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Alternative schemes for exchange of balancing resources between separate synchronous systems in Northern Europe

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Alternative schemes for exchange of balancing resources between separate synchronous systems in Northern Europe

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RESULT (summary)

The development and growing integration of power markets and the rapid expansion of new renewable energy sources (RES) with less predictable output, will increase the need for balancing services in the near future. This is the background for the Competence Building (KMB) project "Balance Management". This report discusses the special aspects related to exchange of balancing resources between the *separate synchronous systems* in Northern Europe. The discussion refers to the key principles published by the European Regulators' Group ERGEG, and to the recently reported experiences from the exchange scheme between UK and France.

The most important differences from exchange between control areas within *one synchronous system* are related to the separation of the two systems by HVDC links and the fact that the exchange will affect the frequency in two systems.

The Nordic region acts as one control area with a common merit order list for balancing resources. This means that only congestions in the grid should cause deviation from the merit order in normal operation, and in principle could all HVDC links to the Northern Central European (NCE) system be utilized for balancing resources in parallel. The ongoing merging of control areas in NCE, initiated by Germany, indicates a potential future exchange of balancing resources between the common Nordic and a common NCE merit order lists. The benefit from the conflation of the originally 4 control areas in Germany is estimated to about 260 million EUR per year in total. This counts for large potential benefits from further integration.

The exchange of balancing resources between control areas is limited by the reserves needed for security of supply and to the forecast error related to consumption and wind in the respective area. The expected increase in wind production will affect the operational routines with regard to defining the need for local reserves. Forecasts on daily basis will most likely be needed.

The efficiency of utilizing different balancing control objects related to network losses and geographical location is not systematically considered by the Transmission System Operators (TSOs) today. Load flow calculations show that the difference from using a generator behind a congested corridor and alternatively a reducible load in a load centre could be up to 40 %. The share of control objects from industrial and/or residential consumption will most probably increase, which counts for control object efficiency assessments in real time operation.

6 different exchange schemes for exchange via HVDC connections are presented in this report, one related to imbalance netting, one between the TSO and a Balance Service Provider (BSP) in the opposite system and 4 alternative trading models where the TSOs on each side are mediators.

The TSO-TSO alternatives seem to represent the most cost efficient schemes with regard to the social economics. The TSO- BSP alternative does, however, provide economic incentives to central market players, which might be decisive for the development of future exchange corridors and schemes.

Two comprehensive models have been developed as a part of the PhD work in this project. The models are utilized in analyses of future exchange of balancing resources and integration of balancing markets in Northern Europe in this report.

KEYWORDS

SELECTED BY AUTHOR(S)		
	Balance Management	Exchange schemes
	HVDC links	Power system optimisation

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TERMS AND ABBREVIATIONS

ACE	Area Control Error
AGC	Automatic Generation Control
BRP	Balance Responsible Party
BSP / BP	Balance Service Provider / Balance Provider
EMPS	Multi area Power Market Simulator
ENTSO-E	European Network of Transmission System Operators for Electricity
ERGEG	European Regulators’ Group for Electricity and Gas
ETSO	Former association of European TSOs
HVDC links	High Voltage Direct Current links
ISO	Independent System Operator
LFC	Load Frequency control (in this context on national level)
MOL	Merit Order List
SCR	Secondary control Reserves
SvK	Svenska Kraftnät
TCR	Tertiary Control Reserves
TSO	Transmission System Operator

1 INTRODUCTION

The present report is one of the two final reports in the project "Balancing Management in Multi-national Power Markets" (2007-2011). This report has a more practical and operational view, while the other report "Balancing Market Design" [34] is addressing principle and conceptual issues related to potential future market design.

The objective of this report is to introduce and discuss different models for exchange of balancing services between the control regions/areas in Northern Europe. Optimisation of the trading potential via the HVDC connections between the separate synchronous systems is a key aspect in this context.

The solutions presented are based on the more principle approach to balancing market design and integration [2] and ideas and analysis from the first part of the "Balance Management"-project [1], [3].

The ongoing process towards an integrated market structure in Europe is the reference for the basic conceptual thinking in this report. The work presented in documents from ERGEG [4] and ETSO[1] [5] and information about the integration of control areas in Germany [7] - [21] are significant sources.

A summary of the present exchange of balancing resources and the plans for further development of the exchange scheme between France and UK [6] is included as an example of trading solution between separate synchronous systems.

So far, much of the discussion has been related to the exchange of balancing services over separate links, e.g. NorNed. The main assumption in this report is that the Nordic balancing resources can best be exploited by having access to all of the HVDC connections simultaneously in the market clearing. This will reduce the hours of limited capacity available for the balancing services as shown in [3]. The main obstacle to this approach is the fact that the Central European system is based on area control schemes of which there are 8 in the Northern part. Potential benefits and paths towards a common "Central European North" control area are discussed on the basis of the present merging efforts in Germany.

Further is development/improvement of the balancing market discussed. One aspect is how to make an optimal choice of regulation objects in a system where there is no ACE[2] control and the only technical restrictions are bottlenecks and minimisation of network losses. A solution where loss factors and sensitivities related to congested lines is combined with the bidding information from the balance service provider is presented.

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[1] Included in ENTSO-E from July 2009
[2] ACE = Area Control Error

Finally are 6 alternative trading schemes discussed. The schemes relates to the basic models discussed in the parallel report "Balancing Market Design" [2]. These include exchange of both manual and automatic secondary control (LFC/AGC)[3].

[3] LFC = Load Frequency Control, AGC= Automatic Generation Control

2 BACKGROUND

The present control structure in Northern Europe was presented in the first report from this project [1]. The Nordic synchronous system acts as one control area, which means that the frequency- and time- deviation are the main control criteria. The main message in this context is that the Nordic synchronous system has managed to establish a common merit order list of regulation power. This implies that the previous control areas, which mainly were divided by the respective country borders, are removed. The activation of the regulation objects is performed by the respective TSOs: Statnett SF, Norway, Svenska Kraftnät (SvK), Sweden, Fingrid, Finland and Energinet.dk, Denmark. Statnett and SvK have the main responsibility for maintaining the frequency and time deviation. Fingrid and Energinet.dk (for Denmark East) will normally only activate reserves after contacting SvK.

In the Northern part of the Central European (CE) system there are 8 control areas: The Netherlands, Belgium, 4 in Germany, Poland and Western Denmark. The control area structure in the Central European system has many good objectives and might be a necessary concept to control this huge system. The fact that the borders for these control areas are the same as the national borders or the different TSOs control zones, is however, not necessarily optimal. In any case a division in control areas might create unnecessary control actions compared to the optimal system operation, as discussed in chapter 4 and 5.

The figure below shows the different control areas and the dotted line indicates the separation between the separate synchronous systems. The yellow colour of the 8 CE North areas indicates the future potentially merged control area which might be realized in the near future.

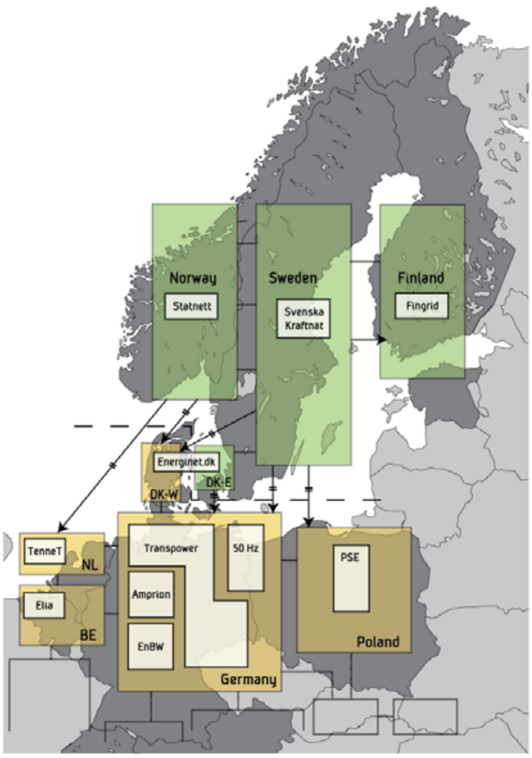

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Figure 2-1: Control areas Northern Europe

2.1 Key principles for Balance Market integration

The European Regulators' Group for Electricity and Gas, ERGEG, has published Guidelines of Good Practice on Electricity Balancing Markets Integration (GGP-EBMI). The ERGEG document of September 09 [4] is the main source for defining the precondition for future cross border balancing. The national regulators will of course have a central role in the development of and the governance of the future market rules.

2.1.1 Security of supply

The TSOs are responsible to ensure system security within their control area. Cross-border balancing shall not jeopardise system security.

2.1.2 Market based Mechanisms

The purpose of the balancing markets is to secure balance between supply and demand of the system in short term in an economically-efficient manner. Hence, balancing markets shall operate in a market-oriented way.

For reasons of overall efficiency, the selection of bids shall be based on the merit order of the balancing offers as well as network constraints. Any deviation from the merit order shall only be accepted when it is necessary to maintain system security.

2.1.3 Effective Competition

A well-functioning balancing market shall be robust to any exercise of market power.

2.1.4 Impact of Cross-Border Trade

Cross-border balancing shall not lead to withdrawal of interconnection capacity from the market players and neither shall it limit opportunities for cross-border trade.

Comment: *In special case where HVDC capacity is reserved for cross-border balancing, procurement of reserve capacity shall be subject of evaluation of the TSOs, in accordance with criteria defined by ENTSO-E and approved by regulators in a transparent way.*

2.1.5 Compatibility of balancing mechanisms

The balancing services mechanism should be compatible with both markets and retain a fundamental level of compatibility with the evolving harmonisation of the European balancing markets.

2.1.6 Trading parties

Background: ETSO has defined two alternative models for trading of balancing resources:
Conceptual model 1: Direct operational and commercial relationship between service providers and the TSO in the neighbouring control areas.

Conceptual model 2: Direct commercial relationship between the TSOs in the connected control areas. The TSOs would, effectively, act as agents to indicate the balancing services that may be offered to the connected TSO.

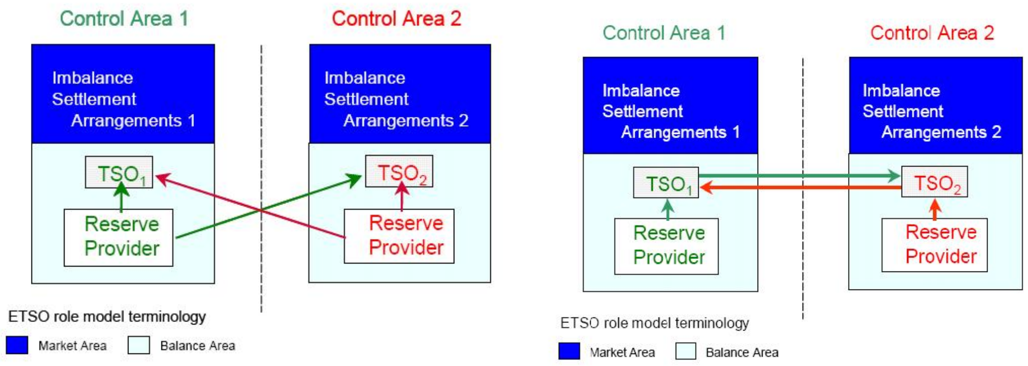

Figure 2-2: Reserve Provider[4]-TSO and TSO-TSO tertiary reserve trading models (ETSO 2005)

ERGEG states that:
Towards integrating balancing markets, the TSO-TSO model (conceptual model 2) with common merit order list is the target model to exchange manually activated balancing reserves.

In the special case of HVDC interconnectors and when capacity is reserved, the TSO-Provider approach might be accepted if it is proven that transparency and security of supply and non-discrimination between national and foreign market participants are ensured.

[4] In this report also denoted as Balance Service Provider (BSP)

2.2 The France-UK-Ireland initiative (example)

The proposed scheme for exchange of balancing services between France and Great Britain [6] is a good starting point for further development of exchange of reserves via HVDC connections.

The initiative was launched by ERGEG and the work is based on the principles described in the previous chapter. The French and British TSOs, RTE and National Grid, with input from other stakeholder representatives are the main parties behind the proposition.

The quality and security of supply is the primary consideration of the proposed scheme. Further should the balance service mechanism be compatible with both markets and *retain a fundamental level of compatibility with the evolving harmonisation of the European Balancing markets.*

According to the ERGEG principles will *the TSOs not be able to reserve interconnector capacity for the purpose of securing cross border balancing services*. This means that it is only beyond the point of gate closure for the Intra day trading that the TSO can use unutilised capacity for balancing transactions.

Finally Conceptual Model 2, TSO-TSO exchange, is preferred by the stakeholders.

2.2.1 Current Practices between National Grid and RTE

France & Great Britain currently have in place an inter-connector agreement which sets out the commercial arrangements and operational circumstances under which the flow on the inter-connector can be managed post gate closure. It also establishes the arrangements by which reciprocal emergency assistance can be requested and delivered.

The agreement allows for the submission of a buy and sell price by each TSO. When services are requested by National Grid, they are cleared at the prices submitted by RTE and vice versa for the services requested by RTE.

At present each TSO submits a single pair of prices that cover the price of utilisation for the subsequent calendar day.

The prices submitted by National Grid represent the forecasted cost to National Grid of providing that service to RTE. Predominantly this will be based on the anticipated costs of bids and offers that would need to be activated in order to cover that service requested by RTE through the inter connector agreement.

Although predominantly an assessment of the cost of energy delivery in the GB market, considerations such as the cost of replacing any lost plant margin and any increased impact on the costs of resolving system constraints are factored into the price.

The prices submitted by RTE are based on the Day Ahead (D-1) Powernext results and are determined in order to recover at least anticipated maximum costs on the French balancing mechanism “Mécanisme d’Ajustement”.

The interconnector prices submitted by both RTE and National Grid are published on the “system warnings and other messages” page of the Balancing Services Reporting Service web site. The prices are published on a daily basis at approximately 18:00 and cover the subsequent 23:00 to 23:00, 24 hour period.

RTE uses the balancing services available through this agreement on the same principles as all the other Assistance contracts RTE has signed with other neighbouring TSOs. These services are only called as a security rescue measure, when local offers are no longer available to solve the faced problems.

RTE publishes a monthly report on Balancing Mechanism utilisation which includes reporting on use of each RTE-TSO contract (energy per day and direction).

National Grid utilises the balancing services available through this agreement in a similar manner to all other balancing services available. The merit order cost of energy, the required lead time for activation (and associated certainty of use) and the implications for levels of system availability are all considered in the determination of whether or not to procure cross border balancing services. However, unlike RTE at the present time, the foreign balancing resources are utilised in balancing timescales in the GB on a commercial basis.

2.2.2 Proposal – formulation of offers

The following Proposal has been designed based on TSO-TSO offers and procurement.

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Volume

Figure 2-3 shows the technical characteristics of the product, which is built up of nominal one hundred MW blocks.

- The product will be offered with one hour duration at regular intervals and close to real time for delivery between [X+1h, X+ 2h)]
- The activation of the product should be performed up to at least 30 minutes before the start of delivery.
- The TSO offers will be formulated periodically post intra day interconnector gates closure[5].

[5] In the first instance it is likely that intra-day closures will occur every 2 hours. In this circumstance, TSOs will still expect to exchange balancing offers every hour to ensure the flexibility, firmness of offers and up-to date knowledge of BM market prices and forecast margins.

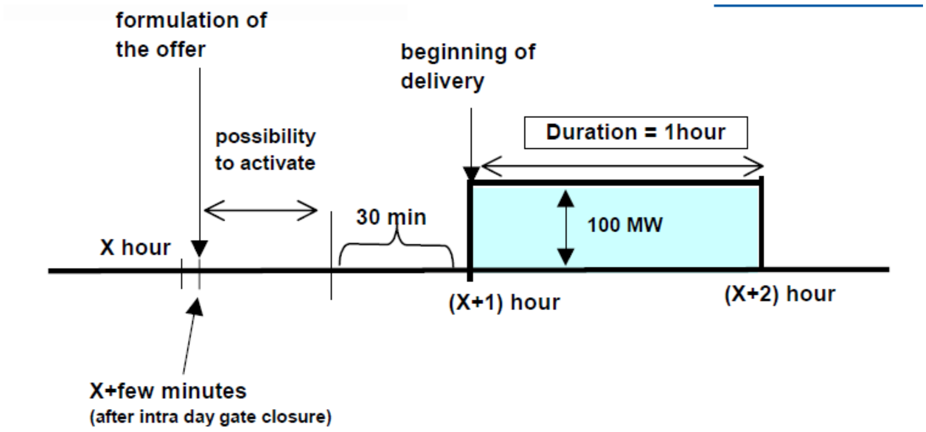

Figure 2-3: Technical characteristics of the product [6]

The TSOs initially intended to offer up to 500 MW availability in 100 MW increments at 2 hours ahead. The level of volume will be reviewed after a suitable time (12 months is indicated).

Security of supply restriction

The main principle is that the TSO only formulates an offer if the security of the system is not endangered by the activation of such offers as illustrated in Figure 2-4. For example will National Grid always refer to the need for sufficient Short Term Reserve (STR) to allow for the largest loss on the system and demand level.

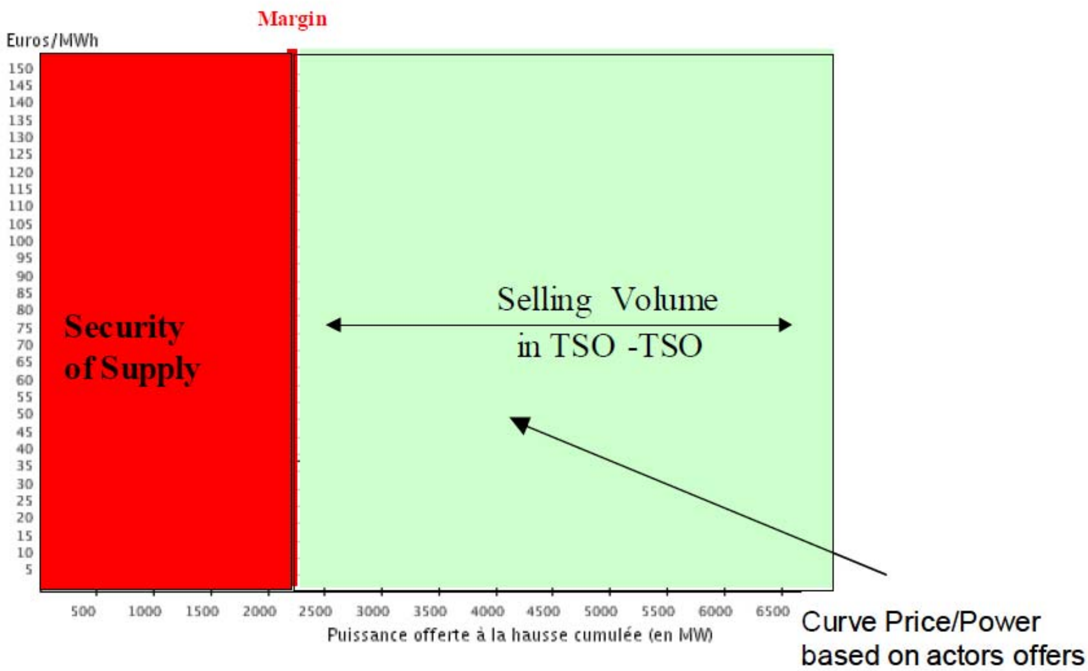

Figure 2-4: Selling volume [6]

Pricing methodology:

Both RTE and National Grid approaches propose that the offers should be based on the projected cost to the domestic control area providing them.

RTE:
The TSO-TSO offers are based on the expected procurement prices defined by:
- Expected internal imbalances
- The determination of the marginal prices of each block based on the Price/Power curve (CPP) of the actors offers.

RTE will have the same management of TSO-TSO offers as the one which is applied for emergency contracts with other TSOs. *This means that the transaction is considered as any activated balancing offers regarding settlement of imbalance prices.*

National Grid:

The marginal price will be derived from a point on the price curve that reflects historic deviations between 2 hours ahead and real time away from a central forecast of energy imbalance.

The price curve is based on bids submitted by the balancing market participants, which can be changed at 1 hour's notice.

All interconnector balancing services called for by RTE are tagged as "un-priced" and as *such their cost currently has no direct influence on the imbalance price in the GB market.*

3 MERGING OF CONTROL AREAS IN NORTHERN CENTRAL EUROPE SYSTEM

ERGEG states that interconnection capacity should not be reserved for trade of balancing resources. This statement might limit the possibility for optimal utilisation of the Nordic balance resources, even if there is an opening for special arrangements for HVDC connections as indicted in Chapter 2.2.

An early assumption in the Balance Management project was that if the exchange of balancing services between the Nordic synchronized area and the Northern part of the Central European system could utilize all the HVDC connections in parallel there would be longer periods with free capacity for exchange of balancing services. This is exemplified in Figure 3-1, which is copied from the study “Simulation of HVDC utilization using a flow-based market model” [2]. The figure shows that although most HVDC connection are fully exploited in one or the other direction most of the time, the sum of exchange between the Nordic system and Central Europe gives a rather smooth curve. The result shows that, in most of the time, it will be possible to exchange rather high amounts of balancing power between the Nordic system and Central Europe.

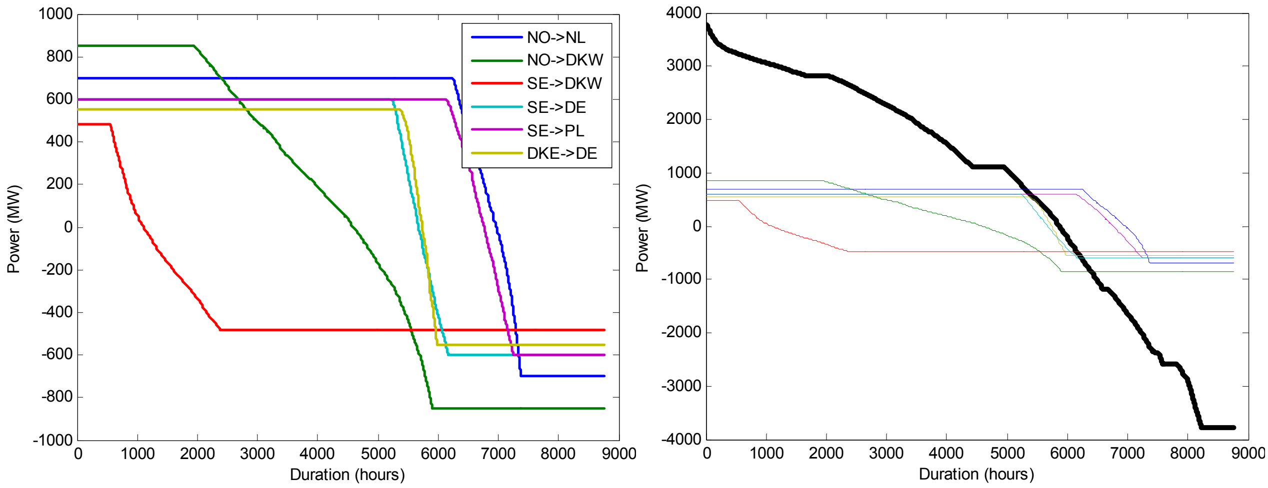

Figure 3-1: Exchange on individual HVDC connections between the Nordic and CE systems (left). The right figure also shows the total exchange between the synchronous systems (black line).

This approach would be more feasible if the control areas involved on each side of the HVDC links are merged or at least operated as one. It is therefore of special interest to follow the ongoing process towards integration/ merging of the German control areas. A brief description of this initiative is presented in the following section.

3.1 The German balancing market

According to the UCTE division in primary, secondary and tertiary, control reserves for each of these controls have to be acquired by the TSOs. This is done based on individual markets for each of the three different control types and for the four different control areas in Germany.

Primary control reserves, incremental as well as decremental, are procured via auctions which are held biannually. The capacity bought at this auction must be provided at each day of the bidding period. Only available capacity is paid for. The energy called from the primary control reserves during operation is not compensated. The cost for primary reserve is passed on to the consumers via the transmission fees.

Auctions for secondary control reserves take place every month. Since the end of 2006 this is done on a common auction platform in the internet. This reserve procurement is done Germany-wide, if the reserves are prequalified for the control areas. For the secondary control reserves a capacity payment, when procuring them and an energy payment, if they are called during operation is given.

Tertiary reserves, called minute reserve, are auctioned on a daily basis, which is done likewise on the common internet auction platform. Minute reserves are compensated by capacity payment if selected, as well as an energy payment if called during the system operation.

All the costs for capacity payments are passed on to the consumers as a part of the transmission fees. The energy payments are recompensed by the system imbalance settlement. All the bids for regulating reserves selected and the bids called during system operation are “paid-as-bid”, which means that the bid price applies for the selected bids (unlike marginal pricing where all the players receive the marginal price). The imbalance price used to settle the system imbalance, i.e. paid by the BRP for being imbalanced is the average price of the regulating reserves called during the systems operation [10]. A BRP is called “Bilanzkreisverantwortlicher” in Germany.

In order to participate as a bidder in the German balancing markets, BSPs have to be prequalified by the TSOs. To be prequalified they need to have an IT-connection to the TSO and fulfil further technical, organizational and economic requirements in order to guarantee a secure provision of regulating reserves. Secondary and Tertiary reserves can not only be bid into the control area where the balance provider is situated, but also into other control areas. In order to bid into other control areas the balance provider has to be prequalified also in these areas, including IT-connections to the other TSOs [7].

To ensure a stable operation of the transmission system the balance between production and consumption in the transmission grid has to be kept. Primary, secondary and tertiary regulating reserves are used for that. Primary control reacts automatically. The TSO is responsible for the activation of secondary and tertiary reserves. Thereto the imbalance in the transmission grid is determined and the area control error (ACE) calculated. This ACE signal is forwarded to the controller of the automatic generation control (AGC), which controls the activation of secondary reserves. Depending on the systems imbalance the AGC activates bids for regulating reserves according to the merit-order list which contains all of the regulating bids given into the control area. The control principle can be found in Figure 3-2.

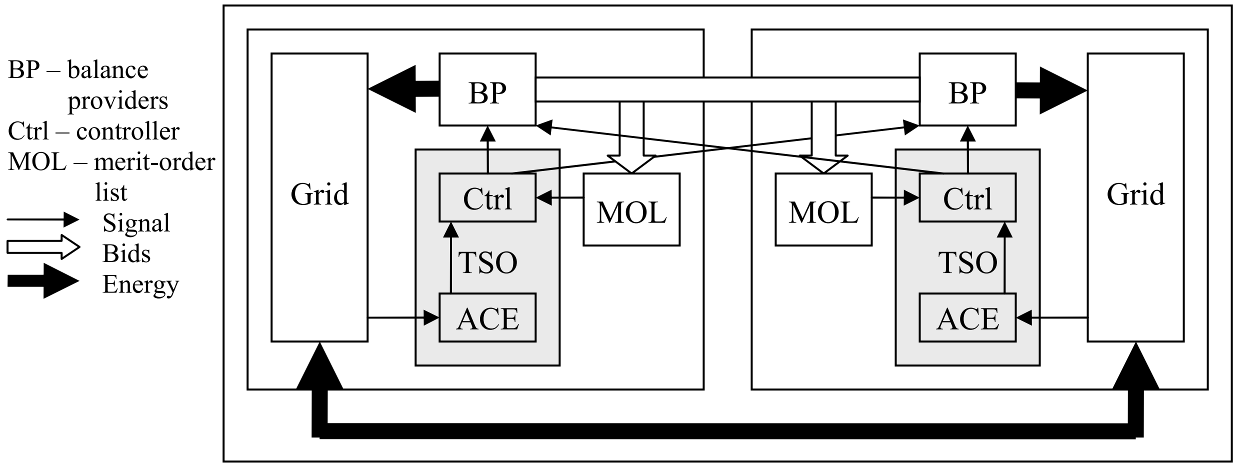

Figure 3-2: Transmission system control principle for individual control areas

3.2 The German Perspective "Netz AG"

The German transmission grid is presently divided into four control areas. Already in the first main report of the monopoly commission in 1977 it was suggested to constitute a central system operator [11]. The economic savings, problems regarding proprietary rights and technical feasibility were were the main arguments for the foundation of a central system operator.

After the privatization and liberalisation of the electricity sector this topic became even more important, being also perceived among the politics and population.

Due to suspicion of the abuse of market power and investigation done at offices of E.ON, the European Commission introduced proceedings against E.ON May 2008 [12]. The proceedings concerned the abuse of market power in the balancing market of E.ON control area. The possibility for that is due to the market-dominating position and the possibility as TSO to hinder competitors participating in the market. E.ON suggested voluntarily obligations regarding grid control ability and responsibility. The commission accepted these obligations and suspended the proceedings, whereas the disposal has to be done in half a year and two years time frame respectively.

The FNA[6] introduced proceedings in order to regulate the utilization of regulating reserves [13]. Basis for the application is a report investigating the potential saveable regulating energy in case of a cooperation of the control areas. The potential reduction in costs for regulating energy is estimated for 2006 to 314 million EUR and for 2007 to 341 million EUR respectively. In the

[6] FNA: Federal Network Agency

cause of the proceedings a report [14] was investigating the amount of required regulating capacity, suggesting an essential possible reduction of regulating reserves which need to be procured. Further on FNA asked for concepts of cooperation of the control areas [13].

In 2009 two different concepts were discussed to be implemented. On the one hand there was the concept of a “zentraler Netzregler” (central grid controller), which was suggested by Amprion[7] with itself being the responsible control entity [21]. Here all the four control areas should be merged into one. On the other hand there was the concept of the “Netzregelverbund” (grid control cooperation) suggested by transpower stromübertragungs GmbH[8], Vattenfall Europe Transmission and EnBW Transportnetze AG, which keeps the current control areas [15], [16]. These concepts were analyzed with respect to their technical feasibility, system security, the socio-economic profit and the possible future development.

Finally it was decided to implement the second concept, the grid control cooperation. In the beginning only the three suggesting out of the four German TSOs started the cooperation out of their own will, enforcing the decision in favour of their own suggestion. As the cooperation proved its possibilities it was chosen as the way to go by the FNA, forcing Amprion to join the cooperation latest in May 2010. However, it is clearly mentioned by FNA, that this cooperation not necessarily is the last state and that it is not only limited to the German control areas.

Taking a general view on the future development of the German transmission grid the federal government, the monopoly commission as well as the FNA favour the establishing of a grid agency or one system operator[9] respectively, adverting the socio-economic benefit of conflating the four German control areas [16], [18], [19].

3.3 Conflation concepts

Consecutively the both above mentioned concepts for either the fusion or the cooperation of the German control areas will be presented. An estimation of the socio-economic benefit is given afterwards. The description is based on a number of reports, press releases and presentation made available by the FNA and the TSOs [15], [16] and [20].

3.3.1 Grid Control Cooperation (GCC)

In response to RWE’s (Amprion’s) central grid control concept, the other three German TSOs developed and suggested the concept of a grid control cooperation. This concept is based on four modules. It optimises the use of regulating reserves in a compound of control areas, keeping a decentralize control structure.

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[7] RWE Transportnetze Strom GmbH was renamed to Amprion on the 01.09.2009 to indicate an independency from RWE.

[8] Formerly known as E.ON Netz GmbH, now part of TenneT

[9] This system operator is usually called Netz AG, referring to the responsibility for the transmission grid

The optimisation of the utilization of regulating reserves is done by the means of the following four objectives each addressed by one of the modules:

1. Netting of the imbalances -> avoidance of counter balancing
2. Sharing of regulating reserves -> common dimensioning of reserve procurement
3. Constitution of a common market area, BP connected only to one TSO, "virtual connections" to other TSOs
4. Establishing of a common merit-order list

Each of those aims is implemented in one of the modules, which leads to a stepwise integration of the regulating markets. This concept concentrates mostly on secondary reserves. For the call of tertiary reserves a common operational concept is developed. Tertiary reserves are also regarded in dimensioning the amount of common reserve to be procured.

In **module 1** the counteracting activation of regulating reserves in the participating control areas should be avoided. This is to be obtained by summing up the imbalances of the single control areas. The net imbalance of the control compound is determined. This net imbalance is distributed pro rata on the control areas, being the inputs to the areas' controllers. Thus the direct connection between the determination of ACE and the AGC at each TSO is removed and routed through the imbalance netting. With the implementation of module 1 in all control areas the same type of reserves, either upward or downward regulating, is activated at all points in time. This results in a decreased amount of regulating energy, which is utilized. The module is in operation in Germany since December 2008.

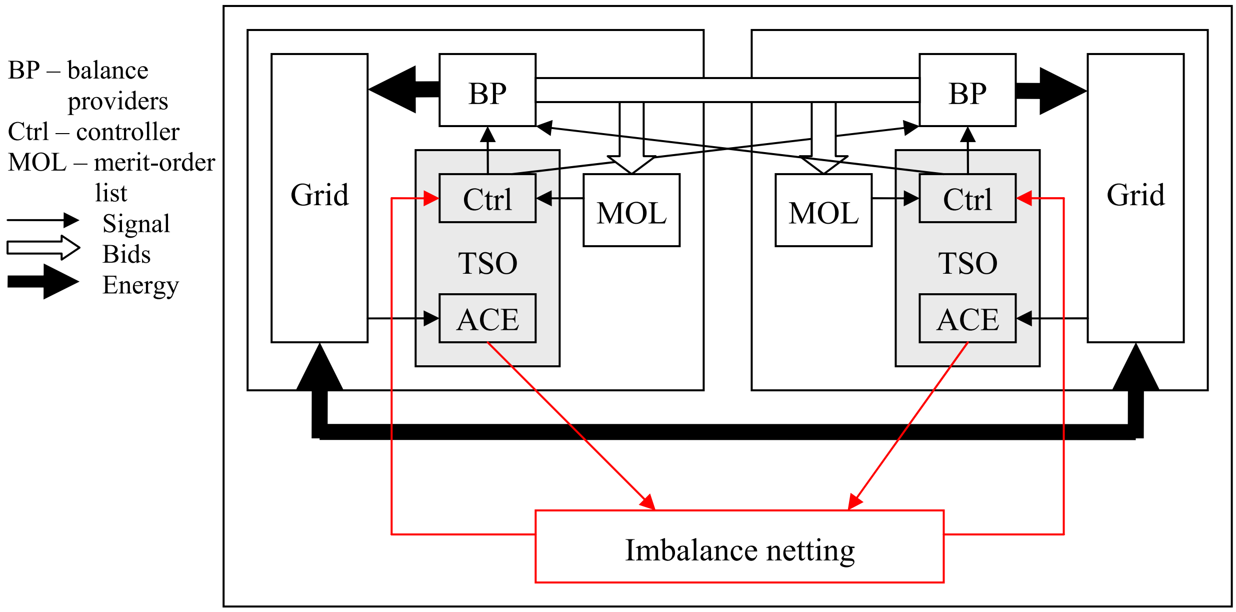


Figure 3-3: GCC module 1 – common netting of imbalances

Module 2 contains the mutual provision of available regulating reserves. I.e. a TSO normally uses the regulating reserves that are available in its control area. If there are insufficient reserves[10] a

[10] All available regulating reserves in the own area are activated

TSO can gain regulating reserves from the other TSOs. This will be possible by implementing IT-connections between all participating TSOs. The mutual provision of available regulating reserves gives the ability to dimension the amount of procured regulating reserves according to the cooperation wide requirements, which complies with the amount required for a central control. That results in a decrease of the amount of regulating reserves being procured. Within this framework a common imbalance price for the participating control areas is defined. The module was implemented in June 2009 in Germany.

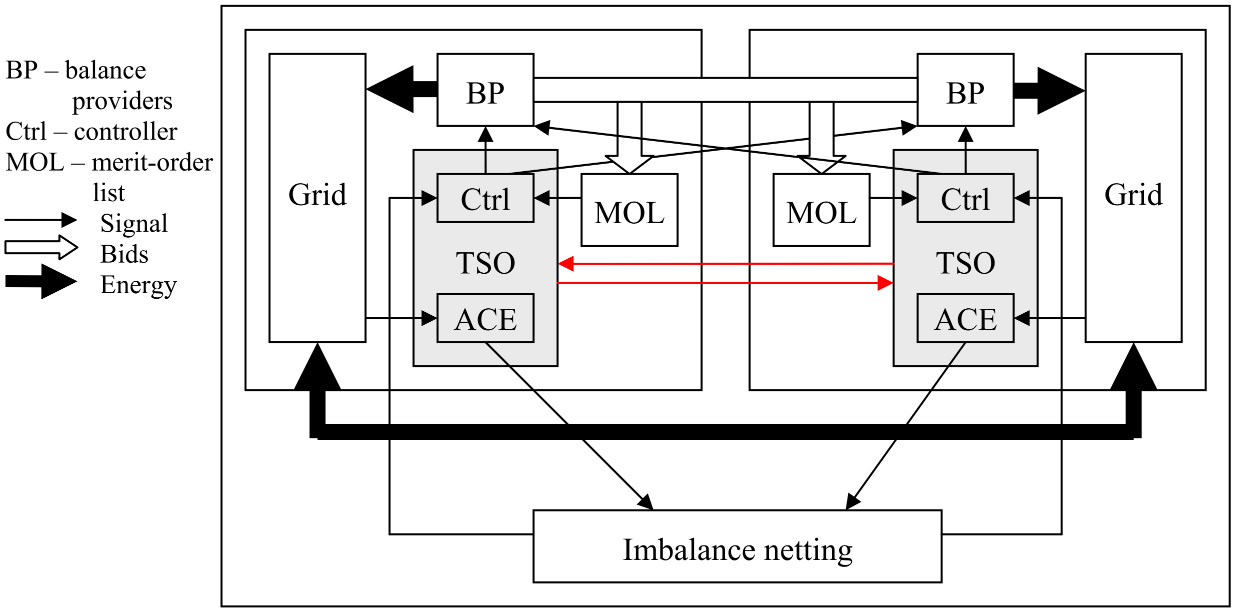


Figure 3-4: GCC module 2 – mutual provision of regulating reserves

By **Module 3** a common market area for secondary regulating reserves is created. Balance providers now only need an IT-connection to the TSO of the control area they are situated in. IT-connections between TSOs and exterior balance providers are abolished and substituted by "virtual" connections. Calls for activation of regulating reserves from other control areas are assured by forwarding the signal to the according balance provider via its TSO. Forwarding the call from one TSO via another TSO to the balance provider establishes a "virtual" IT-connection between them, i.e. each of the TSOs is connected to all of the balance providers. By the prequalification through its TSO and the corresponding IT-connection, a balance provider is automatically prequalified to all other participating control areas. Thus it can provide regulating reserves to its and all other control areas. Bids for providing regulating reserves are automatically provided in all participating areas. With balance providers having an IT-connection to only one TSO, the complexity of the control structure is decreased. Module 3 was commenced in July 2009.

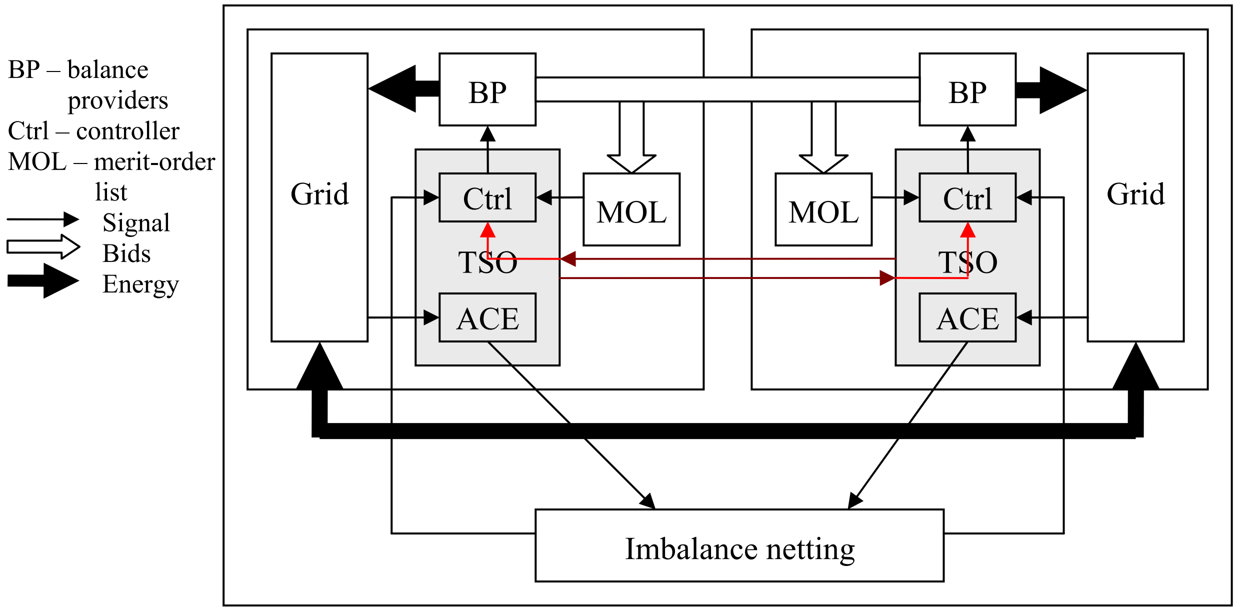


Figure 3-5: GCC module 3 – BP only connected to own TSO, "virtually connected" to other TSOs

In **module 4** a cooperation wide common merit-order list of bids for regulating reserves is established. The merit-order list ensures that always the next (-cheapest) bid for regulating reserves in the control cooperation is selected. This module is the last one to implement and represents the final aim of the control cooperation, optimising the utilization of regulating reserves in the participating areas. With all four modules implemented using regulating reserves should be done in the same manner as using a central control. The difference in the grid control cooperation is that there is no superior control entity, despite the imbalance netting. The implementation of the grid control cooperation was finished in October 2009.

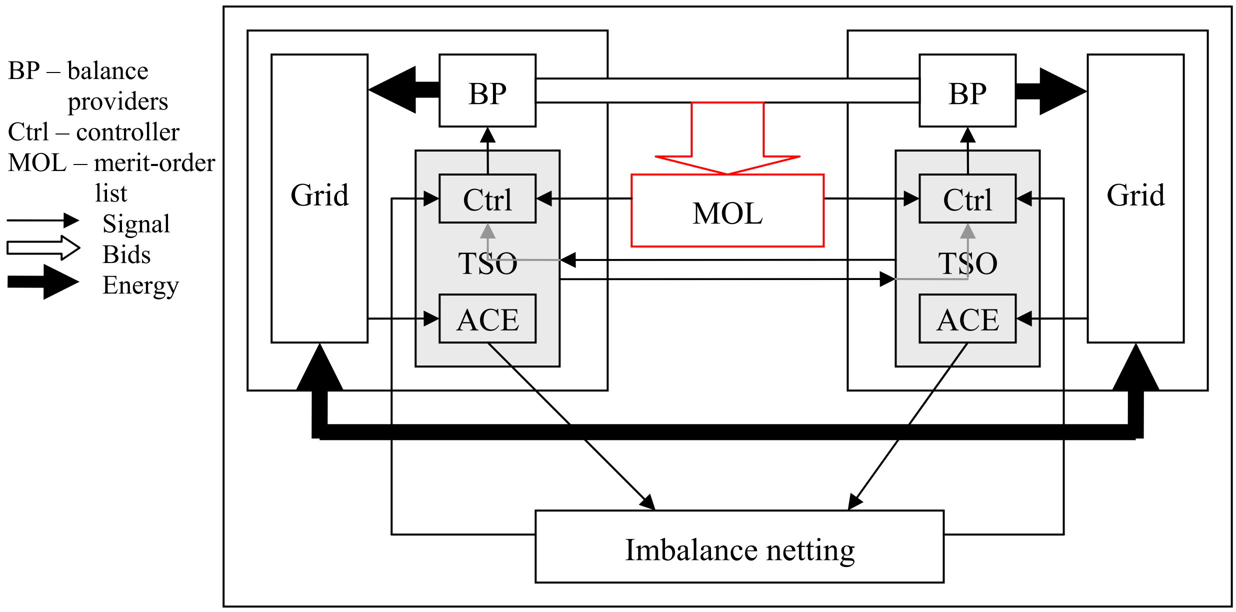


Figure 3-6: GCC fully implemented – common merit-order list established

3.3.2 Activation of tertiary control reserves

All these above presented modules are about secondary control. For handling tertiary control, the so-called minute reserve, a common operational concept was develop and implemented within the framework of module 2.

The activation of tertiary reserves is done decentrally, based on common rules. As criteria for activating tertiary reserves in a control area, the activated secondary control reserves in the control area and in the whole control region is used. It means that tertiary control reserves in a control area are only activated if the secondary control reserves utilized in this control area, as well as in the control region, are above a certain limit. This operation concept (common rules) should avoid activation of minute reserves working in opposite directions in different control areas.

The grid control cooperation concept represents a stepwise introduction of balance market integration, split up in four modules. As the former controllers, control infrastructure and control areas are kept, this concept should be reversible. Further areas can join the control cooperation at any time. The participation can be done completely or only up to a certain degree i.e. a certain module in this case. An extension of this concept to foreign countries is possible, whereby especially module 1 can be extended over congestions as well as price borders. Furthermore the grid control cooperation concept is possible to develop further into a central control.

3.3.3 Future concept - Central grid controller (CGC)

The concept, suggested by Amprion, intends to abolish the current four different control areas. In order to balance the system, the border integral of the former four control areas, including VKW (Austria) and Luxemburg, is calculated and used as the input signal to a central controller. The further areas currently included in the German control block are taken out of this integral. The procurement and utilization of regulating reserves is done Germany wide using a merit-order list. The principle of the central grid controller is shown in Figure 3-7.

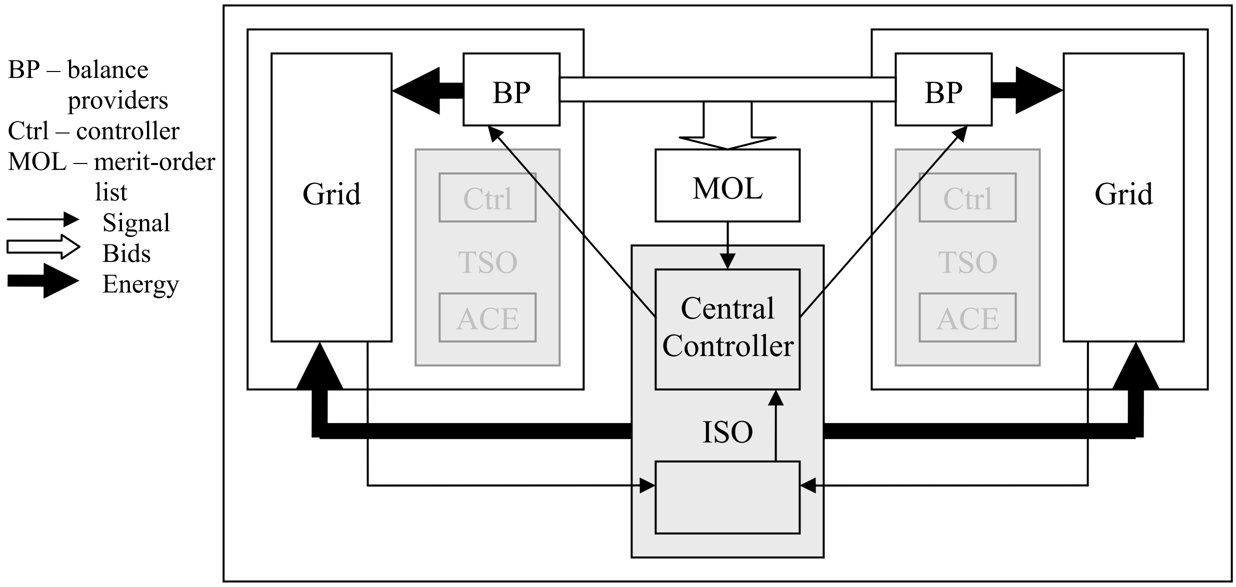


Figure 3-7: Central grid controller

For implementing a central grid control all balancing providers have to be directly connected to the central controller. The complexity of the control system using the central grid controller would be lower than the current, removing one control layer and making inner-German measurements unnecessary. As RWE is currently responsible for the German control block, there already exist connections to most of the balancing providers as well as to the transmission lines connecting Germany to foreign countries. Due to this a short-term realisation of this concept should be possible. For the central control the German block controller in Brauweiler shall be used.

In order to take into account congestions a *region model* is suggested. As the energy flows due to the day-ahead trades are more than ten times higher than regulating energy flows, congestions are only likely to occur when there already are congestions in the day-ahead energy flow. Thus the region model should be based on regular occurring physical network congestions, splitting up the central control area in a number of regions.

In general it can be said, that a common German control area is the future way favoured by the FNA, the monopoly commission and further institutions. It was not implemented yet due to the significant changes in the current system compared to the easy implementation of the grid control cooperation.

3.4 Socio-economic outcomes of the control area conflation

Investigating the economic impacts can be split into two different parts. There will be a reduction in the cost of activating of regulating reserves (energy payments) as well as in the cost of procuring reserves (capacity payments) [15].

Both possible cost reductions result in potential total savings of about 260 million EUR per year. These savings are achievable for both previous discussed conflation concepts, as the amount of not activated regulating energy and the reduction of regulating reserves to be procured are supposed to be equal in both concepts.

3.4.1 Reserve activation - cost reduction

With the implementation of the first module of the grid control cooperation an essential reduction of activated regulating reserves could be achieved. In the period from 01.12.2008 to 01.03.2009 the saved regulating energy added up to 122.8 GWh. With an average regulating energy price of 135.75 EUR/MWh for positive and -2.88 EUR/MWh for negative regulating energy, these are savings of 17 million EUR for 3 months, being approximately 68 million EUR in one year. In the case of the control area of RWE joining the netting of imbalances it is estimated to have a further decrease by 80 %, ***resulting in yearly savings of 124 million EUR***. The decrease in the cost of activating regulating reserves can be achieved by only implementing module 1 i.e. netting imbalances of the different control areas.

3.4.2 Cost reduction for capacity payments

With the integration of the four German control areas comes a possible reduction of reserves that are required to be procured. This only accounts for secondary and tertiary control reserves, as primary reserves are already defined in a system wide perspective. The following suggested possible decrease of required regulating reserves is based on a former study [14].

The dimensioning of the reserve requirements for secondary and tertiary regulating reserves is based on the deficit / surplus probability (Prd / Prs). This is the probability that there are insufficient upward respectively downward regulating reserves available in the control area. In Germany the common value for these probabilities was Prd = Prs = 0.1 % for each of the control areas, which corresponds to approximately ten hours per year. It means that during ten hours of a year the imbalance in a control area is higher than the available reserves in the area. These cases were handled by mutual “help agreements” between the four TSOs. It resulted in actual deficit/ surplus probabilities that were far lower than 0.1 % for the German system.

Table 3-1 shows the required reserves, split in secondary (SCR), tertiary (TCR) and the summed up (CR) control reserves in the case of four individual control areas for a deficit / surplus probability of 0.1 %.

Table 3-1: Required reserve [MW] for four individual control areas – Prd = Prs =0.1 %

		SCR	TCR	CR
Amprion[11]	pos.	1003	898	1901
	neg.	725	984	1709
TenneT[12]	pos.	830	1135	1965
	neg.	590	380	970
50 Hertz[13]	pos.	638	345	983
	neg.	399	808	1207
EnBW	pos.	537	427	964
	neg.	331	174	505

In the case of integrating the control areas, there will not be any mutual help in the case of insufficient reserves, as there is only one control area. Thus, in order to maintain the same system reliability the deficit / surplus probability has to be adapted. To achieve an appropriate security of supply the least reasonable deficit / surplus probability of 0.0028 % is chosen, which corresponds to one quarter hour of a year.

According to this probability new reserve requirements for the integrated control area are determined. These reserve requirements, the former requirements of the individual control areas and the difference between these are shown in Table 3-2. It can be seen, that there is a significant reduction of required reserves, which are around 400MW of upward regulating and 1000MW of downward regulating reserves. However, there is an increase of the requirements for tertiary upward regulating reserves, which is justified by an enhanced utilization of tertiary instead of secondary reserves. This increase is due to the fact that it is suggested to utilize more tertiary instead of secondary reserve, as it would result in a further cost reduction. The increase of tertiary reserves is a special German characteristic and should not be seen as a general suggestion.

Table 3-2: Required reserves [MW] for individual control areas compared with an integrated control area

	type	Secondary control reserves	Tertiary control reserves	Sum control reserves
individual control areas	pos.	3008	2805	5813
	neg.	2045	2346	4391
integrated control area	pos.	1794	3610	5404
	neg.	1488	1877	3365

The reduction of costs due to the decrease in the amount of regulating reserves, which are required to be procured, ***sums up to savings of about 141 million EUR per year.***

[11] Formerly known as RWE Transportnetze Strom GmbH
[12] Formerly known as E.On Netze GmbH and transpower stromübertragungs GmbH
[13] Formerly known as Vattenfall Europe Transmission

Table 3-3: **Possible reserve requirement reduction [MW] and capacity prices [17]**

	type	Secondary control reserves	Tertiary control reserves	Sum control reserves
difference	pos.	-1206	+805	-401
	neg.	-557	-409	-966
average capacity prices	pos.	111 €/kW/year	47 €/kW/year	
	neg.	59 €/kW/year	23 €/kW/year	

The requirements shown above are as previously mentioned based on a deficit / surplus probability of 0.0028 %. This extreme low deficit / surplus level will most probably change. There are several reasons for that. Firstly, when the deficit level of 0.1% was introduced, there were no mutual help agreements. Secondly there can be such mutual help agreements between different European countries improving the actual deficit / surplus probability and with it the security of supply.

4 EXCHANGE OF RESERVES TO/FROM THE NORDIC SYSTEM

In this chapter different aspects related to availability and the trade of Balancing Resources (BR) over the HVDC links are discussed. The challenges and solutions described are to some extent discussed from a Nordic point of view, but should also have a general interest.

4.1 Reserve and control definition

There has been some confusion with regard to the different term used for the reserves activated by the balancing market and the terms for the automatic and manual control action.

In the first report we used the following term for the reserves traded in the balancing markets, as defined by ETSO [2]:
Frequency Restoration Reserves (FRR) are operating reserves necessary to restore frequency to the nominal value after sudden system disturbance occurrence and consequently replace *Frequency Containment Reserves (FCR)* if the frequency deviation lasts longer than 30 seconds. This category includes operating reserves with an activation time typically between 30 seconds up to 15 minutes. Operating reserves of this category are typically activated centrally and can be activated automatically or manually.

The corresponding terms in the Nordic system are:
FCR: Frequency Controlled Normal Operating Reserves (FCNOR) + Frequency Controlled Disturbance Reserves (FCDR)
FRR: Fast Active Disturbance Reserves (FADR)

The control actions that activate these reserves are called *secondary control* (automatic Load Frequency Control, LFC) and *tertiary control* (manual) in the ENTSO-E system. In the Nordic system the "Restoration" is done by manual control only, which means that the control action is *secondary* as explained in the first report.

The introduction of automatic secondary control that is announced by the Nordic TSOs, makes it more convenient to name the manual Nordic activation of reserves as *tertiary control,* even if this in the near future remains the main source for activation of the FRR.

4.2 Exchange between separate synchronous systems

An example of exchange of balancing services between the central European synchronous system and the UK system (The France-Uk-Irland initiative) is described in Chapter 2.2. The trade involves only manual tertiary reserves and does not require reservation of HVDC transmission capacity.

In this section we'll discuss the impact of security of supply restrictions to the exchange and the potential control signals between the synchronous systems.

4.2.1 Balancing resources available for exchange

The security of supply in each TSO's power system is the most important aspect that must be taken into account when exchange of balancing services is considered. This is why ERGEG states that *Cross-border trade shall not jeopardise system security*.

One way to ensure that this is satisfied, is to make sure that only reserves beyond the defined reserve requirement for each part of the system are available for sale to other areas. This implies that reserves covering both loss of the largest production unit and the expected forecast error with regard to consumption and wind production shall be kept for local purposes. It is also anticipated that only reserves bid into the Balancing Market are available for sale. We suggest therefore the following equation for the definition of balancing resources available for export:

$$\mathbf{BR_{export} = BR_{Bid} - BR_{SoS} - BR_{FE}}$$

$\mathbf{BR_{Bid}}$ = Resources bid into the Regulation Power Market
$\mathbf{BR_{SoS}}$ = Resources kept for Security of Suply (SoS), referring to dimensioning fault
$\mathbf{BR_{FE}}$ = Resources kept for potential Forecast Error

This is illustrated in the figure below, suggesting that the most attractive (cheapest) resources are kept for "local" purposes, while more expensive resources that are not needed locally are made available for export. Although this is a natural starting point for cooperation, a more flexible approach should be aimed for in the longer run to optimize the use of common resources.

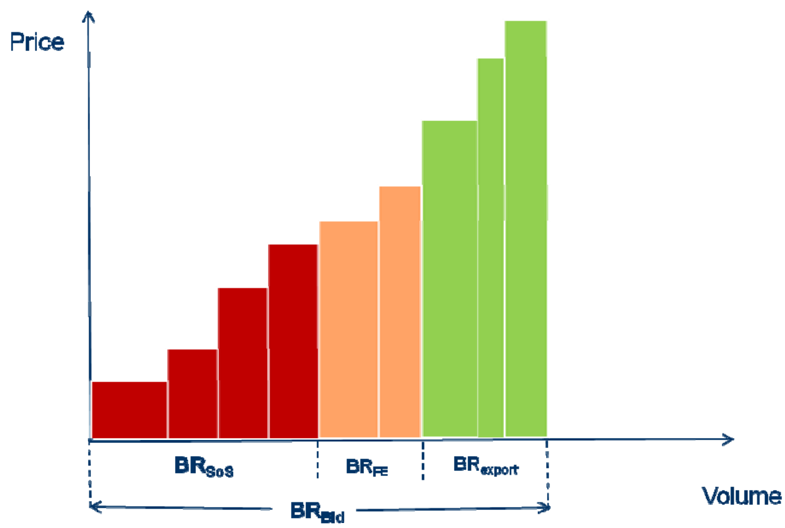


Figure 4-1: Balancing resources available for export

The need for extra reserve as a consequence of the forecast error is not included in the recommendations from ERGEG. The uncertainty with regard to the real level of consumption the next day is by the Norwegian TSO, Statnett, estimated to about 800 MWh/h in winter time due to uncertainty in the temperature and other causes. This volume, BR_{FE}, is therefore added to the dimensioning fault as basis for the reservation of reserves in the Statnett RKOM[14] market.

In countries with a large share of wind uncertainties of wind production require similar considerations with respect to reserve requirement. This aspect is further discussed in Chapter 4.5.

4.2.2 Control signals

Within one synchronous system, the frequency is a common control signal, and if the whole synchronous system is *one* control area (like the Nordic system), it is the only control signal that governs the load frequency control. If there are two or more control areas, the frequency is one of the two signals that together determine the Area Control Error, ACE, defined as:

$$ACE = P_{measured} - P_{program} + K \cdot \Delta f$$

$P_{measued}$ - $P_{program}$: *The deviations from the planned exchange*
K: The frequency bias in the area, Δf: *Frequency deviation*

Neither the ACE nor the frequency in the opposite system is relevant control signals for exchange of balancing power between separate synchronous systems. The frequency in each system is only interrelated via the change of flow over the HVDC connections. It is therefore necessary to exchange explicit control signals to the HVDC terminals and possibly generators in the other system to enable the exchange of balancing services.

4.3 Main actors and trading parties

The two conceptual models from ETSO mentioned in Chapter 2.1.6 are based on TSO – BSP and TSO –TSO trade respectively. According to ERGEG should the TSO –TSO model be the first option, which also is the case in the France- UK scheme.

The TSO –TSO (e.g. Statnett – TenneT or SvK – Ve-T) seems to be the most relevant alternative also for the Nordic system from the start. This might however lead to sub optimal solutions taking into account the qualities of the common Nordic balancing market. It seems obvious that coordination between the Nordic TSOs e.g. with common pricing principles will be the most optimal solution for the synchronous system.

[14] RKOM: Reserves Option Market

The TSO – BSP concept is recently introduced as an alternative for new HVDC link projects, where dedicated hydro plants are linked directly to the respective Central European TSO as secondary control objects.

In the long run, and provided that the control areas in northern Central Europe are merged, introduction of Independent System Operator (ISO) for each region is a third alternative. The ISO model has been discussed previously in the Nordel context with the conclusion that the TSO cooperation (with a special responsibility for Statnett and SvK for the frequency control.) is the best solution.

The ISO model might, however, be more attractive if the main purpose is to optimize the exchange between the two separate synchronous areas.

The ISO option needs a more thorough investigation which is not included in this project.

4.4 Nordic system characteristics

The Nordic synchronous system has since 2002 been operated as one control area. Since then only frequency and time deviation has been used as control criteria, restricted by potential congestions in the grid.

Prior to this, the ACE[15] for each country was the main control criteria also for the Nordic system, and the imbalances were adjusted by manual regulation based on a merit order list for each country. This means that ACE not necessarily has to be connected to automatic secondary control.

When stationary frequency deviation occurs due to imbalances, the cheapest regulation object in the Nordic system according to the RPM[16] bids, is called by the TSO. Only congested lines or special operational situations allow deviation from the merit order list. This means that FRR is activated with a response requirement of 15 minutes.

Figure 4-2 shows the Nordic system with the main physical intersections (black lines) that occasionally might be congested. Potential congestions need to be taken into consideration when the reserves in the system are allocated, and they represent a restriction when the reserves are activated in the operational phase.

[15] Called "Innstillingsfeil"
[16] RPM= Regulation Power Market

Figure 4-2: The Nordic power system and relevant transmission constraints

4.4.1 Nordic system security and frequency response

The figure below shows that the frequency quality in the Nordic synchronous system is falling. The number of incidents where the frequency deviation extends the recommended +/- 0.1 Hz was in 2010 ~8 times higher than the registrations from 1995.

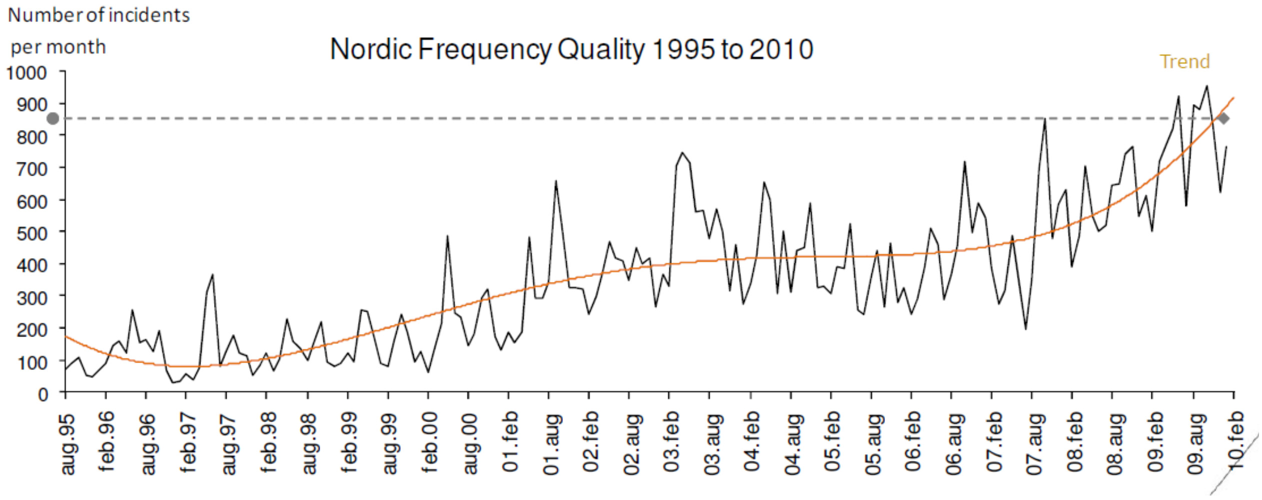


Figure 4-3: Nordic frequency quality (source Statnett SF)

Based on this observation the Nordic TSOs have concluded that the synchronous system in the near future will be difficult to control within the required Δf= +/- 0,1 Hz and Δt =+/ 10 sec with today's manually controlled balancing power. This means that there is a need for automatic and faster control schemes. In other words automatic secondary control for this system should be developed independent of the exchange of balancing services over the HVDC links.

So, from a system optimizing point of view, the Nordic frequency control should be in focus. This means that the effect of the exchange of balancing services should always be related to the need for up or down control due to the stationary frequency deviation following the primary control. This applies for both TSO – TSO and TSO - BSP exchange.

4.4.2 Reserves requirement

The Nordic system has a total Frequency Controlled Disturbance Reserve of 1160 MW and a Fast Active Disturbance Reserve of 4680 MW [24]. In addition Norway uses 800 MW of forecast error reserves. The amount of reserves is related to the ENTSO-E "principle of responsibility", which states that each control area is responsible for restoring its own balance within a certain time.

These requirements have not been changed after the introduction of the common Nordic balancing market. The German example, where the need for capacity reservation is expected to be reduced significant due to the merging of control areas (see Chapter 3.4), is an indication of a need for revision of the present Nordic requirement. Central considerations in this context are:

- Reserves are exchanged as long as there is available transmission capacity
- Congested intersections are more relevant than country borders for the size of reserves needed
- The impact of the distribution of wind production in the Nordic area

4.5 Reserves requirement related to forecast uncertainties

Both uncertainties in consumption and wind production the next period of operation have to be taken into consideration when the TSO decides the need for reserves.

The market players and the TSOs need to act in accordance to different time horizons referring to the Day Ahead marked clearing and the need for balancing the next hour. The Day Ahead contractual obligations for the next 12-36 hours in the Nordic market are known when the Elspot market clears at 12 o'clock. At this stage there is a risk for deviation in the production and the real consumption according to the forecast uncertainty for demand and intermittent production. This uncertainty will, however, decrease considerably towards the operational hour. The future high share of wind production counts for more focused attention to the potential forecast error and the interrelation between wind and consumption.

4.5.1 Consumption forecasts

Methods and tools for load forecasting have for a long time been available for the TSOs and are also used by larger market payers. Weather variables like, temperature, wind etc. has been of importance for the results. The temperature dependency of the electrical heating will, especially for the Nordic system, have a significant impact.

The consumption pattern is expected to change the coming years, due to the climate changes and the measures introduced; like better insulation of houses and the trend towards zero emission buildings. This will reduce temperature dependency. Additionally will load control and smart grids concepts increase price elasticity and controllability of the residential load, and the consumption in the power intensive industry will probably be more and more dependant of the international competition and the market trends.

Forecast of demand for power (MW) and especially the reducible load related to balance market participation is another aspect that so far has had limited attention. It is expected that models and tool for such assessments will be asked for in the context of the smart grids development.

4.5.2 Impact of wind production share

There are no detailed studies so far quantifying the extra reserve requirements of regulating power needed for balancing wind power in the Nordic region. A preliminary estimate for Norway referring to three wind scenarios and recent studies of wind uncertainty [25], [26] is presented in Table 4-1 [27]. A more detailed discussion of the wind forecast uncertainties is presented in the project memo [29].

Table 4-1: Increase in reserves for regulating capacity due to installed wind power. % refer to installed capacity. [27]

Wind Scenario **[MW]**	**Year production [TWh]**	**Max [MW]** 1h (1.5 % - 4 %)	**Average [MW]** 24h (10 %)	**Max [MW]** 24h (22.5 %)
2670	**8**	**40 - 105**	**267**	**600**
4000	**12**	**60 - 160**	**400**	**900**
5330	**16**	**80 - 215**	**533**	**1200**

Although the above estimates are approximate, they already indicate the dependence of the extra reserves for regulating capacity needed to balance wind power, on planning horizon (day-ahead or intra-day trading) and wind power penetration level. Increased wind forecast uncertainty increases the need for reserve procurement. Guidelines for reserve procurement need to be revised to ensure system security. Due to the uncertain characteristics of the wind production, the general way of the reserve management for wind integration is to provide additional reserve margin by conventional plants. Because wind power production is characterised by variations on all times scales, allocation of such reserve margin necessarily becomes a dynamical operational process.

4.5.3 Dynamic reserve allocation – example from the Spanish TSO REE

Below, we present an example of “state-of-the art” operational dynamic reserve allocation, by the Spanish TSO “Red Eléctrica de España” [28].

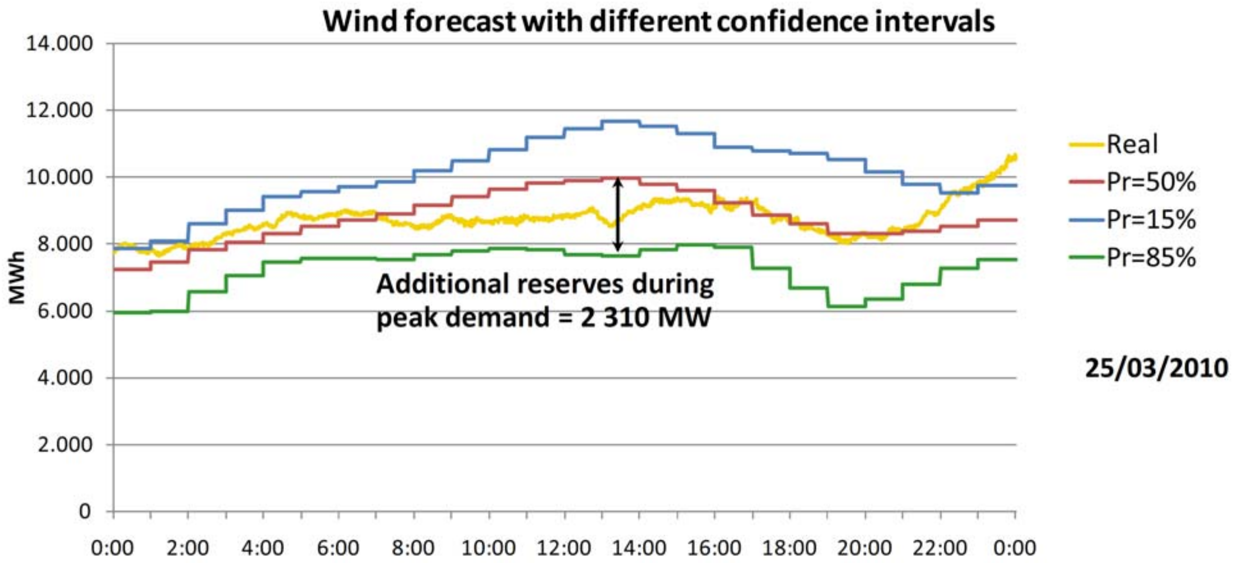


Figure 4-4: Day-ahead technical constraint management, Courtesy of *Red Eléctrica* de *España* [28]

The TSO checks upward and downward spinning reserves that the system will have for the next day, after receiving the market results of the day D-1 (“day ahead”) allocation, before 11 a.m.. If reserves are found not to be sufficient to overcome the expected uncertainties, thermal groups might be switched on or off in a market based mechanism named “day-ahead technical constraint management”.

Therefore, prediction of the wind power variations reliably becomes essential and wind forecast becomes an essential component of system operation. Currently, in day ahead (D-1), hot reserves are sized considering a probabilistic wind prediction for every hour of the next day. The wind forecast prediction tool gives hourly values of wind generation forecast with three different confidence intervals:

- **Pr-85 %**: 85 % probability of the wind forecast value being *below* the actual wind production for each hour. This constitutes the *lower-bound* of the wind forecast with a 15 % confidence margin.

- **Pr-50 %**: 50 % probability of the wind forecast being below the actual wind production at the given hour. This constitutes the “benchmark” of the wind forecast.

- **Pr-15 %:** 15 % probability of the wind forecast being below the actual wind production at the given hour, *i.e.* 85 % probability of the wind forecast being *above* the actual wind production at the given hour This constitutes the *higher-bound* of the wind forecast with a 15 % confidence margin.

In Figure 4-4, the peak hour of March 25th 2010, is chosen as example. The difference between the (most likely) P-50 % forecast and the P-85 % forecast was **2310 MW** for that hour. This is then the amount that had to be added to the reserves needed. In Ref.[15], it is mentioned that the typical wind production measured in the Spanish system around that period (March 2010) was around **10 000-13 000 MW** whereas the total installed capacity is was **18 805 MW** . This means that additional reserves needed in this example are approximately ~ 17-23 % of the produced capacity and ~12 % of the total installed capacity.

4.6 Balancing resources - Control objects

The Nordic and especially the Norwegian hydro plants are the most used regulation objects in the Nordic Regulation Power market. But also thermal plants and reducible loads are on the list.

The objects from the consumption side tend to be high priced and are therefore seldom activated. These reserves play, however, an important role as the last resource with regard to the system security.

The volume available for balancing up or down in the hour of operation is dependant of the bids to the common Regulation Power Market. The impact of the intraday trading with regard to available volume is an important issue for further studies.

4.6.1 Intraday trading impact on balancing resources

The Intra Day (Elbas) trading in the Nordic system has recently been expanded from being a market for the “thermal” countries Finland and Sweden” to cover all players in the Nord Pool market, and from 2007 also the German market. The market players are able to reduce their potential imbalance by adjustments to trades done in the day-ahead market until one hour prior to delivery. The traded volume on this market is expected to increase in accordance with the growing share of wind production.

The question is how this will affect the needs for FRR and resources in the Regulation power market:

- Will the real time imbalances be reduced?
- Will the intraday trading reduce the resources available for the Nordic Regulation Power Market?

These questions are not further discussed in this report and could be subject for further research.

4.6.2 Optimal choice of regulation objects taking network losses into consideration

The marginal losses for the different nodes in the Norwegian power system are published daily by Statnett. The cost of losses is the marginal loss percentage times the flow in/out of the node times the area Elspot price. The marginal losses should therefore be included in the bids from the market players. This applies to some extent for the day ahead market (Elspot), but it is quite uncertain whether this is the case in the Regulation Power market.

The network losses are nevertheless an important factor with regard to the efficiency of an activation of balancing power. In e.g. a situation where the intersection in northern Sweden is fully loaded from the north (as it often is), are the marginal losses up to 30-40 %. This means that if a future wind farm of 100 MW in Northern Norway trips only 60 MW load reduction near the load centre of the Nordic system (around Stockholm) is needed compared to 100 MW near the wind farm.

Another aspect is the control object's sensitivity of the different bottlenecks in the system. The next object on the merit order list might have a much greater impact on the congestion than number two or three.

This means that the geographical location of the control object is important with regard to the need for activated volume and the total system costs. This also means that it is not obvious that the nearest control object to e.g. the HVDC terminal is the most efficient when the export/import changes. This depends of the total flow in the system and in most cases will actions near the load centres be the most technical efficient.

Table 4-2 shows as an example the bids (volume & price) and the calculated loss factors and sensitivities with regard to a specific network interface (H) [22]. These data represents additional information to the original bid price and should be utilized when final priority of the regulation objects is to be decided, either manually or directly as a result of the power flow (e.g. OPF) analyses.

Table 4-2: Physical impact of regulation

Regulation objects	Volume Δ MW	Bid price [NOK]	Loss factor	Sensitivity "Interface H"
I (Production)	100	150	1.0519	0.45
II (Production)	40	155	1.0930	0.12
III (Load)	80	160	0.9822	0.75
IV (Production)	60	175	1.0646	0.10

A methodology for dispatch of regulation resources based on an incremental DC optimal power flow formulation is proposed in [29] . The results of this model are compared with today's practice for some cases of up- and downward regulation, and the potential for cost reduction is observed. The method requires automatic secondary control LFC/AGC.

4.7 Reservation of transmission capacity

The present HVDC connections are reserved for Day Ahead trade, which also is according to the guidelines from ERGEG. This means that the flow is decided for the next 24 hours period via the implicit auction[17] related to the spotmarket clearing.

According to present practice at Nord Pool, are all Elbas trade implicitly utilising free cross border capacity following the Day Ahead trade. Available cross border capacity for intra-day trading is updated after each executed trade. The question is then whether the future potential profit from Intraday Trade and exchange of balancing resources could defend reservation of HVDC capacity?

Figure 4-5 shows the potential allocation of the Available Transfer Capacity (ATC) defined by the TSOs for each program time unit, (ptu - e.g. hour). Ideally the capacity should be allocated according to a socio-economic assessment with regard to the three trading options Day Ahead (P_{DA}), Intraday (P_{ID}) and Balancing Resources (P_{BM}).

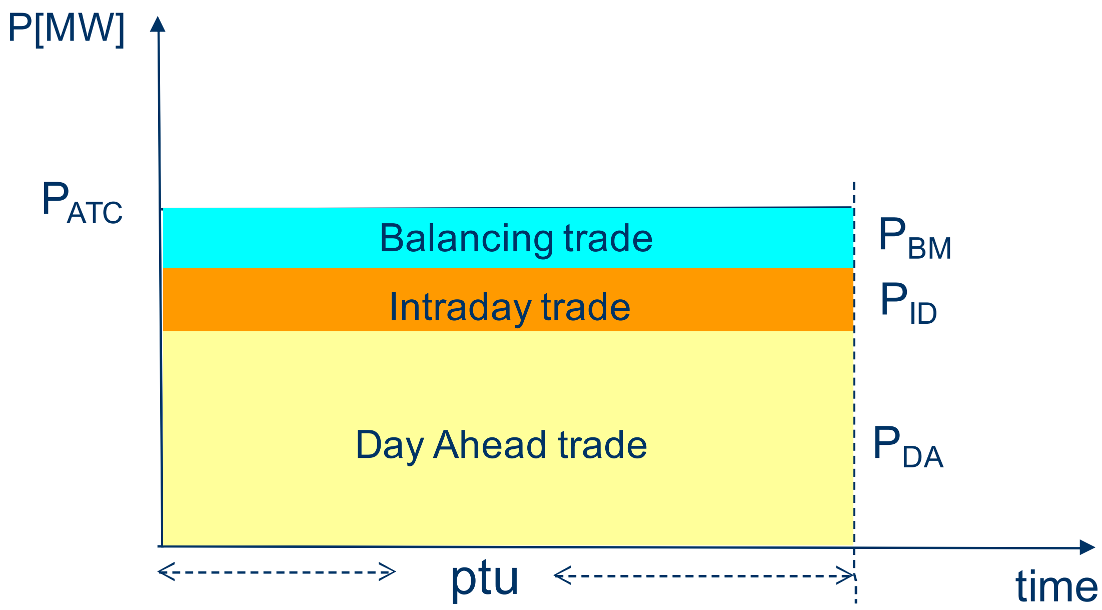


Figure 4-5: Utilisation of the transmission capacity per ptu

[17] Implicit Auction: With implicit auction the day-ahead transmission capacity is used to integrate the spot markets in the different bidding areas in order to maximize the overall social economics in both (or more) markets. The flow on an interconnector is found based on market data from the marketplace/s in the connected markets. Thus the auctioning of transmission capacity is included (implicitly) in the auctions of electricity in the market. (Source: Nord Pool Spot)

4.7.1 Example of reservation of HVDC capacity for Balancing trade on a separate link

The agreement between the Norwegian TSO Statnett SF and the Danish TSO Energinet.dk, which is the basis of the application for concession for the HVDC link Skagerak 4 [31], includes reservation of 100 MW out of 700 MW ATC for balancing services. The exact calculations behind this agreement are not known. The application states, however, that the costs for producing these services is much lower in Norway than in Denmark and it is therefore expected that this part of the trade will be added social economics and provide benefit for both parties. The expectation is that the trade of balancing services will provide a significant higher income per MW reserved than the alternative DA trade.

4.7.2 Assessment of benefit of reservation of HVDC capacity with simultaneous optimization of all parallel HVDC links

Note that the discussion in this section differs from the commercial example presented in the previous section. This is primarily related to the effect of parallel utilization of the HVDC links and the calculation of the HVDC capacity reservation cost.

Modelling

A three stage fundamental model is used in this analysis, depicted in Figure 4-6, which is presented in detail in [32]. It simulates an integrated Northern European regulating power market, which is based on a common day-ahead market, including the Nordic countries Denmark, Finland, Norway, Sweden and the continental European countries Germany and the Netherlands.

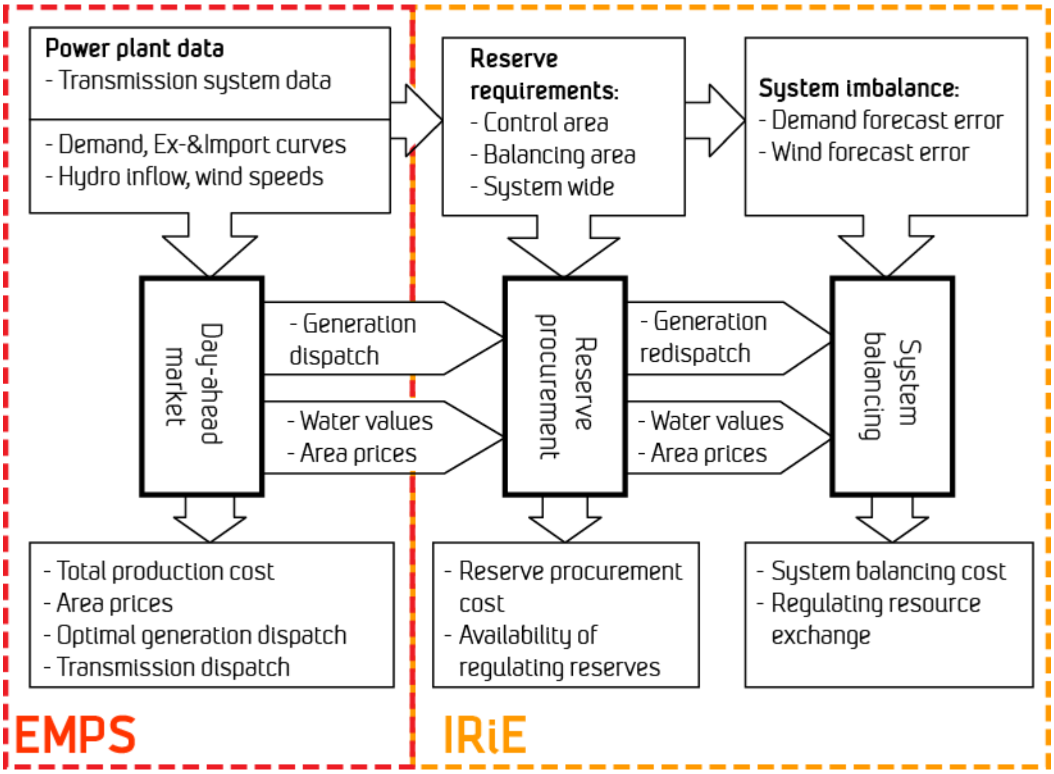


Figure 4-6: Model structure and workflow

The simulation is split into two general parts, represented by two different models, which are the Multi-area Power-market Simulator (EMPS) and the Integrated Regulating power market in Europe (IRiE) respectively. The latter is developed in the PhD work related to this project. The EMPS model represents a long- and mid-term optimisation, whereas IRiE has a short-term horizon.

__Analyses__

The calculations are performed in 3 steps as described below:

The day-ahead market step is implemented by EMPS. This model developed by SINTEF Energy Research is a long- and mid-term optimisation model determining the socio-economic optimal dispatch of electricity generation on a weekly basis, assuming perfect market behaviour with a time horizon of several years. Weeks are divided in several subsequent periods, by which an hourly resolution of the optimisation process can be achieved.

The in- and outputs of EMPS are indicated in Figure 4-6. Transmission lines connecting the areas are modelled by net transfer capacities (NTC) including linear losses. The results and output of this model is the optimal generation dispatch, area prices and the water values for the Nordic reservoirs. The water values are the opportunity costs of the stored water and are used as production costs for the hydro power plants in the subsequent steps.

The reserve procurement is performed after the day-ahead market clearing, the remaining transmission capacity and the given reserve requirements in the control areas are taken into account. Regulating reserves are procured for each individual hour, taking into account start-up costs of thermal units and their reduced efficiency at partial load. In order to simulate an exchange of regulating reserves, required reserves in one control area can be procured in another if sufficient transmission capacity is available after day-ahead market clearing. The procurement is done in a socio-economic optimal way, based on marginal production costs of the thermal units and the water values for the hydro power plants.

The third step covers *the system balancing*, by activating the least-cost regulating reserves in order to compensate the system imbalance. The available transmission capacities are taken into account. In order to account for the geographic spread of the analysed system, the transmission losses are included by a linear approximation. The balancing is done for each PTU using recorded imbalances from the respective control areas as an input. The costs for balancing the system are rough estimates based on the marginal production costs of thermal units and the water values for hydro units. However, the definition of balancing costs is done in a way that supports a utilization of hydro regulating reserves instead of thermal ones.

Results

The results from the simulations show that a small reservation of transmission capacity increases the exchange of regulating resources significantly. This also results in a significant reduction of reserve procurement and system balancing costs. However, this cost reduction is far lower than the decrease in the socio-economic benefit in the day-ahead market. Looking at different participants in the day-ahead market it turns out that the outcome of this reservation is different for producers, consumers and the TSOs. Especially for the TSOs there is a benefit of reserving transmission capacity for reserves in both the day-ahead market and the regulating power market. As the TSOs are operating the links, the analysis suggests that it would be profitable for them to implement such a capacity reservation. This calls for an active role of the regulators in order to achieve the best socio-economic outcome. The overall decrease of the socio-economic benefit suggests that such reservation is not profitable to be implemented when the exchange of all the parallel HVDC links are optimized.

A more detailed description and discussion of this subject is presented in the paper [32].

4.8 Pricing principles

There are several options with regard to the pricing of the balancing services that will be exchanged, and this topic might turn out to become one of the main challenges. This is related to the different interests from the point of view of the large producers who wants to optimise the corporate profit of their production capacity in the most attractive geographical areas, e.g. in the southern part of Norway, compared to the providers having regulation capacity in more distant units.

One option is to copy the French – UK scheme and let the TSOs offer the available balancing resources in the balancing market on each side at the national price referred to the merit order list. The volume and price offered will then be incorporated in the merit order list on the opposite side. Note that UK doesn't allow the foreign bids to affect the national imbalance price.

A second alternative is to use the mid price principle which means that the settlement price of the exchange will be the difference of the marginal price on each side divided by two.

There is also a question of how to include the costs of reservation of the reserves (regulation objects) in the bids. It seems to be fair that the TSOs would recover the costs related to capacity procurement e.g. via the RKOM[18] market in the Norwegian case.

If automatic secondary control will become a separate trading product both individual and coordinated contracts are optional solutions.

Examples of alternative pricing strategies for exchange via HVDC are given in Chapter 5.3.

[18] RKOM is the Norwegian option market for reserves

5 POTENTIAL TRADING MODELS

In the following alternative trading and exchange schemes for the exchange of balancing energy between the two separate synchronous systems are discussed with reference to the general approach presented in the parallel report "Balancing Market Design" [2].

The utilisation of the HVDC links and the principles for reservation of capacity for BM and ID trading are central issues with regard to the future trading schemes as discussed in Chapter 4.7. So is also the control of the HVDC flow, where direct set point regulation could be linked to the automatic secondary control (LFC) in one or both systems.

In this chapter we will mainly focus on the technical aspects, trading options and the distribution of benefits from the trade referring to the following basic models:

"Imbalance netting ": Automatic control of the HVDC flow with the purpose of avoiding counter regulation in the two systems.

BSP-TSO trade: Trading scheme where the BSP in one system can offer balancing resources in the other and possibly in both systems. The main purpose of this scheme is to provide flexibility for the market player and thereby incentives for innovative schemes.

TSO-TSO trade: Trade facilitated by the TSOs on both sides. Three levels of development are discussed: a) TSO as an intermediary for exchange between single BSPs in one area and the TSO in the other - or between the respective balancing markets b) Introduction of a separate voluntary pool and c) Common merit order list.

5.1 Imbalance netting

In the description of general market designs in [2] ACE-netting was introduced as an obvious first step towards the integration of balancing markets.

ACE-netting implies potential benefits from reduced counter regulations in two control areas within the same synchronous system.

If the ACE of one control area is positive, and the ACE in another control area is negative, only their net effect influences the system frequency. The load frequency control of the cooperating control areas are adapted to take into account only the net ACE of the combined areas, thus avoiding upward regulation in one control area and at the same time downward regulation in the other area. This means that the individual ACEs of the control areas become "uncontrolled", and in reality these areas become one common control area from the point of load frequency control.

Similar netting can be obtained between separate synchronous areas. We choose to call this ***imbalance netting***, which is more general and valid regardless if ACE is used in the cooperating areas or not. Specifically for the case of the Nordic system, the system frequency is used as the only control signal, and ACE is not a relevant concept.

However, when looking at two interconnected control areas, each within a separate synchronous system, it can be beneficial for both systems to change the flow on the interconnection in a situation where one system needs upward regulation, and the other system downward regulation.

The concept is illustrated in Figure 5-1. In the figures in the following we generally define "Synchronous System 1", which constitutes one control area and therefore only uses the frequency deviation to govern the load frequency control (like the Nordic system), and "Synchronous System 2", which exists of several control areas using the ACE as control signal (like the Central European system). This is done to relate the concepts to e.g. the exchange over NorNed. However, the concepts are more general and just as relevant if both systems are divided in control areas.

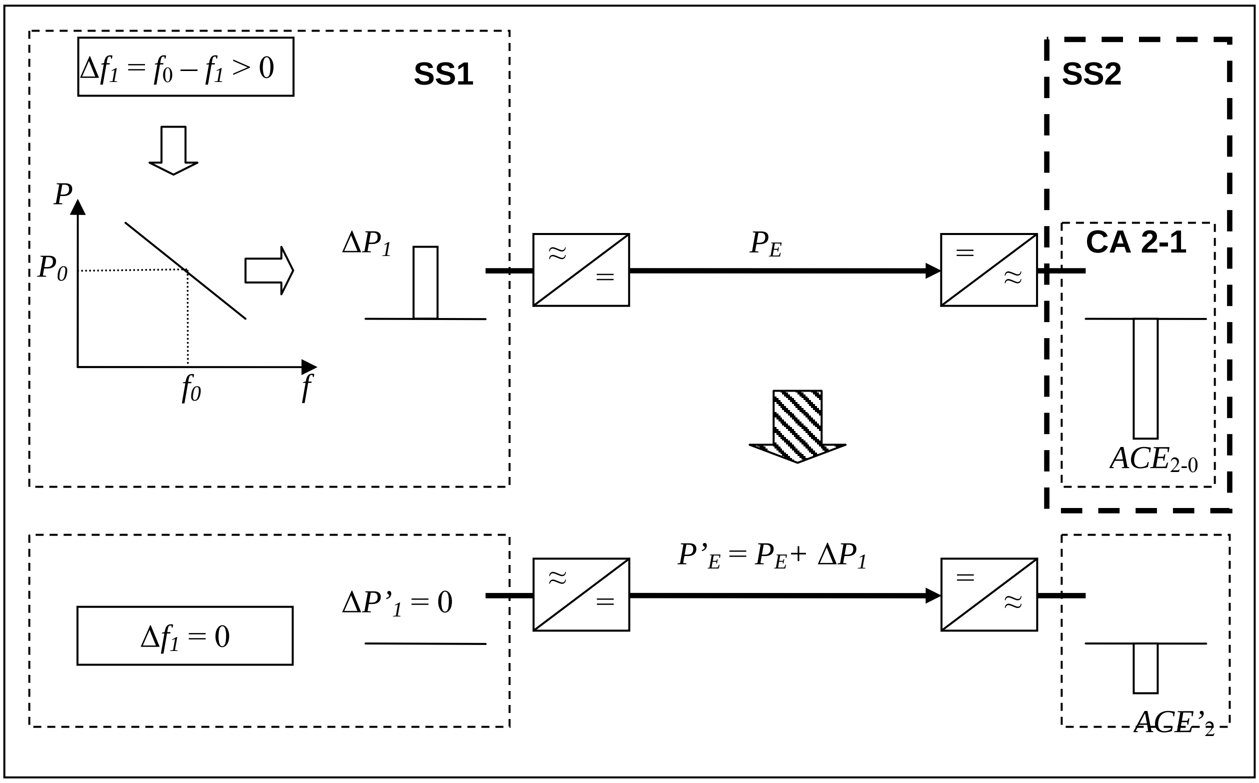


Figure 5-1: Imbalance netting between synchronous systems

On the upper left hand side of the figure a synchronous system is indicated where the whole system is one control area from the point of load frequency control, i.e. the frequency deviation Δf serves as the only control signal. Through the system's power frequency characteristic, the frequency deviation can be converted to a power deviation. In the figure a positive frequency deviation is indicated, and in theory the resulting ΔP_1 would restore the frequency to f_0. This would be the purpose of either secondary or tertiary control in this system, and without interaction with the other system, a downward regulation ΔP_1 would be performed. On the upper right hand side of the figure, another synchronous system is indicated, and within this system a control area with ACE-control[19]. In the actual situation the control area $ACE_{2\text{-}0}$ (equal to $P_{measured} - P_{program} + K_r \cdot \Delta f_2$) is indicated to be negative. Without interaction with the other system, the automatic load frequency control of the control area would initiate upward regulation to bring the ACE back to zero. The power flow on the HVDC interconnection between the systems is P_E.

Instead of undertaking two separate control actions in the opposite direction, it would be possible to change the flow on the interconnection. This is indicated in the lower part of Figure 5-1. If the flow from system 1 to system 2 is increased to $P_E + \Delta P_1$, this will have the same effect as decreasing production with the same amount for system 1, and the frequency will be restored to f_0. System 2 will see an increase in injected power, with the same effect as an upward regulation with the same amount. In the figure the absolute value of ACE_2 is greater than ΔP_1, so in system 2 the ACE is not brought back to zero, and the remaining deviation will have to be handled in the conventional way. We thus assume that the system with the highest absolute deviation is responsible for the remaining deviation after the imbalance netting.

With this arrangement both systems reduce their regulation efforts, and therefore both the volume and often the price of regulation. On average the prices for upward regulation will go down, while the prices for downward regulation will go up. This is of course an advantage for BRPs with imbalances (the “consumers”), and a disadvantage for BSPs (the “producers”).

A negative side of this arrangement is that the benefits may be unevenly distributed between system 1 and 2. If for example the costs in system 2 are significantly higher than in system 1, the benefits for system 1 are obviously much greater. In this case a form of payment from system 2 to system 1 would be reasonable to obtain a more equal sharing of the benefits. Of course this leaves difficult questions about the size of the payment and even more about who would receive it. Because the BSPs in system 1 are the losers of the agreement, they would be the natural beneficiaries, but it still would not be clear how the benefits would be divided. A possible option would be to divide it in accordance to periodical regulation provided by each BSP.

A possible realisation is illustrated in Figure 5-2.

[19] If system 2 is the ENTSO-E Central European system, the control area can be one of the existing control areas (e.g. the Netherlands), or a balancing region existing of several control areas. Even if several existing control areas (to some extent) merge into larger balancing regions, the resulting region will still have an Area Control Error that can be used in the present context.

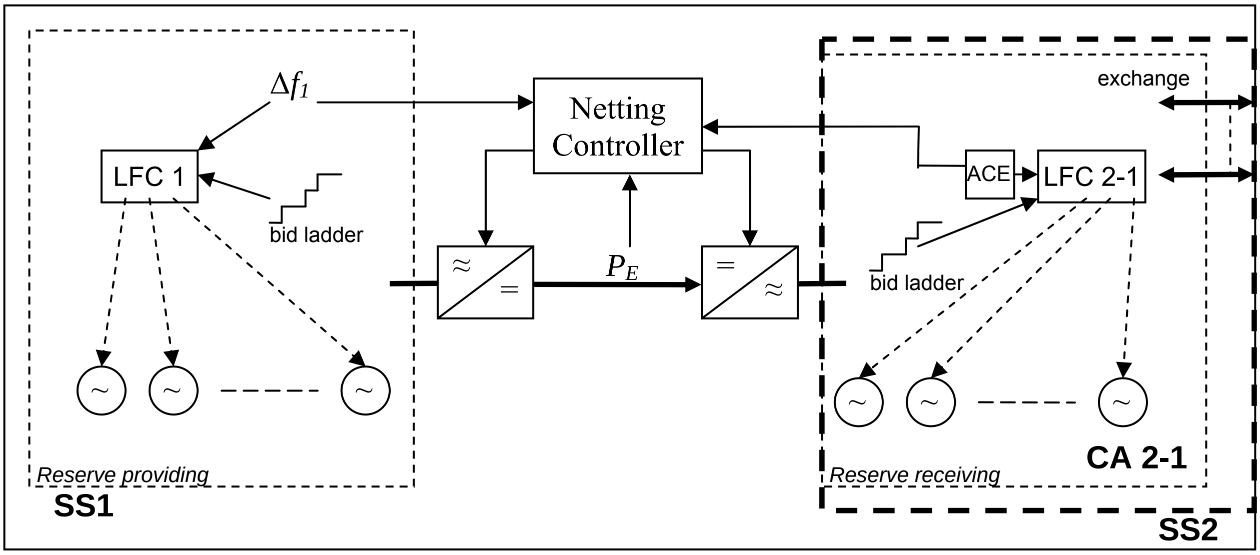


Figure 5-2: Netting controller for imbalance netting

Synchronous system 1 on the left hand side uses the deviation from the system frequency f_1 as the control signal for secondary (or tertiary) control. The bid ladder for the balancing market is used by the load frequency control LFC1 to select the generators (or consumers) for the next regulation action. Synchronous system 2 uses the deviation from the system frequency f_2 and the deviation from the exchange program with the other control areas within the synchronous system to calculate the Area Control Error. Based on ACE and the bid ladder, the actual generators are selected for the necessary regulation action.

The "Netting Controller" takes as input the frequency deviation Δf_1 in system 1 and ACE in system 2 as indicated by the arrows. It also takes into account P_E, the current exchange between the areas, because this limits the extent to which netting is possible. E.g. it is not possible to net a positive deviation in system 1 with a negative deviation in system 2 if there is already maximum export from system 1 to system 2. If the deviations in the system have the opposite sign ($\Delta f_1 > 0$ and $ACE_{2\text{-}1} <0$ or $\Delta f_1 < 0$ and $ACE_{2\text{-}1} >0$) *and* there is available capacity on the interconnection in the necessary direction, the Netting Controller sends a signal to the HVDC controller to increase respectively decrease the flow in the desired direction.

We have not in detail looked at the applicability for tertiary reserves as presently used in the Nordic system. However, the relevant dynamics and time constants are probably hard to combine with relatively slow manual actions, and therefore this model seems most relevant for secondary reserves also in "system 1".

Compared with imbalance netting within the same synchronous system, this is obviously more complicated. Still, regulation actions would be reduced at a relatively small cost, basically the adaptation of HVDC controller. An advantage is also that this form of imbalance netting can coexist with other forms of interaction, cf. the next sections. A significant challenge is a fair distribution of the benefits as discussed above.

5.2 BSP-TSO trading

BSP-TSO trading means that Balancing Service Providers (normally generators but in principle also consumers) are allowed to bid in another control area, or in the present case, another synchronous system. For a synchronous system, the principle is illustrated in [23] Section B-D7.1 for secondary control and Section C-D2.1 and C-D2.2 for tertiary reserves. In the case of two synchronous systems, it is necessary to control the flow over the interconnector and possibly also the generator for the balancing area to be effective in the control area of the "Reserve Receiving TSO" in the words of ENTSO-E.

We will first only focus on the exchange of balancing energy, disregarding reserve capacity. We assume a market where bids for the balancing energy market are submitted *after* the clearing of the day ahead market. At this stage it will be known how much exchange capacity on the interconnector between the systems is available for the exchange of balancing energy, and the reserve receiving TSO will of course only ask for bids from the other system if there is transfer capacity available after the clearing of the day ahead market.

One challenge with this model lies in the bidding strategy of the BSPs. In principle each BSP can now bid in two separate markets. Naturally they would primarily want to participate in the market with the highest potential prices. If they are allowed to bid in only one market, a possible outcome of this is that most BSPs bid in the market with the highest price. If there are many BSPs, competition will move their bids in the direction of their marginal costs. The winner of the scheme would be the BRPs in the system with the highest expected prices. Correspondingly, the losers would be the BRPs in the system with the lowest expected prices, but also security of supply in the low price system could be reduced because of the lack of balancing resources.

Another option is to allow the BSPs to bid in both systems. The TSOs would then use the bids on a first-come-first-serve basis. This would give a more flexible use of the available reserves, but less predictability on what would actually be available.

This scheme is not very attractive for Norwegian BSPs as long as the demand for balancing energy in other synchronous systems is limited, because competition would drive prices down to marginal costs. An issue is also to determine which BSPs are eligible to participate. If more interconnections are built and if the TSOs in the other systems are willing to buy balancing energy, and especially if they are willing to import a higher share of their reserves, this will gradually increase demand and prices. At the same time, reserve capacity will be removed from the Nordic system, and increase prices there.

An illustration of a possible realization is shown in the figure below.

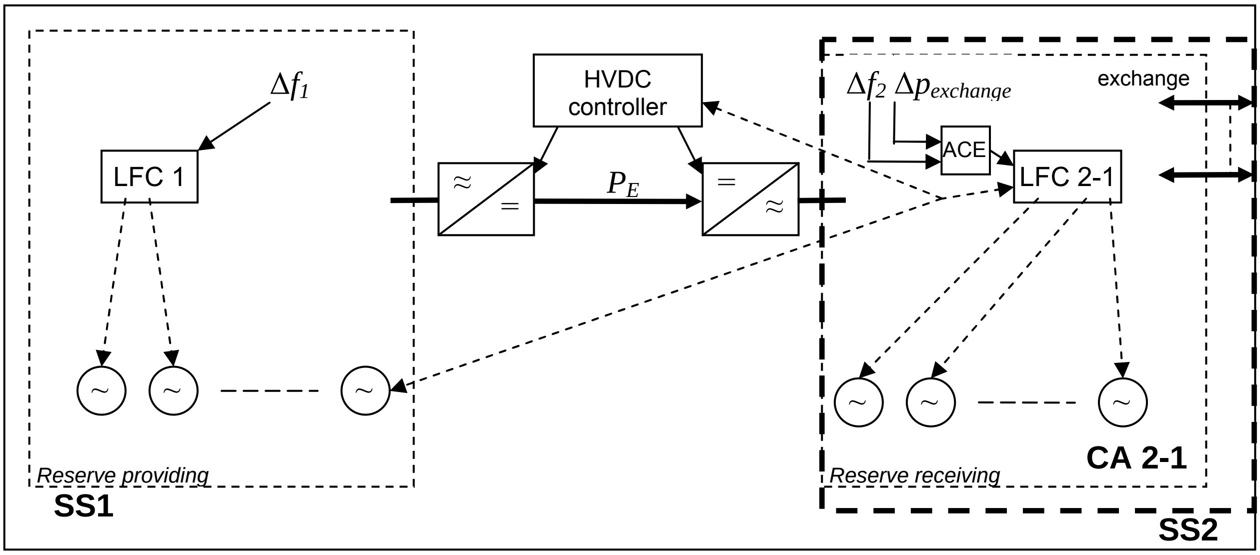


Figure 5-3: BSP-TSO trading

Like in the previous section, the system on the left hand in the figure only uses the frequency deviation as a control signal, while the control areas in the right hand system use the Area Control Error. The left hand system is the reserve providing system, while the right hand system is the reserve receiving system. The rightmost generator in system 1 is now no longer (actively) connected to the load frequency control in system 1, but instead to the load frequency control in system 2. If this particular generator is the next bid to be activated on the bid ladder of the LFC of control area 2-1, it must first be checked that there is available transfer capacity on the inter-connection. This can in general not be guaranteed, because other events may have changed the flow from the calculated day ahead market solution. If transfer capacity is available, a signal is sent to the HVDC controller that will change the flow on the interconnection correspondingly. Simultaneously, the production of the actual generator in system 2 is changed with the same quantity, modified for the marginal change in losses in system 1.

The activation of the bid could also be made through the reserve providing TSO as described in [23]. In this case this TSO would have a more active role, but it would not change the principal properties of the model.

This scheme is applicable for both secondary and tertiary reserves.

An important market design issue is how the imbalance of the participating BSP is calculated [6]. If the BSP does not deliver, it should pay the balancing price in the reserve receiving (presumably high price) system. If it pays the (presumably lower) balancing price in the reserve providing system, this opens up for gaming by not delivering, getting paid the high price and paying the low price for the imbalance. However, the actual imbalance is in the reserve providing system, so this requires a careful design of the settlement rules.

Security of supply does not need to be compromised as long as sufficient reserves are kept available within each system, cf. Figure 2-4, but an issue is how to ensure this.

5.3 The TSO-TSO model

The TSO-TSO model can take many different forms, and is applicable both for secondary and tertiary reserves. In the following we will discuss several models that are relevant for cooperation between synchronous systems.

The principle characteristics of the model are shown in Figure 5-4.

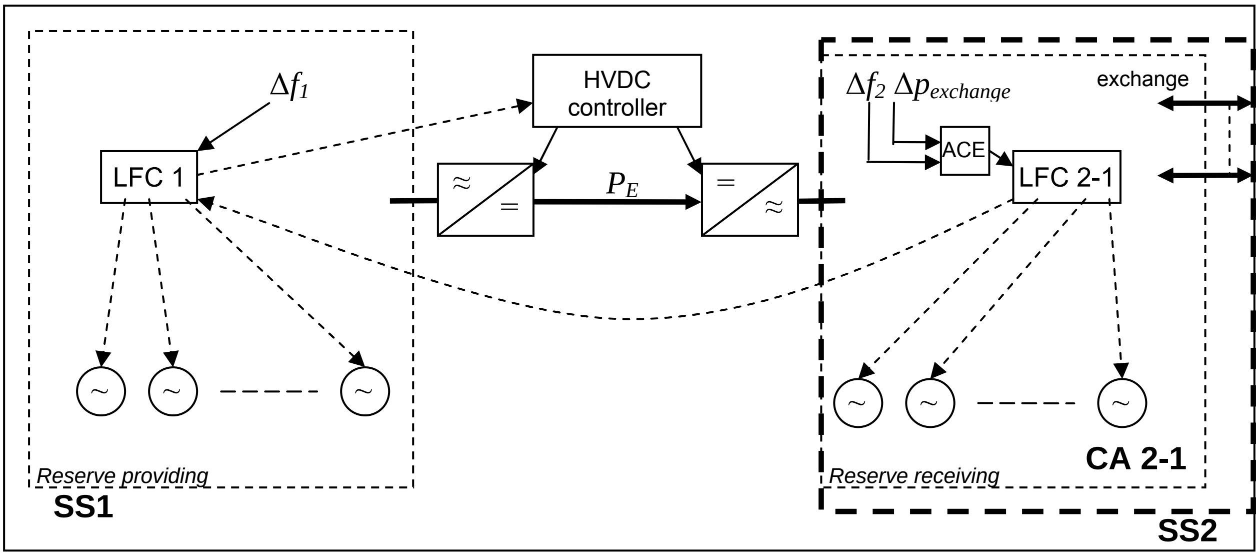


Figure 5-4: TSO-TSO trading

This figure is quite similar to Figure 5-3, but in this case the reserve receiving TSO does not directly control the BSP in the reserve providing system, but acts through the TSO in the latter system. In this case the latter TSO would probably also send the flow change signal to the HVDC controller, but this may depend on implementation details.

5.3.1 TSO acts as intermediary

In this model the TSO is basically an intermediary between the reserve receiving TSO in the other system and actual generators in its own system. There will be a direct coupling between adjustment of the cable and the participating generators. The only effect on the reserve providing system will be through increased or decreased losses. This model can be further organized in many different ways, e.g.

- Daily bidding from all BSPs
- Periodical bidding from all BSPs
- Daily or periodical bidding from dedicated BSPs

From a market point of view, the first case is equal to the model described in the previous section, but the realization of the control process is different.

Periodical bidding implies that the TSO holds regular auctions (weekly, monthly…) for balancing services directed towards the other synchronous system. The bidding includes at least a price and a quantity for balancing energy, and might include a reservation price for capacity. However, the reserve receiving TSO would hardly pay for capacity if it cannot at the same time reserve interconnection capacity, which may be problematic (see also Chapter 4.7).

In both the first two cases *all* generators can in principle participate, but there would be a requirement of Automatic Generation Control for the case of direct coupling between the regulation of the cable and the generators. This would not be the case for tertiary control. All BSPs would in principle have the same opportunity to participate, but it may be necessary to take into account grid effects. If losses are not taken into account, this means that the TSO pays for the losses, and they will ultimately be paid by all market participants through the grid tariffs, but the effect may also be decreases in losses. Specific analysis for particular cases is necessary.

Another alternative is that only dedicated BSPs participate. To constitute a level playing field, in principle there should be an open process (e.g. an auction) to determine who should participate.

5.3.2 TSO is an active provider of balancing services

We now assume that the TSO in the reserve providing system is the commercial counterpart of the other TSO, without a direct link with BSPs. The reserve providing TSO must then in some way obtain the balancing resources within the system. The obvious way is to use the existing balancing market(s) for secondary and/or tertiary reserves.

In principle all combinations of secondary and tertiary control should be possible, cf. the table below.

Table 5-1: Combinations of control

<table>
<tr><th></th><th>Reserve receiving system</th><th>Control of HVDC setpoint</th><th>Reserve providing system</th><th>Example</th></tr>
<tr><td rowspan="4">Type of control</td><td>secondary</td><td>automatic</td><td>secondary</td><td>-</td></tr>
<tr><td>secondary</td><td>automatic</td><td>tertiary</td><td>Netherlands – Norway</td></tr>
<tr><td>tertiary</td><td>manual</td><td>secondary</td><td>-</td></tr>
<tr><td>tertiary</td><td>manual</td><td>tertiary</td><td>UK – France</td></tr>
</table>

It is assumed that the cable is controlled directly (or indirectly through the other TSO) by the reserve receiving system. As long at the demands from the reserve receiving system are marginal compared with current deviations in the reserve providing system, tertiary control can be acceptable, but should this increase significantly, secondary control will be required.

This model is used for tertiary reserves on the interconnection between France and the UK [6] .

An advantage of this model is that the activation of balancing resources in the reserve providing system is done in the optimal way, based on the bid ladder of this system. Resources need not be divided in different groups, and regulation in the wrong direction (as seen from the need of the reserve providing system) is avoided.

There are several challenges related to this model. One is how the TSO in the reserve providing system should bid in the other system. The TSO has no balancing resources, and must use the resources within its system. But although the bids are known, the TSO will not know how much of balancing power will be activated in real time. Moreover bids may be changed up to relatively short time before operation. Therefore it is impossible for the TSO to know the balancing price beforehand, and there is no obvious price to bid in the reserve receiving system. Somehow the TSO must make an estimate of the needed regulation volume, and by use of the bid ladder, the resulting balancing price in its system. If the estimate is unbiased, this will represent the expected marginal cost, and therefore it will be the optimal bid in a perfect market, assuming risk neutrality. This is described as "present practice" of National Grid in Chapter 2.2.1. Alternatively, a higher price could be used. According to [6] RTE's bids are determined in order to recover at least anticipated maximum costs on its "Mécanisme d'Ajustement". In general, the higher the price, the lower the utilization, and if the price is quite high, the service gets the character of an emergency service.

An apparent option seems to be dynamic pricing of the reserves, based on the cost of the current step on the bid ladder. This is illustrated in Figure 5-5.

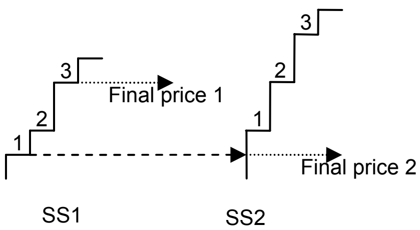


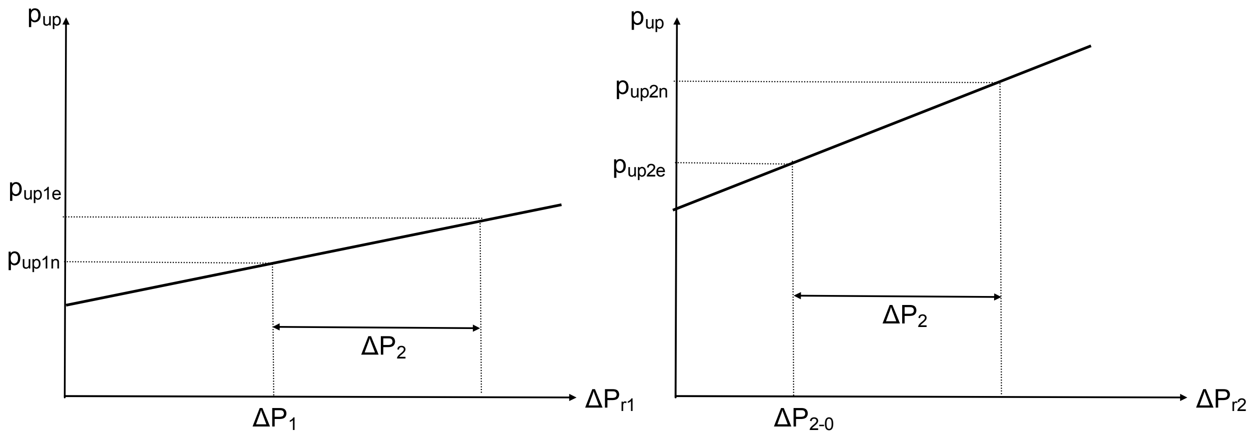
Figure 5-5: Dynamic pricing of exchanged reserves

In this case the Load Frequency Controller in the reserve receiving system would continuously receive information on the current marginal price in the reserve providing system. It could then dynamically update its own bid ladder, and choose the cheapest resource, which would either be one of its own BSPs or the other system through the interconnection. However, this system has a significant drawback, which is illustrated in the figure. The marginal price for up- or downward regulation will develop in the course of the PTU, depending on the needs of the system and bid prices. Assume that early in the PTU system 2 uses a cheap step of the bid ladder in system 1, but does not need further upward regulation later in the PTU. In the figure, the upward regulation price in system 2 would be equal to the price of the first step on the bid ladder of system 1 as illustrated. Later in the same PTU, system 1 needs upward regulation, and ends up with a higher price than system 2. The inefficiency is caused by the fact that the exchange is not mutual – if system 1 could have utilized step 1 of system 2's bid ladder instead, its price would have been lower. Also, the systems should probably have the same price. However, this is close to the case of a common voluntary pool or a common merit order list, discussed in Chapters 5.3.3 and 5.4.

Another challenge is the use of resources the TSO has reserved in a reserve capacity market. These are presumably acquitted for the use in its own market to satisfy the minimum need for reserves. In the BSP-TSO model or in the TSO-TSO models described in 5.3.1, a conflict can easily be avoided by requiring that resources that are paid for in the reserve capacity market cannot be exported, i.e. these resources cannot participate in bids in other systems. In the present model, there is a potential conflict between use in the own system or export to another system. Basically, the TSO will ensure that the required volume of reserves as indicated in Chapter 4.2.1 is available all the time. As long as this is satisfied, demand for regulation from the other system can be satisfied. Now assume that the TSO has paid for 300 MW in the reserve capacity market. In a situation where there is no need for balancing in the TSO's own system and at the same time export of 200 MW upward regulation, it may be alleged that reserves that were paid for by the users of one system are used in the other system, without a payment for the capacity costs. One way to avoid this is not to use the resources from the reserve capacity market for export, but this would not be economically efficient. Anyway, the TSO would (or should) not buy more reserves in the capacity market than indicated by the red and orange areas in Figure 4-1. Still, this can be a contentious issue, related to the next point.

A final challenge is the distribution of the revenues from the exchange. Initially, the TSO makes profits from selling balancing energy in the more expensive market while buying it in the cheaper market. The BSPs would increase their profits through the effect of increased prices (and decreased prices for downward regulation), based on the increase in the demand for balancing from the other system. But for the increased volume, they would still only get paid the price in their own system, while the price difference goes to the TSO. Of course this is what also happens with the economic exchange of energy over the same interconnections today, where the revenues pay for the cost of the cable. Depending on the agreements for use of the interconnection, this may or may not be acceptable. In any case, the BSPs would want to have a larger share of the benefits from selling balancing services to another system.

Calculation of revenues – example



The left hand panel illustrates the supply curve for upward regulation in Synchronous System 1. For simplicity we assume a continuous function showing the bid price p_{up} as a function of the required amount of upward regulation ΔP_{r1}. Without export, there is a need ΔP_1 for upward regulation, and the price is p_{up1n}. The right hand panel shows the corresponding picture for Synchronous System 2 that has a need for upward regulation equal to $\Delta P_{2-0} + \Delta P_2$, resulting in a price p_{up2n}.

If however the quantity ΔP_2 is delivered from System 1 to System 2, the price in System 1 will increase to p_{up1e} and in System 2 it will decrease to p_{up2e}. In the example the export is constrained and the price p_{up2e} is higher than p_{up1e}. How the exchange affects the market participants will depend on the market design. We first assume that the market price in System 1 is equal to p_{up1e} for all participants.

Model 1

TSO1 receives $\Delta P_1 \cdot p_{up1e} + \Delta P_2 \cdot p_{up2e}$ and pays $(\Delta P_1 + \Delta P_2) \cdot p_{up1e}$ which give a profit of $\Delta P_2 \cdot (p_{up2e} - p_{up1e})$. Without the exchange the profit of the TSO is zero, so this is the net gain of the exchange for TSO1.

The gain for the BSPs in System 1 is $\Delta P_1 \cdot (p_{up1e} - p_{up1n}) + \frac{1}{2} \cdot \Delta P_2 \cdot (p_{up1e} - p_{up1n})$ where the first term represents the *price* effect and the second term the *volume* effect.

The loss for the BRPs in System 1 is $\Delta P_1 \cdot (p_{up1e} - p_{up1n})$ which is caused by the *price* increase.

The economy of TSO2 is unaffected.

The BSPs in System 2 lose $\Delta P_{2-0} \cdot (p_{up2n} - p_{up2e}) + \frac{1}{2} \cdot \Delta P_2 \cdot (p_{up2n} - p_{up2e})$, where the first term represents the *price* effect and the second term the *volume* effect.

The BRPs in System 1 gain $(\Delta P_{2-0} + \Delta P_2) \cdot (p_{up2n} - p_{up2e})$ representing the *price* reduction.

Summing up and reorganizing these terms results in a total net gain of

$$\Delta P_2 \cdot (p_{up2n} - p_{up1e}) + \frac{1}{2} \Delta P_2 \cdot (p_{up1e} + p_{up2e} - p_{up1n} - p_{up2n}).$$

The first term represents the effect of the price reduction in System 2, while the second term

Calculation of revenues – example

represents the effect of the cost reduction for upward regulation.

Numeric example

ΔP_1 = 100 MW, $\Delta P_{2\text{-}0}$ = 200 MW, ΔP_2 = 200 MW, p_{up1n} = 50 €/MWh, p_{up1e} = 60 €/MWh, p_{up2n} = 120 €/MWh and p_{up2e} = 100 €/ MWh. Assume for simplicity that all regulation takes place at the start of the hour (of course this is not realistic, we could have assumed an average duration of *x* minutes and multiplied the numbers below with *x*/60).

TSO1 gains: 200 · (100 – 60) = 8000 €
BSP1 gain: 100 · (60 – 50) + 0.5 · 200 · (60 – 50) = 2000 €
BRP1 lose: 100 · (60 – 50) = 1000 €
BSP2 lose: 200 · (120 – 100) + 0.5 · 200 · (120 – 100) = 6000 €
BRP2 gain: (200 + 200) · (120 – 100) = 8000 €

The total gain of the exchange is 11000 €, 9000€ for System 1 and 2000 € for System 2, with the major winners TS01 and the BRPs in System 2, and the major losers the BSPs in System 2. Note that the numerical results for the BRPs and BSPs depend strongly on the assumptions, but the sign of the results will always be the same. The gain of the TSO1 will depend on the final price difference.

In the example the exchange is twice the domestic deviation. If we keep the same numbers as above, but with ΔP_1 = 1000 MW, the exchange is only a minor share of the domestic deviation. In this case:

BSP1 gain: 1000 · (60 – 50) + 0.5 · 200 · (60 – 50) = 11000 €
BRP1 lose: 1000 · (60 – 50) = 10000 €

The result for the other market actors is unchanged, as well a the total ain.

Model 2

Secondly we look at a market design where the BRPs in System1 pay the price p_{up1n}, while the BSPs receive p_{up1e}.

TSO1 receives $\Delta P_1 \cdot p_{up1n} + \Delta P_2 \cdot p_{up2e}$ and pays $(\Delta P_1 + \Delta P_2) \cdot p_{up1e}$ which give a profit of $\Delta P_1 \cdot (p_{up1n} - p_{up1e}) + \Delta P_2 \cdot (p_{up2e} - p_{up1e})$. Note that the first term is *negative* and that the TSO might lose on these transactions.
The gain for the BSPs in System 1 is like above, while the BRPs are unaffected, i.e. their gain is zero.

The situation in System 2 is as before.

Numeric example

With the same numbers as above:

Calculation of revenues – example

TSO1 gains: 100 · (50 – 60) + 200 · (100 – 60) = 7000 €

With these numbers, the gain for TSO1 is positive, however with a large price increase in System 1 and/or a large pre-exchange deviation, TSO1 can lose in particular hours. E.g. with the same numbers but ΔP_1 = 1000 MW, TSO1 would loose -2000 €.

To be able to estimate the long term effect it is necessary to do simulations.

Model 3

A third possibility would be to differentiate between BSPs that participate in the export of balancing energy, and those that serve the domestic market, paying them p_{up1e} and p_{up1n} respectively. Although this may be possible in specific cases, in general it would be hard to do this differentiation, and it would give incentives to gaming in order to receive the higher price.

When it comes to the *sharing* of the revenues in the case of Model 1, there are several possibilities:

1. Let the TSO keep the revenues.

This does not look a fair alternative, because the BSPs sell the actual service to System 2, the TSO is only a mediator. However, if the TSO is regulated in such a way that these revenues to not increase its revenue cap (implicit or explicit), these revenues would flow back to the market participants through reductions in the grid tariffs. The actual sharing between BSPs and BRPs would then depend on their shares of the grid tariffs.

Numeric example

Using the same example as above, we make the additional assumption that the BRPs pay 70 % of the grid tariffs and the BSPs 30 %. In this case of the 8000 € profit of TSO1 5600 € would be given back to the BRPs (with a delay), while 2400 would go back to the BSPs. In effect this would mean a price reduction of 5600/100 or 56 €/MWh for the BRPs (giving a final price of 4 €/MWh for imbalances), while the BSPs would get a price increase of 2400/300 or 8 €/MWh to 68 €/MWh. This example is somewhat special because the exchange is so large compared with the domestic imbalance. With ΔP_1 = 1000 MW, the price decrease for the BRPs would be 5.6 €/MWh, giving a final price of 54.4 €/MWh.

The numeric example shows that the division between BRPs and BSPs can be quite random and intuitively unfair. Effective imbalance prices become very volatile and unpredictable, which is a disadvantage with respect to incentives to be in balance. This model is not very attractive for the BSPs, and gives little incentives to provide additional balancing services. Another possibility is to do an *ex post* calculation of the increase in balancing prices caused by the export of balancing energy, and using a part of the TSO revenues to compensate the BRPs for this price increase. The disadvantage is that it becomes complicated and opaque.

2. Give the revenues to the BSPs.
This would be fair from the point of view that the BSPs deliver the balancing energy that is exported. A straightforward approach would be to share the revenues proportionally between all the BSPs that participated in the regulation in the actual hour, without distinguishing between them. Distinguishing between them would lead to similar problems as mentioned under Model 3 in the example above.

Numeric example

Using the same example as above, we make the additional assumption that three BSPs participate in the upward regulation in System 1, producing 50, 100 and 150 MW each for the whole hour.

The BSPs would receive $\frac{50}{300}, \frac{100}{300}$ and $\frac{150}{300}$ times 8000 € or 1333, 2667 and 4000 € respectively.

5.3.3 Additional voluntary pool

With an additional voluntary pool, the TSOs agree on sharing some of their resources in a common pool that is used on a first-come-first-serve basis. This common pool comes in addition to the local balancing resources in each system. The volume on the local bid ladders would be determined by the considerations discussed in the context of Figure 5-3, and the remaining resources can be placed in the common pool. The principle is illustrated in Figure 5-6.

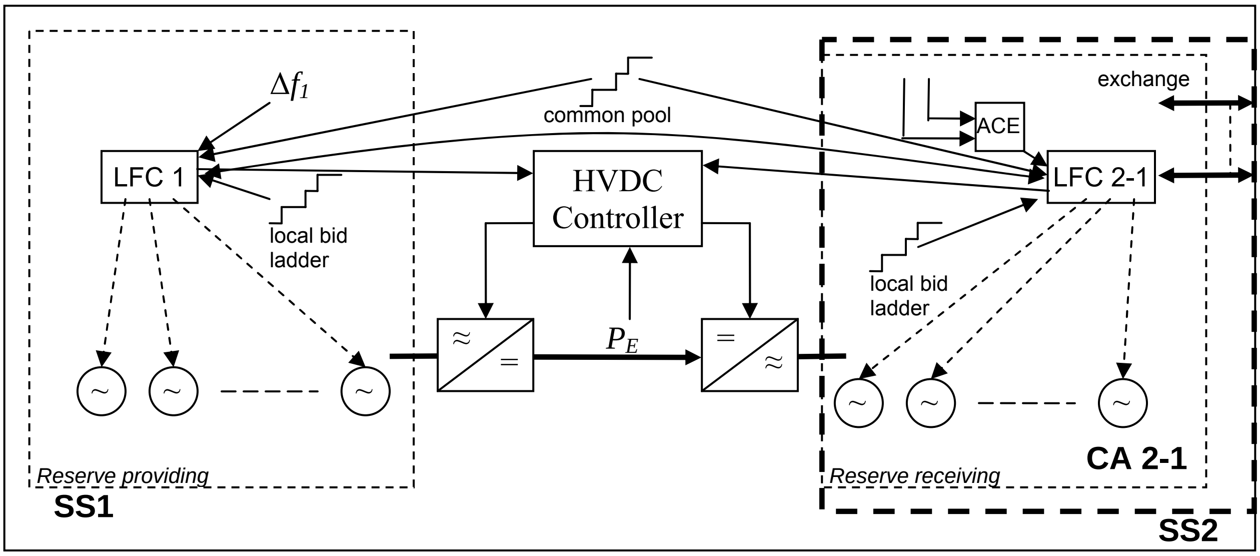


Figure 5-6: Additional voluntary pool

Whenever there is a need for regulation, the LFC compares the resources on the local bid ladder and the common pool. If the cheapest resource is on the local bid ladder, this is used in the “business as usual” fashion. However, if the cheapest resource is in the common pool, this is used instead. If the corresponding BSP is in its own system, no other action is necessary, but the resource must be marked as “used” so that also the LFC of the other system is aware of this when it assesses the resources in the common pool. However, if the BSP is in the other system, a signal is sent to the HVDC controller to verify if an adjustment in the desired direction is feasible, and to adjust the flow if this is the case (if not, local resources must be used). In addition a signal must be sent to the actual BSP to adjust the correspondingly. In the figure it is assumed that this is done through the LFC in the other system, as symbolized by the bowed arrow between the LFCs. Note however that this may be inefficient, i.e. the reserve providing system may actually be in balance after the change in the exchange or may even need regulation in the opposite direction.

The advantage of this model is that it has resources in a *common* pool, which is a step in the direction of using at least some common resources optimally. If the cost structure of the balancing resources in the systems is similar, only the more expensive resources would be placed in the common pool, and they would not be used much, but still constitute additional security for each of the systems. If the model works well in practice, the TSOs may also be willing to share more of their resources as discussed under Figure 5-3, and the model may gradually develop in the direction of the common merit order list discussed in the next section. If the systems have quite different characteristics, and one system has ample low priced balancing resources while the other system doesn’t (e.g. NorNed), the benefit of this model is greater, as the cheaper resources in one system are made available to the other, without locking them in as in the BSP-TSO model. A remaining inefficiency in the model is that as long as only some of the balancing resources are shared, balancing will normally be suboptimal. The systems may have different balancing prices even if there is available exchange capacity in the necessary direction.

Challenges for this model are *how* much resources to place in the common pool, *which* resources, e.g. taking into account price but also location, and how to divide the benefits. In this model, the systems would probably often have different balancing prices, depending on the marginal resource they have activated within the PTU. Then it would be natural that the BSPs receive the price in the system they have been activated in. As a result of this, it becomes more attractive for the BSPs in the lower cost system to be in the common pool. If the TSO keeps the cheapest resources in its own market, there will be a tendency to bid higher, to end up in the common pool. This would lead to upward pressure of the prices in the lower cost system, and a tendency towards equalizing of the balancing prices in the systems.

5.4 Common merit order list: the cost-minimizing model

Synchronous system 1 (or a control area within the system) and the connected control area in synchronous system 2 could have a common merit order list with a coordinated secondary control.

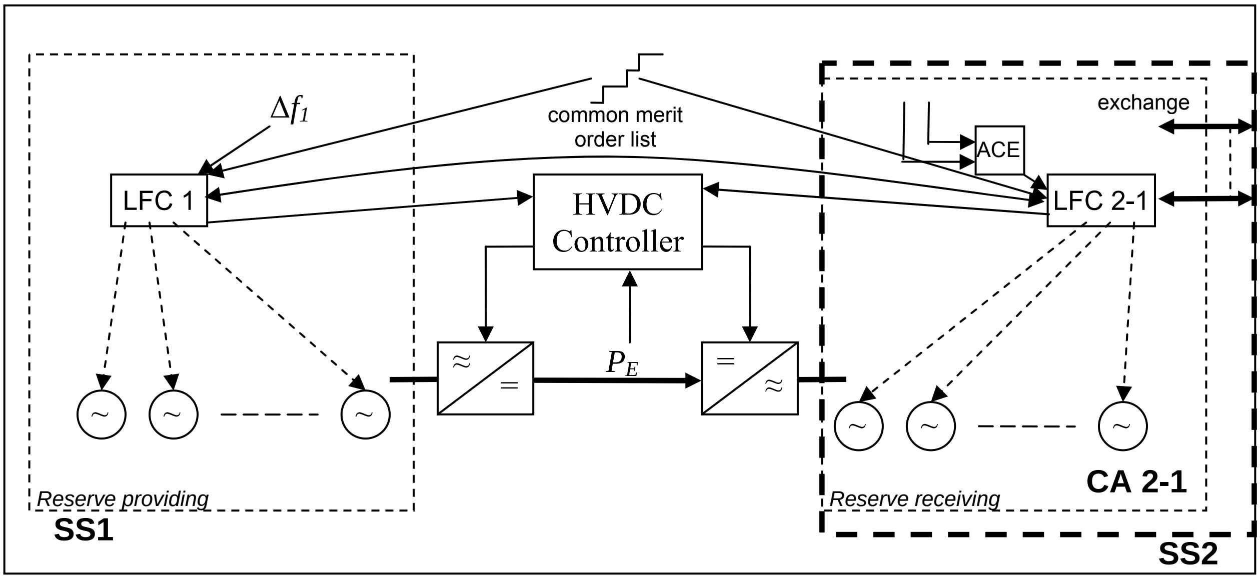


Figure 5-7: Common merit order list

So far we have discussed the context of one HVDC interconnection between two synchronous systems. The Nordic and Central European systems are however presently interconnected by a number of cables, and there are several plans for new cables. Within a synchronous system, it is ultimately irrelevant *where* electrically an up- or downward regulation takes place, as long as there are not transmission bottlenecks limiting the necessary change in flows. Of course, as long as focus is on a *control area*, the regulation must be within the control area to bring the ACE to zero. However, several control areas may be seen as one “virtual control area” or “balancing region”. When this view is accepted and the market organization adapted, optimal control within the whole area allows for a flexible utilization of *all* interconnections and all resources within the total connected system. This is illustrated by model calculations in the next chapter.

5.5 Model summary

In this chapter four different models for trading of balancing energy between two synchronous systems have been presented and discussed.

Least requiring is the Imbalance Netting model, where the exchange over the HVDC interconnection is changed whenever the interconnected systems have opposite sign imbalances and there is available capacity in the desired direction of the interconnection. This model may result in significant savings in spite of a low cost.

The TSO-BSP model appears to have the attractive property that it is relatively easy to introduce, because it does not require major changes in the market design. However, in the discussion we focus on the negative aspects of using the same resources in two different markets and the possibilities for significant inefficiencies.

The TSO-TSO model has three different implementations. In she first one the TSO is a pure intermediate in the TSO-BSP model. Compared with that model the advantage is that the TSO has more control. In the second one the reserve providing TSO is an active participant in the balancing market of the reserve receiving TSO, and in the third one, the Additional Voluntary Pool, the TSOs share some of their resources in a common pool. We have discussed the second implementation in most detail, especially focusing on the outcome for the various market parties (TSOs, BSPs and BRPs) and the sharing of the revenues of the reserve providing TSO. Simple examples show that the reserve providing TSO may be one of the major beneficiaries of such a scheme, and an important issue is how these revenues should be shared between market participants. In the example we illustrate how such sharing can be done with a one-hour perspective. An alternative is to take a longer perspective (e.g. one year) and share the TSO's revenues between all BSPs according to their annual delivered balancing energy. Details should be worked out further, but one option is to share the upward regulation revenues between all BSPs that have delivered upward regulation, downward regulation revenues between those that delivered downward regulation and using revenues obtained when there was no regulation in the reserve providing system to reduce grid tariffs. Long term simulations are necessary to work out the impact of the various schemes.

The final model concerns a fully integrated market, where reserves are activated on common criteria for the cooperating systems.

5.6 Comparison of alternative trading models

In Table 2 is the impact of the different trading models commented with focus on the following aspects:

- Reduction of counter regulation (one of the main sources of benefit in the German control area conflation)
- Feasibility with regard to automatic (secondary) and manually (tertiary) control actions
- Balance market price impact (e.g. Nordic Regulation Power Market (RPM))
- Balance service provider (BSP) income

The table shows that the TSO-TSO alternatives give the most cost efficient schemes with regard to the social economics. The TSO- BSP alternative does, however, provide economic incentives to central market player, which might be decisive for the development of future exchange corridors and schemes.

Table 2: Comparison of alternative trading models

Trading model	Reduce counter regulation	Control options		Economic impact	
		Secondary	tertiary	**Balance Market price**	**Balance Service Provider income**
Alt I Imbalance netting					
Automatic control referred to simultaneous imbalances	The scheme will reduce counter regulation in both areas	Ok	Ok	An unevenly distributed benefit between the two systems is a challenge. RPM price reduced due to less regulation need.	Less regulation need will reduce producer income
Alt II BSP –TSO					
Trading scheme where the BSP can offer balancing resources in the opposite and possibly in both systems.	The scheme will probably increase counter regulation within the selling area	Ok	Probably too slow?	Higher than today due to sub optimal regulation	High for those directly involved. Higher than the present system for others due to the reduction of resources available for the "local" TSO Will provide investment incentives
Alt III TSO-TSO					
Alt IIIa1. TSO acts as intermediary for BSP-TSO trade	More TSO control implies lower than II	---- "----	---- "---	-------------- " ---------------	-------------- "----------------
Alt IIIa2 TSO active provider of resources from existing MOL	No change	Ok	Ok	Higher than today due to increased demand	Higher due to increased demand
Alt III b Voluntary pool	--------- " --------	Ok	Probably too slow?	Higher than IIIa2 due to reduction in RPM resources	Higher due to increased demand and reduction in RPM resources
Alt III c Common MOL	Minimized. Optimal choice of control objects	Ok	Ok	Optimal common price	Probably higher due to higher demand

6 MODELLING OF BALANCING MARKET INTEGRATION IN THE NORTHERN PART OF EUROPE

The regulating reserves in the Northern Europe (NE) region are presently procured inside each control area except for the Nordic area and Germany where the cheapest regulating objects are selected from common merit order lists.

In the analyses presented in this chapter we illustrate by way of the detailed description of two specific cases how the implementation of a common Northern European cross-border balancing market influences the procurement and dispatch of balancing resources and how this changes cross-border flows. We also report cost savings for these particular hours.

The cross-border procurement of reserves takes into account transmission constraints through a simultaneous market clearing and reserve procurement. Although this is not in accordance with current practice, it could be realized by letting generators give simultaneous bids for energy and balancing. In any case the analysis shows the effect of cross-border procurement of reserves. The analysis also shows the effect of optimal utilization of reserves during system operation, and these results can also be obtained with other procedures for procurement of reserve capacity.

A more detailed description of the subject is given in the paper [33].

6.1 Modelling day ahead dispatch and balancing energy market

In the modelling approach the day-ahead dispatch and the balancing energy market are settled separately. Firstly the day-ahead market is modelled as a common market on an aggregate level for the whole European continent.

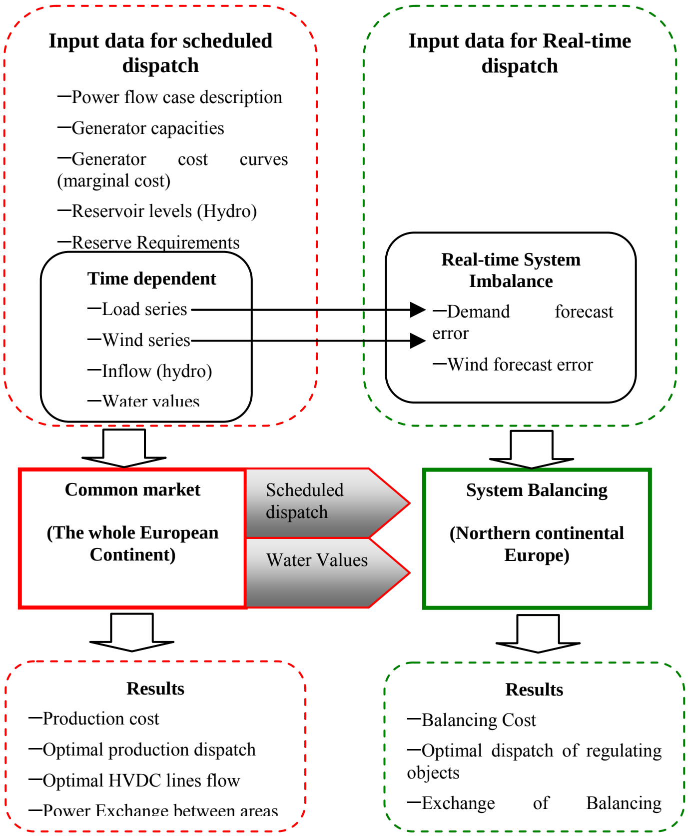


Figure 6-1: Schematic diagram of model approach steps

Reserve procurement is done simultaneously with the day-ahead dispatch. Reserve procurement is limited to the Nordic area, Germany and the Netherlands, designated as the NE area. Available transmission capacity is taken into account in the reserve procurement phase. Secondly the balancing energy market is modelled as a real-time power dispatch in order to minimize the cost of compensating for deviations from the initial market balance. The day-ahead market clearing results and real-time imbalances are used as an input to real-time system balancing model. Figure 6-1 schematically shows model steps.

Based on today's situation in the Nordic system each country is considered as one control area except Denmark where the western part belongs to the central European synchronous system. Before recent reforms, Germany was divided into 4 control areas and each was controlled by individual TSO, cf. Chapter 3. The Netherlands is separate control area.

In order to handle transmission congestion within control areas, they are divided into subareas. Figure 6-2 shows the modelled control areas and subareas.

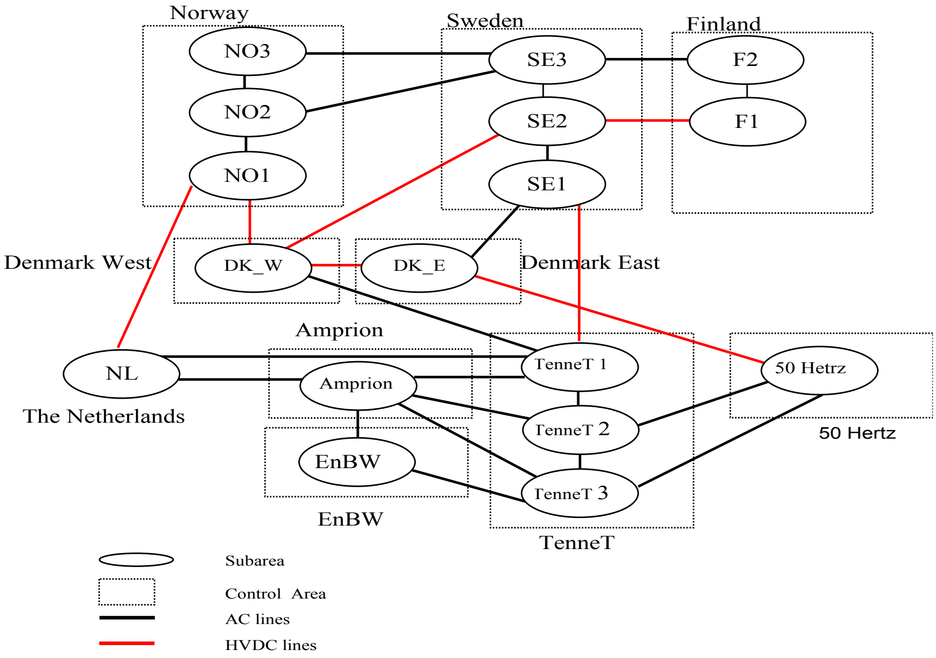


Figure 6-2: Model of the Northern European system

The grid model consists of the aggregated DC power flow data for the Nordic system, the Central European transmission network, Great Britain and Ireland. The power flow data for the three systems are merged together, resulting in optimal power flow problem for the whole system that consists of 1380 nodes, 2220 branches, 525 generators and several HVDC connections. The model has 32 generators in the Nordic system and a total of 142 in the NE area. Electrical parameters of transmission lines are estimated from their length and voltage level. They are adjusted in such a way that they to a significant degree reflect the most interesting bottlenecks in the system.

Thermal plants are either modelled providing base load with low/zero marginal cost and zero start-up cost or as regulating plants that also are able to provide spinning reserve. The latter plants are re-dispatched in real-time to compensate for real-time imbalances. They have higher marginal costs and start-up costs are modelled. Hydro generators have additional constraints related to reservoir use. Different types of generators are:

Non-regulating generation	Regulating generation
▪ Nuclear	▪ Gas
▪ Lignite-Coal	▪ Oil
▪ Wind	▪ Oil-Gas
▪ Renewable other than wind	▪ Hard-Coal
	▪ Hydro
	▪ Pump storage

Figure 6-3 depicts the share of regulating generation within the area.

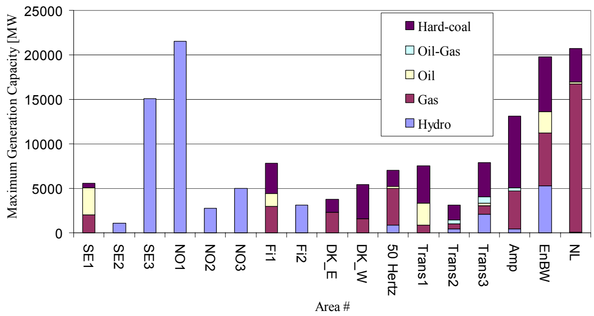


Figure 6-3: Installed regulating generation capacity in each subarea

As can be seen from Figure 6-3 hydro generation has the highest share of regulating capacity in the Nordic system. However bottlenecks in the network will not allow allocating all spinning reserve to the Nordic system, even without constraints in the amount of reserve procured outside each control area.

6.2 Example analysis

The following three cases for reserve procurement and real-time reserve activation are defined:

- Case I: represents the situation of the system before the integration of German regulating market. There is no possibility to exchange balancing services between each control area in Germany and the Netherlands, while there are exchange possibilities between the control areas in the Nordic system. Subareas inside the TenneT control area in Germany are modelled to handle internal constraints.
- Case II: represents the state of the system after integration of the four German control areas. Balancing power can be exchanged between the German control areas/subareas and also between the areas and subareas within the Nordic system. However it is not possible to exchange balancing services between the Nordic system, Germany and the Netherlands.
- Case III: represents the state of the system after full integration of balancing markets in the NE area. Reserves can be exchanged between all area and subareas shown in Figure 6-2. The required reserve can be procured outside the area, provided there is enough available capacity on the transmission line to the reserve providing subarea.

6.2.1 Day-ahead dispatch and reserve procurement for specific hours

Reserve requirements for each control area based on the actual values for each area. These values are the requirements for secondary reserve in Germany and the Netherlands and Fast Active Disturbance Reserve (FADR) in the Nordic system. The values are divided between the subareas relative to total area annual demand. The total up- and downward required reserve is 3308 MW and -2345 MW for Germany and the Netherlands respectively and 4485 MW and -4485 MW for the Nordic system.

6.2.2 Procurement cost

To illustrate the effect of the integration of the balancing methods, we show and discuss the detailed results of two specific hours in 2010.

- Scenario 1: hour 1171 which is an hour in the winter, 150 GW total load in NE area. In this hour the Nordic system assists the German and Dutch system with the provision of regulating reserve.
- Scenario 2: hour 7284 which is an hour in the late autumn, 156 GW total load in NE area. In this scenario congestion on the HVDC links lead the export of reserve from continental Europe to the Nordic system specially Denmark West.

Table 6-1shows the reserve procurement cost for the different cases, calculated as the difference in total dispatch cost with and without the reserve requirement.

Table 6-1: Total reserve procurement cost for the NE area [1000 €]

Sc.	Case I	Case II	Case III
1	96	89	78
2	130	121	112

As can be seen from Table 6-1 the cost of reserve procurement is reduced from the state of the system before German control area reforming to full integration of the regulating markets. For Scenario 1 and 2 it is reduced with 7 and 9 k€ respectively from case I to II and 11 and 9 k€ from case II to III.

6.2.3 Procured reserve

The analyses show in detail how plant dispatch and exchange between areas both on HVDC and AC interconnections change for different levels of integration of the balancing markets. This illustrates that it is possible and profitable to exchange reserves between synchronous systems, using existing HVDC interconnections. Tables with detailed results are given in [33].

For Scenario 1, integration of the German control areas (Case II) leads to a shift in the provision of upward regulation reserves from the 50 hertz, TenneT1 and Amprion control areas to the TennetT2, 3 and EnBW areas. Also note that the amount of upward regulation reserves in the Nordic system and downward regulation reserves in both systems significantly exceeds the requirement, indicating ample availability of such reserves in this hour. However, not necessarily all reserve are available for utilization due to transmission constraints.

The total amount of available upward regulation reserves within Germany and the Netherlands is equal or greater than 3308 MW, the requirement in those areas. Changing the generation dispatch in the German areas will alter energy exchange between the control areas and consequently the power dispatch in the other areas. The optimal procurement in the area NO1 also slightly changes as an indirect effect of the integration of the German areas.

In Case III, the total amount of upward regulation reserves procured within Germany and the Netherlands is reduced to 2582 MW, while the remainder is provided from NO1.

For Scenario 2, the transition from Case I to Case II has a similar but stronger effect than for Scenario 1, i.e. nearly all upward regulation reserves are procured in the EnBW area. However, full market integration, Case III, now leads to a slightly increased procurement of reserves in the German areas, which now supports DKW in the Nordic area, while the need for reserves in DKW was covered by imports from DKE in Cases I and II. However, in Case III these import opportunities are quite limited due to congestion between DKE and DKW, Scenario 2 illustrates that although the normal result would be export of reserves from the Nordic area to continental Europe, special circumstances and congestion can lead to the opposite result.

We have assumed that there are no limitations on the share of reserves in a control area that can be procured outside the area. Including such a constraint is straight forward, but would reduce the benefit of integration.

6.2.4 Real time balancing and activation of reserves

The model of real-time balancing is implemented as an incremental power flow where the inputs are the results of generation dispatch after day-ahead market clearing and the system imbalances. The model’s imbalances are represented by recorded imbalance scenarios for Germany and the Netherlands as well as the Nordic system. We use a common Program Time Unit (PTU) of 15 minutes, corresponding to the present practice in Germany and the Netherlands.

To model the cost of balancing in accordance with the actual behaviour of the balancing markets, increasing the costs of the hydro plants with 10 % for upward regulation and decreasing them with 10 % for downward regulation. For thermal plants costs are correspondingly increased and decreased with 40 %.

For the real-time balancing we focus on the NE area only – i.e. it is assumed that the Netherlands and Germany maintain their Area Control Errors with other neighbouring countries.

In Scenario 1, Cases I and II the activated volume is equal to the deviation within each area except for the Nordic system where there is a common market for balancing. This is also the case for Germany in Case II. In Case III, most of the reserve activation is moved to the Nordic system. Given the opposite direction of system imbalances in the Nordic and other systems, netting has occurred, implying a flow of 278 MW from the Nordic system to German and Dutch system in that specific hour. The high amount of this activated reserve is procured by the cheap Norwegian hydro generators located in NO1 subarea.

In Scenario 2, Cases I and II, the net activated reserve is -493 MW in the Nordic area and 72 MW for and German and Dutch systems. In Case III, the activated reserve is -280 MW and -140 MW for the Nordic system and German and Dutch systems respectively. Again there is a strong netting effect in the German and Dutch systems and a net export from the Nordic system to these systems.

Two additional issues must be discussed in this context. Firstly, with today's manual reserve dispatch in the Nordic system it would not be possible to change the set point of different number of generates at the same time. The proposed solution would require the use of Automatic Generation Control (AGC). This is presently discussed between the Nordic TSOs. Secondly, it may be necessary to include ramp rates to increase the realism of the analysis. Implementation is relatively straight forward by adding relevant constraints in the mathematical framework.

6.2.5 Cross border balancing energy exchange

The results of Scenario1, Case III shows that the capacity exchange on interconnections between the Nordic system and the German and Dutch system is increased with 278 MW, compared to day-ahead, showing the export of upward regulating power from the Nordic to the German and Dutch system. In the second scenario the exchange is increased with 212 MW showing the import of upward regulating power from the Nordic system.

The essence of the model presented in this chapter is that it takes a "control-region" view to optimize both the procurement and the utilization of secondary reserves. The major new contribution is that the control region consists of control areas in two separate synchronous systems and includes the HVDC interconnections between them. In the procurement phase, which in the model takes place simultaneously with the clearing of the day ahead market, the use of interconnections for the day ahead market or reserve capacity respectively, is the implicit result of the minimization of the total cost. During system operation, at any time cheapest regulation objects will be selected, taking into account congestion. Thus the cost minimizing solution for the balancing of total control-region will be found. The model can be seen as an extension of module 4 in Chapter 4.7.2 for a control region covering two synchronous systems. The model results clearly illustrate the feasibility of such a model.

7 CONCLUSIONS

The Balance Management project is focused on multinational exchange of balancing resources between within the hour of operation. This involves both reservations of reserves through the Capacity Markets and activation of reserves (energy) based on specific criteria related to the synchronous system frequency and/or the area imbalance (ACE).

This report is discussing special aspects related to exchange of balancing resources between the separate synchronous systems in Northern Europe. The discussion refers to the key principles published by the European Regulators' Group ERGEG, and to the recently reported experiences from the exchange scheme between UK and France.

The most important differences from exchange between control areas within one synchronous system are related to the separation of the two systems by HVDC links and the fact that the exchange will affect the frequency in two systems.

The Nordic region acts as one control area with a common merit order list for balancing resources. This means that only congestions in the grid should cause deviation from the merit order in normal operation, and in principle could all HVDC links to the Northern Central European (NCE) system be utilized for balancing resources in parallel. The ongoing merging of control areas in NCE, initiated by Germany, indicates a potential future exchange of balancing resources between the common Nordic and a common NCE merit order lists.

The benefit from the conflation of the originally 4 control areas in Germany is estimated to about 260 million EUR per year in total. This counts for large potential benefits from further integration.

The exchange of balancing resources between control areas is limited by the reserves needed for security of supply and to the forecast error related to consumption and wind in the respective area. The expected increase in wind production will affect the TSO routines with regard to defining the need for local reserves. Forecasts on daily basis will most likely be needed.

The efficiency of utilization of different balancing control objects with regard to network losses and geographical location is not systematically considered by the TSOs today. Load flow calculation shows that the difference from using a generator behind a congested corridor and alternatively a reducible load in a load centre could be up to 40 %. The share of control objects from industrial and/or residential consumption will most probably increase, which counts for control object efficiency assessments in real time operation.

6 different exchange schemes for exchange via HVDC connections are presented in this report, one related to imbalance netting, one between the TSO and a BRP in the opposite system and 4 alternative trading models where the TSOs on each side are mediators.

The TSO-TSO alternatives seem to represent the most cost efficient schemes with regard to the social economics. The TSO- BSP alternative does, however, provide economic incentives to central market players, which might be decisive for the development of future exchange corridors and schemes.

Two comprehensive models have been developed as a part of the PhD work in this project. The models are utilized in analyses of future exchange of balancing resources and integration of balancing markets in Northern Europe in this report.

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