

Modelling An Integrated Northern European Regulating Power Market Based On A Common Day-Ahead Market

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Abstract—A growing share of wind power production in the northern European countries results in an increasing need for regulating resources. An integration of the northern European regulating power markets can be socio-economically beneficial, especially regarding to the good capabilities provided by the Nordic hydro-based power system. An model of such an integrated northern European regulating power market is presented in this paper. The regulating power market is based on a common day-ahead market, including the Nordic countries Denmark, Finland, Norway, Sweden and the northern continental European countries the Netherlands and Germany.

The model of the regulating power market considers regulating reserve procurement as well as the activation of regulating reserves, taking into account available transmission capacity. Case studies are done, analysing different levels of regulating power market integration. It evinces, that there is a socio-economic benefit by integrating regulating power markets, which results in a system-wide procurement of regulating reserves and an exchange of regulating resources between the Nordic and the continental European power systems.

Index Terms – market integration, regulating resource exchange, reserve procurement, power system balancing, linear optimisation model

NOMENCLATURE

BSP	Balance Service Provider
EMPS	EFI's Multi-area Power-market Simulator
ENSTO-E	European Network of Transmission System Operators for Electricity
NTC	Net Transfer Capacity
PTU	Program Time Unit
TSO	Transmission System Operator
UCTE	Union for the Coordination of the Transmission of Electricity

I. INTRODUCTION

THE need for sustainable energy production leads to an increasing share of wind power production in northern Europe, notably in Denmark and Germany but also in the Netherlands. This prospectively significant share of intermittent wind power production results in a rising need

for balancing services in order to ensure a secure system operation [1]. The Nordic, especially the Norwegian hydro based power production system has capabilities for offering such balancing services to continental Europe, being provided via the increasing interconnection capacity between the Nordic and the continental European power systems.

With the Electricity Market Directives 96/92/EC and 54/EC the European Union enforces the contemporaneous process of the liberalisation and integration of the national European power markets. Regulation 1228/2003 thereby explicitly addresses cross-boarder issues [2]. There is already huge progress in coupling and integrating forward, especially day-ahead markets. Examples are the common Nordic day-ahead market (NordPool), the trilateral market coupling (TLC) between the Netherlands, Belgium and France or the market coupling between Denmark and Germany (EMCC). In the case of integrating regulating power markets, the first steps are taken by constituting regional cooperations. There still is a long way to go to achieve an integrated European regulating market, whereas a northern European regulating power market would already be an important development. The integration of regulating power markets will be essential in order to exchange regulating reserves [3].

There are several studies done on national regulating power markets, mostly investigating price behaviour, forecasting regulating power prices [4] - [6] and optimising the bidding strategies of market participants [7], [8]. A rough estimation of the economic value of exchanging regulating resources between the Nordic system and continental Europe is done in [9]. In order to estimate the possible socio-economic outcome of integrating northern European regulating power markets and the possibility of exchanging regulating resources, in this paper a model of an integrated regulating power market is developed, which is based on a common day-ahead market clearing. The modelled areas include the Nordic countries Denmark, Finland, Norway and Sweden and the northern European countries the Netherlands and Germany representing 2008's state of the system, shown in Fig. 1.

This paper is divided into eight sections. In sections II and III a short overview on the system which is modelled and on system balancing is given. Section IV summarizes the current state of regulating power market integration in Europe. In the next section V the developed model is described with

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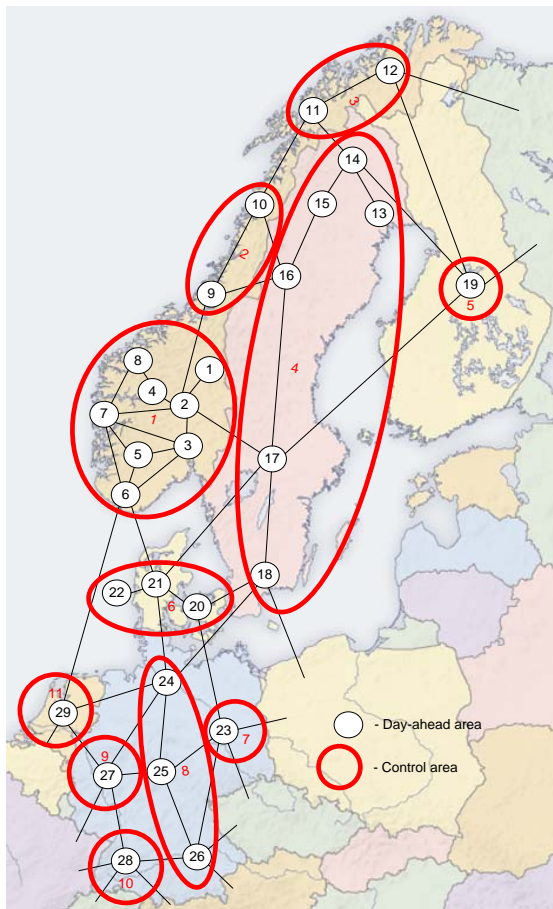


Fig. 1. Geographic overview of the modelled system

detailed formulations stated in the appendices B to D. To study the integration of the northern European regulating markets, different cases are studied in section VI. Their results are presented and discussed in section VII. Finally a conclusion of the paper is given in section VIII.

II. SYSTEM OVERVIEW

The modelled system, shown in Fig. 1, comprises the Nordic power system Nordel¹ including Denmark, Finland, Norway and Sweden and the northern part of the continental European power system UCTE including the Netherlands and Germany. An summary of the included control areas and the corresponding transmission system operators (TSO) is given in Table I.

The overall power generation in the Nordic part amounts to about 400 TWh annually, whereof 170 TWh are produced by hydro power plants. Still the power generation characteristics in the Nordic system differ significantly from country to country. In Denmark the annual power production of about 40 TWh generation is mainly thermal based, containing a considerable share of combined heat and power plants. There

¹In July 2009 ETSO's succeeding organisation ENTSO-E was founded, with Nordel and UCTE as the regional Nordic and Continental Europe subgroups. In the paper it is still referred to this systems as Nordel and UCTE, as also most of the literature include originates from these former organisations

TABLE I
CONTROL AREAS

No.	TSO	Abbr.	Former name
1		NO1	
2	Statnett	NO2	
3		NO3	
4	Svenska Kraftnät	SWE	
5	Fingrid	FIN	
6	Energinet.dk	DK	
7	50Hertz Transmission	DE1	Vattenfall Europe Transmission
8	transpower	DE2	E.ON Netz
9	Amprion	DE3	RWE Transportnetze
10	EnBW Transportnetze	DE4	
11	TenneT	NL	

is a rapidly increasing share of wind power production, which supplies about 20% of the total energy annually. In Finland, which has an annual power production of about 80 TWh, generation is based on a mix of hydro power production and thermal power production, including nuclear, hard-coal and gas power plants. In Sweden power generation with about 150 TWh per annum is mainly supplied by hydro power and nuclear power plants at an equal share. In Norway with an annual production of about 130 TWh, almost all the power production is based on hydro power [10].

The continental European power system is mainly based on thermal generation. The power production in the Netherlands and Germany sums up to about 740 TWh annually, whereof the Netherlands have a share of 105 TWh. The power production is based on a mix of hard-coal, gas-fired and oil-fired power plants, with a substantial share of CHP power plants. An increasing share of power is supplied by wind power generation, which currently is about 3.5% of the total annual production. The German system as the biggest part of the model has an annual production of about 635 TWh. A substantial share is provided by nuclear and lignite power plants, being together approximately 300 TWh per annum. The remainder is supplied by a mix of hard-coal, gas, oil, hydro and other power plants and an increasing share of wind power production as well, being about 40 TWh annually [11] - [14].

The energy volumes presented here are total annual volumes settled in bilateral contracts, future as well as forward markets. The shares between these different alternatives differ quite essentially between the northern continental European areas and the Nordic area. In the German day-ahead market run by EEX only about 20% of the total energy volume is settled, whereat more than 50% of the energy volume in the Nordic area is settled in the day-ahead market run by NordPool.

III. SYSTEM BALANCING

The day-ahead market clearing results in a balance between the expected electricity production and the expected consumption in the power system. During the real-time operation of the power system an deviation between the actual production and the actual consumption, called system imbalance, occurs quite likely. As electricity cannot be stored large-scaled, the

same amount of power has to be produced as is consumed at any point in time. This system balancing is one of the main responsibilities of a transmission system operator (TSO). To be able to balance the system, a TSO needs balancing services. Those services are provided by either producer or consumer, being called balance service providers (BSP).

Balancing services are divided in different types regarding their response time and the type of activation. Due to the different characteristics of the Nordic and the northern European systems, there is a difference in the definition of balancing services in those areas. In the UCTE balancing services are divided into primary, secondary and tertiary reserves. Primary reserves are fast-responding reserves with an activation time of 30 s, which react on frequency deviations in the system. Secondary reserves are automatically activated with a maximum activation time of 15 min, which react on the area control error (ACE). They are used to replace activated primary reserves and restore the nominal system frequency. In addition there are tertiary reserves, which are manually activated. Tertiary reserves are used to free activated secondary reserves [15]. In the Nordic system balancing services contain frequency controlled reserves (FCR), divided into frequency controlled operation reserves (FCNOR) and frequency controlled disturbance reserves (FCDR). Those reserves have a maximum activation time up to 30 s, being automatically activated, reacting on system frequency deviations. FCR equal the primary reserves of the continental European system. Furthermore there are fast active disturbance reserves (FADR) with an activation time up to 15 min, which are activated manually based on the total imbalance of the Nordic system [16]. A detailed overview of different balancing services definitions and specifications can be found in [17].

The provision of balancing services is either mandatory, contracted bilaterally or done via auctions on a regulating power market. There are markets for the different types of balancing services. In the regulating power markets there can be auctions for reserve capacity, corresponding to the procurement of regulating reserves. The activation of regulating reserves during real-time system balancing corresponds to the auction of regulating energy (regulating resources), being likewise part of the regulating power market. An analysis of different regulating power market designs can be found in [18]. The time basis for clearing the regulating power markets is the program time unit, which is 15 min in the UCTE and 60 min in Nordel.

Primary reserves are essential for the operational security. In the Netherlands their provision is mandatory for units above a certain capacity [19]. In Germany primary reserves are procured through a biannual auction [20]. In the Nordic area they are contracted either bilaterally or through a market for primary reserves as it was opened in Norway in 2008 [16], [21].

As described above, there is a distinction between the procurement of regulating reserves and the actual activation of these regulating reserves. As hydro power production has a high regulating capability due to the rapid ramping ability of hydro power plants, there are normally sufficient regulating reserves available in the Norwegian system. However, during

periods with tight capacity a reserve option market (RKOM) is run in Norway, what mainly happens in the winter time. In the Swedish system it is required that all available reserves are bid into the market, what is somehow similar in the Finish system. In a thermal system, the procurement of regulating reserves is essential. In the Denmark reserves are contracted bilaterally [22]. The same accounts for the Netherlands, where this contracting is done annually on a bilateral basis. Contracted BSPs are obliged to bid into the secondary reserve market, what can be done until one hour before real-time. In Germany, the regulating reserve procurement for secondary reserves is based on monthly auctions [20]. In this auction capacity bids as well as energy bids are specified. The German regulating market for tertiary reserves is held daily.

IV. INTEGRATION STATE OF EUROPEAN REGULATING MARKETS

The successful integration of European day-ahead markets, as is aspired by the Price Coupling of Regions (PCR), covering 80% of Europe's total power production [23], can provide experience and a basis in order to integrate European regulating power markets. To exchange such balancing services, an integration of national regulating power markets is necessary to provide a common basis [18].

By now there are proposals from ETSO [24], Nordel [25], Eurelectric [26], ERGEG [27], Bundesnetzagentur (BNA) [28], [29] and Frontier Economies & Consentec [30] suggesting different approaches for the cross-border exchange of balancing services, i.e. the integration of regulating power markets. An overview of these different approaches is likewise given in [31]. These proposals can generally be divided into two approaches, depending on the balancing service exchanging parties. In the first approach, exchange of balancing services is done between a TSO and BSP situated in neighbouring areas. This is currently implemented by RTE (France) and some of its neighbouring countries (Germany, Switzerland, Spain) as well as between Germany and Austria, where BSP can mutually provide tertiary reserves [20]. The second approach constitutes the exchange of balancing services between TSOs at a different degree of integration. An exchange of balancing services is currently implemented between RTE and National Grid (UK), which only includes the exchange of regulating resources in the case of available transmission capacity [32]. The recently constituted grid control cooperation (GCC) in Germany was implemented by four subsequent steps, each corresponding to a higher step of regulating market integration [29]. The German regulating power market integration was suggested by studies of Consentec [33] and Lichtblick [34] showing possible savings in the case of Germany-wide regulating reserve procurement and activation, as well as system imbalance netting. From May 2010, a Germany-wide GCC is enforced by the BNA [35]. In the Nordic system there is a fully integrated regulating power market with a harmonisation of balancing services, introduced in March 2009 [25].

In order to exchange balancing services in a Europe-wide area instead of countrywise, the transmission system has to be

considered, taking into account cross-border congestions. Thus there has to be a trade-off between the day-ahead exchange and the exchange of balancing services. One approach is to use a joint market model as implemented by Risø in Wilmar [36], where the day-ahead market and the regulating market are cleared at once, taking into account all system constraints. Such a joint market model would require major changes in the design of European power markets, and is not realistic in any near future. However, it is quite useful as a reference, providing a theoretical optimal solution.

V. MODELLING

In order to develop a model of an integrated northern European regulating power market, a generic electricity market design is assumed. The regulating power market is based on a day-ahead market, using the day-ahead's outcome as input to the regulating power market. Furthermore the day-ahead market is assumed to be common northern European, on which an aspired integrated northern European regulating power market can be based. The modelled markets are assumed to be perfect. As discussed in the previous section there are different alternatives and sequences of electricity market designs. Sequence refers to the temporal order of clearing the markets, e.g. first running a reserve procurement and clearing the day-ahead market afterwards or vice versa. The sequence especially concerns the knowledge of the day-ahead clearing prices and volumes when running the regulating power market, particularly when procuring regulating reserves. In case of procuring reserves before day-ahead market clearing, an expected day-ahead market clearing would have to be taken into account, resulting in a stochastic problem. In the presented model, a deterministic approach is implemented. Thus a sequence is chosen, where first the day-ahead market is cleared and subsequently the regulating power market is run. Running the regulating power market includes the regulating reserve procurement and finally the system balancing in real-time. The chosen time basis for the day-ahead market clearing is one hour according to NordPool, the APX and the EEX. As PTU length for the regulating power market, i.e. the resource procurement and the system balancing, 15 minutes are chosen to match the PTU length of the UCTE. Fast reacting primary reserves are neglected in the model and only slower secondary and tertiary reserves are taken into account.

The systematics of the model are shown in Fig. 2. It consists of the following three subsequent steps: the common day-ahead market, the regulating reserve procurement and the system balancing. The common day-ahead market is simulated by the use of EFI's Multi-area Power-market Simulator (EMPS) [37]. The outputs of EMPS are the optimal day-ahead dispatch, taking into account the unit-commitment issue, the according area prices and water values. These results are used as inputs to the subsequent steps. In the second step regulating reserves according to defined reserve requirements are procured, resulting in a redispatch of the available generation capacity in order to fulfil the reserve requirements. This generation redispatch then is the input to the last step, the real-time system balancing. In the following subsections each of these steps

with the according model are described in more detail, with a discussion of reserve pricing in the last subsection.

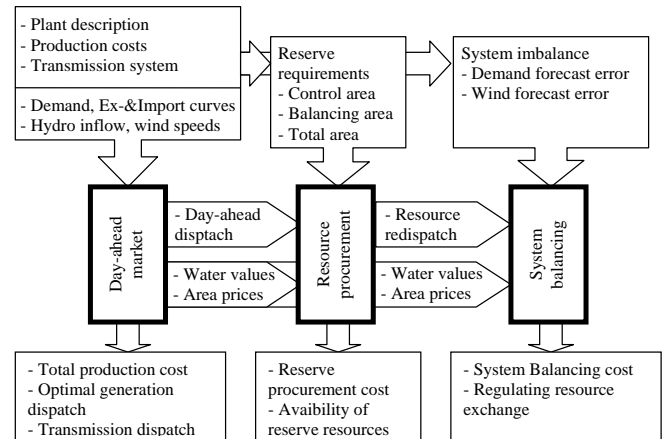


Fig. 2. Schematic diagram of the subsequent model steps

As shown in Fig. 1, the model consists of 29 interconnected day-ahead areas. The areas are defined according to country borders, the geographic distribution of generation capacity and existing bottlenecks in the transmission system. Germany is subdivided according to the suggestion given by [38], [39] and according to areas chosen in [1], [40]. The subdivision of the Norwegian system takes into account different water courses in the hydro system. On a second level, these 29 day-ahead areas are aggregated into 11 control areas, which are in accordance with the current control areas in the UCTE [41] and in Nordel² [16]. A further aggregation of these control areas into three balancing areas, being Nordel, the Netherlands and Germany, which complies with the currently defined control blocks, is done on a third level. The system is modelled in its 2008's state regarding the installed power plants, the transmission system, the exchange with its neighbouring countries, the power production and consumption. To model the stochastic power production 40 different inflow and corresponding wind scenarios covering the years 1951 to 1990 are simulated.

A. Day-ahead market

The day-ahead market is modelled with EMPS [37]. It is a mid- and long-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 a hourly resolution of the optimisation process can be achieved.

As can be seen in Fig. 1, the modelled system is split in different areas in which production and consumption is

²According to Nordel's System Operation Agreement [16] the Nordic area is one control area, with a common Nordic merit order list of regulating bids. Just as the areas defined in the day-ahead market clearing by NordPool [42], the Nordic system can be split into areas during real-time system operation, taking into account congestions. In this case the activation regulating bids can deviate from the common merit-order list. The areas during real-time operation can, but do not need to match the day-ahead areas. The division chosen in this model is according to 2008's division.

aggregated. The transmission lines connecting the areas are modelled by net transfer capacities (NTC) and linear losses, not distinguishing between AC and DC transmission lines.

EMPS was developed for the Nordic system, including Denmark, Finland, Norway and Sweden, thus taking into account hydro based power generation. As there is no real cost for the water, but a limited amount of water in the hydro reservoirs, its long term utilization has to be optimised. Therefore EMPS contains a detailed water course description of the hydro power production. Within the optimisation, the water values for the hydro reservoirs are determined. They represent the opportunity cost of hydro power production using the water stored in a hydro reservoir. A further explanation of the water value approach is given in [37]. For the hydro power plants, the water values of the according hydro reservoirs are used as the marginal production cost. Employing a detailed, rule-based reservoir draw-down model and using these marginal costs, the optimal dispatch for the hydro power production is determined.

Thermal power plants are modelled, which are described by a marginal production cost and start up & shut down costs [43]. Wind power generation is modelled as a fixed input to the system, being defined by the installed wind power generation capacity and nominal wind power production. The nominal wind power production is based on wind speed scenarios gained from reanalysis data as utilized in [1]. In EMPS consumption is defined by curves based on real measurements [19], [44] - [47] with the possibility of including demand elasticity and temperature dependency. Exchange to neighbouring countries is modelled by a scheduled energy exchange [48] rather than a price-dependent exchange.

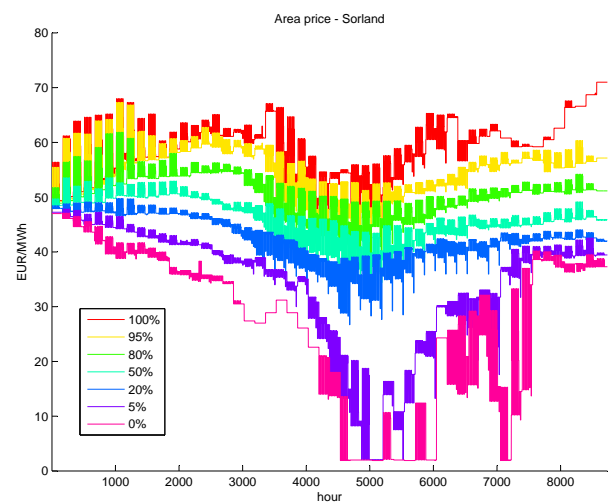
The thermal generation is modelled in two different ways, either as scheduled production, for which a production profile during a year is given or as dispatchable production. The division of power plant types in scheduled and dispatchable production is shown in Table II. However, some of the hard coal, gas & oil fired power plants are used for district heating, thus having a partly fixed production profile. The available dispatchable generation capacity is modelled in the form of single power plants with individual marginal production and start up & shut down costs.

TABLE II
POWER PLANT TYPES MODELLED IN THE NORTHERN CONTINENTAL
EUROPEAN AREAS

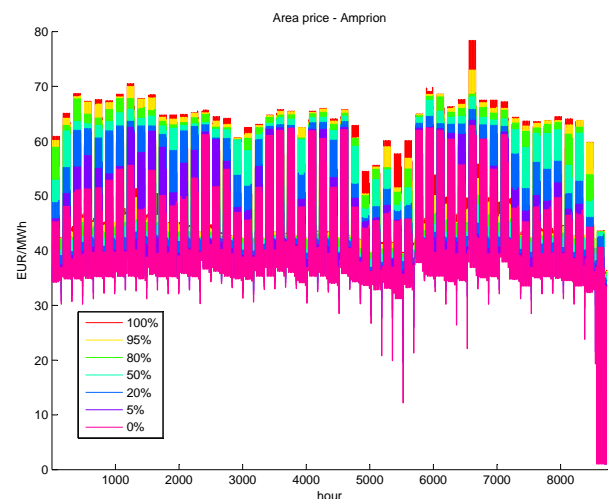
Non-dispatchable generation	Dispatchable generation
Nuclear	Hard-coal
Lignite	Gas fired
CHP	Oil fired
Biomass	
Photovoltaic	
Wind	
Hydro	

Some results of the common day-ahead market clearing are presented in the following. Fig. 3 shows the area prices for the 40 different inflow and wind scenarios as percentiles for two selected areas. The percentiles give the probability

of prices lying below the indicated value. The depicted areas are southern Norway, which has a high installed hydro power production capacity, and the Amprion area, which is a thermal area with the highest share of consumption in Germany. The area price curves clearly show the characteristics for each of the areas. In the hydro area (Fig. 3a) there is a high variation between the different percentiles, which indicates a price dependency on the inflow scenario. However, there is no high variation of the single percentiles. Although in the thermal area (Fig. 3b) the variation between the percentiles is not significant, but the variation of each percentile. This indicates a high price variation between the different periods during a week (e.g. peak, off-peak, weekend). In both areas the prices are around 50 EUR/MWh on average, which matches the average price of the dispatchable thermal power plants. This shows that the marginal production costs of the thermal power plants to a large extent determine the area prices in the Nordic System.



(a) Southern Norway



(b) Amprion

Fig. 3. Percentiles of area prices in a hydro and a thermal area

Fig. 4 and Fig. 5 show a detailed dispatch of thermal generation units during one week in the Amprion area. Here only the dispatchable generation units are plotted. The colour indicates the marginal production cost of the individual units, from blue being cheap units up to red, the most expensive ones. In each of the blocks ten units are aggregated. The marginal cost stated for the block is the one for the most expensive unit within the block. The plot shows the increasing marginal production costs, resulting from higher production during peaking periods. Because of the consideration of start up costs and the minimum generation capacity of thermal units in the optimisation problem, some of the more expensive units still run during off-peak periods, even though the area price is below their marginal production cost, as shown in Fig. 5a. Furthermore, the available regulating reserve resources are plotted in Fig. 5b, showing that there is a huge difference between peak and off-peak hours. During peak-hours the available regulating reserves are quite few, resulting in the necessity to procure further regulating reserves, what is done in the next step.

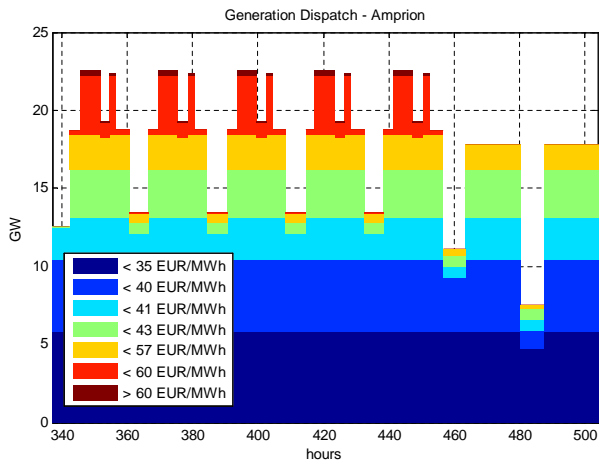
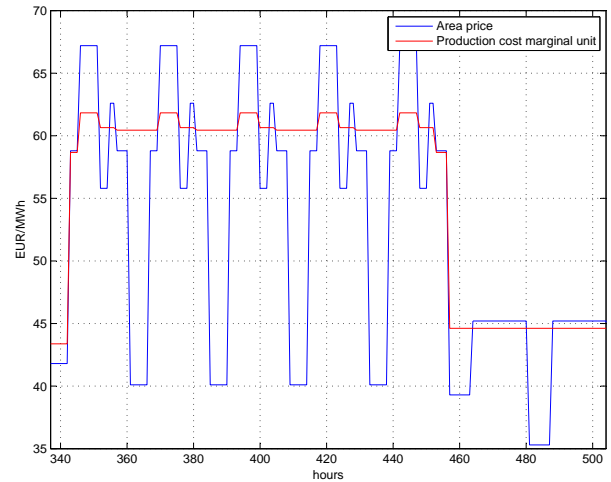
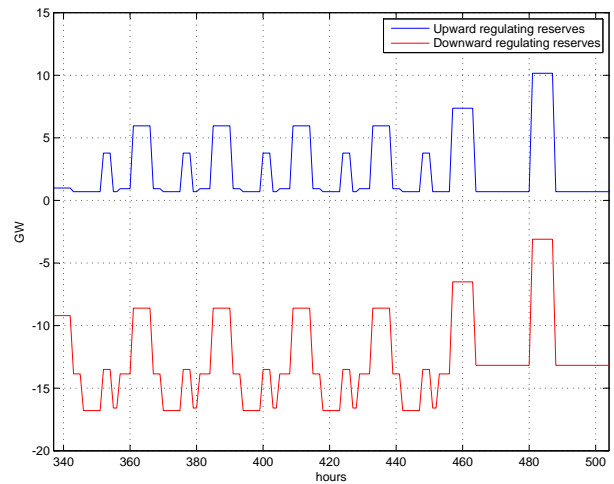


Fig. 4. Generation dispatch of Amprion during week 3

In Fig. 6, the aggregated day-ahead dispatch of the transmission lines between the Nordic system and northern continental Europe is depicted. The transmission lines include the Denmark-West Germany interconnection, the NorNed, the Baltic and the Kontek HVDC-cables. The plot shows the percentiles of the annual duration curve of the transmission for the 40 different inflow and wind scenarios. It can be seen that the exchange strongly depends on the scenario, i.e. the inflow to the Nordic system. In approximately 40% of the time there is free transmission capacity on the lines, providing the possibility of exchanging up- as well as downward regulating energy. During the rest of the time only either up- or downward regulating resources can be exchanged between the Nordic and the northern continental European area.



(a) Area price vs. marginal production cost



(b) Reserve resources

Fig. 5. Generation dispatch of Amprion - Analysis

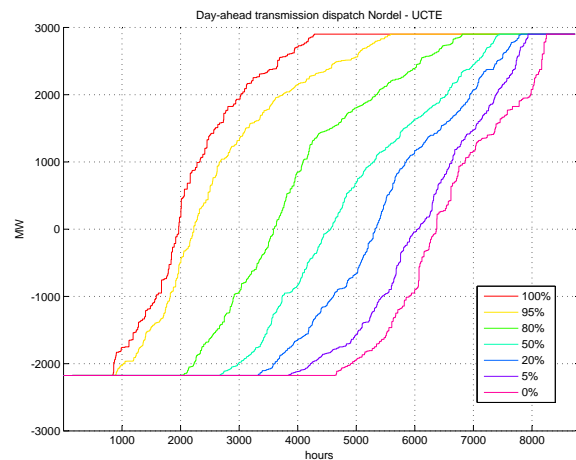


Fig. 6. Day-ahead dispatch of transmission between Nordic and northern continental European system

B. Reserve procurement

Given the day-ahead market clearing, required regulating reserves are procured in the second step, as shown in Fig. 2. This is done by a redispatch of the generation units. The approach of reserve procurement in the model is different from the reserve capacity markets run in the northern European areas, as described previously in section III. In reality by running the reserve capacity markets, generation capacity is deducted from the day-ahead market prior to that and procured for system balancing, ensuring that enough generation capacity is available during real-time system operation. As perfect market behaviour is modelled, it is assumed that all available generation capacity is bid into the markets, the day-ahead as well as the regulating power market. Thus, it does not differ if generation capacity is withdrawn from the day-ahead market beforehand or if this generation capacity is procured as regulating reserves afterwards. The only difference in procuring the regulating reserves after the day-ahead market clearing is, that in this case the marginal generation capacity is always chosen in order to provide regulating reserves. If the regulating reserves are procured before day-ahead market clearing, the procurement has to be based on an expected day-ahead market outcome, as discussed previously. Thus it is not ensured that the marginal units are chosen in order to provide the regulating reserves. The sequence chosen in this model can be seen as the socio-economic most beneficial approach, an idealized reserve procurement, probably resulting in a too low reserve procurement cost estimation.

The procured reserves comprise up- and downward regulating reserves, but spinning reserves only in the case of thermal power plants. The definition of spinning reserves used throughout this paper is depicted in Fig. 7. There is a distinction between hydro and thermal units providing reserves. For hydro units it is assumed that their start up costs can be neglected and that they do not have a minimum production capacity. Thus their full production capacity can be used as regulating reserves and the units do not need to be started in order to provide regulating reserves. However, thermal units do have start up costs and a minimum production capacity. Hence only units that are started up, i.e. producing above their minimum production capacity, can provide reserves. Spinning upward regulating reserves can be provided up to the unit's maximum production capacity. On the other hand, spinning downward regulating reserves can only be provided down to the level of the minimum production capacity, as indicated in Fig. 7, and not down to zero, as it is the case for hydro units. The remaining capacity of thermal units is defined as non-spinning reserves.

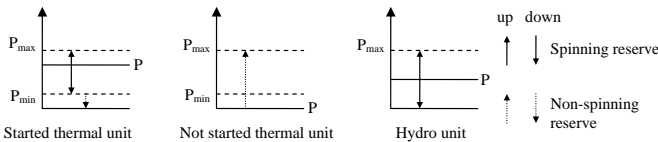


Fig. 7. Definition of spinning and non-spinning reserves

In order to define the required regulating reserves, the

day-ahead areas of EMPS are aggregated according to the current control areas, as described previously. Furthermore three balancing areas are formed. Reserve requirements are then defined for the control areas, the balancing areas and the total system. The reserve requirements for the single control areas are shown in Table III. These requirements are based on actual values for the areas, which can be found in [16], [19] and [20]. The values chosen are the requirements for FADR in the Nordic system and the requirements for secondary reserves in the Netherlands and Germany. In Norway the requirements are defined for the whole country instead of the three control areas.

TABLE III
RESERVE REQUIREMENTS FOR THE NORDIC AND NORTHERN
CONTINENTAL EUROPEAN SYSTEM IN MW

	NO1	NO2	NO3	SWE	FIN	DK
Up	520			560	365	175
Down	-520			-560	365	175

	DE1	DE2	DE3	DE4	NL
Up	640	830	1000	540	300
Down	-400	-590	-725	-330	-300

The regulating reserve procurement is modelled as a linear optimization problem. A detailed formulation of the reserve procurement can be found in appendix B.

The aim of the reserve procurement is to change the given day-ahead dispatch in a way to allocate sufficient regulating reserves according to the defined reserve requirements $\bar{r}_k^K, \underline{r}_k^K, \bar{r}_b^B, \underline{r}_b^B, \bar{r}^T, \underline{r}^T$, see appendix A. These reserve requirements are defined in equations 11 to 14, where the sum over all regulating reserves provided by thermal and hydro plants situated in a control area, a balancing area or in the total system has to be higher than or equal to the required reserves.

In order to fulfil the reserve requirements, the day-ahead dispatch has to be changed, which is done by a redispatch of the generating units. Two examples of such a redispatch are explained shortly hereafter. Sketches of them are shown in Fig. 8 for the procurement of upward regulating reserves and in Fig. 9 for downward regulating reserves. In these examples unit 1 is the cheaper and unit 2 the more expensive one.

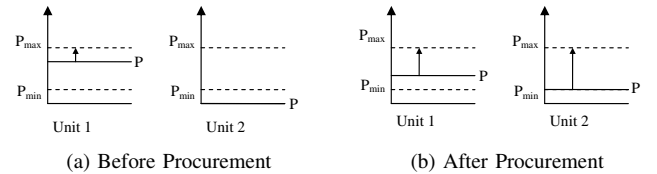


Fig. 8. Upward regulating resource procurement

In the first case, before the reserve procurement, as shown in Fig. 8a, there are no sufficient upward regulating reserves available. To fulfil the requirements, unit 2 has to be started up. Due to the minimum production capacity, unit 2 has to be started up at least to the minimum capacity, resulting in a decrease of production on unit 1, see Fig. 8b. This results in increased production costs due to the higher marginal

production costs of unit 2 and the additional start up costs for unit 2.

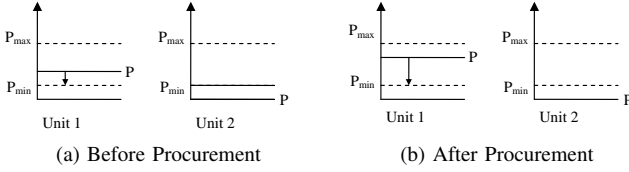


Fig. 9. Downward regulating resource procurement

In the second case, as shown in Fig. 9a, there are not enough downward regulating reserves available before the reserve procurement. This periodically happens during off-peak periods, when some of the dispatchable generating units are still in operation at minimum production capacity to avoid additional shut down and start up costs. To procure additional downward regulating reserves, one of the units has to be shut down, which is unit 2, see Fig. 9b. This shut down results in an increased production of unit 1, providing sufficient downward regulating reserves. In this case the cost for procuring the required resources contains the additional shut down costs for unit 2 and an actual reduction of the production costs due to lower marginal production costs of unit 1 compared with unit 2.

In the model the redispatch for hydro units is defined by equation 3, with the according production limitations in equation 4, where $y_{h,\omega,\tau}^{hydp}$ is the generation dispatch of the hydro unit after the reserve procurement. The available regulating reserves provided by hydro units for upward regulation are $(\bar{y}_h^{hyd} - y_{h,\omega,\tau}^{hydp})$ and for downward regulation $(y_{h,\omega,\tau}^{hydp} - \underline{y}_h^{hyd})$. A minimum production capacity for hydro plants is defined as \underline{y}_h^{hyd} , which normally is zero, but can be negative to represent pumping capabilities of a hydro power plant.

The redispatch for thermal units is defined in equation 5. Equations 6 to 10 are necessary in order to include the start up costs of thermal power plants in a way to be solved approximately in a linear optimisation problem. A detailed description of the approach can be found in [43]. The terms $\Delta_{\uparrow}x_{g,\omega,\tau}^{th}$ and $\Delta_{\downarrow}x_{g,\omega,\tau}^{th}$ define relative values of provided upward respectively downward regulating reserves. In order to determine the provided reserves, those values have to be multiplied by the free dispatchable capacity of the actual thermal power plant $(\bar{y}_{g,\omega}^{th} - \underline{y}_{g,\omega}^{th})$. Equation 9 defines the start up of a thermal power plant between the PTUs $(\tau - 1)$ and τ . Equation 10 defines the whole problem as a "round-coupled problem", i.e. the units started up at the beginning of a week are assumed to be started up at the end of the week. Thus, equations 9 and 10 result in the temporal connection between the PTUs.

During the reserve procurement, a change of the transmission dispatch is not allowed. Thus the production balance in each individual day-ahead area has to be kept, what is defined by equation 2. In addition to the possible redispatch of thermal and hydro units, rationing of demand and shut

down of scheduled production units are added in order to keep the linear problem feasible. Rationing can be compared to anticipated curtailment of demand in order to maintain the operational security during peak periods. Shut down of lignite or other base-load plants can be necessary during off-peak periods as well.

The linear problem is solved for a whole week including all 674 PTUs. The problem is defined to be deterministic, assuming the generation dispatch, area prices and water values to be known for the whole week.

The objective of the linear optimisation problem is the minimisation of the total redispatch cost. The objective function for $C_{\omega}^P(y^*)$ is defined by equation 1. In order to determine the total costs, the marginal costs of redispatching a unit are defined by equations 25 to 28. For the thermal units these marginal redispatch costs are based on the marginal production costs of the unit and the area price. They are increased respectively decreased by 5%. For hydro units the marginal redispatch costs are based on the water values and the area price. A cost increase is only done for the thermal units in order to reduce the procurement of regulating reserves provided by them and substitute it by reserves from hydro units instead. Without such an increase the marginal hydro and thermal units would have the same marginal costs after the day-ahead market clearing, whereas it would not make a difference by which units the regulating reserves are provided. However, in reality it is seen, that provision of regulating reserves from hydro units is preferred. Thus the increase is a rough emulation of the regulating reserve procurement behaviour in reality.

C. System Balancing

In the final step, the system is balanced in real-time. As electricity is not storable in the grid, the production and consumption of power has to be kept in balance during real-time operation of the system, what is done by activating regulating reserves. The activation of regulating reserves corresponds to the acceptance of energy bids in the regulating power market. In order to achieve the best socio-economic outcome, these bids have to be activated in the order of their bid prices, taking into account remaining transmission capacities after the day-ahead market clearing and transmission losses.

A model of the system balancing is implemented as a linear optimisation problem. The detailed formulation of the model can be found in appendix C. Inputs to the system balancing model are the generation dispatch after the resource procurement and results from the day-ahead market clearing, including the transmission dispatch, area prices and water values. A further input is the imbalance of the system. The system imbalance consists of different parts like the load forecast error, hour-to-hour production and consumption changes, unplanned outages and the wind power production forecast error. The model's system imbalance includes a load forecast error and a wind forecast error, which are represented by recorded imbalance scenarios of 2008 for the Netherlands and Germany [19], [44] - [47] as well as recorded imbalance scenarios of 2007 for Norway and Sweden [49]. As there

is a difference between the PTU length in the UCTE and Nordel, the imbalances of Nordel are converted to a 15 minute resolution to have a matching PTU length. Recorded imbalance scenarios are only available for the whole control areas. However, the system balancing model is based on the individual 29 day-ahead areas to include the available transmission capacities after the day-ahead market clearing. Thus, the imbalances are distributed by a share according to the ratio of total annual demand of the area to total annual demand in the control area. This results into imbalances for all the individual areas.

The aim of the system balancing is to equal electricity production and consumption in each individual area, including the exchange of electricity between the areas and taking into account the real-time imbalances. The system balance is defined by equation 16 for each area. Included are the possible change in thermal power production, the possible change of the transmission on the lines, the according change of transmission losses, the possible change of hydro power production, rationing of demand and shut down of production. The overall sum of those has to equal the imbalance in the according area, consisting of the load forecast error and the wind forecast error.

As mentioned previously, during system balancing the day-ahead transmission dispatch can be changed. The actual real-time transmission is defined in equation 18 with the according transmission losses in equation 17. The constants $\delta_l^B \in \{0, 1\}$ define for each of the lines if transmission is allowed to be changed on this line during system balancing. This provides the possibility to define whether a line is available for exchanging regulating resources or not, in order to be able to define different regulating market integration levels.

The activated hydro regulating reserves are defined as $\Delta_{\uparrow} y_{h,\omega,\tau}^{hyd^B}$ and $\Delta_{\downarrow} y_{h,\omega,\tau}^{hyd^B}$, which are determined in equations 19 for upward regulation and 20 for downward regulation respectively. They have to be positive and less or equal to the available reserve for each hydro unit.

The activated thermal regulating reserves are defined in equations 21 to 24. It is distinguished between spinning reserves $\Delta_{\uparrow} y_{g,\omega,\tau}^{th^B}$ and $\Delta_{\downarrow} y_{g,\omega,\tau}^{th^B}$ and non-spinning reserves $\Delta_{\uparrow} y_{g,\omega,\tau}^{th_t^B}$ and $\Delta_{\downarrow} y_{g,\omega,\tau}^{th_t^B}$, as explained previously. Spinning reserves are the reserves available after the resource procurement, as shown in Fig. 7. Non-spinning reserves combine all further generation capacity of dispatchable thermal units. Non-spinning reserves are shown in Fig. 7 likewise. Non-spinning reserves are included in the system balancing model to make all dispatchable thermal generation capacity available for system balancing. The difference for the utilisation of spinning and non-spinning reserves is their activation price, which is discussed below.

The system balancing's objective is to minimize the socio-economic costs of activating regulating reserves. The according objective function for $C_{\omega,\tau}^B(y^P)$ is stated in equation 15. The linear problem is solved for each PTU individually as there are no temporal dependencies defined, such as ramping or the starting and stopping of units. In addition to the activation of regulating reserves, rationing of demand and shut

down of production is defined in the system balancing as well. These can be compared to curtailment of consumption or the shut down of excess wind production during real-time operation of the system.

D. Regulating reserve pricing

In order to estimate the cost for the real-time system balancing, the regulating reserves have to be priced. As discussed above in section IV, there are only a few researches done on estimating or forecasting regulating prices, but none for the determination of actual marginal costs of regulating reserves. As the objective of the system balancing model is a socio-economic optimal activation of regulating reserves, the costs of the regulating reserves used in this paper are based on the marginal production costs of the reserve providing units. The determination of the regulating reserve costs can be found in equations 29 to 34. These are very rough estimates of regulating reserve costs. For hydro units the regulating reserve costs are based on the water value and the area price, being increased or decreased by 10% for upward respectively downward regulating resources. The regulating reserve costs for spinning thermal units are based on the marginal production costs of the these units and the area price. They are increased or decreased by 50% for upward respectively downward regulating resources. The difference between the increase of 10% for hydro units and 50% for thermal units additionally enforces the utilization of hydro regulating reserves instead of thermal ones. To provide all dispatchable thermal capacity for system balancing, in addition to spinning, non-spinning regulating reserves are defined. There are no start up or minimum production requirements on the non-spinning regulating reserves, however, these issues are included in the costs of the non-spinning regulating reserves. The inclusion is done by adding or subtracting related start up costs to, respectively from, the regulating reserve cost. This increases the costs quite substantially, which results into utilisation of non-spinning reserves in exceptional circumstances only.

Rationing is priced at 10000 EUR/MWh during resource procurement as well as system balancing. The shut down of other than dispatchable production is done at 0 EUR/MWh also during resource procurement as well as system balancing.

VI. CASE STUDIES

To test the model and evaluate the possible benefit of integrating regulating power markets, several cases are defined. The case studies in this paper represent a step-wise integration of the northern European regulating power markets, distinguishing between a system-wide exchange of regulating resources and a system-wide procurement of regulating reserves.

As the basis for the case studies, a wet and a dry year are chosen. This refers to the inflow of the Nordic hydro system. An overview of these years is given in Table IV. It can be seen that there is a 40% difference in inflow to the hydro system. Additionally there is 25% less wind power production in the dry year. These differences have an impact on the overall operation of the system, which is shown by the net energy

export to continental Europe during a wet year and the net energy import from continental Europe during the dry year. Furthermore, it also has an impact on the day-ahead dispatched production of the thermal generation in continental Europe which is substantially higher in a dry year, probably resulting in less available reserves.

TABLE IV
COMPARISON BASIS YEARS FOR THE ANALYSIS

	Wet	Dry
Storable & non-storable inflow to Nordic system (TWh)	244.5	146.1
Wind power production in the Nordic system, Germany, the Netherlands (TWh)	74.93	56.1
Annual net exchange between Nordel and UCTE (TWh)	8.46	-8.39
Production of dispatchable thermal generators in Germany and the Netherlands (TWh)	287.5	319.6

For both years, different steps of regulating power market integration are defined. These steps reach from the current state with no integration up to full integration of regulating power markets, including system-wide regulating reserve procurement and the system-wide exchange of regulating resources. The different cases are defined as follows:

a) Case I: is chosen to represent the current state of the system before the integration of the single German regulating power markets, as described in section IV. Regulating reserves have to be procured locally in each control area. There is no possibility of exchanging regulating resources between Nordel and UCTE, no exchange possibility between UCTE's control areas, but exchange possibility between the control areas in Nordel.

b) Case II: represents the state of the system after integrating the regulating power markets of all the four German control areas as described in [29]. It is the same as in Case I except that the exchange of regulating resources is allowed between the four German control areas.

c) Case III: represents the state of integration of balancing markets, when regulating resources can be exchanged system-wide, but regulating reserve procurement still has to be done in each control area.

d) Case IV: allows the procurement of 25% of required regulating reserves for each control area in its according balancing area and the system-wide exchange of regulating resources.

e) Case V: additionally allows the system-wide procurement of 25% of the required regulating reserves for each control area.

In this paper an amount of 25% of required regulating reserves is chosen, to be procured outside the control area or the balancing area respectively. As suggested by UCTE [50] and included in its policy [15], an amount of at most 33% of the required secondary reserves is allowed to be procured outside the control area. A substantial share of the required reserves are necessary to be procured in the control area to preserve the operational security. As the model presented in this paper does not check for available transmission capacity

during the reserve procurement process so far, a lower share compared to the UCTE requirements [15] is chosen.

VII. RESULTS

The common day-ahead market is run for 40 different inflow and wind speed scenarios. A wet and a dry year have been chosen as the basis for the reserve procurement and the system balancing for the previously defined cases. Fig. 10 and Fig. 11 show the details of two chosen areas, being southern Norway and the Amprion area. The plots show case V for the wet year. The 34944 PTUs for a generic year of 364 days are plotted.

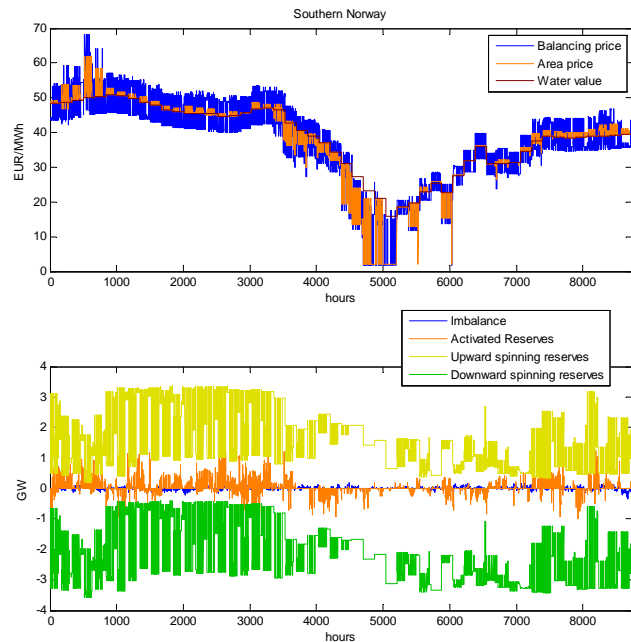


Fig. 10. Result southern Norway, Case V, wet year

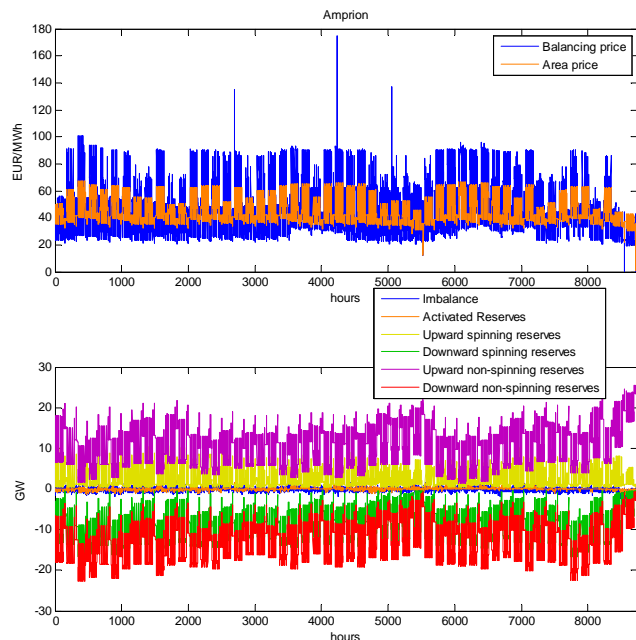


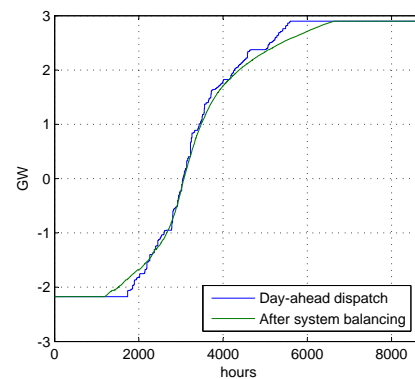
Fig. 11. Result Amprion, Case V, wet year

In the upper diagrams of both figures the prices in the areas are depicted. The plotted prices are the real-time balancing price, the day-ahead area price and for southern Norway as hydro area the water value. For southern Norway it can be seen that the day-ahead area price is spread around the water value. The real-time balancing price is spread around the area price in a certain span, corresponding to the pricing method of the reserves discussed previously. The real-time balancing price is the regulating reserve price of the marginal regulating reserves, which are activated. During summer prices drop down to nearly zero. This happens due to excess inflow to the system and low demand, resulting in shut down of production, which corresponds to spillage in the hydro system. In the Amprion area, a thermal area, the day-ahead area price and the real-time balancing price are plotted in Fig. 11. In the hydro area, the balancing prices are spread around the area prices in a certain span according to the previous regulating reserve price definition. As already discussed for the results of the day-ahead market clearing, it can be seen that the variation of prices during a short period is much higher in the thermal area than in the hydro area. This also results into a higher variation of balancing prices in the thermal area. The drop of prices during summer is not observed in the thermal area. However, during the last weeks and the first week of the year a drop of prices can be spotted. The reason for this price drop is the low demand during Christmas holidays. Furthermore there are some spikes in the balancing prices. These are the times, when activation of non-spinning reserves occurs.

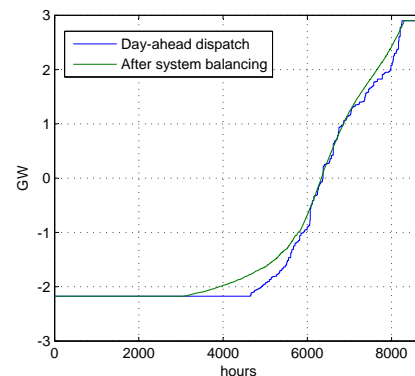
In the lower diagrams of Fig. 10 and Fig. 11, operational values of the areas are shown. These values are the imbalance in the area, the available spinning up- and downward regulating reserves and the actual activated regulating reserves. In the Amprion area, the non-spinning regulating reserves are plotted additionally. As all the hydro power plants can provide regulating reserves, there is a high amount of regulating reserves available in southern Norway. This shows the good regulating reserve providing capabilities of the hydro system. The actual system imbalance in southern Norway is much less than the activated regulating reserves in this area, indicating an export of regulating resources. However, in the Amprion area the situation of regulating reserves is much tighter. Not only spinning upward reserves are quite low and just according to the required volume, but also the availability of downward regulating reserves is quite low periodically. This happens especially during low load periods, as can be seen during the late summer and during Christmas time. Looking at the relation between the imbalance and the actual activated regulating reserves, it can be seen that the actual imbalance is higher. This indicates an import of regulating resources from other areas.

Fig. 12 shows the difference between the day-ahead transmission dispatch and the actual transmission after the system balancing, including the exchange of regulating reserves. The transmission depicted is the aggregated exchange between the Nordic system and northern continental Europe, which includes the West-Denmark Germany interconnection and the NorNed, Baltic and Kontek HVDC-cables. Shown are the transmission duration curves for the wet and the dry year. It

can be seen that the duration curves before and after system balancing are approximately the same, what indicates that the total exchange of energy is nearly constant. The effect of balancing the system results in a smoothing of the duration curves and a reduction of the times, where the exchange is at minimum or maximum. This indicates the capability of the cables to exchange regulating resources. Furthermore, the plots shown in Fig. 12a for the wet year and in Fig. 12b for the dry year show a small shift of the duration curve after system balancing compared to the day-ahead dispatch. The right shift in Fig. 12a indicates a net export of regulating energy from the Nordic system, which corresponds to a net export of upward regulation in the wet year. In the dry year, there is a left shift, indicating a contrary behaviour.



(a) Wet year



(b) Dry year

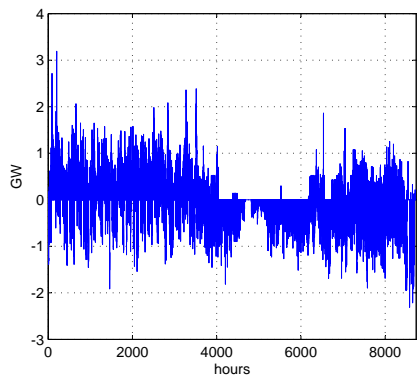
Fig. 12. Duration curve transmission dispatch Nordel-UCTE

In Fig. 13, the difference between the day-ahead transmission dispatch and the actual transmission after system balancing is depicted. As above this is done for the aggregated exchange between the Nordic system and northern continental Europe. This difference can be interpreted as the exchange of regulating resources. During the dry year, shown in Fig. 13b, there is an annual exchange of regulating resources between 2.5 GW and -2 GW with no significant differences between the seasons. In the wet year, shown in Fig. 13a, the exchange of regulating resources is between 3 GW and -2 GW. In this case, there is a significant difference between the seasons. During summer, there is mostly no export of upward regulating resources. Due to the high inflow to the reservoirs, the day-

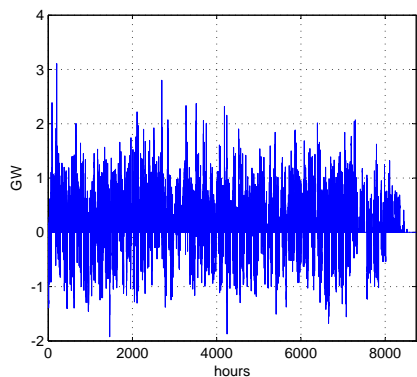
TABLE V
RESERVE PROCUREMENT AND SYSTEM BALANCING RESULTS IN A WET AND A DRY YEAR

Year	Case	Reserve procurement				System balancing						
		Cost	Rationing	Shut down	Redispatch	Cost	Upward regulating	Downward regulating	Net exchange	Gross exchange	Rationing	Shut down
		M€	GWh	GWh	GWh	M€	GWh	GWh	GWh	GWh	GWh	GWh
wet	I	91.92	0.555	167.7	4140	180.7	5865	-5990	0	0	0.036	18.63
	II	91.92	0.555	167.7	4140	96.00	3991	-4116	0	0	0	0.131
	III	91.92	0.555	167.7	4140	60.22	3185	-3328	354	2194	0	0.119
	IV	70.71	0.015	80.27	3900	60.98	3185	-3327	353	2197	0	0.344
	V	49.81	0.015	56.62	2736	62.00	3185	-3327	348	2200	0	0.681
dry	I	436.1	34.22	50.10	4435	206.9	5829	-5936	0	0	0.325	12.68
	II	436.1	34.22	50.10	4435	113.5	3946	-4054	0	0	0.036	0
	III	436.1	34.22	50.10	4435	73.69	3284	-3419	-901.7	1956.5	0	0
	IV	110.8	3.225	21.67	4269	74.10	3284	-3419	-903.6	1956.9	0	0
	V	88.12	3.225	14.28	3062	74.58	3284	-3418	-912.7	1962.6	0	0.121

ahead prices in southern Norway, as depicted in Fig. 10, as well as all the Nordic system drop to nearly zero. Thus, there is already full export to northern continental Europe during the day-ahead dispatch. This results in no available transmission capacity for an additional export of upward regulating energy during the whole summer of a wet year.



(a) Wet year



(b) Dry year

Fig. 13. Regulating resource exchange Nordel-UCTE

Table V shows a summary of all the above described cases. The results are divided into the reserve procurement and the system balancing. The results for reserve procurement for

cases I to III are equal as the procedure of reserve procurement is the same here. Compared to case IV, there is a decrease in the necessary redispatched energy of about 165 GWh in the dry year and 240 GWh in the wet year, which comes with a significant reduction of the procurement costs. The difference between these both cases is the ability to procure parts of the required regulating reserves in the balancing area, where a control area is situated in, instead of procuring all required regulating reserves in the control area. The main reduction of redispatched energy is achieved in Germany. This step can be compared to the recent integration of the German control areas. In [29] and [33], the savings due to Germany-wide procurement are estimated to be around 100 M€, which is much more than calculated by this model with approximately 20 M€ per annum for the wet year. In a dry year the procurement costs are significantly higher. The reason for this is the drastic increase of rationing during the resource procurement resulting in a huge share of the procurement costs.

With the implementation of a system-wide possibility of reserve procurement, the redispatched energy can be decreased additionally by approximately 30% in the wet as well as the dry year. This further reduction of redispatching energy is accompanied by a decrease of the procurement costs, which are comparable with the previous step, being about 20 M€ per annum.

Analysing the rationing and shut down during the reserve procurement, a difference can be seen between a wet and a dry year. Rationing during reserve procurement happens in a case when there already is high load near to the total installed generation capacity. In this case, even if taking into account all available generation capacity, there are not enough reserves available. In order to fulfil the reserve requirements, parts of the load have to be curtailed, which happens at a high price.

Rationing is no big issue in a wet year as there are sufficient generation resources. There is significant rationing in dry years, though. The rationing only occurs in the northern continental European areas even though it is caused by the low availability of generation due to inflow shortage in the

Nordic areas. The higher rationing is caused by an export of energy from continental Europe to the Nordic system on average in the dry year. This results in a higher utilisation of the dispatchable thermal generation capacity in northern continental Europe. Thus, less reserve resources are available in these areas. With a system-wide reserve procurement, the rationing can be decreased significantly.

In reality, the TSO comes in a quite difficult position if a choice must be made between operation with insufficient reserves and rationing of demand or load shedding. Especially in the case of export, the TSO would probably not allow export that would jeopardize the security in its own system. In theory however, from an economic point of view, the amount of reserves should be chosen such that the marginal cost of the reserves equals the expected marginal outage costs. If the amount of reserves is optimal with a reserve cost of 50 to 100 €/MWh, this amount should obviously be reduced, if the day-ahead price suddenly increases to 10000 €/MWh, indicating that load shedding should not be used to avoid marginal violations of the reserve requirement. In practice, reserve requirements are based on more technical criteria, which are treated as absolute constraints. Thus the ultimate consequence is, that load shedding is necessary if there is no other way to satisfy these constraints, which is the approach taken in the model.

At the shut down during the reserve procurement, production of base load power plants like nuclear or lignite is decreased, which is covered by starting up more expensive ones like hard coal. This is done as nuclear and lignite power plants cannot provide regulating reserves, but dispatchable power plants are needed to provide the required resources. This applies for upward as well as downward regulating reserves. The shut down is only done in northern continental Europe. It is higher during a wet year, when there is net import of energy. A reduction by about 30% can be achieved by a system-wide reserve procurement.

Analysing the difference between the studied cases in the system balancing, the main difference occurs between cases I-III. This corresponds to the different steps of exchanging regulating resources. In case I exchange of regulating resources between the German control areas is not allowed, whereas this is allowed in case II. This results in a significant decrease of balancing costs by approximately 50% and a reduction of the activated regulating reserves by approximately 30%. The reduction of reserves being activated is the result of netting the imbalances of the control areas. The reduction of the balancing costs includes the activation of cheaper regulating reserves and the previously mentioned overall lower activation of regulating reserves. The step from case I to case II can also be compared to the recent integration of the German regulating power markets. In [29] and [34] savings of 100 M€ are estimated, which are comparable with the savings calculated by this model. In case III exchange of regulating resources system-wide is allowed. With that comes a further reduction of the balancing costs and the activated regulating reserves. Netting of the total system imbalances results in a reduction of activated regulating reserves by approximately 20%. The balancing costs can be reduced further by 30%.

Looking on the exchange of regulating resources between the Nordic system and northern continental Europe it can be seen that in an integrated regulating market 30% of the regulating resources are imported to continental Europe. The net exchange of regulating resources depends, if it is a wet or dry year, being positive in a wet year, which corresponds to a net export of upward regulating energy. In a dry year the net export is negative. Between cases III-V there are no significant differences which shows that the different methods of reserve procurement does affect the system balancing only marginal.

Due to the procurement of reserves, mostly there are enough regulating reserves available in the system. Regarding rationing, it only occurs in the case when there is no exchange of regulating energy allowed between the German control areas during the wet year. During the dry year there also is some rationing in case II, what occurs due to the tighter generation situation. By exchanging regulating resources system-wide, rationing can be prevented completely. The shut down of production during real-time system balancing happens more often than rationing. It can be seen that the amount of shut down production can also be decreased significantly by exchanging regulating resources system-wide.

The above presented results are in accordance with estimates of Frontier Economics, who estimated in their 2009 study [51] a possible additional socio-economic benefit of 5.4 M€ to 15.9 M€ per annum in the trade of balancing services by the reservation of 50MW of exchange capacity, taking prices of France the UK, Germany and the Netherlands as a basis. Likewise Abbasy et al. in [9] estimated an additional socio-economic benefit of exchanging balancing services between northern continental Europe and the Nordic system at about 80 M€ per annum.

VIII. CONCLUSION

In this paper, a model is developed which shall represent an integrated northern European regulating power market, being based on a common northern European day-ahead market clearing. It arises that in the Nordic system ample regulating reserves are normally available, due to the good regulating capability of the hydro power production, which constitutes a high share of power production in the Nordic system. Due to the characteristics of the thermal-based system in the northern continental European area, it is necessary to procure upward as well as downward regulating reserves. In this paper it is suggested to procure parts of the required regulating reserves in the Nordic system and exchange regulating resources system-wide, taking into account available transmission capacity from the day-ahead market clearing.

With different defined cases, a stepwise integration of the northern European regulating power markets is studied. A comparison with the recent integration of the German regulating markets is done to test the model's consistency. It shows that by a system-wide regulating reserve procurement, the necessary redispatch can be reduced by 30%, which indicates that there are ample regulating reserve available in the Nordic system. These can be used in continental Europe. The activation of regulating reserves can be reduced by 20% due to

netting of the imbalances in the system. Furthermore one third of the activated regulating resources are exchanged between the Nordic system and the northern continental European system.

The socio-economic benefit of procuring regulating reserves and exchanging regulating resources system-wide, depends on the costs of the regulating reserves. In this paper, the costs of regulating reserves are rough estimates. Comparing the results with the recent integration of the German regulating markets [29] shows consistency, though. The reduction of operation costs is therefore tentative, however, it is shown that there are good possibilities of exchanging regulating resources and an estimation of the possible amount of exchange is done.

The installation of further intermittent generation capacity like wind power production results in an increased necessity for regulating reserves. As shown in this paper, the Nordic, especially the Norwegian hydro based electricity production can provide parts of these regulating reserves. In order to exchange regulating resources between the Nordic countries and continental Europe, an integrated regulating power market is needed. Modelling such an integrated northern European regulating power market, which is based on a common day-ahead market clearing, shows that there is a socio-economic benefit in exchanging regulating resources.

APPENDIX

A. Notation

The notation used throughout the paper is stated below.

a) Indicators:

*	Day-ahead market
P	Resource procurement
B	System balancing
\uparrow / \downarrow	Upward / downward
$\bar{ } / \underline{ }$	Maximum / minimum

b) Sets and indexes:

$a \in A$	Day-ahead areas defined in EMPS
$k \in K$	Control areas
$b \in B$	Balancing areas
$h \in H$	Hydro plants with H_a, H_k being subsets of hydro plants situated in areas a or k respectively
$g \in G$	Thermal plants with G_a, G_k being subsets of thermal plants situated in areas a or k respectively
$l \in L$	Transmission lines with L_a^{to}, L_a^{fr} being subsets of lines transmitting to and from the area a
$\omega \in W$	Weeks
$\tau \in T$	Quarter hours during a week

c) Functions:

$C_\omega^P(y^*)$	Cost function of reserve procurement
$C_{\omega,\tau}^B(y^P)$	Cost function of system balancing

d) Water values and area prices:

$v_{a,\omega}, p_{a,\omega}$	Water value and day-ahead price in each area
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e) Thermal generation:

$y_{g,\omega,\tau}^{th*}$	Day-ahead dispatch of thermal plants
$y_{g,\omega,\tau}^{thP}, \Delta_\uparrow y_{g,\omega,\tau}^{thP}, \Delta_\downarrow y_{g,\omega,\tau}^{thP}$	Redispatch of thermal plants during reserve procurement
$\Delta_\uparrow y_{g,\omega,\tau}^{thB}, \Delta_\downarrow y_{g,\omega,\tau}^{thB}$	Secondary up- and downward regulating of thermal plants in real-time balancing
$\Delta_\uparrow y_{g,\omega,\tau}^{thB}, \Delta_\downarrow y_{g,\omega,\tau}^{thB}$	Tertiary up- and downward regulating of thermal plants in real-time balancing
$\bar{y}_{g,\omega}^{th}, \underline{y}_{g,\omega}^{th}$	Maximum and minimum generation capacity of thermal plants
c_g^{th}, s_g^{th}	Marginal cost and start up cost of thermal plants
$\uparrow c_{g,\omega,\tau}^{thP}, \downarrow c_{g,\omega,\tau}^{thP}, s_{g,\omega,\tau}^{thP}$	Marginal redispatch cost and starting cost of thermal plants in reserve procurement

$$\uparrow c_{g,\omega,\tau}^{th_s^B}, \downarrow c_{g,\omega,\tau}^{th_s^B}$$

Marginal up- and downward regulating cost of thermal plants for secondary reserve

$$\uparrow c_{g,\omega,\tau}^{th_t^B}, \downarrow c_{g,\omega,\tau}^{th_t^B}$$

Marginal up- and downward regulating cost of thermal plants for tertiary reserve

$$x_{g,\omega,\tau}^{th}, \Delta \uparrow x_{g,\omega,\tau}^{th}, \Delta \downarrow x_{g,\omega,\tau}^{th}$$

Per unit start up and per unit up- and downward provision of thermal plants

f) Hydro generation:

$$y_{h,\omega,\tau}^{hyd^*}$$

Day-ahead dispatch of hydro plants

$$y_{h,\omega,\tau}^{hyd^P}, \Delta \uparrow y_{h,\omega,\tau}^{hyd^P}, \Delta \downarrow y_{h,\omega,\tau}^{hyd^P}$$

Redispatch of hydro plants during reserve procurement

$$\Delta \uparrow y_{h,\omega,\tau}^{hyd^B}, \Delta \downarrow y_{h,\omega,\tau}^{hyd^B}$$

Up- and downward regulating of hydro plants in real-time balancing

$$\bar{y}_h^{hyd}, \underline{y}_h^{hyd}$$

Maximum and minimum production of hydro plants

$$\uparrow c_{h,\omega,\tau}^{hyd^P}, \downarrow c_{h,\omega,\tau}^{hyd^P}, s_{g,\omega,\tau}^{th^P}$$

Marginal redispatch cost of hydro plants

$$\uparrow c_{h,\omega,\tau}^{hyd^B}, \downarrow c_{h,\omega,\tau}^{hyd^B}, s_{g,\omega,\tau}^{th^B}$$

Marginal up- and downward regulating cost of hydro plants

g) Transmission lines:

$$t_{l,\omega,\tau}^*, t_{l,\omega,\tau}^B$$

Day-ahead dispatch and real-time exchange on transmission lines

$$\bar{t}_l, t_l$$

Maximum and minimum transmission limits

$$\alpha_l, \delta_l^B$$

Linear losses and availability for balancing of transmission lines

$$d_{l,\omega,\tau}^*, d_{l,\omega,\tau}^B$$

Transmission losses for day-ahead dispatch and real-time exchange

h) Rationing and shut down:

$$y_{a,\omega,\tau}^{rat^P}, y_{a,\omega,\tau}^{rat^B}$$

Rationing during reserve procurement and in real-time balancing

$$y_{a,\omega,\tau}^{sh^P}, y_{a,\omega,\tau}^{sh^B}$$

Generation shut down during reserve procurement and real-time balancing

i) Resource requirements:

$$\bar{r}_k^K, \underline{r}_k^K$$

Up- and downward reserve requirements in each control area

$$\bar{r}_b^B, \underline{r}_b^B$$

Up- and downward reserve requirements in each balancing area

$$\bar{r}^T, \underline{r}^T$$

Up- and downward reserve requirements in the total system

j) Regulating demand:

$\tilde{e}_{a,\omega,\tau}, \tilde{w}_{a,\omega,\tau}$ Demand forecast and wind forecast error in each area

In the following the models for the regulating reserve procurement and the system balancing are shown in detail.

B. Resource procurement

k) Objective function:

$\forall \omega \in W$:

$$C_\omega^P(y^*) = \min \left\{ \sum_{\tau \in T} \left[\sum_{a \in A} \left(y_{a,\omega,\tau}^{rat^P} \cdot 10000 - y_{a,\omega,\tau}^{sh^P} \right) + \sum_{g \in G} \left(\Delta \uparrow y_{g,\omega,\tau}^{th^P} \cdot \uparrow c_{g,\omega,\tau}^{th^P} - \Delta \downarrow y_{g,\omega,\tau}^{th^P} \cdot \downarrow c_{g,\omega,\tau}^{th^P} + s_{g,\omega,\tau}^{th^P} \right) + \sum_{h \in H} \left(\Delta \uparrow y_{h,\omega,\tau}^{hyd^P} \cdot \uparrow c_{h,\omega,\tau}^{hyd^P} - \Delta \downarrow y_{h,\omega,\tau}^{hyd^P} \cdot \downarrow c_{h,\omega,\tau}^{hyd^P} \right) \right] \right\} \quad (1)$$

l) Constraints:

$\forall a \in A, \omega \in W, \tau \in T$:

$$\sum_{g \in G_a} \left(\Delta \uparrow y_{g,\omega,\tau}^{th^P} - \Delta \downarrow y_{g,\omega,\tau}^{th^P} \right) + \sum_{h \in H_a} \left(\Delta \uparrow y_{h,\omega,\tau}^{hyd^P} - \Delta \downarrow y_{h,\omega,\tau}^{hyd^P} \right) + y_{a,\omega,\tau}^{rat^P} - y_{a,\omega,\tau}^{sh^P} = 0 \quad (2)$$

$\forall h \in H, \omega \in W, \tau \in T$:

$$y_{h,\omega,\tau}^{hyd^P} = y_{h,\omega,\tau}^{hyd^*} + \Delta \uparrow y_{h,\omega,\tau}^{hyd^P} - \Delta \downarrow y_{h,\omega,\tau}^{hyd^P} \quad (3)$$

$$\underline{y}_h^{hyd} \leq y_{h,\omega,\tau}^{hyd^P} \leq \bar{y}_h^{hyd} \quad (4)$$

$\forall g \in G, \omega \in W, \tau \in T$:

$$y_{g,\omega,\tau}^{th^P} = y_{g,\omega,\tau}^{th^*} + \Delta \uparrow y_{g,\omega,\tau}^{th^P} - \Delta \downarrow y_{g,\omega,\tau}^{th^P} \quad (5)$$

$$y_{g,\omega,\tau}^{th^P} = \underline{y}_{g,\omega}^{th} \cdot x_{g,\omega,\tau}^{th} + \Delta \downarrow x_{g,\omega,\tau}^{th} \cdot \left(\bar{y}_{g,\omega}^{th} - \underline{y}_{g,\omega}^{th} \right) \quad (6)$$

$$\Delta \uparrow x_{g,\omega,\tau}^{th} + \Delta \downarrow x_{g,\omega,\tau}^{th} \leq x_{g,\omega,\tau}^{th} \leq 1 \quad (7)$$

$$s_{g,\omega,\tau}^{th^P} \geq 0 \quad (8)$$

$\forall g \in G, \omega \in W, \tau \in T \setminus \{1\}$:

$$s_{g,\omega,\tau}^{th^P} \geq s_g^{th} \cdot \left(x_{g,\omega,\tau}^{th} - x_{g,\omega,\tau-1}^{th} \right) \quad (9)$$

$\forall g \in G, \omega \in W$:

$$s_{g,\omega,\tau}^{th^P} \geq s_g^{th} \cdot \left(x_{g,\omega,1}^{th} - x_{g,\omega,max(T)}^{th} \right) \quad (10)$$

$\forall k \in K, \omega \in W, \tau \in T$:

$$\bar{r}_k^K \leq \sum_{g \in G_k} \Delta \uparrow x_{g,\omega,\tau}^{th} \cdot \left(\bar{y}_{g,\omega}^{th} - \underline{y}_{g,\omega}^{th} \right) + \sum_{h \in H_k} \left(\bar{y}_h^{hyd} - y_{h,\omega,\tau}^{hyd^P} \right) \quad (11)$$

$$\underline{r}_k^K \leq \sum_{g \in G_k} \Delta \downarrow x_{g,\omega,\tau}^{th} \cdot \left(\bar{y}_{g,\omega}^{th} - \underline{y}_{g,\omega}^{th} \right) + \sum_{h \in H_k} \left(y_{h,\omega,\tau}^{hyd^P} - \underline{y}_h^{hyd} \right) \quad (12)$$

$\forall \omega \in W, \tau \in T$:

$$\bar{r}^T \leq \sum_{g \in G} \Delta \uparrow x_{g,\omega,\tau}^{th} \cdot \left(\bar{y}_{g,\omega}^{th} - \underline{y}_{g,\omega}^{th} \right) + \sum_{h \in H} \left(\bar{y}_h^{hyd} - y_{h,\omega,\tau}^{hyd^P} \right) \quad (13)$$

$$\underline{r}^T \leq \sum_{g \in G} \Delta \downarrow x_{g,\omega,\tau}^{th} \cdot \left(\bar{y}_{g,\omega}^{th} - \underline{y}_{g,\omega}^{th} \right) + \sum_{h \in H} \left(y_{h,\omega,\tau}^{hyd^P} - \underline{y}_h^{hyd} \right) \quad (14)$$

C. System balancing

m) Objective function:

$\forall \omega \in W, \tau \in T:$

$$C_{\omega}^B(y^P) = \min \left\{ \sum_{\tau \in T} \left[\sum_{a \in A} \left(y_{a,\omega,\tau}^{rat^B} \cdot 10000 - y_{a,\omega,\tau}^{sh^B} \right) + \sum_{g \in G} \left(\Delta_{\uparrow} y_{g,\omega,\tau}^{th_s^B} \cdot \uparrow c_{g,\omega,\tau}^{th_s^B} - \Delta_{\downarrow} y_{g,\omega,\tau}^{th_s^B} \cdot \downarrow c_{g,\omega,\tau}^{th_s^B} + \Delta_{\uparrow} y_{g,\omega,\tau}^{th_t^B} \cdot \uparrow c_{g,\omega,\tau}^{th_t^B} - \Delta_{\downarrow} y_{g,\omega,\tau}^{th_t^B} \cdot \downarrow c_{g,\omega,\tau}^{th_t^B} \right) + \sum_{h \in H} \left(\Delta_{\uparrow} y_{h,\omega,\tau}^{hyd^B} \cdot \uparrow c_{h,\omega,\tau}^{hyd^B} - \Delta_{\downarrow} y_{h,\omega,\tau}^{hyd^B} \cdot \downarrow c_{h,\omega,\tau}^{hyd^B} \right) \right] \right\} \quad (15)$$

n) Constraints:

$\forall a \in A, \omega \in W, \tau \in T:$

$$\sum_{g \in G_a} \left(\Delta_{\uparrow} y_{g,\omega,\tau}^{th_s^B} - \Delta_{\downarrow} y_{g,\omega,\tau}^{th_s^B} + \Delta_{\uparrow} y_{g,\omega,\tau}^{th_t^B} - \Delta_{\downarrow} y_{g,\omega,\tau}^{th_t^B} \right) + \sum_{l \in L_a^f} \left(t_{l,\omega,\tau}^B - t_{l,\omega,\tau}^* \right) - \sum_{l \in L_a^o} \left(t_{l,\omega,\tau}^B - t_{l,\omega,\tau}^* \right) + \frac{1}{2} \sum_{l \in L_a^f \cup L_a^o} \left(d_{l,\omega,\tau}^B - d_{l,\omega,\tau}^* \right) + \sum_{h \in H_a} \left(\Delta_{\uparrow} y_{h,\omega,\tau}^{hyd^B} - \Delta_{\downarrow} y_{h,\omega,\tau}^{hyd^B} \right) + y_{a,\omega,\tau}^{rat^B} - y_{a,\omega,\tau}^{sh^B} = \tilde{e}_{a,\omega,\tau} + \tilde{w}_{a,\omega,\tau} \quad (16)$$

$\forall l \in L, \omega \in W, \tau \in T:$

$$d_{l,\omega,\tau}^B \geq |t_{l,\omega,\tau}^B \cdot \alpha_l| \quad (17)$$

$$\begin{aligned} \underline{t}_l &\leq t_{l,\omega,\tau}^B \leq \bar{t}_l, \text{ for } \delta_l^B = 1 \\ t_{l,\omega,\tau}^B &= t_{l,\omega,\tau}^*, \text{ for } \delta_l^B = 0 \end{aligned} \quad (18)$$

$\forall h \in H, \omega \in W, \tau \in T:$

$$0 \leq \Delta_{\uparrow} y_{h,\omega,\tau}^{hyd^B} \leq \bar{y}_{h,\omega,\tau}^{hyd} - y_{h,\omega,\tau}^{hyd^P} \quad (19)$$

$$0 \leq \Delta_{\downarrow} y_{h,\omega,\tau}^{hyd^B} \leq y_{h,\omega,\tau}^{hyd^P} - \underline{y}_{h,\omega,\tau}^{hyd} \quad (20)$$

$\forall g \in G, \omega \in W, \tau \in T:$

$$0 \leq \Delta_{\uparrow} y_{g,\omega,\tau}^{th_s^B} \leq \Delta_{\uparrow} x_{g,\omega,\tau}^{th} \cdot \left(\bar{y}_{g,\omega}^{th} - \underline{y}_{g,\omega}^{th} \right) \quad (21)$$

$$0 \leq \Delta_{\downarrow} y_{g,\omega,\tau}^{th_s^B} \leq \Delta_{\downarrow} x_{g,\omega,\tau}^{th} \cdot \left(\bar{y}_{g,\omega}^{th} - \underline{y}_{g,\omega}^{th} \right) \quad (22)$$

$$0 \leq \Delta_{\uparrow} y_{g,\omega,\tau}^{th_t^B} \leq \bar{y}_{g,\omega}^{th} - y_{g,\omega,\tau}^{th^P} - \Delta_{\uparrow} x_{g,\omega,\tau}^{th} \cdot \left(\bar{y}_{g,\omega}^{th} - \underline{y}_{g,\omega}^{th} \right) \quad (23)$$

$$0 \leq \Delta_{\downarrow} y_{g,\omega,\tau}^{th_t^B} \leq y_{g,\omega,\tau}^{th^P} - \Delta_{\downarrow} x_{g,\omega,\tau}^{th} \cdot \left(\bar{y}_{g,\omega}^{th} - \underline{y}_{g,\omega}^{th} \right) \quad (24)$$

D. Reserve pricing

o) Resource procurement:

$\forall a \in A, h \in H_a, \omega \in W, \tau \in T:$

$$\uparrow c_{h,\omega,\tau}^{hyd^P} = \max(v_{a,\omega}, p_{a,\omega,\tau}) \quad (25)$$

$$\downarrow c_{h,\omega,\tau}^{hyd^P} = \min(v_{a,\omega}, p_{a,\omega,\tau}) \quad (26)$$

$\forall a \in A, g \in G_a, \omega \in W, \tau \in T:$

$$\uparrow c_{g,\omega,\tau}^{th^P} = \max(c_g^{th}, p_{a,\omega,\tau}) \cdot 1.05 \quad (27)$$

$$\downarrow c_{g,\omega,\tau}^{th^P} = \min(c_g^{th}, p_{a,\omega,\tau}) / 1.05 \quad (28)$$

p) System Balancing:

$\forall a \in A, h \in H_a, \omega \in W, \tau \in T:$

$$\uparrow c_{h,\omega,\tau}^{hyd^B} = \max(v_{a,\omega}, p_{a,\omega,\tau}) \cdot 1.1 \quad (29)$$

$$\downarrow c_{h,\omega,\tau}^{hyd^B} = \min(v_{a,\omega}, p_{a,\omega,\tau}) / 1.1 \quad (30)$$

$\forall a \in A, g \in G_a, \omega \in W, \tau \in T:$

$$\uparrow c_{g,\omega,\tau}^{th^B} = \max(c_g^{th}, p_{a,\omega,\tau}) \cdot 1.5 \quad (31)$$

$$\downarrow c_{g,\omega,\tau}^{th^B} = \min(c_g^{th}, p_{a,\omega,\tau}) / 1.5 \quad (32)$$

$$\uparrow c_{g,\omega,\tau}^{th_t^B} = \max(c_g^{th}, p_{a,\omega,\tau}) \cdot 1.5 + \frac{s_g^{th}}{y_{g,\omega}^{th}} \quad (33)$$

$$\downarrow c_{g,\omega,\tau}^{th_t^B} = \min(c_g^{th}, p_{a,\omega,\tau}) / 1.5 - \frac{s_g^{th}}{y_{g,\omega}^{th}} \quad (34)$$

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