Methodology and concepts for the Nordic Flow-Based Market Coupling Approach

Abbreviations:

AC	Alternating Current
CNTC	Coordinated Net Transfer Capacity
CGM	Common Grid Model
CNE	Critical Network Element
CO	Critical Outage
DC	Direct Current
FAV	Final Adjustment Value
FB	Flow-Based
Fmax	Max Capacity on a CNE
Fref	Flow on a CNE in the base case
Fref'	Flow on a CNE at zero net position
FRM	Flow Reliability Margin
GSK	Generation Shift Key
IGM	Individual Grid Model
NC CACM	Network Code on Capacity Allocation and Congestion Management
NC FCA	Network Code on Forward Capacity Allocation
N-CGM	Nordic Common Grid Model
NP	Net position
PTDF	Power Transfer Distribution Factor
PX	Power Exchange
RAM	Remedial Action
TSO	Transmission System Operator

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1. Purpose and Scope

The purpose of this document is to describe the Flow-based (FB) capacity calculation methodology for the day-ahead market in general and the issues and options for the Nordic region in particular. The document will evolve in time, and a final version is not to be released until a decision on whether to go live with FB or stay with the CNTC methodology has been issued by the Nordic TSOs.

Not only the ingredients of the FB capacity calculation are elaborated upon (such as Critical Network Elements (CNE), Generation Shift Keys (GSK), etc.), but also the recipe; i.e. how to perform the FB capacity calculation by using those ingredients. The document does not serve as an operational handbook though. The document is organized in three main Sections:

- **Pre-market coupling**
  All activities performed by the TSOs in order to deliver grid constraints to the allocation mechanism (i.e. the actual capacity calculation that defines the total solution space available for the market algorithm)

- **Market Coupling**
  All activities performed by PXs to find the market equilibrium and provide the resulting net positions and prices. The focus in this report is not on the capacity allocation as such, but merely on the requirements that are imposed by this stage upon the capacity calculation.

- **Post-market coupling**
  All FB activities performed by PXs and TSOs after the day ahead market has been cleared. Requirements may be imposed by other allocation timeframes, such as the ID (CNTC) timeframe.

Roughly the following guidelines apply for the scoping of this document.

- **In scope**
  FB capacity calculation for the day ahead market
  Requirements imposed on the capacity calculation by Euphemia
  Requirements imposed on the capacity calculation by the post-market coupling stage and other allocation timeframes
- **Not in scope**
  FB capacity calculation operational procedures
  Capacity allocation
  Congestion income sharing
  Operational and other necessary agreements that have to be made by the TSOs

2. The FB market system in brief

The intention of this Chapter is to provide a high-level overview of the FB methodology. As such, the Chapter may be read separately from the rest of the document. For more details on the FB approach, we refer to Chapter 4 and onward.

FB market coupling is the preferred market design in the Network Code on Capacity Calculation and Congestion Management (NC CACM) (See Chapter 3). The basic idea separating FB from the current Coordinated Net Transmission Capacity (CNTC) is the introduction of a simplified grid model in the market clearing algorithm. This change introduces the ability for the market to prioritize flows that are most economically efficient in managing congestions. This is in contrast to the current methodology where operators are making decisions on capacity allocations in advance of the market clearing.

With CNTC, only commercial exchanges between bidding zones are considered by the market algorithm. Real physical flows, including transit flows, are left to the TSO to manage. Congestions are solved on a "border by border" basis by regulating the net positions on each side of the congested border. In order to manage the real physical flows in an effective manner, the TSOs have to prioritize and allocate capacity to certain borders in order to manage the effect of transit flows and internal congestions. As transit flows are hard to predict, capacity calculation in meshed grid becomes more complex.

FB does things differently. The transmission capacities provided to the market come together with information on the physical flows (linearized as such) on all Critical Network Elements (CNE), induced by a change in the net position in every bidding zone[1]. Transit flows are then monitored and overloads are managed directly by the market algorithm. The TSO can provide maximum capacity to the market, and the market algorithm will find the optimal welfare economic flow on all grid components by itself.

Because the TSO doesn't have to prioritize capacity on certain border in advance, more solutions are available to the market algorithm. This implies that theoretically the solution domain (See the next Section), given to the market by a FB Capacity Calculation, is as large as or larger than the CNTC domain. All CNTC market solutions are available to the FBMC, but the FBMC provides access to solutions outside the CNTC solution domain. Whenever the optimal solution is within the CNTC domain, both market designs will find it, but the FBMC may find an optimum outside what is available to the CNTC. In theory, the FBMC has to be more efficient than the CNTC at the same level of system security, while practical implementation may sometimes prove otherwise.

2.1 Grid constraints limit the domain for the market solution

The generic market optimization problem may be formulated as:

[1] Bidding Zones may differ from price areas in that one price area may contain several bidding zones

CNTC formulation:	Objective function:	Maximize welfare economic surplus
	Subject to:	∑ NPs = 0,
		CNTC constraints
FB formulation:	Objective function:	Maximize welfare economic surplus
	Subject to:	∑ NPs = 0,
		FB constraints

NP (Net Positions) = Supply - Demand

Without diving into the mathematics of these relations, they point to the fact that the objective function is the same for CNTC and FB, while the constraints are different. The objective function is to maximize total welfare economic surplus in the power market, which is the sum of producer surplus, consumer surplus and congestion income.

The constraints are limiting the solution domain to the market optimization problem, and they are the key to understand why FB may provide a better solution than CNTC. The fact is that, given the same level of operational security, the boundaries of the FB domain will always be located on or outside the boundaries of the CNTC domain. This implies that if the optimum market solution is found within the CNTC domain, both CNTC and FB will find the same solution. However, the optimum solution may be within the FB domain, but outside the CNTC domain.

2.2 CNTC and FB constraints

We can illustrate the difference between the FB and the CNTC using the simple three-node grid in **Feil! Fant ikke referansekilden.**. In this example, all lines have a thermal capacity of 1000MW and equal impedance (equal "electrical distance"). Node C is a consumption node, and the nodes A and B are generation nodes. The question faced by the TSO, is how much capacity can be provided to the market for each line (CNE).

At the time of capacity calculation (D-1)[2], the Transmission System Operator (TSO) does not know which area (A or B) is to produce. The physical property of the grid is however known. Due to the described grid topology, one MW produced in A will induce a flow of 2/3 MW on the line AC, 1/3 MW on the line AB, and 1/3 MW on the line BC. The same holds for generation in B of which -1/3 appears on AB, 1/3 on AC and 2/3 on BC. These sensitivity factors are commonly referred to as Power Transfer Distribution Factors

[2] The capacity calculation starts at D-2. Final values are provided to the market at D-1.

(PTDF). Node C is the slack node, and all power injected in A and B is absorbed in this slack. The same holds for node C itself: all power injected in C is absorbed in the slack node C, as such node C individually has no influence on the flows in the grid. The flow influence of each node to each line comprises the PTDF matrix, which is shown in **Feil! Fant ikke referansekilden.**.

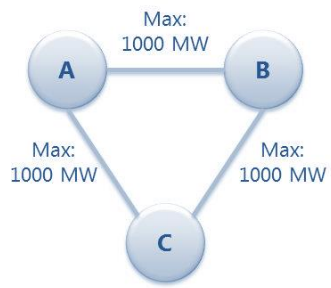

Figure 1. Grid with three nodes

Three bidding zones connected by three lines with equal impedances (equal "electrical distance"). In this example, the three lines are the constraining CNEs. N-1 contingencies are ignored

The PTDF factors, translating the change in net positions into physical line flows, are not provided to the market algorithm under CNTC. Within the CNTC approach, transit flows are ignored and the algorithm only relates to the total provided capacity on each border. In **Feil! Fant ikke referansekilden.**, this implies that one MW produced in A and consumed in C will bring an "CNTC load" of for example 0,5 MW on the lines AB and BC, and 0,5 MW on AC. Bluntly setting the CNTCs to thermal limit values, would allow the CNTC market algorithm to carry 2000 MW of trade from A to C, or from B to C even though it is not physically feasible and will create an overload.

Line	RAM	A	B	C
A->B	1000	1/3	-1/3	0
A->C	1000	2/3	1/3	0
B->C	1000	1/3	2/3	0

Table 1 PTDF matrix of the grid in Feil! Fant ikke referansekilden.

The physical reality in our small three-node example, reflected by the PTDFs, is that 2000 MW generated in A will load AC with 2/3*2000 = 1333 MW, which is above the thermal capacity of that line. The maximum generation (net position) in each of A and B that is possible in order to avoid overloads, is 1500 MW (however not simultaneously). The operator (TSO) has to limit the total export from A and B to this level under the CNTC approach. One possible set of CNTC capacities that can be provided to the market will be a capacity of 750 MW on AC, BC and AB, which gives a secure CNTC solution domain. This is also the maximum simultaneous net positions that can be obtained within the CNTC approach in the network illustrated in **Feil! Fant ikke referansekilden.**. The solution CNTC domain is illustrated in **Feil! Fant ikke referansekilden.**.

The solution domain indicates which net positions are physically safe within a particular grid topology. (This is elaborated further in Section 4.4.1.). What the CNTC market optimization boils down to is: find the optimum market position inside the (CNTC) domain (indicated by the blue lines in **Feil! Fant ikke referansekilden.**).

When FB constraints are provided to the market, the solution domain (or security domain) will change. The FB constraints consist of both information on flows induced (PTDFs) and the CNE-capacities given to the market called Remaining Available Margins (RAM). In our small three-node example, the RAM is 1000 MW on each line (N-1 and security margins are ignored). As with CNTC, a net position of 1500 MW for each of A and B is still feasible within FB. However, the larger maximum simultaneous net position of 1000 MW for A and B also becomes possible with FB. This corresponds to the net positions off A=1000, B=1000, C=-2000 (point 1 in **Feil! Fant ikke referansekilden.**). Flow induced on AB is 1000*(2/3) + 1000*(1/3) = 1000, the flow on BC is 1000*(1/3) + 1000*(2/3) = 1000, and the flow on AB is 1000*(1/3)+1000*(-1/3)=0.

Another market position accessible in FB but not in CNTC, is a net position of 2000 MW for both A and B (but not simultaneously) Illustrated as point 2 in **Feil! Fant ikke referansekilden..** A net position of 2000 MW for A corresponds to the following net positions A=2000, B=-1000, C=-1000, and the flow induced on line AB is 2000*1/3 -1000*(-)1/3 -1000*0=1000.

If all such "extra" points are added to the former CNTC domain, we have the FB domain, which is shown in grey in **Feil! Fant ikke referansekilden.**. In all situations where the optimal solution is found within the grey area, but outside the blue area, the FB solution is a better solution in terms off welfare economics than the CNTC solution.

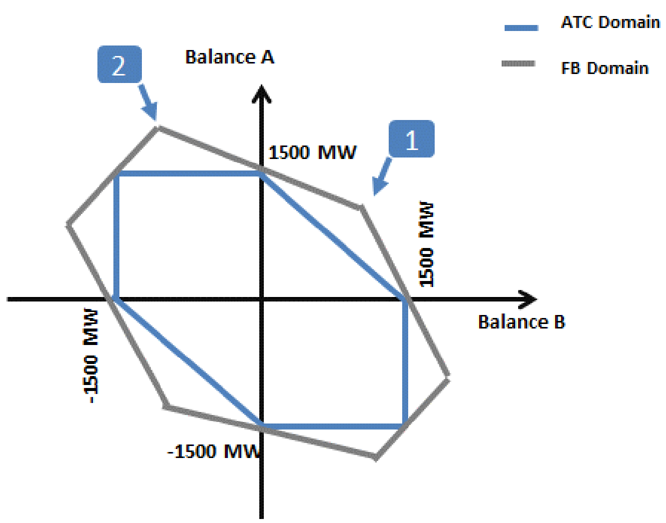

Figure 2. CNTC and FB domains

The Figure shows a safe CNTC and FB domain derived from the grid in Figure 1 with the same level of system security

All points on the FB boundaries reflect congested situations somewhere in the grid that will induce price differences in all nodes without implying that all lines are congested simultaneously. These market positions are however not possible in CNTC due to the fact that the CNTC algorithm doesn't know the real physical flows (the PTDFs) between bidding zones.

2.3 Nodes and bidding zones with FB

In Section **Feil! Fant ikke referansekilden.** we discussed the implementation and implications of the FB onstraints in the market algorithm based on bidding zones. In the three-node example of Section **Feil! Fant ikke referansekilden.** most issues are easy to comprehend. Moving towards the real world however, complexity increases. Amongst other things, physical connections are between single nodes, while bidding zones comprise multiple nodes. As we start off creating grid models in the real world to be used for FB parameter calculations, this means everything is based on nodes and single lines, rather than bidding zones and tie-lines. This means that our nodal calculations and results have to be aggregated to bidding zones and Critical Network Elements[3] (CNEs). As each node within the same bidding zone has a different node-to-CNE PTDF, it is very hard to find an optimal strategy to make an aggregate zone-to-CNE PTDF. In case the node-to-line PTDFs were to be used directly by the market algorithm, it would have been a nodal pricing market design. By using the same technology but aggregating to bidding zones and CNEs, we get what is known as FBMC. The actual aggregation from nodes to bidding zones is discussed further in Section 4.2.

2.4 Capacity allocation at the power exchange (Euphemia)

The common market algorithm used in Northwestern Europe is called Euphemia. In principle, Euphemia is doing what is described in the generic model in Section **Feil! Fant ikke referansekilden.** above. In essence, Euphemia is calculating the welfare maximum, but due to the stepwise nature of real world bids, several "optimum" price/volume combinations may exist. Euphemia uses a heuristic to choose a solution when steps are overlapping. This implies that the interpretation of shadow prices in Euphemia might not necessarily be in line with theory, which requires smooth continuous curves.

[3] A network element is a component in the power grid exposed to an electric flow induced by generation and consumption. A network element could be a line, a transformer and the like. A critical network element is a network element that the TSO requires to monitor for potential overloads.

2.5 Overview of the Flow-Based Market coupling process

Three distinct phases can be identified in the operational procedure in a power market irrespective whether it is based on a FB or a CNTC methodology; pre-market coupling, market coupling and post-market coupling.

Pre-market coupling is the preparatory phase where the TSOs do the capacity calculation. This is a TSO-only operation where the solution domain for the market is calculated. The pre-market coupling basically consists of:

(1) Creating a "base case" containing expected grid topology for the next day together with expected net positions of all bidding zones and corresponding flows on all CNEs.
(2) Defining GSKs, CNEs, the corresponding outages and Remedial Actions
(3) Defining and applying operational experience (Final Adjustment value, FAV) in order to adjust the FB domain.
(4) Applying GSKs and CNEs to do the parameter calculation creating PTDFs and market margins (capacities).
(5) Verification of the FB parameters, making sure that the domain is proper.
(6) Sending the parameters to the power exchange.

The pre-market coupling starts the evening on D-2 and lasts until 10:00 on D-1 when the parameters are published on the Power Exchange web site.

Market coupling is the actual solving of the market. This phase is carried out by the power exchange. The Market coupling process consists of:

(1) Publishing the parameters to the market
(2) Collecting bids from the market players
(3) Calculate the market equilibrium
(4) Publishing the market result

The market coupling process starts at 10:30 and ends at 13:00 when market results are published.

The **post-market coupling** process is carried out at the TSOs. This process consists of:

(1) Verification of the market results
(2) Congestion income sharing
(3) Analyses of operational security

2.6 Uncertainty

The fundamental element in managing uncertainty in capacity calculation is the reliability margin (Flow Reliability Margin or FRM in FB). Due to uncertainty, the power system operator cannot predict precisely what flow will be realized on each CNE in the hour of operation. The flow may be larger or smaller than anticipated, and if the flow turns out larger, there may be an overload on a CNE. In order to reduce the probability of physical overloads to an acceptable risk level, some of the capacity on a CNE will be retained from the market as an FRM. The capacity provided to the market will be the maximum capacity on a CNE less the FRM. The size of the FRM will normally be based on a statistical evaluation of the deviations between the flows estimated by the FB method and the actual flows observed.

There are many reasons why uncertainty occurs in capacity calculation, such as temperature, precipitation, fuel prices and sun. However, there are two uncertainties that are fundamental and specific to FB procedure. The first is the linearization of the grid model. The second is the manner in which we choose to aggregate the node-to-CNE PTDFs to zone-to-CNE PTDFs. On the other hand, the flows between bidding zones are solved by the market itself when FB is applied. This means that transit flows are calculated in the FBMC, which reduces these kind of uncertainties.

All uncertainties will however in the end be reflected in the Flow Reliability Margin (FRM) which reduces the market capacity compared to the physical capacity.

3. Network code requirements related to FB

Several Network Codes (NCs) are at the moment being prepared for the European Power Market. The NCs are the EU-wide implementation of the Third Framework Program for the European Power Market, and they will define a common set of rules for the European electricity markets. As the NCs are still under development, the final text and content are not yet known. But the basic framework is there and most of the issues have been covered.

Several NCs are being developed that influence the FB methodology. The Network Code on Capacity Allocation and Congestion Management (NC CACM) is the most relevant one in this perspective.

3.1 Network Code on Capacity Allocation and Congestion Management (NC CACM)

The most important NC, from a FB point of view, is the NC CACM which will have implications for capacity calculation and allocation and which is also setting forth requirements for the input to these processes. Two issues are of particular interest to FB:

1. Requirements to the capacity calculation methodology
2. Requirements for a European Common Grid Model (methodology)

CACM specifies that the methodology for capacity calculation should either be a coordinated NTC (CNTC) or FB approach for both the day-ahead and intraday timeframes. The preferred approach however shall be a FB capacity calculation unless:

a) In regions where interdependencies between cross-zonal capacities are low, and
b) There is no added value to apply the FB approach

Furthermore, the CACM states that each Coordinated Capacity Calculator applying the FB Approach, shall use the Common Grid Model (CGM), Generation Shift Keys (GSKs) and contingencies to calculate the Power Transfer Distribution Factors (PTDFs).

The CGM itself shall represent the European interconnected system, and it shall facilitate transmission capacities to be calculated in a coordinated manner. The CGM will include the transmission system with the locations of generation and load units relevant for capacity calculation, grid topology, and rules to change this during capacity calculation.

In further details, the CGM shall contain descriptions of the specific scenarios to be used, where each scenario is to be defined per market segment for both day-ahead and the intraday market. The code prescribes the process for how to merge individual (national) grid models into a CGM, in which each individual/national grid model shall be based on the best forecast for the operational conditions in the given scenario at the time the model is produced. All TSOs are to ensure that the individual grid models contain all information necessary to run a load flow analysis, and in appropriate instances, the models should be prepared to run dynamic analyses.

4. Pre-market coupling

In this Section we explain all activities performed by the TSOs in order to produce grid constraints to be used by the allocation mechanism (i.e. capacity calculation) in detail. We dive into how the FB parameters are calculated and which simplification are made. As such, this Section dives into the details of what was explained on a high level in Section **Feil! Fant ikke referansekilden.**.

We start off by explaining the relation between the physical grid (described by the AC load flow equations) and the PTDFs that the TSOs provide to the market algorithm. Subsequently, we explain the other central parameter, the market margin (Remaining Available Margin, RAM). The rest of the Section is dedicated to explain how to deal with GSKs, CNEs, DC cables, reliability margins, and further details behind the FB parameters.

4.1 The sensitivity parameters (PTDF)

The power transfer distribution factors (PTDFs) in FB are calculated based on a standard set of power flow AC equations. This section starts with a short introduction of the basics of the AC power flow equations and how the DC power flow representation of the grid, that is used in FB, is derived.

4.1.1 Power flow equations

The active and reactive power flows in steady state can be described by the following non-linear[4] equations:

Equation 1 $$P_i = V_i \sum_{k=1}^{n} V_k (G_{ik} \cos(\delta_i - \delta_k) + B_{ik} \sin(\delta_i - \delta_k))$$

Equation 2 $$Q_i = V_i \sum_{k=1}^{n} V_k (G_{ik} \sin(\delta_i - \delta_k) - B_{ik} \cos(\delta_i - \delta_k))$$

where

P_i	=	Active power balance in node *i* (per unit MW)
Q_i	=	Reactive power balance in node *i* (per unit Mvar)
i, k	=	Node number
n	=	Number of nodes
V_i	=	Voltage magnitude in node *i*
δ_i	=	Voltage angle of node *i*
δ_k	=	Voltage angle of node *k*
G_{ik}	=	Conductance between node *i* and *k* with negative sign
G_{ii}	=	Sum of all conductances connected to node *i*

[4] The equations are nonlinear due to the trigonometric sine and cosine elements.

B_{ik}	=	Susceptance between node *i* and *k* with negative sign
B_{ii}	=	Sum of all susceptances connected to node *i*

The two, active and reactive, node-balance equations above show the balance of each node in the AC network as the sum of the flow on branches and shunts connected to the node. The aim of these power flow equations is to determine the voltages (magnitude and angle) at all buses. If the voltages are known, it is possible to determine the power flows, losses and currents.

The terms conductance (G) and susceptance (B) above constitute the complex admittance (measured in Siemens) given by Y:

Equation 3 $$Y = G + jB = \left\{G = \frac{r}{r^2+x^2}\ ,B = \frac{-x}{r^2+x^2}\right\} = \frac{r}{r^2+x^2} + j\frac{-x}{r^2+x^2}$$

Here r represents the resistance and x the reactance of the connected circuit. The circuit can be e.g. a line or transformer. **Figure 3** below illustrates the notation used in the equations.

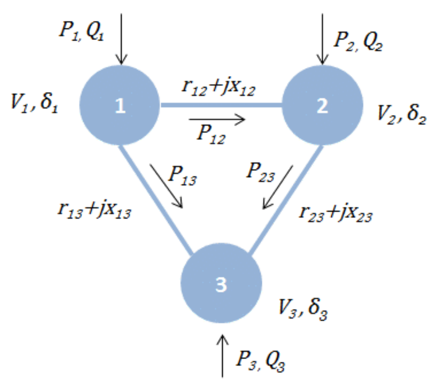

Figure 3 Example grid with three nodes

The node and line parameters used in the power flow equations are illustrated in the figure

The FB market solution for the energy market in Europe is based on a linearization of the equations (1) and (2). The following is a brief description of the approximations made in the linearization.

The first approximation is based on the fact that the grid resistance normally is much less than the grid reactance. If r is small compared to x it can be observed in (3) that:

Equation 4 $$r < x \quad \rightarrow \quad \mathrm{G} \approx 0 \quad \text{and} \quad \mathrm{B} \approx \frac{-1}{X}$$

The power flow equations (1) and (2) now become:

Equation 5 $\quad P_i = V_i \sum_{k=1}^{n} V_k (B_{ik} \sin(\delta_i - \delta_k))$

Equation 6 $\quad Q_i = V_i \sum_{k=1}^{n} V_k (-B_{ik} \cos(\delta_i - \delta_k))$

The second approximation is based on the fact that the voltage angle between two buses normally is small at stable operation of the power system. Sine and cosine can be approximated as

Equation 7 $\quad \sin\delta \approx \delta \quad$ and $\quad \cos\delta \approx 1$

The power flow equations (5) and (6) now become:

Equation 8 $\quad P_i = V_i \sum_{k=1}^{n} V_k \big(B_{ik}(\delta_i - \delta_k)\big)$

Equation 9 $\quad Q_i = V_i \sum_{k=1}^{n} V_k (-B_{ik})$

The third approximation is based on the assumption that all the voltage magnitudes will be almost equal to the reference voltage. If one uses the per unit (pu) system, where the reference voltage is normalized to 1.0, the following approximation can be made:

Equation 10 $\quad V_i, V_k \approx 1$

The power flow equations (8) and (9) now become:

Equation 11 $\quad P_i = \sum_{k=1}^{n} B_{ik} (\delta_i - \delta_k)$

Equation 12 $\quad Q_i = \sum_{k=1}^{n} -B_{ik}$

Because Q_i turns into a constant term, it has no impact on the flow in the network, and only the equation of active power, P_i, is needed to compute the voltage angles for a given level of consumption and production.

This method is labeled "DC power flow".

The equations so far have established the relationship between the power injection in each node and the flows of the connected lines. The voltage angles, in an example with three nodes, can be computed from the following equation:

Equation 13 $$[P]=\begin{bmatrix}P_1\\P_2\\P_3\end{bmatrix}=\begin{bmatrix}B_{12}+B_{13} & -B_{12} & -B_{13}\\ -B_{21} & B_{21}+B_{23} & -B_{23}\\ -B_{31} & -B_{32} & B_{31}+B_{32}\end{bmatrix}\begin{bmatrix}\delta_1\\\delta_2\\\delta_3\end{bmatrix}=[B][\delta]=[Ybus][\delta]$$

In equation (13) the *Ybus*-matrix is symmetric as $B12 = B21$ and corresponds to the negative susceptance between node 1 and 2. The diagonal elements are equal to the sum of all susceptances connected to the node. This *Ybus*-matrix is also called the *B*-matrix or the bus admittance matrix. Notice that δ is the vector with the voltage angle at the nodes.

The voltage angle are then given by

Equation 14 $$[\delta]=\begin{bmatrix}\delta_1\\\delta_2\\\delta_3\end{bmatrix}=\begin{bmatrix}B_{12}+B_{13} & -B_{12} & -B_{13}\\ -B_{21} & B_{21}+B_{23} & -B_{23}\\ -B_{31} & -B_{32} & B_{31}+B_{32}\end{bmatrix}^{-1}\begin{bmatrix}P_1\\P_2\\P_3\end{bmatrix}=[Zbus][P]$$

where the inverted *Ybus* matrix is referred to as the *Zbus* or bus impedance matrix.

There is an infinite set of possible solutions of equation (14), since the injected power P only depends on the differences between the voltage angle δ, and not on the absolute values. The problem is that there is a dependency in the three equations, implying that one equation may be obtained from the other two. As such, the inverse of the *Ybus*-matrix is singular. In order to have a unique solution, at least one of the diagonal elements must contain an additional value, creating a "reference point" for the absolute values of the system. This node is referred to as the slack-bus or slack-node and is set to δ = 0. If node 1 is set as the slack-node, $\delta_1 = 0$, the corresponding column and row (column 1 and row 1) in the *Ybus* matrix in (13) is eliminated. The remaining voltage angles can then by calculated by

Equation 15 $$\begin{bmatrix}\delta_2\\\delta_3\end{bmatrix}=\begin{bmatrix}B_{21}+B_{23} & -B_{23}\\ -B_{32} & B_{31}+B_{32}\end{bmatrix}^{-1}\begin{bmatrix}P_2\\P_3\end{bmatrix}$$

Given the voltage angles in each node, the active power flow between two nodes can be calculated with

Equation 16 $$P_{\mathrm{ik}}=B_{\mathrm{ik}}(\delta_{\mathrm{i}}-\delta_{\mathrm{k}})$$

Instead of eliminating a row and a column in the *Ybus*-matrix for the slack-bus, as in (15), another method is to add "+1" to one of the diagonal elements. Hence, if node 1 is selected as the slack node, the voltage angles can be calculated as

Equation 17 $$[\delta] = \begin{bmatrix}\delta_1\\\delta_2\\\delta_3\end{bmatrix} = \begin{bmatrix}1+B_{12}+B_{13} & -B_{12} & -B_{13}\\ -B_{21} & B_{21}+B_{23} & -B_{23}\\ -B_{31} & -B_{32} & B_{31}+B_{32}\end{bmatrix}^{-1}\begin{bmatrix}P_1\\P_2\\P_3\end{bmatrix} = [Zbus][P]$$

The end result is the same in approach in (15) and (17), but the latter might be more straightforward.

4.1.2 Calculating the PTDF

The power transfer distribution factor (PTDF) reveals a certain node's flow participation on a certain branch. For example, the PTDF for node 1 at line 1-2 in the example above is denoted $PTDF_{12,1}$. The PTDF matrix then includes each node's PTDF for all lines in the system.

The PTDF is derived in the following way. For example, assume that additional power, ΔP_1 , is fed into the network in node 1. From (17) the change in angles in node 1 and 2, given this injection, can be calculated as

Equation 18 $$\Delta\delta_1 = \Delta P_1(1 + B_{12} + B_{13}) = \Delta P_1(Zbus_{11})$$

Equation 19 $$\Delta\delta_2 = \Delta P_1(-B_{21}) = \Delta P_1(Zbus_{21})$$

The elements multiplied with P_2 and P_3 in (17) do not result in a change of the angles since the power is injected in node 1 in this example leaving ΔP_2 and ΔP_3 to be zero.

The change of active power flow in line 1-2 due to this injection in node 1 can now be calculated by combining (16) with (18) and (19)

Equation 20 $$\Delta P_{12} = B_{12}(\Delta\delta_1 - \Delta\delta_2) = B_{12}(Zbus_{11} - Zbus_{21})\Delta P_1$$

If ΔP_1 is set to unity (1.0) the PTDF for node 1 at line 1-2 become

Equation 21 $$PTDF_{12,1} = \Delta P_{12} = B_{12}(\Delta\delta_1 - \Delta\delta_2) = B_{12}(Zbus_{11} - Zbus_{21})$$

More generic, the PTDF can be expressed as

Equation 22 $$PTDF_{ik,n} = B_{ik}(Zbus_{in} - Zbus_{kn})$$

Equation (22) should be interpreted as the PDTF value from node n to the line between nodes i and k. By repeating this procedure for all nodes and all lines, the PTDF matrix can be computed. The matrix describes how the net balance of the nodes influences the power transfers on the lines. Remember here that B_{ik} is the susceptance of the line between node i and k, which corresponds to the inverse of the reactance of the line since we assume that the resistance is negligible.

Example: Calculating PTDFs

Figure 4 below shows a three-node network where the nodal transfer PTDFs are going to be calculated. The impedances of the lines are included in the figure, being the sum of resistance and reactance. The slack node is located in node 3 in this example.

The line resistance is negligible compared to the reactance (e.g. line 1-2 has a 2/0.01=200 times higher reactance) and hence the assumption in (4) can be applied. The DC power flow approximation is applied.

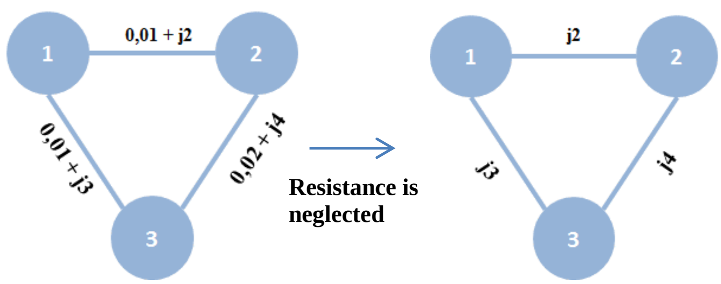

Figure 4 Example grid with three nodes

The node and line parameters used in the power flow equations are illustrated in the figure

The $Ybus$ matrix, given by (13), is defined by the data in **Figure 4**. Recall that the susceptance between two nodes equals the inverse of the reactance for the line, since the resistance was neglected.

Equation 23
$$Ybus = \begin{bmatrix} 1/2+1/3 & -1/2 & -1/3 \\ -1/2 & 1/2+1/4 & -1/4 \\ -1/3 & -1/4 & 1/3+1/4 \end{bmatrix}$$

As in (17), the $Zbus$ matrix is then constructed by adding "+1" to the diagonal element corresponding to the slack-node in the $Ybus$ matrix in (23), followed by an inverse operation. Node 3 is in this example selected as slack node.

Equation 24
$$Zbus = \begin{bmatrix} 1/2+1/3 & -1/2 & -1/3 \\ -1/2 & 1/2+1/4 & -1/4 \\ -1/3 & -1/4 & 1/3+1/4+1 \end{bmatrix}^{-1} = \begin{bmatrix} 3,00 & 2,33 & 1,00 \\ 2,33 & 3,22 & 1,00 \\ 1,00 & 1,00 & 1,00 \end{bmatrix}$$

The PTDF value from node n for the line between nodes i and k can then be calculated with (22).

Equation 25 $$PTDF_{ik,n} = B_{ik}(Zbus_{in} - Zbus_{kn})$$

For example, the PTDF value from node 1 to the line between node 1 and 2 can be calculated as

Equation 26 $$PTDF_{12,1} = B_{12}(Zbus_{11} - Zbus_{21}) = \left(\frac{1}{2}\right)(3{,}00 - 2{,}33) = 0{,}33 = 33\%$$

For production in node 1, 33% of the power will flow on the line 1 to 2. For consumption (which is the negative production) the effect will be the reverse, i.e. the line is loaded in the opposite direction.

For each line ik (row) and node n (column) the $PTDF_{ik,n}$ is calculated, resulting in the following PTDF matrix (nodal transfer PTDF matrix to be precise) with node 3 being the slack-node:

Equation 27 $$\mathrm{PTDF} = \begin{array}{cc} & \textbf{Node} \\ & \begin{array}{ccc} \textbf{1} & \textbf{2} & \textbf{3} \end{array} \\ \textbf{Line} \begin{array}{c} \textbf{1-2} \\ \textbf{1-3} \\ \textbf{2-3} \end{array} & \begin{bmatrix} 0{,}33 & -0{,}44 & 0 \\ 0.67 & 0.44 & 0 \\ 0{,}33 & 0{,}56 & 0 \end{bmatrix} \end{array}$$

4.2 From nodal PTDFs to bidding zone PTDFs using shift keys

In FB market coupling, zone-to-CNE PTDFs are used by the market algorithm to asses whether a change in area balance respects the grid constraints. The PTDFs are calculated based on an estimated base case (see Section 4.2.2) for each hour of operation. The base case describes the anticipated grid topology, net positions and corresponding power flows in each hour of operation on a nodal level for day D. The base case is created either by using D-2 data, or a combination of D-2 data and forecasts for generation and consumption.

The Base Case is derived from snapshots (SN) from the SCADA systems. A snapshot is like a photo of a TSO's transmission system, showing the voltages, currents, and power flows in the grid at the time of taking the photo. The snapshot is adjusted by including anticipated changes in grid topology, production and consumption (both planned outages and forecasts) for the hour of Day D and forms the base case.

Being a nodal model, PTDFs computed from the base case are node-to-CNE PTDFs. The FB methodology however depends on Zone-to-CNE PTDFs, where net positions of bidding zones give the flow on particular CNEs. This creates a need for calculating zone–to-CNE PTDFs from the node-to-CNE PTDFs.

Figure 5 shows three bidding zones, A, B and C, each consisting of five nodes (N1-N5). These nodes are connected by both internal lines and tie lines between the areas. The task at hand is to convert the node-to-CNE PTDFs into zone-to-CNE PTDFs.

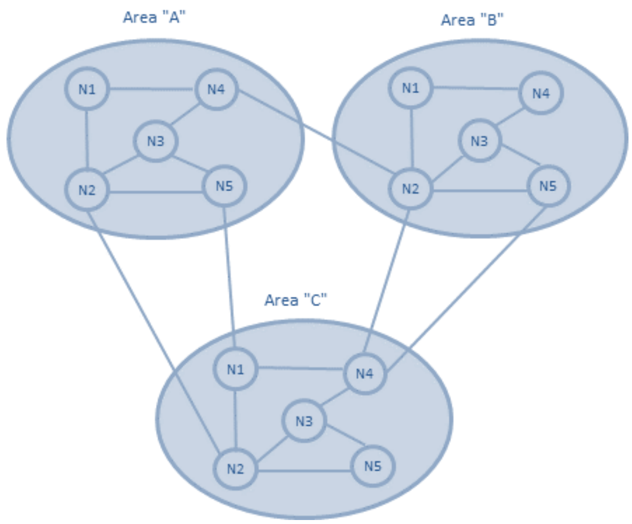

Figure 5 From Nodes to Bidding Zones

Three bidding zones, each comprising 5 nodes. Node-to-CNE influence has to be aggregated into zone-to-CNEarea-to-line influence

An aggregation problem arises from the fact that each node within the same area has a particular influence on each line or CNE. If one particular node gets too much or too little weight in the aggregation, the zone-to-CNE PTDF is inaccurate. Unfortunately there is no straightforward theoretical way of finding the "correct" rule for aggregation (ref Section 2.6 over).

In **Figure 5**, the difference in nodal and area PTDFs can be illustrated by the fact that the impact of N4 in "A" will probably be different from the impact of N5 in "A" on the flow on the tie line between area "A" and "C". If the aggregation is not in line with reality, the zonal PTDFs will behave as a poor estimate for actual flows. One further problem is that the most viable rule for aggregation probably changes over time.

FB makes use of shift keys to describe how the net position of one node changes with the net position of the area it is a part of. We can have different shift keys related to consumption and generation, and even related to different technologies (like wind shift keys). In this context however, we'll use the general term generation shift keys (GSK).

The GSK is a value used in the translation from node-to-CNE PTDFs to zone-to-CNE PTDFs. The relation is formally expressed as:

Equation 28 $PTDF_{i,j}^{A} = \sum_{\forall \alpha} GSK^{\alpha} PTDF_{i,j}^{\alpha}$, and $\sum_{\forall \alpha} GSK^{\alpha} = 1$

$\mathrm{PTDF}_{i,j}^{A}$ = Sensitivity of line i,j to injection in area "A"

$\mathrm{PTDF}_{i,j}^{\alpha}$ = Sensitivity of line i,j of injection in node "α"

GSK^{α} = Weight of node α on the PTDF of area "A"

4.2.1 Strategies for the generation shift keys

There is no theoretically "right or wrong" methodology on how to generate GSKs. However, the choice of GSKs will influence the market, and if inaccurate, the influence may be extensive. GSKs may be one of the major sources of inaccuracies of the FB parameter calculation, and hence need to be treated with great care. This is why we introduce different GSK strategies, or different rules for generating GSKs in order to find the empirically best GSKs.

When designing the GSKs, it is important to be aware that this is a linear approximation of a non-linear relation. No matter what shifts are imposed to the net positions by the market, the linear relation is assumed to hold.

The simplest form of GSK strategy is a "flat participation" of each node, i.e. the GSK of each node is set to 1/5 in **Figure 5**. One of the drawbacks of the flat type of strategy (and some other strategies), is that this could give more generation to a node than the max installed capacity at that node (if sufficient net injection is assigned to the area). Furthermore, it adds a fictitious generator to every bus even though there are many buses that do not have a load or generator connected to it.

Several GSK strategies may be implemented, but as discussed in Section 4.2.2, there are always both advantages and disadvantages related to all strategies.

It may be the case that different strategies turn out to be optimal for different bidding zones, countries or time stamps. This is something that may be discovered with an ex-post analysis of the capacity calculation and allocation. Reasons why this could happen is for example that the generation technology mixture varies between bidding zones or that the geographical distribution of generation and generation technologies varies significantly between areas.

From a theoretical point of view, whenever different strategies seem optimal for different areas and/or over time, different strategies are likely to be applied by the different TSOs. Also from a technical point of view, it is fully possible to introduce different GSK strategies for different areas and/or time slots. However, the GSK parameters are used to calculate the PTDFs and thereby define the solution domain for the market. Hence the chosen strategy will have effects on the market solution. Because of this, there should be harmonized rules guiding how GSKs are defined in order to avoid potential obscure incentives and to insure transparency in the capacity calculation process. This is also a requirement in the CACM NC.

In our initial version of the FB procedure, we are opting for a flat GSK strategy. However, the outcome of the flow predictions from different GSK strategies will be monitored over time, which will give a base for developing a potential better strategy in a later version of the Nordic FB.

4.2.2 Generation technology considerations

As we start a PTDF calculation, the relevant nodes to consider in a GSK strategy are those responding to net injection changes from the base case, which are the marginal nodes. The relation between marginal nodes and marginal technology is the spatial distribution of the technologies. By specifying the response of the marginal technology to a change in a net position, we indirectly specify the response from the 'marginal' nodes as well. This is illustrated in the example below.

FB uses a linear approximation of how the real flow changes as a function of net position. As illustrated by the red and black dashed lines in **Figure 6**, there is more than one solution as to how such a linearization could be made. The challenge is to find the "best" method.

The PTDF defines the slope of the linear relation between the net position and the flow induced on a CNE as: Flow on line i,j = Fref' + PTDF*net position. The brown solid line illustrates the real flow on the line under a varying net position of "A", with the different technologies responding at certain net positions. The different line segments on the brown line represent the flow response[5] corresponding to different technologies (with an ex-ante spatial distribution on the nodes in the area). The order of the technologies on the line implicitly represents the merit order of the technologies.

The brown line as a whole is non-linear (being only piecewise linear) and thereby too complex to fit in the FB approach. We need a linearization of the real physical flow in the form of one PTDF value. Different strategies can be applied to do so.

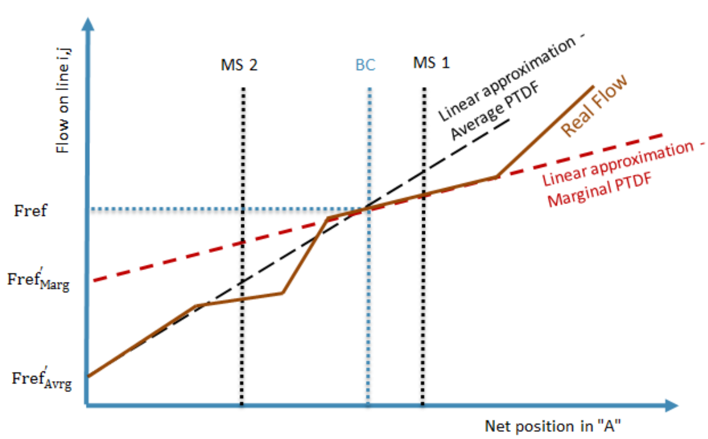

Figure 6 Example of AC and DC load Flow

Possible relation between flow on line (i,j) as a function of the net position. The brown line reflects the actual flow. The red and black dashed lines represent the linear approximations obtained by a marginal and an average GSK strategy

In the figure 6, the blue dotted line (BC) indicates the net position in the base case of bidding zone A and the corresponding flow on the line(i,j), being the intersection of the blue dotted line (BC) and the brown

[5] The line segments are piecewise linear for pedagogical reasons.

solid line reflecting the real flow. Let us consider two different GSK strategies to assess the slope of the linear relation between the net position and the flow induced on the line(i,j). The first one assumes a flat distribution of the influence of each node when aggregating the node-to-CNE PTDFs into a zone-to-CNE PTDF (which is the black dashed line in **Figure 6**). The second strategy assumes the marginal technology to represent the zone-to-CNE PTDF (which is the red dashed line).

If the net position reflected in the Base Case (BC) turns out to be the final market solution as well, both strategies correctly predict the flow on the line i,j. If the final market solution turns out to be "MS 1", we see that in this example, the predicted flow on line i,j is more accurate in the case where the marginal strategy is used than in the case where the average strategy is used. However, if the market turns out in "MS 2", it is the other way around. In general, we expect that a "marginal GSK strategy" is the most accurate as we expect the market solution to be close to the Base Case, while a flat GSK strategy may be the more robust strategy when the market turns out far away from the net position of the base case. While this may not always be true, it leaves us with a potential choice of more accuracy versus more robustness. All kind of strategies have comparable challenges, presenting a choice between accuracy versus robustness.

4.2.3 Intermittent power generation and volatility

Renewable energy production (wind and run-of-river hydro) and consumption (temperature) can change quite rapidly from day to day and hour to hour. After D-2, when the snapshots for capacity calculation are retrieved and the Base Cases are established, large changes in production and consumption can occur. The implication for the capacity calculation is that these changes could have a significant influence on the PTDFs and market margins.

A reference snapshot is the last complete representative grid model that is available for day D. Saturdays and Sundays are different from weekdays, and the last complete grid model is from the week before, D-7. A similar effect holds for Mondays and Tuesdays, as the last complete grid representation is the last Friday, D-3 and D-4. A possible schedule for choosing the reference snapshots is shown in Table 2.

Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Sunday
D-3	D-4	D-2	D-2	D-2	D-7	D-7

Table 2 Possible schedule for retrieving Snap Shots

Figure 7 shows a comparison of actual net positions with that of the last comparable day in line with the above table. In some areas, as **Figure 7** indicates, the proposed schedule is a less than perfect forecast for the actual day.

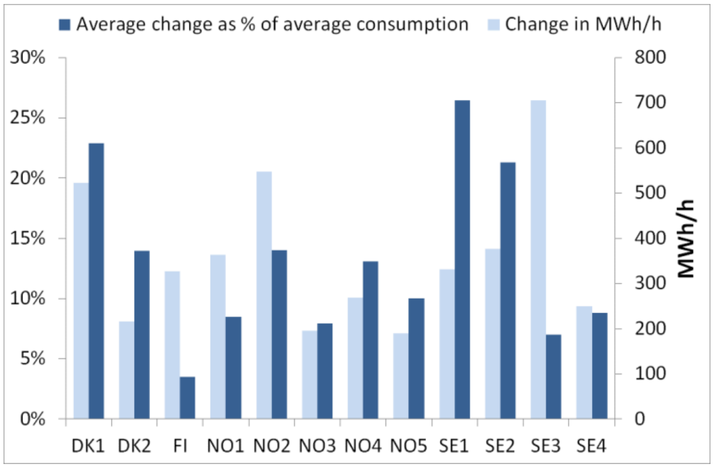

Figure 7 Difference in Net Positions compared to last comparable day (Time period des. 2011- des 2013)

One way of managing large shifts in net positions is to opt for a more robust generic GSK strategy. A flat strategy might for example be more robust to errors in the base case than a marginal strategy, but this needs to be investigated. Forecasting may however improve the base case and reduce the potential issue linked to intermittent power. Our initial position on this is to use a flat GSK strategy in the short term, while developing a forecasting methodology at a later stage.

4.3 Remaining Available Margin (RAM)

The PTDF matrix is one of two fundamental parameters for providing grid constraints to the market optimization at the PX. The other is the Remaining Available Margin (*RAM*). This is the "free margin" that can be used by the allocation mechanism on CNEs. The RAM differs from the max capacity of the CNE as in the following equation:

Equation 29 $$\boldsymbol{RAM = F_{max} - FRM - FAV - Fref'}$$

RAM= The Remaining Available Margin
Fmax= The maximum allowed flow on the CNE (see Section **Feil! Fant ikke referansekilden.**)
Fref'= *T*he reference flow at zero net positions when using the computed PTDF
FRM= *T*he Flow Reliability Margin (see Section 4.8.2)
FAV= *T*he Final Adjustment Value (see Section 4.9.2)

In this equation, *Fref'* is the reference flow at zero net position that is obtained by using the calculated PTDF matrix from the base case:

Equation 30 $$\boldsymbol{Fref' = Fref - PTDF * NP^{BC}}$$

Fref= The loading of the CNEs in the base case given the net positions reflected in the base case
NP^{BC}= Net position of all bidding zones in the base case

The relation between the net position, flow and RAM is illustrated in **Figure 8**. The RAMs on CNEs with their associated PTDF factors form the so-called FB constraints:

Equation 31 $\boldsymbol{PTDF * NP \leq RAM}$

In general, the RAMs will be positive and the flows on the CNEs, induced by the net positions that are optimized by the market coupling mechanism, will be restricted by those values. It may however happen that a certain CNE is pre-congested (already congested before the actual allocation). In this case the Fref' exceeds the Fmax-FRM-FAV value resulting in a negative RAM. In the case that a negative RAM is provided to the market coupling algorithm, the market is enforced to relieve that congestion irrespective of the market preferences. In the example below, the constraint enforces the induced flow on the CNE to be -10 or smaller (e.g. -15).

Example of negative RAM: $PTDFa * NP(A) + PTDFb * NP(B) + PTDFc * NP(C) \leq -10$

The market coupling mechanism will find the most efficient way of relieving the congestion.

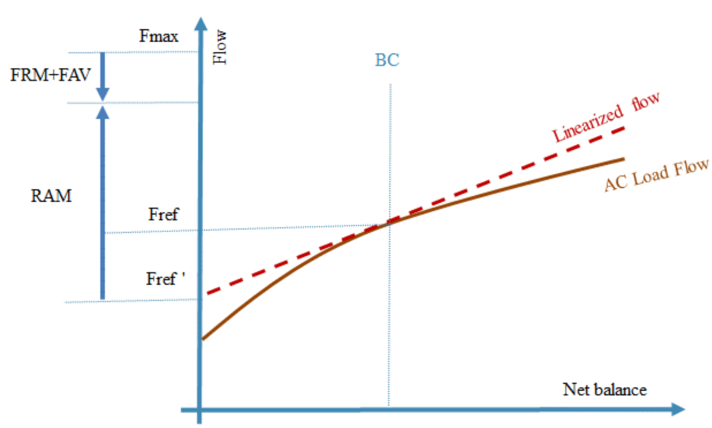

Figure 8 Relation between flow, net position and RAM

Our initial position is to allow for negative RAMs (if the case arises) and to let the market algorithm relieve the initial congestion.

4.4 FB constraints

The RAMs on the CNEs with their associated PTDF factors form the so-called flow-based constraints. Note that an RAM of a CNE is defined in one direction only. If both directions are to be monitored, two CNEs have to be defined, one for each direction. The FB constraints represent the grid constraints in the Market Coupling mechanism:

Objective function: Maximize economic surplus (Welfare)

Subject to: $\sum$ NPs = 0

FB constraints

4.4.1 FB domain and its indicators

The FB constraints will ultimately limit the market to a fixed set of possible solutions. It is the TSO that calculates these constraints in what is known as "capacity calculation". Capacity calculation is thereby important from a welfare economic point of view. The methodology and principles of FB are discussed in the following Section based on a three-node network[6] illustrated in Figure 9.

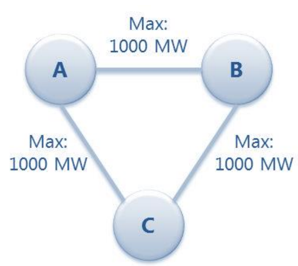

Figure 9 Example network, three bidding areas

The network has the following characteristics:

- *Equal impedances (equal "electrical distance")*
- *Max flow on the branches: 1000 MW*
- *With zero NPs, the lines between the Bidding Zones are unloaded*

The maximum export from A to any of the two other bidding areas amounts 1500 MW. This is due to the physical reality where the electricity always follows the path of least resistance, and flows fan out in accordance to Kirchhoff's laws. In the example, this implies that the flow from A to C will distribute as 1/3'd on the longest route and 2/3'ds on the shortest route as in Figure 10.

The FB constraints represent a simplified linearized grid model. The model reflects both the impact (flow) of import/export from every bidding zone on each CNEs in the grid, and the total capacity available for the market on each CNE. This is illustrated in the graphs and table in **Figure 10** and **Figure 11** where A, B and C are bidding zones, and the connecting tie lines are the CNEs.

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[6] Example based on Schavemaker: Flow-Based Concept and Methodology, Norwegian Flow-Based stakeholder forum (December 2013)

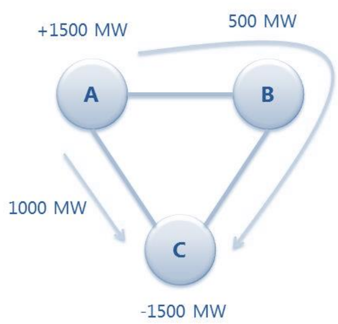
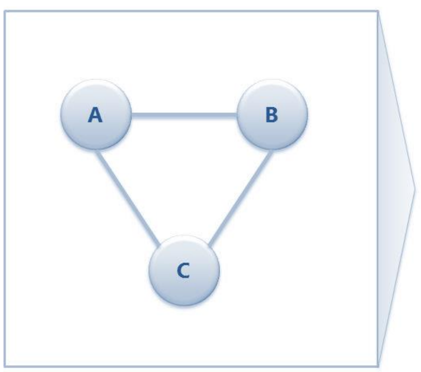


Figure 10 Physical flows in a three-node network. Equal impedance on each CNE/line.

The impacts of the various bidding zones on the CNEs are evaluated in the form of PTDFs, being a sensitivity factor stating how much (%) of one MW of export from a certain bidding zone will occur on a particular CNE. Considering the PTDFs in both direction provides us with the full set of FB parameters as illustrated in the table in **Figure 11**.



FB constraints ('grid model'):

Line	Maximum flow (Margins)	Influence from area A (PTDF factors)	Influence from area B (PTDF factors)	Influence from area C (PTDF factors)
A>B	1000 MW	33 %	- 33 %	0
B>C	1000 MW	33 %	67 %	0
A>C	1000 MW	67 %	33 %	0
B>A	1000 MW	-33 %	33 %	0
C>B	1000 MW	- 33 %	- 67 %	0
C>A	1000 MW	- 67 %	- 33 %	0

Figure 11 FB parameters in a three-node network, max flows and PTDFs.

PTDFs are calculated for both directions.

The FB constraints for the three-node system define the FB domain: the import/export positions that are available for the market solution while not jeopardizing the grid security. The domain is visualized in **Figure 12**.

The lines limiting the FB domain can be easily found from the FB parameters. Let's zoom in on the constraint imposed by the line A>C. When the NP(A) = 0, NP(B) can reach a value of 1000/0.33 = 3000 MW (i.e. the intersection point at the x-axis). When the NP(B) = 0, NP(A) can reach a value of 1000/0.67 = 1500 MW (i.e. the intersection point at the y-axis). With these two points the line ("Constrained by AC") can be drawn in **Figure 12** below.

We can continue to find the next constraint, imposed by the line B>C. When NP(A) is zero, NP(B) can reach the value of 1000/0,67 = 1500 MW. When NP(B) is at zero, NP(A) can reach a value of 1000/0,33 = 3000 MW. This is the line "Constrained by B>C".

From the FB domain in **Figure 12**, we see that both points NP(A)=3000 MW, and NP(B)=3000 MW are invalid points that are outside the FB domain at all time. Both points NP(A)=1500 MW and NP(B)=1500 MW are valid points, but they can't occur at the same time though, e.g. (NP(A), NP(B), NP(C)) = (1500, 0, -1500) is a point that is within the FB domain. The point NP(A)=1000 MW and NP(B)=1000 MW is also a valid point, and they can occur at the same time: (NP(A), NP(B), NP(C)) = (1000,1000,-2000).

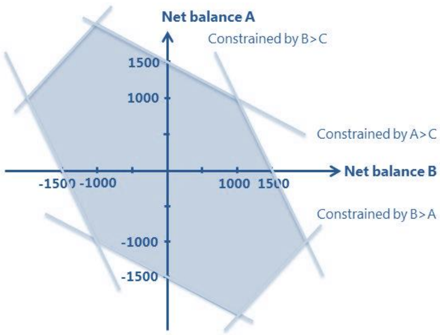


Figure 12 FB domain

The domain as derived from Figure 11

The FB domain also provides additional means to characterize the FB constraints:

- The vertices of the FB domain, in the example above, the points (1000,1000,-2000) and (1500,0,-1500) are examples of vertices. The full set of vertices gives the domain as illustrated in **Figure 12**
- The maximum net positions feasible in the FB domain, in the example above: max NP(A) = 2000, min NP(A) = -2000, max NP(B) = 2000, min NP(B) = -2000
- The maximum bilateral exchanges feasible within the FB domain (by assuming that no other exchanges take place), e.g. the maximum exchange from A to C equals 1500 MW in our example
- The volume of the FB domain

4.4.2 Comparison to a CNTC domain

The indicators that can be extracted from the FB domain can also be derived for the CNTC domain and provide a basis for comparison:

- The vertices of the FB and CNTC domain
- The maximum net positions feasible in the FB and CNTC domain
- The maximum bilateral exchanges feasible within the FB and CNTC domain
- Volume of the FB and CNTC domain
    - Volume of the common part of the domains (intersection)
    - Volume of the FB domain not in the CNTC domain
    - Volume of the CNTC domain not in the FB domain

The CNTC and the FB domains for the three-node example are shown in **Figure 13**. We can see that the CNTC domain is completely inside the FB domain. Indeed, in the FB setup, more options are available to the market than in a CNTC setup.

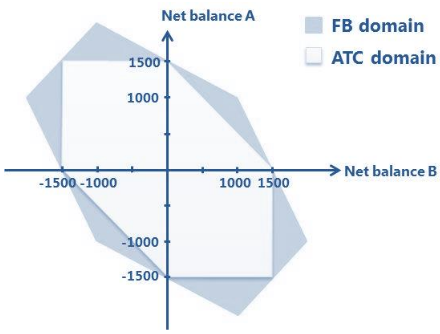


Figure 13 Comparing CNTC and FB solution domain

The domain is derived from Figure 11, and the CNTC values are all set to 750 MW

4.4.3 Removal of redundant constraints

When a TSO defines its CNEs, it is driven by operational experience and grid security considerations. The import/export positions that the market is allowed to reach under the market coupling, are known only after the FB parameters have been computed. At this stage, the constraints that are potentially limiting the market coupling outcome (the solid lines) are known as well, as illustrated in **Figure 14**. The dashed lines in the figure are the redundant constraints (redundant from an optimization point of view) which

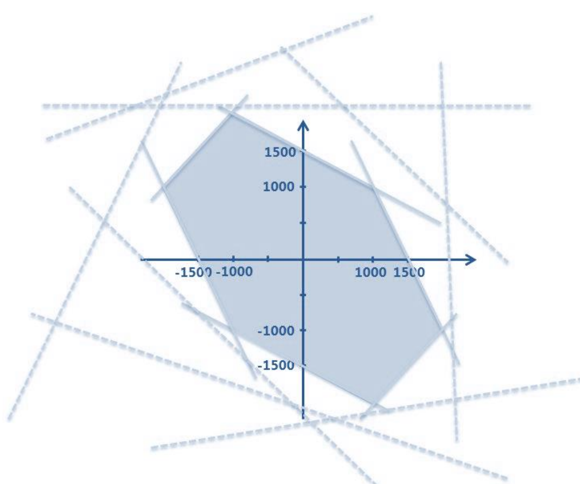


Figure 14 Redundant constraints

will not limit the market coupling outcome. These can be removed from the set of constraints before publication to the market and to the PX. Which constraints are redundant will however change from hour to hour. One particular CNE may be constraining, and be part of the matrix provided to the PX in one hour, but redundant and removed in the next. Removing redundant constraints will speed up the computation time at the PX without any loss of information.

Redundant constraints will be removed on an hourly basis from the parameter matrix sent to the PX

4.4.4 Threshold on PTDFs

There may be occasions where a trade between two areas far from a particular CNE can create an overload on this particular CNE. The PTDF causing this may be small in numerical value, but the trade behind may be significant. In order to prevent that a CNE in Finland (FI) is blocking a trade between NO2 and NO1, one can imagine that a threshold is introduced; all "zone-to-zone" PTDF[7] factors that are below a certain threshold are automatically set to zero. The reason could be that the uncertainty in the PTDF matrix itself justifies the reduction of the precision level of the PTDF matrix down to a certain level or the mitigation of situations where large trades are being blocked by distant CNEs, if this is considered to be an unwanted effect.

Although in this way, from an allocation point of view, the trade between NO2 and NO1 does not induce a flow on the FI CNE, physically there is an impact. Indeed, the threshold value would need to be set in such a way, that the physical impact of these flows remains within acceptable limits[8].

As it is the zone-to-slack PTDFs that are provided and used in the allocation mechanism, it is the zone-to-slack PTDF values that need to be altered in this case, rather than the zone-to-zone PTDFs. As the zone-to-slack PTDFs are defined against a single slack node, bidding zones with comparable PTDF factors have an equivalent impact on the respective CNE. In the example in Table 3, both bidding zones A and B have a comparable impact on the CNE. It can be decided to actually make the impact the same, by giving both bidding zones the same PTDF factor for this specific CNE (in this case the PTDF factors are made equal by taking the average of the two values). Given the approximate character of the DCLF / PTDF approach, this method is a pragmatic proposal to discard minor differences in PTDF factors and a possible market impact due to that. In this case, the zone-to-zone PTDF factor for a trade A>B for this CNE equals zero.

[7] The zone-to-CNE PTDFs provided to the PX, assumes that all power are absorbed in the slack node. Such PTDFs are referred to as "zone-to-slack" PTDFs. However, one can derive a "zone-to-zone" PTDF factor by subtracting the last zone-to-slack PTDF from the first zone-to-slack PTDF.

[8] Please note that e.g. between SE2-SE3 large trading volumes are possible. As such, even with a low zone-to-zone PTDF factor for a certain CNE, a large trade between SE2 and SE3 can induce a significant flow on the CNE. In the case that thresholds on PTDF factors would be evaluated, this fact needs to be considered / taken into account. On the other hand, a negative effect of introducing such a threshold is that it might decrease the accuracy of the FB flow calculations – thus giving rise to a larger FRM which in turn reduces the capacity in all hours

$$\begin{bmatrix} 0.14 & 0.13 & 0.26 & 0.02 \\ & & & \\ & & & \\ & & & \end{bmatrix} \begin{bmatrix} A \\ B \\ C \\ D \end{bmatrix} = \Delta flow \quad \Rightarrow \quad \begin{bmatrix} 0.135 & 0.135 & 0.26 & 0.02 \\ & & & \\ & & & \\ & & & \end{bmatrix} \begin{bmatrix} A \\ B \\ C \\ D \end{bmatrix} = \Delta flow$$

Table 3 Example of averaging Zonal PTDFs

Please note that the exercise to establish equivalent PTDF factors is not straightforward. Let's imagine that we would like to apply this approach to the following zone-to-slack PTDF factors and that we would like to consider PTDFs to be equal that are, in terms of sensitivity, 4% apart:

$$\boldsymbol{PTDF} = \begin{bmatrix} 0.05 & 0.08 & 0.11 \\ \dots & \dots & \dots \\ \dots & \dots & \dots \end{bmatrix}$$

Then the outcome could be:

0.065 0.065 0.11

Or:

0.05 0.095 0.095

Initially, we will not remove or round off any PTDF values. All calculated PTDFs will be kept in order to observe the results and to build statistics in order to monitor the effects of "distant" CNEs.

4.5 Grid losses

Grid losses will initially, as today, be bought on the day-ahead market by providing the PX with a best estimate of the required volume (MWh/h) for each bidding zone and market clearing hour. The losses are then cleared at the market price hence the TSOs have no control over the price they pay for their losses.

4.6 DC cables in the FB methodology

Opposed to a standard AC connection, a DC connection provides the ability to control the power flow. The implication is that no transit flows are induced on the DC connection by any trades elsewhere in the system. From both a market and physical point of view, if all connections were DC, there would be no reason to go beyond the CNTC methodology. In other words, a DC line is in a way the physical reality of a CNTC as the line is fully controlled (and that is exactly what the allocation mechanism does). However, when mixing DC with AC, a benefit is provided by the FB methodology, as it allows for a fair competition between the AC and DC exchanges for the possible scarce capacity in the AC grid.

The mixture of AC and DC elements (FB and CNTC) in a single allocation mechanism is often referred as "hybrid coupling". The difference in functionality and manageability of AC and DC connections calls for a particular method, or consideration in how to handle DC connections within the FB methodology. In principle there are two possible ways to do this.

1. Reserve capacity on the AC connections (margin of the FB constraints) for the DC line exchanges: i.e. DC line exchanges receive a priority access to the AC grid (referred to as standard hybrid market coupling)
2. Compute PTDF factors at the nodes where the DC-cable is connected, making the sending and receiving end of the DC connection acting as two virtual bidding zones: DC line exchanges are directly linked to the margins of the FB constraints (referred to as advanced hybrid market coupling)

In both solutions, the DC lines are treated as CNTCs in the allocation mechanism. The main difference is linked to the question whether the impact of the DC exchanges on the RAMs are taken into account in the market clearing or is given ex ante priority by the TSO.

Example - Standard hybrid market coupling

FB capacity calculation and allocation is applied in the 4 Bidding Zones A, B, C, and D. Bidding zone D is interconnected with the other three bidding zones by means of DC interconnectors. Standard hybrid market coupling is applied.

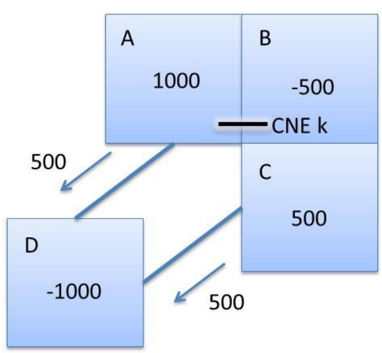


Figure 15 Four-area power system with standard hybrid coupling

- One area is DC connected
- *Three areas are AC connected*
- *The numbers refer to net positions and flows*

The overall net position is defined as the sum of the "Flow-Based net position" (resulting from the FB constraints) and the outgoing CNTC exchanges (on the DC lines):

$$Sell_A - Buy_A = NP_A = NP_A^{FB} + Exchange_{A>D}$$

$$Sell_B - Buy_B = NP_B = NP_B^{FB}$$

$$Sell_C - Buy_C = NP_C = NP_C^{FB} + Exchange_{C>D}$$

$$Sell_D - Buy_D = NP_D = NP_D^{FB} - Exchange_{A>D} - Exchange_{C>D}$$

Using the numbers in **Figure 15**:

$$Sell_A - Buy_A = 1000 = 500 + 500$$

$$Sell_B - Buy_B = -500 = -500$$

$$Sell_C - Buy_C = 500 = 0 + 500$$

$$Sell_D - Buy_D = -1000 = 0 - 500 - 500$$

The variables **NP^{FB}** have to satisfy the **FB constraints**, whereas the variables **Exchange** need to satisfy the **CNTC constraints**.

CNTC constraints:

Equation 32 $$-CNTC_{D>A} \leq Exchange_{A>D} \leq CNTC_{A>D}$$

Equation 33 $$-CNTC_{D>C} \leq Exchange_{C>D} \leq CNTC_{C>D}$$

FB constraints:

Equation 34 $$\boldsymbol{PTDF * NP^{FB} \leq RAM}$$

From Equation 34 we can clearly see that the CNTC exchanges over the DC lines do not have a link to the margins of the FB constraints.

The **PTDF** matrix and **NP^{FB}** vector are illustrated below.

PTDF =

A	B	C	D	
...	...	...	0	CNE k

$(NP^{FB})^T$ =

A	B	C	D
500	-500	0	0

Table 4 PTDF matrix and corresponding NP vector

Indeed, the example is rather extreme, as there is only a cross-zonal exchange possible for bidding zone D by means of the DC cables. As such, there is a "FB net position" of zero for bidding zone D.

Example - Advanced hybrid market coupling

FB capacity calculation and allocation is applied in the four Bidding Zones A, B, C, and D. Bidding zone D is interconnected with the other three bidding zones by means of DC interconnectors. Advanced hybrid market coupling is applied.

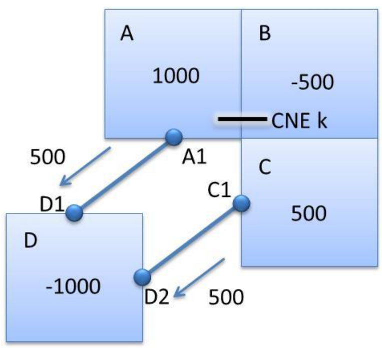


Figure 16 Four area power system with advanced hybrid coupling

- *One area is DC connected*
- *Three areas are AC connected*
- *The numbers refer to net positions and flows*

The sending and receiving end of each DC line is modelled as two virtual bidding zones (A1, C1, D1, and D2), with a net position that reflects the exchange over the line (with opposite sign). The virtual bidding zones are taken into account during the FB capacity calculation: they act as additional bidding zones in the PTDF matrix (i.e. as many columns are added to the PTDF matrix as there are virtual bidding zones).

The NPs of the virtual bidding zones are:

$$NP_{A1} = -\ Exchange_{A1>D1} = -500$$

$$NP_{D1} = Exchange_{A1>D1} = 500$$

$$NP_{C1} = -\ Exchange_{C1>D2} = -500$$

$$NP_{D2} = Exchange_{C1>D2} = 500$$

For the bidding zone NPs, it holds:

$$Sell_A - Buy_A = NP_A = 1000$$

$$Sell_B - Buy_B = NP_B = -500$$

$$Sell_C - Buy_C = NP_C = 500$$

$$Sell_D - Buy_D = NP_D = -1000$$

Being a hybrid market coupling, both FB constraints as well as CNTC constraints need to be respected.

CNTC constraints:

$$-CNTC_{D1>A1} \leq Exchange_{A1>D1} \leq CNTC_{A1>D1}$$
$$-CNTC_{D2>C1} \leq Exchange_{C1>D2} \leq CNTC_{C1>D2}$$

In addition, we need to connect the two ends of the DC by the constraints:

$NP_{A1} = - NP_{D1}$
$NP_{C1} = - NP_{D2}$

FB constraints:

PTDF * NP ≤ RAM

The PTDF matrix and NP vector are illustrated in **Table 5**.

PTDF =

A	A1	B	C	C1	D	D1	D2	
…	…	…	…	…	0	0	0	CNE k

NP^T =

A	A1	B	C	C1	D	D1	D2
1000	-500	-500	500	-500	-1000	500	500

Table 5 PTDF matrix and corresponding NP vector

Not only the effect of the bidding zones A, B, C, and D is taken into account when assessing the flows induced in the AC grid and the RAMs available, but also the impact of the virtual bidding zones A1, C1, D1, and D2. The treatment of DC connections embedded in an AC grid is further elaborated in Section **Feil! Fant ikke referansekilden.** below.

4.6.1 Requirements for the Nordic region

In the Nordic region, the DC lines have a major impact on the system. There are DC connections both to other synchronous areas but also within the synchronous area (SE3<->FI and the planned SE3<->SE4). Roughly speaking there is almost 13 000 MW HVDC capacity interconnecting the Nordic market system. With the same calculation there is almost 27 000 MW of AC market capacity between all the Nordic bidding zones. There's thereby a ratio of roughly 1:2 which is also why the DC connections need to be modeled as advanced hybrid.

As such, a simple approach like the standard hybrid market coupling (approach 1) will not suffice, and DC lines should be taken into account during the FB capacity calculation and allocation.

Applying the advanced hybrid coupling implies that the impact of DC interconnector exchanges on the AC grid is properly reflected and that the DC exchanges compete for the scarce capacity in the AC grid during allocation. This will lead to an optimal allocation and maximum economic welfare surplus. Annex 1 contains a list of existing and decided DC lines in the Nordic area.

There is a considerable amount of DC connections within the Nordic grid. Therefore, we plan to take on the second approach for DC lines, namely the advanced hybrid coupling, which is the optimal way of integrating DCs in the FB approach for the Nordics.

4.6.2 PTDF Calculations for DC lines inside one synchronous area

Figure 17 illustrates the PTDF calculation for a DC transmission line whose terminals are inside the same synchronous area. The PTDF is calculated by modelling an injection of power at the inverter terminal, which is absorbed at the rectifier terminal. The PTDF monitors the influence of the exchange on the DC to the CNE in the AC grid.

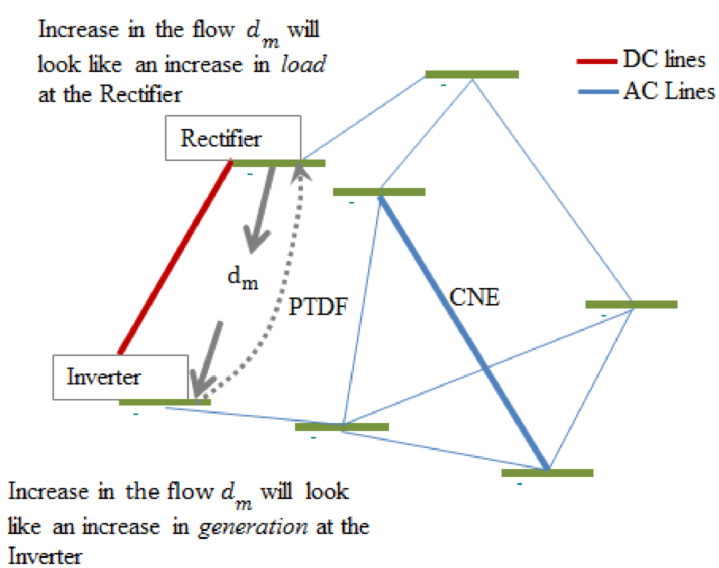


Figure 17 DC line embedded in an AC grid

The interpretation (of **Figure 17**) is that the rectifier "consumes" power from the AC grid and delivers this at the inverter, which than appears as a generator. The rectifier and the inverter are constrained to have the same value net position with opposite signs. The real power goes from the rectifier to the inverter, but to the FB system it will look like a flow going from the inverter (generator) to the rectifier (consumer) through the AC system. Thus the PTDF (the influence on the CNE), will be calculated from the inverter to the rectifier.

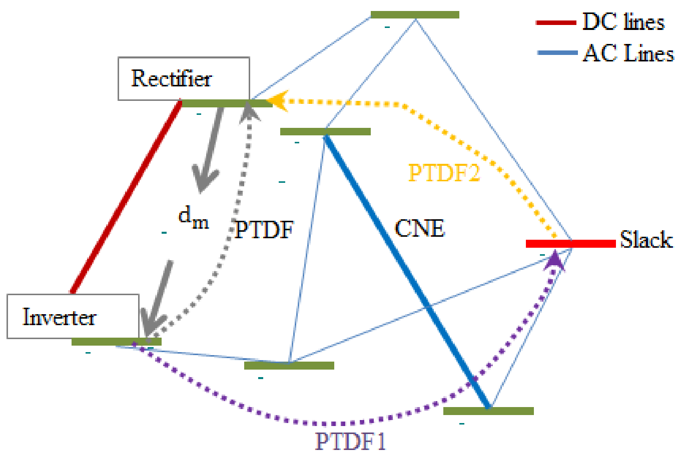


Figure 18 PTDF calculation with a DC line embedded in an AC grid

1. *Calculate PTDF1 as the transfer of power from the Inverter to Slack*
2. *Calculate PTDF2 as the transfer of power from the Slack to the Rectifier*
3. *Calculate PTDF = PTDF1 + PTDF2*

Another way to think of this is as two transfers: one from the inverter terminal to the slack bus, and a second from the slack bus to the rectifier bus. The combination of these two transfers is equivalent to transferring directly from the inverter to the rectifier. The illustration in Figure 18 may seem complicated, but is useful to help with the understanding of the PTDF calculation for the impact of DC transmission lines which span two synchronous areas as well.

4.6.3 PTDF Calculations for DC lines spanning two synchronous area

Figure 19 illustrates the PTDF calculation for a DC line whose terminals are inside different synchronous areas. The treatment of these DC lines is identical to the treatment of DC lines in one synchronous area, where the PTDF is computed from two transfers going through the slack bus for a DC line. The difference is that there will be different slack buses, one for each synchronous area as demonstrated in the image below.

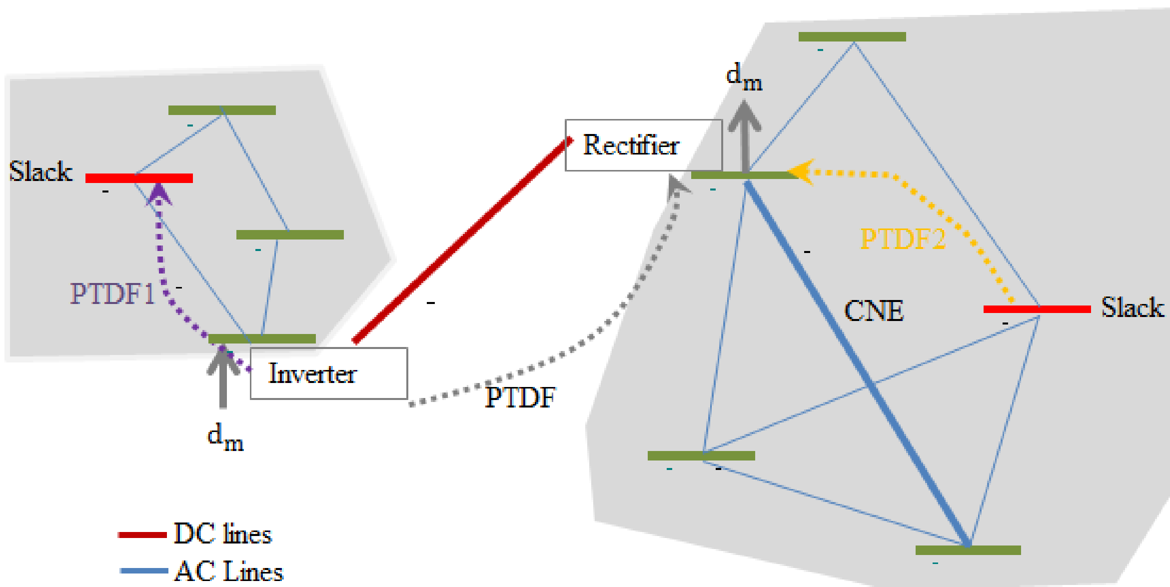


Figure 19 PTDF calculation with a DC line connecting two synchronous areas

1. *Calculate PTDF1 as the transfer of power from the Inverter to Slack*
2. *Calculate PTDF2 as the transfer of power from the Slack to the Rectifier*
3. *Calculate PTDF = PTDF1 + PTDF2*

PS! PTDF1 will be zero in this example as the CNE branch is in the other synchronous area

In the Nordic FB methodology, the PTDF factors are computed against a slack node; this also holds for the PTDF computation of the virtual bidding areas introduced by DC connections

4.7 Input data

In this Section the data necessary for calculating the FB parameters is discussed.

The FB parameter calculation, or capacity calculation, for day "D" will take place at day "D-1". The basic input data for this calculation is a Nordic Common Grid Model (or rather 24 Nordic grid models, one for each hour of the day), the constraints to be monitored (CNEs) and the GSK strategy. The grid models are discussed in Section 4.7.1, and the constraints in Section 4.7.2.

4.7.1 Grid Model

The Nordic Common Grid Model (N-CGM) is based on individual grid models (IGM) from each of the Nordic countries/TSOs. All the IGMs for the Nordic synchronous area are merged to form the N-CGM. The IGMs from the individual countries are also a requirement to build the European CGM (see Section 3), and all EU (and EEA) member states have to provide this information for the European CGM.

4.7.1.1 Grid representation

Each of the Nordic IGMs has a detailed description of the national grid, and a more coarse representation of the neighboring grids. In the N-CGM, we need the detailed view of the total Nordic grid in order to produce accurate FB parameters. We obtain this by retrieving and putting together the detailed view of the national grid from each IGM while removing the coarser parts. This procedure is referred to as "merging", and in the operational version of the FB system, we need a function/office to do the merging on a daily basis.

Each IGM are based on "snapshots[9]" (SN) of the real-live operation of the power system that are created by the national SCADA systems from each TSO. Each of the SNs may, or may not, be updated in line with expected topology-, load- and generation changes in order to represent the day of operation (day D) for each system in the form of an IGM.

In order to obtain a balanced N-CGM, it is important that the individual snapshots are retrieved at the exact same point in time. Ten minutes difference in any of the snapshots can cause differences in net positions and flows resulting in an unbalanced N-CGM. In a balanced N-CGM, it is a requirement that the sum of all net positions are exactly zero.

Each IGM contains information about grid topology (how the network elements are connected in the power system at a particular voltage level at a particular point in time) and the net positions of all the nodes in the system at the same point in time. This information is sufficient for doing an AC load flow in order to obtain the resulting flows on all network elements.

The merging procedure of the IGMs implies that all network elements have to be uniquely defined across the IGMs in order to be correctly recognized and represented in the merged N-CGM. The information contained in the snapshots together with the AC load flow calculation is sufficient to calculate the FB parameters.

4.7.1.2 Base case

The individual national snapshots to be used for day "D" are normally retrieved from an earlier complete day (e.g. "D-2", See Section 4.2.3)

In order to produce more accurate FB parameters however, we may need to update the individual snapshots to represent the most likely situation for day D (whenever better information is available and manageable). The merged "updated snapshots" is known as the base case, and the potential components for an update are:

- Planned outages
- Load forecasts

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[9] Snapshot = Output of the SCADA/EMS State estimator

- Production forecasts

The first component "planned outages" is vital information for the grid topology of day "D". Outage planning takes place ahead in time, so this information is normally known one week in advance of day "D" and is fairly easy to predict.

Load forecasting is done on a regular basis at each of the TSOs and should also be fairly easily retrieved. Accurate production forecasts are more difficult to retrieve, particularly in a system with large amounts of intermittent power like wind and photovoltaic. But the existence of intermittent generation itself signifies the importance of production forecasting. Large shifts in uncontrollable generation like wind and run-of-river hydro can occur quickly with changes in wind and weather conditions, and will have a significant influence on the geographical distribution of power generation.

4.7.2 FB Constraints

Large-scale power systems are normally run under what is referred to as the *N-1 criterion*[10]. The criterion states that the power system has to be able to stay within grid security limits after the loss of any one (1) component. To monitor that the system is *N-1* stable, the TSO uses a list of possible contingencies and monitors certain grid elements to see if they exceed a certain threshold. These monitored grid elements will be referred to as a *critical network element (CNE)* and the contingency, applied when monitoring the CNE, will be referred to as a *critical outage (CO)*.

The FB capacity calculation, as it is defined today, has been developed to monitor violations of steady-state limitations. There are a variety of such limitations but the main factor is the thermal capacity of a single component in the power system such as a line, circuit breaker, disconnector, current transformer and so on. Other examples of possible limitations are the min/max net position of an area in order to enforce enough reactive power capacity, frequency control capability, short circuit management or inertia. In the FB project so far we are only implementing thermal steady-state limitations. The other major part limiting a power system are the dynamic constraints, which comprise of frequency stability, voltage stability and rotor angle stability. These cannot be assessed by using the FB capacity calculation as such, but need to be taken into account in the FB capacity allocation.

The project has decided on the following approach for applying steady-state and dynamic limitations.

- Dynamic limitations: The TSOs will perform dynamic simulations in offline tools, and the limitations will be implemented as a maximum allowed flow on a cross-section of certain

10 N-1 def. according to ENTSO-E glossary: The rule according to which elements remaining in operation within TSO's Responsibility Area after a Contingency from the Contingency List must be capable of accommodating the new operational situation without violating Operational Security Limits. [NC OS]

transmission corridors (that consists of multiple CNEs). These flows will then be monitored in an N-system state/intact grid.

Example: The southbound power flow on the internal Swedish transmission corridors between SE1<->SE2, SE2<->SE3, SE3<->SE4 is most of the time restricted by voltage stability constraints. Since these can't be simulated in the FB capacity calculation, but need to be respected during the FB capacity allocation, Svenska Kraftnät will perform voltage stability simulations with certain contingencies in order to find the dimensioning fault for each transmission corridor. This dimensioning fault will give Svenska Kraftnät a preliminary maximum allowed flow southbound on the internal transmission corridors. This value will then be used for defining the maximum allowed sum of trade over the specific CNEs.

- Steady-state limitations: The TSOs will identify which CNEs, in combination with or without certain COs, are critical for system security. The CNE + CO combinations (CNECOs) will create multiple simulated N-1 system states and the CNEs are therefore monitored under N-1 system conditions.

Example: A normal contingency analysis is performed by TSOs selecting different possible N-1 contingencies. During simulations the TSO will then identify which components in the power system that will be stressed to their thermal limitation after the specified contingency. These pairs of stressed components and specific contingencies will then be used as CNECOs.

For many contingencies the TSOs use a specific and individual set of actions if and when a contingency occurs. These actions can be a change in network topology, redistribution of active power generation/loading and so on, and are used to increase the domain of *security of supply (SoS).* These actions may be more efficient, from an economic point of view, than large physical investments in the power system. The specific actions taken after a specific contingency will hereafter be referred to as a *remedial action (RA)*.

4.8 Future developments

In the current state of the FB algorithm development we have been able to implement both steady-state (thermal N-1 limitations) and "pseudo-dynamic" (cut limitations) CNE constraints. The next step will be to implement RAs as well as COs that cause a change in the active power balance of the system (e.g. outages of generation units).

Indeed, in its current form, the FB algorithm can only simulate changes in grid topology and no changes in the active power balance itself. This needs to be implemented as well, as some of the major dimensioning faults in the Nordic system are generation outages (a trip of a nuclear unit for example). The possibility to implement RAs involving tripping of load and/or generation is also needed.

4.8.1 Limitations on the FB approach

This Section gives a brief overview on what the constraints on the market domain are derived from.

Certain restrictions are necessary to maintain a stable operation under the N-1 criteria. These constraints can be divided into physical and market constraints.

4.8.1.1 Market limitations, NC CACM

The restrictions that are enforced on the market today in the Northern European power system are mainly on HVDC interconnections:

- A maximum change of +/- 600 MWh/h from hour to hour

The restrictions are enforced since HVDC interconnection have a much greater ramping capability than other ordinary production and load. If these ramp rates were not enforced, the system would (with a high probability) use much of its frequency reserves to only balance these changes, thus putting the system at a higher stress level. These market restriction have a physical background.

It is also possible to restrict the market capacity due to economic reasons: *Constraints intended to increase Economic Surplus for the single day ahead or intraday coupling* [NC CACM art. 27 (3) b)].

4.8.1.1.1 Change of net position (from hour to hour)

In the Nordic system there are no ramping constraints currently applied on the trading plans in the synchronous area, i.e. there does not exist any constraint on changes in net position. Such limitations are however possible to implement in Euphemia. There is however a possibility to limit the trading capacity from one hour to the next which is defined as *scaling*.

Nordic System Operation Agreement (SOA) 2013:

- **Scaling** means restricting changes in the AC and DC *trading capacity* (NTC) between two *bidding areas* from one hour to the next. This change may be a maximum of 600 MW from one hour to the next, unless otherwise agreed.
- SOA Appendix 8 of System Operation Agreement: "4 Step by step of the trading capacity"

The Nordic system operations agreement thereby introduces a possibility to limit the trading capacity from one hour to the next. This scaling is usually used during large shifts in transfer capacity during planned outages and is set by the TSOs' during the agreement of the capacities of day D during D-1.

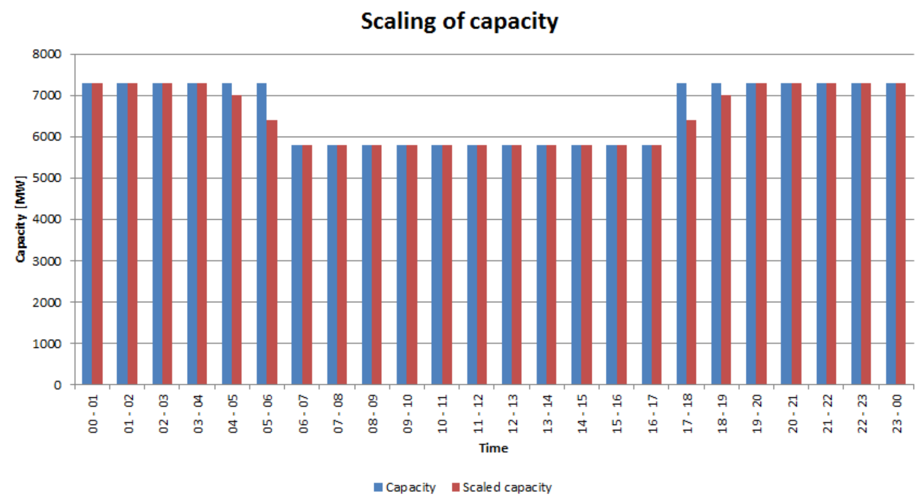

Figure 20 Example of scaling of capacity when the system goes from an outage state to a non-outage state

4.8.1.1.2 Ramping of DC cables

In the Nordic system there is currently a ramping constraint on trading plans and actuation of trading plans for 600MWh/h and 30MW/min. These are defined in the Nordic SOA 2013 as

- **Ramping** means restricting changes in DC *Elspot trading* on one or more cross-border links individually and together from one hour to the next. Also *see scaling.*
- SOA Appendix 8 of System Operation Agreement - **5 Ramping of trading plans on HVDC connections**

Major changes to the *trading plans* on the HVDC connections from the Nordic *synchronous area* can result in major changes in power flows at the change of hours. These major changes can be difficult to manage in *balance regulation*. Thus, constraints are placed on the magnitude of changes to the *trading plans* from one hour to the next. This change may be a maximum of 600 MW from one hour to the next on each of the following connections: NorNed, Estlink, Skagerrak, Konti-Skan, Kontek, Stora Bält, Baltic Cable and SwePol Link.

For Skagerrak and Konti-Skan, the total changes to the *trading plans* on the two connections may be a maximum of 600 MW from one hour to the next.

These ramping constraints are enforced by Nordpool Spot in their algorithm during the market allocation process.

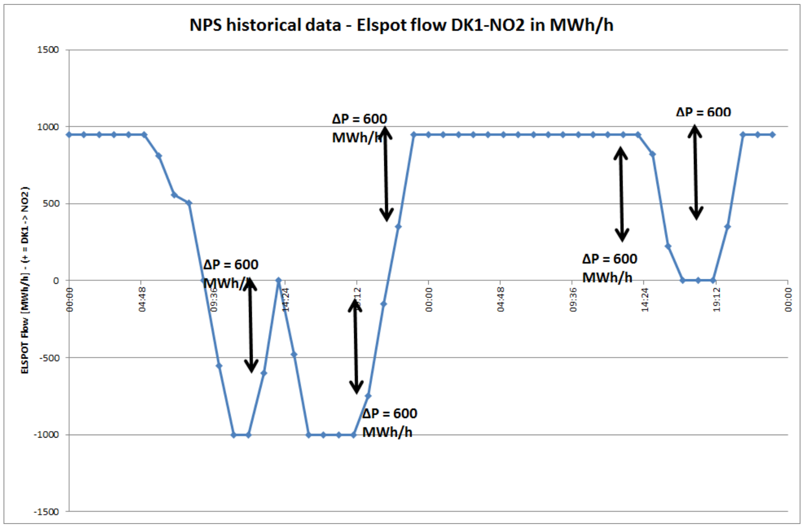

Figure 21 Example of a ramping constraint being activated to limit hourly change of the trade over an HVDC connection

4.8.2 Flow Reliability Margin

The fundamental element in managing uncertainty in capacity calculation is the reliability margin (Flow Reliability Margin, FRM). Due to uncertainties, the power system operator cannot predict precisely what flow, either active or reactive, will be realized on each CNE. The flow may be larger or smaller than anticipated, but if the flow turns out larger, there may be an overload on a CNE. In order to reduce the probability of physical overloads, some of the capacity on a CNE will be retained from the market as an FRM.

In the Article 2 of the CACM grid code the following definition is given:

> *"Reliability Margin means the necessary margin reserved on the permissible loading of a Critical Network Element or Cross Zonal Capacity to cover uncertainties of power flows in the period between the capacity calculation and real time, taking into account the availability of Remedial Actions".*

The FRM is based on historical registration of the difference between the power flow of a CNE forecasted two days ahead of time and the actual flow. The FRM, being expressed in MWs, will be different for each CNE but could be based on the same percentile of the statistical distribution of the difference between forecasted and actual power flow.

The origin of the uncertainty involved in the capacity calculation process for the day-ahead market comes from phenomena like approximations within the FB and CNTC methodology (e.g. GSK and capacity used by reactive power). This uncertainty must be quantified and discounted for in the allocation process, in order to prevent that on day D the TSOs will be confronted with flows that exceed the maximum allowed flows of their grid elements. Therefore, for each CNE, a Flow Reliability Margin (FRM) has to be defined, that quantifies at least how the before-mentioned uncertainty impacts the flow on the CNE. Inevitably, the FRM reduces the remaining available margin (RAM) on the CNEs because a part of this free space that is provided to the market to facilitate cross-border trading must be reserved to cope with these uncertainties. The approach for determining the FRM value is illustrated in **Figure 22**[11].

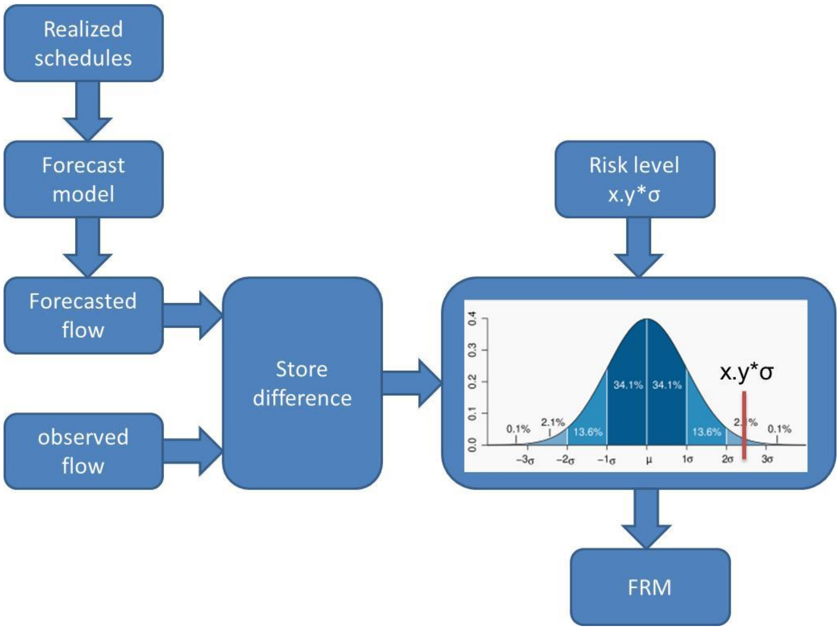

Figure 22 Determination of the FRM

The basic idea behind the FRM determination is to quantify the uncertainty, by comparing the forecasted flow of the FB model with the observed flow of the corresponding timestamp in real time. More precisely, the calculated PTDFs for day D are used to calculate the flows in the real day D market result. These flows are then compared to the flows in the snap shot of day D.

In order to compare the observed flows from the snapshot with the predicted flows in a coherent way, the FB model is adjusted with the realized schedules corresponding to the instant of time that the snapshot was created. In this way, the same net positions are taken into account when comparing the forecast flows with the observed ones (e.g. Intraday trade is reflected in the observed flows and need to be reflected in the predicted flows as well for fair comparison).

The differences between the observations and predictions are stored in order to build up a database that allows the TSOs to make a statistical analysis on a significant amount of data. Based on a predefined risk level, the FRM values can be computed from the distribution of flow differences between forecast and observation.

By following this approach, the subsequent effects are covered by the FRM analysis:

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[11] Based on CWE approval document: http://www.casc.eu/media/CWE%20FB%20Publications/Approval%20Documents/130801%20CWE%20Flow%20Based%20MC%20solution%20Approval%20document.pdf

- Unintentional flow deviations due to operation of load-frequency controls
- Internal trade in each bidding area (i.e. working point of the linear model)
- Uncertainty in Load and generation forecasts
- Assumptions inherent in the Generation Shift Key (GSK)
- Application of a linear grid model, constant voltage profile and reactive power

The structure of the FRM analysis is shown in **Figure 23**.

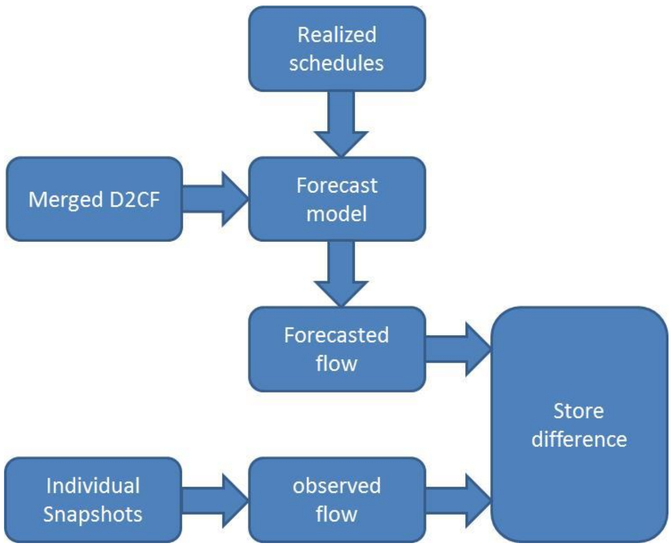


Figure 23 Structure of the FRM calculation

In the Nordic FB methodology, the FRM will be calculated based on the same method for the statistical distribution of the difference between forecasted and estimated power flow including contingencies.

4.9 FRM for N-1 cases

As CNEs are monitored both under N conditions and N-1 conditions, the question arises whether the FRM value assessed under N conditions is representative for N-1 conditions as well. In case N-1 FRM values need to be assessed, the structure depicted above needs to be changed slightly as indicated in Figure 24.

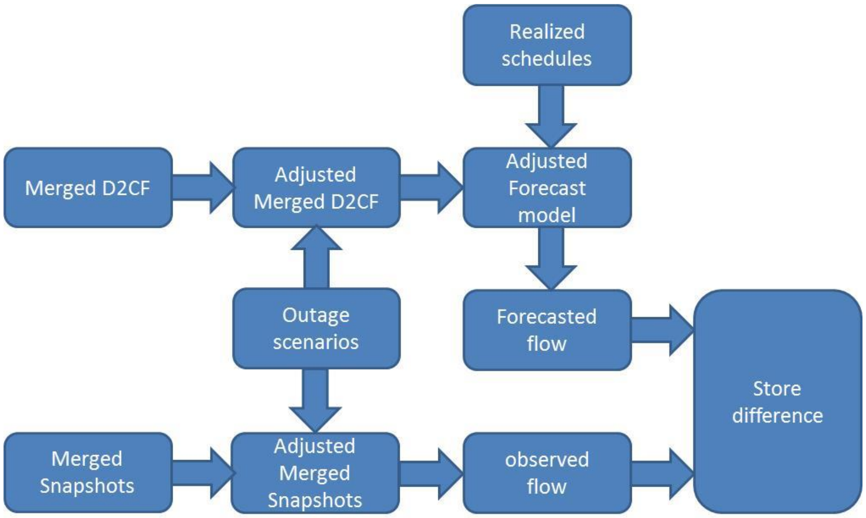


Figure 24 Structure of the FRM calculation under N-1 conditions

Indeed, where the assessment of the N FRM values is based on a comparison between realized flows and the predicted flows, i.e. observation versus simulation, the N-1 FRM analysis boils down to a comparison between two simulations.

4.9.1 Pre-allocated capacity

In the draft Network Code on Forward Capacity Allocation (1 October 2013) it states:

"Each Transmission System Operator shall issue Long Term Transmission Rights unless National Regulatory Authorities competent on the relevant Bidding Zone Border(s) have issued a decision that the Transmission System Operators shall not issue Long Term Transmission Rights."

And,

"Long Term Cross Zonal Capacity shall be allocated to Market Participants by the Allocation Platforms in the form of Physical Transmission Rights pursuant to the Use-it-or-sell- it (UIOSI) principle or in the form of Financial Transmission Rights."

This may imply that Physical Transmission Rights (PTRs) or Financial Transmission Rights (FTRs) need to be implemented on several borders besides the Danish/German border in the Nordic region in the nearby future. FTRs are of no consequence for the physical flows, but PTRs are interlinked to the DA capacity calculation stage from a physical point of view. Indeed, with a PTR being a right whose holder is entitled to physically transfer a certain volume of electricity in a certain period of time between two Bidding Zones in a specific direction, a part of the capacity can be nominated before the DA allocation. This is referred to as pre-allocated capacity.

There is no pre-allocated capacity in the Nordic system as of today. However, if introduced, pre-allocated capacity will be represented in the base case as production and consumption which is influencing the net positions in the base case. As this contributes to the base case flows, pre-allocated capacity will indirectly influence the RAM by shifting the Fref'. However, due to the GSKs, the shift in Fref' will not necessarily be directly linked to the real physical pre-allocated capacity. If nominated (in case of PTR), pre-allocated capacity cannot be provided to, and allocated by, the day ahead market.

However, as the pre-allocated capacity already is shifting the Fref' in the base case, removing all of it from the RAM will overestimate the level of pre-allocated capacity to remove from the market. The way of dealing with pre allocated capacity is to move the point of origo on the X-axis to the right to calculate a new Fref' taking pre-allocated capacity (PAC in **Figure 25**) into consideration.

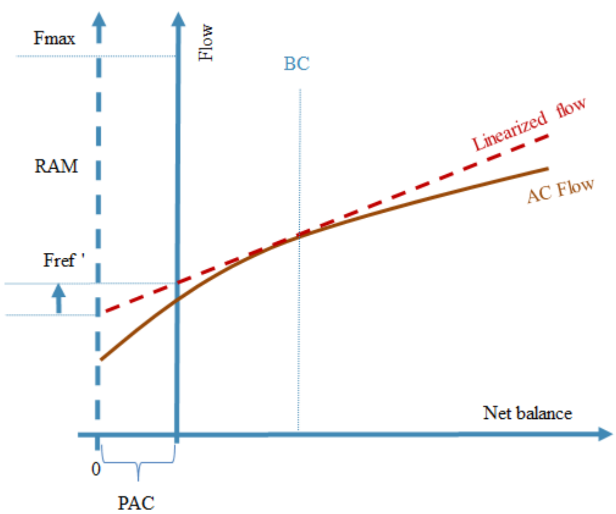


Figure 25 Removal of pre-allocated capacity (PAC) from the RAM

4.9.2 Operational experience and remedial actions

The term FAV stands for Final Adjustment Value. With the Final Adjustment Value (FAV), operational skills and experience that cannot formally be calculated in the FB system can find a way into the FB approach by increasing or decreasing the RAM on a CNE (see Section 4.3).

RAM = Fmax – Fref’ – FRM - FAV

All the other elements, Fmax, Fref’, and FRM, are the result of computations. As such, if the FAV was not included in the right-hand side of the RAM equation, the RAM would have been the direct result of a computation. If from an operational perspective, despite the computational result, a reduction of the RAM would have been needed or an increase of the RAM would have been possible, a rather intransparent process of RAM values would result. Indeed, the main part of the values would result from computations whereas a part of the results would have been manually adjusted.

The FAV has been introduced to allow a manual adjustment of the RAM, but in a transparent way. The default value of the FAV is zero; it may be decided that any deviation from zero requires a short negotiation among the TSOs. National Regulators may require that FAV usage is reported on a regular basis.

As such, a negative FAV reflects the effect of an additional margin on a CNE due to e.g. complex RAs which cannot be modelled and taken into account in the FB parameter calculation. A positive FAV reduces the margin on a CNE, if e.g. operational expertise or additional grid security computations indicate that the original RAM on a CNE is too high and might endanger the grid integrity.

4.10 Local analysis at the TSO

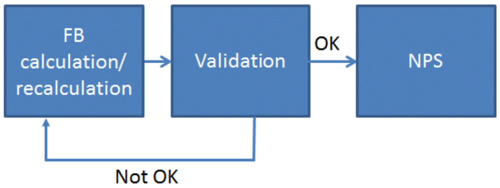
The PTDFs and the RAMs are calculated and reported in the form of a matrix, the PTDF-matrix. In the Nordic case, the PTDF-matrix will have 26 columns (real and virtual areas) and 100'ths of rows (constraining CNEs) for each hour of the day, depending on how many of the original CNEs that are actually constraining. This is an extensive amount of data provided in an unfamiliar way for the operators. Interpreting and understanding the PTDF-matrix is necessary in order to confirm the validity of the calculated domain.

4.10.1 Validation of FB results

The PTDF matrix itself expresses the full amount of possible market solutions which is within the security limits defined by the TSOs (the market/security domain). From a purely mathematical point of view, the domain can be expressed in terms of a volume. This number itself however, is hard to interpret and may change significantly from day to day. The domain may also be expressed in terms of possible flows and/or net-balances. Those numbers may also be difficult to relate to, as all variables (flows and net-balances) are interlinked to one another. For example, it is not possible to express a unique (possible) flow on any single CNE, independent on the value of all other variables that are defining the domain.

This is a challenge because, in order to verify the outcome of the PTDF calculation, the operators need familiar information in order to recognize potential errors and difficulties if and when they occur within the PTDF-matrix. The operators need a simple method to validate the results of the FB calculation and to check the parameters before releasing the capacity/domain to the market. If potential errors or other difficulties are discovered, TSOs need to correct this before the PTDF-matrices are released. The validation process is illustrated in **Figure 26**.

Figure 26 The validation process for the FB parameters



4.10.2 Possible quality and sanity checks

There are many potential ways of retrieving information from the PTDF-matrices. Some of which are quite obvious, some are rather comparable to the CNTC information, and some information that is unfamiliar in the current practice in the operating environment. The obvious ones are easy to calculate and to visualize, and should be rather straight forward for the operators to deal with. The ones that resemble CNTC information are somewhat more tricky to relate to, as the interpretation is a bit different than under CNTC. The last type is the kind of information bearing little resemblance to anything we use today.

Potential information that can be retrieved from the PTDF-matrices to be used for verification of the domain:

- All PTDFs between -1 and 1
- No rows or columns with only zeroes
- Minimum and maximum values of PTDFs to be monitored over time (detection of outliers)
- Max zone-to-zone PTDF sensitivity for all CNEs
- Examples from FB results in different flow and production situations/market outcomes
- Possible min/max NPs for all areas
- Possible min/max bilateral exchange between two areas (assuming all other exchanges to equal zero)
- Aggregated flow on all tie lines of each bidding zone should add to the net position
- CNTCs extracted from the FB domain to be compared with historical values
- Angles of vertices
- Sum of PTDFs per row
- Starting from the base case, how close are we to the borders of the FB domain
  - For each CNE (sorted top 10)
  - For each pair of areas

4.10.3 ACLF analyses to circumvent the DCLF approximations (reactive power and voltage)

The active power capacity, Fmax, of a transmission line is calculated by:

Equation 35 $Fmax = \sqrt{3}\, x\ operating\ voltage\ x\ thermal\ current\ limit\ x\ cos\varphi$

φ = The ratio between active and reactive power.

As discussed in 4.1 the FB algorithm will disregard reactive power flow and assume constant operating voltages. Usually, the error introduced by the reactive power can be neglected. If for instance the reactive power constitutes 20% of the active power this may cause Fmax to be overestimated by 2% (=1-cos(atan(0.2)).

Typically, operating voltage vary 5-10 per cent and due to the linear relation this factor will cause an error of 5-10% on Fmax. The uncertainty in the Fmax calculation can corrected for in the FRM analysis.

5. Market coupling

The market coupling phase takes place at the power exchange (PX) after the transmission capacities have been provided by the TSOs. The first part of the market coupling process is the publication of these capacities to the market. After publication, bids are gathered from the market players, as of today, and fed into the market clearing algorithm. After the gate closure time, no more bids are accepted and the market solution is calculated. The resulting prices and net positions will be published to the market.

The market coupling process remains the same for a FB as for an CNTC-based market. The only difference is the grid information provided to the PX and the market players by the TSOs. The objective function in the market clearing algorithm remains unchanged.

The financial markets are based on the system price and on area prices. As this information remains available in a FB market, the financial market will function as of today.

6. Post-market coupling

The market coupling at the PX determines which consumption and production bids are accepted and rejected in each area. For special kinds of bids the timing is also decided. As a consequence the planned net position in each area is uniquely determined for each time period, and is always within the limits set by the TSOs. The PX also provides a single price for each bidding area.

In addition to the prices and net positions, the PX also provides a set of scheduled power flows between the bidding areas and distributes the congestion rent among the Nordic TSOs. After the closure of the day-ahead market, the TSOs provide CNTCs for the intra-day market. All these processes are important for the power market, and they will be impacted when FBMC is implemented in the day-ahead market. These topics are further described below.

6.1 Flow determination

In addition to providing prices and net positions, the PX also provides a set of scheduled flows between the bidding areas; these schedules are used by the TSOs as a starting point when deciding on the planned flow on the HVDC interconnectors.

The scheduled flows are not uniquely determined by the area net positions. To select a single set of scheduled CNTC flows, the PX employs a post-process to the market coupling. Each tie-line is given a cost-coefficient by the TSOs, and a set of flows is found that minimizes the sum of flow multiplied by cost-coefficient on all lines. The cost coefficients have been set to minimize losses and to maximize the security of supply. Exchange of balancing services may also be considered.

6.2 Congestion income allocation

In cases of scarce capacity, and price divergence between connected bidding areas there is a difference between the amount paid by the consumers and the amount paid to the producers at the PX. This difference is called congestion rent and occurs both in CNTC and FB. The CR is due to scarce transmission capacity – i.e. when market parties would like to exchange more power between bidding areas than is feasible. This remaining monetary sum is divided among the owners of the transmission infrastructure.

Under FB the differences in power prices between neighboring bidding areas are the result of all binding CNEs in the entire FB area, while under CNTC a price difference only occurs at the constraining tie lines. This difference in interpretation of price differences may necessitate a different division of congestion rent between the infrastructure owners if FBMC is implemented.

In theory, the total congestion rent for the market area may be calculated from the output of the PX as either (1) the sum of flow on all tie-lines times the price difference between the connected bidding areas or (2) as the sum of flow on all critical network elements (CNEs) times the shadow price of the CNEs. The shadow price on the CNEs is an output from the market coupling at the PX and represents the marginal cost of a binding constraint in the market outcome.

Under CNTC market coupling the two interpretations above are exactly the same, as price difference between bidding areas equals the shadow prices, and the tie-lines are equal to the CNEs. Under FBMC the tie-lines will be different from the CNEs, and although the two interpretations yield the same total, the geographic source of the CR will be different. This may necessitate a different division of CR between the infrastructure owners.

6.3 Compatibility to the ID timeframe

The Nordic intraday market is currently based on CNTCs, and will probably remain so in the early stages after the possible implementation of FBMC in the Nordic region. In the current implementation, the intraday market receives the remaining CNTC after the market coupling ('left-over' capacity), although the TSOs retain the ability to modify the CNTCs. As both the day-ahead (DA) market and the intraday market are based on CNTC, the remaining capacity can be transferred directly.

If FBMC is implemented in the DA market only, there will be a need to calculate valid CNTCs for the ID market. An obvious approach would be to calculate these based on the FB parameters and the accepted bids at the PX – in effect, provide a set of CNTCs that complies with the limits of the FB parameters, referenced to the net positions in the DA market.

As multiple sets of CNTCs may be possible. We need to create a method that extracts a single intraday CNTC domain from the day ahead FB domain. The structure of this method will be developed at a later stage.

7. Publication of day-ahead capacity for the market participants

The capacity available for day-ahead cross-border trade needs to be published to the market participants ahead of the Market Coupling so that the market participants are able to anticipate scarcity, to predict prices, and to provide their bids to the PX.

For years now, market participants receive CNTC values. Those values are embedded in the trading systems, and have set a certain reference… not only in terms of values, but also in terms of interpretation.

When instead of the CNTC domain, the FB domain is applied by the TSOs to confine the market outcome in order to safeguard the grid security, the FB parameters need to be published to the market. As described in Section 4.3.3, only the non-redundant constraints will be published to the market and to the PX.

Besides the FB constraints only, it may be needed to provide the market with additional information. One can think of indicators that are extracted from the FB domain, like the minimum and maximum net positions per bidding zone, and the maximum exchanges feasible within the FB domain (see also Section 4.3.1). In addition, the development of those indicators over the day may provide useful insights. The CWE utility tool (http://www.casc.eu/en/Resource-center/CWE-Flow-Based-MC/Publication-CWE-Flow-based-External-parallel-run) may serve as a template/example for this.

Indeed, the provision of useful information to the market, and more specifically the determination of what is useful or even indispensable information, is an exercise that needs to be taken up together with the market participants (this was also requested for during the Norwegian FB seminar with market participants (December 2013)). The outcome of this collaboration, being a market tool, should have materialized before a potential start of an external parallel run so that it can be thoroughly tested and experimented with.

ANNEXES

Annex 1 List of existing and future (decided) DC lines

Border	Station_1	Station_2	MW	Name
DK1-NO2	150 kV Tjele	300 kV Kr.sand	250	Skagerrak 1
DK1-NO2	150 kV Tjele	300 kV Kr.sand	250	Skagerrak 2
DK1-NO2	400 kV Tjele	300 kV Kr.sand	500	Skagerrak 3
DK1-NO2	400 kV Tjele	400 kV Kr.sand	700	Skagerrak 4 (2014)
DK1-SE3	400 kV Vr. Hassing	400 kV Lindome	340	Konti-Skan 1
DK1-SE3	400 kV Vr. Hassing	132 kV Lindome	340	Konti-Skan 2
DK2-DE	400 kV Bjæverskov	380 kV Bentwisch	600	Kontek
FI-EE	Espoo	Harku	350	Estlink 1
FI-EE	Anttila	Püssi	650*)	Estlink 2 (2014)
FI-SE3	Rauma	Dannebo	500	Fenno-Skan 1
FI-SE3	Rauma	Finnböle	800	Fenno-Skan 2
NO2-NL	Feda	Eemshaven	700	NorNed
SE3-LT	Nybro	Klaipeda	700	NordBalt (2016)
SE3-SE4	Barkeryd	Hurva	1400	SydVästlänken (2015)
SE4-DE	Arrie	Herrenwyk	600	Baltic Cable
SE4-PL	Karlshamn	Slupsk	600	SwePol Link

PLEASE CHECK LIST AND CAPACITIES

*) The capacity of Estlink 2 is only 510 MW from Finland to Estonia and 660 MW from Estonia to Finland.

The capacity of Vyborg back to back station to Finland is 900 MW. In March 2014 is planned to start the transmission to Russia, Capacity is 350 MW.