Alternative model for Area Price determination in the Nordic system

by

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Abstract:

The area price model used by Nord Pool in the Nordic day ahead market, is an option for the future European spot market for electricity. However, improvements in the methodology for area price determination are needed to make the model suitable for the more meshed and complex power system in Continental Europe. An alternative methodology, where load flow calculations are included, is proposed in this paper. The proposed methodology is demonstrated in a demo model based on a combination of nodal and area pricing. The criterion of optimization is minimization of the Socio economic Congestion Cost.

The main principles for the proposed model are described, and case studies are preformed on a "Basic" and an "Extended" model of the Nordic system. The Basic model is based on the present predefined price areas, while the Extended model includes extra bid nodes in order to promote a more representative load flow.

The case studies show that both the Basic and Extended Model calculation result in reduced Socio-economic Congestion Cost in the system and reduced maximum area price difference. *This means that the transmission system utilization is improved and the market player risk referred to area prices is reduced.*

Keywords: Day ahead Market, Market Splitting, Congestion Management, Power Exchange

1. INTRODUCTION

The Nordic Area price Model (Market Splitting) is one of the options considered in the discussion of the future model for the European spot market for electricity.

Several references from ETSO, Europex and EU [e.g. 1, 2, 3] states that this model has the following advantages:

- The day ahead prices in the total system are calculated simultaneously.
- The price differences between the predefined areas will adjust the power exchange to the available transfer capability (ATC) and reflect the consequences of congested corridors.
- Separate auctions of transfer capacity will not be needed.

However, the present model for calculating the Nordic day ahead prices have some vital drawbacks/limitations, which should be considered before introduction of the model in the more meshed and complicated Continental Europe power system. The main drawbacks are:

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1. Lack of, or negative incentives, for investments in the grid because the area price differences will create an income to the Network Owners.
2. Non Optimal utilization of the transfer capability in meshed networks because of limitations with regard to network representation in the presently used area price calculation methodology.

Point 1 is discussed in [4] where the conclusion is that the income from congestions should be paid back to the market players by reduction in the grid tariff (like it presently is done in Norway), and the Socio-economic Congestion Cost caused by lack of transmission capacity should be a real cost for the System Operator by introduction of a congestion penalty.

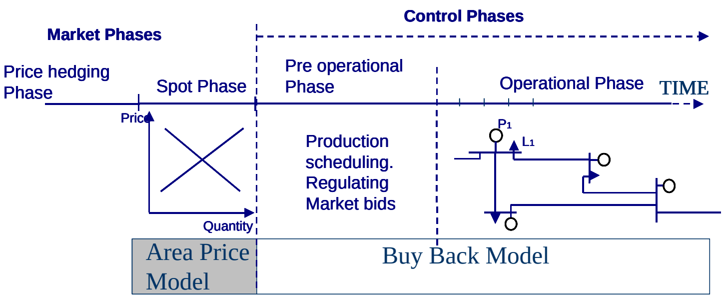
Point 2 is discussed in this paper where an alternative model for calculation of area prices based on optimal power flow calculations is proposed.

In both cases minimization of the Socio-economic Congestion Cost is the main objective.

2. BASIC PRINCIPLES AND MODEL DESCRIPTION

2.1 Congestion management in the Nordic countries

Congestions in the Nordic power system are handled by two different models as illustrated in figure 1: *The Area Price Model*, leading to different area prices calculated by Nord Pool in the "spot phase" and The "*Buy Back*" (counter trade) *model* that is used when congestion occurs within the defined price areas in the "operational phase" [4, 5].



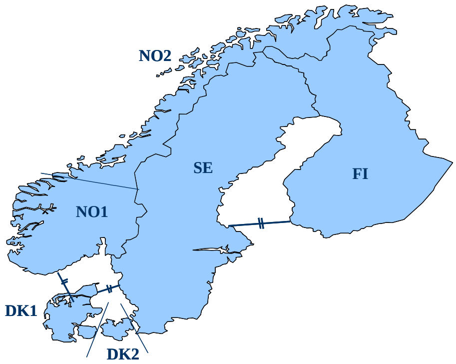


Figure 1 Congestion Management in the Market and Control phases **Figure 2** Nord Pool price areas

Figure 2 shows the normal predefined price areas in common Nordic day ahead market operated by Nord Pool. The first step of calculation of the day ahead prices is the determination of the "system price", which is the intersection of the demand and supply curves for the whole system. Separate area prices are calculated from the area bid curves if the Exchange capacity for one or more area is violated.

2.2 Socio economic congestion cost

In [4] it is shown how the socio-economic congestion cost for the area price model can be calculated as the reduction of producer and consumer surplus due to the congestion. Some of the market players will gain on congestion in the network and some will loose. *The area prices should therefore be calculated in a way that provides the lowest congestion cost to society.*

The Socio-economic Congestion Cost (SCC) is the *cost of not having enough exchange capacity* as required by the unrestricted System Price calculation. This cost is a function of the reduced transfer capacity (E_{red}) compared to market requirements and can be approximated with the area of the triangle in Figure 3, where the area prices in each area (p_A, p_B)as function of exchange capacity (E) defines the sides:

$SCC \approx ½ (p_A\text{-}p_B) E_{red}$ (1)

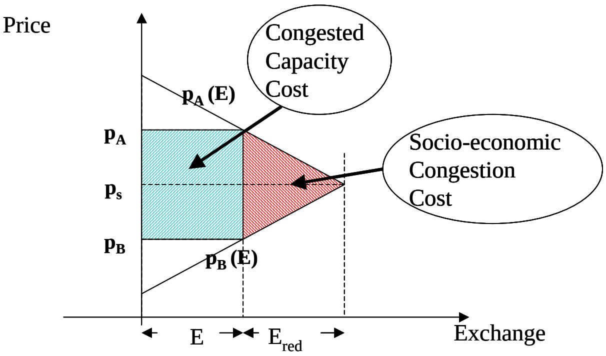


Figure 3 Costs due to congestion

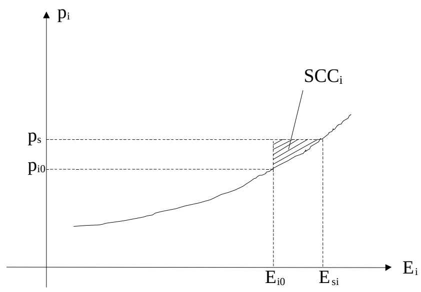


Figure 4 SCC area i.

The left square in Figure 3 is the Congested Capacity Cost paid by the market players. This cost creates an income to the network owner, which in the Norwegian case is paid back via grid tariff reduction[5].

The graph in Figure 4 is showing the area-price p_i in area i as a function of net exchanged power E_i from area i. The Socio economic Congestion Costs for area i is the area SCC_i. As a first approach it can be assumed that the price functions can be approximated with linear functions:

$$p_i(E_i) \approx \frac{p_s - p_{i0}}{E_{si} - E_{i0}} E_i + b \quad (2)$$

It can then be shown that for an arbitrary E_i the total Socio-economic Congestion Cost for area i is:

$$SSC_i = \frac{1}{2}\frac{p_s - p_{i0}}{E_{si} - E_{i0}}(E_i - E_{si})^2 = \frac{1}{2}\frac{\Delta p_i}{\Delta E_i}(E_i - E_{si})^2 \quad (3)$$

If, the assumption in Eq. 2 is done for all areas in an N-area model, the total cost function for the system is:

$$SCC_{\text{total}} = \frac{1}{2}\sum_{i=1}^{N}\frac{\Delta p_i}{\Delta E_i}(E_i - E_{si})^2 \qquad (4)$$

2.3 Present and new model for area price determination

In the present model used by Nord Pool there is no “link” between the different areas - only an Exchange (E) capacity including all lines and corridors to/from the respective area. The model can be illustrated as in Figure 5 where the Exchange between the areas meets in a star point.

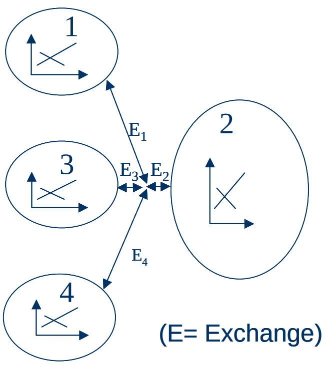


Figure 5 Present model

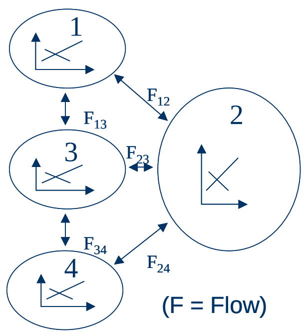


Figure 6 New model

The new proposed model, Figure 6, is based on a combination of the nodal pricing and the area price model. Each area is defined as one node and a network equivalent represents the transmission system. The new model includes the real flow (F) between the areas instead of the net exchange (E).

3. METHODOLOGY AND APPROACH

A demo version of the model is established. The model meets the following requirements:

- The model combines the area price principle and the nodal principle where each node represents a predefined “Price Area” or a “Bid Area” reflecting network constraints. A Price Area could be identical to a Bid Area or include two or more Bid Areas.
- The network equivalent represents the real power lines or corridors between the areas.
- HVDC links between Bid Areas are treated separately.
- The Bid Curves are estimated from real curves from Nord Pool
- The criterion of optimisation is minimization of the Socio-economic Congestion Cost.

3.1 Network modelling

The load flow problem is solved using Direct Current load flow, also called P-δ load flow. The following simplifications are made in order to run the system with DC load flow:

1) All line resistances are neglected: $z_{ij} = jx_{ij}$
2) All voltage angles are assumed to be small: $sin(\delta) \approx \delta$
3) All voltages are assumed constant and equal to 1.0 pu

With these assumptions the power E_i injected into the bus for each area can be expressed as:

$$\underline{E} = \underline{P} + \underline{Y}\,\underline{\delta} \qquad (5)$$

Where:

E_i- represents the net exchange (diff. between generation and load) in each area

Y_{ij} - the admittance between area i and area j $\left(-1/\mathrm{x}_{\mathrm{ij}}\right)$.

Y_{ii} - the sum of all the admittance connected to area i ($\sum_{i \neq j} 1/\mathrm{x}_{\mathrm{ij}}$).

δ_i - the phase angle difference between the voltage on bus i and the swing bus

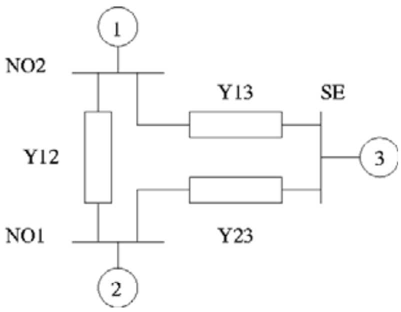
P_i - the power flowing in the HVDC-links represented as load/generation on both sides of the HVDC-link

E_i will be known initially from Nord Pool as the net Exchange at the area price in area i. Y_{ij} is known from the line/cable impedances in the system. The flow between the areas is given by:

$$F_{ij} = \frac{1}{x_{ij}}\left(\delta_i - \delta_j\right) \quad (6)$$

3.1.1 Estimating the impedances in the area model

Even though the actual impedances of the transmission lines are well known, it is difficult to obtain very accurate values for the impedances between the different areas in the equivalent model. In the real system there might be several lines between two areas. In addition, the impedances are dependent on where in an area the power is produced. Simulations on a detailed model give an indication on how to adjust the impedances in relation to each other. To illustrate this an example is given in the following:



$$\begin{bmatrix} Y_{12} & -Y_{12} & 0 \\ Y_{13} & 0 & -Y_{13} \\ 0 & Y_{23} & -Y_{23} \end{bmatrix} \begin{bmatrix} \delta_1 \\ \delta_2 \\ \delta_3 \end{bmatrix} = \begin{bmatrix} F_{12} \\ F_{13} \\ F_{23} \end{bmatrix} \qquad (7)$$

Figure 6: An extracted part of the Nordic system

The flow equations for the system in are given by the matrix (7).

From the simulation it is possible to find the flows F_{12}, F_{13}, and F_{23}. However, the angles and admittances are unknown. Assuming that bus 3 is the swing bus, δ_3 equals zero. Nevertheless, there are still 5 unknowns and only 3 equations and it is not possible to find a solution.

$$(8) \quad \begin{bmatrix} Y_{12} & -Y_{12} & 0 & 0 & 0 & 0 \\ Y_{13} & 0 & 0 & 0 & 0 & 0 \\ 0 & Y_{23} & 0 & 0 & 0 & 0 \\ 0 & 0 & Y_{12} & -Y_{12} & 0 & 0 \\ 0 & 0 & Y_{13} & 0 & 0 & 0 \\ 0 & 0 & 0 & Y_{23} & 0 & 0 \\ 0 & 0 & 0 & 0 & Y_{12} & -Y_{12} \\ 0 & 0 & 0 & 0 & Y_{13} & 0 \\ 0 & 0 & 0 & 0 & 0 & Y_{23} \end{bmatrix} \begin{bmatrix} \delta_1 \\ \delta_2 \\ \overset{*}{\delta}_1 \\ \overset{*}{\delta}_2 \\ \hat{\delta}_1 \\ \hat{\delta}_2 \end{bmatrix} = \begin{bmatrix} F_{12} \\ F_{13} \\ F_{23} \\ \overset{*}{F}_{12} \\ \overset{*}{F}_{13} \\ \overset{*}{F}_{23} \\ \hat{F}_{12} \\ \hat{F}_{13} \\ \hat{F}_{23} \end{bmatrix}$$

To deal with this problem the number of equations must be increased (eq. 8). It is assumed that a new simulation is performed, where there is a change in the production/load in each of the areas. The new load flow will add three new equations, though the increase in the number of unknowns is only given by the two new angles. The number of unknowns is now 7 while there are 6 equations. A third simulation will results in 9 unknowns and 9 equations, and the admittances can be found.

3.1.2 How to handle HVDC links

The HVDC linkes are included in the optimizing problem as a free variable $\underline{P}_{HVDC}$ with zero cost and a size given by the numbers of HVDC links. From Eq. (5) and Eq (9) it is seen that the power flowing in the HVDC links gives the possibility to manually adjust the power flow.

$$\begin{bmatrix} \underline{Y} & -\underline{I}_E & \underline{K} \end{bmatrix} \begin{bmatrix} \underline{\delta} \\ \underline{E} \\ \underline{P}_{HVDC} \end{bmatrix} = \underline{0} \quad (9)$$

The connection point matrix $\underline{K}$ for the HVDC links has either the value 1 or –1 depending on the direction of the power flow in the HVDC link.

3.2 Object function and constraints

The area prices are determined by an Optimal Power Flow (OPF) calculation. The cost function in Eq. 4 can be expressed as the following quadratic object function:

$$\min_x Cost_{total} = \min_x G(x) = \frac{1}{2} x^T H x + F^T x$$

given: (10)

$$Ax \le b \qquad A_{eq} x = b_{eq} \qquad L_b \le x \le U_b$$

where:

- H and F determine the cost of all the second and first order elements respectively in the cost function.
- A and b describe the transmission constraints between the areas.
- A_{eq} and b_{eq} are given by the load flow equations.

$$\underbrace{\begin{bmatrix} \underline{Y} & -\underline{I}_E & \underline{I}_{HVDC} \\ \underline{0} & \underline{0} & \underline{I}'_{HVDC} \end{bmatrix}}_{A_{eq}} \underbrace{\begin{bmatrix} \underline{\delta} \\ \underline{E} \\ \underline{P}_{HVDC} \end{bmatrix}}_{x} = \underbrace{\begin{bmatrix} \underline{0} \\ \underline{0} \end{bmatrix}}_{b_{eq}} \qquad (11)$$

- $\underline{I}_{HVDC}$ and $\underline{I}'_{HVDC}$ is the matrix for HVDC connections point in areas and between two areas respectively. The later preserves the power flow in the HVDC links.
- L_b and U_b are the lower and upper bounds on x.

3.3 Market representation

It is necessary in each area to obtain the area-price as a function of the net exchange in order to solve the optimal power flow problem. The basis for the curves giving area price as a function of net exchange in each area is simply the bid curves provided by Nord Pool for the given area. For simplification it has with a few exceptions been assumed that the curves for area-price versus net exchange are linear and they are found by applying a linear regression on the data giving the real curves.

4. MODELLING THE NORDIC SYSTEM

Two different equivalent models for the Nordic system are established:

- "The Basic Model " (Figure 7) consists of 6 nodes corresponding to the predefined Price Areas that are typical for the system (see Figure 2).
- "The Extended Model" (Figure 8), where additional "bid nodes" are introduced to promote a more representative load flow. The areas in the extended model are fixed and in principle structural, referring to constraints in the network. Sweden has been divided into 4 bid areas and Northern-Norway into 3 bid areas, otherwise the other areas are as in the basic model.

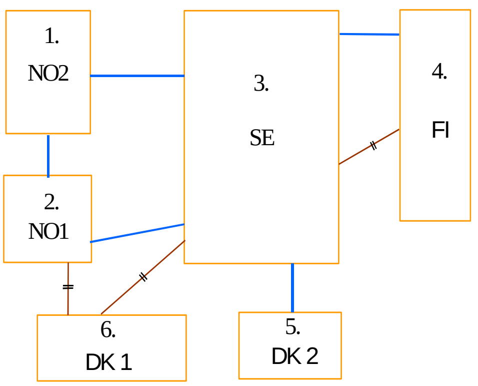


Figure 7 Basic Model

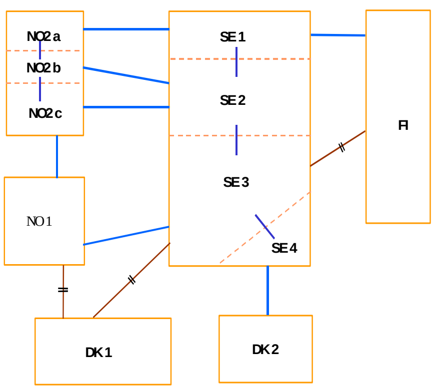


Figure 8 Extended Model

4.1 The Basic Model

The configuration of the basic model is shown in Figure 7. DC load flow was the used method to find the load flow for a given production and consumption in each area. Thus, the power E_i injected into the bus for each area can be expressed as (area 3, Sweden, is defined as the swing bus):

$$\begin{bmatrix} E_1 \\ E_2 \\ E_3 \\ E_4 \\ E_5 \\ E_6 \end{bmatrix} = \begin{bmatrix} 0 \\ P_{skag} \\ P_{konti} + P_{fenno} \\ -P_{fenno} \\ 0 \\ -P_{skag} - P_{konti} \end{bmatrix} + \begin{bmatrix} |Y_{12}|+|Y_{13}| & -|Y_{12}| & 0 & 0 & 0 \\ -|Y_{12}| & |Y_{12}|+|Y_{23}| & 0 & 0 & 0 \\ -|Y_{13}| & -|Y_{23}| & -|Y_{34}| & -|Y_{35}| & 0 \\ 0 & 0 & |Y_{34}| & 0 & 0 \\ 0 & 0 & 0 & |Y_{35}| & 0 \\ 0 & 0 & 0 & 0 & 0 \end{bmatrix} \begin{bmatrix} \delta_1 \\ \delta_2 \\ \delta_4 \\ \delta_5 \\ \delta_6 \end{bmatrix} \quad (12)$$

$$\begin{bmatrix} F_{12} \\ F_{13} \\ F_{23} \\ F_{26} \\ F_{34a} \\ F_{34b} \\ F_{35} \\ F_{36} \end{bmatrix} = \begin{bmatrix} Y_{12}(\delta_1 - \delta_2) \\ Y_{12}\delta_1 \\ Y_{23}\delta_2 \\ P_{skag} \\ -Y_{34}\delta_4 \\ P_{fenno} \\ -Y_{35}\delta_5 \\ P_{konti} \end{bmatrix} \quad (13)$$

The indices in corresponds to the different areas as shown below:

E_i- represents the net exchange (Generation minus Load) in each area
Y_{ij} - the admittance between area *i* and area *j*.
δ_i - the phase angle difference between the voltage on bus *i* and the swing bus (δ_3)
P_{skag} - the power flowing from NO1 to DK1 in the Skagerrak HVDC-link
P_{konti} - the power flowing from SE to DK1 in the Kontiskan HVDC-link
P_{fenno} - the power flowing from SE to FI in the Fennoskan HVDC-link
Fij - the power Flow in the lines / corridors between areas

E_i will be known initially as the net Exchange at area-price in area *i*. Y_{ij} is known from the line/cable impedances in the system. Thus, by removing row 3 in Eq. 12 and solving for the angles δ_i, it is possible to compute the power flow in the different connectors between the areas. Equation 13 is expressing the power Flow F_{ij} in the connectors between the areas.

4.2 The Extended model

As for the 6 areas Basic Model, DC load flow is used for the load flow calculations. The equations for exchange from each area and the flow in the lines are not shown here, but they can be derived in the same manner as for the Basic Model. In the case of Extended Model, the number of flow equations is 15, and the number of equations for exchange is 11.

5. CASE STUDIES

Case studies are preformed to demonstrate the *functionality* of the Basic and the Extended Model. Note that these studies only are *demo examples* (based on real data) and must not at this stage of development be looked upon as complete alternative area price calculation for the Nordic system.

The following real data from Nord Pool for one specific hour are used in the studies:
The bid curves for each area, the area prices, the net exchange from each area at the area price, the system price, the exchange from each area at system price and the ATCs defined by the Transmission System Operator.

The initial load flow (Base Case) is based on the Exchange to/from each area at the given area prices. Table I shows the basic data from Nord Pool, the calculated area prices and the reduction of Socio-economic Congestion Costs (SCC) for the Basic (6 area) and the Extended Model.

Table I Case study results

Areas / Models	DK1	DK2	FI	NO1	NO2 (a-c)	SE (1-4)	Estimation of reduced SCC in the system compared to the base case [NOK/h]
Base Case	109.7	109.7	109.7	109.7	145.6	109.7	
Basic Model	108,4	108,4	108,4	108,4	132,7	108,4	4800
Extended Model	118,0	117,4	118,1	118,0	123,2 125,8 119,9	118,1 117,2 117,4 117,4	7350

The examples show that both the Basic and Extended Model calculation result in:

- Reduced Socio- economic Congestion Cost in the system
- Reduced maximum price difference between the Price Areas

As expected, the extended model provides the best results.

This means that the transmission system utilization is improved and the market player risk referred to area prices is reduced.

Note that different prices might occur even if the ATC between the areas are not exceeded. This is caused by the choice of optimizing the flow (minimizing the SCC), which means that restriction on a single line might affect all the prices.

6. CONCLUSION, FURTHER DEVELOPMENT

This paper describes an alternative approach to area price determination where load flow calculations are included. The proposed methodology is demonstrated in a demo model based on a combination nodal and area pricing. The criterion of optimization is minimization of the Socio economic Congestion Cost.

Case studies show that the transmission system utilization is improved and the market player risk referred to area prices is reduced.

The following subjects will be focused in the further development of the model:

- Network modeling, where the goal is to establish network equivalents for each hour with significant changes in network topology (maintenance etc.)
- Market modeling, where representation of demand and supply curves in test cases (e.g. for the European Continent) is the main challenge. This challenge will be reduced if/when real bid curves for all the areas involved are available.

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