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Discussion paper

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Abstract: In the European market, the promotion of wind power leads to more network congestion. Zonal pricing (market coupling), which does not take the physical characteristics of transmission into account, is the most commonly used method to relieve congestion in Europe. Zonal pricing fails to provide adequate locational price signals regarding the energy resource scarcity and thus creates a large amount of unscheduled cross-border flows originating from wind-generated power, making the interconnected grid less secure. Prior studies show that full nodal pricing works better in integrating wind power into the grid. In this paper we investigate the effects of applying a hybrid congestion management model, i.e. nodal pricing model for one country embedded in a zonal pricing system for the rest of the market. We test how nodal pricing works in such a hybrid context with more wind power. We find that, compared to full nodal pricing, hybrid pricing fails to fully utilize all the resources in the network and some wrong price signals might be given. However, hybrid pricing still performs better than zonal pricing. The results from the hybrid pricing model of Poland, Germany, Slovakia and the Czech Republic show that, within the area applying nodal pricing (Poland), better price signals are given; the need for re-dispatching reduces; more congestion rent is collected and the unit cost of power is reduced. The results also show that international power exchange increases between the nodal pricing area and the zonal pricing areas, especially on windy days. Moreover, the nodal pricing area has less unscheduled cross-border power flow from the zonal pricing area entering its network and collects more cross-border congestion rent.

Keywords: Congestion management, nodal pricing, zonal pricing, redispatching, renewable energy

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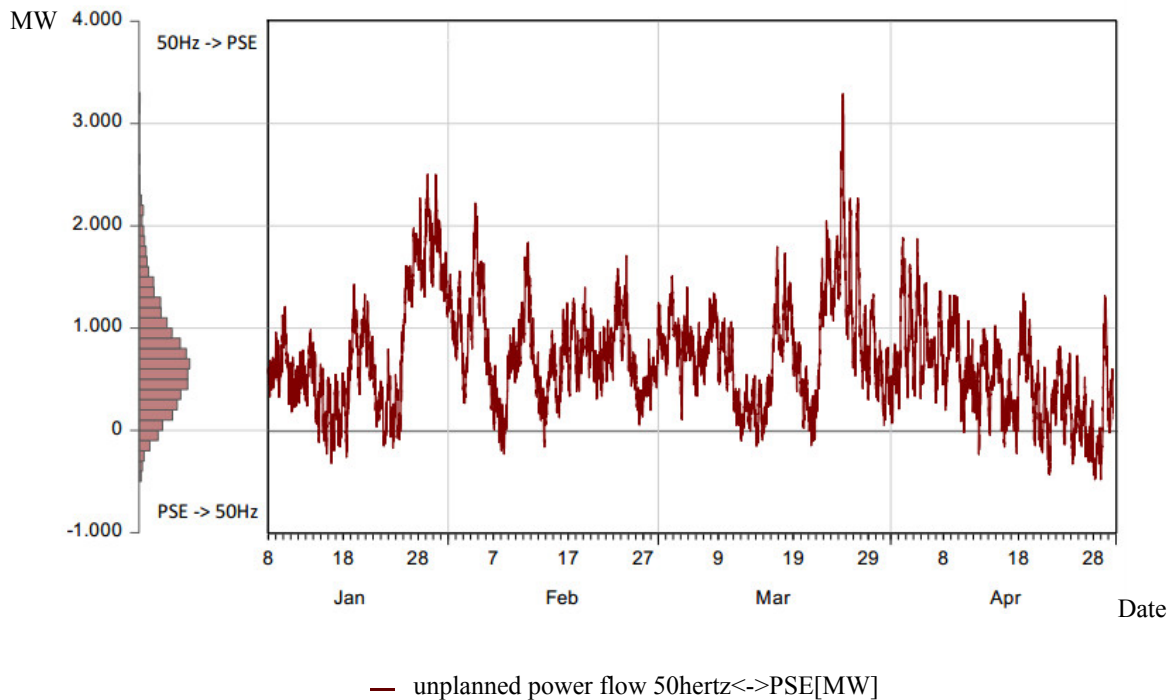
1. Introduction

The efforts to meet the renewable energy target of the Renewable Energy Directive 2009/28/EC have led to a large number of wind capacity installations in the EU countries. Promotion of renewable energy sources has challenged the current power systems. As wind power requires high upfront capital investment and its operation costs are low, it is placed in the beginning of the merit order curve and has priority access under the current European power network which relies on zonal pricing to handle congestion. Due to the uncertainty of wind generation, excess wind power might lead to grid congestion. Furthermore, the installed wind power plants are usually located in places without sufficient consumption. Therefore, the utilization of wind energy often requires long distance transportation, which creates an extra burden for the network and may exacerbate congestion. The impact of wind energy on network congestion has been 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).

Power grids are connected within European countries, therefore the effect of wind power is not limited by national border. The use of zonal pricing (uniform pricing) for congestion management in most of the European countries has made this problem difficult to solve. Zonal prices are achieved regardless of network capacity and physical laws constraints within their domestic markets, and international commercial power exchange between two countries is limited by a pre-planned Net Transfer Capacity (NTC) value. Therefore, the scheduled commercial power exchange is not necessarily equal to the real (physical) power exchange. In windy days, due to the effect of loop flow, countries that are close to wind farms might greatly suffer from unscheduled power exchange. For example, the Polish and Czech network operators claimed that unscheduled cross-border flows from wind generation in Germany overloaded their transmission networks more frequently, making their grids less stable and secure (Kunz 2012).

In order to limit the large number of loop flows caused by wind/solar generation from Germany, Poland uses a very low Net Transfer Capacity (NTC) to reduce the power exchange with Germany. However, a low NTC can only restrict physical power exchange by restricting commercial trading between two connected countries. It cannot prevent the wind-generated power from entering the network because information regarding the location of the power generation and the network

constraint is not used. Figure 1 below shows the unplanned power flows, which are the differences between the day-ahead scheduled commercial flows and the physical power flows between the 50Hertz area (Germany) and the PSE area (Poland) for the period between January and April 2014. The large magnitudes of unplanned flows indicate that a lower NTC did not help Poland to eliminate the loop flow caused by the wind-generated power from Germany.¹



Source: 50Hertz (2014)

Figure 1: Unplanned power flows between the 50Hertz area (Germany) and the PSE area (Poland)

In contrast to zonal pricing, nodal pricing gives the value of power for each location by including all the physical and technical constraints (Schweppe et al. 1988). Nodal pricing limits the needs for re-dispatching and reduces the corresponding cost. Furthermore, it gives the correct incentives for future investments by reflecting the value of scarce transmission capacity (Hogan 1992).

Leuthold et al. (2008) have shown that the nodal pricing scheme is economically superior to the zonal pricing scheme for the integration of wind and solar power into the German grid. However, Leuthold et al. (2008) do not examine how intercountry power exchange affects the application of nodal pricing. This question is crucial because Europe has launched a Price Coupling of Regions

¹ Both the day-ahead market solution, which does not take the network constraints into account, and the re-dispatching procedure (i.e., changes on load/generation) could lead to unscheduled power flows.

(PCR) project in order to enhance power exchange among different countries and create a single European day-ahead market (EIRGRID 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. Therefore, applying nodal pricing in a single European country should not ignore the loop flow effect from the other countries.

Bjørndal et al. (2014) investigate a pricing model for an electricity market with a hybrid congestion management method, i.e. part of the system applies the nodal pricing scheme and the rest applies the zonal pricing scheme, and test the model in a 13-node power system. The model determines prices and net transfers for all the involved regions using a joint calculation. Their results indicate that part of the network is better utilized by applying nodal pricing in such a hybrid context. However, nodal pricing fails to function fully as it is supposed to due to the influence of the zonal pricing areas. They find that wrong price signals are given at nodes (within the nodal pricing area) connected to the zonal pricing area, which might trigger more unplanned power flow.

Poland had planned to implement nodal pricing within its domestic market in 2015 (Sikorski 2011) but the project has been abandoned. In the long run, nodal pricing has been questioned within the European market. One of the main concerns is that nodal pricing might impede market harmonization as it imposes more restrictions (e.g., network capacity constraints) than zonal pricing, and thus could limit power exchange. However, applying zonal pricing might also reduce international power trades, and even to a larger extent. Sensfuss et al. (2008) argue that the merit-order effect would decrease the day-ahead market prices in Germany as more wind mills are installed and thus Germany would reduce its power import.

In our study, we apply the hybrid scheme proposed by Bjørndal et al. (2014) for a joint power market for Poland, Germany, Czech, and Slovakia. We assume that Poland applies nodal pricing and that the rest of the countries apply zonal pricing. The Polish network is inter-connected with other continental countries, and even if Poland applies nodal pricing, it is still inevitable that the network will be affected by the flows from zonal pricing areas. In our study, we compare the hybrid pricing scheme to the full nodal pricing scheme (i.e., all the four countries apply nodal pricing) and the full zonal pricing scheme (i.e., all the four countries apply zonal pricing). We find that the hybrid pricing helps to provide price signals by identifying the power resource scarcity within the

Polish market, and that this results in increased international power exchange between Poland and the rest of the countries.

An interesting research question raised by our study is to test whether hybrid pricing can help Poland in integrating its neighboring wind-generated power into the grid when the Polish nodal-pricing market is surrounded by zonal-pricing countries. We investigate a Business-as-Usual (BAU) scenario and a High-Wind-Level (HIGH WIND) scenario for comparison. Specifically, we study the following questions: First, does hybrid pricing perform as well in the HIGH WIND scenario as it does in the BAU scenario in terms of giving correct pricing signals? Second, what is the impact of wind penetration on day-ahead market prices and cross-border power exchange when hybrid pricing is applied? Third, does hybrid pricing affect the physical power exchange?

2. Model

The target model for the European day-ahead power market is to simultaneously determine volumes and prices in all relevant zones based on the marginal pricing principle (ACER, 2013). In this paper, we apply the hybrid pricing model in a joint day-ahead market, in which there are two different pricing schemes, i.e., zonal pricing and nodal pricing. Different areas are not isolated from each other and commercial trading is considered regardless of the pricing schemes. This implies that both the day-ahead volumes and later re-dispatch in the zonal pricing areas will affect the nodal pricing areas.

Assumptions regarding the day-ahead market clearing and re-dispatching are briefly illustrated in Figure 2. We have a step-wise supply bidding curve which assumes that all the generators bid at their marginal cost. Wind/solar-generated power is placed at the beginning of the supply curve, with very low marginal cost. The system is to maximize social welfare and the day-ahead market clearing price (P^*) and quantity (Q^*) are determined by the interaction of the supply and demand bidding curves. Due to the network constraints not taken into account in the day-ahead market, some of the contracted power cannot be dispatched and therefore re-dispatching is needed. In the re-dispatching model, we assume that power plants that fail to dispatch the contracted power would pay their saved marginal cost to the market and power plants that increase their generation in order to satisfy the demand would be compensated by their short-run marginal cost of production (i.e., no economic profit is accruing from the re-dispatching procedure, neither for generation or load.).

Increased generation which replaces the non-dispatchable contracted power is more expensive and leads to an extra cost, which is shown as the yellow area in Figure 2.

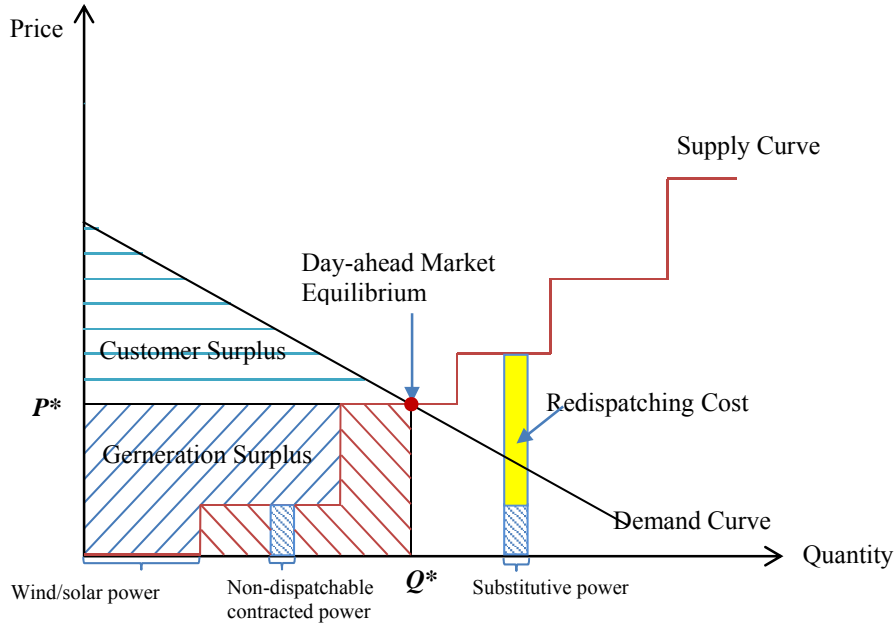


Figure 2: Market clearing procedure and re-dispatching (without load/supply shedding)

The complete mathematical formulation of the model is given below:

Set

- $c \in C$ Set Conventional power plants
- C_n Set of conventional power plants located at node n
- C_z Set of conventional power plants located in zone z
- $n, nn \in N$ Set of all nodes
- $NODAL$ Set of nodes in the nodal pricing area
- $ZONAL$ Set of nodes in the zonal pricing area
- $HYBRID$ Set of nodes that are in the nodal pricing area and connected to the zonal pricing area
- $l \in L$ Set of all transmission lines
- $l \in L_{NODAL}$ Set of transmission lines within the nodal pricing area

$z, zz \in Z$ Set of all zones

Parameters

a_n Intercept of the demand function at node n

$bvector_{n,nn}$ Series susceptance of line n, nn [$1/\Omega$]

$bigM$ Curtailment cost [EUR/MWh]

cg_c The electricity generation cost for power plant c [EUR/MWh]²

gda_c Contracted generation of plant c in the day-ahead market [MW]

$gmax_c$ Maximum generation of plant c [MW]

$gsolar_n$ Solar generation at node n [MW]

$gwind_n$ Wind generation at node n [MW]

m_n Slope of the demand function at node n

$ntc_{z,zz}$ Net transfer capacity between zone z and zz [MW]

$pmax_{n,nn}$ Thermal transmission limit of transmission line l [MW]

qda_n Contracted demand at node n in the day-ahead market [MW]

Variables

Δ_n Voltage angle at node n [rad]

$G_{c,n}$ Generation of plant c locating at node n [MW]

GDN_c Decreased generation of plant c locating at node n [MW]

GUP_c Increased generation of plant c locating at node n [MW]

$LF_{n,nn}$ Power flow between nodes n and nn [MW]

$LOADSHED_n$ Load curtailments at node n [MW]

NI_n Net input at node n [MW]

² The electricity generation cost is composed of two parts (i.e., fuels cost and carbon cost).

p_n	Price at node n
Q_n	Demand at node n [MW]
$SOLSHED_n$	Solar power curtailments at node n [MW]
$TF_{n,nn}$	Commercial trading between nodes n and nn [MW]
$WINDSHED_n$	Wind power curtailments at node n [MW]

Details of the nodal pricing and zonal pricing schemes are based on the ELMOD framework described in Leuthold, Weigt and von Hirschhausen (2012). The full explanation of the model is given below.

2.1 Day-ahead market model

$$\max_{Q,G} \sum_n (a_n * Q_n + 0.5 * m_n * Q_n^2) - \sum_c c g_c * G_c \quad (1)^3$$

Subject to:

$$NI_n = \sum_{c \in C_n} G_c + gwind_n + gsolar_n - Q_n, \forall n \in NODAL \quad (2.a)$$

$$\sum_{nn} (TF_{n,nn} - TF_{nn,n}) = \sum_{c \in C_n} G_c + gwind_n + gsolar_n - Q_n, \forall n \in ZONAL \quad (2.b)$$

$$NI_n + \sum_{nn} (TF_{n,nn} - TF_{nn,n}) = \sum_{c \in C_n} G_c + gwind_n + gsolar_n - Q_n, \forall n \in HYBRID \quad (2.c)$$

$$G_c \leq gmax_c \quad (3)$$

$$LF_{n,nn} = bvector_{n,nn} (\Delta_n - \Delta_{nn}), (n, nn) \in L_NODAL, \forall n, nn \in NODAL \quad (4)$$

$$NI_n = \sum_{nn: (n,nn) \in L_NODAL} LF_{n,nn} - \sum_{nn: (nn,n) \in L_NODAL} LF_{nn,n}; \forall n \in NODAL \quad (5)$$

$$-pmax_{n,nn} \leq LF_{n,nn} \leq pmax_{n,nn}, (n, nn) \in L_NODAL, \forall n, nn \in NODAL \quad (6)$$

$$\Delta_{n'} = 0, n' = slackbus \text{ in the nodal pricing area} \quad (7)$$

³ The model assumes a linear inverse electricity demand function of the form: $p_n(Q_n) = a_n + m_n \cdot Q_n$ at each node n of the network. In the Appendix I, it is shown how to determine the prohibitive price and slope by using reference price and demand. The model maximizes the total social welfare, which is defined as

$$\sum_n \int_0^{Q_n} p_n(Q_n) dQ_n - \sum_c \int_0^{G_c} c g_n(G_c) dG_c$$

. Inserting the linear inverse demand function into the social welfare function,

$$\sum_n \left[\int_0^{Q_n} (a_n + m_n \times Q_n) dQ_n \right] - \sum_c \int_0^{G_c} c g_c dG_c = \sum_n \left(a_n Q_n + \frac{m_n}{2} Q_n^2 \right) - \sum_c c g_c G_c$$

the expression becomes

$$\sum_{n \in Z} \sum_{nn \in ZZ} TF_{n,nn} \leq ntc_{z,zz}, \forall n \in ZONAL \cup HYBRID, \forall z, zz \in Z, z \neq zz \quad (8)$$

$$G_c \geq 0, Q_n \geq 0, TF_{n,nn} \geq 0 \quad (9)$$

The objective of the day-ahead market model is to maximize social welfare Eq. (1), considering the network constraints. The model distinguishes between nodal pricing and zonal pricing areas.

2.1.1 Nodal pricing area

The areas applying nodal pricing is constrained by energy balance (Eq. (2.a)), maximum generation capacity of thermal power plants (Eq. (3)), and restrictions on power transmission (Eq. (4)-(6)). Energy balance (Eq. (2.a)) ensures that at node n , net input or withdrawal NI_n is equal to the difference between power generation (including all the conventional power generation G_c at node n , wind generation $gwind_n$, and solar generation $gsolar_n$) and nodal demand Q_n . Conventional power generation is restricted by the maximum generation requirement $gmax_c$ (Eq. (3)). The Direct Current approximation (DC) approach (see Chao et al. (2000) and Sauma and Oren (2006)) is used to determine the load flows $LF_{n,nn}$ (Eq. (4)) in each line and the resulting injection or withdrawal NI_n (Eq. (5)) at each node in the nodal pricing area. Eq. (6) limits the absolute physical exchange between system nodes and Eq. (7) is to specify the slack bus.

2.1.2 Zonal pricing areas

In the areas applying zonal pricing, we assume free trading within the domestic markets regardless of the physical laws and network capacity constraints. Therefore, trading within zonal pricing area are only constrained by energy balance (Eq. (2.b)) and capacity restrictions of power plants (Eq. (3)). The commercial flows between two nodes $TF_{n,nn}$ introduced in Eq. (2.b) will never go from a higher price area to a lower price area.⁴

2.1.3 Interfaces

The nodes that are within a nodal pricing area but connected with a zonal pricing area(s) are constrained by both types of pricing schemes (Eq. (2.c)). We assume that the power exchange

⁴ The variable $LF_{n,nn}$ is positive if the physical power flow goes from defined starting point of line l and is negative otherwise. $TF_{n,nn}$ is defined as commercial flow between two points and is enforced to be no less than 0. Commercial flow will not go from a higher price to a lower price area. That is $TF_{n,nn} = 0$ if $p_n > p_{n,nn}$. The physical flow $LF_{n,nn}$ however, could go from a higher price area to a lower price area due to the effect of loop flow in the nodal pricing model.

between such nodes and the zonal pricing area is commercial trading. That is, the flow between a nodal pricing area and a zonal pricing area is not modeled taking physical laws into account.

Commercial transfers between two connected pricing areas are limited by Net Transfer Capacity $ntc_{z,zz}$ (NTC) (Eq. (8)), which is set by the Transmission System Operator (TSO) before the clearing of the day-ahead market.⁵ We assume that commercial trading is limited not only between two connected zonal pricing areas but also between a nodal pricing area and its connected zonal pricing areas. NTC values have two directions (i.e., one for importing and one for exporting power from/to one or several country (countries)). In the full zonal pricing scheme, between two countries, only one direction of NTC values will be used and power exchange happens only from a lower price area to a higher price area. However, in the hybrid pricing scheme, power exchange could happen in both directions between a nodal pricing zone and a zonal pricing zone as the prices in the nodal pricing area are not uniform.

2.2 Re-dispatching model

Because the zonal pricing areas consider only restrictions on inter-zonal transfers, a separate re-dispatching model has to be specified to manage physical congestion within the zones. However, the nodal pricing area is inevitably affected by the zonal pricing area due to the impact of the loop flow laws. Thus, re-dispatching could be needed in the nodal pricing area as well. The uncertainties regarding the supply (e.g., both wind and solar are available at this specific hour) and demand are not modeled in this paper and re-dispatching occurs only due to the physical network constraints that are not taken into account in the day-ahead market.

We assume that the re-dispatching model takes a pay-as-bid approach. Power plants increasing their generation are compensated by their short-run marginal cost of production; power plants decreasing their generation pay their saved marginal costs. However, in practice, the TSOs may not always find the cheapest available power and thus an even higher re-dispatching cost could

⁵ Two approaches could be found to formulate the NTC constraints in the full zonal pricing scheme, i.e., the gross approach which sets the gross commercial flows in each direction to be no larger than the pre-defined NTC value (e.g., CASC.EU (2014), Kunz (2012)) and the net approach which sets the net commercial flows in each direction to be no larger than the NTC value (e.g., Bjørndal et al. (2014)). When it comes to formulate the NTC constraints between a nodal pricing area and a zonal pricing area, these two approaches might give different results. The gross approach is stricter than the net approach. The gross approach allows that both directions of the NTC constraints are binding at the same time.

occur. We further assume that the TSOs can only access the re-dispatching resource within their own area.⁶

Below the formulation of the model is given:

$$\min[\sum_c(cg_c * GUP_c - cg_c * GDN_c) + \sum_n bigM * (WINDSHED_n + SOLSHED_n + LOADSHED_n)] \quad (10)$$

Subject to:

$$NI_n = \sum_{c \in C_n}(gda_c + GUP_c - GDN_c) + (gwind_n - WINDSHED_n) + (gsolar_n - SOLSHED_n) - (qda_n - LOADSHED_n), \forall n \in N \quad (11)$$

$$0 \leq gda_c + GUP_c - GDN_c \leq gmax_c, \forall c \quad (12)$$

$$LF_{n,nn} = B_{n,nn}(\Delta_n - \Delta_{nn}), (n, nn) \in l, \forall n, nn \quad (13)$$

$$NI_n = \sum_{nn:(n,nn) \in L} LF_{n,nn} - \sum_{nn:(nn,n) \in L} LF_{nn,n}, \forall n \in N \quad (14)$$

$$-pmax_{n,nn} \leq LF_{n,nn} \leq pmax_{n,nn}, (n, nn) \in L, \forall n, nn \quad (15)$$

$$\Delta_{n'} = 0, n' = slackbus \quad (16)$$

$$\sum_{c \in C_z}(GUP_c - GDN_c) = 0, \forall z \in Z \quad (17)$$

$$GUP_c \geq 0, GDN_c \geq 0, \forall c \quad (18)$$

The objective of the re-dispatching model is to minimize total re-dispatching costs (Eq. (10)). The generation from the hybrid model can be increased by GUP_c or decreased by GDN_c . To ensure the feasibility of the re-dispatching model, the model allows options to curtail nodal (consumer's) load ($LOADSHED_n$) and to reduce solar ($SOLSHED_n$) and wind generation ($WINDSHED_n$). However, the marginal costs of these options are assumed to be significantly higher ($bigM \gg 0$) than any other marginal generation cost.

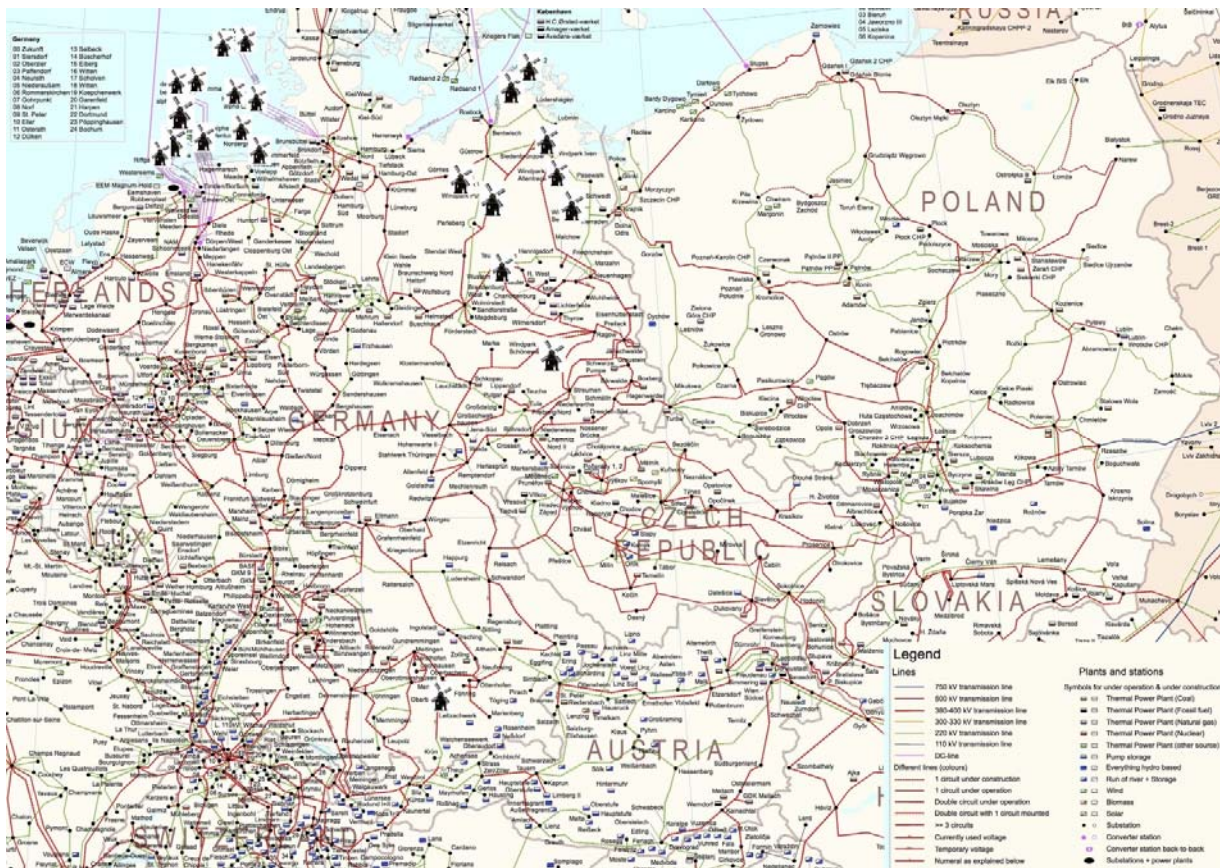
The dispatching from the day-ahead model is treated as input in the re-dispatching model, which implies that both the demand Q_n and the generation G_c are now given and represented in the model by the parameters qda_n and gda_c respectively. The energy balance constraint (Eq. (11)) and the generation capacity constraint (Eq. (12)) have to be taken into account. Again, the DC

⁶ See Oggioni and Smeers (2013), which discuss different degrees of coordination among the TSOs in the re-dispatching models.

approximation approach is used to reflect the physical flow in the network (Eq. (13) – (16)). We assume that the system operators are fully aware of operations by other system operators in the re-dispatching model. However, re-dispatching is restricted within the same pricing area. 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 pricing area (Eq. (17)).

The day-ahead market model is a quadratic problem and the re-dispatching model is linear. Models are coded in GAMS. The time frame is 1 hour. For simplification, the unit commitment decisions and block bids are not taken into account.

3. Power System and Data



Source: ENTSO-E

Figure 3: Map of Grid and the German Wind Power Plants Distribution

3.1 Network

We apply the models in the previous section for a hypothetical joint market for Germany, Poland, Slovakia, and Czech Republic. The network topology together with the AC lines' physical characterization is derived from Kunz (2012)⁷, by choosing the nodes and lines relevant to the countries under consideration (i.e., Germany, Poland, Slovakia and Czech Republic). Interconnections of these countries with the rest of the European countries are not taken into account. In total, 529 buses, 835 lines, and 411 power plants are used for this analysis. The transmission network for these countries is displayed in Figure 3. The capacity of transmission lines is de-rated to 80% of their nominal capacity to approximate N-1 security constraints in the network (Leuthold, Weigt, & von Hirschhausen, 2012).

3.2 Market data

In order to get more realistic results, we have collected data (e.g., reference load, price, and NTCs) given by the involved day-ahead markets. As congestion most likely happens in the hours with high demand, we define a high load hour (i.e., 1.2 times the average hourly load in 2012) for the analysis. Therefore, we arbitrarily choose a specific hourly load (i.e., 9 a.m. in 2012-03-01) which is approximately equal to 1.2 times the average hourly load in 2012 and use the corresponding day-ahead market prices as the reference prices.

From	TO	EXPORT NTC	IMPORT NTC
DE	CZ	1400	1800
PL	CZ-DE-SK	1700	200
PL	SK	600	500
SK	CZ	1200	1800
CZ	PL	600	400

Sources: ENTSO-E

Table 1: NTC values (in MW) ⁸

Net Transfer Capacities (NTCs)⁹, which indicate the maximum commercial power exchange volumes, are used to limit the physical power exchange between two connected zones. For instance, a great amount of wind power generated in North Germany is transported to South Germany using

⁷ The original dataset is based on 2008 market data and has been updated to 2011 market data.

⁸ Instead of publishing a separate NTC value for each country, the Polish transmission system operator defines a common NTC for all polish cross-border exchange, including the borders with Germany (DE), Czech Republic (CZ) and Slovakia (SK) altogether.

⁹Data regarding NTCs are obtained from the ENTSO-E portal.

the Polish transmission network. In order to restrict the German wind-generated power running through the Polish transmission system, the Polish TSO publishes very low NTCs for the Germany-Poland cross-border commercial exchange. However, the NTCs may fail to limit physical power exchange, especially when wind blows. This is because countries applying the zonal pricing scheme disregard the internal network restrictions and physical laws in their areas. Before the contracted power is dispatched, the location of the power is unknown (i.e., could be anywhere within a zone). Therefore, Poland could fail to stop the German wind power from getting into its transmission system, which could make its power network less secure especially during peak hours.

3.3 Definition of scenarios

The wind and solar installations (Table 2) are assumed to be at the 2011 installation levels (Source: EWEA 2013, EPIA 2013). Germany accounts for more than 90% of the wind/solar installations in the four countries. Wind power locations are concentrated to a few specific areas and causes large amounts of loop flow in our study case. We specifically estimate how the power system would be affected by the increased wind power by defining two different scenarios, the Business-as-Usual (BAU) scenario and the High-Wind-Level (HIGH WIND) scenario, according to wind power penetration level. We assume that the availability of wind power is 21% of the total installation capacity in the BAU scenario and a higher wind level, 50% of the total installation capacity is assigned to the HIGH WIND scenario.^{10, 11} We keep availability of solar power to be 9% of total installation capacity in both scenarios.

Country	Wind	Solar
CZ	217	1959
DE	29071	24807
SK	3	508
PL	1616	3

Table 2: Wind and Solar installations (in MW)

4. Results

In this part, we first clarify some concepts in order to conduct further analysis.

¹⁰ The mean capacity factor for wind power (the ratio of average delivered power to theoretical maximum power) during the period 2003-2008 for Europe is close to 21% (Boccard 2009).

¹¹ The HIGH WIND scenario shows the impact of adding more wind generation into the grid. We assume a higher wind availability in our analyses, however, as an alternative we could have expanded existing wind capacity.

1. p_n

Market price (p_n): The dual variable of Eq. (2), i.e., the marginal cost/benefit of increasing one unit of power at node i , defines the price at node i . Price within each zonal pricing area is uniform as there are no restrictions on intra-zonal trading. Prices within the nodal pricing area can be different as the model takes both the physical laws and thermal capacity limits into account.

$$2. DC = \sum_n p_n Q_n \quad (19)$$

Demand cost (DC): Defined as the sum of the product of nodal demand Q_n and nodal or zonal spot price.

$$3. GI = \sum_n [p_n \sum_{c \in C_n} gda_c] + \sum_c [cg_c GUP_c] - \sum_c [cg_c GDN_c] \quad (20)$$

Generation incomes (GI): Defined as income earned in the day-ahead market plus incomes from re-dispatching if up-regulation is required (minus costs caused by re-dispatching if down-regulation is required).

$$4. GC = \sum_c [cg_c (gda_c + GUP_c - GDN_c)] \quad (21)$$

Generation cost (GC): Refers to the costs of the final generation dispatching given the re-dispatching results.

$$5. GS = GI - GC \quad (22)$$

Generation surplus (GS): Defined as generation income (GI) minus generation cost (GC). The generation surplus does not increase after re-dispatching as we assume that the generators will only be compensated by their marginal cost.

$$6. RC = \sum_c [cg_c GUP_c] - \sum_c [cg_c GDN_c] \quad (23)$$

Re-dispatching cost (RC) is the cost caused by re-dispatching.

$$7. CR = \sum_n p_n Q_n - \sum_n p_n \sum_{c \in C_n} gda_c = \frac{1}{2} \sum_n \sum_{nn} (p_{nn} - p_n) \times TF_{nn,n} + \sum_n \sum_{nn} (p_{nn} - p_n) \times LF_{n,nn} \quad (24)$$

Congestion rent (CR) collected from the day-ahead market can generally be described as the difference between day-ahead market payment received from consumers and day-ahead market payment to generators.¹²

¹² Also referred to merchandizing surplus (MS) (Wu et. al 1996).

In a full zonal pricing regime, congestion rent for the transmission system operator only results from allocation of international net transfer capacity (i.e., $TF_{nn,n}$) during the day-ahead market clearing. That is, because day-ahead price is uniform, no congestion rent will be collected within each area (country) applying zonal pricing. In contrast, within countries applying nodal pricing, congestion rent results not only from international trading but also from the differences in locational marginal prices.

We assume that the rent from cross-border commercial trading is equally shared by the two system operators.

4.1 Day-ahead market prices

Table 3 presents the day-ahead market prices (without re-dispatching cost) for the four countries in the two scenarios under different schemes. Prices are consumption volume weighted. In the BAU scenario, the full zonal solution shows that Poland has the lowest price among these four countries, mainly due to the low marginal generation costs of its coal and gas-fired generation. Therefore, Poland does not import power from the other three countries. In the hybrid pricing model, the average price within Poland increases after taking into consideration the physical constraints. Therefore, the power in the other three countries becomes comparatively cheaper (without considering re-dispatching cost). Poland in this case imports power from other countries.

Pricing Scheme	BAU			HIGH WIND		
	Zonal	Hybrid	Nodal	Zonal	Hybrid	Nodal
Czech Republic	50.89	50.30	48.13	48.25	48.08	49.34
Germany	50.89	51.03	52.67	48.25	48.08	49.15
Poland	49.76	52.49	52.11	48.88	50.45	49.95
Slovakia	50.89	50.30	48.51	48.25	48.08	48.43

* Nodal prices where applicable are consumption volume weighted

Table 3: Day-ahead prices (in € per MWh)

In the HIGH WIND scenario, market prices given by all the three pricing schemes generally decrease given the input of low-cost wind power. The full zonal pricing scheme gives similar prices for all the four countries (prices for Czech, Germany and Slovakia are identical), of which Poland has the highest price mainly because it restricts power exchange with other countries by setting a lower NTC value. In the hybrid pricing scheme, Poland again has the highest price mainly due to the consideration of network constraints. (The prices for the other three countries are lower without

counting the re-dispatching cost.) Moreover, the uniform pricing in the zonal-pricing areas makes it more difficult for Poland to identify low-cost power. For instance, power in North Germany should have been cheaper on a windy day and Poland could have imported the power, which does not happen due to the uniform pricing in Germany.

Pricing Scheme	BAU		HIGH WIND	
	Zonal	Hybrid	Zonal	Hybrid
Czech Republic	51.01	50.25	48.29	48.09
Germany	51.54	51.71	48.60	48.43
Poland	50.98	49.72	49.66	48.79
Slovakia	50.81	50.24	48.24	48.08

Table 4: Unit prices with re-dispatching cost and congestion rent (in € per MWh)

Compared to zonal pricing, hybrid pricing helps Poland reduce its cost for re-dispatching and collect a great amount of congestion rent. (This is discussed in Section 4.3 and 4.4 of the article.) Consumers in Poland could potentially benefit from this improvement. Table 4 gives the unit prices for both the zonal and hybrid pricing schemes after taking into consideration the re-dispatching cost and congestion rent (i.e., the prices include re-dispatching cost but deduct congestion rent). In both the BAU and HIGH WIND scenarios, the hybrid pricing solution reduces the unit prices for Poland.

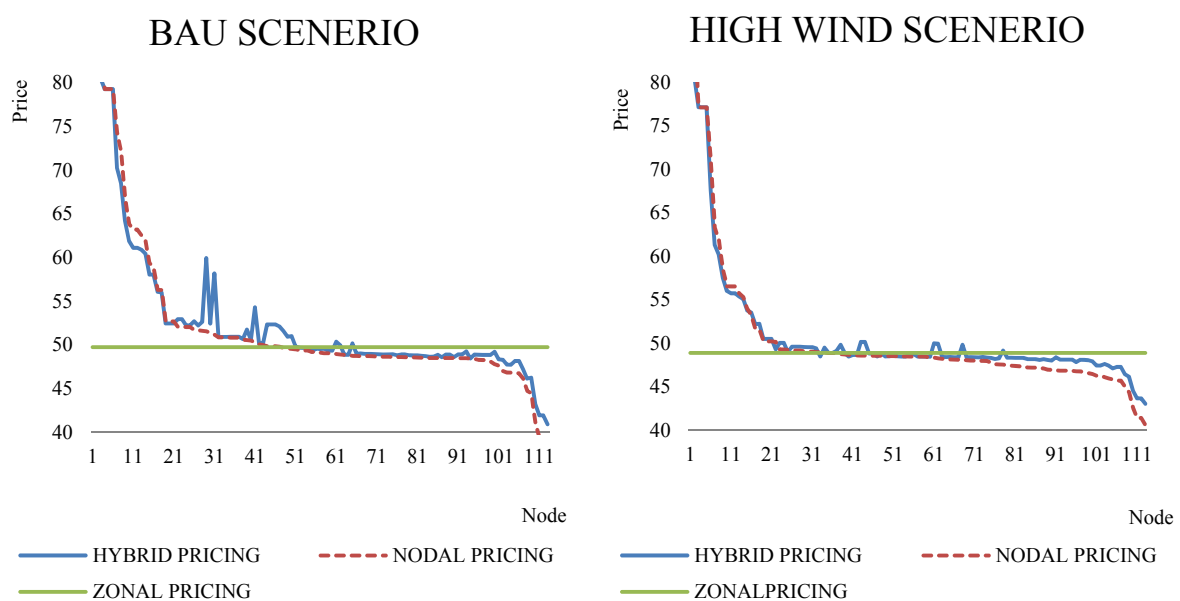


Figure 4: Day-ahead Price comparisons in Poland

We further assess the hybrid model by evaluating whether the prices in Poland could truly reflect the network congestion. We compare the prices in Poland given by the hybrid pricing scheme to those given by full nodal pricing scheme in Figure 4. We use t-tests to identify any statistically meaningful difference between the hybrid prices and the full nodal prices in both scenarios.¹³

In both the BAU and HIGH WIND scenarios, the hybrid prices fluctuate but generally match with the full nodal prices, indicating that hybrid prices in such a context are able to capture the congestion signals within the network. However, in both scenarios, the average hybrid prices are significantly higher than the average nodal prices.¹⁴ This indicates that hybrid pricing cannot fully utilize all the available resource in the network. The major reason is that the lack of price signals in the zonal pricing areas (i.e., uniform prices within Germany, Czech Republic, and Slovakia) prevents Poland from trading optimally both with respect to location and prices. For example, in the full nodal pricing solution of the BAU scenarios, prices in the southern part of Poland are lower than those in the northern part. This induces Polish export to the Czech Republic, which is further exported to serve the great demand for power in Southern Germany. In contrast, in the hybrid system, uniform prices are given for the inter-connected countries (i.e., Germany, Czech Republic, and Slovakia) and thus no price signals are received by Poland. As a result, compared to full nodal pricing, Poland exports more power to Germany and Slovakia but less power to Czech Republic (as shown in Figure 5). This increases the prices at nodes connected with Germany and Slovakia (as displayed in Table 3) within Poland. Because no transparent price signals are revealed within the Czech market, Poland does not export its power from the best inter-connected nodes indicated by full nodal pricing. Therefore, some inter-connected nodes experience higher prices (i.e., exporting more power) while others have lower prices (i.e., exporting less power) compared to the full nodal pricing solution.

Furthermore, the trading cap (i.e., NTC value) in the hybrid pricing scheme further restricts some optimal trades suggested in the full nodal pricing scheme. This is especially important in the HIGH WIND scenario, in which the input of wind power greatly reduces the prices in the full nodal scheme. The low NTC value restricts Poland from importing cheap power from Germany, leading to an even higher price differences compared to nodal pricing.

¹³ A t-test is any statistical hypothesis test in which the test statistic follows a Student's t distribution if the null hypothesis is supported. It can be used to determine if two sets of data are significantly different from each other.

¹⁴ The actual average hybrid prices should be even higher if re-dispatching cost is considered.

Hybrid prices are more variant in the BAU scenario than in the HIGH-WIND scenario. This is shown by the higher standard deviation of the price differences in Table 5, which means that the hybrid prices and nodal prices differ to a larger extent in the BAU scenario than in the HIGH-WIND scenario (i.e., the absolute value of the differences is higher). In the BAU scenario, Poland has more commercial trading with other countries and therefore is more likely to be affected by the zonal pricing area. In the HIGH-WIND scenario, Poland greatly limits its import from other countries and becomes a relatively more independent system, thus getting less affected by the zonal pricing area. This indicates that more frequent interactions with other zonal pricing areas will enlarge the price differences (in absolute value) between hybrid prices and nodal prices.

	BAU SCENERIO	HIGH WIND SCENERIO
Mean (Price differences)	0.36 €	0.47 €
Observed Number (Node)	113	113
Standard Deviation(Price differences)	1.98	1.09
T-statistic	1.94	4.58

Table 5: Price matches for nodal pricing and hybrid pricing in Poland

4.2 Power exchange

Figure 5 gives the commercial cross-border trading volumes in both the BAU and HIGH WIND scenarios for different pricing schemes.^{15,16} We find that international exchange would reduce in the HIGH WIND scenario; however, the hybrid pricing scheme has more international exchange than the full zonal pricing does. International power exchange is reduced in the HIGH WIND scenario because Germany, as the main importing country in the BAU scenario, produces wind power that satisfies its own load demand. Another reason leading to the low international power exchange is that Germany's uniform pricing system does not allow other countries to identify the cheap wind power. Therefore, countries, such as Poland, are not able to import as much power as indicated by the solution of the full nodal pricing scheme. For example, in the full nodal pricing scheme, Germany exports 623MW to Poland. In comparison, Germany exports 100 MW to Poland in the full zonal pricing scheme, and exports 200 MW to Poland in the hybrid pricing scheme. The zonal-pricing areas (e.g., Germany) therefore could hold their cheap energy in their own countries

¹⁵ Commercial flows given by the full nodal pricing solution are the same as the physical flows.

¹⁶ Solutions regarding the commercial trading among areas with identical price may not be unique. Congestion rent between such areas is always 0.

before they have transactions with the inter-connected countries, leading to a reduction in international power exchange. Besides, this indicates that Germany is using the Polish network to transport its power without paying corresponding congestion rent. (This is further discussed in the next section 4.3.)

We further find that the power exchange for Poland under hybrid pricing is affected by the zonal pricing areas. In the BAU scenario under the hybrid pricing scheme, Poland exports most of its available commercial trading amount and also imports 200MW from Germany to help relieve its grid congestion.¹⁷ This is because price signals indicate more congestion in the northern part of Poland and it would cost less for Poland to import than to produce the power. However, in the full nodal pricing, Poland does not import power from other countries in the day-ahead market.

Under the HIGH WIND scenario, great amount of wind generated power brings down the price in Germany, greatly reduces its power import, and creates an uncongested power market for Germany, Czech Republic, and Slovakia (i.e., identical market price for these three countries) in both the hybrid pricing scheme. The market prices for these three countries do not provide transparent signals for Poland. As a result, the interface node (nodes) in Poland with the least cost (i.e., lowest market price) trades with the zonal-pricing areas. In our case, power is traded in the Polish-German border. However, physical power exchange given by the full nodal pricing solution model indicate that no power flows should go directly from Poland to Germany. Flows should have first gone to Czech and finally enter the German jurisdiction.

4.3 Re-dispatching and unplanned physical flows

The physical power flow between two nodes follows the least loss path. As we assume no uncertainty regarding generation supply or load demand, power flows are feasible and re-dispatching is not needed in the full nodal pricing scheme. However, day-ahead markets that apply zonal pricing or hybrid pricing produce commercial power flows, which are not necessarily equal to actual physical power flows and might need re-dispatching in order to relieve grid congestion.

Table 6 and Table 7 give both the commercial power flows and physical power flows for the two scenarios. Physical power flows without re-dispatching are calculated based on the day-ahead

¹⁷ Poland has several nodes connecting with one country. As the prices vary within the Polish network, Poland could import power at some of the connected nodes while export power at other nodes.

market solution.¹⁸ Physical power flows might not be feasible. To ensure feasible power flow, re-dispatching is needed.

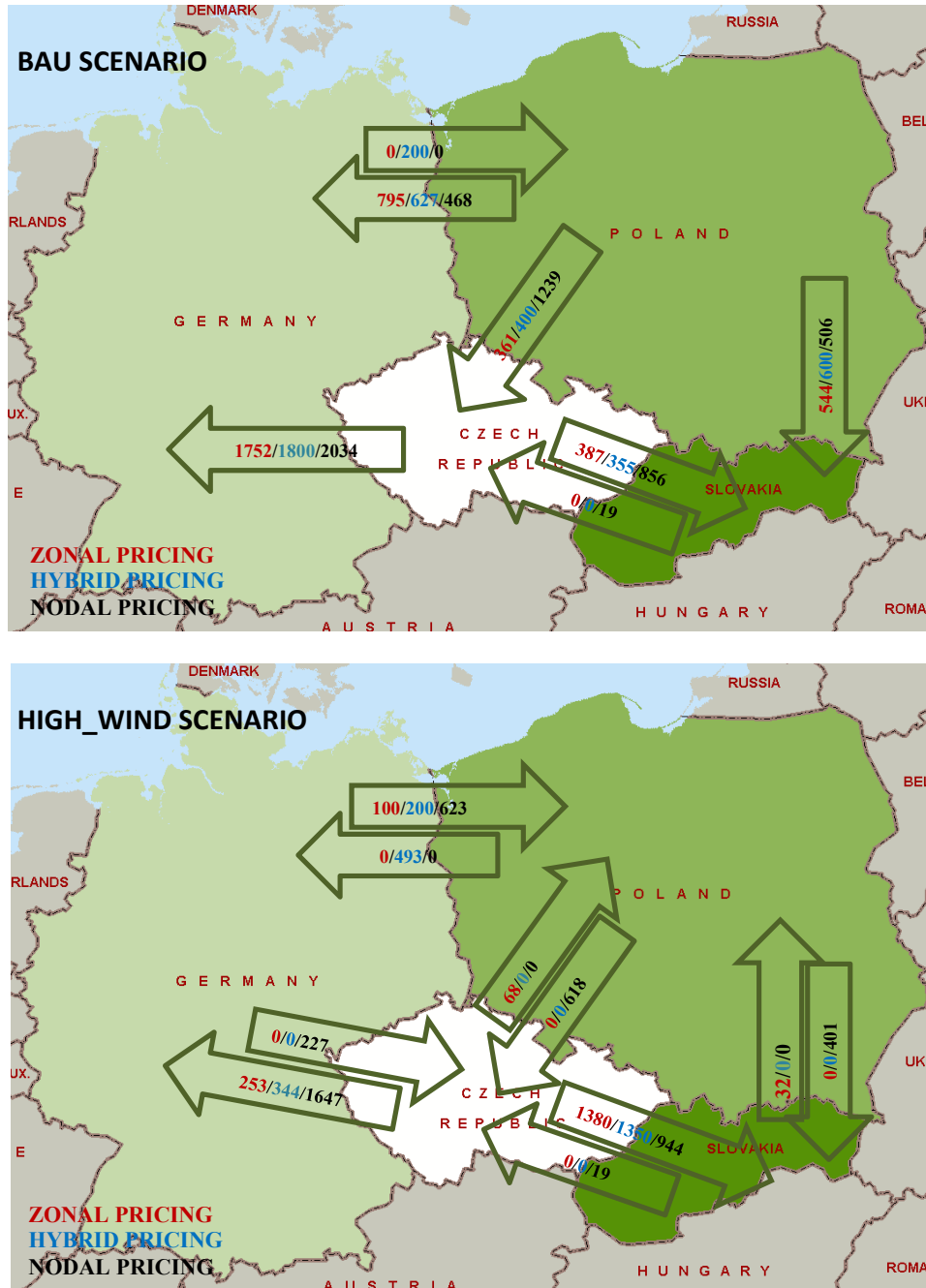


Figure 5: Cross-border commercial trades (in MW)

¹⁸ To calculate the physical power flows of the zonal and hybrid pricing solution, we fix the values of nodal load and generation. We use these values as inputs for a detailed network model to re-compute the final line flows. This network model takes loop flow into consideration, and minimizes the losses caused by dispatching, but does not consider thermal capacity constraints. Thus we obtain the power flows that will result from injections and withdrawals in the nodes given by the zonal and hybrid pricing solutions (Bjørndal et al. 2012).

In the BAU scenario, Poland, as the main exporting country, is only to a limited extent influenced by flows from other countries. Under both full zonal and hybrid pricing, the net physical power exchange between Poland and its neighboring countries is close to the net commercial power exchange: power flow is rearranged on the border.

Commercial Exchange (Day-ahead market)						Physical Power Exchange (without re-dispatching)						Physical Power Exchange (with re-dispatching)					
Zonal pricing						Zonal pricing						Zonal pricing					
To From	CZ	DE	PL	SK	SUM	To From	CZ	DE	PL	SK	SUM	To From	CZ	DE	PL	SK	SUM
CZ	-	1752	0	387	2139	CZ	-	2271	0	639	2910	CZ	-	2269	0	592	2861
DE	0	-	0	0	0	DE	0	-	0	0	0	DE	0	-	0	0	0
PL	361	795	-	544	1700	PL	1022	275	-	403	1700	PL	966	278	-	456	1700
SK	0	0	0	-	0	SK	110			-	110	SK	117	0	0	0	117
SUM	361	2547	0	931	3839	SUM	1132	2547	0	1041	4720	SUM	1083	2547	0	1048	4678
Hybrid Pricing						Hybrid Pricing						Hybrid Pricing					
To From	CZ	DE	PL	SK	SUM	To From	CZ	DE	PL	SK	SUM	To From	CZ	DE	PL	SK	SUM
CZ	-	1800	0	355	2155	CZ	-	2026	0	595	2621	CZ	-	2147	0	603	2750
DE	0	-	200	0	200	DE	0	-	0	0	0	DE	0	-	50	0	50
PL	400	627	-	600	1627	PL	784	201	-	442	1427	PL	895	131	-	451	1478
SK	0	0	0	-	0	SK	81	0	0	-	81	SK	100	0	0	-	100
SUM	400	2427	200	955	3983	SUM	865	2227	0	1036	4129	SUM	995	2278	50	1055	4378

Table 6: Cross-border Power flows in the BAU scenario (in MW)

In the HIGH WIND scenario, Poland in total imports 200 MW power from other countries in the day-ahead market given the full zonal pricing solution. However, the physical power flows entering the Polish network given by the day-ahead market and re-dispatching models are 1122 MW (922 MW of unplanned power flows) and 1342 MW (1142 MW of unplanned power flows) respectively. Thus, a low NTC in the zonal pricing solution does not prevent power flows from entering the Polish network. This large number of unplanned power flows indicates that other countries have utilized the Polish network to transport power, which might threaten the Polish network security. By applying the hybrid pricing model, Poland still imports in total 200 MW in the day-ahead market. However, Poland is able to export power and thus reduces the unplanned import power flows. Specifically, instead of importing from all the other three countries under full zonal pricing, hybrid pricing suggests that Poland should only import power from Germany (to relieve its grid congestion in the northern part) and export power in its southern part. Ideally, Poland should have exported power to Czech and Slovakia as the nodal pricing model indicates. Although Poland exports power

to Germany instead, this could still to a large degree prevents the Polish network from being occupied by the German wind power. As a result, the physical power flows entering the Polish network given by the day-ahead market and re-dispatching models are reduced to 730 MW (530 MW unplanned power flow) and 863 MW (663 MW unplanned power flow). That is, applying hybrid pricing could help Poland to reduce unplanned power flow entering its network by around 35%.

Cross-border Exchange (Day-ahead market)						Physical Power Exchange (without re-dispatching)						Physical Power Exchange (with re-dispatching)					
Zonal pricing						Zonal pricing						Zonal pricing					
To From	CZ	DE	PL	SK	SUM	To From	CZ	DE	PL	SK	SUM	To From	CZ	DE	PL	SK	SUM
CZ	-	253	68	1380	1700	CZ	-	1586	19	1189	2795	CZ	-	1837	0	894	2730
DE	0	-	100	0	100	DE	331	-	1103	0	1434	DE	342	-	1342	0	1684
PL	0	0	-	0	0	PL	763	0	-	158	922	PL	688	0	-	454	1142
SK	0	0	32	-	32	SK	0	0	0	-	0	SK	0	0	0	-	0
SUM	0	253	200	1380	1832	SUM	1094	1586	1122	1348	5150	SUM	1030	1837	1342	1348	5557
Hybrid Pricing						Hybrid Pricing						Hybrid Pricing					
To From	CZ	DE	PL	SK	SUM	To From	CZ	DE	PL	SK	SUM	To From	CZ	DE	PL	SK	SUM
CZ	-	344	0	1350	1694	CZ	-	1680	20	905	2605	CZ	-	1848	0	885	2733
DE	0	-	200	0	200	DE	333	-	710	0	1043	DE	348	-	863	0	1211
PL	0	493	-	0	493	PL	578	0	-	446	1023	PL	690	0	-	466	1156
SK	0	0	0	-	0	SK	0	0	0	-	0	SK	0	0	0	-	0
SUM	0	837	200	1350	2388	SUM	911	1680	730	1350	4671	SUM	1039	1848	863	1350	5100

Table 7: Cross-border Power flows in the HIGH WIND scenario (in MW)

Table 8 summarizes the re-dispatching cost given by the full zonal pricing and hybrid pricing schemes. As expected, Poland could greatly reduce its re-dispatching cost in the hybrid pricing model. Compared to the full zonal pricing scheme, re-dispatching costs for Poland have been reduced by 93% in the BAU scenario and 88% in the HIGH WIND scenario when Poland uses nodal pricing.

	BAU		HIGH WIND	
	ZONAL PRICING	HYBRID PRICING	ZONAL PRICING	HYBRID PRICING
CZ	1220	646	448	374
DE	43481	46609	24209	23537
PL	24346	1624	15061	1732
SK	0	0	0	0
SUM	69047	48879	39718	25642

Table 8: Re-dispatching Cost

4.4 Congestion rent

Changes in cross-border trades lead to the reassignment of congestion rent. In the full zonal pricing scheme, prices are uniform within each zone and therefore congestion rent is only collected for cross-border trades. In the hybrid pricing scheme, Poland could also collect congestion rent within its domestic market. Table 9 summarizes congestion rent for cross-border trades. We assume that the congestion rent resulting from cross-border commercial trading is equally shared by the two system operators. Table 10 gives the congestion rent collected by each country for their inter-zonal and intra-zonal trade.

In the full zonal pricing solution under the BAU scenario, price differences only exist between Poland and the other countries. Therefore, congestion rent is collected only in the Polish border. In the hybrid pricing solution, more congestion rent could be collected as more power has been transferred among the countries. In the hybrid pricing model, Poland exports less power to Germany, which increases the price in Germany and creates price differences between Germany and other countries. Because of this, Poland collects less cross-border congestion rent while the other countries collect more. However, Poland would collect a great amount of congestion rent within the domestic market when applying nodal pricing.

In the HIGH WIND scenario, because more power is traded in the hybrid pricing scheme, more congestion rent is collected than in the full zonal pricing solution. However, the total international congestion rent is greatly reduced compared to the BAU scenarios. Less international power exchange is the main contributor of the reduction in congestion rent. Prices outside the Polish network are the same in both the zonal pricing and hybrid pricing solutions. Therefore, congestion rent could only be collected in the Polish border.

BAU					HIGH WIND				
Zonal pricing					Zonal pricing				
To	CZ	DE	PL	SK	To	CZ	DE	PL	SK
From CZ	-	0	0	0	From CZ	-	0	43	0
From DE	0	-	0	0	From DE	0	-	64	0
From PL	411	905	-	620	From PL	0	0	-	0
From SK	0	0	0	-	From SK	0	0	20	-

Hybrid Pricing					Hybrid Pricing				
To	CZ	DE	PL	SK	To	CZ	DE	PL	SK
From CZ	-	1314	0	0	From CZ	-	0	0	0
From DE	0	-	284	0	From DE	0	-	346	0
From PL	737	0	-	430	From PL	0	0	-	0
From SK	0	0	0	-	From SK	0	0	0	-

Table 9: Cross-border congestion rent (in €)

BAU					HIGH WIND				
	ZONAL PRICING		HYBRID PRICING			ZONAL PRICING		HYBRID PRICING	
	Inter-zonal	Intra-zonal	Inter-zonal	Intra-zonal		Inter-zonal	Intra-zonal	Inter-zonal	Intra-zonal
CZ	205	×	1025	×	CZ	22	×	0	×
DE	452	×	799	×	DE	32	×	173	×
PL	968	×	725	53062	PL	64	×	173	33123
SK	310	×	215	×	SK	10	×	0	×

Note: Revenues from cross-border commercial trading are equally shared by the two system operators

Table 10: Congestion rent collected by each country (in €)

4.5 Supply and demand adjustment

The re-dispatching models allow the options to curtail the nodal load, solar and wind generation in order to ensure a feasible solution.¹⁹ There is no need for curtailment of solar and wind generation for any of the studied cases (i.e., Table 11). Load curtailments happen in all the studied cases. Hybrid pricing yields a lower load curtailment than zonal pricing does. In the full zonal pricing schemes, Germany and Poland are the only two countries (i.e., Table 12) that face load shedding. Poland does not need to curtail its load in the hybrid pricing scheme.

¹⁹ The load, wind and solar shedding costs are assumed to be 500 €/MWh (higher than any other marginal cost of electricity production).

	BAU		HIGH WIND	
	ZONAL PRICING	HYBRID PRICING	ZONAL PRICING	HYBRID PRICING
Load Shedding	107.92	28.71	82.62	14.75
Solar Curtailment	×	×	×	×
Wind Curtailment	×	×	×	×

Table 11: Curtailment for different pricing schemes (in MW)

	BAU		HIGH WIND	
	ZONAL PRICING	HYBRID PRICING	ZONAL PRICING	HYBRID PRICING
CZ	×	×	×	×
DE	YES	YES	YES	YES
PL	YES	×	YES	×
SK	×	×	×	×

Table 12: Load shedding countries

5. Conclusion

This paper attempts to investigate how efficiently the hybrid pricing scheme works in a coupled European power market as more wind-generated power enters the grid. This paper applies a pricing model with two types of congestion management methods. Four countries Czech Republic, Germany, Poland, and Slovakia are involved in the research, of which Poland applies nodal pricing. We construct two different wind levels (i.e., BAU and HIGH WIND) to test how nodal pricing performs in different perspectives.

We find that countries that are greatly affected by neighboring wind-generated power, such as Poland, would benefit from applying nodal pricing to address its network congestion. In the HIGH WIND scenario, international power exchange has been greatly reduced in the full zonal pricing as wind-generated power satisfies a significant portion of the demand within German market. However, the real (physical) power exchange does not accordingly reduce due to the physical characteristics of power transmission. Therefore, a large amount of unscheduled power flow enters the Polish power grid. Though transparent price signals are missing in Polish neighbor countries, nodal pricing helps Poland to identify resource scarcity within its domestic market. Poland has more demand in its northern part while cheaper resources in its southern part. Therefore, Poland

could import power in its northern part but export power in its southern part in the nodal pricing scheme. This helps Poland to reduce the unplanned power flows from Germany.

We also find that using nodal pricing, Poland would reduce its need for re-dispatching and collect a great amount of congestion rent. The Polish consumers might benefit from applying the nodal pricing scheme. Taking the re-dispatching cost and congestion rent into account, the average unit price given by the hybrid pricing solution decreases compared to the zonal pricing solution. We also find that nodal pricing would reduce the need for load curtailment.

Another interesting result is that in countries with a great amount of wind-generated power, such as Germany, they will benefit from keeping zonal pricing. In such a way, Germany would be able to keep the low-cost energy within their countries. Furthermore, they could transmit the power using their neighboring grid without paying corresponding congestion rent.

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Appendix

Determination of prohibitive price and slope using reference price and demand

The model assumes a linear inverse electricity demand function of the form:

$$p_n(Q_n) = a_n + m_n * Q_n$$

$$\text{Demand function: } Q_n(p_n) = -\frac{a_n}{m_n} + \frac{1}{m_n} * p_n$$

Definition of elasticity: $\varepsilon = \frac{\partial Q_n}{\partial p_n} * \frac{p_n}{Q_n}$ (The elasticity is assumed to be -0.25 in the model.)

$$\varepsilon = \frac{1}{m_n} * \frac{p_n}{Q_n}$$

Determination of prohibitive price and slope using reference price and demand:

$$m_n = \frac{p^{ref}}{d^{ref}} * \frac{1}{\varepsilon}, a_n = p^{ref} - m_n * Q_n^{ref}$$

	load (MW)	Ref. Price (Euro)
CZ	8636	57.01
DE	64421	62.01
PL	19499	48.68
SK	3692	57.01

Table AI :Electricity load and reference prices for the four countries on 13.02.2013²⁰

²⁰ Hourly day-ahead prices for Germany are available from the European Power Exchange Spot. For Poland the day-ahead price is calculated from as the quantity-weighted mean value of three auction prices provided by the Polish Power Exchange.