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Discussion paper

Peak price hours in the Nordic power market winter 2009/2010: effects of pricing, demand elasticity and transmission capacities

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Abstract

The Nordic electricity market experienced extremely high prices during the winter 2009/2010. Using real data from the peak price hours the zonal solution from the Nordic market is replicated and compared to the nodal price solution when the central grid and its physical characteristics are explicitly modelled. Demand elasticity is introduced to the bid curves and its effect on prices and network utilisation is studied for the nodal solution. The sensitivity of the zonal solution to the changes in aggregate transfer capacities is investigated. The results demonstrate that better system utilisation is possible without capacity expansion. Nodal pricing solutions compared to the actual zonal pricing mechanism give insights into how the system functions in strained capacity situations and what hinders a more efficient system utilisation.

1 Introduction

In a market with free competition the equilibrium price for the product is equal to its marginal cost. Market prices for power vary and in that way reflect the current consumption, production and transmission conditions in the Nordic power market. Sometimes the price can be higher than pure operating costs of the most expensive production unit in use. This is explained by limited capacities in the network or production facilities, or both. High prices can occur in the market without being purely attributed to the exercise of market power. In the periods with high demand it will be either the facilities with high production costs or the willingness to pay that is price-setting in the market. These in turn will be influenced by the presence of a production capacity and (or) a transmission capacity bottlenecks. Periods with high prices help the high load facilities to cover their costs. In the long run high prices give signals on the need for investments into new production or/and network capacity.

On three occasions during the winter 2009-2010 the Nordic electricity market experienced prices of 1000 EUR/MWh or higher. The yearly average for the past ten years has only been higher than 50 EUR/MWh on a few occasions. A number of factors that have contributed to the high market prices have been identified.

That winter was colder than a typical winter, with longer periods when temperatures were below average. Households in the Nordic area use predominantly electric heating which contributed to the high levels of consumption during peak price periods. According to the

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Norwegian regulator (NVE[2]) industrial demand in Norway was lower during winter 2009/2010 than the year before, and slightly higher in Sweden and Finland.

Aggregate transmission capacities between market areas are determined by the Transmission System Operator (TSO) the day before operation, based on the forecasted demand for the respective hours. As a result of anticipated high demand, transmission capacities have been significantly reduced on several connections. Particularly low capacity was allocated from Southern Norway to Sweden due to technical problems and high expected consumption in the Oslo area. Also, the *NorNed* cable connecting Southern Norway and the Netherlands went out of operation on the 29th of January 2010. Additionally, TSO-allocated capacity from Western Denmark to Sweden has been reduced to its half due to technical problems.

Swedish power production was significantly lower due to scheduled maintenance and modernisation work on the nuclear power plants that took longer than planned. The plants' total capacity during peak price periods was below 70%.

The high prices indicated that utilisation of the available production capacity was close to its maximum, coupled with low short-term flexibility of demand. For highly populated areas this means that a single disruption of a production facility or a network component could have resulted in power outages or required disconnection of consumers. Increased demand flexibility can play a key role in bringing the prices down in this kind of strained situations.

From the 11th of January 2010 two new market areas NO1 and NO2 have been established in Southern Norway replacing the old NO1 area. The Norwegian TSO (Statnett) decided on this new division due to reduced capacity on the Rød–Hasle cable going across the Oslofjørd. As a result of this decision the end nodes of this connection are located in different market areas.

Just a few months later, from 15th of March, Statnett added yet another area in Norway, NO5, consisting of parts of the previous NO1 and NO2 areas. This new division was explained as a preventive measure for the possible lack of energy into this geographical area. NO5 area covers western Norway north of and including Bergen.

The creation of two new bidding areas within two months is quite unusual and is an indication of the network utilisation close to its capacity limit as a result of increased production, consumption and exchange volumes. As will be shown in this work efficient system utilisation is highly dependent on how the market mechanism is implemented, and what measures are available for future improvements.

2 Nordic power market operation

The timeline of operations and deadlines in the Nordic power market are visualised in Figure 2-1. Nord Pool Spot (NPS) operates a day-ahead spot market Elspot, an intraday market Elbas with continuous trading up to one hour prior to delivery. Market participants are power producers, distributors, large industrial customers and brokers. The regulating (balancing) markets are operated by the national TSOs. There are auctions for reserves and rules for price settings for up- and down-regulations that differ among the countries. Special regulation takes place when transmission bottlenecks within the bidding areas are alleviated using the bids from the regulating market disregarding the merit order.

[2] Norges vassdrags- og energidirektorat, www.nve.no.

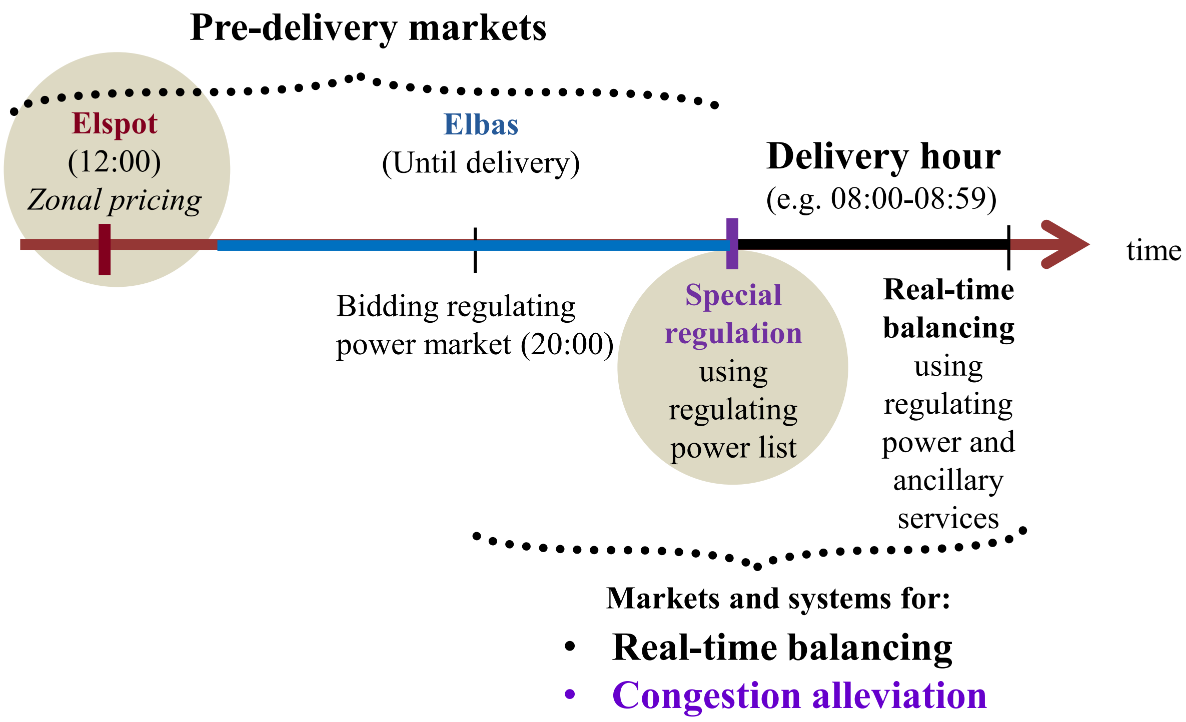


Figure 2-1. Operations in the Nordic power market (timeline).

2.1 Market clearing and balancing

Elspot is the auction based day-ahead market at NPS. About 80% of Nordic consumption is traded through NPS as physical contracts. The rest is handled through bilateral agreements. The spot market is also the basis for power flow balancing between Nordic countries performed by the system operators. Market participants submit buy and sell bids for each of the hours of the following day by 1200 the day before. Each bid specifies the volume that the actor is willing to buy or sell for with a corresponding price. Bids are given by discrete points that are interpolated into piece-wise linear curves. Since bids by market participants are given on area level depending on their geographical location, their individual bid functions are aggregated into total demand and supply curves that are used by the Elspot algorithm to establish system or area prices for each hour of the day. The system price is the single price for the market when the flow between the bidding areas is within the pre-set trade capacities. If the flow between the areas is above these aggregated capacities, market clearing results in area prices, where a net demand area (*constrained off*) will settle on a higher price and a net supply area (*constrained on*) – at a lower price.

Trade capacities that are actually made available at NPS are reported by the system operator at 0930, 2.5 hours ahead of the final deadline for submitting orders for the day ahead.

The NPS price algorithm (SESAM at the time of the cases in focus, presently EUPHEMIA) is based on a physically aggregated network model. Market participants submit their orders for the bidding area where they are located, and there is no further geographic specification of their location, so bids remain on area level. The information on the exact location of bids becomes available only after the market is cleared, when market participants submit their production plans to the TSO (around 1900 on the day ahead). In this way the location of bids is not fully a part of the price setting process. The price algorithm only takes area supply and demand bids and the trade capacities between the bidding areas into account. Transmission capacities within the zones are not represented and physical laws that determine the flow of electricity in the network are not accounted for.

The balance between supply and demand is for the most part secured in the day-ahead market. In order to trade, market participants in Norway must sign a balance agreement with the system operator Statnett. Thereby the buyers and sellers of power become responsible for their own power balance. The balance responsible party bears the economic responsibility for the transactions in the regulation market.

In situations when the market cannot be cleared because supply and demand curves do not cross (at any allowed price level) NPS follows certain procedures where available measures are applied in a priority order. These measures include activation of peak-load reserves, release of more transmission capacity by the TSOs, and pro-rata curtailment of demand bids.

It is important to have enough power available in the operational phase to manage high load situations and be able to avoid disruptions in the system. Peak-load reserves include extra capacities both on the supply and the demand sides that are available on a very short notice, in practice, momentarily. Total available peak-load reserves amount to around 2600 MW and are mainly located in Sweden and Finland. In the extreme hours in winter 2009/2010 discussed in this paper there was no price under the price cap of 2000 EUR/MWh that would provide market equilibrium, so the peak-load reserves in Sweden and Finland were activated. Technically they come in the shape of a flat supply bid marginally above the last commercial bid. In the extreme hours reserves have been used to a varying degree and up to 230MW.

System protection tools are established for increasing transmission limits in the network without reducing system security. These, among others, include disconnection of production and consumption, activation and deactivation of reactive power, and, load following, otherwise known as quarter moving. Quarter moving is the acceleration or postponement in time of planned production changes by up to 15 minutes with the intent of achieving a better alignment between planned production and estimated consumption and keeping the frequency within the limits. TSO then covers the costs of losses incurred by the producer.

If other measures are not sufficient to achieve market clearance then pro-rata curtailment of demand bids will take place. In this case the price is set to a maximum of 2000 EUR/MWh. All participants on the demand side get their orders reduced in the same proportion. If they don't adjust their real purchases they will be forced to purchase curtailment from the intraday or regulation market, usually at much higher prices. In this way they have a clear incentive to reduce their demands to the requested level.

Elbas is the intraday market for trading power at NPS. It is a continuous market where trading takes place around the clock until one hour before actual operation. Capacities available for trading at Elbas are published at 1400, and prices are set on a first-come, first-serve principle where highest buy prices and lowest sell prices are picked first. Intraday market participants have the opportunity to trade themselves back into balance and thus avoid paying for their imbalances in the regulation market. Intraday trading across Elspot areas implies available network capacity after the spot market is settled.

System responsibility implies providing instantaneous balance between production and consumption at any point in time and that operations run within the physical limits of the system. The system operator shall also coordinate power producers and end users' configurations with the aim of achieving adequate supply quality and an effective utilisation of the power system. Power system balancing is performed by Statnett using regulation categorised into primary, secondary and tertiary regulation. In primary regulation, frequency controlled reserves are activated automatically when frequency deviates from 50,0 Hz. Secondary regulation makes sure that frequency deviations are quickly reset releasing the primary reserves for regulation of new imbalances. Tertiary regulation is the *regulation market* used by Nordic system operators for achieving balance between production and consumption in the hour of operation. This type of regulation is applied in cases of production or line failures, for dealing with transmission constraints, or when demand deviates from the prognosis from the day before. Active participants in this market have the ability to regulate up or down at a 15 minute notice. Large consumers that can disconnect their consumption at a short notice are also active in the market. Market participants submit their price-quantity bids for up/down regulation for the next 24 hours by 2000 the day before. These bids can be changed up until 45 minutes before the hour of operation. At the point of bidding the actors know what bids were accepted in the Elspot and the price(s), and use this as a basis for their bids. During the hour of operation the system operator continuously assesses the need for regulation and activates the cheapest bids available at that point. The last bid that is used in that hour sets the price. In this way pricing is uniform in the regulation market.

According to Statnett, disconnection of demand was in practice the only measure to avoid reduced operational security in the Oslo area in the winter 2009/2010 (see [5]). The disconnected volumes accounted for between 5% and 10% of the total demand in the areas with disconnections. For the particular hours that are investigated, when prices peaked, the following measures have been taken. Ahead of the hour of operation peak load reserves in Sweden and Finland have been activated (around 200MW in total at most). In the delivery hour, loads with interruptible tariff have been disconnected. Significant down-regulation has taken place (around 2500MW at most) partly due to reduced consumption in the operational phase as a result of unrealised expectations on weather conditions. Other imbalances occurred due to start-up and disconnections of additional production capacity. In the BKK area in Bergen radial operations were introduced to secure reliable operations. For 6% of the total time until 21st of February operational security was reduced due to increased flow over critical security cuts. And as the major consequence, an additional bidding area was introduced from 11th January, and, as a result, two new bidding areas were defined in Southern Norway.

2.2 Congestion management

In the Nordic market congestion management is partly done by zonal division into bidding areas and partly with the help of counter trading in the regulation market. The former is currently used to handle long-lasting bottlenecks at country borders, while the latter should firstly relieve bottlenecks internal to price areas.

According to regulations[3] (*FoS*) the system operator shall establish the bidding areas in order to handle large and long-standing bottlenecks in the regional and central grids. The system operator will normally also determine separate bidding areas under anticipated power shortage in a geographically restricted area.

[3] Forskrift om systemansvaret i kraftsystemet. FOR-2002-02-07 nr 448.

Counter trading (*special regulation* in direct translation from Norwegian) occurs when there is a need for relieving a bottleneck within a price area using the bids from the regulation market. It takes its name *special regulation* from the fact that activated bids do not follow the merit order from the regulation bid curves. The bids used for special regulation are taken out of the calculation in the regulation market. Costs of special regulation are covered through the central network tariff. This means that all consumers pay extra even if there is no congestion in their geographical area. Statnett uses the rule of thumb that creation of a new bidding area should be considered when special regulation costs go over 20 MNOK. By the end of March 2010 special regulation costs that can be directly connected to shortages in the BKK area amounted to NOK 37.7 mill. The total special regulation cost for Western Norway was the same time at already NOK 43.4 mill.

Due to the way power flow between bidding areas is modelled in the NPS price algorithm zonal prices will usually have a positive net income for the system operator, while counter trading entails costs. The net effect of these two mechanisms is attributed to the central grid customers. In the long run this does not have economic significance for the system operator as the positive income will later be used to offset the network tariffs. However, the system operator is incentivised towards more restrictive trade capacities. Too much capacity reduces the short-term income and results in costs for counter trading that in its turn lead to increase in network tariff, which will not be so well met by the society. Less capacity increases the short-term income that in turn may lead to lower network tariff with time together with reduction in counter trading costs and operational problems.

Congestion rent is an ownerless income in the spot market generated by price differences between the bidding areas. The congestion rent from one area connection for one particular hour is calculated as the difference in prices between the high and low price areas times the planned flow between these areas. Within the Nordic region the congestion rent is allocated to the TSOs according to the rules stipulated in a separate agreement. Congestion rent in the Nordic market for 2010 amounted to nearly EUR 250 mill where EUR 78 mill were collected in January and February. The rent collected on the connection between NO1 and NO2 accounted for nearly one-third, and together with the rent from DK1 to NO2 connection constitutes almost half of the total yearly income.

3 Methodology and cases

The analysis to follow is performed using the models developed and presented in our previous research [2]. The models are based on a DC approximation of an Optimal Power Flow (OPF). They simulate different congestion management methods based on locational prices: nodal, optimal zonal and simplified zonal. The latter is an approximation of the current day-ahead market solution from the Nordic electricity market. The models provide solutions to one-period (hourly) cases where no block bids or ramping restrictions are considered. The underlying network is modelled with the level of detail of a central grid. An in-depth description of the models together with the mathematical formulations, as well as the details on data calibration can be found in [2].

The analysis is based on the data from six individual hours with extreme prices during winter 2009/2010; hours 8-10 on Friday 8th of January and hours 9-11 on Monday 22nd of February 2010. Note that there are four areas in Norway after 11th of January.
In the morning hours on the 8th of January areas NO2, NO3, DK2, SE and FI were the high price areas with the prices of 1000 EUR/MWh, with the total import varying between 1900 MW and 2600 MW. The lower price areas were NO1 and DK1 with the area price varying between 52 EUR/MWh and 65 EUR/MWh. In the morning hours on the 22nd of February the high price areas with the price of 1400 EUR/MWh were NO3, NO4, DK2, SE and FI, with the total import between 2500 MW and 2900 MW. The prices in NO1, NO2 and DK1 were around 170 EUR/MWh, 62 EUR/MWh and 48 EUR/MWh respectively.

4 Model calibration

4.1 Economic infeasibility

The starting point for the analysis is the nodal pricing solution for an hourly case for hour 8 on 8th January 2010. A number of line and cut capacity constraints are binding. In total eight individual line constraints are binding: three within bidding areas (intra-zonal) and five between the areas (inter-zonal). Among the cut constraints four are binding, one on connections between northern Norway and Sweden and three in western Norway around the Bergen area. Studying the prices from the three pricing models (see Table 4-1) economic infeasibilities in the nodal solution are uncovered, with prices at the price cap of 2000 EUR/MWh and even negative prices below the lower bid limit of – 200 EUR/MWh. This solution is technically feasible and optimal, all constraints are satisfied, but in economic terms we are dealing with infeasibility.

Table 4-1. OptFlow prices versus actual NPS prices, 08-01-2010, hour 8.

Bidding area	NPS	Zonal simplified	Zonal optimal	Optimal nodal average	Optimal nodal min	Optimal nodal max
NO1	51.64	51.64	629.48	536.35	-588.27	2000.00
NO2	1000.01	1000.02	1000.00	734.88	42.95	2000.00
NO3	1000.01	1000.02	415.66	78.56	34.39	404.97
DK1	57.10	51.64	31.70	300.04	300.04	300.04
DK2	1000.01	1000.02	120.28	458.25	458.25	458.25
SE	1000.01	1000.02	390.00	471.84	43.99	1000.02
FI	1000.01	1000.02	495.15	482.24	482.24	482.24

The results in Table 4-1 indicate that extreme prices are attributed to the bidding areas (zones) NO1 and NO2 in Norway. More specifically, there are nine nodes with extreme prices: five in NO1 and four in NO2. The line connections that are binding and have the two highest shadow prices in this solution originate or finish in one of these nodes. NO1 nodes can be divided into two groups: three located in Oslo area and two around Bergen. Nodes from NO2 are all located on the Midwestern coast of Norway. Let’s have a closer look at the price infeasibilities grouped by their geographic location.

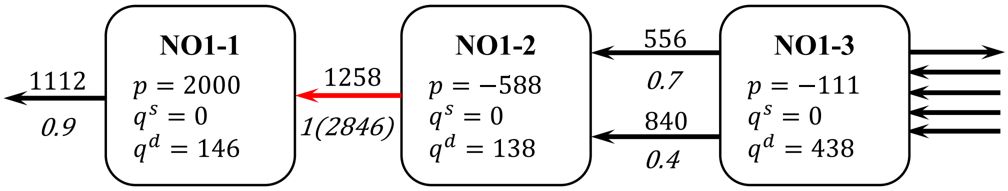


Figure 4-1. Interconnections and data for extreme price nodes in the Oslo area, nodal solution, 08-01-2010, hour 8.

A diagram of the Oslo nodes with line connections between them in Figure 4-1 provides a better visual representation of the nodal pricing solution. The arrowed lines show the direction of the flow and the number of links between the nodes. The total flow from the current solution is indicated above the lines, and the loads in proportion to available capacity are indicated under the lines in cursive. The red arrowed line between NO1-2 and NO1-1 means that the thermal line capacity constraint is binding in this solution and the corresponding shadow price is shown below the line in cursive. NO1-3 and NO1-2 are connected by two parallel lines of the same voltage level but different transmission capacities; hence the two pairs of numbers. Adjacent nodes not included in Figure 4-1 have economically feasible prices in the nodal solution.

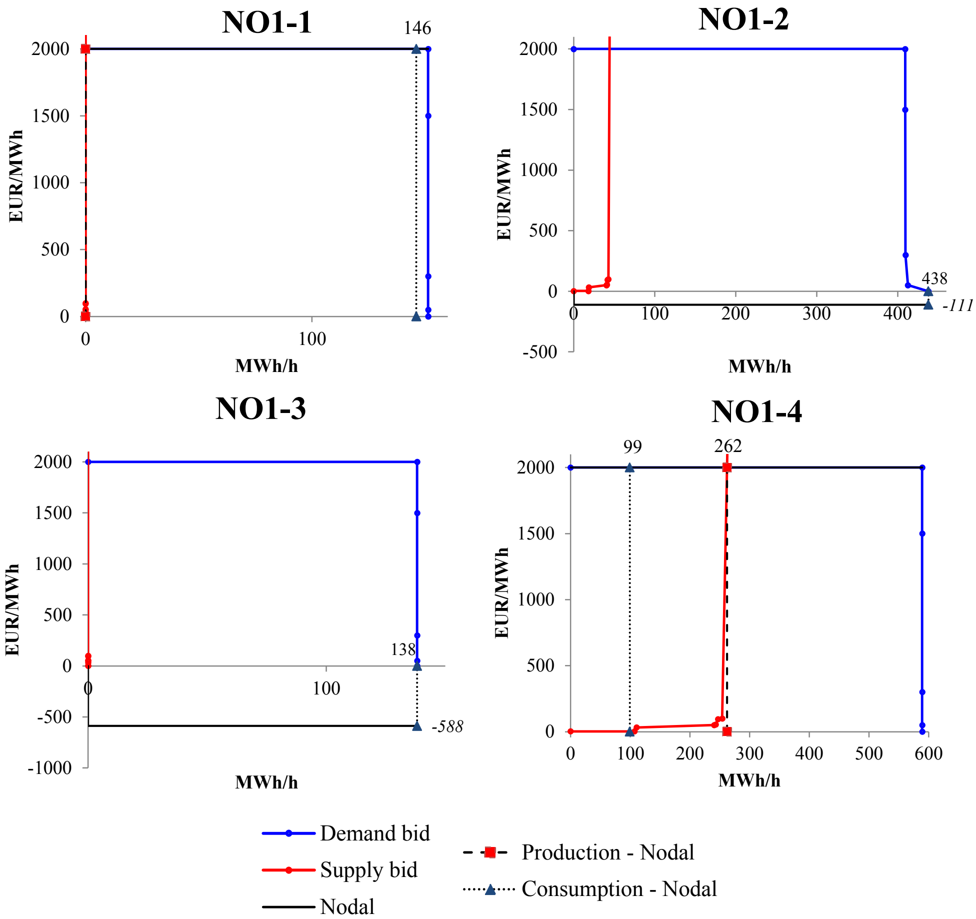


Figure 4-2. Nodal solution price and quantity diagrams for the nodes in NO1, 08-01-2010, hour 8.

The three nodes from NO1, NO1-1, NO1-2 and NO1-3, are situated around Oslo where flow and demand are highest. NO1-1 and NO1-2 are nodes with no production capacity available, and in NO1-3 production capacity for the hour in question is limited to 55 MWh/h. The flow moves from NO1-3 via NO1-2 into NO1-1. Demands are satisfied in the first two nodes, and demand in NO1-1 is curtailed (146 MWh/h out of 151MWh/h available) due to lack of production capacity and a congested line from NO1-2. The price in NO1-1 is at the maximum of 2000 EUR/MWh, while prices in NO1-2 and NO1-3 are - 588 EUR/MWh and - 111 EUR/MWh respectively. Demand is inelastic for both NO1-2 and NO1-1. The price and quantity diagrams for this solution for all nodes with extreme prices in NO1 are presented in Figure 4-2. It is clearly visible that for all three nodes in Oslo the nodal solution results in no production and lie on either the horizontal (NO1-1) or vertical (NO1-2 and NO1-3) extensions of the bid curves.

Table 4-2. Bergen security cuts: lines and capacities.

Cut	Lines			Max
BKK	NO1-10	↔	NO1-7	670
	NO1-9	↔	NO1-8	
Bergen 1	NO1-8	↔	NO1-6	670
	NO1-7	↔	NO1-5	
Bergen 2	NO1-8	↔	NO1-6	670
	NO1-5	↔	NO1-4	

Two nodes close to Bergen, NO1-4 and NO1-4-0, also within the NO1 bidding area, have the nodal prices at the cap of 2000 EUR/MWh. NO1-4 is one of the nodes on the ends of a line included in the Bergen 2 cut (security) constraint that is binding in this case. Table 4-2 provides an overview of lines included in the three Bergen cuts with the corresponding maximum capacity of the cuts.

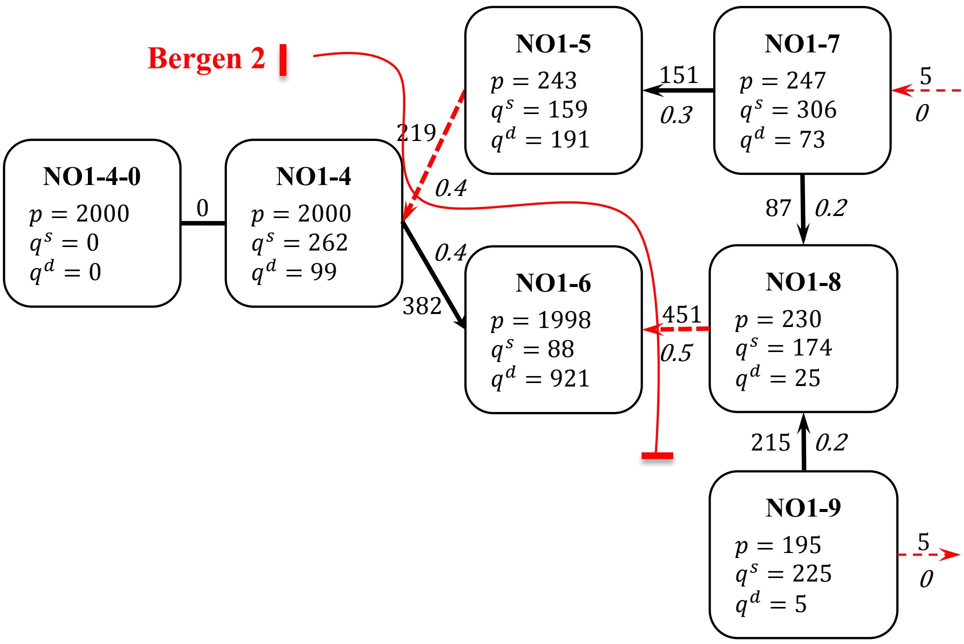


Figure 4-3. Interconnections and data for extreme price nodes in the Bergen area, nodal solution, 08-01-2010, hour 8.

The diagram in Figure 4-3 visualises the details of the nodal solution in NO1-4 and adjacent nodes that are the end points of the lines included in the Bergen cut constraints. Production in NO1-4 is at its allowed maximum of 262 MWh/h while demand was strongly curtailed from 589 MWh/h to 99 MWh/h. Market clearing demand quantity lies on the horizontal extension of the demand curve. NO1-4-0 has no demand and a thermal production capacity that is not continuously in operation and was off for this particular case, meaning no production and no demand.
The two thicker red dashed lines indicate connections included in the Bergen 2 cut (shown as a red line across the two connections) that is binding for this solution. At the same time we see that individual line capacities are under-utilised. The capacity of the Bergen 2 cut together with high demand in NO1-6 can explain the shortage of supply experienced in NO1-4, and thus the extremely high price. The thinner red dashed line going into NO1-7 is a connection from NO1-10 that is both part of the BKK (Bergen) cut and another cut binding in this solution, Fardal overskudd 1. The other thinner dashed red line leaving NO1-9 shows the connection to NO1-11 that is part of the Fardal overskudd 2 cut constraint, also binding in this nodal solution. The utilisation of both of these individual lines is however below 1%. In this way, the three binding cut constraints are interrelated, which is most likely the result of high demands in NO1-6 and NO1-4. An example of adverse flow is visible on the connection between NO1-7 and NO1-5, i.e. power is flowing from a higher to a lower price node, even though the price difference is not very large.

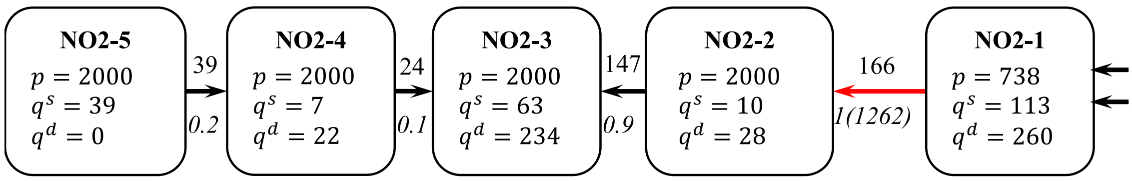


Figure 4-4. Interconnections and data for extreme price nodes in NO2, nodal solution, 08-01-2010, hour 8.

Four nodes in NO2, NO2-5, NO2-4, NO2-3 and NO2-2, all with the nodal price of 2000 EUR/MWh, are connected in a radial line with no other connections other than with each other, and NO2-5 is only connected to NO2-4. The high prices are likely explained by the binding thermal line capacity constraint between NO2-1 and NO2-2, and that, as a result, the demand in NO2-2 is not fully satisfied. The interconnections between these nodes, direction of the flows and the prices and quantities from the nodal solution are presented in Figure 4-4.
The market clearing solutions presented in the diagrams in Figure 4-5 are located on the horizontal extensions of demand curves that are inelastic for all nodes apart from NO2-5 where demand is zero. Demand is curtailed in NO2-2, which most probably decides the extremely high price in all nodes on this side of the transmission constraint.
The real-life examples of market prices in organised spot markets exceeding the highest submitted bid have been provided by [8]. Prices above real bid prices are shown to arise as a consequence of transmission constraints, especially in markets with inelastic demand. The extremely high prices are not necessarily the result of exercise of market power but rather the result of interaction of competitive market forces and technical constraints in a market where sellers lack market power. In these cases the price caps intended to mitigate market power can have an adverse effect. A locational marginal price expression is provided in [7] that can be

used to show that the price can reach a very high value much higher than the highest bid. This fact is somewhat counterintuitive and has been ignored in many market designs that have introduced price caps in anticipation that the prices would be kept within the caps. If in a situation with a binding transmission constraint there exists a penalty on the shadow prices, wide price spreads can occur including very high negative prices.

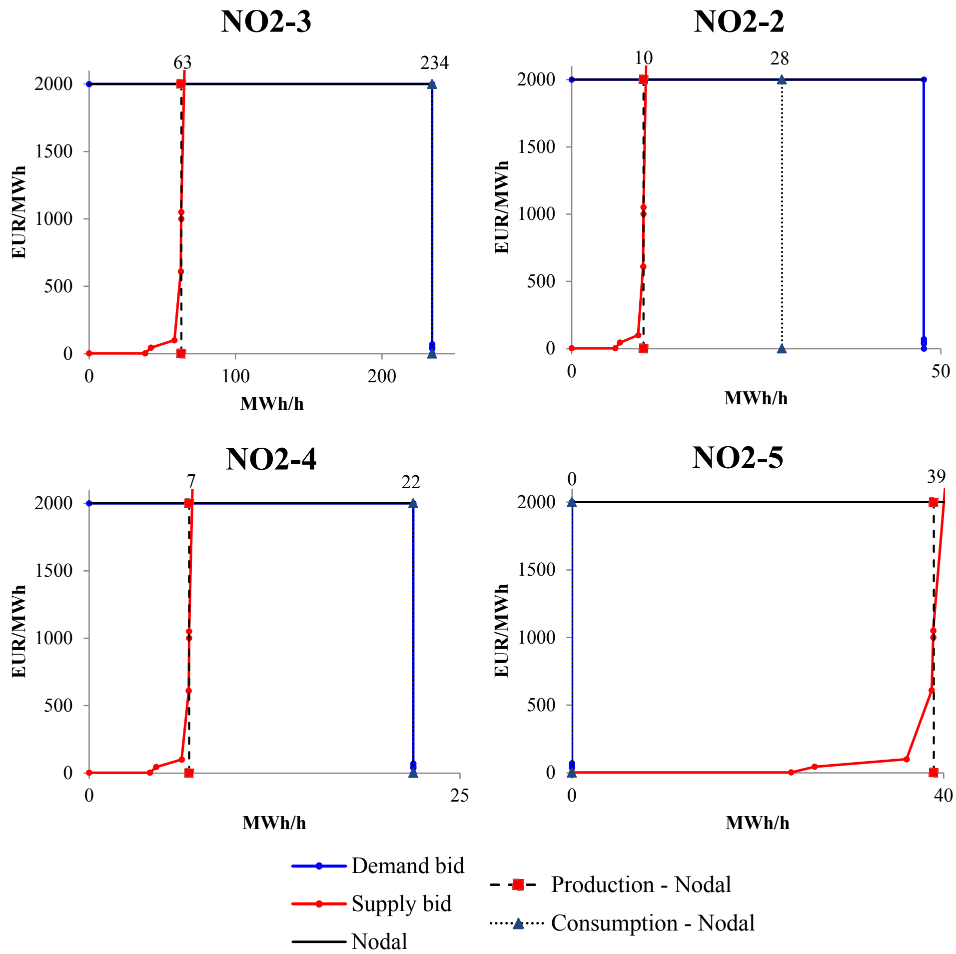


Figure 4-5. Nodal solution price and quantity diagrams for the nodes in NO2, 08-01-2010, hour 8.

As shown by [4] in an economic dispatch all nodal prices are related through the following expression (1)

$$p_l = p_n - \sum_{i=1}^{n} \sum_{j=1}^{n} \mu_{ij}\, \beta_{ij}^{l} \tag{1}$$

where n is a base node, μ_{ij} is the congestion price for link $i-j$ (shadow price on the thermal transmission capacity constraint), and β_{ij}^{l} is a load factor, that is the increase in power flow on link $i-j$ as the result of injection of one unit of power at node l that is withdrawn in node n. The expression in (1) is valid for any $l = 1, \ldots, n-1$.

This relation can be extended further to include the shadow prices and respective load factors for the security cut constraints that are a part of our optimal zonal and nodal models, as shown below

$$p_l = p_n - \left(\sum_{i=1}^{n} \sum_{j=1}^{n} \mu_{ij}\, \beta_{ij}^{l} + \sum_{k}^{CUTS} \varepsilon_k \gamma_k^{l} \right) \tag{2}$$

where ε_k is the congestion price for security cut k (shadow price on cut constraints) and γ_k^{l} is a load factor. The above expression in (2) is valid for any $l = 1, \ldots, n-1$.

Knowing that the shadow prices on transmission constraints (both thermal and cut) will in our formulation be always positive, and load factors could be both positive and negative depending on the direction of the flows, it is easy to see that the economic dispatch can also produce negative nodal prices.
The nodal model takes into account the actual network and includes all the necessary physical and security constraints. Its solution thus demonstrates the real shortages in production and transmission capacities in the correct points on the network where they occur. The infeasibilities we have described above need to be resolved for this to be a functioning market solution. Similar analysis was performed for a case of an evening hour in December 2010 in [1] when security constraints for the Bergen area were active and binding and resulted in an economic infeasibility of prices at the price cap in the nodal solution. The Bergen cut constraints were relaxed to obtain feasible prices, but also to demonstrate a situation present frequently in the Norwegian power system when it operates for extended periods of time below the agreed standards, at *N-1/2* or *N-0* security level. This was much discussed before and after the winter situation of 2009/2010, and was a major argument for reinforcing the grid on Sima–Samnanger connection (which has been put into operation in 2013). The reinforcement of that line has undoubtedly increased the transmission capacity in the area and will contribute to increased export capacity from the area in the summer months, but, more importantly it still does not solve the problem related to the Bergen cut constraints.
This example case from January is taken on in the next section by testing out and analysing the effects on infeasibilities (prices in particular) in one or both bidding areas of different adjustments of supply and demand, transmission capacities, security cuts, and combinations of the above.

4.2 Fine-tuning the model

This section investigates what causes the economically infeasible nodal solution as described in section 4.1. For that, a number of adjustments are introduced into the model for the hourly example case. The effects of these adjustments are assessed together with quantitative indication to what extent they are required in order to avoid the infeasibilities in the extreme price nodes. It is of interest whether there are interdependencies between the infeasibilities in different bidding areas, and whether taking care of infeasibilities in, for example, the NO2 nodes will have a positive effect on the extreme price in NO1-4 and thus the Bergen cut constraints. Alternatively, it will be confirmed that these are separate problems experienced in particular grid areas that are not interrelated.
First, as was previously done in [2] for an hourly case in December, Bergen cut constraints are relaxed. Second, pro-rata consumption reduction is applied in two of the zones. Third, supply capacity is increased in the nodes adjacent to the congested transmission lines. Fourth, thermal capacity is increased on critical interconnections. And last, a redistribution of demand between the nodes within predefined groups is applied.

Relaxing Bergen cut constraints

As seen in the previous section the binding Bergen 2 cut constraint is leading to a strained situation in NO1-4 (where demand is curtailed and price is at the cap of 2000 EUR/MWh) and nodes around it. Due to high demand in the area and the interrelation between all three Bergen cut constraints (Bergen 1, Bergen 2, BKK), all of them need to be relaxed to achieve a solution in which demand in NO1-4 is satisfied.

After relaxing the Bergen cut constraints the average nodal prices have somewhat increased for all zones, with the smallest increases in DK1 and NO1. The negative prices have somewhat improved, and the extremely high prices are still present, though they are now not attributed to NO1-4. The market clearing demand for NO1-4 now lies on the vertical inelastic segment of the curve, demand is satisfied, leading to a solution at a price of 364 EUR/MWh. Demand in NO1-1 is however further curtailed, but the negative price in NO1-2 is somewhat higher while demand is unchanged. Supply increase in NO1-3 has led to a feasible solution at the price of 25 EUR/MWh. The flows between NO1-2, NO1-1 and NO1-3 have not changed. The market clearing solutions for the critical nodes within the NO2 are still at the price cap of 2000 EUR/MWh. These results reveal that relaxing the Bergen security constraints in this case does not take care of the infeasibilities in all critical nodes.

The calculation below shows the flows through all the Bergen cuts once they have been relaxed. The cuts are overloaded by 7%, 64% and 74% for BKK, Bergen 1 and Bergen 2 respectively, demonstrating how tight the security limits are compared to the flows required for this solution.

BKK: $249 + 467 = 716 = 670 * 1.069$

Bergen 1: $732 + 369 = 1101 = 670 * 1.643$

Bergen 2: $732 + 437 = 1169 = 670 * 1.745$

Increasing production in critical nodes (on top of relaxed Bergen cut constraints)

In the first adjustment relaxing the relevant cut constraints was applied as one of the measures to avoid curtailment of demand, namely. However, in this hourly case it was not enough to solve the infeasibilities. In this adjustment production in the relevant node is increased just enough so that demand curtailment disappears. The Bergen cut constraints are relaxed and in addition supply capacity is added in NO1-1 in NO1 and NO2-2 in NO2, proportionally for all the segments of the bid curve. Additional 30 MW and 60 MW is needed in NO2-2 and NO1-1 respectively to arrive at a feasible solution. Adjustments in the two areas are needed as adding the extra capacity in just NO1-1 or NO2-2 does not solve the infeasibilities in the other bidding area. As a result the extreme prices are no longer present, the highest nodal price being in NO1-1 at 551 EUR/MWh. Price in NO1-4 is further decreased compared to the first adjustment, and all the NO2 nodes settle at the same price of 387 EUR/MWh. The flows between the critical nodes in NO1 do not change but the shadow price on the NO1-2→NO1-1 connection is now much lower. The constraint on the flow from NO2-1 to NO2-2 is no longer binding.

Increasing thermal capacity on critical lines (on top of relaxed Bergen cut constraints)

While still keeping the Bergen cut constraints relaxed the effects of increasing thermal transmission capacity on the two congested lines (one in NO1 and NO2 each) are tested. The supply capacities are at their original level. Again, the adjustments in both areas are required. A feasible market clearing solution is achieved after an increase in the transmission capacity on the connection from NO1-2 to NO1-1 of 70 MW and 20 MW from NO2-1 to NO2-2. Both constraints are still binding but with lower shadow prices. Prices in the nodal solution decrease for all areas apart from DK1 compared to the original solution with infeasibilities. For the critical nodes in NO1 the prices are now more equal at the level around 400 EUR/MWh, showing an increase for all nodes but NO1-1 compared to solution with the adjustment of supply capacity. For the NO2 nodes the prices have also increased and are now all equal to 603 EUR/MWh.

Applying redistribution of demand (on top of relaxed Bergen cut constraints)

After consulting industry experts regarding the strained situation on the NO1-2→NO1-1 connection it became apparent that the overload on this constraint is not real but rather the result of incorrect redistribution of consumption between the nodes in the Oslo area. During the initial model calibration some corrections were made to load and supply data that was received from Statnett (Norwegian TSO), since due to incorrect reporting loads in some nodes had negative values and some supply volumes exceeded maximum installed capacity. This was dealt with by creating groups of nodes within load and supply got redistributed according to predefined weights. Weights were calculated for all nodes in the network based on the data from the top load hour in 2010.

The strained situation in Oslo area can also be explained by the fact that in reality power flows get redistributed through the regional network as well, which is not reflected in our model as we only deal with the central grid.

Figure 4-6 illustrates a bigger part of the network around the binding NO1-2→NO1-1 connection. Nodes represented in this simplified network picture loosely follow their geographic location, i.e. nodes on the left side are west of the nodes on the right side that are closer to Sweden. Nodes that are not directly mentioned in the discussion are denoted in the figure as NO1-n. For each node the original nodal solution values are given. Production and consumption numbers in the nodal solution are equal to the total available supply and demand for all nodes for that hour except for NO1-14 and NO1-15 where extra supply of 40MW and 30MW respectively is not used. For this part of the network the total demand is approximately three times larger than the total supply (2768MW vs 912MW).

The highest proportion of demand is accumulated at NO1-12 and NO1-13, and further east, while NO1-3 and NO1-15 get the most of the inflow from other parts of the grid. This is also evident by the direction of flows going from NO1-15 south via NO1-3 towards NO1-12, and from NO1-15 north towards NO1-13. All the connections along these routes are underutilized apart from NO1-2 to NO1-1. If the distribution of demands was different, the overload on this line could be avoided. Also, other connections from the regional network that go around NO1-2 and NO1-1 from NO1-3 to NO1-13 directly would help relieve this overload.

Taking as a starting point the groupings that were originally created for the redistribution of load and supply possibilities of shifting demand between pairs of nodes within these groups

while keeping the total volume constant was studied as a means to relieve NO1-2-NO1-1 constraint and arrive at feasible nodal prices.
NO1-2, NO1-1 and NO1-3 make up one of the groups so we first study the redistribution of demand between NO1-2 and NO1-1. By demand redistribution here we mean the adjustment of total (max) demand quantities for nodes that belong to the same redistribution group while keeping the sum of total (max) demand quantities constant between the pairs of nodes it is applied to.

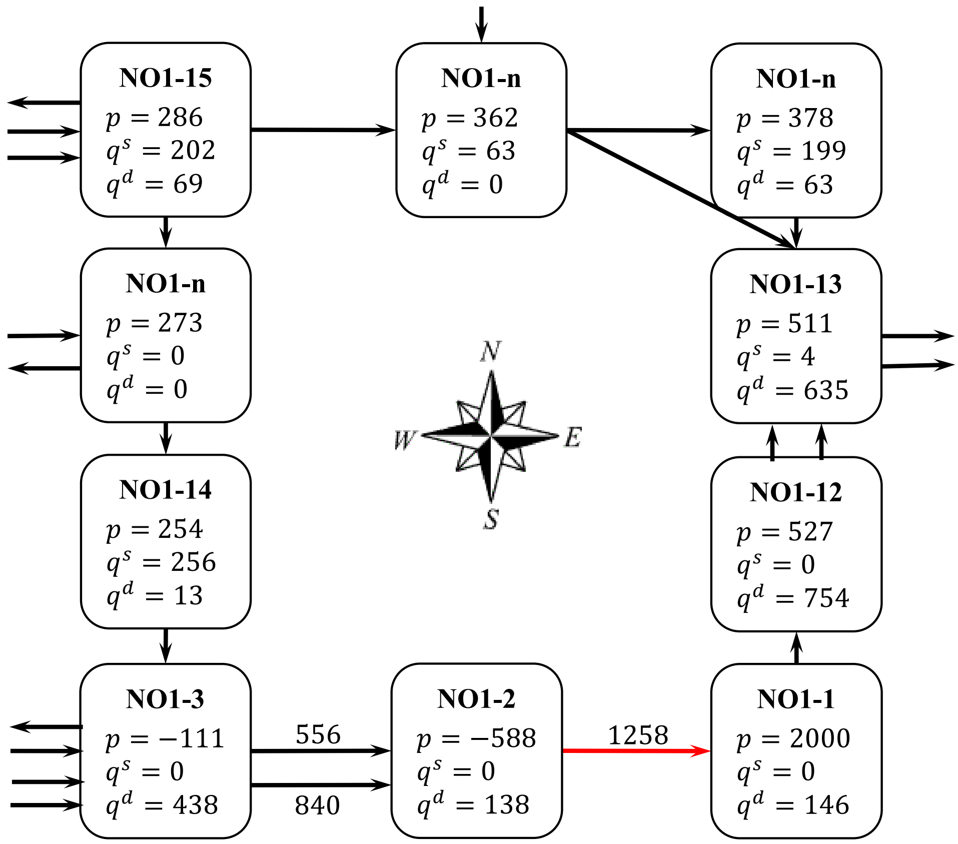


Figure 4-6. Interconnections and the nodal solution in the Oslo area.

From the adjustments discussed in this section relaxing the relevant cut constraints is not enough to achieve feasible prices. It is possible however to obtain alternative optimal solutions by adjusting demand and supply quantities on a nodal level in the directions pointed out by the shadow price values, in this way also imitating the needed up/down regulation in these particular points on the network.
Based on the analysis in this section it can be concluded that efficient nodal pricing requires higher level of detail represented, by for example taking into account the regional distribution network.

5 Nodal and zonal pricing solutions

As concluded in the previous chapter the best way for calibrating the model so that the prices are economically feasible in the nodal price solution was in this case to apply redistribution of demand within groups of nodes that include the nodes with extreme prices. The necessary adjustments have been applied to all hourly cases. The new solutions including the necessary redistribution of demand within predefined groups of nodes will now become the base case for further analyses.

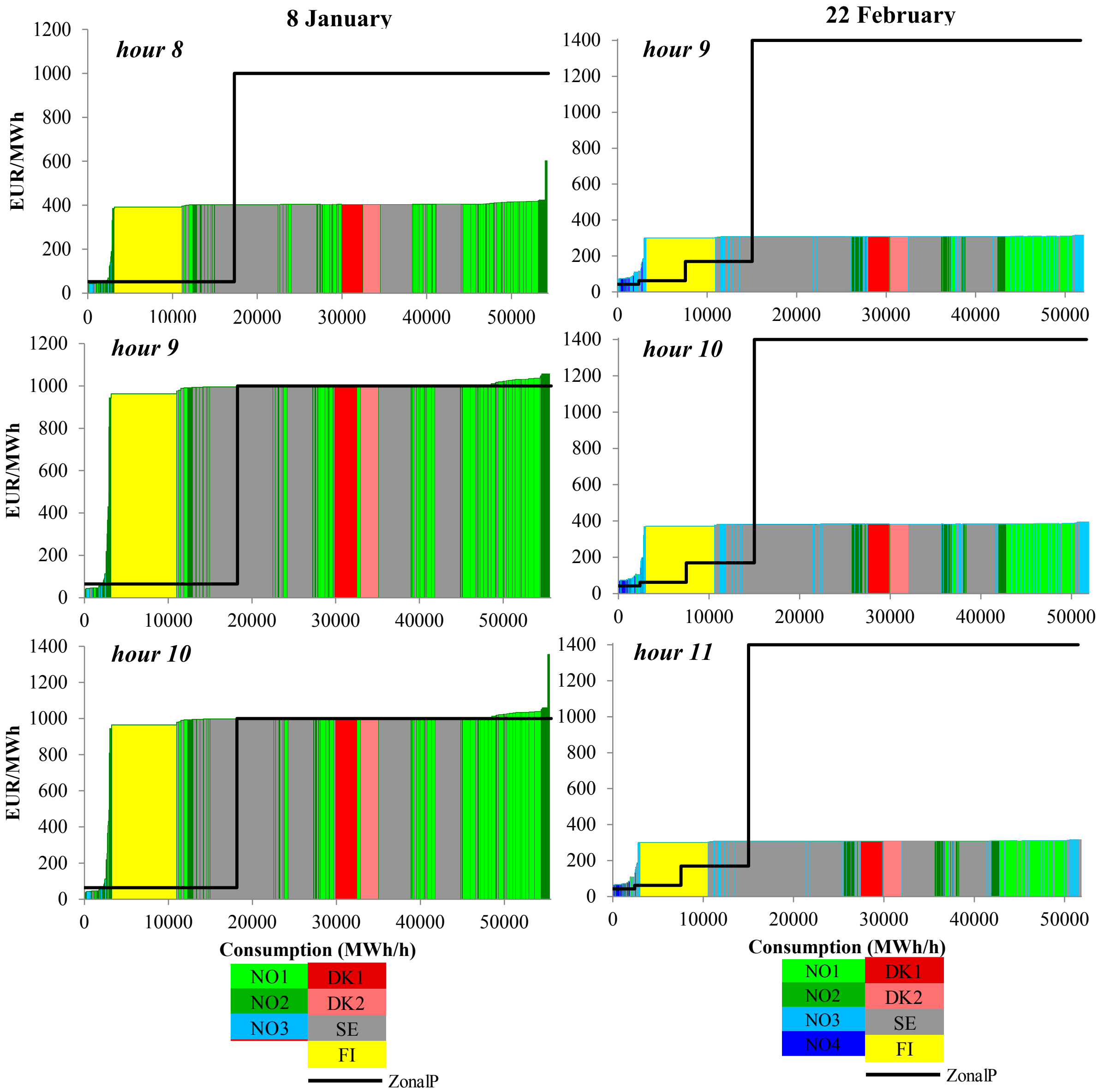


Figure 5-1. Nodal prices with simplified zonal benchmark.

The price levels for all hourly solutions are presented in Figure 5-1. The three graphs on the left-hand side correspond to the January case hours, and the ones on the right-hand side to the hours from February. Simplified zonal prices sorted from lowest to highest are visualised by the black line. Nodal prices sorted in the same way and weighted by consumption are given in colours. This provides a good visual representation of the price levels even though the zonal attributes are not directly comparable. Nodal prices are on average considerably lower for four out of the six hours. Some very high prices though under the price cap are still present in the January cases. The nodes with highest prices in the January cases are located in the NO2 area, and are the same nodes that accounted for the infeasibilities in section 4.1. Those were the nodes interconnected in a radial manner and adjacent to a binding transmission constraint.

Even though it does not directly follow from the graphs, the zones where nodal prices were on average higher than the simplified zonal are NO1 (and NO2 in February) and DK1. In general it is apparent that the nodal pricing solutions are better in terms of price level and differences between the zones.

An overview of the number of thermal inter- and intra-zonal constraints and security cuts that are infeasible in the simplified zonal solution and the same type of constraints that are binding in the nodal solution is given in Table 5-1. It is easy to see that these numbers are very similar. Also, the same security cuts are problematic in both solutions. The number of thermal constraints is somewhat higher in the nodal solution which can be explained by the fact that the constraints are explicitly included in the model. For all cases the constrained thermal interconnections with the highest shadow prices correspond to the infeasible thermal constraints from the simplified zonal solution.

Table 5-1. Number of binding line and cut constraints and infeasibilities.

Date	**08 January**			**22 February**		
Hour	**8**	**9**	**10**	**9**	**10**	**11**
Simplified zonal	**No. of infeasibilities**					
Thermal interzonal	1	1	1	1	1	1
Thermal intrazonal	3	3	4	2	2	2
Security cuts	2	2	2	2	2	2
Nodal	**No. of binding constraints**					
Thermal interzonal	3	3	3	1	2	2
Thermal intrazonal	3	2	3	4	2	2
Security cuts	2	2	3	3	2	2

All the Bergen cuts are relaxed for all congestion management methods simulations. In Table 5-2 the percentage overload on the Bergen cuts is provided for the nodal solutions of all cases. The overload is substantial particularly for the Bergen 1 and Bergen 2 cuts where it reaches 80%. This demonstrates the extent to which the security standards in the Bergen area can be violated.

Table 5-2. Overload of the Bergen cuts in the nodal solution.

Date	**08 January**			**22 February**		
Hour	**8**	**9**	**10**	**9**	**10**	**11**
BKK	16 %	10 %	10 %	6 %	7 %	5 %
Bergen 1	68 %	70 %	70 %	50 %	48 %	47 %
Bergen 2	77 %	80 %	80 %	60 %	59 %	58 %

To conclude, some insights on the changes in the redistribution of surpluses when moving from the simplified zonal to the nodal solution is given in Table 5-3 for all the cases.

Table 5-3. Surplus differences: simplified zonal relative to the nodal solution.

Date	08 January			22 February		
Hour	**8**	**9**	**10**	**9**	**10**	**11**
Producer	182 %	76 %	75 %	339 %	272 %	335 %
Consumer	81 %	124 %	125 %	57 %	59 %	57 %
Grid	31 %	12 %	12 %	195 %	157 %	205 %
Total	100 %	100 %	100 %	99 %	98 %	98 %

One clear trend is that the total surplus is not strongly affected by the pricing method, although the nodal solutions for the February cases demonstrate a small visible increase in total social surplus. A difference should be noted between the hours without a large price change (8 January hours 9 and 10, ref. Figure 5-1) and the rest, where nodal prices are much lower than the zonal. For the producer, consumer and gird surpluses the results are opposing in January and February. For the February cases the tendency is that consumer surplus increase, while producer and grid surpluses decrease for the nodal solution compared to the zonal. For the January cases apart from hour 8, the results are the opposite.

6 Demand side elasticity sensitivity

Reliable operation of the electricity system is achieved through a perfect balance between supply and demand in real time. Most end-users do not observe the real-time prices and hence cannot react to them. Demand and supply levels can change rapidly and unexpectedly due to many reasons such as forced outages of generation, line outages and rapid changes in load levels. Demand side response is one of the cheaper resources available for reliable system operation, given also that electricity system infrastructure is highly capital intensive. Demand response defined broadly refers to participation by customers in electricity markets by observing and responding to prices as they change over time. With regards to system reliability, demand side participation provides more options and tools to the system operator that can be used to reduce the risk of outages and supply interruptions. Giving consumers a possibility to participate in the market and/or affect market prices contributes to reduced price volatility in the spot market and reduces the ability of large market players to exercise market power. It has been reported in [3] that a 5% reduction of demand could have resulted in 50% price reduction during the California electricity crisis.

An important benefit of demand response is the avoided construction of expensive power plants or new transmission lines to serve peaks that occur for just a few hours per year. Industrial loads presently participate in the balancing market in Norway. The share of price dependent day-ahead bids from the demand side is however typically low. This is mainly related to the lack of economic incentives and lack of suitable technology to respond.

It is important to have some insight into the order of magnitude of demand response in order to assess the policy options in this direction. Real-time elasticity is defined as the price elasticity of demand on the hour-to-hour basis. Very few empirical estimates of the real-time elasticity are available. In the study by [6] the real-time elasticity is proved to be rather low for the consumers actively participating in the spot market. The analysis is based on energy use and price figures from the Netherlands in 2003 looking at total demand versus spot market price. The real-time price elasticity is measured to be -0.0014 and -0.0043 with the linear and log-linear specifications respectively. Results from a pilot study on daily demand response from households in Norway are presented in [9]. The potential demand response from 50 % of Norwegian households has been estimated at 1000 MWh/h (4.2 % of registered peak load demand in Norway).

The price elasticity of demand measures the change in quantity demanded as a result of a price change and is calculated as following:

$$e = -\frac{\Delta Q}{\Delta P}\frac{P}{Q}$$

For ease of reference in the following analysis the elasticities are referred to in their absolute values, and thus have been defined as negatives in the formula above.

The effects of increased demand elasticity on nodal prices and the redistribution of surpluses have previously been studied for a single hour case based on the data from the Nordic electricity market (see [1]). Elasticity of demand was introduced into the bid curves on an aggregate level, specifically to the inelastic segments of the curve which include the NPS solution. This analysis was performed for a case hour in December 2010 with no extreme prices.

In this paper the increased price elasticity of demand is modelled on a nodal level. For each of the nodes in Norway a dummy node with both demand and supply bids is added, see example in Figure 6-1. Demand and supply bids are modelled as linear one-segment bids starting in the reference price point. The average yearly system price for 2010 equal to 53 EUR/MWh is chosen as the reference price (P_{SYS}). Available supply quantity is set equal to the volume of inelastic demand in the node (Q_{inel}). The slopes of the bid curves are symmetrical calculated from the ratio of the reference price and the maximum supply quantity (P_{SYS}/Q_{inel}) and predefined price elasticity. Thereby a so-called *prosumer* is modelled for each of the Norwegian nodes that will result in production when prices are above the reference price or in consumption when prices are below. The extra production would in this case be equal to a decrease in consumption as a result of more price elastic demand. By introducing demand elasticity into the model in this way it will be possible to observe the effects of price-elastic demand on a nodal level.

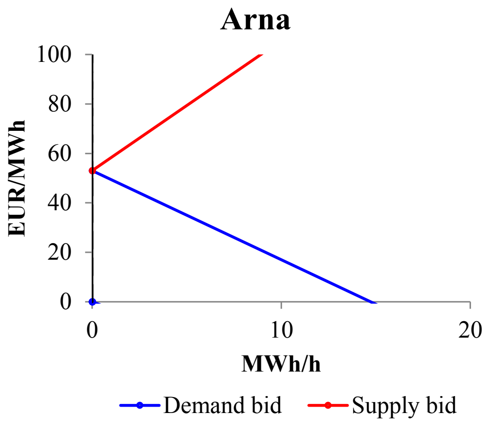


Figure 6-1. Prosumer bid curves – example node, e = 0.025.

The effects of demand elasticity for values between 0.025 and 0.1 with an increment of 0.025, and a case of low elasticity of 0.01 are tested. The lowest value comes closest to the real-time demand elasticity estimates found in the literature, and the rest were chosen for the purpose of extended analysis.

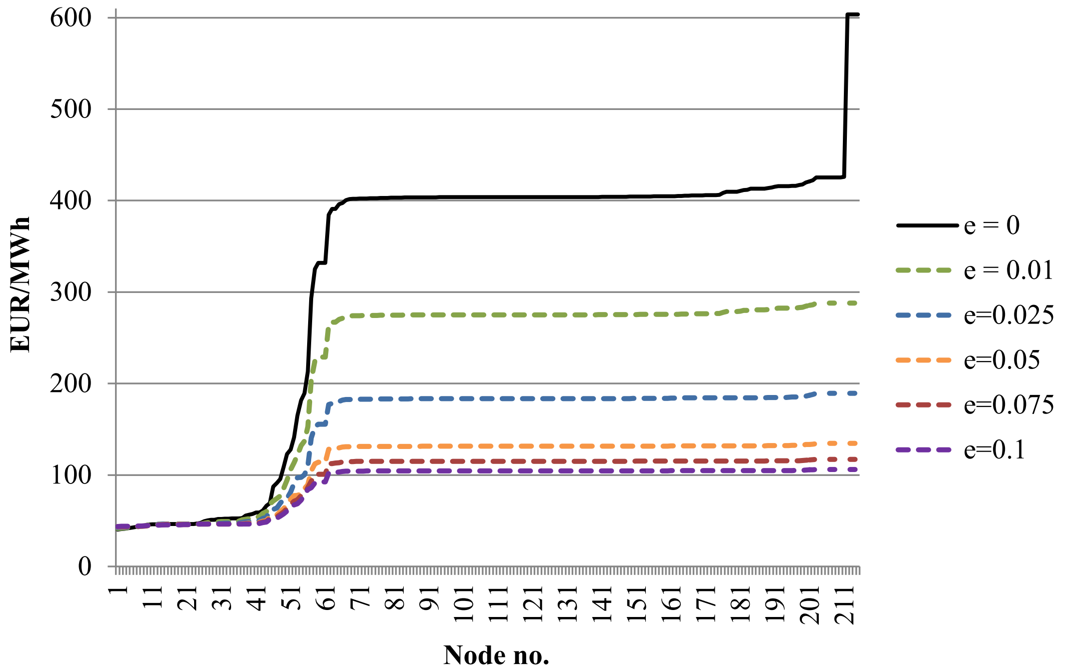


Figure 6-2. Nodal prices under various demand elasticities, 08-01-2010, hour 8.

In all six hourly cases the increased demand elasticity results in on average lower nodal prices. This can be seen in Figure 6-2 for all modelled elasticities for one of the January cases where nodal prices are sorted in ascending order and compared to the base case with no demand elasticity (black curve). The same effect is visible from the mean and standard deviation values of nodal prices under different demand elasticities provided in columns three and four of Table 6-1.

Table 6-1. Nodal prices and consumption decrease under various demand elasticities for nodes in Norway, 08-01-2010, hour 8.

Demand elasticity	Cons. decrease (%)	Nodal prices		Ave price decrease (%)			
		Mean	SD	Total	NO1	NO2	NO3
0	-	317.1	154.4	-	-	-	-
0.01	3.7	219.2	96.1	24.5	27.9	31.8	11.6
0.025	5.3	149.5	57.5	41.5	47.8	51.9	19.5
0.05	6.4	110.3	35.7	51.1	59.1	63.0	23.9
0.075	7.5	97.9	28.9	54.1	62.6	66.5	25.1
0.1	8.3	90.0	24.5	56.0	64.9	68.9	26.0

There is a steady decrease for both types of values with increasing demand elasticities. The mean price decreases to under 1/3 of its value in the base under the highest elasticity of 0.1, while the largest difference is between the base case and the lowest elasticity of 0.01. The four rightmost columns in Table 6-1 provide an overview of average percentage decrease in prices for all the Norwegian nodes, and each of the zones in Norway in particular relative to the base case with no demand elasticity. We see that the average price decrease for nodes in

Norway is close to 25% when demand elasticity increases from 0 to 0.01. Prices decrease on average but the effect is smaller with higher demand elasticities. For nodes in NO3 the decrease in prices is not as strong as for NO2 where it is the highest among all the zones (close to 70% decrease for the most elastic demand) and NO1 that is somewhat behind NO2. For all of the hourly cases increased demand elasticity results in decreased consumption. Under the highest elasticity of 0.1 the total consumption in Norway is only around 90% of its original volume. Lower prices and less consumption have a positive visible effect on the redistribution of surpluses. Under higher demand elasticity the total system surplus only increases by some 0.5%. The redistribution between producers and consumers moves strongly in the favour of consumers. This is true for all the hourly cases in winter 2010.

The average nodal percentage decrease in consumption volume compared to the base case is given in the second column of Table 6-1 for our January case. It ranges between 3.7% and 8.3% for elasticities between 0.01 and 0.1. We can see for example that for the case with demand elasticity of 0.025 a 5% decrease in consumption leads to an average price decrease of ca 40% compared to the case with no elasticity.

We go down to the level of individual nodes to study where decrease in consumption has been the highest. For the January cases nodes in NO1 have contributed the most to less consumption. In February due to the new zonal division these nodes are part of both NO1 and NO2. In particular, nodes that have less consumption and help the most in relieving high prices and network flow are located in the Oslo and Bergen areas. This is not surprising, as these areas had the highest load and flow strain in the actual hours. This again shows that encouraging a more elastic demand would to some extent help alleviate capacity constraints and would thus bring the nodal prices down.

It is also interesting to see whether allowing for more demand elasticity has the desired effect on network utilisation. In Table 6-2 we show an example of the effects of various demand elasticities on the flow along the individual lines that were constrained in the base case. We see that two of the line connections within NO1 and NO2 are no longer constrained as the elasticity increases above 0.025. The shadow prices for all the remaining line connections gradually decrease with increasing elasticities. This is also true for the other winter cases with extreme prices, and based on these results we can conclude that more demand elasticity contributed to a better network utilisation. This is also visible as the grid surplus in the system goes down with the increasing elasticities.

Table 6-2. Shadow prices for line capacity constrains under various demand elasticities, 08-01-2010, hour 8.

Line			**Elasticity**					
			0	**0.01**	**0.025**	**0.05**	**0.075**	**0.1**
NO2	Intrazonal 1		624.6	366.7	193.7	94.9	64.4	45.9
SE	→	**NO3**	373.3	239.9	144.6	90.7	73.7	62.8
NO2-1	→	**NO2-2**	178.2	-	-	-	-	-
NO1-2	→	**NO1-1**	25.8	15.4	-	-	-	-
FI	→	**SE**	12.1	7.8	4.7	2.9	2.4	2.0
DK1	→	**SE**	0.3	0.2	0.1	0.1	0.1	0.1

7 Aggregate capacity sensitivity

There exist two main ways of setting aggregate transfer capacity limits: net transfer capacities and trade capacities. The latter are used for implicit auction within the Nordic market clearing. Below we explain the differences between these capacity limits and how they are applied in practice.

7.1 Types of aggregate transfer capacity limits

Net transfer capacity (NTC) is defined by the European TSOs[4] as the maximum exchange between two bidding areas compatible with security standards applicable in both areas and taking into account the technical uncertainties on future network conditions. NTC is calculated as following: NTC = TTC – TRM. Total transfer capacity (TTC) is the maximum exchange between two areas compatible with operational security standards applicable at each system if future network condition, generation and load patterns were perfectly known in advance. The TTC between two subsystems is jointly determined by the TSOs on both sides of the interconnection. The transmission reliability margin (TRM) is a security margin that deals with uncertainties in the TTC values occurring mainly due to load-frequency regulation. On HVDC connections the TTC is normally used as the NTC value in both directions.

The Norwegian power grid is divided into bidding areas in order to handle large and long-term congestions. New areas can also be established in case of strained regional energy situation. The determination of the NTC value between the two bidding areas is based on thermal restrictions and voltage or stability limits present in the transmission system for maintaining an agreed level of security of supply.

On the other hand, trade capacity is the maximum amount of energy that can flow from one bidding area to another. Every day the TSOs determine trading capacities for each hour of the following day the day before. All trading capacity between the Nordic bidding areas is available for the implicit auction within the Elspot price calculation. Both capacities on individual lines and sum limitations for several lines (*cut constraints*) are used in the optimised price calculation. Setting capacities between bidding areas in the market does not completely take into account the properties of the power network. The exact location of production and consumption in the network will affect the networks capacity to deliver power from one point to another. It is thus difficult to establish capacities beforehand without having the knowledge of where and to what extent production and consumption will occur in the network.

Groups of two or more transmission lines that go partly in parallel and connect two larger geographic areas are called transmission interfaces or cross-sections. Some important ones for Norway are *Haslesnittet* (NO1), *Flesakersnittet* (NO1) and *Sørlandssnittet* (NO2). The transmission limit on a cross-section is rarely equal to the sum of thermal capacities of individual lines included in it. This is explained by the fact that transmission limits are also determined by other technical constraints. In addition, the *N-1* criterion must be accounted for, as well as planned revisions and failures in the network. Maximum transmission limits for

[4] Principles for determining the transfer capacities in the Nordic power market, ENTSOE 2011.

network components together with limits for dynamic and voltage stability are provided by the TSO.

Trade capacities are based on determination of transmission limits for important cross-sections for the coming week. No explicit prognosis of load flow is performed for this period meaning that implicitly the prognosis is that daily load flow is the same. The assumptions are revised in two cases: revisions in the network, and temperature effects on the transmission margins of components (the latter one is based on temperature prognosis). The starting point for determining transmission limits are load flow and dynamic analyses on an intact network. These are performed regularly (yearly and weekly basis) for different load levels, but not on a daily basis. According to Statnett the definitions of physical limits from day to day are mainly independent of supply and demand as it is normally the *N-1* criterion that is the deciding factor. This leads to that physical transmission limits and thus trade capacities are more or less the same throughout the year unless important lines are disconnected or the network settings deviate from the usual. One of the exceptions is the transfer capacity between south Norway and Sweden that is dependent on the net outflow in East Norway called the Oslo load (*Oslolast*).

Capacity determination for the day ahead is therefore based on transmission limits determined during year- or week-level planning, and is adjusted based on the experiences from the day before or from other comparable periods. Internal transmission limits within bidding areas are sometimes taken into account by either reducing transfer capacities on individual cross-sections (for example *Haslesnittet*) or, by reducing the sum of capacities over several cross-sections, and, letting the price algorithm decide the distribution.

7.2 Varying aggregate transfer capacities

In this section we demonstrate and analyse how the aggregate transfer capacities set between zones affect the area prices of the simplified zonal model and the corresponding utilization of individual link capacities and cut constraints. We focus on the lines and cuts that whose capacities are violated or close to being so in the simplified zonal model. We limit our scope to connections where nominal capacities have been significantly reduced and that are binding in the simplified zonal solution. The relevant links are the following, listed according to the direction of the flow, area from and area to: NO1-SE, NO1-NO2, DK1-SE, and DK1-DK2. Aggregate transfer capacities are varied between 0 and their NTC value. For two of these links the NPS capacity was set to 0 by the TSOs. As we will show in the next subsection the actual flows on these links from the nodal solution were always higher than 0.

As an example, consider the capacity between South Norway and Sweden, NO1 to SE, often referred to as the Hasle interface. The capacity between these areas has often been reduced in the NPS market clearing due to constraints internal to Southern Norway and/or Sweden. A procedure known as *Hasletrappen* has been developed to explain how the Norwegian system operator sets capacity on the NO1-SE connection based on the expected load in the Oslo area.

The higher the load in Oslo, the lower the export capacity to Sweden, and this is due to the capacity of the Hallingdal and Flesaker interfaces within Southern Norway. Figure 7-1 shows the effects of changing the aggregate capacity of NO1-SE on some of the individual line flows that at some point are above their capacity limit. The nominal capacity of the NO1-SE connection is 2145 MW (black vertical line on the right hand side), while the capacity given to the market for this specific hour is 0 MW (purple line). Reducing the capacity of NO1-SE leads to the utilization of some of the lines decreasing until below 1, particularly for capacities under 1000 MW, while for other lines it increases, for example NO3 Intrazonal 2. For two lines, one from Finland to Sweden and NO2 Intrazonal 1, the capacity is violated i.e. the flow to capacity ratio is above 1 irrespective the total aggregate capacity available.

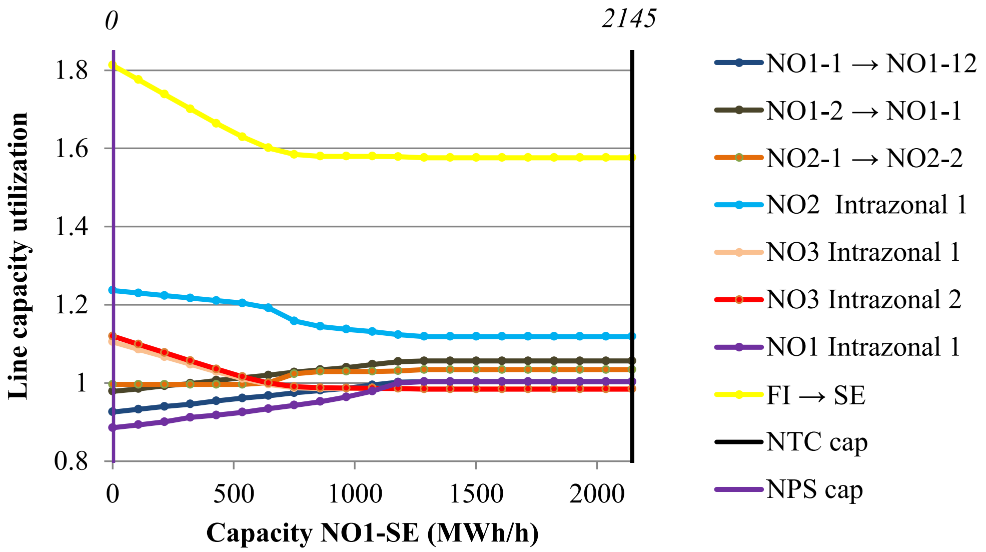


Figure 7-1. Line capacity utilization versus NO1-SE capacity, 08-01-2010, hour 8.

From Figure 7-2 we note that the cut capacity utilisation increases in most cases with increasing aggregate transfer capacity over NO1-SE, apart from the Nordland cut where the flow remains at the same level above the allocated capacity. These results are representative for all January cases and show that more aggregate transfer capacity will lead to higher flows over the cross-sections defined for security constraints. This can be an indication of lack of transfer capacity in the network as a whole. The results for individual lines are also very similar for all the January cases and do not show the expected unambiguous decrease in line utilization as a result of increased aggregate transfer capacity on the NO1-SE connection.

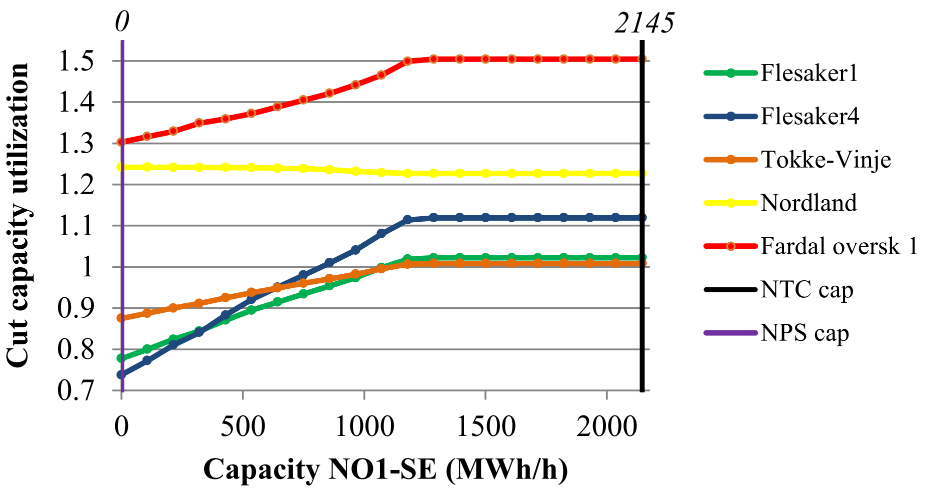


Figure 7-2. Cut capacity utilization versus NO1-SE capacity, 08-01-2010, hour 8.

The effects on area prices are however very interesting. In Figure 7-3 we show the example for the same case as above, but it is also representative for all the January cases. Increased aggregate transfer capacity leads to convergence of area prices to a single price that is much lower for the NPS high price areas and somewhat higher for the low price areas. This is an important result demonstrating the effect of a less restrictive aggregate transfer capacity on area prices. A similar effect is observed for capacities between NO1 and NO2 for all the January cases. At the same time the change in capacities between DK1 and SE, and DK1 and DK2 do not have any effect on area prices.

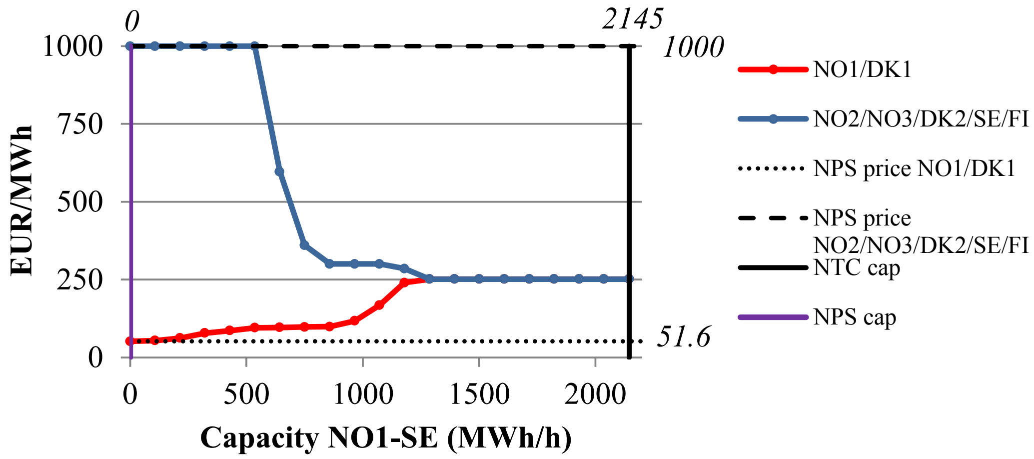


Figure 7-3. Area prices versus NO1-SE capacity, 08-01-2010, hour 8.

7.3 Setting aggregate transfer capacities

This section presents the effects on prices and infeasibilities in the simplified zonal solution of setting aggregate transfer capacities equal to the flows from the optimal zonal and nodal solutions. The results are quite similar for all cases, so one case hour in February is taken as a representative example.

Table 7-1. Capacities for links between zones in the simplified zonal model, 22-02-2010, hour 9 (MWh/h).

Links between zones		NPS capacity		Cap. from nodal flow		Cap. from opt. zonal flow	
		Forward	Backward	Forward	Backward	Forward	Backward
DK1	**DK2**	0	0	316	0	312	0
DK1	**NO2**	950	1000	399	0	403	0
DK1	**SE**	370	0	740	0	740	0
DK2	**SE**	1700	0	1237	0	1233	0
FI	**SE**	1140	560	603	0	639	0
NO1	**NO2**	1700	2200	0	3068	0	3072
NO1	**NO3**	0	0	194	0	188	0
NO3	**NO4**	0	900	0	631	0	636
NO1	**SE**	150	0	856	0	831	0
NO3	**SE**	600	600	0	166	0	168
NO4	**SE**	700	600	369	0	364	0

The aggregate transfer capacities that will be used in further analysis are presented in Table 7-1. These include the actual NPS capacities and flows from the nodal and optimal zonal solutions that will be used as interzonal capacities. The differences between the flow-based capacities are minimal. For five link capacities the flow-based values are higher than the actual NPS capacities used in the market calculation. For example, the nodal flow between NO2 and NO1 is 3068 MWh/h while the maximum NPS allocated capacity is only 2200 MWh/h. This demonstrates how the TSO-set capacities restrict possibilities for a better network solution.

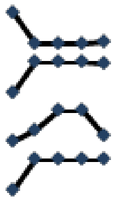
Table 7-2. Prices with different aggregate transfer capacities, 22-02-2010, hour 9 (EUR/MWh).

		Simplified zonal				
Bidding area	**Actual NPS**	**Actual NPS capacities**	**Cap. from nodal flow**	**Cap. from opt. zonal flow**	**Optimal zonal**	**Optimal nodal (average)**
NO1	169.86	169.67	169.77	169.71	257.57	284.79
NO2	62.25	62.23	169.77	169.71	310.60	305.67
NO3	1400.11	1400.03	300.07	300.08	323.87	275.88
NO4	1400.11	1400.03	55.83	55.83	105.00	88.72
DK1	48.10	42.33	169.77	65.45	65.45	308.44
DK2	1400.11	1400.03	300.07	300.08	107.51	308.44
SE	1400.11	1400.03	300.07	300.08	305.73	305.11
FI	1400.11	1400.03	300.07	300.08	300.03	300.06

Comparing the prices in Table 7-2 we see that area prices under flow-based capacities from the nodal solution are more uniform between the areas and considerably lower for the high price areas from the NPS solution. Area prices for this solution are on average also lower than the average nodal prices under the actual NPS aggregate transfer capacities.

Table 7-3. Surpluses and infeasibilities with different aggregate transfer capacities, 22-02-2010, hour 9 (absolute values, 1000 Euros).

	Simplified zonal				
	Actual NPS capacities	**Cap. from nodal flow**	**Cap. from opt. zonal flow**	**Optimal zonal**	**Nodal**
Producers	51372.6	12887.9	12489.1	13775.2	15140.2
Consumers	50205.1	90268.2	90515.1	89229.4	88046.4
Grid	440.5	518.7	666.0	661.4	484.0
Total	102018.2	103674.7	103670.3	103666.1	103670.6
Infeasibilities	4 lines 2 cuts	3 lines 3 cuts	3 lines 3 cuts	None	None



Studying zonal and nodal pricing solutions under the TSO-set capacities a significant redistribution of surpluses in the favour of consumers can be observed in Table 7-3. Then, comparing the nodal with the simplified zonal solution with flow-based aggregate transfer capacities there is a further increase in consumer surplus but also higher grid revenue while the total is almost the same. This could be considered a better solution if line and cut infeasibilities are disregarded.

7.4 Effect of more bidding areas

During 2010 the number of bidding areas for the Norwegian part of the market increased from three to five. On 11th of January two new area configurations were adopted into the market, the new NO1 and NO2 areas bringing the total number of areas to four. From the 15th of March 2010 Norway was divided into five bidding areas when new area NO5 was established in the South-West of Norway. Since 1st November 2011 Sweden is divided into four bidding areas. This is a direct result of TSOs dealing with long-lasting congestion situations and, as in the case of NO5, an attempt to secure more regional stability.

It is possible that if these zonal configurations were adopted earlier it would have had a positive effect on avoiding the situations with extreme prices in the winter 2009/2010. This section studies the results from introducing four and five zones in Norway, and then four zones in Sweden for one of the January cases from 2010. The different cases with zonal configurations are presented in Table 7-4. An overview of the number of zones is given together with the manner in which the aggregate transfer capacities are set. Cases I and VI are the original simplified zonal and nodal solutions respectively with the actual NPS capacities. For the rest of the cases interzonal flows from the nodal solution were used for setting capacities in the simplified zonal model. Case VI is the original nodal solution and serves as a benchmark for comparisons of prices. It should be noted that other system parameters as load and supply levels are kept constant.

Table 7-4. Cases of different zonal configurations.

Case	No of zones in Norway	No of zones in Sweden	Setting of aggregate transfer capacities
I	3	1	NPS capacities
II	3	1	Nodal-flow capacities
III	4	1	Nodal-flow capacities
IV	5	1	Nodal-flow capacities
V	5	4	Nodal-flow capacities
VI	nodal		NPS capacities

An overview of surpluses for the different cases is provided in Table 7-5. Cases I to V concern the simplified zonal solution. Surpluses for case II to VI are given as the percentage change relative to the absolute values in case I. Number of line and cut infeasibilities and the corresponding flow overload in percent is provided for the simplified zonal solutions. The results indicate that increasing the number of zones does not have a visible effect on the total surplus. Using the nodal flow for setting aggregate capacities has the strongest effect on the redistribution of surpluses between producers and consumers in the cases of three and four zones. The number of line infeasibilities goes down by one when moving from case I. The percentage overload decreases for some of the lines and cuts in the last two cases with the highest number of zones. Overall, the effects of more zones on surpluses and network utilisation when other system parameters are kept on the same level as in the base case (case I) are minimal.

Table 7-5. Surpluses (1000s Euros) and critical line and cut overloads under different zonal configurations, 08-01-2010, hour 8.

		Simplified zonal					Nodal
		I	II	III	IV	V	VI
Total surplus		108628.8	0.5 %	0.5 %	0.5 %	0.5 %	0.5 %
Producer		37618.9	-17.6 %	-22.7 %	-20.7 %	-17.7 %	-15.6 %
Consumer		70753.8	17.9 %	23.0 %	21.0 %	17.5 %	15.6 %
Grid		256.1	0.2 %	0.2 %	0.2 %	0.8 %	0.5 %
Infeasibilities		4 lines 2 cuts	3 lines 1 cut	3 lines 2 cuts	3 lines 2 cuts	3 lines 2 cuts	None
Line overload (%)	NO3→SE	81 %	58 %	58 %	58 %	47 %	-
	NO2 Intrazonal	24 %	15 %	15 %	15 %	16 %	-
	NO3 Intrazonal 1	11 %	-	-	-	-	-
	NO3 Intrazonal 2	12 %	-	-	-	-	-
	NO2-1→NO2-2	-	3 %	3 %	3 %	2 %	-
Cut overload (%)	Nordland	24 %	-	1 %	1 %	1 %	-
	Fardal oversk 1	30 %	42 %	42 %	28 %	27 %	-

These results also correspond to the ones from Table 7-3, when the number of infeasibilities is not strongly affected by the way the aggregate capacities are set in the simplified zonal model when number of zones kept constant. Using the nodal flows to set the aggregate capacities also means that the very limited aggregate capacities set by the TSO for some of the connections are disregarded in cases II to V.

Table 7-6. Prices under different zonal configurations, 08-01-2010, hour 8.

	Simplified zonal					Nodal	
	I	II	III	IV	V	min	max
NO1	51.64	99.15	99.15	300.86	356.91	45.88	420.93
NO2	1000.02	300.94	99.15	300.86	356.91	51.09	603.42
NO3	1000.02	43.85	300.75	300.86	356.91	40.34	332.04
NO4			44.57	44.57	44.57		
NO5			-	49.76	49.76		
DK1	51.64	300.94	300.75	300.86	405.42	403.87	403.87
DK2	1000.02	300.94	300.75	300.86	405.42	403.87	403.87
SE1	1000.02	300.94	300.75	300.86	62.99	44.00	412.91
SE2					356.91		
SE3					405.42		
SE4					405.42		
FI	1000.02	1000.00	300.75	300.86	390.94	390.94	390.94

The development in prices under different zonal configurations however reveals the benefits of having more zones. The changes observed when moving from case I to V yield smaller price spread between the zones and in general a more uniform price level as seen in the results for case V with the highest number of zones. The extremely high prices are not present in any of the cases with more bidding areas. Overall, the prices tend to move towards the nodal price level of the original solution. This is both the expected and the desired result of a more fragmented zonal network representation.

8 Conclusions

In this paper nodal and zonal pricing solutions for the six extreme price hours from the winter 2009/2010 in the Nordic electricity market have been modelled and compared. Solutions' sensitivity analysis in the form of increased demand elasticity and varying aggregate transfer capacities has been analysed. Based on the results from these real-time cases certain conclusion can be drawn.

Central grid network representation is not a detailed enough level for achieving economically feasible nodal prices in cases of a highly strained system. The solution to the optimal nodal pricing model provides for the needed transparency on structural bottlenecks and highlights the importance of detailed modelling of the transmission system for the identification of scarcities and potentials for improved efficiency. Nodal prices observed for the hourly cases with extreme prices in winter 2010 were on average lower than the simplified zonal prices. The nodal pricing solution for the extreme price hours results in higher consumer benefit.

Extreme prices are attributed to particular nodes that are adjacent to binding thermal capacity constraints. There is a high level of correspondence between the infeasible thermal and cut constraints from the simplified zonal solution and the binding transmission constraints in the nodal solution. Congested lines in all studied cases attribute to known areas with high load and frequent transmission bottlenecks, particularly the Oslo and Bergen areas. It is impossible to achieve an economically feasible solution without disregarding some of the cut constraints. In a very strained system with a zonal market clearing relaxing individual transfer limits is not enough to alleviate large price differences between zones.

Increased price elasticity of demand leads to on average lower nodal prices and higher consumer surplus. When elasticity is introduced on a nodal level it is possible to see which nodes in particular contribute the most to alleviating extreme prices.

The manner in which the aggregate transfer capacities are set in the zonal model affects prices, network utilisation and the redistribution of surpluses between producers and consumers. Setting aggregate transfer capacities based on the nodal flow has a relieving effect on extremely high zonal prices. Increased aggregate transfer capacity on a single critical connection leads to convergence of area prices to a single price that is much lower than for the high price areas in a simplified zonal solution.

9 References

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