Flow Based Activation of Reserves in the Nordic Power System

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Abstract-- **In the Nordic market, manually activated tertiary control based on bids for upward and downward regulation is used for system balancing. Although a system wide merit order list is used, the resulting regulation is suboptimal because of the congestion and the effect of losses, which are not taken into account. This paper proposes an algorithm for the dispatch of regulation resources based on an incremental DC optimal power flow formulation. The results of this model are compared with today's practice for some cases of up- and downward regulation, and a potential for cost reduction is observed. However, the method requires Automatic Generation Control that is not in use in the system, although it is presently evaluated. Also pricing of regulation is an issue, because Location Marginal Prices probably are unacceptable to market participants.**

***Index Terms*-- Nordic regulating market, Incremental DC-OPF, Location Marginal Pricing (LMP), Congestion management, Marginal losses.**

I. Introduction

To maintain the operational security of a power system it is necessary to keep a continuous balance between generation and demand. Thus the operational requirements of a power system comprise such issues as maintaining sufficient operational reserves, distributing these reserves between subsystems and the activation of the reserves in such a way as to ensure the continuous secure operation of the system. The operational reserves are used to compensate for deviations from the forecasts and variations in the electricity consumption, and to limit the impact of operational disturbances in the production and transmission system. In a European context, these reserves are normally divided between primary, secondary and tertiary reserves [1].

Primary control uses the primary reserves to maintain the balance between generation and demand in the network using turbine speed governors. Secondary control is a centralized automatic function to regulate the generation in a control area based on secondary reserves to maintain the exchange between control areas and to keep the frequency between the designated limits. Secondary control is applied by changing the setpoints of selected generators. Tertiary control is applied by manual or automatic changes in generator setpoints. Primary and secondary reserves are divided between control areas by ENTSO-E guidelines. For tertiary only recommendations are given.

In the Nordic system, secondary reserves using Automatic Generation Control are presently not in use (the exception is West Denmark, which is a part of the Central European synchronous system). Imbalance regulation is performed using so called Fast Reserves, that are manually activated and that must be fully activated within 15 minutes. The TSOs receive bids for upward or downward regulation from market participants who are willing to raise or lower their production or consumption. A bid for upward regulation indicates how much the player asks to be paid to sell a certain volume of regulating power corresponding to increased production or reduced consumption. A bid for downward regulation indicates how much the player is prepared to pay to buy a certain quantity of regulating power corresponding to reduced production or increased consumption [4].

In January 2007, the European Commission published its Energy Sector Inquiry, which stressed the fact that balancing energy and reserve markets are highly concentrated, and pointing to the fact that the inadequate integration of balancing markets is a key impediment to the development of a single European electricity market [2]. In the Nordic area the TSOs have since 2002 submitted all their national bids to a common Nordic regulation list. The list is available to all Nordic TSOs in a common information system NOIS (Nordic Operational Information System). These resources are thus traded on a "single-buyer" market, where the TSOs act jointly as buyer in procuring resources for the balance regulation. This "market" is called the regulating power market (RPM) in the Nordic region [4]. Recently, steps have been taken to further harmonize the balancing market rules in the area [3].

According to the market rules, upward regulation will be done by using the cheapest bid on the common Nordic list, unless this causes congestion. With the integration of balancing markets over several control areas, it becomes more complicated to assess which regulations will cause congestion, because congestion is generally more prevalent between than within control areas. Also, in the case of larger cooperating balancing areas it becomes more important to take into account the effect of transmission losses. These issues become even more prevalent if the HVDC connections to the European continent are going to be used for balancing in the future. Increased integration of wind is another factor that can create larger deviations at specific locations. In general, the lowest price bids are not necessarily those that minimize the total cost of regulation.

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These considerations suggest the use of a framework based on Optimal Power Flow (OPF), which would implicitly assess both concerns. However, such an approach would raise questions about the payment for and pricing of balancing. Presently the spot market is split in several price areas with different prices in the case of congestion. Also RPM prices will differ if congestion between areas influences the use of balancing resources. Within each area the RPM price is set by the marginal activated bid. This marginal price is paid to all activated resources and also paid for all imbalances, resulting in revenue neutrality for the TSO if there is no congestion. The use of OPF would implicitly result in Location Marginal Prices (LMP) in the RPM, which would be a major change in the market rules. On the other hand, also other pricing mechanisms could be used.

In this paper we will present the problem formulation for an OPF based framework for the Nordic Regulation Power Market. We will argue for the use of Incremental DC Optimal Power Flow including marginal losses. Subsequently we will describe some major characteristic of the Nordic system, as well as the aggregate model used for the present analysis. Results of some relevant simulations will be presented and compared with today's practice. Finally we will discuss the results as well as some possible pricing mechanisms.

II. Problem formulation and Solution methodology

In the present Nordic Regulating Power Market required reserves are manually activated by the operators of the system based exclusively on the common Nordic merit order list of regulating reserve bids. If there is no congestion within the system, the regulating price is identical for the all subsystems. However, in the case of congestion, some of the regulating bids will be disregarded, and the regulating price for the congested area will become higher (in the case of upward regulation) or lower (in the case of downward regulation) than the other parts of the system to match the transferred power and available capacity on the tie-lines. For the time being Norway is split into three and Denmark into two area prices whilst the area price in Finland and Sweden is equal in the whole country. The congestion within each area is relieved by a counter trade procedure where the TSO buys and sells at both ends of the congested line to relieve the congestion. Since the costs of congestion and losses are not considered explicitly in the dispatch of reserves, the resulting solutions are different from the optimal dispatch of the reserve.

An alternative methodology to consider these costs in the reserve dispatch is to use Optimal Power Flow for the calculation of Location Marginal Pricing (LMP) to minimize the total operating cost. An AC based OPF represents the most accurate methodology for calculating the LMPs. Apart from being computationally expensive, the AC-OPF is difficult to implement in the current regulating market in the Nordic area. Since the LMPs are determined based on the gradient of objective function, they are very sensitive to small deviations. This would require many small control actions, which makes it difficult to implement.

An alternative to the AC-OPF formulation is to formulate the problem as a DC-OPF, focusing exclusively on real power constraints in the linearized form. The results of the DC-OPF problem can be interpreted in a more meaningful way than the AC-OPF in an electricity market context. As is well-known, the major approximation in a DC power flow is to neglect the line resistance and reactive power, and to assume a flat voltage profile in all nodes (all voltage magnitudes will be equal to 1.0 p.u.). A quadratic cost curve can be represented with piecewise-linear curves to be able to formulate the DC power flow as an LP problem. Generally the DC-OPF can be expressed as [5]:

$$Min\ F = \sum_{i=1}^{N_G} c_i \times P_i^G$$

subject to:

$$\sum_{i=1}^{N_G} P_i^G - \sum_{i=1}^{N_L} P_i^L = 0 \tag{1}$$

$$\Delta f_{\min}^{kl} \le \sum_{i=1}^{N_G} a_{kl,i} (\Delta P_i^G - \Delta P_i^L) \le \Delta f_{\max}^{kl} \qquad \text{for} \quad kl = 1, 2, \ldots, M$$

$$P_i^{\min} \le P_i^G \le P_i^{\max} \qquad \text{for} \ \ \mathrm{i} = 1, 2, \ldots, N_G$$

where,

N_G	number of generators
N_L	number of loads
M	number of transmission lines
P_i^G	generated active power at bus *i* (MW)
c_i	marginal generation cost at bus *i* (€/MWh)
P_i^L	active power consumption at bus *i* (MW)
$\Delta f_{\max}^{kl}, \Delta f_{\min}^{kl}$	maximum and minimum transmission limit of line *kl* respectively (MW)
$a_{kl,i}$	Power Transfer Distribution Factor (PTDF) at line *kl* regarding power changes at bus *i*
$P_i^{\max}, P_i^{\min}$	maximum and minimum generation output at bus *i* respectively (MW)

A. DC-OPF including marginal losses

The problem with the standard DC formulation (1) is that the losses are neglected. However, as discussed in the introduction, taking into account losses was one of our main considerations. To consider the losses in the DC-OPF, a marginal loss or incremental loss factor is calculated. Mathematically it can be written as:

$$\rho_i = \frac{\partial P_{loss}}{\partial P_i} \tag{2}$$

where,

∂P_{loss}	incremental total active losses of the system
∂P_i	incremental power at bus *i*

The total active losses are equal to the sum of the losses for each transmission line:

$$P_{Loss} = \sum_{j=1}^{M} R_j \times I_j^2 \tag{3}$$

where,

I_j	flow on transmission line *j* (A)
R_j	resistance of transmission line *j* (Ω)

The marginal loss factor is equal to the change in system losses according to a change in the power injected or withdrawn at bus *i*.

An alternative approach is to define a hub or a reference bus, which can be the slack bus in the system. An increase in generation in bus *i* by ΔP_i will result in a decrease in the hub bus production by ΔP_{ref} that is equal to the increase of the total active losses of the system minus the increase in generation at bus *i*. This can be expressed as:

$$\Delta P_{ref} = \Delta P_{loss} - \Delta P_i \tag{4}$$

In a lossless system, ΔP_i would be equal to the negative of ΔP_{ref} whereas the flows on the system are changed as a result of the two generators' adjustment. This change in flow causes a change in losses. When losses are considered, ΔP_{ref} is necessarily not equal to ΔP_i. With this assumption the delivery factor (β) as the ratio of negative change in reference bus can be written as [5]:

$$\beta_i = -\frac{\Delta P_{ref}}{\Delta P_i} \tag{5}$$

Substituting (4) in (5) will result in the marginal loss factor:

$$\beta_i = \frac{(\Delta P_i - \Delta P_{loss})}{\Delta P_i} = 1 - \frac{\Delta P_{loss}}{\Delta P_i} \tag{6}$$

or using (2):

$$\rho_i = 1 - \beta_i \tag{7}$$

Depending on the sign of the change in losses, the marginal loss factor can be positive or negative. Including this factor in the cost function of a generator will reflect the required cost of the losses arising from generator contribution to the power flow. In a market with Location Marginal Prices, this marginal loss factor would be reflected in the nodal prices. The LMPs can be calculated as [6].

$$\lambda_i = \lambda_{ref} + \gamma^L + \gamma^C \tag{8}$$

where,

λ_i	LMP at bus *i* (€/MWh)
λ_{ref}	reference bus energy price (€/MWh)
γ^L	marginal cost of losses (€/MWh)
γ^C	marginal cost of congestion (€/MWh)

γ^C is the dual value of the transmission line constraints in (1) which can be positive or negative depending on the flow direction.

Since the flow on each transmission line is the linear combination of the contribution of all producers and consumers, a superposition theorem can be applied. Then the marginal loss between a producer and a consumer point is equal to the marginal loss between the producer and the hub minus the marginal loss between the consumer and the hub. The linear combination of the marginal losses divided by the total load represents the marginal loss for the aggregate load. This can be written as:

$$\gamma^L_{P_L-tot} = \frac{\sum_{k=1}^{N_L} P_K \times \gamma^L_k}{\sum_{k=1}^{N_L} P_K} \tag{9}$$

where,

$\gamma^L_{P_L-tot}$	marginal loss between aggregate load and hub point
γ^L_K	marginal loss between load *K* and hub point
P_K	load at bus *K* (MW)

This factor can be employed in (8) to account for the marginal loss of generator *i* feeding a set of loads at different points of the system. In order to calculate the losses within a DC-OPF an iterative process is employed where first results from DC-OPF are considered as initial results to estimate losses. The allocated loss on each transmission line is calculated based on (3). Half of the losses is added at each end of the line [7] as shown in Fig. 1.

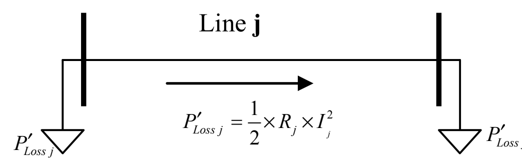

Fig. 1. Loss represented as loads at both ends of transmission line

Then these estimated losses will be used to obtain a new dispatch. This process is repeated until the results between two iterations are within a certain tolerance. The results from this iterative process and an AC-OPF are very similar while the DC-OPF is faster [7].

B. IDC-OPF considering marginal losses

A regulating market deals with the real-time reserve dispatch to keep the balance between production and consumption, caused by e.g. deviations between forecast and actual demand or generation outages. In real time, the basis for the calculations would be the actual situation in the system as indicated by the state estimator. However, in a model approach the basis can be an assumed day ahead spot market dispatch. Subsequently an incremental optimization approach is used to minimize the cost of compensating for deviations from the initial market balance.

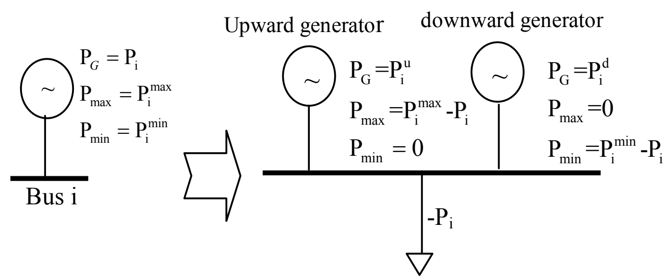

Fig. 2. Generators represented in IDC-OPF

We will use an Incremental DC-OPF (IDC-OPF) formulation that takes into account grid congestion and marginal losses when determining the optimal dispatch of regulation resources. Fig. 2 illustrates how each generator contributing in real time reserve dispatch is modelled as a fixed negative load representing the spot dispatch ($-P_i$) and two hypothetical generators representing upward and downward regulation respectively. The IDC-OPF model can be formulated as [8]:

$$Min\ F = \sum_{i=1}^{N_G} \hat{c}_i^u \Delta P_i^u + \sum_{i=1}^{N_G} \hat{c}_i^d \Delta P_i^d$$

subject to:

$$\begin{aligned} &\sum_{i=1}^{N_G} \Delta P_i^u - \sum_{i=1}^{N_G} \Delta P_i^d = P_{dev} + P_{Loss} \\ &\Delta f_{\min}^{kl} \le \sum_{i=1}^{N_G} a_{kl,i} (\Delta P_i^u - \Delta P_i^d) \le \Delta f_{\max}^{kl} \qquad \text{for } kl = 1, 2, \ldots, M \\ &0 \le \Delta P_i^u \le P_i^{\max} - P_i \qquad \text{for } i = 1, 2, \ldots, N_G \\ &P_i^{\min} - P_i \le \Delta P_i^d \le 0 \qquad \text{for } i = 1, 2, \ldots, N_G \end{aligned} \tag{10}$$

where,

$\Delta P_i^u, \Delta P_i^d$	upward and downward incremental generation at bus *i* respectively (MW)
$\hat{c}_i^u, \hat{c}_i^d$	upward and downward marginal generation cost at bus *i* respectively, including marginal losses (€/MWh)
P_{dev}	real-time deviation (MW)
P_i	committed generation capacity at bus *I* (MW)
P_{Loss}	The total active system losses (MW)

III. Nordic power system & PSST model

The Nordic area includes Sweden, Norway, Finland and Denmark. West Denmark is a part of the synchronous Central European system, while the remainder constitutes a separate synchronous system (the former Nordel system), cf. Fig.3.

Fig. 3. The Nordic countries

The system had a peak demand of 61 GW and annual generation of 414 TWh in 2008 [9]. Table I shows how annual generation was divided between countries and generation technologies in 2008.

TABLE I. Share of annual generation in 2008 by generation type in the Nordic power system [9]

Type	Denmark	Finland	Norway	Sweden	Nordic
Hydropower	0.08	22.78	98.55	46.86	57.59
Nuclear Power	-	29.73	-	41.96	20.12
Other thermal power	79.79	47.14	0.80	9.81	18.86
Wind power	20.14	0.35	0.64	1.37	3.43

The table illustrates the dominating position of hydropower. The favourable characteristics of hydropower in general and the highly storable Norwegian hydropower specifically, make this technology a perfect candidate for the provision of regulating services. This property will become more and more required with an increasing integration of wind power in the Nordic system as well as the Central European system. However, increased use of hydropower for regulation purposes increases the need for a more efficient use in the context of system regulation.

There are a number of HVDC cables between the Nordic area and the Central European power system, cf. Table II.

TABLE II. HVDC cable connection between Nordic and UCTE power system [9]

Countries/ Cable name	Rated voltage [kV]	Transmission Capacity [MW]	
		From [a]	To [b]
Sweden-Poland (SwePol)	450	600	600
Sweden-Germany (Baltic)	450	600[c]	600[c]
Denmark East-Germany (Kontek)	400	600	600
Sweden- Denmark West (KontiSkan)	2×285	740	680
Norway- Denmark West (Skagerrak)	250/350	1000	1000
Norway-The Netherlands (NorNed)	450	700	700

[a] Transmission capacity from the first country in Countries name list
[b] Transmission capacity to the first country in Countries name list
[c] Due to limitation in Germany the transmission capacity is 460 MW from Germany and 390 MW to Germany.

In addition to the cable interconnections shown in the table, several new ones are being considered. This creates an increasing opportunity to utilize Norwegian hydropower for balancing purposes in Central Europe.

As explained before, tertiary reserve in the Nordic power system is activated manually, where the cheapest regulating bid is selected from a common merit order list irrespective of nationality, provided there is no congestion problem in the grid. In the case of congestion to an area some of the regulating bids will be disregarded and regulating prices will be different from other areas [4].

Manual activation of reserve based on human operator experience has worked satisfactory in the Nordic system so far, although following the large (net) load increases during the morning hours sometimes is challenging. This is caused by the fact the daily exchange with the Central European system has the characteristics of a pumped storage scheme, where Norwegian hydropower is exported during the daytime, while cheap thermal low load power is imported during the night.

An increasing exchange of both peak and balancing power introduces the need for a more sophisticated methodology for dispatch of activated reserves. It may also become necessary to introduce automatically activated secondary reserves. The proposed IDC-OPF based model for the RPM can be used as a kernel to solve these challenges.

IV. Simulation & Results analysis

In this section we will compare the results of using the proposed model for balancing in the Nordic system with the present practice. Simulation of the balancing market must be started with a day ahead system dispatch, which is established in two steps:

1. Calculation of the market dispatch, based on a zonal model with 6 nodes in the Nordic system (Western Denmark is considered part of the Central European system in the model). This results in different zonal prices whenever there is congestion between zones.
2. The zonal dispatch may result in congestion within zones. In the market such congestion is relieved by counter trade as explained in Section I. In the model this is approximated by using a DC-OPF model. This may result in different marginal costs at different buses within the same zone.

To establish the base case situation (step 1), we use the Power System Simulation Tools (PSST) developed under the Tradewind project [10]. This model is based on DC-OPF and includes a representation of the European grid with the main physical characteristics of the European system at an aggregate level, including the HVDC connection between the Nordic and Central European system and time-varying parameters such as wind, load, and hydro inflows. The impedances of the model are adjusted in such a way that the results most closely correspond to a detailed model. The results of the model will be the optimum dispatch of generators and the optimum flow on the HVDC connection, given the zonal representation of the Nordic system. The model simulates the flow based market coupling within the whole continental Europe taking into account wind power production scenarios. To relieve intra-zonal congestion (step 2), a more detailed model of the Nordic system is used, shown in Fig. 4.

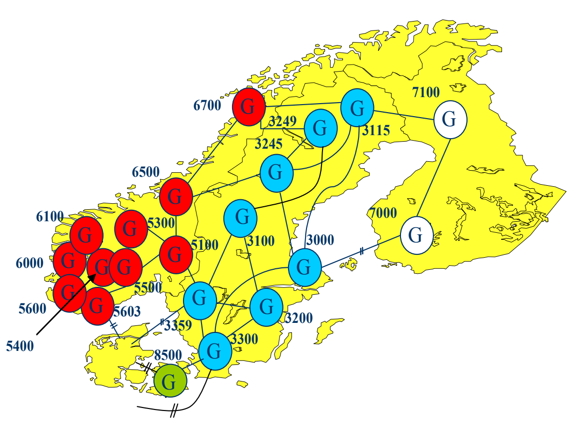

Fig. 4. The Nordic power system

This model has 41 buses with generation at 23 of them. At the generator buses a total of 35 generators are connected, because different technologies are represented by different generators wherever applicable. E.g. there are 6 generators connected to bus 7000 representing Finland, each of them representing a specific technology such as nuclear, hydro, gas, lignite etc.

For the simulation of the Regulation Power Market, we look at a typical peak load day. Fig. 5 presents the forecasted Nordic load on the second Wednesday in February 2010 [9]. As the figure shows, there is a fast increase of the load from 59 to 63 GW between hours 7 and 8. Between hours 19 and 20, there is a decrease of 1000 MW. It should be noted that large changes on the interconnections with the Central European system will occur at the same time, and that the Norwegian generation system will take up a large share of these changes, making considerable requirements to the ability of the control systems in the Norwegian system. The greatest deviations with the day ahead dispatch plans therefore typically occur during these hours, and we therefore use the demand in hours 8 and 19 as the basis for our calculations.

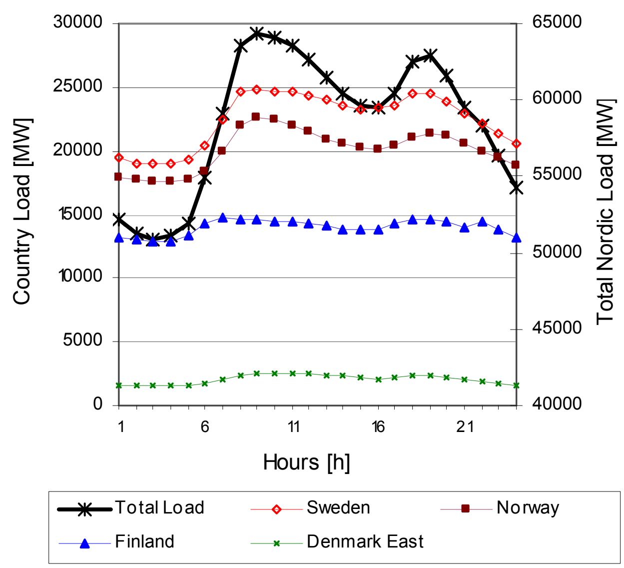

Fig. 5. Forecast hourly load on the second Wednesday in February 2010

An earlier study modelling the need for regulation power [12] estimated the expected deviations in the Nordic system. These were assumed to occur at the major load areas Oslo (bus-5100) in the Norwegian and Stockholm (bus-3000) in the Swedish power system and were taken as the basis for the subsequent analyses.

A. Day ahead dispatch

The generator bids were approximated by assumed fuel costs and water values in the case of hydropower. The water values were obtained by the results of simulations with the EMPS model, a long term optimization model for systems with large shares of hydropower [13]. Fig. 6 shows the resulting merit order list, and also indicates the total load of 63572 MW in hour 8 and 62848 MW in hour 19. Without congestion, there would be one system price given by the most expensive running generator on this list.

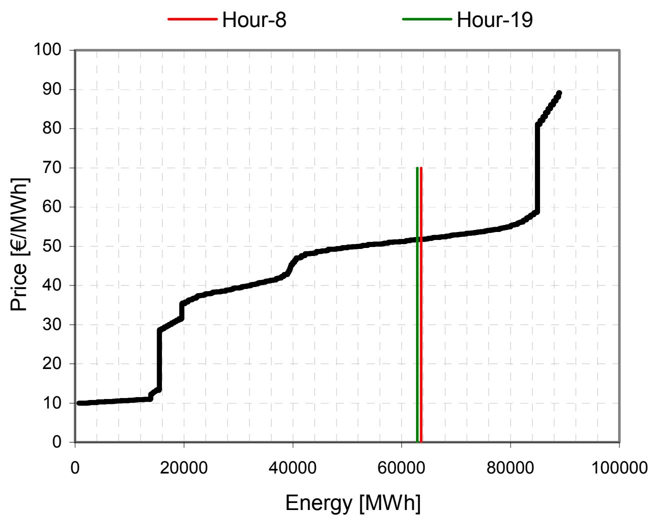

Fig. 6. Nordic merit order list for hour 8 and 19 in the morning

However, congestion between the areas occurs, resulting in different zonal prices as shown in Table III.

TABLE III. ZONAL PRICES IN HOUR 8 AND 19 [€/MWH]

Area	Price [€/MWh]	
	Hour 8	Hour 19
SW (Sweden)	51.44	52.07
NO1 (South of Norway)	49.91	50.41
NO2 (Mid Norway)	42.67	43.06
NO3 (North of Norway)	37.63	37.91
FI (Finland)	51.44	52.07
E-DK (Eastern Denmark)	50.05	50.63

However, before we consider what happens in the Regulation Power Market, it is necessary to do a redispatch to relieve intra-zonal congestion. This results in the dispatch and prices given in Table IV.

TABLE IV. MARGINAL COSTS AFTER COUNTER TRADING IN HOURS 8 AND 19 [€/MWH]

Zone	Gen. #	Hour 8		Hour 19	
		power [MW]	Price [€/MWh]	power [MW]	Price [€/MWh]
SW	3000	5477	10.94	5477	10.93
	3000	868	51.14	868	51.84
	3100	1860	52.04	1860	52.95
	3115	3967	52.84	3967	53.47
	3200	362	10.93	362	10.93
	3245	1674	50.98	1674	51.67
	3249	4091	51.88	4092	52.68
	3300	519	41.08	519	41.07
	3300	1369	51.01	1597	51.60
	3359	3617	10.92	3617	10.92
NO1	5100	1757	53.26	1465	53.67
	5300	2237	30.00	2237	30.07
	5400	1855	48.00	1855	48.68
	5500	976	51.21	1139	52.53
	5603	2319	48.77	2319	49.42
	5600	98	50.69	81	50.80
	6000	1822	39.15	1822	39.44
	6100	3303	40.91	3775	41.74
NO2	6500	2783	42.88	2783	43.30
NO3	6700	4979	38.49	4979	38.77
FI	7000	4271	10.99	4271	11.00
	7000	3400	41.14	3400	41.16
	7000	3000	52.84	3000	52.86
	7000	1200	45.33	1200	45.34
	7100	1741	52.35	1741	53.04
E-DK	8500	1451	41.30	1451	41.29
	8500	1024	50.05	1536	51.22

Note that the dispatch for the zone SW (Sweden) is almost the same for both hours, because the load is very similar and there is congestion to areas with lower costs, cf. Table V.

TABLE V. POWER EXCHANGE BETWEEN AREA PRICING

From	To	Capacity [MW]	Power exchange [MW]	
			Hour 8	Hour 19
NO1	SW	1000	1000	1000
NO2	NO1	500	100.44	106.87
NO2	SW	500	290.84	303.06
NO3	NO2	1000	472.9	442.36
NO3	SW	600	600	600
SW	FI	1200	1174	876.48
SW	E-DK	1350	1350	1350

The grid losses are bought in the spot market by the respective TSOs and paid for by the market participants through the grid tariffs. A weekly updated point tariff is based on average losses during day and night periods respectively, and can be viewed as a coarse approximation to LMP.

B. *Activation of reserves based on merit order list*

We approach the present practice of regulation by using the cheapest generator on the Nordic merit order list, whenever that is possible without causing congestion. The results are shown in the table below.

TABLE VI. RESULTS OF MANUAL REGULATION

Case #	Deviation [MW]	Bus #	Regulation			
			Gen #	Production [MW]	Price [€/MWh]	Cost [€]
1	+187	5100	5100	187	53.88	10075
2	+123	3000	3000	123	52.78	6492
3	-147	5100	5600 5603	-146	49.42	-7260
4	-101	3000	3000	-101	48.87	-4936

C. *Simulation results using IDC-OPF model applied in the Nordic system*

We now use the algorithm described in Section II to find the optimal regulation for each of the four cases. Table VII shows the dispatch of the activated regulating reserves.

It can be seen from the table that instead of large steps at one or two generators, the regulation is spread with partially small steps on several generators. To some extent this is caused by congestion, but also by the fact that losses are taken into account. As it is shown in the table, in the first case the activated reserve is lower than the deviation, which means that this dispatch pattern decreases the total system losses and the required reserve will become lower.

TABLE VII. .OPTIMAL REGULATION RESULTS [MW]

Gen. #	Case 1	Case 2	Case 3	Case 4
3115	-	30.38	-	-14.10
3245	-	3.74	-	-
7000	-	45.01	-	-
7100	-	34.10	-	-53.14
5100	132.20	-	-107.77	11.46
5300	-5.02	-	-	-
5500	40.57	-	-	-
5600	2.45	-	-	-
5603	16.27	-	-	-
6700	-	9.88	14.44	8.98
6500	-	-	-54.11	-54.11
Sum	**+186.47**	**+123.11**	**-147.44**	**-100.91**

Prices are listed in Table VIII at the buses where the reserve resources have been activated.

TABLE VIII. PRICES AT GENERATION AND CONSUMPTION BUSES [€/MWh]

Gen. #	Case 1	Case 2	Case 3	Case 4
3115	-	52.74	-	49.09
3245	-	50.88	-	-
7000	-	52.25	-	-
7100	-	52.25	-	50.41
5100	53.03	-	51.08	53.52
5300	28.50	-	-	-
5500	51.38	-	-	-
5600	49.25	-	-	-
5603	50.77	-	-	-
6700	-	38.39	38.61	38.63
6500	-	-	47.50	46.99

The TSO's cost in different cases is compared with the current situation of the market based on merit order list and presented in Table IX.

TABLE IX. TSO COSTS COMPARISON IN THE DIFFERENT METHOD OF RESERVE ACTIVATION (IDC-OPF AND MERIT ORDER LIST)

Case #	TSO cost [€]		Difference [€]
	IDC-OPF	Merit order list	
1	9917	10075	-158
2	6306	6492	-186
3	-7458	-7260	-198
4	-4953	-4936	-17

The results in the table indicate that the IDC-OPF algorithm will dispatch the reserve more efficiently than the merit order list method and this could result in significant cost reductions in the long-term running of the system.

D. Discussion

In the present market solution, the cost of losses and congestion is not explicitly considered in the market. Using some examples of the regulation of moderate deviations, it is shown that an optimization model using an IDC-OPF algorithm taking into account the losses results in a lower cost of regulation. Instead of using one or a few generators for the regulation, the optimal procedure in our examples uses four to six generators in the optimal solution.

Two issues must be discussed in this context. Firstly, with today's manual dispatch of tertiary reserves it would not be possible to change the setpoint of many generators at the same time. The proposed solution would require the use of secondary control based Automatic Generation Control to be feasible. This is presently discussed because system operation with the existing procedures becomes more and more challenging.

Secondly, there is the issue of pricing in the Regulation Power Market. Today all activated generators get paid the marginal price for regulation in the actual hour, while all Balance Responsible Parties pay the same marginal price for their imbalances. There may be different prices between the zones if congestion limits the use of Regulation Power on a system wide basis. The use of OPF in the RPM in principle results in Location Marginal Prices for Regulation Power (but note that zonal prices in the day ahead market can still be used). However market participants will probably be reluctant to accept LPM because it increases the uncertainty they face. Other alternatives are possible, but they are in principle sub optimal (because different market participants face different prices). Differences between prices paid to the providers of regulation and prices paid for imbalances also affect the revenues and costs of the TSO, which should be carefully analyzed.

V. CONCLUDING REMARKS

Regulation of imbalances in the Nordic market today is done on the basis of a system wide merit order list for up- or downward regulation using manual tertiary control. Congestion is mainly handled on the basis of operator experience. Because of this and the fact that tertiary control is used, regulation is clearly not optimal, even though system wide merit order list is used. This is partly because congestion is not handled in an optimal way, partly because large regulation steps are taken on a few generators and partly because losses are not taken into account.

We propose a method based on Incremental DC-OPF (IDC-OPF), based on an optimal redispatch after a deviation. The model is tested on positive and negative deviations occurring in the load centres and the results show a decrease in costs.

The implementation of the proposed method requires the introduction of secondary control using Automatic Generation Control, because the present manual tertiary control cannot handle the many small adjustments that are result from the proposed method. It is also important to evaluate pricing options, because the introduction of LMP in the Regulation Power Market probably will be unacceptable for market participants.

Further work will focus on the implementation of the method in a framework of Stepwise Power Flow to simulate the continuous operation of the market and to analyze the effect of the exchange of balancing services with Continental Europe.

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VII. Biographies

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Gerard L. Doorman (M’99) received the M.Sc. degree in electrical engineering from the Norwegian Institute of Technology (NTH), Trondheim, Norway, in 1981 and the Ph.D. degree from the Norwegian University of Science and Technology (NTNU, formerly NTH) in 2000. He started his career as a research scientist at EFI. Later, he worked with a power company with hydropower optimization and as a consultant, among others, with demand-side management. From 1992, he was with SINTEF Energy Research, Trondheim, working with hydropower optimization and deregulation issues. Presently, he is a Professor in electric power systems at NTNU.

Olav Bjarte Fosso graduated from The Department of Electrical Engineering, the Norwegian institute of Technology, Trondheim, Norway with the M.Sc. in 1985, and received his Ph.D. in electrical engineering at the same institute in 1989.

From 1989 to 2002 he has been with SINTEF Energy Research except for an employment in 1997/1998 at Powel (a company providing decision support tools in a deregulated market environment).

A main responsibility at SINTEF Energy Research has been development of tools for analysis and decision support in transmission and power production systems. Since March 2002, he holds a full-time professor position at the Norwegian University of Science and Technology (NTNU) and a part-time position at SINTEF Energy Research as Scientific Advisor.