MODELING OF BALANCING MARKET INTEGRATION IN THE NORTHERN EUROPEAN CONTINENT

Hossein Farahmand
Norwegian University of Science and Technology (NTNU)
Trondheim, Norway
hossein.farahmand@elkraft.ntnu.no

Gerard L. Doorman
Norwegian University of Science and Technology (NTNU)
Trondheim, Norway
gerard.doorman@elkraft.ntnu.no

Abstract - In the present work we analyse the integration of the regulating power markets in the northern continental Europe including the Nordic system, Germany and the Netherlands. Different levels of balance market integration are analysed, varying from the current state with no integration to full integration of the regulating markets. The day-ahead dispatch and the balancing energy market are settled separately. Firstly the day-ahead market is modelled with simultaneous reserve procurement for the northern continental Europe. 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 using the day-ahead market clearing results as the basis.
Detailed results show how plant dispatch and power flows change as a result of more market integration between two synchronous systems. Cost savings are obtained due to less activation of reserves caused by imbalance netting and the use of cheaper balancing resources.

Keywords - market integration, balancing services exchange, reserve procurement, real-time power balancing

NOMENCLATURE

Superscript

d	day-ahead dispatch
hyd	hydro units
$hvdc$	HVDC cables
L	loads
r	real-time dispatch
rat	rationing
th	thermal units
Tr	transmission lines

Indices

a, b	control areas
$\acute{a}, \acute{b}$	sub-areas
ft	network AC transmission line from bus f to bus t
gr	thermal regulating generators
g	thermal generators
h	hydro generators
i, j	buses in the system
τ	hour during the year

Sets

A	set of balancing areas
Bus	set of buses in the system
G	set of thermal generators
GR	set of regulating resources
H	set of hydro generators
$HVDC$	set of HVDC interconnections
$Line$	set of AC transmission lines
SA	set of day ahead sub-areas
T	set of simulation hours

Parameters

$B_{i,j}$	the i, j^{th} element of bus Susceptance matrix (B)
B_{ft}	the Susceptance of the network AC transmission line connecting bus f to bus t
$C_{h,\tau}^{hyd,d}$	marginal cost of hydro unit h at time step τ in day-ahead dispatch (€/MWh)
$\overline{C}_{h,\tau}^{hyd,r}, \underline{C}_{h,\tau}^{hyd,r}$	marginal cost of up- and downward regulation of hydro unit h at time step τ in real-time dispatch (€/MWh)
C^{rat}	rationing cost (€/MWh)
$C_{g}^{th,d}$	marginal cost of thermal unit g in day-ahead dispatch (€/MWh)
$\overline{C}_{g,\tau}^{th,r}, \underline{C}_{g,\tau}^{th,d}$	marginal cost of up- and downward regulation of thermal unit g at time step τ in real-time dispatch(€/MWh)
$Cs_{g}^{th,d}$	start-up cost for thermal unit g (€)
L_{τ}	length of time step τ (hour)
$Cs_{g}^{th,d}$	start-up cost for unit g (€)
$NTC_{\acute{a}\acute{b}}$	NTC (Net Transfer Capacity) from sub-area $\acute{a}$ to $\acute{b}$ (MW)
$\tilde{P}_{i,\tau}^{dev,r}$	real-time imbalance at bus i at time step τ (MW)
$P_{i,\tau}^{L}$	demand at bus i at time step τ (MW)
$\overline{P}_{h}^{hyd}, \underline{P}_{h}^{hyd}$	maximum and minimum generation capacity of hydro unit h (MW)
$\overline{P}_{ij}^{hvdc}$	maximum transmission capacity of HVDC cable from bus i to bus j (MW)
$\overline{P}_{g}^{th}, \underline{P}_{g}^{th}$	maximum and minimum generation capacity of thermal unit g respectively (MW)
$\overline{P}_{ft}^{Tr}$	maximum transmission capacity of AC line from f to t (MW)
$Q_{h,\tau}^{hyd,d}$	inflow to reservoir of hydro unit h at time step τ (MWh)

$\overline{Re}_{\acute{a}}$	upward reserve requirement for sub-area $\acute{a}$ (MW)
$\underline{Re}_{\acute{a}}$	downward reserve requirement for sub-area $\acute{a}$ (MW)
$Rl_{h,\tau}^{hyd,d}$	reservoir level hydro unit h at time step τ in day-ahead dispatch (MWh), (determined in the outer loop of optimization)

Variables

$F_{\tau}^{d}(\cdot), F_{\tau}^{r}(\cdot)$	cost function of day-ahead and real-time dispatch respectively (€)
$imp_{\acute{a}\acute{b},\tau}^{dw,d}$	reservation of downward regulating exchange capacity from sub-area $\acute{a}$ to $\acute{b}$ (MW)
$imp_{\acute{a}\acute{b},\tau}^{up,d}$	reservation of upward regulating exchange capacity from sub-area $\acute{a}$ to $\acute{b}$ (MW)
$P_{ij,\tau}^{hvdc,d}$	exchanged energy on HVDC interconnection from i to j (MW) at time step in day-ahead dispatch τ (MW)
$P_{h,\tau}^{hyd,d}$	production of hydro unit h at time step τ in day-ahead dispatch (MW)
$\Delta\overline{P}_{h,\tau}^{hyd,r}$	upward regulation of hydro unit h at time step τ in real-time dispatch (MW)
$\Delta\underline{P}_{h,\tau}^{hyd,r}$	downward regulation of hydro unit h at time step τ in real-time dispatch (MW)
$P_{i,\tau}^{rat}$	load rationing at bus i at time step τ (MW)
$P_{g,\tau}^{th,d}$	production of thermal unit g at time step in day-ahead dispatch (MW)
$\Delta\overline{P}_{gr,\tau}^{th,r}$	upward regulation of thermal unit gr at time step τ in real-time dispatch (MW)
$\Delta\underline{P}_{gr,\tau}^{th,r}$	downward regulation of thermal unit gr at time step τ in real-time dispatch (MW)
$Str_{g,\tau}^{th,d}$	approximate relative start-up cost for unit g and time step τ , ∈[0,1]
$X_{1,g,\tau}^{th,d}$	per unit production between 0 and minimum production of thermal unit g and time step τ , ∈[0,1]
$X_{2,g,\tau}^{th,d}$	per unit production between minimum and maximum production of thermal unit g and time step τ , ∈[0,1]
$X_{3,g,\tau}^{th,d}$	per unit share of spinning reserve capacity of thermal unit g and time step τ , ∈[0,1]
$\delta_{i,\tau}$	bus i voltage angle (in radians) at time step τ

1 INTRODUCTION

THE European Union Directive 2003/54/EC gives common rules for the internal electricity market, while regulation 1228/2003 regulates the access to the network for cross-border exchanges and spells out the principles of cross-border congestion management [1].

The first step towards the development of one single electricity market in Europe has been to establish regional markets. The European Regulators' Group for electricity and gas (ERGEG) agreed in the spring of 2006 to launch an initiative to create seven Regional Energy Markets (REM) in Europe as an interim step with the aim to remove barriers to cross-border trade in those regions. The results will include improved transparency of information, better managing of congestion at borders by requiring TSOs to cooperate on how to calculate and allocate cross-border capacity and efforts toward balancing market integration. Examples of regional markets are the Nordic market (Nord Pool), Trilateral Market Coupling (TLC) including France, Belgium and the Netherlands and the Iberian market between Spain and Portugal. The European Market Coupling Company (EMCC) currently carries out market coupling on the two interconnectors between Germany and Denmark (DK West) [2].

The need for adequate and optimal reserve resources is increased by strongly increasing amounts of intermittent renewable energy resources such as wind power. This development requires large amounts of balancing energy. Hydro power and especially Nordic hydro power with large reservoirs has favourable characteristics to provide this. Therefore integration of regulating markets of the Nordic and Central European systems can facilitate the procurement of Nordic regulating resources. From an economic point of view, the frame work for efficient regulating market integration should maximize social welfare. Several studies have been carried out on national regulating power markets modelling; For instance in [3] an econometric analysis of the regulating market presented. it introduces a linear model that takes into account the influence of the regulating volume. [4] and [5] represent the analysis of forecasting balancing prices. The optimum biding of market participants is illustrated in [6] and [7]. Reference [8] proposes an algorithm based on incremental DC optimal power flow and compares the results with the today's practice for the Nordic system. An estimation of the economic value of exchanging regulating resources between the Nordic system and continental Europe is done in [9]. A model of an integrated northern European regulating power market with main focus on generation scheduling and unit commitment is presented in [10]. In the present work we use a two-step model to estimate the benefit of integration northern Europe regulating power markets and the exchange of balancing services between the Nordic countries and Germany and the Netherlands, using the existing interconnections. The two steps in the model represent the day-ahead and regulating power markets respectively. The main objective of the paper is to show some examples of how procurement and activation of reserve power change with different levels of integration between markets.

The paper is divided into six sections. Section 2 states the mathematical description of the model both for day-ahead and real-time dispatch. The mechanism of reserve procurement and system balancing are described in Section 3. A case study and result analysis are presented in Section 4. Section 5 discusses the results discussion. Finally, the conclusions are drawn in Section 6.

2 MATHEMATICAL DESCRIPTION

The day-ahead market is modelled as a common market for the whole European continent. Reserve procurement is done simultaneously with the clearing of the day-ahead market, but the reserve procurement is limited to northern continental Europe. Subsequently the balancing energy market is modelled as a real-time power dispatch using the day-ahead market clearing results as the basis. A DC optimal power flow (DCOPF) is used for both day-ahead and real-time dispatch.

2.1 Day-ahead dispatch

Eq. 1 expresses the cost function for day-ahead dispatch. These costs exist of thermal costs including start-up costs and the cost of using reservoir water.

$$F_\tau^d(\cdot) = \tag{1}$$
$$min\left\{\sum_{\tau\in T}\left[\sum_{g\in G}\left(Str_{g,\tau}^{th,d}\cdot Cs_g^{th,d} + C_g^{th,d}\cdot P_{g,\tau}^{th,d}\right)\right.\right.$$
$$\left.\left. + \sum_{h\in H}\left(C_{h,t}^{hyd,d}\cdot P_{h,\tau}^{hyd,d}\right) + \sum_{i\in Bus}\left(C^{rat}\cdot P_{i,\tau}^{rat,d}\right)\right]\right\}$$

Eq. 2 states the energy balance at each bus for a given time step τ.

$$P_{i,\tau}^{th,d} + P_{i,\tau}^{hyd,d} + \sum_{j\in Bus}\left(P_{ji,\tau}^{hvdc,d} - P_{ij,\tau}^{hvdc,d}\right) + P_{i,\tau}^{rat,d}$$
$$- \sum_{j\in Bus}\left(B_{i,j}\cdot\delta_{j,\tau}^d\right) = P_{i,\tau}^L$$
$$\forall\, i\in Bus,\ \tau\in T \tag{2}$$

Line transmission constraints are formulated by Eq. 3.

$$-\overline{P}_{ft}^{Tr} \le B_{ft}\left(\delta_{f,\tau}^d - \delta_{t,\tau}^d\right) \le \overline{P}_{ft}^{Tr}$$
$$\forall\, ft\in Line,\ \tau\in T \tag{3}$$

Eq. 4 defines the Net Transfer Capacity (NTC) between areas.

$$NTC_{\acute{b}\acute{a}} \le$$
$$\sum_{f\in\acute{a}}\sum_{t\in\acute{b}}\left(B_{ft}\left(\delta_{f,\tau}^d - \delta_{t,\tau}^d\right)\right) \le NTC_{\acute{a}\acute{b}}$$
$$\forall\, \acute{a},\acute{b}\in SA,\ \tau\in T \tag{4}$$

HVDC transmission constraint is expressed by Eq. 5.

$$-\overline{P}_{ij}^{hvdc} \le P_{ij,\tau}^{hvdc,d} \le \overline{P}_{ij}^{hvdc}$$
$$\forall\, ij\in HVDC,\ \tau\in T \tag{5}$$

The thermal generation should be between the maximum and minimum production capacity at each time step.

$$\underline{P}_g^{th} \le P_{g,\tau}^{th,d} \le \overline{P}_g^{th} \quad \forall\, g\in G,\ \tau\in T \tag{6}$$

The hydro power production at each time step should also be between minimum and maximum production capacity while the maximum production of hydro can be limited by the reservoir level at each time step:

$$\underline{P}_{h,\tau}^{hyd} \le P_{h,\tau}^{hyd,d} \le min\left(\overline{P}_h^{hyd}, \frac{Rl_{h,\tau}^{hyd,d}}{L_\tau}\right)$$
$$\forall\, h\in H,\ \tau\in T \tag{7}$$

Inflow is divided evenly among the hours within the week and the reservoir levels for hydro generators are updated at each time step.

$$Rl_{h,\tau}^{hyd,d} = Rl_{h,\tau-1}^{hyd,d} + Q_{h,\tau}^{hyd,d} - p_{h,\tau-1}^{hyd,d}\cdot L_{\tau-1}^d$$
$$\forall\, h\in H,\ \tau\in T \tag{8}$$

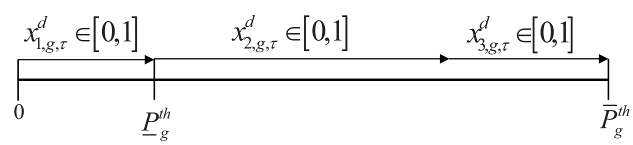

Figure 1: Thermal plant representation

An LP based approximate algorithm is used to model start-up costs in order to avoid excessive calculation times. Additional relative variables are introduced as shown in Figure 1. Equations 9 to 12 define the constraints related to these variables:

$$P_{g,\tau}^{th,d} = X_{1,g,\tau}^{th,d}\cdot\underline{P}_g^{th} + X_{2,g,\tau}^{th,d}\cdot\left(\overline{P}_g^{th} - \underline{P}_g^{th}\right)$$
$$\forall\, g\in G,\ \tau\in T \tag{9}$$

$$X_{1,g,\tau}^{th,d} \ge X_{2,g,\tau}^{th,d} + X_{3,g,\tau}^{th,d} \quad \forall\, g\in G,\ \tau\in T \tag{10}$$

$$X_{2,g,\tau}^{th,d} + X_{3,g,\tau}^{th,d} \le 1 \quad \forall\, g\in G,\ \tau\in T \tag{11}$$

$$X_{1,g,\tau}^{th,d} - X_{1,g,\tau-1}^{th,d} \le Str_{g,\tau}^{th,d} \quad \forall\, g\in G,\ \tau\in T \tag{12}$$

Eq. 9 gives the coupling to the actual production of generator unit g. Eq. 10 shows that the unit has to be started before it can start to production. Eq. 11 requires that the sum of generation and reserves above minimum production does not exceed maximum production. Eq. 12

ensures that if $X^{th,d}_{1,g,\tau}$ increases in time step τ compared with its value in the previous time step, the start-up cost has to be at least equal to their difference. This way of modelling start-up costs has proven to result in much more realistic dispatch solutions than leaving out start-up costs altogether, with acceptable increases in computation times.
In order to handle congestion within control areas, each balancing area is divided into sub-areas which are connected by a number of tie-lines. Optimal reserve procurement is determined on a daily basis as part of the day-ahead dispatch, taking into account transmission constraints. The implicit reservation $imp^{up,d}_{\acute{a}\acute{b},\tau}$ of upward regulating power Exchange capacity between sub-areas $\acute{a}$ and $\acute{b}$ is defined as:

$$imp^{up,d}_{\acute{a}\acute{b},\tau} \leq NTC_{\acute{b}\acute{a}} + \sum_{f\in\acute{a}}\sum_{t\in\acute{b}} B_{ft}\cdot\left(\delta^{d}_{f,\tau}-\delta^{d}_{t,\tau}\right)$$
$$\forall\,\acute{a},\acute{b}\in SA,\ \tau\in T \tag{13}$$

Eq. 14 requires that the sum of available reserve on all regulating units inside sub-area plus the import upward regulation opportunity from other sub-areas exceeds the reserve requirement:

$$\sum_{h\in\acute{a}}\left(\overline{P}^{hyd}_{h}-P^{hyd,d}_{h,\tau}\right)+\sum_{gr\in\acute{a}}\left(X^{th,d}_{3,gr,\tau}\cdot\left(\overline{P}^{th}_{gr}-\underline{P}^{th}_{gr}\right)\right)$$
$$+\,imp^{up,d}_{\acute{a}\acute{b},\tau}\geq\overline{Re}_{\acute{a}}$$
$$\forall\,\acute{a},\acute{b}\in SA, h\in H, gr\in GR,\tau\in T \tag{14}$$

Correspondingly, we introduce $imp^{dw,d}_{\acute{a}\acute{b},\tau}$ as the opportunity to import downward regulating power between sub-areas $\acute{a}$ and $\acute{b}$:

$$imp^{dw,d}_{\acute{a}\acute{b},\tau} \leq NTC_{\acute{a}\acute{b}} - \sum_{f\in\acute{a}}\sum_{t\in\acute{b}} B_{ft}\cdot\left(\delta^{d}_{f,\tau}-\delta^{d}_{t,\tau}\right)$$
$$\forall\,\acute{a},\acute{b}\in SA,\ \tau\in T \tag{15}$$

The requirement to downward regulating power is defined by Eq. 16.

$$\sum_{h\in\acute{a}} max\left[\left(P^{hyd,d}_{h,\tau}-\underline{P}^{hyd}_{h}\right),0\right]$$
$$+\sum_{gr\in\acute{a}}\left(X^{th,d}_{2,gr,\tau}\cdot\left(\overline{P}^{th}_{gr}-\underline{P}^{th}_{gr}\right)\right)+imp^{dw,d}_{\acute{a}\acute{b},\tau}\geq\underline{Re}_{\acute{a}}$$
$$\forall\,\acute{a},\acute{b}\in SA, h\in H, gr\in GR,\tau\in T \tag{16}$$

2.2 *Real-time dispatch model*

Eq. 17 shows the real-time dispatch cost function. The aim is to follow the initial day-ahead schedule as closely as possible while minimizing balancing costs.

$$F^{d}_{\tau}(\cdot)=min\left\{\sum_{gr\in GR}\left(\overline{C}^{th,r}_{gr,\tau}\cdot\Delta\overline{P}^{th,r}_{gr,\tau}+\underline{C}^{th,r}_{gr,\tau}\cdot\Delta\underline{P}^{th,r}_{gr,\tau}\right)\right.$$
$$\sum_{h\in H}\left(\overline{C}^{hyd,r}_{h,\tau}\cdot\Delta\overline{P}^{hyd,r}_{h,\tau}+\underline{C}^{hyd,r}_{h,\tau}\cdot\Delta\underline{P}^{hyd,r}_{h,\tau}\right)$$
$$\left.+\sum_{i\in Bus}\left(C^{rat}\cdot P^{rat,r}_{i,\tau}\right)\right\}\ \forall\,\tau\in T \tag{17}$$

As in Eq. 2 for the day-ahead dispatch, Eq. 18 states the energy balance at each node for a given time step τ taking into account the real-time imbalances.

$$\left(\Delta\overline{P}^{th,r}_{gr,\tau}-\Delta\underline{P}^{th,r}_{gr,\tau}\right)+\left(\Delta\overline{P}^{hyd,r}_{h,\tau}-\Delta\underline{P}^{hyd,r}_{h,\tau}\right)$$
$$+\sum_{j\in Bus}\left(P^{hvdc,r}_{ji,\tau}-P^{hvdc,r}_{ij,\tau}\right)+P^{rat,r}_{i,\tau}$$
$$-\sum_{j\in Bus}\left(B_{i,j}\cdot\delta^{r}_{j,\tau}\right)-P^{L}_{i,\tau}=\widetilde{P}^{dev}_{i,\tau}$$
$$\forall\,i\in Bus,\ \tau\in T \tag{18}$$

Exchanged power between the areas is limited using equations similar to Eq. 3, Eq. 4 and Eq. 5.
Eq. 19 and Eq. 20 show the production capacity of regulating generators for up- and downward regulation respectively. All the day-ahead values are the optimum results of day-ahead dispatch.

$$P^{th,d}_{gr,\tau}\leq\Delta\overline{P}^{th,r}_{gr,\tau}\leq\overline{P}^{th}_{gr,\tau}\quad\forall\,gr\in GR,\ \tau\in T \tag{19}$$

$$\underline{P}^{th}_{gr,\tau}\leq\Delta\underline{P}^{th,r}_{gr,\tau}\leq P^{th,d}_{gr,\tau}\quad\forall\,gr\in GR,\ \tau\in T \tag{20}$$

For hydro generators contributing in real-time reserve dispatch we have similar assumption as the thermal regulating generators and they are represented in Eq. 21 and Eq. 22 .

$$0\leq\Delta\overline{P}^{hyd,r}_{h,\tau}\leq\left(min\left(\overline{P}^{hyd}_{h},\frac{Rl^{hyd,d}_{h,r}}{L_r}\right)-P^{hyd,d}_{h,\tau}\right)$$
$$\forall\,h\in H,\tau\in T \tag{21}$$

$$0\leq\Delta\underline{P}^{hyd,r}_{h,\tau}\leq\left(P^{hyd,d}_{h,\tau}-\underline{P}^{hyd}_{h}\right)$$
$$\forall\,h\in H,\tau\in T \tag{22}$$

In the case studies illustrated in Section 4, the real-time deviation from day-ahead dispatch is completely compensated inside the control area as shown in Eq. 23.

$$\sum_{h \in a'} \left(\Delta \overline{P}^{hyd,r}_{h,\tau} - \Delta \underline{P}^{hyd,r}_{h,\tau} \right) + \sum_{gr \in a'} \left(\Delta \overline{P}^{th,r}_{gr,\tau} - \Delta \underline{P}^{th,r}_{gr,\tau} \right)$$
$$+ \sum_{i \in a'} \left(P^{rat,r}_{i,\tau} \right) = \sum_{i \in a'} \left(\widetilde{P}^{dev}_{i,\tau} \right)$$
$$\forall\, h \in H, gr \in GR, i \in Bus, a' \in SA, \tau \in T \qquad (23)$$

This constraint will be relaxed in subsequent analyses.

3 RESERVE PROCUREMENT AND SYSTEM BALANCING

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 [11].

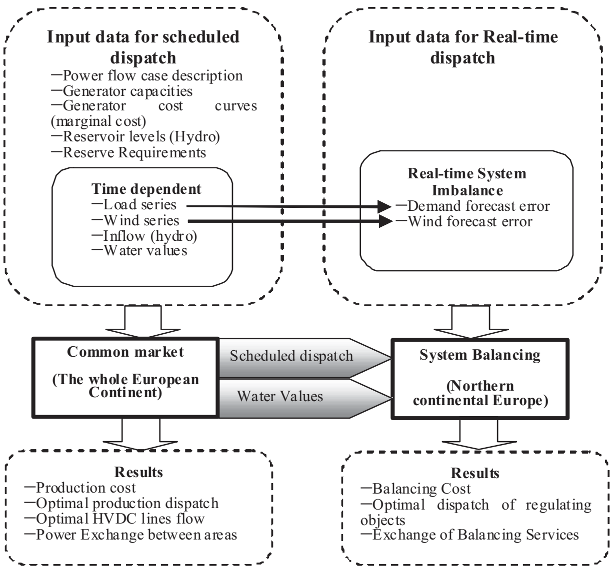

Figure 2: Schematic diagram of model approach steps

Reserve procurement is done simultaneously with the day-ahead dispatch. Reserve procurement is limited to the Nordic system, Germany and the Netherlands, designated as the Northern Europe (NE) area in this paper. 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 2 schematically shows model steps.

4 RESERVE PROCUREMENT AND SYSTEM BALANCING

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. The Netherlands is also one control area.

In order to handle transmission congestion within control areas, they are divided into sub-areas. Figure 3 shows the modelled control areas and sub-areas.

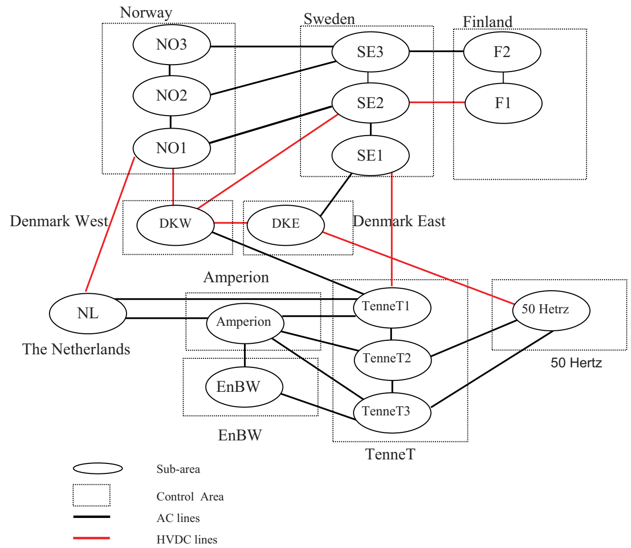

Figure 3: Model of the Northern European system

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 an 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. More details can be found in [12] and [13].
Thermal plants are either modelled providing base load with low/zero marginal cost and zero start-up cost or as regulating plants providing 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 4 depicts the share of regulating generation within the area.

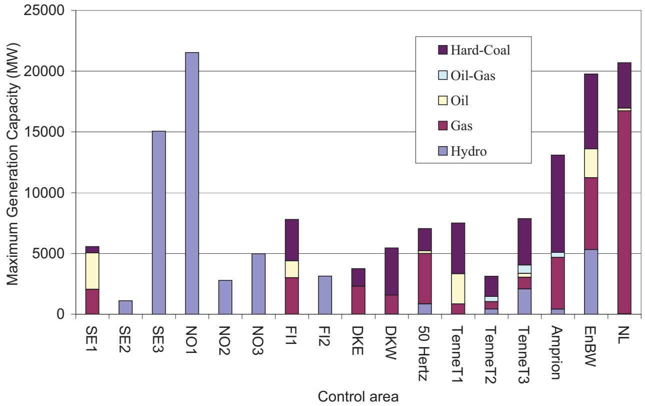

Figure 4: Installed regulating generation capacity in each sub-area.

As can be seen from Figure 4 hydro generation has the highest share of regulating capacity. However it is mainly situated in the Nordic system. 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. We now define three cases for reserve procurement and real-time reserve activation:

- 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. Sub-areas 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 [14]. Balancing power can be exchanged between the German control areas/sub-areas and also between the areas and sub-areas within the Nordic region. 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 sub-areas shown in Figure 3. The required reserve can be procured outside the area, provided there is enough available capacity on the transmission line to the reserve providing sub-area.

4.1 Day-ahead dispatch and reserve procurement for specific hours

Reserve requirements for each control area based on the actual values for each area, which can be found in [15], [16] and [17]. These values are the requirements for secondary reserve in Germany and the Netherlands and Fast Active Disturbance Reserve (FADR) in the Nordic system. These values are divided between the sub-areas relative to total area annual demand. Table 1 shows the reserve requirement for NE control areas and sub-areas. 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.

Control areas	Sub-areas	Up	Down	Up	Down
Sweden	SE1	1220	-1220	208	-208
	SE2			780	-780
	SE3			232	-232
Norway	NO1	1200	-1200	915	-915
	NO2			142	-142
	NO3			143	-143
Finland	FI1	865	-865	580	-580
	FI2			285	-285
DKE	DKE	580	-580	580	-580
DKW	DKW	580	-580	580	-580
Nordic		4485	-4485		
50Hertz	50Hertz	638	-400	638	-400
TenneT	TenneT1	830	-590	243	-173
	TenneT2			281	-200
	TenneT3			306	-217
Amprion	Amprion	1003	-725	1003	-725
EnBW	EnBW	537	-330	537	-330
NL	NL	300	-300	300	-300
GE+NL		3308	-2345		

Table 1: Reserve requirement for the control area and sub-areas in NE system [MW]

4.1.1 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.

- Scenario 2: hour 7284 which is an hour in the late autumn, 156 GW total load in NE area.

Table 2 shows the reserve procurement cost for the different cases, calculated as the difference in total dispatch cost with and without the reserve requirement.

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

Table 2: Total reserve procurement cost for the NE area [1000 €]

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

4.1.2 Procured reserve

Table 3 and Table 4 show the optimal procurement of reserves for each sub-area in scenario 1 and scenario 2 respectively. 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 TennetT1, 2 and EnBW areas. Also note that while there is an excess of upward regulation reserves in Case I, the procurements exactly match the requirements in Case II. With respect to the downward regulation reserves, the effect is the opposite.

	case I		case II		case III	
Sub-areas	Up	Down	Up	Down	Up	Down
SE1	0	1929	0	1929	0	1929
SE2	744	372	744	372	744	372
SE3	9568	5496	9568	5496	9568	5496
NO1	9115	2414	9161	12368	9456	12073
NO2	636	2147	636	2147	636	2147
NO3	1423	3556	1423	3556	1423	3556
FI1	0	4550	0	4550	0	4550
FI2	2184	950	2184	950	2184	950
DKE	0	1311	0	1311	0	1311
DKW	0	2618	0	2764	0	2922
Nordic	23670	35343	23716	35443	24011	35306
50Hertz	638	1896	251	1979	143	2087
TenneT1	496	1776	33	1927	376	1694
TenneT2	48	1628	191	1485	95	1581
TenneT3	462	4598	719	4221	514	4502
Amprion	1003	6425	234	6672	141	6333
EnBW	1381	9395	1580	9469	1305	9471
NL	300	4387	300	4468	8	5035
GE+NL	4328	30105	3308	30221	2582	30703

Table 3: Available reserves, Scenario1 [MW]

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 procured upward regulation reserves within Germany and the Netherlands is equal or greater than 3308 MW, the requirement in those areas. Note that the optimal procurement in the area NO1 (which is directly connected to Denmark and the Netherlands) also slightly changes as an indirect effect of the integration of the German 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. 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 system, 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, cf. Section 4.1.3 Scenario 2 illustrates that although the normal result would be export of reserves from the Nordic system 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.

	case I		case II		case III	
Sub-areas	Up	Down	Up	Down	Up	Down
SE1	0	529	0	529	0	529
SE2	124	992	124	992	124	992
SE3	4352	10712	4310	10754	4310	10754
NO1	5447	16082	5585	15944	5585	15944
NO2	1062	1721	1074	1708	1074	1708
NO3	2048	2932	2093	2886	2093	2886
FI1	0	1527	0	1687	0	1700
FI2	461	2673	482	2652	499	2635
DKE	0	1110	0	1121	0	1280
DKW	227	3120	2	3337	2	3106
Nordic	13721	41398	13670	41610	13687	41534
50Hertz	638	2769	0	2969	0	2969
TenneT1	93	2591	0	2637	0	2691
TenneT2	371	1750	0	1979	0	1979
TenneT3	693	4886	146	5393	258	5281
Amprion	1623	7448	0	8357	0	8463
EnBW	2365	8654	3029	8335	3352	7983
NL	300	8331	300	8166	16	8341
GE+NL	6083	36429	3475	37836	3626	37705

Table 4: Available reserves, Scenario2 [MW]

4.1.3 Interconnection availability and energy flows

Table 5 and Table 6 show the availability of the corridors between sub-areas for reserve exchange in scenario 1 and scenario 2 respectively . As shown in Section 4.1.2, in Scenario1, Case III we need to procure 1346 MW in the Nordic system including 3308-2582 = 726 MW for the German and Dutch system and 620 MW for Denmark west. The available HVDC capacity for upward regulating power after the day ahead market clearing on all HVDCs except SE1-FI1 is $2 \times (485{+}850{+}700{+}600{+}600{+}550) =$ 7570 MW (grey cells) which covers the required interconnection transmission availability. Furthermore there is sufficient available capacity on the AC interconnections between Denmark West-TenneT1 and TenneT1-the Netherlands for the balancing services exchange.
In Scenario 2, Case III, the available reserved capacity for upward regulating reserve on the HVDC interconnections to the other synchronous area including Denmark West is equal to (600-512) + (550-338) = 300 MW (grey cells). The procured reserve in Denmark west is 2 MW. Therefore the total procured reserve from the Nordic system is equal to 302 MW. In addition we need to procure 620-302 = 318 MW upward regulating reserve for Denmark West from Germany and the Netherlands to satisfy the

requirement in the Nordic system. Thereby the procured reserve in the German areas and Dutch system is equal to 3306+318= 3626 MW.

	From	To	Cap.	Case I	Case II	Case III
	SE1	FI1	550	550	550	550
	SE2	DKW	485	-485	-485	-485
	NO1	DKW	850	-850	-850	-850
HVDC	NO1	NL	700	-359	-404	-700
	DKE	DKW	600	-600	-600	-600
	SE1	TenneT1	600	-600	-600	-600
	DKE	50Hertz	550	-550	-550	-550
	DKW	TenneT1	3620	297	485	700
AC	TenneT1	NL	2000	742	795	933
	Amprion	NL	6923	3108	3055	2870

Table 5: Day-ahead flows, Scenario1 [MW]

	From	To	Cap.	Case I	Case II	Case III
	SE1	FI1	550	534	5454	454
	SE2	DKW	485	485	485	485
	NO1	DKW	850	850	850	850
HVDC	NO1	NL	700	700	700	700
	DKE	DKW	600	-20	-18	512
	SE1	TenneT1	600	600	600	600
	DKE	50Hertz	550	550	550	338
	DKW	TenneT1	3620	2580	2568	2770
AC	TenneT1	NL	2000	412	396	428
	Amprion	NL	6923	3438	3454	3422

Table 6: Day-ahead flows, Scenario2 [MW]

4.2 Real-time balancing in NE area for specific hours

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. Table 7 shows the real-time imbalances for both scenario 1 and 2.

Control areas	Scenario1	Scenario 2
Sweden	12	122
NO1	-90	218
NO2	0	0
NO3	0	0
Finland	0	0
DKE	-20	-506
DKW	0	-327
Nordic	-98	-493
50 Hertz	327	-304
TenneT	149	290
Amprion	0	41
EnBW	-50	62
NL	61	-16
GE + NL	487	72

Table 7: Real-time Imbalances for both Scenarios [MW]

To model the cost of balancing in accordance with the actual behaviour of the balancing markets we made a similar assumption as in [10], 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.

4.2.1 Balancing production cost

Table 8 represents the NE area balancing cost for the first PTU in both scenarios.

Scenario	Case I	Case II	Case III
1	35.40	32.95	22.97
2	27.30	24.80	1.87

Table 8: Total reserve procurement cost for the NE area [1000 €]

The balancing cost is reduced with 2.45 k€ and 2.50 k€ from case I to II and 9.98 k€ and 22.93 k€ from case II to III in scenarios 1 and 2 respectively. The significant reduction in Case III is caused by the cancelling out of positive and negative imbalances ("imbalance netting") in the respective systems as illustrated below.

4.2.2 Activated reserve

Table 9 shows the activated regulating reserve in each scenario for the respective cases. 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. The high amount of this activated reserve is procured by the cheap Norwegian hydro generators located in NO1 sub-area.
In Scenario 2, Cases I and II, the net activated reserve is -493 MW in the Nordic system and 72 MW for 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.

	Scenario 1			Scenario 2		
Sub-areas	Case I	Case II	Case III	Case I	Case II	Case III
SE1	0	0	0	0	0	0
SE2	0	0	39	-113	-110	-69
SE3	0	0	32	0	0	0
NO1	-78	-78	109	-378	-380	-193
NO2	0	0	0	-2	-2	-18
NO3	0	0	0	0	0	0
FI1	0	0	0	0	0	0
FI2	0	0	0	0	0	0
DKE	-20	-20	0	0	0	0
DKW	0	0	0	0	0	0
Nordic	-98	-98	180	-493	-493	-280
50Hertz	327	327	34	-304	-304	-169
TenneT1	149	77	175	51	114	0
TenneT2	0	22	0	14	0	0
TenneT3	0	0	0	225	146	29
Amprion	0	0	0	41	106	0
EnBW	-50	0	0	62	26	0
NL	61	61	0	-16	-16	0
GE+NL	487	487	209	72	72	-140

Table 9: Activated reserves in each sub-area [MW]

4.2.3 *Cross border balancing energy exchange*

The balancing energy exchange in scenario 1 and 2 is shown in Table 10 and Table 11 respectively. 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.

	From	To	Case I	Case II	Case III
HVDC	SE1	FI1	0	0	0
	SE2	DKW	0	0	0
	NO1	DKW	0	0	0
	NO1	NL	0	0	186
	DKE	DKW	0	0	20
	SE1	TenneT1	0	0	72
	DKE	50Hertz	0	0	0
AC	DKW	TenneT1	0	0	20
	TenneT1	NL	22	4	-62
	Amprion	NL	-22	-4	-63

Table 10: Balancing exchange Scenario1 [MW]

	From	To	Case I	Case II	Case III
HVDC	SE1	FI1	16	25	42
	SE2	DKW	-397	-396	-153
	NO1	DKW	-415	-416	-262
	NO1	NL	0	0	0
	DKE	DKW	485	485	88
	SE1	TenneT1	0	0	0
	DKE	50Hertz	0	0	212
AC	DKW	TenneT1	0	0	0
	TenneT1	NL	-1	7	-7
	Amprion	NL	1	-7	-9

Table 11: Balancing exchange Scenario2 [MW]

5 DISCUSSION

In the present market in the NE area the regulating reserves are procured inside each control area except for the Nordic system and Germany where the cheapest regulating objects are selected from common merit order lists. In these analyses we illustrate by way of the detailed description of two specific cases how the implementation of cross-border balancing markets influences the procurement and dispatch of balancing resources and how this changes cross-border flows. We also report cost savings for these particular hours. A broader discussion on costs and prices is outside the scope of this paper.

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.

Three additional issues must be discussed in this context. Firstly according to current practice it is not accepted to procure the whole required reserve from the outside of control area. The model can easily be modified to the ENTSO-E policies where at most one third of the required secondary reserve is allowed to be procured from the outside of the area [18]. However, increasingly integrated markets may over time relax this requirement. Secondly, with today's manual reserve dispatch in the Nordic area 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. Thirdly 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 CONCLUDING REMARKS

An integration of balancing power markets can facilitate the procurement of mutual reserves. This also leads to a better utilization of the HVDC interconnections. In this paper we propose a model for the optimal utilization

of the procurement of reserve capacity and exchange of balancing energy, taking into account transmission constraints in the case of exchange between two synchronous areas. The model is also used to compare various levels of integration between the markets.
A detailed comparison between three levels of integration is done for two specific scenarios for the exchange between the Nordic system and Germany and the Netherlands.
In both scenarios a full integration leads to moderate savings in the reserve procurement market but considerable savings in the balancing reserve exchange markets. This is due to the effect of imbalance netting and the activation of cheaper reserve resources. 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 clearly illustrates that it is possible and profitable to exchange reserves between synchronous systems, using existing HVDC interconnections.
Further work will focus on analysis of the effect of reserve procurement, long term analysis in order to estimate expected annual savings, and the effects of large scale wind integration.

7 ACKNOWLEDGMENT

The authors would like to thank for the comments received from and the discussions done with Professor Olav Bjarte Fosso and PhD student Stefan Jaehnert. The conclusions and remaining errors are the authors' responsibility. The present work is done within the project "Balancing Management in Multinational Power Markets", financed by the Norwegian Research Council, the Next Generation Infrastructure Foundation in the Netherlands, the Norwegian and Dutch TSOs and power producers.

REFERENCES

[1] L. Meeus and R. Belmans, "Electricity market integration in europe," *Revue E*, vol. 124, Issue 1, 2008.

[2] KULeuven and T. E. Suez, "Electricity study of the interactions and dependencies of balancing markets, intra day trade and automatically activated reserves," Tech. Rep. TREN/C2/84/2007, Feb. 2009.

[3] K. Skytte, "The regulating power market on the Nordic power exchange Nord Pool," *Energy Economics*, vol. 21, Issue 4, pp. 295–308, Aug. 1999.

[4] M. Olsson and L. Söder, "Modelling real-time balancing power market prices using combined SARIMA and Markov processes," *IEEE Transaction on Power Systems*, vol. 23, Issue 2, pp. 443–450, May 2008.

[5] S. Jaehnert, H. Farahmand, and G. Doorman, "Modelling of prices using the volume in the norwegian regulating power market," in *Proc. IEEE PES PowerTech 2009*, Bucharest, Romania, Jun. 2009.

[6] S. Fleten and E. Pettersen, "Constructing bidding curves for a price-taking retailer in the Norwegian electricity market," *IEEE Transaction on Power Systems*, vol. 20, Issue 2, pp. 701–708, May 2005.

[7] K. Ravnaas, H. Farahmand, and G. Doorman, "Optimal wind farm bids under different balancing market arrangements," in *Proc. IEEE PMAPS 2010*, Singapore, Singapore, Jun. 2010.

[8] H. Farahmand, S. M. A. Hosseini, G. Doorman, and O. B. Fosso, "Flow based activation of reserves in the nordic power system," in *Proc. IEEE PES General Meeting 2010*, Minneapolis, USA, Jul. 2010.

[9] A. Abbasy, R. van der Veen, and R. Hakvoort, "Effect of integrating regulating power markets of northern europe on total balancing costs," in *Proc. IEEE PES PowerTech 2009*, Bucharest, Romania, Jun. 2009.

[10] S. Jaehnert and G. Doorman, "Modelling an integrated northern european regulating market based on a common day-ahead market," in *Proc. IAEE* 33^{rd} *International Conference 2010*, Rio de Janeiro, Brazil, Jun. 2010.

[11] M. Korpås, L. Warland, J. O. G. Tande, K. Uhlen, K. Purchala, and S. Wagemans, "Grid modelling and power system data," SINTEF Energy Research, TradeWind EU project, Tech. Rep. D3.2, Dec. 2007.

[12] Q. Zhou and J. W. Bialek, "Approximate model of european interconnected system as a benchmark system to study effects of cross-border trades," *IEEE Transaction on Power Systems*, vol. 20, Issue 2, pp. 782–788, May 2005.

[13] B. Bakken, "Technical and economic aspects of operation of thermal and hydro power system," Doctoral Dissertation, Norwegian University of Science and Technology, Trondheim, Norway, Feb. 1997.

[14] TU Dortmund, E-Bridge Consulting GmbH,(2009), wissenschaftliches gutachten: Optimierung der ausregelung von leistungsungleichgewichten. [Online]. Available: http://www.bundesnetzagentur.de/cae/servlet/contentblob/151484/publicationFile/6058/Gutachten_optimierte_Ausregelung_ZNR.pdf

[15] Nordel, (2006), system operation agreement. [Online]. Available: http://www.entsoe.eu/index.php?id=63

[16] Amprion, EnBW TNG, transpower, VE-T.,internet-plattform zur vergabe regelleistung. [Online]. Available: http://www.regelleistung.net

[17] TenneT TSO B.V., system operation agreement. [Online]. Available: http://www.tennet.org/english/operationalmanage-ment/exportdata.aspx

[18] ENTSO-E Operation Handbook, p1 - Policy 1: Load-frequency control and performance [C]. [Online]. Available: https://www.entsoe.eu/fileadmin/user_upload/_library/publications/ce/oh/Policy1_final.pdf