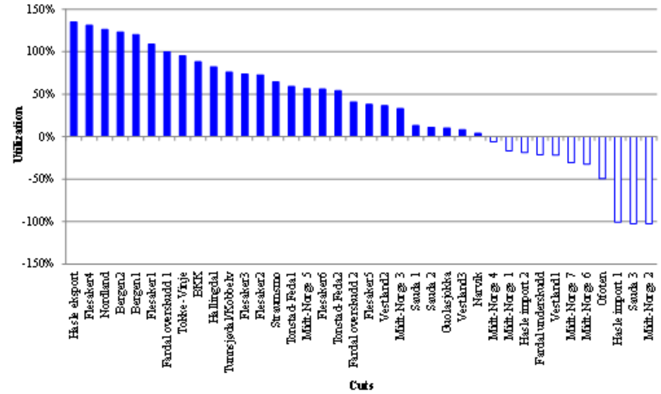

Fig. 8. Security cut capacity utilization with line capacities set to 100% of nominal capacities.

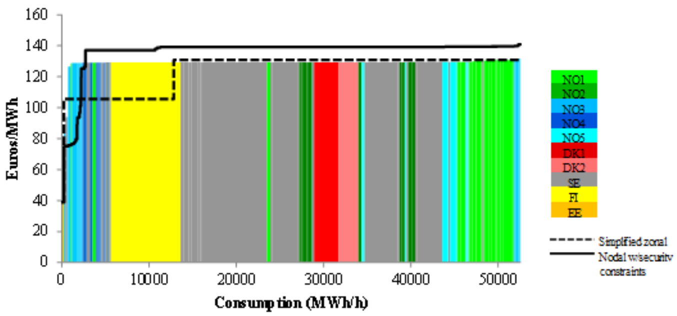

Fig. 9. Nodal prices with line capacities set to 80% of nominal capacities.

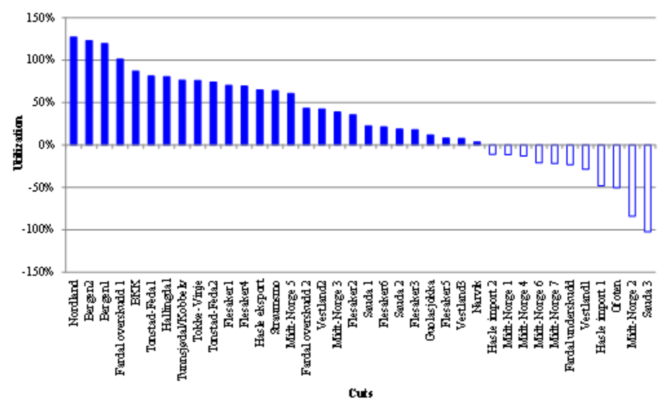

Fig. 10. Security cut capacity utilization with line capacities set to 80% of nominal capacities.

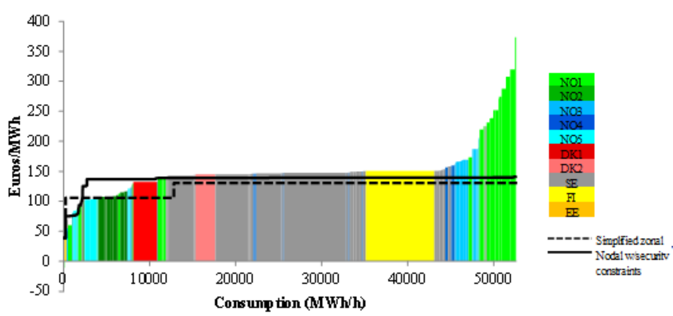

Fig. 11. Nodal prices with line capacities set to 70% of nominal capacities.

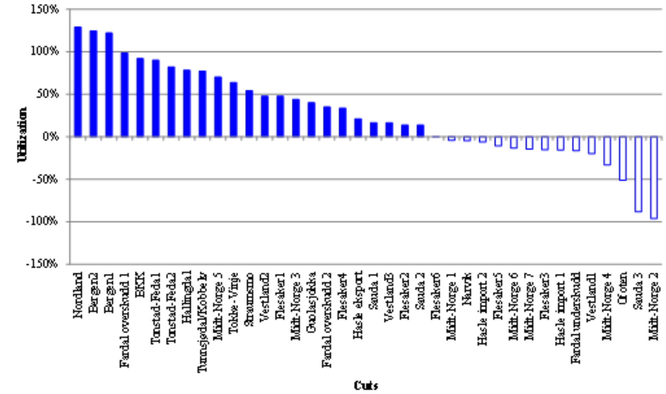

Fig. 12. Security cut capacity utilization with line capacities set to 70% of nominal capacities.

Table VI shows the changes in surpluses and infeasibilities for the three cases above. When restricting capacities, surplus is transferred from consumers to producers and the grid. When capacity is lowered to 70 % of the nominal values, we see that the grid revenues increase a lot, and that the total social surplus is also negatively affected. Note, however, again that the surpluses cannot be directly compared as the solutions differ when it comes to infeasibilities.

TABLE VI
UNLIMITED SURPLUS AND SURPLUS DIFFERENCES (1000 EUROS) WITH DIFFERENT SECURITY CONSTRAINTS

	Unconstrained	Simplified zonal	Nodal with red. line capacities				Nodal w/sec. cut constraints
			100 %	90 %	80 %	70 %	
Producers	6799,5	38,0	85,8	108,1	274,8	949,9	624,8
Consumers	99249,1	-111,7	-126,0	-169,9	-355,3	-1498,9	-761,4
Grid	0,0	68,6	36,5	57,8	72,9	516,3	120,9
Total	106048,7	-5,1	-3,6	-4,0	-7,7	-32,6	-15,6
Infeasibilities	2 ind. lines 1 cut	2 ind. lines 1 cut	4 cuts	5 cuts	2 cuts	1 cut	None

VII. CONCLUSIONS

We have simulated the effects of different congestion management methods on the market outcomes for a specific high load winter hour using given bid curves, i.e. we assume that bids do not change even when the congestion management method does. Moreover, we have focused on two ways of representing approximations of *N*-1 type security constraints.

The calibrated nodal bid curves match quite well the aggregated Nord Pool Spot bid curves, however, the disaggregation depends on many assumptions and may not reflect the actual nodal bid curves underlying the real Nord Pool Spot bid curves. Thus, the simulation performed must be evaluated not with respect to the actual power flows on the specific hour we have considered, but with the calibrated nodal bid curves as the starting point.

The findings of the analyses indicate that in many cases the price changes with nodal pricing are not so dramatic and the price variation is related to small volumes of production and consumption. The choice of method for representing security constraints may be at least as important.

In future research we will incorporate counter trading in the model in order to compare infeasible to feasible solutions.

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