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Evaluating the impacts of priority dispatch in the European electricity market

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ABSTRACT

This paper compares the impact of the Nodal Pricing and European Market Coupling organizations on different economic agents of the power system under two main wind policies. Under the "priority dispatch" policy, Transmission System Operators (TSOs) must accommodate all wind energy produced, which thus has the priority over energy produced by conventional plants; in the "no priority dispatch" policy, TSOs can decide not to inject all potential wind power in the grid in order to limit congestion problems. The effects of these two wind policies are measured by developing simple stochastic programming models that consider cases with different wind penetration levels, existing capacities and endogenous investments, as well as assumptions on the EU-ETS.

Our computational experiments show that, when there is "priority dispatch", Nodal Pricing and Market Coupling evolve in a similar way as long as wind penetration is not too high. In contrast, a significant increase of wind penetration causes the collapse of the Market Coupling organization while Nodal Pricing continues to perform well. On the other hand, "no priority dispatch" removes most of the problems resulting from Market Coupling, which still exhibits a slightly lower efficiency than Nodal Pricing. These outcomes do not depend on the contextual assumptions (fixed capacities vs. investment; EU-ETS vs. non EU-ETS) that characterize the several cases analyzed. This suggests that our policy conclusions are robust. Furthermore, our models overestimate the flexibility of conventional plants, which means that these conclusions would likely be reinforced with a more detailed model.

1. Introduction

The development of renewable energy is a key element of European climate policy. A first objective is a 20% penetration of renewable energy by the year 2020 (European Commission, 2009a). A follow up target is an almost full decarbonization of the power system in 2050 (European Commission, 2011a, 2011b). This development takes place in a complex set of policies that involve the restructuring of the gas and power sectors (European Commission, 2009b, 2009c), the Emissions Trading System (EU-ETS) (European Commission, 2009d) and energy conservation (European Commission, 2011c). It is now well accepted that a high penetration of wind generation poses long and short-term problems for the restructured power sector (IEC, 2012). This paper deals with a short-term question at the intersection of the renewable and restructuring policies: we concentrate on some of the grid problems raised by the introduction of intermittent sources in a restructured electricity market organized using the Market Coupling regime that is now emerging as the reference mechanism for managing transmission among European countries.

The problem can be stated as follows. Wind speed and hence wind generation cannot be forecast more than a few hours before actual generation (four hours) (see Foley et al., 2012 for a recent survey). The wholesale electricity market clears a day ahead, that is, much before wind speed is known with any degree of certainty.[1] Real time electricity injections in the grid can drastically differ from those forecasted a day ahead. This may pose grid management difficulties: even though the estimated flows resulting from the clearing of the day-ahead market are normally feasible for the grid,[2] real-time flows can violate grid constraints with extreme deviations from forecasted wind generation. The Transmission System

[1] An intraday market would mitigate this problem. One is currently in the design phase as stated in ENTSO-E/Europex (2012) and Gence-Creux (2012) contributions on intraday. This market will be built on the new "Flow Based Market Coupling" that has been delayed for several years (see also Gence-Creux's contribution on the matter). It is thus difficult to foresee what the efficiency of that system will be, since experience of the EU power restructuring has in general encountered unexpected difficulties. We accordingly do not include the intraday market in this work.

[2] We explain in Oggioni and Smeers (2013) that TSOs restrict announced "Available Transmission Capacities (or ATCs)" in order to avoid as much as possible countertrading. This policy, which is sustainable in a system with few countries and little wind, becomes more complicated with the multiplication of large zones and wind penetration.

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Operators (TSOs) must then restore feasibility by re-dispatching operations (known as counter-trading). Past experiences with the discontinued zonal system in the US, even with comparatively lower wind penetration (e.g. ERCOT), have shown that counter-trading may be very expensive and even sometimes impossible when discrepancies between day-ahead and real-time injections are too large. Needless to say, larger wind penetration increases the possibility of greater discrepancies between the day-ahead and real-time injections; this in turn requires more counter-trading operations and increases costs. We study the impact of these possible discrepancies in this paper.

Real-time injections result from the dispatch of power generators, including wind generation. Which plants operate depends on the extent to which wind potential exists and is turned into energy. Because wind power is essentially free after the installation of the generation capacity, it may seem natural to use whatever wind energy is available at any moment of time, even if this implies counter-trading. Alternatively, one can allow TSOs to curtail wind generation to decrease expensive counter-trading. We refer to the policy that requires TSOs to accommodate all potential wind generated power as the "priority dispatch" policy. Alternatively, allowing TSOs to reduce wind generation (and hence to spill some potential wind energy) is referred to as the "no priority dispatch" policy. The literature contains many papers modeling the possibility of wind spillage (see, e.g., Morales et al., 2011, 2012) but to the best of our knowledge none of these analyze its impacts on the efficiency of different market organizations. Our paper addresses the question of the viability of "priority dispatch" and "no priority dispatch" policies in Market Coupling and, if viable, which one is preferable from an economic point of view.

We study this question by simulating these two wind priority policies on a stylized representation of part of the European power system. In order to emphasize the role of the market architecture (here Market Coupling), we compare the outcomes of the "priority dispatch" and of "no priority dispatch" policies in Market Coupling with a Nodal Pricing regime. Our models of these systems are highly stylized but they capture two of the essential differences in these market designs. First, the definition of the spot market is different: it takes place in real time in the nodal system but in the day ahead in Market Coupling. The second difference is in the spatial granularity of the grid: the market is cleared at each physical node in the nodal system, using a full description of the grid. It is cleared in virtual nodes or zones in Market Coupling, using a simplified representation of the grid that results from clustering nodes into zones.

Nodal Pricing and Market Coupling thus have different capabilities for accommodating unpredictable wind energy. The objective of the comparison of the "priority dispatch" and "no priority dispatch" policies through numerical experiments is twofold: on one side, we numerically quantify the gain achieved by the switch from the "priority dispatch" to the "no priority dispatch" policy in Nodal Pricing; on the other side, we explore whether the same switch also benefits Market Coupling. In order to assess these potential gains, we analyze different cases using these two market designs. Specifically, we consider four different levels of wind penetration. Because model results always depend on assumptions, we verify the robustness of our results by examining different "contextual cases". We first consider the alternatives of keeping conventional generation capacities fixed versus allowing for new investment. Because of the importance of carbon policy and the questions that it raises today in European policy, we also consider the alternative system with and without EU-ETS. We conclude that the results of our analysis of the "priority dispatch" and "no priority dispatch" policies on "Nodal Pricing" and "Market Coupling" are robust with respect to these assumptions.

The paper is organized as follows. Section 2 gives a brief introduction to the model and explains major simplifications made with respect to real systems. Sections 3 and 4 respectively present the Nodal Pricing and Market Coupling models developed under the assumptions indicated above. Section 5 contains the case study and the corresponding results for Nodal Pricing and Market Coupling are explained respectively in Sections 6 and 7. Section 8 provides further insight into our analysis. Finally, Section 9 is devoted to conclusions and final comments. Additional model information and results are reported in Appendices.

2. Assumptions and modeling principles

Our analysis compares the performance of two market designs in the presence of wind penetration. The models make important simplifications with respect to reality but retain some of the main differences between the Nodal and Market Coupling organizations. The full set of notation and equations are given in Sections 3 and 4.

We consider a spatial power grid consisting of generation and demand nodes connected by transmission lines. Electricity can be generated using different technologies characterized by capacity and operating costs and CO_2 emissions. The price of emission allowances is exogenous. Capacities can be exogenous or endogenous depending on the case; when endogenous, the model includes the investment costs associated with the amount and type of capacity. We do not model investment in wind generation beyond specifying the wind capacity. Wind injections are exogenous in every case but depend on the installed capacity and wind availability. The models are static and cover a period of one day decomposed into twenty-four hourly segments on which we build different wind scenarios (see Appendix D) and run dispatch models. Investment costs, when relevant, are converted to daily values (annualized costs divided by 365).

This neglects important phenomena related to unit commitment and equipment dynamics (conventional and wind), which become crucial with wind penetration. We return later to the unit-commitment issue and briefly discuss how our simplification can be overcome at the cost of additional and sometimes non-standard computations.

The dispatch models are formulated as welfare maximization problems (computed over twenty-four successive hours) using exogenously given inverted demand and cost functions. The grid is modeled using standard Power Transfer Distribution Factor (PTDF) coefficients (DC approximation of Kirchhoff's laws[3]). Real systems contain security criteria such as N-k reliability, where the system with N components can operate with k contingencies occurring. We neglect these security issues throughout and simply assume a single configuration of the network in all our computations.

Two representations of the grid affect the equilibria. The clearing of the nodal market and counter-trading operations are performed on the (assumed) true representation of the grid. The clearing of the day-ahead market in Market Coupling is conducted on a zonal representation of the grid that is based on an aggregation of nodes and lines. We use expected wind injection in the day-ahead market cleared by Power Exchanges (PXs) with Market Coupling. The nodal-pricing market clears in real time using actual wind injections. Counter-trading is also conducted by TSOs in real time using actual wind injections.

Our models contain considerable simplifications with respect to real systems as we discuss in the next subsections. Specifically, we overestimate the flexibility of conventional plants by not including start-up and shut-down costs, which makes it easier to accommodate wind fluctuation. A more realistic representation of the system would reinforce our conclusions.

2.1. Implications for the Nodal Pricing system

2.1.1. Two settlement system

In contrast with our single, real-time model, nodal markets are organized as two settlement systems (see Stoft, 2002 for a textbook discussion and ISO web sites, e.g. PJM, 2013). The day-ahead market is an auction that commits the units and clears a forward energy market. The real-time market is also organized as an auction but clears energy

[3] See Appendices A.1 and A.2 respectively for Kirchhoff's laws and PTDF functioning.

on an hourly basis, possibly after revising the commitment (see Stoft, 2002).[4] The two settlements are of particular importance in thermal systems, as the limited flexibility of the plants prevents an instantaneous adjustment to fast-changing and difficult-to-forecast events (such as wind generation) and hence requires some ex ante action. Our assumption of a single static dispatch model with fully flexible equipment bypasses the need for a two settlement system but is obviously an important simplification. It is possible to partially overcome this approximation by considering a two settlement system modeled as a single two-stage stochastic program, as stated in Pritchard et al. (2010). An alternative is to use stochastic unit commitment models that are currently a subject of intense research (see Papavasiliou and Oren, 2013; van der Weijde and Hobbs, 2011). Both of these remedies are only partial, as there is no universally accepted standard for representing the two settlement system.

2.1.2. System representation

Nodal markets whether day ahead or real time clear on a nodal basis defined by the granularity of the physical grid. Given that we do not represent grid security, we need only a single topology of the grid. Real systems embed a representation of security constraints. It is a standard matter (even though possibly computationally demanding) to embed N-k security constraints in dispatch or unit commitment models.

In contrast with these two simplifications that can be overcome at the cost of additional computation, the inclusion in our model of markets for other ancillary services (such as reserves) would require a change of paradigm. This would also cloud the comparison between the Nodal Pricing and Market Coupling market organizations, as the latter does not have markets for these services, or else organizes them in a very different way.

2.2. Implications for the Market Coupling organization

2.2.1. Two settlement system

Market Coupling has become the paradigm of the European power system. Today it is organized as a single settlement system where the energy market clears one day ahead using forecasts. Deviations between the planned transactions and real-time actions are settled through a regulated balancing mechanism which is not meant to be a real-time market. Intraday markets exist in most European countries but, as stated in ENTSO-E/Europex (2012) and Gence-Creux (2012), remain largely in development. Unit commitment constraints are directly included in so called block orders submitted together with more conventional orders in the day-ahead market (see Djabali et al., 2011 that describes the COSMOS algorithm used for organizing Market Coupling in "Central West Europe"). As in the nodal organization, our use of a continuous optimal dispatch model introduces a considerable simplification by assuming flexible power plants. In contrast with the nodal system, it would not be a standard matter to remove these simplifications and to treat machine inflexibility as is done in the COSMOS model of Market Coupling.[5]

2.2.2. System representation

Market Coupling clears energy one day ahead on the basis of a zonal representation of the grid. Its current implementation is based on a so called "Available Transmission Capacity (ATC)" model of the grid and should be replaced eventually by a "Flow-Based" model that is a first and second law representation of an aggregate grid (see the reference lists of Oggioni and Smeers, 2012, 2013; Oggioni et al., 2012, for studies that use the flow based system in the day-ahead market). These notions have been extensively discussed in the European literature of the electricity market. We adopt the ATC model for the clearing of the day-ahead market, because the notion of available transmission capacity is well known and the model is the one currently in use. The "Flow-Based" model is an idiosyncratic construction of the European internal electricity market that is not yet operational; invoking that model in this paper would unnecessarily complicate the discussion (see Appendix B for more details). A remaining problem is the construction of the simplified, aggregate network used for clearing the day-ahead market. There is no exact algorithm for doing so. TSOs have so far not published their heuristic method of network aggregation which means that our work is based on our own interpretation of this aggregation.

Network simplifications in the day-ahead market and differences between wind forecasts and real-time realizations imply that TSOs periodically have to intervene through counter-trading to restore the feasibility of real-time flows in the grid. This requires a second dispatch model that uses a full representation of the grid, that is, the one used in the nodal system. Because cross border counter-trading is still in evolution in Europe, we do not try to model a particular situation (as that model would be idiosyncratic anyway) but adopt an ideal view of the market based on first principles. Specifically, we assume a single PX clearing the day-ahead market and a single TSO (this is a surrogate for full cooperation, which is one of the stated objectives in the EU) conducting counter-trading at minimal global cost on the zone covered by the model. This assumption can be interpreted either as representing a TSO with perfect knowledge of cost and demand (which is a common assumption in computable models) or as a perfectly competitive market both in day ahead and counter-trading. The first interpretation should better be described as optimal re-dispatch, while counter-trading is well suited for the second interpretation. We simplify the presentation by only referring to counter-trading.

3. Nodal Pricing models

This section presents the Nodal Pricing models. This market organization is not implemented in Europe but we still take it as the benchmark because of its properties of economic efficiency. The following introduces relevant notation and the optimization models representing the different assumptions on wind priority policies, investments and emissions regulations.

3.1. Notation

Sets

- $n \in N$: Set of nodes;
- $p \in P$: Set of technologies;
- $l \in L$: Set of flowgates (or lines) of the transmission grid;
- $s \in S$: Set of scenarios considered;
- $h \in H$: Set of hours.

Parameters

- $G_{p,n}$: Hourly capacity of plant type p in node n (MWh);
- $cost_{s,p,n}$: Hourly variable costs of an existing unit p in node n (€/MWh);
- $costinv_{p,n}$: Hourly variable costs of a new unit p in node n (€/MWh);
- $Icost^{h}_{p,n}$: Hourly fixed costs of a new unit p in node n (€/MWh);
- em_p: Emission factor associated to technology p (ton/MWh);
- CO_2price: Allowance price (€/ton);
- $wind^{h}_{s,n}$: Hourly h real wind power produced at node n in each scenario s (MWh);
- $increase^{h}_{s,n}$: Hourly h increase in wind power production at node n in each scenario s (%);
- τ_s: Probability associated to each scenario s (%);
- a^{h}_{n}: Intercept of consumers' affine demand functions at node n in hour h (€/MWh);

[4] Forward transactions are settled at the forward price and deviations between the forward and real-time transactions are settled at the real-time price. Virtual bidding (see Celebi et al., 2010 and ISO web sites, e.g. PJM, 2013) takes place between the day-ahead market and the real-time market and allows for arbitrage between the two.

[5] Machine inflexibility is represented by constraints that can be modeled by standard mixed integer programming formulations and hence treated by commercially available codes; in contrast COSMOS is an idiosyncratic product specifically designed for Market Coupling.

- b_n^h: Slope of consumers' affine demand functions at zone i in hour h (€/MWh^2);
- $PTDF_{l,n}$: Power Transfer Distribution Factor matrix of node n on line l;
- L_l: Hourly limit of flow through line l (MWh).

Variables

- $g_{p,n}^h$: Power generated in hour h by existing unit p in node n (MWh);
- $ginv_{p,n}^h$: Power generated in hour h by new unit p in node n (MWh);
- $I_{p,n}$: Capacity in hour h of new plant type p at node i (MWh);
- d_n^h: Power consumption in hour h by consumers located in node n (MWh);
- $P_n^h(d_n^h)$: Inverse demand function in hour h at node n. This function can be stated as $P_n^h(d_n^h) = a_n^h - b_n^h \cdot d_n^h$;
- p_n^h: Electricity price in hour h at node n (€/MWh);
- $windused_{s,n}^h$: Wind power used in hour h at node n in each scenario s under the "**no priority dispatch**" policy (MWh);
- $windloss_{s,n}^h$: Wind power spilled in hour h at node n in each scenario s under the "**no priority dispatch**" policy (MWh);
- $\varphi_{p,n}^h$: Marginal value (scarcity rent) in hour h of technology capacity p in node h (€/MWh);
- $phub^h$: Electricity price in hour h at the hub (€/MWh);
- $\lambda_l^{h,+,-}$: Congestion rent of line l; depending on flow direction (+,−) (€/MWh).

3.2. Nodal Pricing models without investments

We first present the models without investments in new generation capacity for which we consider the following cases:

- **Case 1**: No Wind, no EU-ETS
- **Case 2**: No Wind, EU-ETS
- **Case 3**: Wind, priority dispatch, no EU-ETS
- **Case 4**: Wind, priority dispatch, EU-ETS
- **Case 5**: Wind, no priority dispatch, no EU-ETS
- **Case 6**: Wind, no priority dispatch, EU-ETS

These cases cover different assumptions on wind penetration ("No Wind" and "Wind") and wind policies ("priority dispatch" and "no priority dispatch") that we compound with EU-ETS assumptions ("no EU-ETS" and "EU-ETS"). Note that the "priority dispatch" policy requires the system operator to accommodate all wind generation. This effectively corresponds to giving renewable generation a priority dispatch and forcing conventional plants to adapt to it.

We first introduce a "base case" model without wind penetration ("No Wind" model), that is then modified to account for different levels of wind penetration and the EU-ETS regulation.

3.2.1. Nodal Pricing model without investments: "No Wind"

The ISO maximizes social welfare over twenty-four hours and over all nodes (1) by taking into account generation (2) and transmission capacity (3) constraints. The clearing of the energy market is ensured by condition (4). Electricity generated ($g_{n,p}^h$) and demanded (d_n^h) are non-negative variables (5).

$$\textbf{Max} \quad \sum_{h,n}\int_0^{d_n^h} P_n^h(\xi)d\xi - \sum_{h,p,n} cost_{p,n}\cdot g_{p,n}^h - CO_2price\cdot\sum_{h,p,n} em_p\cdot g_{p,n}^h \tag{1}$$
s.t.

$$G_{p,n} - g_{p,n}^h \geq 0 \qquad \left(\varphi_{p,n}^h\right) \quad \forall h,p,n \tag{2}$$

$$-L_l \leq \sum_n PTDF_{l,n}\cdot\left(\sum_p g_{p,n}^h - d_n^h\right) \leq L_l \qquad \left(\lambda_l^{h,\pm}\right) \quad \forall h,l \tag{3}$$

$$\sum_{p,n} g_{p,n}^h - \sum_n d_n^h = 0 \quad \left(phub^h\right) \quad \forall h \tag{4}$$

$$g_{p,n}^h; \quad d_n^h \geq 0 \quad \forall h,p,n; \quad \forall h,n \tag{5}$$

The objective function in Eq. (1) is the difference between the consumers' willingness to pay ($\sum_{h,n}\int_0^{d_n^h} P_n^h(\xi)d\xi$) and the variable costs incurred by generators. These are the fuel ($\sum_{h,p,n} cost_{p,n}\cdot g_{p,n}^h$) and the emission ($CO_2price\cdot\sum_{h,p,n} em_p\cdot g_{p,n}^h$) costs. Note that emission costs are zero in "Case 1" with no EU-ETS ($CO_2price = 0$ and $CO_2price > 0$ respectively in "Case 1" and "Case 2".)

3.2.2. Nodal Pricing model without investments: "Wind"

We modify the Nodal Pricing model in Eqs. (1)–(5) by inserting wind power and obtain the model in Eqs. (6)–(11) that summarizes the four "Wind" cases listed above. These are obtained by changing the value attributed to some variables and parameters as we now explain. Total wind potential is identified by the parameter $wind_{s,n}^h$ that depends on node n, hour h and scenario s. Multiplying $wind_{s,n}^h$ by the parameter $increase_{s,n}^h$ identifies the potential for a particular assumption of wind penetration.[6] Wind penetration requires a "wind balance constraint" (8) imposing that the wind potential under consideration ($wind_{s,n}^h\cdot increase_{s,n}^h$) equals the wind generation ($windused_{s,n}^h$) plus the unused wind potential ($windloss_{s,n}^h$). In the "priority dispatch" policy ("Case 3" and "Case 4"), $windloss_{s,n}^h$ is zero and $windused_{s,n}^h$ is exactly equal to the wind potential. In the "no priority dispatch" policy ("Case 5" and "Case 6"), $windloss_{s,n}^h$ may be positive and $windused_{s,n}^h$ is then lower than the wind potential.

Wind power production affects both transmission and energy balance constraints. Starting from Eqs. (3) and (4), we obtain constraints in Eqs. (9) and (10) by inserting variables $windused_{s,n}^h$. As indicated above, these variables are either equal or lower to the potential wind depending on the wind priority policy.

Because of the uncertainty associated with wind energy production, social welfare (6) is computed as the expected value over all wind scenarios taking into account the parameter τ_s defining the probability attributed to each of these scenarios s. It is stated as follows:

$$\textbf{Max} \quad \sum_s \tau_s\cdot\left(\sum_{h,n}\int_0^{d_{s,n}^h} P_n^h(\xi)d\xi - \sum_{h,p,n} cost_{p,n}\cdot g_{s,p,n}^h - CO_2price\cdot\sum_{h,p,n} em_p\cdot g_{s,p,n}^h\right) \tag{6}$$
s.t.

$$G_{p,n} - g_{s,p,n}^h \geq 0 \qquad \left(\varphi_{s,p,n}^h\right) \quad \forall h,s,p,n \tag{7}$$

$$wind_{s,n}^h\cdot increase_{s,n}^h = windused_{s,n}^h + windloss_{s,n}^h \quad \left(\beta_{s,n}^h\right) \quad \forall h,s,n \tag{8}$$

$$-L_l \leq \sum_n PTDF_{l,n}\cdot\left(\sum_p g_{s,p,n}^h + windused_{s,n}^h - d_{s,n}^h\right) \leq L_l \quad \left(\lambda_{s,l}^{h,\pm}\right) \quad \forall h,s,l \tag{9}$$

$$\sum_{p,n} g_{s,p,n}^h + \sum_n windused_{s,n}^h - \sum_n d_{s,n}^h = 0 \quad \left(phub_s^h\right) \quad \forall h,s \tag{10}$$

$$g_{s,p,n}^h; \quad d_{s,n}^h \geq 0 \quad \forall h,s,p,n; \quad \forall h,s,n. \tag{11}$$

3.3. Nodal Pricing models with investments

The cases presented in Section 3.2 are adapted here for accounting of investments in generation capacity.

[6] The parameter $increase_{s,n}^h$ could be $=0$, $=1$ and >1. If $increase_{s,n}^h = 0$, model in Eqs. (6)–(11) becomes equivalent to model in Eqs. (1)–(5) with no wind penetration; $increase_{s,n}^h = 1$ implies a certain level of wind penetration that is increased by imposing $increase_{s,n}^h > 1$.

3.3.1. Nodal Pricing model with investments: "No Wind"

The introduction of investment requires the following changes in the model of Section 3.2.1. First, the objective function in Eq. (1) is transformed into Eq. (12) that now includes the variable ($\sum_{h,p,n} costinv_{p,n} \cdot ginv^h_{p,n}$) and fixed ($\sum_{h,p,n} Icost^h_{p,n} \cdot I_{p,n}$) costs of new power plants. CO_2 emission costs now include those of new capacities through the variable $ginv^h_{p,n}$.

$$\textbf{Max} \sum_{h,n} \int_0^{d^h_n} P^h_n(\xi) d\xi - \sum_{h,p,n} cost_{p,n} \cdot g^h_{p,n} + \\ -\sum_{h,p,n} costinv_{p,n} \cdot ginv^h_{p,n} - CO_2price \cdot \sum_{h,p,n} em_p \cdot \left(g^h_{p,n} + ginv^h_{p,n}\right) \\ -\sum_{h,p,n} Icost^h_{p,n} \cdot I_{p,n} \quad (12)$$
s.t.

$$G_{p,n} - g^h_{p,n} \geq 0 \qquad \left(\varphi^h_{p,n}\right) \quad \forall h,p,n \quad (13)$$

$$I_{p,n} - ginv^h_{p,n} \geq 0 \qquad \left(\varphi inv^h_{p,n}\right) \quad \forall h,p,n \quad (14)$$

$$-L_l \leq \sum_n PTDF_{l,n} \cdot \left(\sum_p \left(g^h_{p,n} + ginv^h_{p,n}\right) - d^h_n \right) \leq L_l \qquad \left(\lambda^{h,\pm}_l\right) \ \forall h,l \quad (15)$$

$$\sum_{p,n} g^h_{p,n} + \sum_{p,n} ginv^h_{p,n} - \sum_n d^h_n = 0 \quad \left(phub^h\right) \quad \forall h \quad (16)$$

$$g^h_{p,n}, ginv^h_{p,n}; \quad I_{p,n}; \quad d^h_n \geq 0 \quad \forall h,p,n; \quad \forall p,n; \quad \forall h,n \quad (17)$$

New plant generation $ginv^h_{p,n}$ also affects transmission in Eq. (15) and energy balance in Eq. (16) and requires a new capacity constraint in Eq. (14).

3.3.2. Nodal Pricing model with investments: "Wind"

The modeling of wind penetration follows the same reasoning already explained in Section 3.2.2 for the "Wind" cases without investments. The Nodal Pricing model is as follows:

$$\textbf{Max} \sum_s \tau_s \cdot \left(\sum_{h,n} \int_0^{d^h_{s,n}} P^h_n(\xi) d\xi - \sum_{h,p,n} cost_{p,n} \cdot g^h_{s,p,n} - \sum_{h,p,n} costinv_{p,n} \cdot ginv^h_{s,p,n} + \\ -CO_2price \cdot \sum_{h,p,n} em_p \cdot \left(g^h_{s,p,n} + ginv^h_{s,p,n}\right) \right) - \sum_{h,p,n} Icost^h_{p,n} \cdot I_{p,n} \quad (18)$$
s.t.

$$G_{p,n} - g^h_{s,p,n} \geq 0 \qquad \left(\varphi^h_{s,p,n}\right) \quad \forall h,s,p,n \quad (19)$$

$$I_{p,n} - ginv^h_{s,p,n} \geq 0 \qquad \left(\varphi inv^h_{s,p,n}\right) \quad \forall h,s,p,n \quad (20)$$

$$wind^h_{s,n} \cdot increase^h_{s,n} = windused^h_{s,n} + windloss^h_{s,n} \quad \left(\beta^h_{s,n}\right) \quad \forall h,s,n \quad (21)$$

$$-L_l \leq \sum_n PTDF_{l,n} \cdot \left(\sum_p \left(g^h_{s,p,n} + ginv^h_{s,p,n}\right) + windused^h_{s,n} - d^h_{s,n} \right) \leq L_l \quad \left(\lambda^{h,\pm}_{s,l}\right) \quad \forall h,s,l \quad (22)$$

$$\sum_{p,n} g^h_{s,p,n} + \sum_{p,n} ginv^h_{s,p,n} + \sum_n windused^h_{s,n} - \sum_n d^h_{s,n} = 0 \quad \left(phub^h_s\right) \quad \forall h,s \quad (23)$$

$$g^h_{s,p,n}, ginv^h_{s,p,n}; \quad I_{p,n}; \quad d^h_{s,n} \geq 0 \quad \forall h,s,p,n; \quad \forall p,n; \quad \forall h,s,n. \quad (24)$$

4. Market Coupling models

Market Coupling is the most advanced organization of the European electricity market. It is based on a zonal representation of the energy market, where each zone is controlled by a PX and a TSO. TSOs provide PXs with a simplified representation of the transmission grid used to clear the day-ahead market. The outcome of this operation may not be feasible for the real network depending on the way ATCs have been constructed (see Oggioni and Smeers, 2013) with the consequence that TSOs may have to engage in counter-trading operations to restore feasibility. Market Coupling simplifies the task of traders at the cost of increased difficulties for the TSOs and inefficiencies for the market. Oggioni and Smeers (2013), Oggioni and Smeers (2012) and Oggioni et al. (2012) analyze some inefficiencies due to the lack of coordination between and within these two groups of market operators.

Regulation 714/2009 (see European Commission, 2009e) article 8 emphasizes the need for coordination among TSOs through the use of common network codes, the development of which can be found on the ENTSO-E web site.[7] As already said, we simplify the problem and assume that zonal PXs and TSOs operate in a coordinated fashion. In other words, we assume that zonal PXs clear an integrated power market (something that Market Coupling approximately achieves in the day-ahead market, up to network approximations) and refer to a single PX. We also assume that the TSOs fully cooperate, something that remains a goal for the future. The integration of transmission is one of the objectives of the European Third Energy Package (see European Commission, 2009e) and TSOs are currently developing multinational arrangements especially in Central Western Europe. Actions to reinforce the coordination of TSOs in counter-trading are described in ACER/ENTSO-E (2012) and Supponen (2012). We make the assumption of full TSO cooperation and therefore refer to a single TSO in the rest of the paper. To sum up, in the following, we make the assumption of full TSO and PX cooperation and, therefore, can build the models as if there is one TSO and one PX.

In all models, we assume that the PX clears the energy market one day ahead on the basis of forecasted (expected) wind generation. Next, the TSO operates in real time to remove the possible difficulties caused by the deviations between real-time wind generation and the day-ahead forecasts. Since wind can be spilled only in real time, the modeling of the "no priority dispatch" policy is only a TSO counter-trading problem.

Generators allocate their capacities between day ahead and real time, with most of the trading taking place in day ahead and long term contracts. This allocation can involve market power and will always require arbitrage between those two time periods. We do not represent these questions both for methodological and practical reasons. From a methodological point of view dealing with market power and arbitrage between day ahead and real time is a subject in itself; it would dramatically complicate the discussion and distract from the objective to measure a rather mechanical phenomenon due to Market Coupling. A computational model that would involve these issues (even only arbitrage without market power) would not scale, in contrast with the one of this paper that can easily be adapted to a full representation of the European grid provided data are made available (something that is in process in European discussions). From a practical point of view counter-trading and its relation to balancing is an opaque subject in Europe and representing it would imply a lot of ad hoc simplifications. Because there is also very little harmonization between Member States on those matters, it would be impossible to come up with a reasonable assumption for a multinational model. Our model therefore relies on first principles. The clearing of the day head market is formulated as a

[7] See https://www.entsoe.eu/major-projects/network-code-development.

welfare maximization; in the same way counter-trading is conducted as a welfare maximization problem using incremental costs and willingness to pay computed at the outcome of the day ahead equilibrium. This set up is compatible with an assumption of perfect competition in both day ahead and counter-trading. It is also compatible with an assumption of total cost minimization in counter-trading. Because the allocation of the cost of counter-trading is opaque and country dependent in Europe, we do not go beyond that representation and only report total cost of counter-trading without allocation between generators and consumers. The subject remains in evolution as one is moving towards harmonization of those functions in Europe and we leave it to the reader to make her own assumption on how counter-trading cost will be obtained and allocated. In other words, the model is agnostic on how generators can benefit from counter-trading.

As in Nodal Pricing, we consider the cases presented in Section 3.2 to Market Coupling. We list here the sets, parameters, and variables specific to this problem and complementary to those indicated in Section 3.1. Specifically some notation changes are required to capture the zonal representation of the energy market. We then present the Market Coupling and the corresponding counter-trading models.

Sets

- $r \in R$: Set of zones (regions) in the network;
- $n_r \in R$: Subset of nodes $n \in N$ that are located in zones/regions $r \in R$;
- $k \in K$: Set of interconnections among market zones.

Parameters:

- $ATC_{r,rr}$: Available Transfer capacity between zone r and rr with $r \neq rr$ (MWh);
- $expwind^h_{n_r}$: Hourly h expected (day ahead) wind power production at node n located in region r (MWh);
- $increase^h_{n_r}$: Hourly h increase in wind power production at node n located in region r (%).

Variables:

- $E^h_{r,rr}$: Hourly h electricity flows from zone r and rr with $r \neq rr$ (MWh);
- $\Delta d^h_{s,n}$: Hourly h counter-trading adjustments operated by the TSO on power consumption at node n resulting from the Market Coupling problem in each scenario s (MWh);
- $\Delta g^h_{s,p,n}$: Hourly h counter-trading adjustments operated by the TSO on power production by existing plants at node n p resulting from the Market Coupling problem in each scenario s (MWh);
- $\Delta ginv^h_{s,p,n}$: Hourly h counter-trading adjustments operated by the TSO on power production by new plants at node n p resulting from the Market Coupling problem in each scenario s (MWh).

4.1. Market Coupling models without investments

We follow the modeling of Oggioni and Smeers (2012). The PX clears the energy market in the day ahead by maximizing the social welfare stated in Eq. (25). It does so while satisfying limits on both plant generation capacities (see Eq. (26)) and the transfer capacities ($ATC_{r,rr}$) of the interconnections between zones r and rr (see Eq. (28)). The PX also ensures energy balances at the zonal level in Eq. (27) after accounting for cross border trade. Finally, Eq. (29) imposes the non-negativity of energy demand d^h_n and generation $g^h_{p,n}$. The market clearing model of the PX can be written as follows.

$$\textbf{Max} \sum_{h,n} \int_0^{d^h_n} P^h_n(\xi)d\xi - \sum_{h,p,n} cost_{p,n} \cdot g^h_{p,n} - CO_2price \cdot \sum_{h,p,n} em_p \cdot g^h_{p,n} \tag{25}$$

s.t.

$$G_{p,n} - g^h_{p,n} \geq 0 \qquad \left(\varphi^h_{p,n}\right) \quad \forall h,p,n \tag{26}$$

$$\sum_{p,n} g^h_{p,n_r} + \sum_{rr} E^h_{rr,r} - \sum_n d^h_{n_r} - \sum_{rr} E^h_{r,rr} = 0 \quad \left(\varepsilon^h_r\right) \quad \forall h,r \tag{27}$$

$$-ATC_{r,rr} \leq E^h_{r,rr} \leq ATC_{r,rr} \qquad \left(\lambda^{h,\pm}_{r,rr}\right) \quad \forall h,r,rr \tag{28}$$

$$g^h_{p,n}; \quad d^h_n \geq 0 \quad \forall h,p,n; \quad \forall h,n \tag{29}$$

This model in Eqs. (25)–(29) covers the “No Wind” cases (“Case 1” and “Case 2”) listed above. In the “Wind” cases (from “Case 3” to “Case 6”), the Market Coupling model differs only from Eqs. (25) to (29), by the fact that the PX clears the day-ahead market taking into account a forecast on wind potential here represented by the term $expwind^h_{n_r} \cdot increase^h_{n_r}$. This term is included in the energy balance constraint that becomes Eq. (30).

$$\sum_{p,n} g^h_{p,n_r} + \sum_n expwind^h_{n_r} \cdot increase^h_{n_r} + \sum_{rr} E^h_{rr,r} - \sum_n d^h_{n_r} - \sum_{rr} E^h_{r,rr} = 0 \quad \left(\varepsilon^h_r\right) \quad \forall h,r \tag{30}$$

As explained for Nodal Pricing models for parameter $increase^h_{s,n}$, the parameter $increase^h_{n_r}$ is used to define different levels of wind penetration.

4.1.1. Counter-trading model without investments: “No Wind”

The TSO intervenes to restore network feasibility when the clearing of the day-ahead market turns out to be infeasible for the grid in real time, due to either the simplified representation of the grid or the discrepancies between expected and real-time wind generation. The TSO counter-trades so as to minimize the total re-dispatching costs indicated in Eq. (31), taking into account several constraints. First, adjustments $\Delta g^h_{p,n}$ and Δd^h_n decided by TSO should be feasible in the sense that corrected nodal generation and demand levels must remain nonnegative (see Eqs. (32) and (33)) and compatible with plant capacities in Eq. (34). Balances in Eqs. (35) and (36) require that the sum of all adjustments must be zero and that the sum of Δd^h_n should equal that of $\Delta g^h_{p,n}$. Seen together, this means that TSO's interventions cannot modify the trade obtained in the energy market. Finally, the resulting flows must be compatible with the transmission constraints of the real network in Eq. (37) as expressed by the same PTDF matrix as in the nodal models.

$$\textbf{Min} \sum_{h,p,n} cost_{p,n} \cdot \Delta g^h_{p,n} + CO_2price \cdot \sum_{h,p,n} em_p \cdot \Delta g^h_{p,n} - \sum_{h,n} \int_{d^h_n}^{d^h_n + \Delta d^h_n} P^h_n(\xi)d\xi \tag{31}$$

s.t.

$$g^h_{p,n} + \Delta g^h_{p,n} \geq 0 \qquad \left(\nu g^h_{p,n}\right) \quad \forall h,p,n \tag{32}$$

$$d^h_n + \Delta d^h_n \geq 0 \qquad \left(\nu d^h_n\right) \quad \forall h,n \tag{33}$$

$$G_{p,n} - g^h_{p,n} - \Delta g^h_{p,n} \geq 0 \qquad \left(\varphi^h_{p,n}\right) \quad \forall h,p,n \tag{34}$$

$$\sum_n \Delta d^h_n + \sum_{p,n} \Delta g^h_{p,n} = 0 \qquad \left(\mu^{h,1}\right) \quad \forall h \tag{35}$$

$$\sum_n \Delta d^h_n - \sum_{p,n} \Delta g^h_{p,n} = 0 \qquad \left(\mu^{h,2}\right) \quad \forall h \tag{36}$$

$$-L_l \leq \sum_n PTDF_{l,n} \cdot \left(\sum_p \left(g^h_{p,n} + \Delta g^h_{p,n}\right) - \left(d^h_n + \Delta d^h_n\right)\right) \leq L_l \quad \left(\lambda^{h,\pm}_l\right) \quad \forall h,l \tag{37}$$

Again, the EU-ETS regulation is modeled by the CO_2 price (CO_2 $price = 0$ or CO_2 $price > 0$). In the computation of the equilibrium, it is possible to link the Market Coupling and the counter-trading problems through an access charge equal to the average re-dispatching cost that we denote as α. This α is computed by dividing the total re-dispatching cost indicated in the objective function (Eq. (31)) by the total amount of electricity generated in the energy market ($\sum_{h,p,n} g_{p,n}^h$) over the time period considered (see Appendix D of Oggioni and Smeers, 2013 for a discussion of this approach). In this paper, we simply assume that the welfare at the Market Coupling equilibrium is given by the welfare before counter-trading minus the total re-dispatching costs (see Section 7 for the analysis of the results).

4.1.2. Counter-trading model without investments: "Wind"

We modify the counter-trading model in Eqs. (31)–(37) by inserting wind power and obtain model in Eqs. (38)–(45) that summarizes the four "Wind" cases presented in Section 3.2. Generation and demand adjustments ($\Delta g_{s,p,n}^h$ and $\Delta d_{s,n}^h$) now depend on scenario s and the objective function becomes as indicated in Eq. (38). We add constraint in Eq. (42) and change counter-trading operations in Eqs. (35)–(36) and transmission constraints in Eq. (37) into Eqs. (43)–(44) and Eq. (45) respectively. Wind energy balance in Eq. (42) states that the wind potential $wind_{s,n}^h \cdot increase_{s,n}^h$ in real time equals the amount of wind generation ($windused_{s,n}^h$) plus the unused wind potential ($windloss_{s,n}^h$). In "Case 3" and "Case 4", wind cannot be spilled ($windloss_{s,n}^h = 0$) and the wind potential ($wind_{s,n}^h \cdot increase_{s,n}^h$) is equal to the wind generated and injected in the network ($windused_{s,n}^h$). The TSO is allowed to spill wind in "Case 5" and "Case 6", and wind generation may be lower than the potential. Constraints (43)–(44) now include the variations between the wind effectively injected in the network ($windused_{s,n}^h$) in real time and the expected wind ($expwind_{n_r}^h \cdot increase_{n_r}^h$) used in cleaning the day-ahead market. Transmission constraints in Eq. (45) now account for actual wind levels ($windused_{s,n}^h$).

$$\begin{aligned}\textbf{Min} \sum_{h,s,p,n} cost_{p,n} \cdot \Delta g_{s,p,n}^h \cdot \tau_s + CO_2price \cdot \sum_{s,h,p,n} em_p \cdot \Delta g_{s,p,n}^h \cdot \tau_s + \\ -\sum_{h,s,n} \tau_s \cdot \int_{d_n^h}^{d_n^h + \Delta d_{s,n}^h} P_{sn}^h(\xi) d\xi\end{aligned} \tag{38}$$

s.t.

$$g_{p,n}^h + \Delta g_{s,p,n}^h \geq 0 \qquad \left(\nu g_{s,p,n}^h\right) \quad \forall h,s,p,n \tag{39}$$

$$d_n^h + \Delta d_{s,n}^h \geq 0 \qquad \left(\nu d_{s,n}^h\right) \quad \forall h,s,n \tag{40}$$

$$G_{p,n} - g_{p,n}^h - \Delta g_{s,p,n}^h \geq 0 \qquad \left(\varphi_{s,p,n}^h\right) \quad \forall h,s,p,n \tag{41}$$

$$wind_{s,n}^h \cdot increase_{s,n}^h = windused_{s,n}^h + windloss_{s,n}^h \qquad \left(\beta_{s,n}^h\right) \quad \forall h,s,n \tag{42}$$

$$\sum_n \Delta d_{s,n}^h + \sum_{p,n} \Delta g_{s,p,n}^h + windused_{s,n}^h - expwind_{n_r}^h \cdot increase_{n_r}^h = 0 \quad \left(\mu_s^{h,1}\right) \quad \forall h,s \tag{43}$$

$$\sum_n \Delta d_{s,n}^h - \sum_{p,n} \Delta g_{s,p,n}^h - windused_{s,n}^h + expwind_{n_r}^h \cdot increase_{n_r}^h = 0 \quad \left(\mu_s^{h,2}\right) \quad \forall h,s \tag{44}$$

$$-L_l \leq \sum_n PTDF_{l,n} \cdot \left(\sum_p \left(g_{p,n}^h + \Delta g_{s,p,n}^h\right) + windused_{s,n}^h - d_n^h - \Delta d_{s,n}^h\right) \leq L_l \quad \left(\lambda_{s,l}^{h,\pm}\right) \forall h,s,l \tag{45}$$

The role of the parameter $increase_{s,n}^h$ is as explained in the Nodal Pricing models. Finally, the average re-dispatching cost α is computed taking into account the expected value of the total re-dispatching costs divided by the total energy produced $\sum_{h,p,n} g_{p,n}^h$.

4.2. Market Coupling models with investments

The Market Coupling model without wind penetration in Eqs. (25)–(29) presented in Section 4.1 ("Case 1" and "Case 2") adapts to investments as indicated below:

$$\begin{aligned}\textbf{Max} \sum_{h,n} \int_0^{d_n^h} P_n^h(\xi) d\xi - \sum_{h,p,n} cost_{p,n} \cdot g_{p,n}^h - \sum_{h,p,n} costinv_{p,n} \cdot ginv_{p,n}^h + \\ -CO_2price \cdot \sum_{h,p,n} em_p \cdot \left(g_{p,n}^h + ginv_{p,n}^h\right) - \sum_{h,p,n} Icost_{p,n}^h \cdot I_{p,n}\end{aligned} \tag{46}$$

s.t.

$$G_{p,n} - g_{p,n}^h \geq 0 \qquad \left(\varphi_{p,n}^h\right) \quad \forall h,p,n \tag{47}$$

$$I_{p,n} - ginv_{p,n}^h \geq 0 \qquad \left(\varphi inv_{p,n}^h\right) \quad \forall h,p,n \tag{48}$$

$$\sum_{p,n} g_{p,n_r}^h + \sum_{p,n} ginv_{p,n_r}^h + \sum_{rr} E_{rr,r}^h - \sum_n d_{n_r}^h - \sum_{rr} E_{r,rr}^h = 0 \quad \left(\varepsilon_r^h\right) \quad \forall h,r \tag{49}$$

$$-ATC_{r,rr} \leq E_{r,rr}^h \leq ATC_{r,rr} \qquad \left(\lambda_{r,rr}^{h,\pm}\right) \quad \forall h,r,rr \tag{50}$$

$$g_{p,n}^h; \quad ginv_{p,n}^h; \quad I_{p,n}; \quad d_n^h \geq 0 \quad \forall h,p,n; \quad \forall p,n; \quad \forall h,n \tag{51}$$

The PX maximizes social welfare in Eq. (46), taking into account generation capacity constraints for both existing (Eq. (47)) and new (Eq. (48)) plants, zonal balance (Eq. (49)), and interconnection capacity limits (Eq. (50)). The objective function accounts for the emission costs when CO_2price is positive.

Wind penetration (from "Case 3" to "Case 6") implies a modification of Eq. (49) into the equality in Eq. (52). Again, the term $expwind_{n_r}^h \cdot increase_{n_r}^h$ defines the wind forecast in the day-ahead market under the different assumptions.

$$\begin{aligned}\sum_{p,n} g_{p,n_r}^h + \sum_{p,n} ginv_{p,n_r}^h + \sum_n expwind_{n_r}^h \cdot increase_{n_r}^h \\ + \sum_{rr} E_{rr,r}^h + -\sum_n d_{n_r}^h - \sum_{rr} E_{r,rr}^h = 0 \quad \left(\varepsilon_r^h\right) \quad \forall h,r\end{aligned} \tag{52}$$

In the following sections, we describe the counter-trading problems associated to this Market Coupling models in the six cases presented above.

4.2.1. Counter-trading model with investments: "No Wind"

Counter-trading can now take place on both existing and new plants. Model in Eqs. (31)–(37) is accordingly modified as follows:

$$\begin{aligned}\textbf{Min} \sum_{h,p,n} cost_{p,n} \cdot \Delta g_{p,n}^h + \sum_{h,p,n} costinv_{p,n} \cdot \Delta ginv_{p,n}^h + \\ +CO_2price \cdot \sum_{h,p,n} em_p \cdot \left(\Delta g_{p,n}^h + \Delta ginv_{p,n}^h\right) - \sum_{h,n} \int_{d_n^h}^{d_n^h + \Delta d_n^h} P_n^h(\xi) d\xi\end{aligned} \tag{53}$$

s.t.

$$g_{p,n}^h + \Delta g_{p,n}^h \geq 0 \qquad \left(\nu g_{p,n}^h\right) \quad \forall h,p,n \tag{54}$$

$$ginv_{p,n}^h + \Delta ginv_{p,n}^h \geq 0 \qquad \left(\nu g_{p,n}^h\right) \quad \forall h,p,n \tag{55}$$

$$d_n^h + \Delta d_n^h \geq 0 \qquad \left(\nu d_n^h\right) \quad \forall h,n \tag{56}$$

$$G_{p,n} - g_{p,n}^h - \Delta g_{p,n}^h \geq 0 \qquad \left(\varphi_{p,n}^h\right) \quad \forall h,p,n \tag{57}$$

$$I_{p,n} - ginv^h_{p,n} - \Delta ginv^h_{p,n} \geq 0 \qquad \left(\varphi inv^h_{p,n}\right) \quad \forall h,p,n \tag{58}$$

$$\sum_n \Delta d^h_n + \sum_{p,n} \Delta g^h_{p,n} + \sum_{p,n} \Delta ginv^h_{p,n} = 0 \qquad \left(\mu^{h,1}\right) \quad \forall h \tag{59}$$

$$\sum_n \Delta d^h_n - \sum_{p,n} \Delta g^h_{p,n} - \sum_{p,n} \Delta ginv^h_{p,n} = 0 \qquad \left(\mu^{h,2}\right) \quad \forall h \tag{60}$$

$$-L_l \leq \sum_n PTDF_{l,n} \cdot \left(\sum_p \left(g^h_{p,n} + \Delta g^h_{p,n} + ginv^h_{p,n} + \Delta ginv^h_{p,n} \right) - \left(d^h_n + \Delta d^h_n \right) \right) \leq L_l \quad \left(\lambda^{h,\pm}_l\right) \forall h,l. \tag{61}$$

Re-dispatching costs incurred on new plants ($\sum_{h,p,n} costinv_{p,n} \cdot \Delta ginv^h_{p,n}$) are included in the objective function (Eq. (53)). Counter-trading operations on these plants affect the energy variation balances in Eqs. (59)–(60) and the transmission constraints in Eq. (61). The variations $\Delta ginv^h_{p,n}$ imposed on new plants should lead to total generation of these plants that are non-negative in Eq. (55) and remain within capacity in Eq. (57). Finally, the average re-dispatching cost α is computed by dividing the total re-dispatching cost indicated in Eq. (53) by the total amount of electricity generated in the energy market ($\sum_{h,p,n} g^h_{p,n} + \sum_{h,p,n} ginv^h_{p,n}$) over the time period considered.

4.2.2. Counter-trading model with investments: "Wind"

The changes implied by the insertion of wind penetration in the counter-trading models are similar to those described in Section 4.1.2. More specifically, the variation balances in Eqs. (59)–(60) and the transmission constraints in Eq. (61) respectively become as indicated in Eqs. (69)–(70) and Eq. (71). Eq. (68) is added to define the balance among wind energy potential ($wind^h_{s,n} \cdot increase^h_{s,n}$), wind effectively injected in the network ($windused^h_{s,n}$) and wind energy spillage in real time ($windloss^h_{s,n}$).

$$\begin{aligned} \textbf{Min} & \sum_{h,s,p,n} cost_{p,n} \cdot \Delta g^h_{s,p,n} \cdot \tau_s + \sum_{h,s,p,n} costinv_{p,n} \cdot \Delta ginv^h_{s,p,n} \cdot \tau_s + \\ & + CO_2price \cdot \sum_{s,h,p,n} em_p \cdot \left(\Delta g^h_{s,p,n} + \Delta ginv^h_{s,p,n} \right) \cdot \tau_s - \sum_{h,s,n} \tau_s \cdot \int_{d^h_n}^{d^h_n + \Delta d^h_{s,n}} P^h_n(\xi) d\xi \\ & \text{s.t.} \end{aligned} \tag{62}$$

$$g^h_{p,n} + \Delta g^h_{s,p,n} \geq 0 \qquad \left(\nu g^h_{s,p,n}\right) \quad \forall h,s,p,n \tag{63}$$

$$ginv^h_{p,n} + \Delta ginv^h_{s,p,n} \geq 0 \qquad \left(\nu g^h_{s,p,n}\right) \quad \forall h,s,p,n \tag{64}$$

$$d^h_n + \Delta d^h_{s,n} \geq 0 \qquad \left(\nu d^h_{s,n}\right) \quad \forall h,s,n \tag{65}$$

$$G_{p,n} - g^h_{p,n} - \Delta g^h_{s,p,n} \geq 0 \qquad \left(\varphi^h_{s,p,n}\right) \quad \forall h,s,p,n \tag{66}$$

$$I_{p,n} - ginv^h_{p,n} - \Delta ginv^h_{s,p,n} \geq 0 \qquad \left(\varphi inv^h_{s,p,n}\right) \quad \forall h,s,p,n \tag{67}$$

$$wind^h_{s,n} \cdot increase^h_{s,n} = windused^h_{s,n} + windloss^h_{s,n} \qquad \left(\beta^h_{s,n}\right) \quad \forall h,s,n \tag{68}$$

$$\begin{aligned} & \sum_n \Delta d^h_{s,n} + \sum_{p,n} \Delta g^h_{s,p,n} + \sum_{p,n} \Delta ginv^h_{s,p,n} + windused^h_{s,n} + \\ & \quad - expwind^h_n \cdot increase^h_{n_r} = 0 \quad \left(\mu^{h,1}_s\right) \quad \forall h,s \end{aligned} \tag{69}$$

$$\begin{aligned} & \sum_n \Delta d^h_{s,n} - \sum_{p,n} \Delta g^h_{s,p,n} - \sum_{p,n} \Delta ginv^h_{s,p,n} - windused^h_{s,n} \\ & \quad + expwind^h_n \cdot increase^h_{n_r} = 0 \quad \left(\mu^{h,2}_s\right) \quad \forall h,s \end{aligned} \tag{70}$$

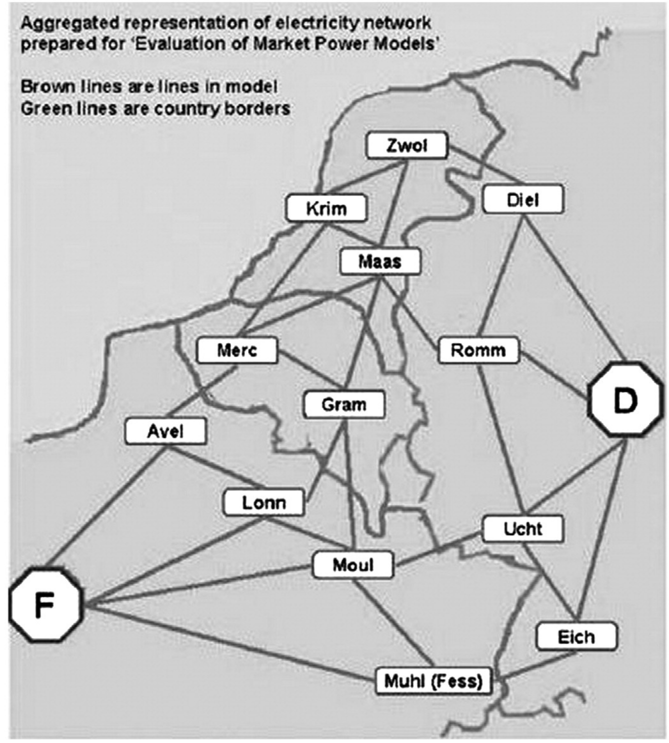

Fig. 1. Prototype of the Central Western European electricity market.

$$\begin{aligned} -L_l \leq \sum_n PTDF_{l,n} \cdot & \left(\sum_p \left(g^h_{p,n} + \Delta g^h_{s,p,n} \right) + \sum_p \left(ginv^h_{p,n} + \Delta ginv^h_{s,p,n} \right) \right. \\ & \left. + windused^h_{s,n} - \left(d^h_n + \Delta d^h_{s,n} \right) \right) \leq L_l \quad \left(\lambda^{h,\pm}_{s,l}\right) \quad \forall h,s,l \end{aligned} \tag{71}$$

The average re-dispatching cost α is computed as the ratio between the expectation of the total average re-dispatching costs over the wind scenarios in Eq. (62) and the total energy produced ($\sum_{h,p,n} g^h_{p,n} + m_{h,p,n} ginv^h_{p,n}$).

5. Case study

5.1. The geographic scope

The analysis is conducted on an aggregate representation of the Central Western European (CWE) electricity market as depicted in Fig. 1. This network has now been used extensively in the literature for looking at problems with meshed grid. CWE is also the oldest implementation of Market Coupling where it has been in use since November 2010.

5.2. The grid

The network is composed of lines with limited transmission capacity (see Appendix C) that connect fifteen nodes located in four main zones, each corresponding to one of the European countries indicated in Fig. 1. Consumers and generators are located at seven of these nodes: these are the two big nodes in France and Germany respectively, two Belgian nodes (Merchtem and Gramme) and three Dutch nodes (Krimpen, Maastricht and Zwolle). The remaining nodes are auxiliary and used only to transfer electricity.

The grid is modeled using a PTDF matrix[8] in the Nodal Pricing and counter-trading problems. The network is simplified for the clearing of

[8] See Appendix A.2 for a more detailed explanation of the functioning of the PTDF matrix. The PTDF data used in our models are reported in Table 17 of Appendix C.

the day-ahead market in Market Coupling and represented by zonal interconnections with limited Available Transfer Capacities (ATCs). In particular, we assume that the market is subdivided into four zones, each corresponding to a country. These zones are connected by four interconnections namely Belgium-Netherlands, France-Belgium, France-Germany and Germany-Netherlands. In the absence of hard information on how ATCs are obtained, we compute ATCs as the sum of the capacities of the aggregate flowgates connecting the nodes in the different countries. Their values respectively amount to 2218 MW, 2372 MW, 2608 MW and 3867 MW. A PX and a TSO operate in each of the four modeled countries. They are integrated into a single pool in the reference "Nodal Pricing model". PXs and TSOs remain separated entities in the implementation of Market Coupling. Recall that we assume that PXs and TSOs coordinate their operations so that one can assume a single PX and a single TSO in the model.

5.3. The generation system

Several generators operate both renewables (wind, run-of-river and biomass) and conventional plants (nuclear, lignite, coal, CCGT and oil based plants), whose capacity is reported in Appendix C. The model is benchmarked on the year 2011, but we took 2012 data when available. The technological representation of the system is standard: each plant is characterized by its investment (see Table 1[9]) and operational (fuel and emission) costs (see Appendix C).

5.4. Wind assumptions

Wind potential is exogenous and depends on the wind penetration level as indicated in the cases listed below:

- "No Wind": No wind generation;
- "Wind": Wind generation in the reference year (2012);
- "Wind Increase": Wind capacities increase with respect to "Wind". We account for three wind increases denoted by "Wind I1", "Wind I2" and "Wind I3". These are calibrated on the basis of the National Renewable Energy Action Plans (NREAPs) foreseen by Article 4 of Directive 2009/28/EC for each European Member Country. In particular, the renewables electricity penetration shares of consumption should achieve the targets of 19%, 11%, 10% and 24% by 2020 respectively in Germany, France, Belgium and The Netherlands. Wind penetration corresponds to those percentages in "Wind I1". The levels are twice as high in "Wind I2" and three times as high in "Wind I3".

These different levels of wind potential are analyzed in the cases presented in Section 3.2. More specifically, the "No Wind" penetration is imposed in "Case 1" and "Case 2"; the "Wind" and the three "Wind Increase" penetration levels are all tested in the cases with wind generation (from "Cases 3" to "Cases 6"). The construction of these wind scenarios is described in Appendix D. Wind penetration is here exogenous and hence corresponds to exogenous infrastructure costs. Table 2 gives an evaluation of wind generation infrastructure annual costs for the different wind penetration.

5.5. Other assumptions

The cases with endogenous investment in conventional generation allow for investment in nuclear, lignite, coal, CCGT or oil plants and assume that this new capacity is immediately available. The models reflect the current investment policies applied in Europe (e.g. investments in nuclear is possible only in France; lignite is developed only in Germany). Investments are obviously affected both by wind penetration and environmental regulations, like the EU-ETS. The EU-ETS regulates CO_2 generated by specific installations as foreseen by Directives 2003/87/EC and 2009/29/EC through a cap and trade system. Emission factors are technology dependent (see Appendix C). Following the dispositions of the third ETS phase for the power sector, we require that generators buy all permits needed to cover their emissions at a market price that is given exogenously in this study. This additional cost may affect investment choices. The current CO_2 price is relatively low (lower than 10 €/ton) and is considered to not give the right signal to investors to build. Our "contextual cases" denoted by "no EU-ETS" represent either a situation where the EU-ETS is not applied or stylized versions of an EU-ETS with a very low allowance price. Discussions with the European Commission are ongoing in order to possibly review the cap and trade system and guarantee a higher allowance price. For this reason, in our study, we impose an allowance price of 40 €/ton in the "contextual cases" denoted by "EU-ETS". A carbon price of 40 €/ton could be considered as a reasonable target for a proper functioning of the EU-ETS system.

We use a time horizon of twenty-four hours in a specific day (corresponding to a scenario). For the computation of the parameters of the inverse demand function, we took the average annual demand allocated on a nodal basis as applied in Hobbs et al. (2004), a reference price of 60 €/MWh[10] and a demand elasticity of −0.1 (see Appendix C).

Table 1
Hourly fixed costs for new conventional plants ([€]/MWh).

[€]/MWh	Germany	France	Merchtem	Gramme	Krimpen	Maastricht	Zwolle
Nuclear	–	53.18	–	–	–	–	–
Lignite	31.77	–	–	–	–	–	–
Coal	29.68	29.02	32.46	32.46	24.93	24.93	24.93
CCGT	14.86	13.95	15.92	15.92	11.07	11.07	11.07
Oil	19.86	19.86	19.86	19.86	25.32	25.32	25.32

Table 2
Wind generation infrastructure annual costs as a function of the wind penetration level.

K[€]	Wind	Wind I1	Wind I2	Wind I3
Germany	4,942,336	11,658,970	23,312,997	34,971,967
France	703,732	2,714,293	5,428,587	8,142,880
Belgium	187,963	824,032	1,651,446	2,472,095
Netherlands	233,744	1,932,592	3,865,183	5,797,775
Total	**6,067,774**	**17,129,886**	**34,258,213**	**51,384,716**

6. Nodal Pricing results

Note at the outset that our nodal problem is in reality a pseudo "Nodal Pricing" system: we effectively start from a zonal system, that we conceptually treat as nodal and then build a coarser zonal system for the analysis of Market Coupling. Notwithstanding this distinction we keep referring to "nodal" and never use "pseudo nodal". We first analyze the impact of the "priority dispatch" and "no priority dispatch" policies in the Nodal Pricing architecture. This is done by considering the increasing wind market shares assumptions under different "contextual cases". The analysis reports global welfare, consumers' surplus, profits of conventional and wind generators, and the TSO's profits. It also gives emissions and investment figures. Except when explicitly mentioned, all figures are valued in euros (€) and refer to a day in a year because of our scenario construction. Recall that all results are obtained assuming that consumers do not pay the cost of wind generation infrastructure (which is taken as sunk and charged to the general public budget). The estimate of the annual infrastructure costs is provided in Table 2 for the reader's information and use. We first present the results

[9] Own computation based on IEA data (see IEA, 2011). We assume that generators can only invest in new conventional plants, e.g. nuclear, lignite, coal, CCGT and oil based plants. Investments in nuclear and in lignite are only allowed in France and in Germany respectively.

[10] We took EEX (European Energy Exchange) data as reference. See http://www.eex.com/en/.

Table 3
Nodal Pricing results without investments (daily values).

[€]	No Wind	Wind	Wind I1	Wind I2	Wind I3
Nodal Pricing, priority dispatch, no EU-ETS, no investments (Case 1 + Case 3)					
Surplus	1,081,930,958	1,098,980,782	1,116,990,581	1,141,768,095	1,167,845,087
Profit	80,096,571	63,100,421	45,991,025	25,965,317	12,154,687
Wind	0	5,527,013	15,030,836	23,007,960	20,246,707
Network	305,518	863,329	1,467,031	2,022,013	2,133,045
Welfare	**1,162,333,047**	**1,168,471,545**	**1,179,479,474**	**1,192,763,385**	**1,202,379,526**
Nodal Pricing, no priority dispatch, no EU-ETS, no investments (Case 1 + Case 5)					
Surplus	1,081,930,958	1,098,980,782	1,116,990,581	1,141,740,160	1,165,451,105
Profit	80,096,571	63,100,421	45,991,025	25,964,757	12,136,993
Wind	0	5,527,013	15,030,836	23,041,728	23,225,572
Network	305,518	863,329	1,467,031	2,018,682	1,880,424
Welfare	**1,162,333,047**	**1,168,471,545**	**1,179,479,474**	**1,192,765,327**	**1,202,694,094**
Nodal Pricing, priority dispatch, EU-ETS, no investments (Case 2 + Case 4)					
Surplus	1,001,650,345	1,005,900,607	1,021,313,463	1,070,689,295	1,122,278,629
Profit	149,807,390	140,666,422	117,717,998	63,595,424	31,717,242
Wind	0	10,561,437	29,672,774	46,959,837	39,396,054
CO_2 cost	37,047,635	31,879,178	22,865,381	11,922,344	4,893,792
Network	644,662	535,799	904,975	3,995,137	3,956,288
Welfare	**1,115,054,762**	**1,125,785,087**	**1,146,743,829**	**1,173,317,350**	**1,192,454,421**
Nodal Pricing, no priority dispatch, EU-ETS, no investments (Case 2 + Case 6)					
Surplus	1,001,650,345	1,005,900,607	1,021,313,463	1,070,660,370	1,119,879,840
Profit	149,807,390	140,666,422	117,717,998	63,594,274	31,680,978
Wind	0	10,561,437	29,672,774	46,995,700	42,409,424
CO_2 cost	37,047,635	31,879,178	22,865,381	11,922,330	4,892,995
Network	644,662	535,799	904,975	3,991,353	3,694,710
Welfare	**1,115,054,762**	**1,125,785,087**	**1,146,743,829**	**1,173,319,368**	**1,192,771,957**

of all models without investments in the different "contextual cases" (Section 6.1); we then show those obtained when generators can build new capacity (Section 6.2).

6.1. Nodal Pricing results without investments

Table 3 presents the results obtained in the different "contextual cases" under the assumption of no investments in new generation capacity. In this table, "Surplus", "Profit", "Wind", "CO_2 cost" and "Network" respectively indicate consumers' surplus, conventional generators' profits, wind generators' profits, emission costs and TSO's profits.

6.1.1. Welfare

We report welfare as affected by three main factors namely wind penetration, the EU-ETS regulation and the priority dispatch policy (Table 3). Wind penetration is the main factor and we report four sub tables that each gives the variation of the different metrics as a function of wind penetration.

Two expected phenomena are directly observable. First welfare increases with wind penetration as this energy is free as long as infrastructure costs are not taken into account. Second the EU-ETS is costly as long as one does not take into account the recycling of the CO_2 tax into account (that is neglecting any possible "double dividend" benefit). One may note that the CO_2 cost reduces with the progressive penetration of wind. Finally, the impact of the "no priority dispatch" policy depends on the level of wind penetration, but not on the EU-ETS regulation. We do not get into the detail of these questions that would lead us too far from the comparison of the "priority" and "no priority" policies.

Coming to this point (priority dispatch vs. no priority dispatch) one notes that welfare values are identical when wind penetration is relatively low, as in the "Wind" and "Wind I1" cases. This happens because the network is able to accommodate all wind production without any problems and thus there are no wind losses (see Table 4). The situation changes when wind penetration is particularly high, as in the "Wind I2" and "Wind I3". In these cases, congestion (and hence TSO revenue as shown in row "Network" in Table 3) is reduced by not injecting all potential wind in the network (see Table 4). Allowing for wind spill in the "no priority dispatch" policy therefore leads to an increase of the social welfare compared to the corresponding cases under the "priority dispatch" policy. As a last point to be kept in mind for the comparison with Market Coupling, one notes that the overall welfare continues to increase with wind penetration whatever the wind and ETS policy. It increases less under "priority dispatch" than in "no priority dispatch", but it keeps increasing. These trends are obviously driven by the extent of congestion and hence by the capacities of the grid. It is impossible to disentangle the effect of equating demand and generation and satisfying network constraints in the clearing of the nodal system without additional runs. This information would obviously be interesting if one were to investigate the impact of a coordinated extension of the grid. While this is much talked about, it does not seem to be a very realistic prospect for the short-term future and is thus not treated here.

The position of the different agents inside this general welfare evolution is generally what could be expected and hence is only briefly discussed below.

6.1.2. Consumers' surplus

Consumers' surplus steadily increases from the "No Wind" to the "Wind I3" penetration level and this will remain so in all "contextual cases". This is due to the availability of free wind energy once the generation and transmission infrastructure is installed and paid for by the general budget. Table 2 gives an evaluation of wind generation infrastructure costs for the different wind penetrations. The final position of the agents obviously depends on how these costs are allocated among them.

Table 4
Nodal Pricing losses in the cases without investments in the CWE market (MW day values).

MW day	No Wind	Wind 2012	Wind I1	Wind I2	Wind I3
Nodal Pricing, no priority dispatch, no EU-ETS, no investments (Case 1 + Case 5)					
Wind loss	0	0	0	71	4,639
Nodal Pricing, no priority dispatch, EU-ETS, no investments (Case 2 + Case 6)					
Wind loss	0	0	0	69	4,380

6.1.3. Profits of conventional generators

Conventional generators can only suffer from the penetration of wind generation with their profit reductions accelerating between the “Wind I1” and “Wind I3” penetration levels. This trend is again common to all “contextual cases”. Profit decreases are due to sales and price decreases but the interplay between them maybe subtle. Sale losses due to wind penetration do not need much explanation. Price changes are more difficult to decipher: prices should normally fall with high wind generation as they effectively do here, but line congestion could lead to higher prices at some nodes (see Tables 23 and 24 in Appendix E for an example). At the same time lower electricity prices, because of price responsive demand, induce an increase in demand that partially compensates for the increased wind generation.

6.1.4. Wind generators' profits

Wind generators' profits exhibit interesting patterns. Note that wind generators are here paid at nodal price and do not benefit from incentives like feed-in tariffs or premium. Wind generators generally increase their profits up to and including “Wind I2”. Then profits may dramatically decrease depending on the case when moving from “Wind I2” to “Wind I3”. The initially higher profits can be explained by an obvious increase in market share with a relatively stable electricity price environment (see Tables 23 and 24). Prices initially remain stable because wind is not the marginal source of supply and prices are set by the fossil-fuel plants. Once wind becomes the marginal source of supply and congestion develops, prices fall dramatically. The drop of profit between “Wind I2” and “Wind I3” in three cases (“priority dispatch” both with and without ETS and “no priority dispatch” with ETS) is a remarkable phenomenon in these runs. As mentioned above, wind generators under the “priority dispatch” policy are inflexible and the nodal prices require them to pay for that inflexibility. As an example, we find a price of −1272 €/MWh in some hour in some wind location in case “Wind I3”. This negative price would be reset to 0 if wind generators could be shut down (and wind spilled). An inflexible injection that is badly located pays the full price of that bad location in the nodal system. Again, this pattern of the wind profit changes appears in almost all “contextual cases”.[11]

6.1.5. The TSO's profits

The TSO clearly benefits from wind penetration in these cases before grid investments, as the TSO captures the rents from transmission congestion. This benefit becomes particularly large in cases “Wind I2” and “Wind I3” compared to the “No Wind” case and results from a dramatic increase in congestion due to wind generation, which is also the source of the decreased profits of wind generators in the “Wind I3” case. This happens both with and without priority dispatch, even though the congestion rents in the “Wind I2” and “Wind I3” cases in the “priority dispatch” policy are higher than those registered in the “no priority dispatch” policy.

These phenomena illustrate the theme of the paper: even though we do not model the inflexibility of conventional generators and hence overestimate the flexibility of the overall system, wind generation under the “priority dispatch” policy already turns out to be a particularly inflexible source of supply that causes considerable dispatching difficulties. On the contrary, the “no priority dispatch” policy makes generators flexible. Wind generators no longer have to pay for their electricity to be taken when the penetration level becomes high and, instead, shut down when a nodal price is negative (when they have to pay to produce). Congestion decreases and the TSO loses the revenue accruing from what was a highly congested system.

This phenomenon is exacerbated in the discussion of Market Coupling.

[11] This does not happen in the contextual case “no priority dispatch, no EU-ETS, no investments” where the wind profits increase also with the “Wind I3” penetration level.

6.1.6. Additional comments

A “no priority dispatch” policy may, at first sight, appear detrimental to wind generators that are guaranteed to produce at their maximal potential under “priority dispatch”. This is not true in the nodal system where a generator receives a price equal to the marginal value of its contribution to the system. A generator, whether wind or conventional, then optimally shuts down when the marginal value of its generation is lower than its operating cost. For wind, this means shutting down in some location if the price at that location is negative, that is, if generation increases congestion. This is reflected in the cash flow from the operations of the wind mills. These are given by the dual variables of the capacity constraints and are here reproduced for the “priority dispatch” and “no priority dispatch” policies in the different wind cases in Tables 25 and 26 in Appendix E. Note that the profits of the wind generators at low penetration levels (“Wind I1” and “Wind I2”) are the same with both policies. Then, with larger capacities they are higher in the “no priority dispatch” policy than with the “priority dispatch” policy. Unsurprisingly this is especially true when wind is effectively spilled, namely in “Wind I2” and “Wind I3”. Needless to say, this result depends on a Nodal Pricing system that remunerates generators for the value that they bring to the system and does not cross subsidize between conventional and renewable generators.

A related comment may be relevant for the TSO. Their profits are higher in the “priority dispatch” case than in the “no priority dispatch” case in all “contextual cases”. This should obviously be balanced with the obligation of the TSO to construct additional infrastructure to accommodate intermittent sources. We do not delve into this issue, which is much more complex than the assessment of capacity costs of wind generation infrastructure reported in Table 2.

6.2. Nodal Pricing results with investments

Table 5 illustrates the results of the investment models under the different “contextual cases” and the different wind penetration levels. The principle is that generators invest when the rents on plant capacity (usually referred to as scarcity rents) are higher than the fixed costs of new capacity. The capacity constraints induce rents on plant capacity when binding.

Tables 23–24 and Tables 25–26 in Appendix E respectively report the electricity prices and the scarcity rents for the different wind levels and at the different nodes: both decrease. Comparing these results with the fixed costs of new capacity in CWE countries (see Table 1), the scarcity rents associated with the different wind penetration levels do not justify investments in conventional plants. Note that this model remunerates energy only and hence does not account for the system services that conventional plants render in a high-wind-penetration case (e.g. ramping capabilities).

Investments may occur when reducing some of the existing capacity lowers costs. Considering the objective of emissions reductions and efficiency increases imposed by the Energy Roadmap 2050, generators should replace coal-fired plants with gas-fired combined-cycle plants.[12] This is confirmed by the generators' recognition that half of the fossil fuel capacity should be shut down in order to meet EU's goals for CO_2 emissions reduction.[13] Moreover, the application of the Directive 2001/80/EC (the so-called Large Combustion Plant Directive) that controls sulphur dioxide (SO_2) emissions imposes the closure, by the end of 2015, of existing coal and oil plants installed before 1987 that are not equipped with adequate emission abatement facilities. The combination of all these factors justifies testing a case of reduced available

[12] Page 11 of the Roadmap 2050 European Commission (2011b), states “*Gas will be critical for the transformation of the energy system. Substitution for coal (and oil) with gas in the short to medium term would help to reduce emissions with existing technologies until at least 2030 or 2035.*”

[13] See http://www.rwe.com/web/cms/en/77256/rwe-power-ag/power-plant-new-build/.

Table 5
Nodal Pricing results with investments and a 50% cut of the existing lignite and coal capacity (daily values).

[€]	No Wind	Wind	Wind I1	Wind I2	Wind I3
Nodal Pricing, priority dispatch, no EU-ETS, investments (Case 1 + Case 3)					
Surplus	1,055,081,536	1,056,053,649	1,088,379,649	1,123,568,166	1,159,830,719
Profit	95,102,457	94,284,917	65,504,615	37,610,238	19,971,604
Wind	0	7,865,642	18,702,768	26,329,625	16,588,667
Network	1,183,598	1,161,485	882,285	2,032,601	2,737,717
Welfare	**1,151,367,592**	**1,159,365,693**	**1,173,469,317**	**1,189,540,630**	**1,199,128,707**
Nodal Pricing, no priority dispatch, no EU-ETS, investments (Case 1 + Case 5)					
Surplus	1,055,081,536	1,056,053,649	1,088,379,649	1,123,300,661	1,152,625,380
Profit	95,102,457	94,284,917	65,504,614	37,608,600	19,845,679
Wind	0	7,865,642	18,702,768	26,651,435	25,783,520
Network	1,183,598	1,161,485	882,285	2,011,743	2,089,906
Welfare	**1,151,367,592**	**1,159,365,693**	**1,173,469,317**	**1,189,572,438**	**1,200,344,485**
Nodal Pricing, priority dispatch, EU-ETS, investments (Case 2 + Case 4)					
Surplus	993,342,624	1,000,850,999	1,015,903,061	1,069,565,960	1,119,436,706
Profit	151,709,695	142,294,298	120,704,557	67,597,952	38,290,210
Wind	0	10,985,125	30,300,627	43,506,064	33,303,462
CO_2 cost	32,863,142	30,479,887	22,353,292	12,181,930	6,168,946
Network	1,164,583	868,270	1,448,515	3,783,466	4,511,874
Welfare	**1,113,353,760**	**1,124,518,805**	**1,146,003,468**	**1,172,271,511**	**1,189,373,306**
Nodal Pricing, no priority dispatch, EU-ETS, investments (Case 2 + Case 6)					
Surplus	993,342,624	1,000,850,999	1,015,903,061	1,069,300,705	1,111,717,336
Profit	151,709,695	142,294,298	120,704,557	67,595,342	38,099,949
Wind	0	10,985,125	30,300,627	43,827,226	43,174,607
CO_2 cost	32,863,142	30,479,887	22,353,292	12,181,778	6,166,495
Network	1,164,583	868,270	1,448,515	3,762,138	3,779,549
Welfare	**1,113,353,760**	**1,124,518,805**	**1,146,003,468**	**1,172,303,633**	**1,190,604,946**

capacity, in particular lignite and coal. According to the generators' plans, we assume a cut of existing lignite and coal capacity of 50% and we ran all investment cases under this assumption.

First, we observe that, even under this assumption, generators have no incentives to invest in new capacity. Investments only appear in the "No Wind" and "Wind I1" when there is no wind penetration or its level is relatively low. Moreover, investments are affected by environmental regulation but do not depend on the priority policy, whether in the EU-ETS or the non EU-ETS. As expected, lignite plants (in Germany) that operate without EU-ETS are replaced, with the implementation of the EU-ETS, by nuclear (in France) and CCGT (see Table 6). The fact that investments are independent of the priority policy is plausible because conventional generation is zero in periods where spillage is economic, whether or not spillage is allowed. Thus, these periods do not produce capacity rents that contribute to the value of adding capacity, independent of the priority policy. These results should be treated cautiously as operational requirements and startup costs that require conventional generation to operate during the spillage times are not modeled here but would impact investments.

Second, results show that investments do not effectively change the comparison of the "priority dispatch" and "no priority dispatch" policies (compare Tables 3 and 5) and the trends of the different "contextual cases" already observed in Section 6.1. Again, wind spillage in the "no priority dispatch" is only registered in "Wind I2" and "Wind I3" as indicated in Table 7.

Finally, we can conclude that the comparison of the "priority dispatch" and "no priority dispatch" policies is not affected by the contextual cases: the trend in the respective priority policies is similar with and without investments.

Table 6
Investments in Nodal Pricing with a 50% cut of lignite and coal existing capacity.

MW	No Wind	Wind	Wind I1	Wind I2	Wind I3
Nodal Pricing, priority dispatch, no priority dispatch, no EU-ETS, investments (Case 1 + Case 3 + Case 5)					
Lignite	4,300	0	0	0	0
Nodal Pricing, priority dispatch, no priority dispatch, EU-ETS, investments (Case 2 + Case 4 + Case 6)					
Nuclear	5376	1915	0	0	0
CCGT	2524	0	0	0	0
Total	**7,900**	**1,915**	**0**	**0**	**0**

Table 7
Nodal Pricing losses in the cases with investments in the CWE market and a 50% cut of lignite and coal existing capacity (MW day values).

MW day	No Wind	Wind 2012	Wind I1	Wind I2	Wind I3
Nodal Pricing, no priority dispatch, no EU-ETS, investments (Case 1 + Case 5)					
Wind losses	0	0	0	695	21,560
Nodal Pricing, no priority dispatch, EU-ETS, investments (Case 2 + Case 6)					
Wind losses	0	0	0	695	21,569

7. Market Coupling results

Nodal Pricing[14] by construction better takes care of the real physical constraints of the system in the day-ahead auction, leaving less need to adjust real flows to economic transactions. This statement applies whatever the degree of refinement of the representation of the system. It thus also applies here even for the very rough description of demand, the grid, and generation adopted in our test cases. Starting from the "Nodal Pricing" system of the preceding section, we now turn to a simulation of Market Coupling.

As discussed in Section 5, Market Coupling implies aggregating the grid into a simpler ATC-based transmission system and replacing the single "real-time" market clearing of the nodal system by a day-ahead market clearing followed by counter-trading operations. It is important to recall here that counter-trading is not a market and hence a day-ahead market clearing followed by counter-trading is quite different

[14] We reiterate at the outset that our nodal system is effectively "pseudo nodal". The test case is effectively a zonal system that we treat as nodal and on which we build a coarser zonal system for representing Market Coupling.

from a double settlement system where the day-ahead and real-time markets successively clear on the same representation of the grid.

The sequence of day-ahead market clearing and counter-trading found in Market Coupling, complicates the analysis when compared to the nodal case. Table 8 in Section 7.1 and Table 10 in Section 7.2 are thus more involved than their counterparts in Section 6 in that they provide results for both the day-ahead market and counter-trading operations. In Tables 8 and 10, the first six rows refer to the clearing of the energy market in the day ahead and have the same interpretation as in the nodal case. The clearing of that market results in a total welfare that is distributed among consumers' surplus, conventional and wind generators' profits, and the TSO's merchandizing surplus. Additional rows deal with re-dispatching and complete the table in the following way. The TSO engages in counter-trading if real-time wind injection and grid constraints make real-time flows infeasible for the grid. The cost of counter-trading is reported in the row "Total Re-dispatching Cost" or TRC. This cost is decomposed into fuel and emission costs (when emissions are priced by the EU-ETS). Re-dispatching might imply a switch towards cheaper but higher-emitting fuels, in which case the row "of which CO_2 cost" reports figures higher than TRC. This is only relevant under the EU-ETS policy. TRC must be subtracted from welfare to give "Net welfare". The two last rows of the table report the "Average Re-dispatching Cost" (ARC) and "Average Re-dispatching Cost Wind" (ARC wind), which are the total re-dispatching costs respectively allocated over generation including and excluding wind. Total re-dispatching cost must be charged to agents. A common policy is to allocate it through access charges paid by consumers and generators according to a certain rule (see ENTSO-E, 2012). Current policy is clearly to charge the consumers. One might expect a reverse of this policy, resulting in a charging of the cost to conventional generators if counter-trading becomes too important. Whatever the assumption, TRC can thus be subtracted from the profit of the conventional generators or from the consumer surplus to get net profits or net surplus depending on the adopted allocation rule. We leave it to the reader to make an assumption on that allocation.

As with the nodal system, we find that our comparison of the "priority dispatch" and "no priority dispatch" policy is not affected by the "contextual cases", which suggests that our conclusions are robust. For this reason, and following up on the methodology adopted in the discussion of the nodal system, we analyze the results in some detail for one contextual case and briefly discuss the rest by comparison. Except when explicitly mentioned, all figures are in value in euros (€) and refer to a day in a year.

Finally, it is important to recall here that the succession of Market Coupling on an simplified network and counter-trading on the exact network is not equivalent to Nodal Pricing, even in the simplest

Table 8
Market Coupling results without investments (daily values).

[€]	No Wind	Wind	Wind I1	Wind I2	Wind I3
Market Coupling, priority dispatch, no EU-ETS, no investments (Case 1 + Case 3)					
Surplus	1,079,761,010	1,091,883,870	1,112,476,117	1,137,818,096	1,167,053,989
Profit	82,439,552	70,347,276	50,072,379	30,302,085	9,978,267
Wind	0	6,364,058	15,917,254	25,368,821	26,105,739
Network	251,556	876,667	1,925,605	1,486,637	1,955,283
Welfare	**1,162,452,118**	**1,169,471,872**	**1,180,391,354**	**1,194,975,639**	**1,205,093,279**
TRC	120,156	1,010,224	2,032,118	4,018,916	Infeasible
Net welfare	**1,162,331,962**	**1,168,461,647**	**1,178,359,236**	**1,190,956,723**	Infeasible
AVC	0.03	0.31	0.68	1.60	Infeasible
AVC wind		0.29	0.58	1.15	Infeasible
Market Coupling, no priority dispatch, no EU-ETS, no investments (Case 1 + Case 5)					
Surplus	1,079,761,010	1,091,883,870	1,112,476,117	1,137,818,096	1,167,053,989
Profit	82,439,552	70,347,276	50,072,379	30,302,085	9,978,267
Wind	0	6,364,058	15,917,254	25,368,821	26,105,739
Network	251,556	876,667	1,925,605	1,486,637	1,955,283
Welfare	**1,162,452,118**	**1,169,471,872**	**1,180,391,354**	**1,194,975,639**	**1,205,093,279**
TRC	120,156	1,010,224	2,032,118	4,018,149	4,305,735
Net welfare	**1,162,331,962**	**1,168,461,647**	**1,178,359,236**	**1,190,957,491**	**1,200,787,544**
AVC	0.03	0.31	0.68	1.60	2.12
AVC wind		0.29	0.58	1.15	1.24
Market Coupling, priority dispatch, EU-ETS, no investments (Case 2 + Case 4)					
Surplus	1,001,211,249	1,008,668,223	1,012,099,802	1,072,320,375	1,095,601,660
Profit	149,676,921	137,314,211	125,178,356	57,869,565	34,692,665
Wind	0	11,268,710	31,236,075	49,223,841	64,589,213
CO_2 cost	36,516,362	30,817,885	21,576,410	8,776,848	2,182,337
Network	915,625	428,285	247,418	5,168,210	5,969,915
Welfare	**1,115,287,433**	**1,126,861,543**	**1,147,185,242**	**1,175,805,143**	**1,198,671,116**
TRC	232,721	1,123,477	2,783,613	6,454,269	Infeasible
Of which CO_2 cost	510,205	1,179,313	2,161,134	4,903,115	Infeasible
Net welfare	**1,115,054,713**	**1,125,738,066**	**1,144,401,629**	**1,169,350,874**	Infeasible
AVC	0.07	0.35	0.98	2.68	Infeasible
AVC wind		0.34	0.84	1.91	Infeasible
Market Coupling, no priority dispatch, EU-ETS, no investments (Case 2 + Case 6)					
Surplus	1,001,211,249	1,008,668,223	1,012,099,802	1,072,320,375	1,095,601,660
Profit	149,676,921	137,314,211	125,178,356	57,869,565	34,692,665
Wind	0	11,268,710	31,236,075	49,223,841	64,589,213
CO_2 cost	36,516,362	30,817,885	21,576,410	8,776,848	2,182,337
Network	915,625	428,285	247,418	5,168,210	5,969,915
Welfare	**1,115,287,433**	**1,126,861,543**	**1,147,185,242**	**1,175,805,143**	**1,198,671,116**
TRC	232,721	1,123,477	2,783,613	6,454,269	9,944,625
Of which CO_2 cost	510,205	1,179,313	2,161,134	4,903,115	4,036,841
Net welfare	**1,115,054,713**	**1,125,738,066**	**1,144,401,629**	**1,169,350,874**	**1,188,726,491**
AVC	0.07	0.35	0.98	2.68	5.19
AVC wind		0.34	0.84	1.91	2.95

economic situation when there is no market power, no uncertainty and no asymmetry of information (see Section 6 of Oggioni and Smeers, 2013).

7.1. Market Coupling results without investments

Table 8 shows the Market Coupling results in the "contextual cases" without investments. A first and important insight is that the "no priority dispatch" policy significantly affects Market Coupling especially when the level of wind penetration is high. We first elaborate on this point.

7.1.1. Welfare

Net welfare has a different behavior depending on the application of priority dispatch or not. In particular, when the "priority dispatch" policy applies, net welfare increases from the "No wind" case to a maximum in "Wind I2", after which the system collapses in "Wind I3". This collapse is identified by the appearance of "infeasible" in the five last rows of the "Wind I3" column. This constitutes the remarkable difference between Nodal Pricing and Market Coupling architectures: the interpretation is that the Market Coupling system crashes because counter-trading cannot clear the market under the assumptions of "priority dispatch" and high wind penetration. We observe here that, even though the clearing of the day-ahead market does not reveal any problems with wind penetration (net welfare increases with wind penetration before paying for infrastructure), counter-trading becomes very large in "Wind I2" and impossible to complete in "Wind I3". The reason is that the clearing of the day-ahead market is based on day-ahead forecast of wind injections and on average transactions. When combined with real time high-wind injections, the transactions cannot be accommodated by counter-trading. This is true in all "contextual cases" and is the main message of that set of "priority dispatch" cases. This implies that the "Wind I3" column will be "infeasible" in all tables after counter-trading, notwithstanding the apparently good results obtained before counter-trading.

The "no priority dispatch" policy completely changes this picture, especially when moving from "Wind I2" to "Wind I3". The collapse of the Market Coupling system disappears here because the "no priority dispatch" policy reduces the demand on counter-trading by shutting off the wind generation that creates excessive congestion. This is a direct effect of the higher flexibility given to wind plants (see Table 9 for the amount of wind spilled). However, this does not eliminate all congestion, but only congestion that implies a counter-trading cost higher than the value of the energy that it substitutes. Moreover, parallel to observations in Nodal Pricing, wind losses only appear with wind penetration levels "Wind I2" to "Wind I3".

Note that, independently of the priority policy, welfare in the Market Coupling before counter-trading is higher than in Nodal Pricing for the corresponding cases. This is expected as Market Coupling gives here (for the chosen ATC) an optimistic view of the system. In contrast, net welfare is slightly smaller with Market Coupling after counter-trading than in Nodal Pricing for all cases up to "Wind I2", until the system crashes in case "Wind I3" under the "priority dispatch" policy, and in all cases in the "no priority dispatch" policy (compare Tables 3 and 8). This is also expected as Market Coupling is, by definition, less efficient than Nodal Pricing and hence should result in a smaller net welfare.

Table 9
Market Coupling losses in the cases without investments in the CWE market (MW day values).

MW day	No Wind	Wind	Wind I1	Wind I2	Wind I3
Market Coupling, no priority dispatch, no EU-ETS, no investments (Case 1 + Case 5)					
Wind losses	0	0	0	39	2,336
Market Coupling, no priority dispatch, EU-ETS, no investments (Case 2 + Case 6)					
Wind losses	0	0	0	62	3,125

Finally, as already observed in Nodal Pricing, the application of the EU-ETS leads to a reduction of the social welfare due to the CO_2 emission costs (compare the cases with and without EU-ETS in Table 8).

7.1.2. Consumers' surplus

Consumers' surplus before counter-trading always increases with wind penetration. After counter-trading, the trend of the net consumers' surplus differs depending on priority policies. In the "priority dispatch" policy, it remains increasing up to "Wind I2", even if the whole TRC is allocated to consumers; in contrast it cannot be computed in "Wind I3" when counter-trading cannot restore grid feasibility. In practice, this implies curtailing and hence significant welfare losses that depend on curtailment rules. Under the "no priority dispatch" policy, net consumers' surplus increases proportionally with the wind penetration level.

This is true in the all "contextual cases" and, when computable, consumers' surpluses are similar in Market Coupling and Nodal Pricing.

7.1.3. Profits of conventional generators

Profits of conventional generators suffer from the penetration of wind generation whether with and without wind spill (e.g. both in the "priority dispatch" and in the "no priority dispatch"). Profits accruing in the day-ahead market tumble because of lower prices (see Table 27 in Appendix F) and loss of market share. TRC needs then to be allocated between generators and consumers through access charges, which further reduces profits. One (in principle unrealistic but in any case instructive) possibility is to assume that TRC is entirely charged to conventional generators, implying that the profit made by those generators is equal to the one accruing from the day-ahead market minus counter-trading costs. One observes that these net profits are in general lower for Market Coupling than for the nodal system when wind penetration level is high. This reflects the cost of the increasing counter-trading activity that already appears in "Wind I1" (and results in the collapse of the system in "Wind I3").

7.1.4. Wind generators' profits

Wind generators sell in the day-ahead market in Market Coupling but are not penalized for deviating from these announcements in real time, at least in this paper. We assume that wind generators bid their expected generation in the day-ahead market, with the consequence that their revenues steadily increase with their market share. Wind generation is thus entirely shielded from the congestion cost that they induce. This does not mean that this cost disappears but simply that it is paid by other agents whether consumers or conventional generators. Consequently, it is a subsidy that adds to those already given for infrastructure costs. The profits accruing to wind generators from the day-ahead market thus remain unchanged after counter-trading in all "contextual cases" with and without priority dispatch, except possibly in "Wind I3" under the "priority dispatch" policy where the revenue accruing to these units should be determined by the rules that prevail in case of curtailment.

7.1.5. TSO's profits

The TSO collects the rent from saturated ATC that is before counter-trading. As expected, that profit increases with wind. The total redispatching cost is also increasing with wind penetration. As discussed before, the way these costs are redistributed to agents depends on the regulation of counter-trading. We do not make any assumption in this respect and thus only report the total cost of counter-trading without any reallocation.

7.1.6. Additional comments

Market Coupling, at least implemented in a way that shields wind generators from counter-trading costs, is obviously favorable to these generators independently of the priority dispatch policy. It adds a subsidy to operations that comes on top of other subsidies for investments

Table 10
Market Coupling results with investments, 50% cut of lignite and coal existing capacity (daily values).

[€]	No Wind	Wind	Wind I1	Wind I2	Wind I3
Market Coupling, priority dispatch, no EU-ETS, investments (Case 1 + Case 3)					
Surplus	1,055,522,941	1,072,004,698	1,076,943,005	1,120,179,370	1,157,652,666
Profit	94,505,713	80,529,070	76,137,587	38,826,175	13,857,795
Wind	0	7,787,261	21,117,740	31,717,600	30,981,107
Network	1,840,268	163,340	120,637	2,483,409	2,469,514
Welfare	**1,151,868,922**	**1,160,484,369**	**1,174,318,969**	**1,193,206,553**	**1,204,961,083**
TRC	1,055,928	1,259,609	2,375,742	Infeasible	Infeasible
Net welfare	**1,150,812,994**	**1,159,224,761**	**1,171,943,227**	**Infeasible**	**Infeasible**
AVC	0.27	0.36	0.81	Infeasible	Infeasible
AVC wind		0.34	0.70	Infeasible	Infeasible
Market Coupling, no priority dispatch, no EU-ETS, investments (Case 1 + Case 5)					
Surplus	1,055,522,941	1,072,004,698	1,076,943,005	1,120,179,370	1,157,652,666
Profit	94,505,713	80,529,070	76,137,587	38,826,175	13,857,795
Wind	0	7,787,261	21,117,740	31,717,600	30,981,107
Network	1,840,268	163,340	120,637	2,483,409	2,469,514
Welfare	**1,151,868,922**	**1,160,484,369**	**1,174,318,969**	**1,193,206,553**	**1,204,961,083**
TRC	1,055,928	1,259,609	2,375,742	5,976,590	6,998,536
Net welfare	**1,150,812,994**	**1,159,224,761**	**1,171,943,227**	**1,187,229,963**	**1,197,962,548**
AVC	0.27	0.36	0.81	2.43	3.52
AVC wind		0.34	0.70	1.74	2.04
Market Coupling, priority dispatch, EU-ETS, investments (Case 2 + Case 4)					
Surplus	993,427,684	1,001,250,706	1,003,329,303	1,073,036,817	1,092,289,039
Profit	150,922,823	139,490,554	129,969,466	57,113,978	35,659,040
Wind	0	11,937,590	32,912,808	49,112,752	66,702,365
CO_2 cost	32,275,159	27,711,180	20,383,756	8,646,758	2,088,957
Network	1,745,939	919,211	1,173,252	5,215,801	6,158,866
Welfare	**1,113,821,287**	**1,125,886,881**	**1,147,001,073**	**1,175,832,590**	**1,198,720,353**
TRC	1,424,642	1,653,687	3,901,301	Infeasible	Infeasible
Of which CO_2 cost	303,934	1,153,243	2,071,869	Infeasible	Infeasible
Net welfare	**1,112,396,644**	**1,124,233,195**	**1,143,099,771**	**Infeasible**	**Infeasible**
AVC	0.43	0.52	1.41	Infeasible	Infeasible
AVC wind		0.50	1.20	Infeasible	Infeasible
Market Coupling, no priority dispatch, EU-ETS, investments (Case 2 + Case 6)					
Surplus	993,427,684	1,001,250,706	1,003,329,303	1,073,036,817	1,092,289,039
Profit	150,922,823	139,490,554	129,969,466	57,113,978	35,659,040
Wind	0	11,937,590	32,912,808	49,112,752	66,702,365
CO_2 cost	32,275,159	27,711,180	20,383,756	8,646,758	2,088,957
Network	1,745,939	919,211	1,173,252	5,215,801	6,158,866
Welfare	**1,113,821,287**	**1,125,886,881**	**1,147,001,073**	**1,175,832,590**	**1,198,720,353**
TRC	1,424,642	1,653,687	3,901,301	7,535,502	12,386,683
Of which CO_2 cost	303,934	1,153,243	2,071,869	5,621,096	5,563,998
Net welfare	**1,112,396,644**	**1,124,233,195**	**1,143,099,771**	**1,168,297,088**	**1,186,333,670**
AVC	0.43	0.52	1.43	3.20	6.67
AVC wind		0.50	1.22	2.27	3.76

computed on the basis of the levelized cost of wind generation obtained by dividing the annual investment cost by an availability factor. Joskow (2011) shows the fallacy of this average cost computation that however remains in wide practice. Renewable generators imply service costs that add to infrastructure costs; they thus imply both network and service cost. These are often entirely charged to the rest of the system in Market Coupling. In contrast, most of these service costs, in particular congestion costs, are imposed on the generators that cause them in "Nodal Pricing".

Table 11
Investments in Market Coupling no priority dispatch, 50% cut of lignite and coal existing capacity.

MW	No Wind	Wind	Wind I1	Wind I2	Wind I3
Market Coupling, priority dispatch, no priority dispatch, no EU-ETS, investments (Case 1 + Case 3 + Case 5)					
Lignite	2,621	0	0	0	0
Market Coupling, priority dispatch, no priority dispatch, EU-ETS, investments (Case 2 + Case 4 + Case 6)					
Nuclear	7710	5960	1453	0	0
CCGT	727	0	0	0	0
Total	**8,437**	**5,960**	**1,453**	**0**	**0**

7.2. Market Coupling results with investments

Table 10 reports the results of the different "contextual cases" for Market Coupling under the assumption of investment in new capacity. As for Nodal Pricing, the values of the average scarcity rents computed at full existing capacity are lower than the fixed costs of new conventional capacity (as example, compare Tables 28, 29, 30 in Appendix F with Table 1). For this reason, generators invest only when existing capacities are reduced. In order to be in line with the results of the Nodal Pricing system, we still consider a 50% cut of existing lignite and coal capacity.

Table 12
Market Coupling losses in the cases with investments in the CWE market and a 50% cut of lignite and coal existing capacity (daily values in MW).

MW day	No Wind	Wind	Wind I1	Wind I2	Wind I3
Market Coupling, no priority dispatch, no EU-ETS, investments (Case 1 + Case 5)					
Wind losses	0	0	0	368	10,481
Market Coupling, no priority dispatch, EU-ETS, investments (Case 2 + Case 6)					
Wind losses	0	0	0	449	14,069

With investments, results are in line with those already discussed in Section 7.1 and are even exacerbated in the presence of "priority dispatch" because counter-trading infeasibility appears both in "Wind I2" and in "Wind I3" (compare Tables 8 and 10). Again, the "no priority dispatch" policy overcomes this problem by restoring network feasibility through wind spillage (see Table 12).

Table 11 reports investment levels for both the "priority dispatch" and "no priority dispatch" policies, depending on whether one implements the EU-ETS or not. As already observed with Nodal Pricing, generators are again induced to invest only when wind penetration is relatively low. Moreover, they invest in low carbon plants when the EU-ETS applies. More specifically, German investments in lignite are replaced by nuclear (in France) and CCGT plants (see Table 11). This happens only in the "No Wind" case without EU-ETS, generators do not invest in new capacity when there is wind penetration. In the presence of CO_2 regulation, investments in nuclear and CCGT are combined with wind until nuclear penetration is limited by wind capacity. Investments are instead identical with and without priority dispatch policy independently of the EU-ETS application.

8. Other general analysis

This section reports some side issues where contextual cases effectively play a role. We successively consider the problems of emission and investments.

8.1. Emissions

A controversy has been raging in the EU as to whether the EU-ETS provides enough incentives for investment in low carbon capacity. The immediate answer from economic theory is that one should, in principle, apply a single instrument for a given policy and that it is likely to be counter-productive to pursue both an EU-ETS to reduce carbon emissions while at the same time implementing a renewable policy that also reduces those emissions. In any case, the fine tuning of the combination of these policies would be difficult. The results reported here may provide some insight into this question. Comparing corresponding EU-ETS and no EU-ETS cases (that is, cases that differ only in the implementation of the EU-ETS), the EU-ETS effectively reduces emissions when the allowance price is high. Conversely, looking at the cases without EU-ETS the exogenous wind penetration also reduces emissions. Thus the need for the EU-ETS is diminished. This does not question the efficiency of the EU-ETS, as sometimes done today, but raises the question of the relevance of combining a carbon trading system and a renewable policy. Going back to basics, the EU-ETS is meant (in theory) to reduce emissions at least cost. In comparison renewables reduce emissions with no concern for costs.

The numerical results presented here give some quantification to the issue, as we discuss for the simpler case of Nodal Pricing. Table 13 gives the detail of the estimates of the cost of CO_2 reduction by implementing

Table 13
Evaluation of the EU-ETS impact by comparing Nodal Pricing models in the cases of no EU-ETS and with EU-ETS under the assumption of "No Wind", no investments, priority dispatch.

Daily values	No EU-ETS	EU-ETS
	"No Wind"	"No Wind"
Emissions (tons)	1,349,575	926,191
Emission value (€)		37,047,635
Welfare (€)	1,162,333,047	1,115,054,762
Welfare + emissions (€)		1,152,102,397
Welfare loss due to ETS (€)		47,278,285
CO_2 drop due to ETS (tons)		423,384
Welfare variations (€)		10,230,650
EU-ETS impact (€/ton)		**24.16**

Table 14
Evaluation of the wind penetration impact by comparing Nodal Pricing models in the "No wind" and the "Wind I1" under the assumption of no investments, priority dispatch, no EU-ETS.

Daily values	No EU-ETS	No EU-ETS
	"No Wind"	"Wind I1"
Emissions (tons)	1,349,575	1,006,454
Welfare (€)	1,162,333,047	1,179,479,474
Wind infrastructure costs (€)		46,931,195
Welfare-wind (€)		1,132,548,279
Welfare variation due to wind (€)		29,784,768
CO_2 variation due to wind (tons)		343,121
Wind impact (€/ton)		**86.81**

just the EU-ETS. Specifically, one compares the difference of total welfare between the "EU-ETS" and "no EU-ETS" without any wind priority policy. The two cases give different emissions (here reported in physical units). Total welfare with the EU-ETS (1,152,102,397 €) is computed by adding the value of the emissions (37,047,635 €) to the welfare obtained by the model (1,115,054,762 €) since the proceeds of the auctions are recycled in the economy. The difference in welfare with and without EU-ETS (10,230,650 €) is then divided by the reduction of emissions (423,384 tons), giving a cost per ton of reduced CO_2 equal to 24.16 €/ton. As expected the average cost is smaller than the marginal cost set by the allowance price.

Table 14 gives results for the reduction obtained solely with a renewables policy. We compare the outcome of introducing "Wind I1" to the "No Wind" policy in the absence of EU-ETS. In "Wind I1", subtracting the daily wind infrastructure costs (46,931,195 €) from the gain of welfare (1,179,479,474 €) computed by the model, one obtains the net welfare 1,132,548,279 €. Comparing this value with the welfare in the corresponding "No Wind" policy, one calculates the value of the emissions reduction (29,784,768 €) with just a wind policy. Allocating this gain to the reduction of emissions, one obtains a value of 86.81 €/ton which is effectively much higher than the 24.16 €/ton of the sole EU-ETS. These figures are consistent with theory: the EU-ETS is more cost-effective than the wind policy. The subsidized penetration of wind energy hides the effectiveness of the EU-ETS, leading some to misleadingly conclude from the low CO_2 market price that the EU-ETS is a failure: the price is low because the wind policy (and the economic recession) contributes to making it low.

8.2. Investments

The problem of investments in generation capacity in a market system has been the object of considerable attention for several years. The discussion mainly centered on the issue of missing money. The current common wisdom is that wind penetration implies a decreasing share of the market served by conventional generators and a downward pressure of energy prices. The latter effect should in principle decrease the free cash flow accruing to power plants and, hence, the incentive to invest. In other words, wind penetration should exacerbate the missing money phenomenon. This problem is partially mitigated in this paper by our adoption of a demand curve (and hence of a representation of demand response). Demand response is commonly advocated as the best remedy to missing money and this is what happens in our model: any disincentive to invest induces a reduction of capacity, which in turn results in an increase in the price of electricity that partially compensates for the decrease due to wind penetration. A moderate amount of wind penetration will thus not endanger revenue adequacy if its reliability costs are properly charged and transferred to conventional generators or demand side instruments that provide the required reliability. The present model however gives no account of the question of reliability and reserves that result from the penetration of wind energy. Investment figures need thus be looked at with considerable prudence.

9. Conclusions

The paper compares the impacts of a "Nodal Pricing" system and "Market Coupling" under different wind policies on different economic agents in the power system. We provide a context for our analysis by considering cases with given capacities and endogenous investments as well as with and without EU-ETS. These cases are meant to test the robustness of the analysis. The lessons accruing from the work can be summarized as follows. Consider first the "priority dispatch" policy. We observe that Nodal Pricing and Market Coupling evolve in a similar way as long as wind penetration is not too great (up to case "Wind I1"). In contrast, Market Coupling collapses while Nodal Pricing still functions very well, when wind penetration increases. Allowing for wind spilling ("no priority dispatch" policy) removes most of the problems with Market Coupling, which still exhibits a slightly smaller efficiency than Nodal Pricing. Numerical results reveal sharply contrasting patterns in the application of the "priority dispatch" and "no priority dispatch" policies on the Nodal Pricing and the Market Coupling architectures. At the same time, the results do not significantly depend on contextual assumptions (fixed capacities vs investment; EU-ETS vs no EU-ETS). This suggests that our policy conclusion on the preference for a "no priority dispatch" policy in a Market Coupling architecture is probably robust. These effects result from a combination of the imperfect representation of the grid in Market Coupling and the imperfect forecast of wind between day ahead and real time. Appendix G provides some insight into the relative importance of theses phenomena. The most striking result is that the overall results in terms of aggregate welfare are quite similar for Nodal and Market Coupling but that the collapse of Market Coupling in case of high wind disappears when wind can be perfectly forecast. This justifies current discussions for bringing the closing of the intraday market as close as possible to real time. This result is similar to one obtained in our previous works (Oggioni and Smeers, 2012, 2013) under the assumption of what we called "perfectly coordinated counter-trading", that is, counter-trading operated by a single TSO covering the whole area (in contrast with the so-called cooperation of TSOs, referred to as "un-coordinated TSOs" or "imperfectly coordinated" in our papers, that could lead to dramatic losses of efficiency). The second remark is that while the overall welfare is unchanged, the distribution of that welfare among agents can be quite different between the Nodal and the Market Coupling systems because of the allocation of counter-trading costs that are far from small.

Recall that the results are obtained under ideal conditions and that a real European implementation should increase the differences between Nodal Pricing and Market Coupling implementations and the "no priority dispatch" and "priority dispatch" policies. As recalled just above, we assume perfectly coordinated counter-trading in Market Coupling as well as perfect harmonization between the "priority dispatch" and the "no priority dispatch" policies in Europe. Lack of coordination among zonal PXs and TSOs respectively in the day-ahead market and in counter-trading would normally exacerbate the problems of Market Coupling. Stakeholders seem to be more and more aware of that state of affairs but the remedies that are so obvious in principle appear a daunting task in practice. More generally, our simplifying assumptions overestimate the flexibilities of both the nodal and market coupling systems. Conventional plants are much less flexible than assumed here, which should exacerbate the system difficulties discussed here. Here too one would expect that the nodal system, because of its more integrated structure, will be more effective in dealing with inflexibilities. An extension of this study to account for real equipment characteristics is doable but far from trivial because of the idiosyncrasies of Market Coupling.

Appendix A. Supplementary data

Supplementary data to this article can be found online at http://dx.doi.org/10.1016/j.eneco.2013.12.009.

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