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The Flow-Based Market Coupling Model and the Bidding Zone Configuration

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Abstract: In May 2015, the Flow-Based Market Coupling (FBMC) model replaced the Available Transfer Capacity (ATC) model in Central Western Europe to determine the power transfer among bidding zones in the day-ahead market. It might be easier to change the bidding zone configuration in the FBMC model than in the ATC model as the FBMC model does not need to determine the maximum trading volume between two bidding zones. In our study, we run a simulation in the IEEE RTS 24-bus test system and examine how the bidding zone configurations affect the performance of both the FBMC and ATC models. We show that by improving the zone configuration, the FBMC model outperform the ATC in terms of reducing the re-dispatching cost only when the systems operators have a higher level of cooperation in the real-time market. Our results also indicate that better cooperation among the system operators would help to reduce the need for load shedding.

1. Introduction

A large amount of renewable energy has been installed in the EU countries in order to meet the renewable energy target of the Renewable Energy Directive 2009/28/EC. However, promotion of renewable energy sources has greatly challenged the current power systems. As the operation cost of renewable energy is usually much lower than conventional energy, it is placed in the beginning of the merit order curve in the day-ahead market and therefore, has priority access to the power network. However, the forecast errors of renewable energy have led to more network congestion and a higher requirement of back-up capacity in real time. Furthermore, the installed renewable power plants are usually located in places without sufficient consumption (e.g., off-shore wind turbines), and the utilization of such energy often requires long distance transportation. This creates an extra burden for the network and may exacerbate congestion. For instance, the impact of wind energy on network congestion has been

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observed in the German electricity network, in which huge amount of power is transported from the northern part where the main installations of wind turbines are located, to the southern and mid-western parts where the demand is high (Deutscher Bundestag, 2010).

Since February 2014, the EU has launched its most ambitious market coupling project to date by using a single price coupling algorithm, which is called EUPHEMIA (acronym of Pan-European Hybrid Electricity Market Integration Algorithm) (EPEX SPOT et al. 2013). This project now involves power exchanges including APX/Belpex, EPEX SPOT, GME, Nord Pool Spot, OMIE, and OTE (NordPool 2014), which accounts for more than 75% of European electricity demand. One advantage of an integrated European power market is that it could help to better handle the renewable energy in the power system by matching supply and demand across a much wider market.

One crucial question in order to integrate the European power markets is to find a solution to manage the cross-border network congestion efficiently. Currently, most of the European countries rely on the ATC (Available Transfer Capacity) model to process power exchange with the other countries, and this model assumes that power can be directly transferred between any two locations within a bidding zone. Only a pre-defined ATC value is used to limit the maximum commercial trading volume between two bidding zones in the day-ahead market.

The ATC model has been criticized for a long time due to some of its features. Firstly, the ATC model does not take the physical characteristics of electricity into account. In contrast, in the real-time dispatch, power flows between any two locations have to follow the paths resulting from Kirchhoff's laws and are also restricted by the thermal limit of the transmission lines. The ATC model in the day-ahead market thus is not able to give correct information regarding the physical power flows in the system. Secondly, it is rather challenging to decide a proper ATC value between bidding zones. Generally, a high ATC value might promote the commercial transaction opportunities but could induce more network congestion, while a low value will unnecessarily limit the commercial transfer and reduce power network utilization. Furthermore, Bjørndal et al. 2017 find that in the cases where the penetration level of renewable energy is high, even a very low ATC value might not truly help to restrict physical power exchange. Thirdly, previous research shows that in order to properly implement the ATC model, a zone should be aggregated in a way such that congestion seldom happens within the zone. Bjørndal and Jörnsten (2001) show that the results of the ATC model could be greatly affected by the zonal configuration. However, currently most of the bidding zones are aggregated according to the national boundaries and stay unchanged during the market clearing procedures, and bottlenecks may occur frequently within a bidding zone.

In recent years, as more and more renewable energy has been connected to the power system, it is required that the power flows should be more accurately monitored. Leuthold et al. (2008) have shown that the ATC model is not the best option in terms of integrating the wind and solar power into the grid. In May 2015, a so called "Flow-Based methodology" Market Coupling (FBMC), which was developed by the European TSOs (Schavemaker et al. 2008), was implemented to replace the ATC model in Central Western Europe (CWE), a region consisting of the Netherlands, Belgium, France, Luxembourg, and Germany. Van den Bergh et al. (2016) give a description of the FBMC model. The FBMC model applies the physical limitations (e.g., the Kirchhoff's law and the thermal limit) to certain transmission lines (i.e., the critical branches). The system operators aim to have better control over the power flow given the fact that the physical constraints are imposed on the important transmission lines during the day-ahead market clearing.

Compared to the ATC model, in the FBMC model, the system operators do not need to limit the maximum power exchange volume between bidding zones in the day-ahead market. In the perspective of mathematical formulations, the FBMC model only directly imposes limitations on selected transmission lines, which are called critical branches (CBs) that are most likely to be the bottlenecks in the system. Therefore, it might be easier for the TSOs to change the configuration of bidding zones using the FBMC model and achieve a better market outcome. This raises the research question for this paper. We would like to test whether the FBMC model will outperform the ATC model by testing different zonal configuration. Currently, the bidding zones are defined mostly according to the national boundaries. The way to define the bidding zones might be a crucial point to implement the FBMC model successfully. In this paper, we test whether higher efficiency could be achieved for the FBMC model by improving the zonal configuration.

The rest of the paper is organized as follows. In section 2 we provide the mathematical formulations of different day-ahead market clearing models (nodal pricing, FBMC, and ATC) as well as real-time redispatch. In section 3 and 4 we describe the data and show different model results in the numerical examples. Some conclusions are given in section 5.

2. Markets, Assumptions and Models

Generally, three distinct phases can be identified in the operational procedure of the markets. That is the preparation phase, the day-ahead market coupling phase and the real-time re-dispatching phase. The preparation phase is where the TSOs prepare the input for the market coupling models (e.g., the ATC and FBMC models in the European markets). In the day-ahead market coupling phase, the market coupling models will produce output, such as prices and contracted power. However, due to the supply and load uncertainties and the incompleteness of the market coupling models (e.g., physical characteristics of the power system are not fully taken into account), re-dispatching is needed in order to guarantee a congestion free network in the real time. The contracted power in the day-ahead market might be adjusted. This would induce an extra cost. The cost of re-dispatching is an important index to evaluate the performance of the market coupling models.

Sets and Indices

$i, j \in N$	Set of nodes
$l \in \mathrm{L}$	Set of lines
N_z	set of nodes belonging to zone z
CB	Set of critical branches
$z, zz \in Z$	Set of independent price zones

Parameters

$atc_{z,zz}$	Upper limit on the flows from zone z zone zz
cap_l	Thermal capacity limit of the line l
$lscost$	The cost of loadshedding
$nptdf_{l,i}$	Node to line PTDF matrix
$qwind_i$	Expected wind generation at node i (bidding volume) in the day-ahead market
$rqwind_i$	Wind generation at node i in real time
$zptdf_{l,z}$	Zone to line PTDF matrix

Variables

$BEX_{z,zz}$	The Exchange from bidding zone z to zz
${FL_l}^N$	Load flow on line l in the nodal pricing model
${FL_l}^{FBMC}$	Flows on line l in the FBMC model
GUP_i	Increased generation at node i
GDN_i	Decreased generation at node i
$LOADSHED_i$	Load curtailments at node i
$WINDSHED_i$	Wind curtailments at node i
NI_i	Net injection at node i
Q_i^s	Conventional Generation quantity (MWh/h) at node i
Q_i^d	Load quantity (MWh/h) at node i

P_i^s	Supply bid curve at node i
P_i^d	Demand bid curve at node i

2.1 The ATC model[1]

$$\max \sum_i \left(\int_0^{Q_i^d} P_i^d(Q)dQ - \int_0^{Q_i^s} P_i^s(Q)dQ \right) \tag{1}$$

Subject to:

$$NI_i = Q_i^s + qwind_i - Q_i^d, \forall i \in N \tag{2}$$

$$NEX_z = \sum_{i \in N_z} NI_i, \forall z \in Z \tag{3}$$

$$\sum_{z \in Z} NEX_z = 0 \tag{4}$$

$$\mathrm{NEX}_z = \sum_{zz} (BEX_{z,zz} - BEX_{zz,z}), \forall z \in Z \tag{5}$$

$$0 \leq BEX_{z,zz} \leq atc_{z,zz}, \forall z, zz \in Z \tag{6}$$

The objective of the ATC model is to maximize the social welfare (Eq.(1)). The Net Exchange Position of zone z NEX_z is equal to the difference between the total generation (i.e., the conventional generation Q_i^s and wind generation, $qwind_i$) and demand within zone z (Eq.(2) and (3)). The volume of wind generation is the expected value of the real time wind power and is given exogenously.[2] The whole system has to be balanced (Eq. (4)). A positive sign of NEX_z indicates that zone z is a net export zone and a negative sign indicates a net import zone. The net position of a zone NEX_z is equal to the difference of its total export and import (Eq. (5)). The total transfer between two bidding zones is limited to a pre-defined cap $atc_{z,zz}$, as in Eq. (6).

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[1] In practice, the model will not be solved like this, since the location on nodes is not known, only the zonal location of a bid is given.

[2] Using the expected wind power may not be the optimal bidding strategy for the wind generators or the system as a whole. However, in this paper, we do not investigate the bidding strategy for the wind generators in the day ahead market. See Bjørndal et al. (2016)

2.2 The FBMC model

The FBMC model is a simplification of the nodal pricing model using PTDFs or power transfer distribution factors. Although the nodal pricing model has been successfully implemented in many regions and countries, such as Pennsylvania – New Jersey-Maryland (PJM), California, and New Zealand, it has not been implemented in any of the European countries. It is considered as an effective method of handling network congestion. The nodal pricing model takes the physical and technical constraints in the whole network into account, which would help to limit the needs for re-dispatching and reduce the corresponding cost. Furthermore, it gives the correct incentives for future investments by reflecting the value of scarce transmission capacity (Hogan 1992). In its simplified version (i.e., the FBMC model), the physical limitations are only applied to part of the network. We display the connections and differences between these models below.

2.2.1 Nodal pricing model

$$\max \sum_i \left(\int_0^{Q_i^d} P_i^d(Q)dQ - \int_0^{Q_i^s} P_i^s(Q)dQ \right) \tag{7}$$

Subject to:

$$NI_i = Q_i^s + qwind_i - Q_i^d, \forall i \in N \tag{8}$$

$$\sum_i NI_i = 0 \tag{9}$$

$$FL_l{}^N = \sum_i nptdf_{l,i} * NI_i, \forall l \in L \tag{10}$$

$$\left| FL_l{}^N \right| \leq cap_l, \forall l \in L \tag{11}$$

The objective of the nodal pricing model is again to maximize the social welfare (i.e., Eq. (7)). The net injection NI_i at each node is equal to the difference between its generation $Q_i^s + qwind_i$ and demand Q_i^d (i.e., Eq. (8)). The total generation should be equal to the demand (i.e., Eq. (9)). The nodal power transfer distribution factor $nptdf_{l,i}$, which is derived from the lossless DC power flow approximation (Christie et al. 2000), illustrates the linearized impact on line l by injecting 1 MW power at node i and subtracting it from the reference node. The power flow on line l is given in Eq. (10) and is restricted by the line thermal capacity limit Eq. (11).

2.2.2 FBMC model

$$\max \sum_{i} \left(\int_{0}^{Q_i^d} P_i^d(Q)dQ - \int_{0}^{Q_i^s} P_i^s(Q)dQ \right) \tag{12}$$

Subject to:

$$NI_i = Q_i^s + qwind_i - Q_i^d, \forall i \in N \tag{13}$$

$$NEX_z = \sum_{i \in N_z} NI_i \,, \forall z \in Z \tag{14}$$

$$\sum_{z \in Z} NEX_z = 0 \tag{15}$$

$$FL_l{}^{FBMC} = \sum_{z} zptdf_{l,z} * NEX_z, \forall l \in CB \tag{16}$$

$$\left| FL_l{}^{FBMC} \right| \leq cap_l, \forall l \in CB \tag{17}$$

In the FBMC model, the physical limitations are only applied to the critical branches (CBs) (Eq.(16) and (17)). The zonal PTDF matrices $zptdf_{l,z}$ are used to estimate the influence of the net position of any zone on the CBs. The zonal PTDF matrices are derived from both the Generation Shift Keys (GSKs) and the nodal PTDF matrices (Eq. (18)).

$$zptdf_{l,z} = \sum_{i \in N_z} nptdf_{l,i} * gsk_{i,z}, \forall l \in L, z \in Z \tag{18}$$

GSKs are a set of factors describing a linear estimation of the most probable change in the net injection at a node in relation to the change of the net position of this zone

(Epexspot 2011). In practice, a precise procedure to define the GSKs is missing. Gebrekiros et al. (2015) show that the GSKs defined based on nodal injections (production minus demand) perform best among three tested schemes. In this paper, we assume the GSKs as the nodal weight of the net position within the zone given by the nodal pricing solution, $gsk_{i,z} = \frac{Q_i^{s^*}+qwind_i-Q_i^{d^*}}{\sum_{i\in N_z}(Q_i^{s^*}-Q_i^{d^*})}, \forall i, z, i \in N_z$, where $Q_i^{s^*}$ and $Q_i^{d^*}$ represent the solution given by the nodal pricing model.

Figure 1 illustrates different market clearing models. Among the three models, the nodal pricing model needs most detailed information regarding the grid topology. In the FBMC model, the nodes in the grid are divided into several bidding zones. The approximated laws of physics are only applied to CBs (bold lines); the other lines (i.e., non-CBs) have no physical restrictions. The CBs could be lines connecting two bidding zones (i.e., interties) or lines within a zone. In the ATC model, the network is also divided into several bidding zones. Instead of using the capacity of individual lines, the ATC model limits power transfer between two bidding zones to be less than an aggregate capacity (i.e., ATC value). No physical restrictions are applied to lines within a bidding zone.

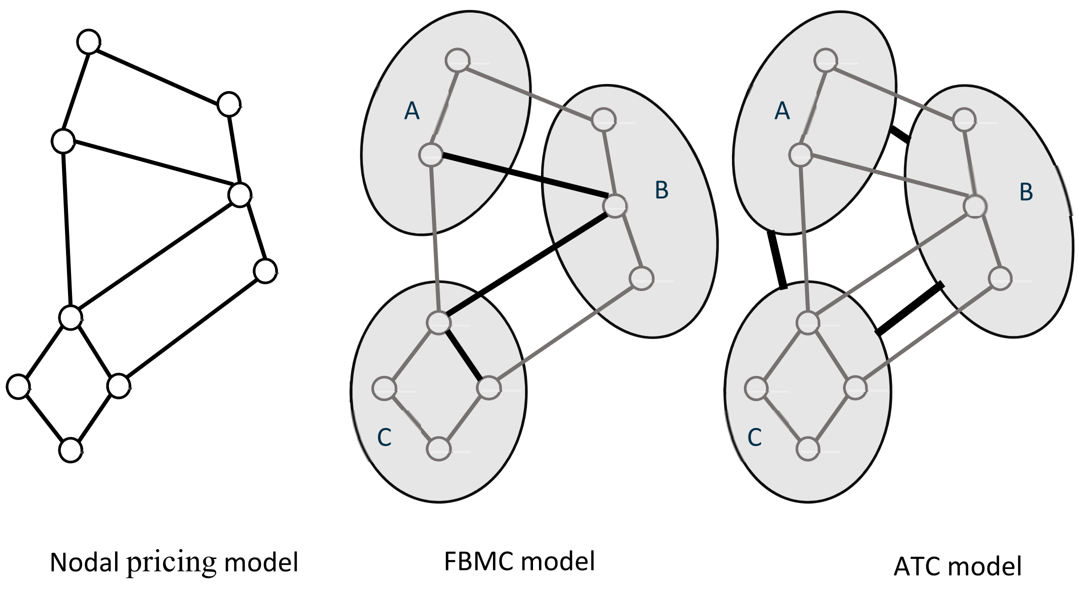


Figure 1: Day ahead market models

2.3 Re-dispatching model

In real time, re-dispatching is needed due to the supply and load uncertainties and the incompleteness of the market coupling models (e.g., physical characteristics of the power system are not fully taken into account). A congestion-free network must be guaranteed. The assumptions that we use for the re-dispatching model in this paper, are the following:

a) We assume that the supply uncertainty is caused only by the forecast errors of wind generation.
b) We assume that the load quantities given by the day-ahead market stay unchanged in the real time. However, in order to guarantee the feasibility of the re-dispatching model, the option to curtail load ($LOADSHED_n$) is possible but at a very high cost as displayed in Figure 2.

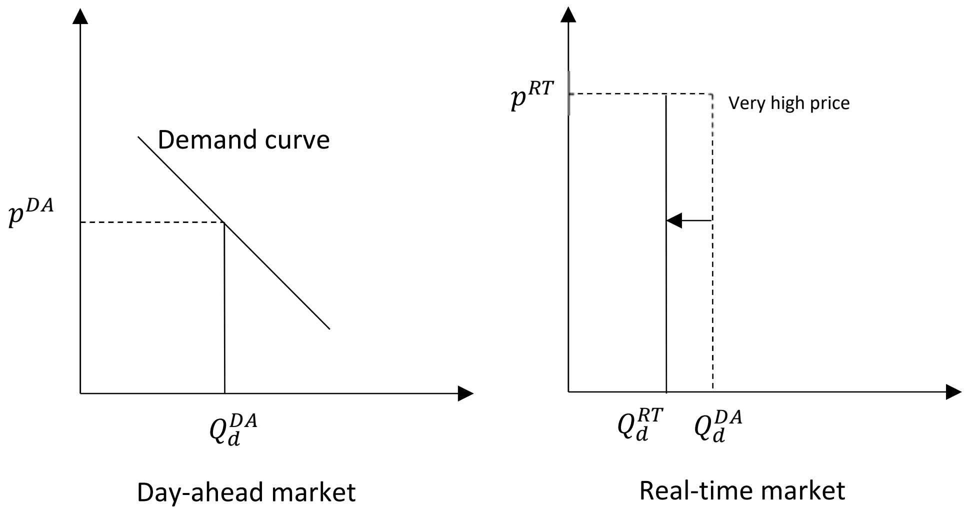


Figure 2: Load shedding

c) Conventional generation has high flexibility and can be adjusted accordingly. We assume that the generators still bid at their marginal cost in the re-dispatching model. Generators that fail to dispatch the contracted power would pay their saved marginal cost to the market and generators that increase their generation in order to satisfy the demand would be compensated by their short-run marginal cost of production. In real life, the re-dispatching cost will increase because the generators might bid at a higher price (i.e., marginal price plus the flexibility cost) and because other costs (e.g., start-up cost) would be taken into account.

d) We test two levels of cooperation among the TSOs (i.e., no cooperation and full cooperation). No cooperation refers to the case when the TSOs can only adjust the generation within their own jurisdiction in the real-time market, and the full cooperation case is when the TSOs can adjust the generation within the whole network.

$$\min \sum_i \int_{Q_i^{s'}}^{Q_i^{s'}+GUP_i+GDN_i} P_i^s(Q)dQ + \sum_i lscost * LOADSHED_i \tag{19}$$

Subject to:

$$NI_i = \left(Q_i^{s'} + GUP_i - GDN_i\right) + (rqwind_i - WINDSHED_i) - (Q_i^{d'} - LOADSHED_i), \forall i \in N \tag{20}$$

$$\sum_i NI_i = 0 \tag{21}$$

$$FL_l{}^N = \sum_i nptdf_{l,i} * NI_i, \forall l \in L \tag{22}$$

$$\left|FL_l{}^N\right| \leq CAP_l, \forall l \in L \tag{23}$$

$$GUP_i, GDN_i, LOADSHED_i, WINDSHED_i \geq 0,\ \forall i \in N \tag{24}$$

The objective of the re-dispatching model is to minimize total re-dispatching costs (Eq. (19)). The generation $Q_i^{s'}$ and the demand $Q_i^{d'}$ from the day-ahead market model are used as input for the re-dispatching model. The generation can be increased by GUP_i or decreased by GDN_i. The option to curtail consumer's load ($LOADSHED_n$) is possible only when the feasibility of the re-dispatching model cannot be guaranteed. We assume the marginal cost of such an option to be significantly higher ($lscost \gg 0$) than any other marginal generation cost. The re-dispatching model guarantees that the solution gives feasible flows by applying the nodal PTDF matrix and thermal capacity limits (Eq.(22) and (23)). We simulate two different levels of cooperation among system operators (i.e., full cooperation and no cooperation). The above formulations assume that the system operators are fully aware of operations by other system operators in the re-dispatching model and the re-dispatching is not restricted within the same bidding zone.

$$\sum_{i \in N_z} \big((GUP_i - GDN_i) + (rqwind_i - qwind_i - WINDSHED_i) - LOADSHED_i\big) = 0, \forall z \in Z \tag{25}$$

Adding Eq.(25) to the above formulations limits re-dispatching within the same bidding zone. That is, the system operators can only increase or decrease generation within their own jurisdiction. Decreased generation should be equal to increased generation within the same bidding zone.

3. Network and Input data

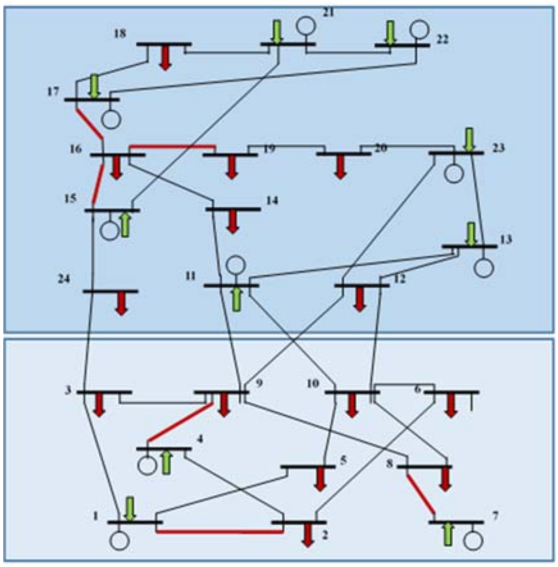


Figure 3: IEEE RTS 24-bus system

The models are tested in the IEEE RTS 24-bus test system (Subcommittee 1979, Ordoudis el al. 2014), which is composed of 24 buses and 34 transmission lines, as displayed in Figure 3. The supply and demand bid functions are derived from Deng et al. (2010) and shown in Table 1. Generators are located at buses 1, 4, 7, 11, 13, 15, 17, 21, 22 and 23. Loads are at the rest of the buses. The parameters for the transmission lines are given in Table 2.

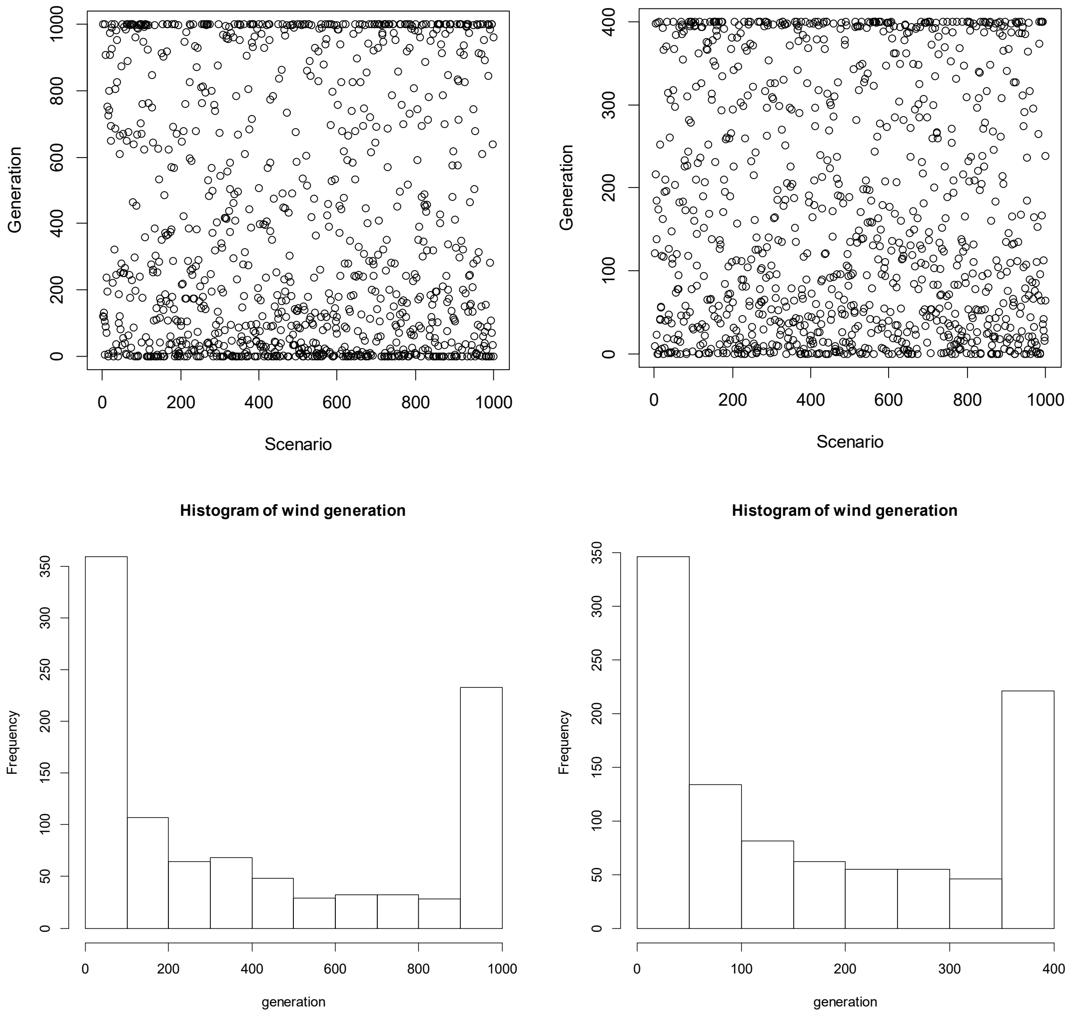
Bus-ID	*Supply Bids*	*Bus-ID*	*Demand Bids*
1	15.483+0.0150q	2	65.000−0.0820q
4	20.000+0.0161q	3	75.517−0.1129q
7	12.555+0.0352q	5	63.000−0.0925q
11	29.000+0.0362q	6	42.289−0.0847q
13	39.859+0.1012q	8	62.517−0.1016q
15	29.678+0.0220q	9	50.517−0.0876q
17	23.180+0.0295q	10	59.517−0.0502q
21	30.031+0.0270q	13	45.289−0.0733q
22	20.966+0.0268q	14	64.517−0.0851q
23	35.330+0.0552q	16	58.289−0.1146q
		18	76.547−0.0792q
		19	72.517−0.0682q
		20	63.289−0.1033q
		24	72.289−0.0733q

Table 1: Bid functions of generation and load for IEEE24 system

From	To	Capacity MVA	Reactance p.u.	From	To	Capacity MVA	Reactance p.u.
1	2	175	0.0146	11	13	400	0.0488
1	3	175	0.2253	11	14	400	0.0426
1	5	350	0.0907	12	13	400	0.0488
2	4	175	0.1356	12	23	400	0.0985
2	6	175	0.205	13	23	400	0.0884
3	9	175	0.1271	14	16	250	0.0594
3	24	400	0.084	15	16	400	0.0172
4	9	175	0.111	15	21	400	0.0249
5	10	350	0.094	15	24	400	0.0529
6	10	175	0.0642	16	17	300	0.0263
7	8	350	0.0652	16	19	400	0.0234
8	9	175	0.1762	17	18	400	0.0143
8	10	175	0.1762	17	22	400	0.1069
9	11	400	0.084	18	21	400	0.0132
9	12	400	0.084	19	20	400	0.0203
10	11	400	0.084	20	23	400	0.0112
10	12	400	0.084	21	22	400	0.0692

Table 2: Reactance and Capacity of Transmission Lines

Wind farms are located at buses 15 and 22 with installed capacity of 1000 MW and 400MW respectively. The expected wind generation in the day-ahead is 500MW at Node 15 and 200MW at Node 22. We generate 1000 scenarios of wind power in real time, as displayed in Figure 4.[3] We assume the cost of wind generated power to be zero.



Bus 15 Bus 22

Figure 4: Wind generation

[3] We used the Weibull distribution to simulate wind speed, and then we used the function from the software package WindPRO (https://www.emd.dk/windpro/) to convert wind speed to power production. The wind turbine would stop working if the rated wind speed is exceeded its cut-out speed.

The buses are initially divided into two countries according to their geographic location. The southern country contains buses 1 to 10 and the northern country contains buses 11 to 24. We keep the configuration of one of the countries unchanged (i.e., the Southern one) while splitting the other one into more bidding zones, and test how the outcome regarding different congestion models changes. The bidding zones in the northern country are under the control of the same system operator. We need to point out that it is not exactly clear how the number of zones and zone-boundaries are to be determined in both the ATC and FBMC models. Stoft (1996, 1997) shows that the partition of the network into zones generally is not obvious, but states that it should be based on price differences given by the nodal pricing solution. However, Bjørndal and Jörnsten (2001) also point out that even if it depends on price differences in the nodal pricing model, it is not straightforward. In our paper, we first run the nodal pricing model using supply and demand information in the day-ahead market, and then roughly group the nodes in the northern part into 3 and 4 bidding zones based on the price differences and node location, as showed in Figure 5.

The FBMC model uses the solution of the nodal pricing model, to decide the GSKs (Eq.(18)) and the CBs (lines that are congested given by the FB solution are set to be the CBs in the FBMC model). To make the ATC model comparable to the FBMC model, we use the flows given by the nodal pricing solution as a basis to set the aggregate capacity limits. The limits are equal to the absolute value of accumulated flows between two bidding zones given by the nodal pricing solution. We also assume that the aggregate capacity limits between two bidding zones are the same in both directions. For instance, the aggregate capacity limits from the northern country to the southern country are equal to those from the southern country to the northern country.

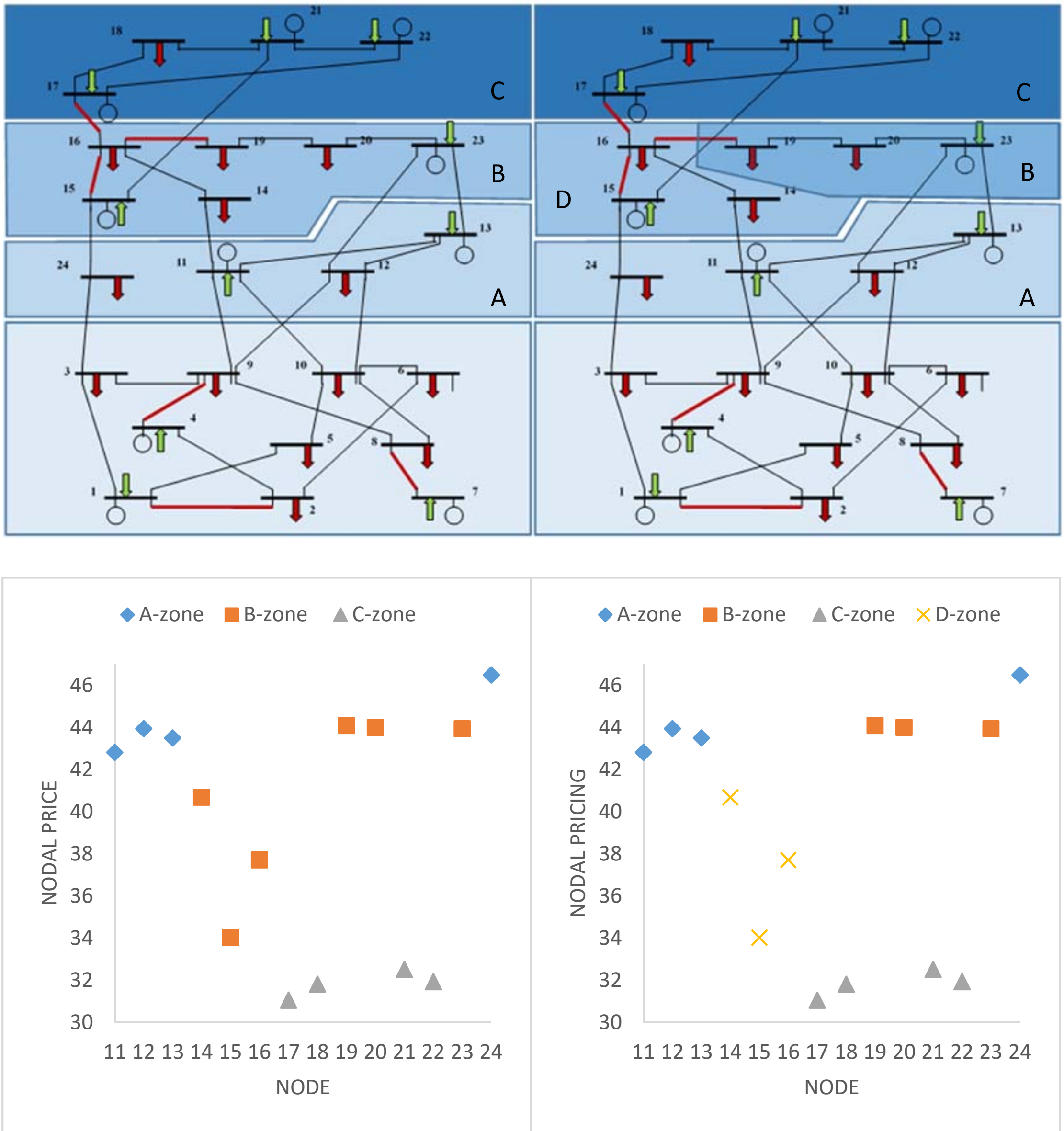


Figure 5: zonal configurations

In the-real time market (i.e., the re-dispatching model), we assume that the TSOs for these two countries can only adjust the generation within their own jurisdiction (i.e., the southern one and the northern one) in the no cooperation case and can adjust the generation freely within the whole network in the full cooperation case. The cost to reduce the load is 1000 (i.e., $lscost = 1000$).

4. Results

We present the simulation results in this section. We study how the bidding zone configuration affects the performance of different cross-border congestion models with two different cooperation levels.

4.1 Impact on the social surplus

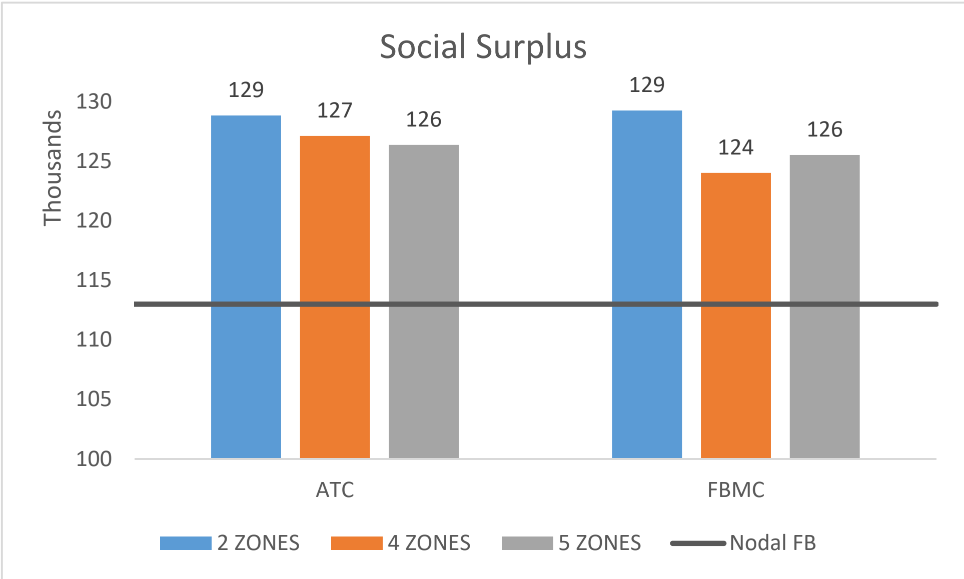


Figure 6: Social Surplus in the Day-ahead market

We first look at the impact on social surplus. In all the cases, the social surpluses given by both the ATC and FBMC models are higher than the corresponding value in the nodal pricing model. With the same zone bidding configuration, the ATC model gives higher social surplus than the FBMC model does in both the 4-zone and 5-zone cases. In the ATC model, the social surplus decreases slightly as the number of bidding zones increases. In the FBMC model, the social surpluses in both the 4-zone and 5-zone cases are lower than the one in the 2-zone case. However, the social surplus is a bit higher in the 5-zone case than in the 4-zone case.

The higher social welfare given by both the ATC and FBMC models imply that more power is sold/exchanged in these day-ahead markets (Table 3) than in the nodal pricing model. However, it is possible that some contracted power in the day-ahead market could not be dispatched due to network limitations. The following re-dispatching may lead to extra cost for the end consumers. To better understand the performance of different day-ahead market models, we need to take the re-dispatching cost into account. The re-dispatching cost is likely affected by the level of cooperation among the system operators. A higher level of cooperation indicates that it is more likely to re-dispatch cheaper power in the system and the re-dispatching cost would be lower.

	2 ZONES	4 ZONES	5 ZONES
ATC	4733	4568	4529
FBMC	4704	4549	4541
Nodal pricing	3431	3431	3431

Table 3: Contracted load in the day−ahead market

4.2 Impact on the re-dispatching cost

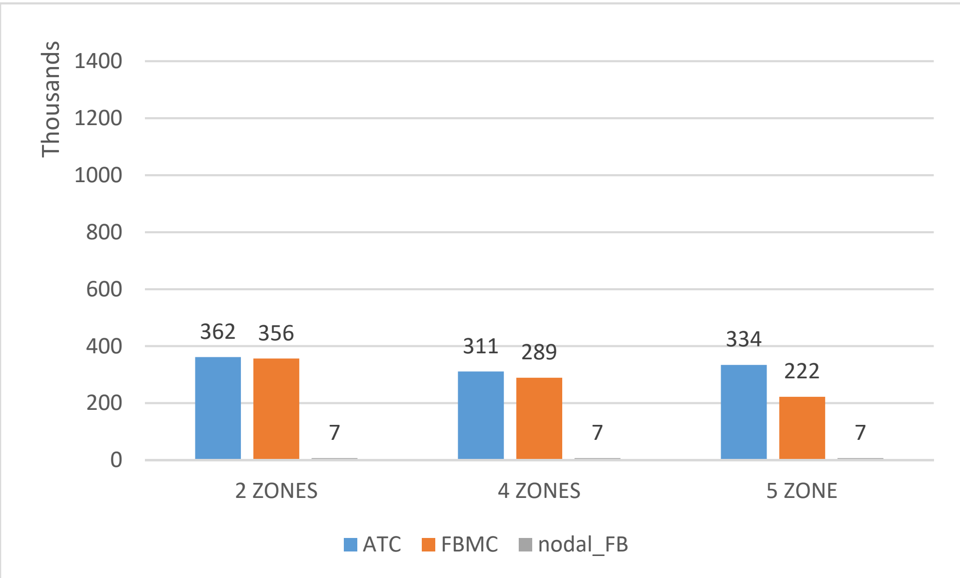


Figure 7: Re-dispatching Cost (Full Cooperation)

We first consider cases with a high level of cooperation (i.e., full cooperation). Figure 7 shows the average re-dispatching cost for the 1000 scenarios. The average re-dispatching cost is about 7000 given by the nodal pricing model, which is the lowest among the three models. The re-dispatching cost is much higher in both the ATC and FBMC models.

The cost in the ATC model falls from 362,000 in the 2-zone case to 311,00 in the 4-zone case (about 14%). The cost in the FBMC model falls from 356,000 to 289,000 in the 4-zone case (about 19%). However, the cost in the ATC increases from the 2-zone case to 334,000 in the 5-zone case (about 7%) while the cost in the FBMC further decreases to 222,000, a decline by nearly 23%.

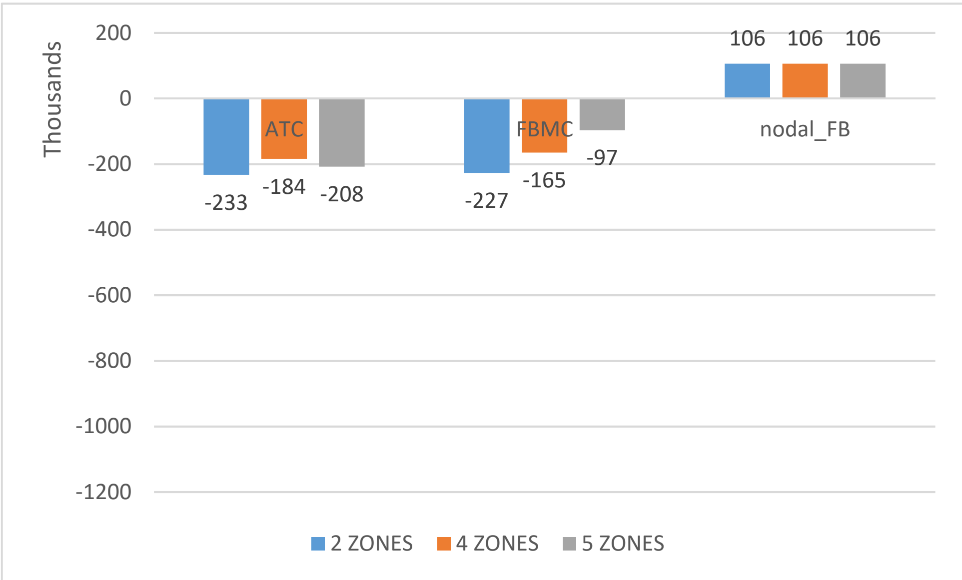


Figure 8: Total social surplus[4] in the full cooperation case

In the cases with a higher level of cooperation, the performance of the FBMC model is better if a more detailed network is given (i.e., more bidding zones). In our example, the FBMC model could be greatly improved if a better zone configuration is given in the full cooperation case. The social surplus from the day ahead increases from 124,000 in the 4-zone case to 126,000 in the 5-zone case, while the re-dispatching cost deceases by nearly 23%. As given by Figure 8, the total social surplus (i.e., the social surplus given by the day-ahead market minus the re-dispatching cost in the real time) is highest in the 5-zone case when applying the FBMC model.

.[4] As the load shedding cost are assumed to be very high, the total social surplus thus could be negative.

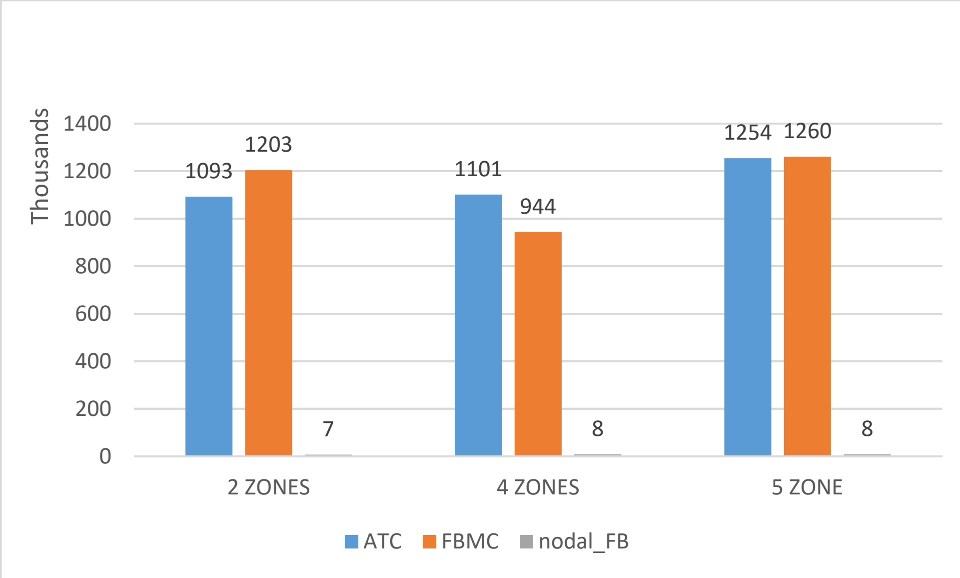


Figure 9: Re-dispatching Cost (No Cooperation)

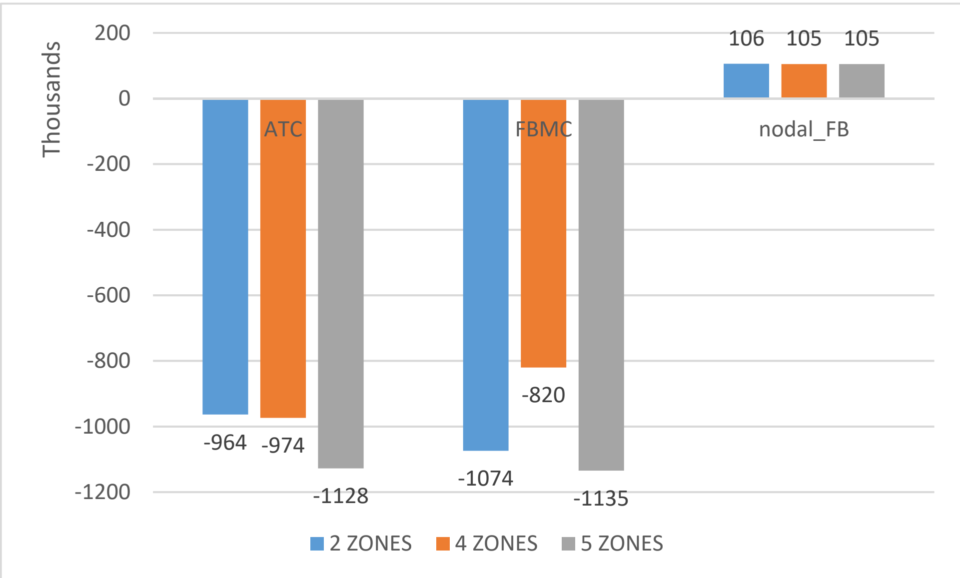


Figure 10: Total Social surplus in the no cooperation case

Figure 9 shows the average re-dispatching cost in the no cooperation case. Again, the nodal pricing gives much lower re-dispatching cost than both the ATC and FBMC models.

In the no cooperation case, the re-dispatching cost in the ATC model does not decrease even when there are more bidding zones. In fact, the re-dispatching cost increases. In the FBMC model, the re-dispatching cost does not always decline as there are more bidding zones. Compared to the 4-zone case, the re-dispatching cost given by the 5-

zone case increase by 33%.The cost for the 5-zone cases is even higher than that the 2-zone cases. In both the ATC and FBMC models, the total social surplus is lowest in the 5-zone case.

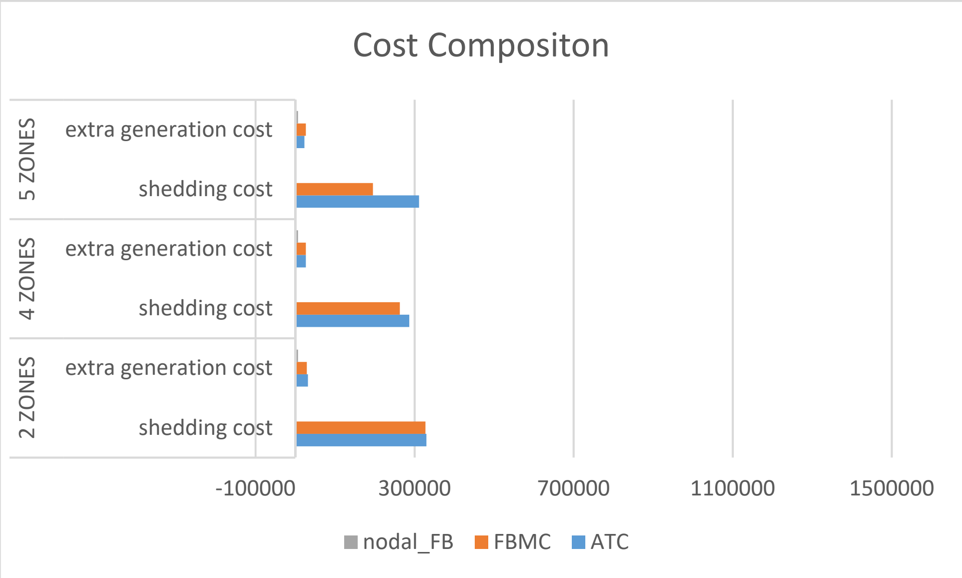


Figure 11: Cost Composition (Full Cooperation)

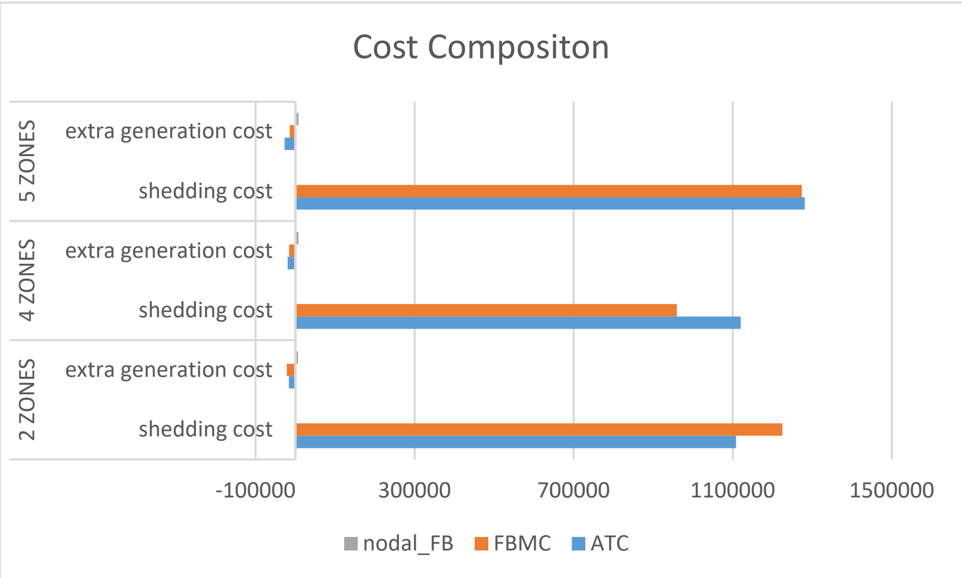


Figure 12: Cost Composition (No Cooperation)

We notice that the the cost of up- and down- generation (extra generation cost) given by both the ATC and FBMC models is negative in the no cooperation case, which indicates that a large amount of contracted power in the day ahead market could not be dispatched in the real time as showed in Table 4. Correspondingly, the load shedding cost in the no cooperation case is much higher than that in the full cooperation case. By strengthening cooperation among the system operators, the shedding cost could be greatly reduced. This may show the importance for the European countries to intergrate the real-time re-dispatching market.

	Full Cooperation				No Cooperation		
	2 ZONES	4 ZONES	5 ZONES		2 ZONES	4 ZONES	5 ZONES
ATC	7%	6%	7%	ATC	23%	25%	28%
FBMC	7%	6%	4%	FBMC	26%	21%	28%
Nodal pricing	0%	0%	0%	Nodal pricing	0%	0%	0%

Table 4: Ratio of load shedding to contracted load

5. Conclusion

Currently the bidding zones of the European power market are defined mostly according to national boundaries. In this paper, we attempt to test how the bidding zone configuration might affect the performance of different network flow models in the day ahead market, given the fact that more and more renewable energy has been connected to the European grid. The paper runs a simulation in the IEEE RTS 24-bus test system by defining different bidding zone configurations and setting two levels of cooperation among the transmission system operators.

In our example, we show that in general, compared to the ATC model, the FBMC model helps to reduce more re-dispatching cost if the zone configuration is improved. We also find that, the FBMC model might perform better in a higher cooperation level. In our example, compared to the 4-zone case, the 5-zone case has a higher social surplus. The re-dispatching cost deceases by almost 23% in the full cooperation case but increases by about 33% in the no cooperation case.

We further notice the main reason for a high re-dispatching cost is that a large amount of contracted power in the day ahead market could not be dispatched in the real time.

By strengthening cooperation among the system operators, the re-dispatching cost could be greately reduced.

Finally, we aslo show that the nodal pricing model will result in a much lower re-dispatching cost than both the ATC and FBMC in both cooperation level, which might indicate the nodal pricing model is a better option for the European power market.

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